Georgia Power Company 2022 Integrated Resource Plan

Unofficial Transcript of **Day One** Hearings (April 4, 2022)

Including GPC Expert Witness Panel No. 1

(Direct Testimony of Jeffrey R. Grubb, A. Wilson Mallard, Michael B. Robinson, and Jeffrey B. Weathers)

and intervenor cross examination

Transcript is synchronized with the YouTube video below, by timestamp:

https://www.youtube.com/watch?v=TpRsTlcIViY

Total time of day one recording is 11 hours 16 minutes (approx. 9:30 am – 8:46 pm)

Transcript

Tricia Pridemore (PSC): [00:00:19] All right. We'll get started in about one minute. Okay. Good morning. How's everybody doing on this fine sunny Monday morning? Okay. All right. This is docket number 44160 Georgia Power Company's 2022 application for approval of its Integrated Resource Plan. Call for appearances.

Daniel Walsh (PIA): [00:03:01] Thank you, Madam Chair. On behalf of the public interest advocacy staff, I'm Daniel Walsh. I'm with the Attorney General's Office. And with me this morning, Preston Thomas and Alex Davis with the Public Service Commission. Thank you.

Tricia Pridemore (PSC): [00:03:14] Thank you, Mr. Walsh. Georgia Power Company.

Steve Hewitson (GPC): [00:03:18] Good morning. On behalf of Georgia Power Company, Allison Pryor, Brandon Marzo and Steve Hewitson.

Tricia Pridemore (PSC): [00:03:24] Thank you, Mr. Hewitson. Americans for Affordable Clean Energy.

Newton Galloway (AACE): [00:03:29] Madam Chair, Newton Galloway on behalf of AACE.

Tricia Pridemore (PSC): [00:03:36] Galloway on behalf of AACE, present. Commercial group.

Alan Jenkins (CG): [00:03:40] Thank you, Madam Chair. Alan Jenkins for the commercial group. Good morning.

Tricia Pridemore (PSC): [00:03:45] Good morning. Thank you, Mr. Jenkins. Concerned Ratepayers of Georgia.

Steven Prenovitz (CRG): [00:03:50] Morning, Madam Chairman. Benjamin J. Stockton. Steven C Prenovitz for Concerned Ratepayers of Georgia.

Tricia Pridemore (PSC): [00:03:57] Thank you, Mr. Prenovitz. You can now mute your line. Thank you. I'll let you know when to unmute. Thank you. Cypress Creek Renewables LLC.

Cypress Creek: [00:04:07] Good morning, Madam Chair

Tricia Pridemore (PSC): [00:04:12] Georgia Association of Manufacturers.

Clay Jones (GAM): [00:04:14] Clay Jones for GAM.

Tricia Pridemore (PSC): [00:04:16] Thank you. Georgia Center for Energy Solutions.

Peter Hubbard (GCES): [00:04:21] Good morning, Madam Chair, Peter Hubbard for Georgia Center for Energy Solutions.

Tricia Pridemore (PSC): [00:04:25] Thank you, Mr. Hubbard. Georgia Coalition of Local Governments.

John Seydel (GCLG): [00:04:30] John Seydel, City of Atlanta [and others].

Tricia Pridemore (PSC): [00:04:34] Mr. Seydel, as the signer of the application, now would probably be a good time for you to give us the list of the local governments that are intervening.

John Seydel (GCLG): [00:04:49] Yes, absolutely. Do you want me to come up?

Tricia Pridemore (PSC): [00:04:50] Sure. That'd be great. That way everybody can hear you.

John Seydel (GCLG): [00:04:57] So the list right now as we have it just does not include Fulton County. So it's DeKalb County. It's the city of Atlanta. City of Decatur. Athens-Clarke County and City of Savannah.

Tricia Pridemore (PSC): [00:05:14] Okay. So five.

John Seydel (GCLG): [00:05:15] That's right.

Tricia Pridemore (PSC): [00:05:16] All right. Thank you. Georgia Interfaith Power and Light and Partnership for Southern Equity.

Jill Kysor (GIPL-PSE): [00:05:19] Good morning, Commissioners. Jill Kysor. And I'm also here with Nicha Rakpanichmanee and Munashe Magarira. Thanks.

Tricia Pridemore (PSC): [00:05:30] Thank you, Mr. Kysor. Georgia large scale solar association and advanced power alliance.

Brad Carver (GLSSA-APA): [00:05:39] Morning Madam Chair, fellow commissioners. Brad Carver from Hall B Smith on behalf of Georgia large scale Solar Association and Advanced Power Alliance.

Tricia Pridemore (PSC): [00:05:48] Thank you, Mr. Carver. Georgia Solar Energy Industry Association. Solar Energy Industry Association, and Vote Solar.

Scott Thomasson (GA SEIA): [00:05:59] Morning Madam Chair and Commissioners. Scott Thomasson on behalf of Georgia SEIA and SEIA. And I'm here with my co-counsel, Katie Ottenweller from Vote Solar.

Tricia Pridemore (PSC): [00:06:07] Thank you, Mr. Thomasson. Georgia Solar Energy Association. Otherwise listed here is GA Solar. Not present, Georgia Watch.

Liz Coyle (GW): [00:06:25] Good morning, commissioners. Liz Coyle for Georgia Watch. Thank you, Ms. Coyle. Interstate gas supply.

Brad Carver (GLSSA-APA): [00:06:37] Brad Carver and Adam Wise on behalf of interstate gas supply.

Tricia Pridemore (PSC): [00:06:43] Mr. Wise is not listed on my appearance list, so check in with the Executive Secretary's office, please. Thank you. Resource Supply Management. Not present. Restore Chattooga Gorge Coalition.

Stephen Jones (RCGC): [00:07:03] Madam Chair. Stephen Jones on behalf of the Coalition which makes up Chattooga Conservancy, Georgia Canoeing Association, Natural Land Trust, and Upstate Forever.

Tricia Pridemore (PSC): [00:07:18] Are those other organizations listed on your application? [Yes, ma'am.] Okay. Thank you, Mr. Jones. Sierra Club.

Zach Fabish (SC): [00:07:31] Morning, Madam Chair. Zach Fabish and my co-counsel, Isabella Ariza, on behalf of the Sierra Club.

Tricia Pridemore (PSC): [00:07:41] Southern Alliance for Clean Energy and South Face Energy Institute.

Robert Baker (SACE-SF): [00:07:45] Madam Chairman. Robert Baker, on behalf of... We have a slight change to the names. We are All American Southern Alliance for Clean Energy and Triple A Southface.

Tricia Pridemore (PSC): [00:08:08] I appreciate your passion, Mr. Baker, and I certainly appreciate your phone book application to this process. But no, it's as filed.

Tricia Pridemore (PSC): [00:08:21] Mr. Baker, Mr. Jacob and Ms. Southworth, OK. Southern Renewable Energy Association.

Simon Mahan (SREA): [00:08:28] Good morning. This is Simon Mahan with the Southern Renewable Energy Association.

Tricia Pridemore (PSC): [00:08:35] OK. All right. That should be everybody, anybody that has been missed. Speak now. Okay, good. All right. Any housekeeping matters to come before us before we begin?

Bubba McDonald (PSC): [00:08:46] Madam Chair?

Tricia Pridemore (PSC): [00:08:47] Yes, Commissioner.

Bubba McDonald (PSC): [00:08:51] Old school folks. We've got a lot of interveners. If you hear the question to ask, don't ask it again. We're not going to just keep repeating and repeat and repeat the same question over and over. Got it.

Tricia Pridemore (PSC): [00:09:10] To reiterate, Commissioner McDonald, I have a couple of housekeeping matters, and one of which is if your question has been asked, please don't ask it again. We are in for a long day. We've got three days of hearings just to kick us off on this docket. So I appreciate everybody being kind and considerate of everybody else's time. Everybody is going to get their moment in the sun. But please don't duplicate questions. Today prepare for a long one. Not only are we here doing this, but our friends across the street are having Sine Die. So we'll have time for lunch. We'll have some breaks. I'll try to do it with consultation from across the street so that we're not all at the cafeteria at the same time. But please be mindful of the fact that Capitol Hill is crowded today. But we are in for a long one. All public comments that have been submitted are put in the record and have been sent to commissioners. Thank you all for submitting public comments at our public forum as well as those who have submitted electronically and via phone. All right.

Tricia Pridemore (PSC): [00:10:13] With that. Mr. Hewitson, would you like to swear in your witnesses?

Steve Hewitson (GPC): [00:10:22] Thank you, Madam Chair. Again, Steve Hewitson on behalf of Georgia Power Company. At this time, I'd like to call Georgia Power's first panel of witnesses on direct. Mr. Grubb, Mr. Mallard, Mr. Robinson and Mr. Weathers. I'll note for the record that we have filed the notice of publication as required by the Commission's rules. Gentlemen, please raise your right hands. Do you swear to tell the truth, the whole truth, and nothing but the truth, so help you God? [Yes.] Mr. Grubb, Would you please start us off by stating your full name, your employer, and your responsibilities for the record?

Jeffrey Grubb (GPC): [00:10:49] Yes, my name is Jeffrey Grubb. I'm the director of resource policy and planning at Georgia Power Company, where I'm able to fortunate enough to lead the group that works on capacity RFPs, PPA administration and then also importantly the development of the Integrated Resource Plan.

Steve Hewitson (GPC): [00:11:09] Mr. Mallard Would you do the same?

Wilson Mallard (GPC): [00:11:11] Hi, I'm Andrew Wilson Mallard. I'm the director of renewable development at Georgia Power, and I lead the group that's responsible for all of Georgia Power's procurements and renewable programs.

Steve Hewitson (GPC): [00:11:22] And Mr. Robinson, would you do the same?

Michael Robinson (GPC): [00:11:25] Morning. Michael B Robinson. I am Vice President of Planning Operations and Policy for our power delivery team. So my team that I lead is a team that has plans and operates the transmission grid for the state of Georgia, as well as our distribution facilities throughout the state. [And Mr. Weathers.]

Jeffrey Weathers (GPC): [00:11:43] Good morning, Commissioners. My name is Jeffrey Weathers. I'm the resource planning manager for Southern Company Services. And in my role, I support Georgia Power and our other retail operating companies and all of their integrated resource planning activities.

Steve Hewitson (GPC): [00:11:55] Thank you, gentlemen. Mr. Grubb, on January 31st of this year, did Georgia Power file its integrated resource plan, also known as the IRP. [Yes.] On April 1st, did you file or cause to be filed an errata to Georgia Power Companies IRP file? [Yes.] Chair Pridemore, for the record, I would like to identify Georgia Power Companies 2022 Integrated Resource Plan, as amended, as Exhibit GPC 1/PD and GPC 1/TS the Public Disclosure and Trade Secret versions.

Tricia Pridemore (PSC): [00:12:24] So moved.

Steve Hewitson (GPC): [00:12:25] Commission staff and all parties who have executed confidentiality agreements have access to the trade secret versions and, Chair Pridemore, I would also move that Georgia Power Exhibits 1/PD and 1/TS be moved into the record subject to cross-examination, of course.

Tricia Pridemore (PSC): [00:12:40] So moved.

Steve Hewitson (GPC): [00:12:41] Mr. Grubb on March 11th of this year did you pre-file or cause to be pre-filed 59 pages of direct testimony in question and answer format in this case. [Yes, I did.] Are there any corrections you need to make to your pre filed testimony?

Jeffrey Grubb (GPC): [00:12:52] Yes, there is one on page 26 of Panel One's testimony on lines 13 to 14, the phrase "to seek SLR approval" should be deleted.

Steve Hewitson (GPC): [00:13:09] Subject to that correction. If I were to ask you the same questions today under oath, would your answers be the same as our set forth in your pre filed testimony? [Yes, they would.]

Steve Hewitson (GPC): [00:13:18] Madam Chair, the Court Reporter has been provided a copy of the pre-filed test, direct testimony. And I now ask that the direct testimony of this panel be copied into the record as if given here today with Mr. Grubbs' correction. [So moved.] And with your permission, I'd like for Mr. Grubb to summarize the pre-filed testimony of this panel. [Go ahead.]

Jeffrey Grubb (GPC): [00:13:38] Good morning, Commissioners. Georgia Power's 2022 IRP offers a comprehensive plan with a balanced portfolio of energy resources to provide customers with clean, safe, reliable and affordable electric service for years to come, even as customer preferences, society's energy needs, technology and the energy landscape continue to evolve. Taking steps to effectively transform its generation fleet, prepare for the retirement of its coal fired generation resources, integrate greater amounts of renewable resources, and invest in its transmission system. The company has been focused on many challenging issues since the 2019 IRP and the 2022 IRP presents a long term plan that is in the best interests of customers. Reliability, continued environmental pressures, the continued transition of the generation fleet, technology developments, and the changing needs of many customers are just some of the issues that this IRP addresses. Specifically, we're here today to present and seek approval of Georgia Power's 2022 IRP, including each of the specific items listed in Chapter 1 and the action plan included in Chapter 19 of the IRP main document. The company also seeks Commission's approval of the application for decertification of nine coal or steam units and three oil-fired combustion turbines. The application for certification of the PPA from six existing gas facilities resulting from the successful 2022-2028 capacity IRP and the application for certification of capacity from blocks 2-4 and blocks five and six. The IRP appropriately considers increasing policy and regulatory pressure related to carbon and environmental standards and the significant increase in customer expectations for renewable and other low or no carbon solutions. It is no longer economic in the long term to operate the company's coal units, given the increasing pressures from existing and future environmental requirements and the current availability of more economical replacement capacity. The success of the capacity RFP delivers value for customers in support of the fleet transition. The company has laid out a strategic retirement plan to allow to responsibly transition its coal fleet without sacrificing reliability for customers. The company proposes to continue its measured and steady approach and growth of renewable resources by adding 2,300 megawatts of renewable resources to be online by 2029 with a plan to achieve 6,000 megawatts by 2035. The company intends to leverage the benefits of renewables in a way that integrates these resources in an economic and reliable manner facilitated by the following three items. Number one, the addition of 1,000 megawatts of company owned storage by 2030. Number two, greater operational control of the renewable resources. And three, transmission system enhancements. The company also proposes to expand its innovative renewable programs to meet increasing customer needs for more options to support renewable energy. The company proposes to invest in the transmission system through its ten year plan and to accommodate the fleet transition in support of coal, unit retirements and renewable resource integration. The company will also continue to invest in hydro fleet, seek to renew its nuclear licenses with the Nuclear Regulatory Commission for Plant Hatch units 1&2 and to invest in technology demonstration projects and do all of this for the benefit of customers. The company is also introducing the application of distributed energy resources, also known as DER, for grid resilience and greater reliability through the DER customer program, as well as seeking to better understand DER as potential distribution and transmission solutions.

Jeffrey Grubb (GPC): [00:17:57] The 2022 IRP demonstrates the company's continued focus on reliability, with the adoption of a winter target reserve margin and a continued focus on seasonal planning. The importance of seasonal planning has been reinforced by the reliability events seen across the country since the 2019 IRP. The company is also including strategic initiatives like the North Georgia Reliability and Resilience Plan, which incorporates near-term actions and long term planning across many disciplines to solve transmission constraints and meet future generation needs. Our panel's testimony will cover the company's supply side plan and supporting analyses, proposed decertification and certification requests, expansion of renewable resources, the Energy Storage Proposal, and the transmission plan. The panel of Francisco Valle, Andy Phillips, Jeffrey Smith and Lee Evans will provide the Commission additional information on the company's load and energy forecast, DSM application and proposed DER customer programs. The panel of Mark Berry and Aaron Mitchell will provide additional information on the company's environmental compliance strategy, carbon pressures facing the generation fleet, and research and development initiatives. As you can tell from our filing in this IRP, the company addresses many opportunities and challenges facing the electric utility industry today. Through the 2022 IRP process, the company will continue to work constructively with this commission to invest in Georgia's energy future, to provide energy industry leading energy solutions that will benefit customers and Georgia's communities for many years to come. Thank you.

Steve Hewitson (GPC): [00:19:44] Thank you, Mr. Grubb. Madam Chair, the panel is available for questions from the Commission, as well as cross-examination.

Tricia Pridemore (PSC): [00:19:50] Thank you, Mr. Hewitson. Any commissioners have questions for the questions for the panel to get us started? If not, I'm sure there will be several as the day goes on. So with that, Georgia Public Service Commission.

Daniel Walsh (PIA): [00:20:18] Thank you very much. Gentlemen, my name is Dan Walsh, and I'm representing public interest advocacy staff. I'm going to be addressing the questions generally to the panel. And whichever one of you would be best suited to answer can go ahead and answer. As part of this integrated resource plan, the company is proposing to retire coal units, acquire purchase power agreements, and adds solar and battery resources. Is that correct?

Jeffrey Grubb (GPC): [00:20:47] That's correct.

Daniel Walsh (PIA): [00:20:49] Is it also correct that the analysis to retire coal units was done independently from other analyses, such as to evaluate the addition of the 6,000 megawatts of solar and to acquire battery resources.

Jeffrey Grubb (GPC): [00:21:04] So in general, yes, commissioners, every model and every process has a specific focus, and there's a sequential nature to what we do. But the unit requirement studies for the coal fleet took into account the impacts and information that we had to do that the process is the same as we've done in prior years. And so each analysis by its nature takes a different time, uses different models. And so we have done that appropriately here in the case, and we've laid that out. So the coal unit retirements are absolutely based on the cost for continuing those coal units and the RFP resources that we have available in the RFP.

Jeffrey Weathers (GPC): [00:21:47] And just to further explain that the analyses are really not independent when you think about the retirement studies uses the outputs of our base IRP analysis so that they're intrinsically tied together because they're using the same information. But it is a different analysis. It's not done in one single optimization. It is a separate analysis.

Daniel Walsh (PIA): [00:22:09] Are you familiar with the term joint optimization?

Jeffrey Weathers (GPC): [00:22:15] You may have to give me your definition, I've heard of the term, but what do you mean by that?

Daniel Walsh (PIA): [00:22:22] Well, let me ask you whether this is your understanding. Is your understanding of the term "joint optimization" that it refers to, where the determination of what resources would be part of the least cost reliable system is made by evaluating all of the resources together. Is that true? Is that consistent with your understanding?

Jeffrey Weathers (GPC): [00:22:41] That's fine. I will accept that definition.

Daniel Walsh (PIA): [00:22:43] Okay. And I understand, I think, what your response was to my prior question. But just to put a point on it, would you agree that the company did not do joint optimization in its evaluation of resources here?

Jeffrey Weathers (GPC): [00:22:59] Well, if you mean specifically, I think it's what you mean. Do we evaluate the coal retirements in the same optimization that we did our resource mix? Is that what you mean?

Daniel Walsh (PIA): [00:23:08] That is what I mean.

Jeffrey Weathers (GPC): [00:23:09] We did not do that. And so, again, we're looking, it's really a two step process. But the unit retirement study is a very robust analysis. It uses outputs from the resource mix process, in particular the avoided energy costs. And it performs an evaluation in a model, but it is a separate process. It captures things that we're not able to fully capture in our resource mix modeling, such as the transmission cost, such as a number of other factors. We capture those in our retirement study, but those are not all inputs to the single optimization model.

Daniel Walsh (PIA): [00:23:51] And I'm not here this morning to debate which is the better method because I'm not capable of doing that. But can you say with certainty that the results of your evaluations would be the same had you conducted analysis using joint optimization, As we've discussed this morning, under the understanding of that term, as we've discussed this morning?

Jeffrey Weathers (GPC): [00:24:11] We have not conducted that analysis either. But it's my belief that they would be the same. I think the economics that we got from the studies are pretty compelling. We actually use the avoided energy cost from the resource mix process and we have for a long time use the avoided energy cost outputs as essentially a good proxy for running the whole analysis back through the optimization models.

Daniel Walsh (PIA): [00:24:38] So it is your belief, but you can't say it with certainty because you didn't do that analysis, correct?

Jeffrey Weathers (GPC): [00:24:43] That is correct.

Jeffrey Grubb (GPC): [00:24:44] But the important thing is the unit retirement studies that we've done here in this IRP are the same as we've done in prior IRPs in terms of looking at what is the value of keeping those coal units and the cost of keeping those coal units versus your replacement options? We have the capacity RFP resources that we've incorporated in this IRP, but otherwise the processes we followed are very robust analysis. They allow us to study what we need to to come up with those recommendations.

Daniel Walsh (PIA): [00:25:12] I'd like to move now to additional sum. When the company builds new generation resources, the company gets to charge customers for return on equity component associated with that new resource, isn't that correct?

Jeffrey Grubb (GPC): [00:25:27] That's correct. It goes into revenue requirements for the Rate Case.

Daniel Walsh (PIA): [00:25:32] And when the company purchases capacity and energy through a purchase power agreement, it doesn't recover a return on equity component, but it does seek to charge customers for an additional sum component. Is that correct?

Jeffrey Grubb (GPC): [00:25:47] As allowed by order, that's correct.

Daniel Walsh (PIA): [00:25:50] And when a generating unit is analyzed and an expansion plan optimization analysis and units such as a combustion turbine or combined cycle are evaluated, the return on equity component is included in that economic analysis. Isn't that correct?

Jeffrey Grubb (GPC): [00:26:09] You're asking about which type of analysis, a build?

Daniel Walsh (PIA): [00:26:13] A generating unit. Or are you, is there a difference if you're doing a self build generating unit and that's analyzed in an expansion plan optimization, with the return on equity component be included in the economic analysis?

Jeffrey Grubb (GPC): [00:26:28] For an expansion plan. Is your specific question is? Yes.

Jeffrey Weathers (GPC): [00:26:31] Yes, yes. If we're looking at a generic expansion plan in our resource mix study, we're looking at the revenue requirements associated with the generic unit. So it would include that.

Jeffrey Grubb (GPC): [00:26:41] And Commissioners, that's how we do our expansion plan, is we we obviously include any planned committed resources we have under PPA. But when you're talking about a 30 year plan, on which resources may be there, we don't know the PPA cost. So we we'll build and model that generic company proposal. Then when you do RFP is when you truly figure out what would a PPA offer so that we've same way we've been doing that for years.

Daniel Walsh (PIA): [00:27:11] May I approach the witness panel?

Tricia Pridemore (PSC): [00:27:14] Yes.

Daniel Walsh (PIA): [00:27:20] I've distributed the company's response to STF-JKA-3-2. And I'd ask that this response be marked for identification as staff Exhibit one. I'll give you a moment to take a look at that, but let me know when you're ready.

Jeffrey Grubb (GPC): [00:27:50] Yeah. We're ready. Okay.

Daniel Walsh (PIA): [00:27:56] Does this response indicate that the additional sum was not included in the cost of the RFP portfolio within the retirement study?

Jeffrey Grubb (GPC): [00:28:04] Yeah, that's correct. And Commissioners, from the company standpoint, when you're talking about retiring your coal unit and replacing it with an RFP, the additional sum should not drive that decision. As a matter of fact, we're not even sure what the additional sum will end up being. We've proposed one, but it's always a point of contention in the case and where you finally settle there. So to presume an additional sum and factor it into unit retirement study is not what should drive that decision. That decision should be driven by, again, the cost of staying in that coal unit, the benefits of that unit compared to your replacement capacity. So we did not include it. Not sure if it would have changed the results, but at the end of the day, the additional sum is a consideration for once we decided to retire the unit and determine which PPA would be certified.

Daniel Walsh (PIA): [00:28:49] So if the company...

Tim Echols (PSC): [00:28:51] Can you hang on just a second on this on this topic? On the finances of Bowen. So let me first ask you, how important is Bowen to North Georgia reliability right now?

Jeffrey Grubb (GPC): [00:29:05] So I'll let Mr. Robinson out here. But it is important, Commissioner. All four units, which is why our retirement of Bowen 1&2 is timed upon completing some transmission projects. Bowen 3&4, as we've stated, we cannot accommodate the transmission projects by the time we need to put ELG [Effluent Limitation Guidelines from coal combustion] controls. But we know for the future retirement of Bowen, we would need to build some transmission. So it is important the timing of our Bowen 1&2 decision is around making sure we ensure that reliability.

Tim Echols (PSC): [00:29:34] So Unit 2 that you're proposing to close at the end of 2028, didn't Unit 2 receive a new capital G generator after the fire and accident there?

Jeffrey Grubb (GPC): [00:29:45] Commissioner, it did. I don't believe it was brand new in terms of built in that year. I think it was the same vintage as the other one. But as far as I don't believe it had been in service anywhere until that time.

Michael Robinson (GPC): [00:29:56] That is correct. That unit was in storage for that period of time, the same vintage as the original unit. So it was in storage for like 40 years or so.

Tim Echols (PSC): [00:30:04] And how many years of life do you think is left on that capital G generator on Unit 2?

Michael Robinson (GPC): [00:30:08] I can't speak to that.

Tim Echols (PSC): [00:30:11] One or ten or 20. Can you give me a ballpark?

Michael Robinson (GPC): [00:30:17] As a transmission expert, I can't speculate on generation.

Jeffrey Grubb (GPC): [00:30:17] I think Commissioner, it will depend on, obviously, what you invest in the unit. And so the fact that that unit was put into service in 2013, we don't take that into account in terms of looking forward at the incremental cost of building one or two or Bowen 1&2. So our recommendation is really not based on the age or the condition of that unit. It's based on the ability to replace it with more cost effective replacement generation and then also avoid future environmental risk.

Tim Echols (PSC): [00:30:48] Is it true that if you left Unit 2 operational to 2035, the same life that you're planning on for 3&4, that you could use the same scrubber wastewater system that you are going to be spending money on for all three of the units. And that that additional expense isn't just for 3&4, it could be used at no additional cost for 2. Is that correct?

Jeffrey Grubb (GPC): [00:31:13] Yes, Commissioner, that's correct. So the ELG treatment is more for a plant wide application, regardless of the number of units. And our economics for Bowen 1&2 have reflected that you don't avoid that cost. So only if you retire the entire plant do you avoid that cost. So you're right, it's not an incremental cost to Bowen 1&2. We did include that in our economics.

Tim Echols (PSC): [00:31:36] And part of your rationale for closing Units 1&2 is that you've delayed O&M on those units because of our decision from 2019. Is that correct?

Jeffrey Grubb (GPC): [00:31:47] That alone isn't the driver for retiring, the retirement recommendation. Our point there is if you don't retire those units, we would have to go spend some more money on it. We do know that if we have a set date on any of our coal units, that we can control the cost from a budgeting standpoint that way. The point there was we recognized that it was pressured and that we would need to revisit that decision in the 2022 IRP, which is exactly what we're doing. So it's not that we, that's not the only driver. The real driver is you've got an opportunity in the capacity RFP to take advantage of some really, really good prices. And it's really more around that future risk of, of, of coal. We just don't see a lot of positives in the future for the coal fleet. And so this ELG timing gives us an opportunity to transition out of these units.

Tim Echols (PSC): [00:32:35] There's two more quick questions. How much money, ballpark, would be needed to bring [Bowen] Unit 2 up to spec? Do you have any idea?

Jeffrey Grubb (GPC): [00:32:43] We would have those in the unit retirement studies, Commissioner, for the 30 year continued operate that we studied. I don't have them off the top of my head here. Again, there's the O&M and there's also the capital. And the spending order out of 2019 was really on the capital side. So if we were going to keep those units to 2035 or so, we would have to put some more money in them. So the unit retirement study has an estimate on that. I just don't know.

Tim Echols (PSC): [00:33:06] And finally, just because you hypothetically kept Unit 2 operational until 2035, it doesn't mean that you actually have to use it every day and actually burn coal there, correct?

Jeffrey Grubb (GPC): [00:33:20] Correct? Yes, sir. So, I mean, the coal units actually haven't been running a lot over the last few years, which is some of the reasons they've got some pressure on them. So I'll let Mr. Robinson speak from a transmission standpoint. There could be cases where we would need to run them for transmission as we continue to do the work. But yes, you do not have to run it every day. That's one of the things we try to factor in to those O&M budgets. I think the important thing from us, from a coal standpoint is transmission. And building that transmission is really what gives us the option for future rules, not to have to lock into those. If we don't build transmission, we keep them, another rule comes, we may not have any options. And so if you do keep it, the transmission point is still very important.

Michael Robinson (GPC): [00:34:04] Yes, Commissioner, as we build that transmission, we take outages on the system to make improvements, it is going to become important that we do run those units for reliability. And that's one of the reasons Bowen 3&4, the dates that we're proposing, we're looking forward to for those, I'd say one of the things that we are interested in looking at, we've talked to our generation partners about this, is the potential conversion of these units to synchronous condensers. So that's where you strip the boiler away and you keep the turbine, the generator, the exciter, and you use it for voltage support. And so it becomes basically a transmission asset that you can use. Other utilities throughout the United States have been successful in converting large units like those to synchronous condensers. And we have been talking to our generation partners about potential of that conversion. [Thank you.]

Tricia Pridemore (PSC): [00:34:51] To follow up on that. Mr. Robinson. So when you say convert them to synchronous...Say that again.

Michael Robinson (GPC): [00:34:58] Synchronous condenser.

Tricia Pridemore (PSC): [00:34:59] Synchronous condensers. All right. That's a new one. Is that, are you talking about Bowen Units 1&2 or 3&4?

Michael Robinson (GPC): [00:35:12] We'd be interested in, if we retired Bowen 1&2 first, the 1&2 units to convert those, particularly though and [Unit] 1 since it's on the 230 KV system, closer to load.

Jeffrey Grubb (GPC): [00:35:22] And Commissioner, those are part of the things we'll look at for that North Georgia Reliability & Resilience plan. Because we know we'll need to retire Bowen 3&4 at some point. We're planning on that. That's that next step, is what do you do in North Georgia. And those are the types of things that we'll look at on Bowen 1&2. If they're retired, if they are converted to that way, then they aren't, Commissioner Echols, to our discussion, they aren't normally in economic dispatch, they're not a capacity resource. And so from the planning side, you still have to replace it. But from a power delivery side, it's got some transmission.

Michael Robinson (GPC): [00:35:56] The transmission operators, Commissioners, would have that unit to call upon to provide reactive support, whether it's positive or negative, to help with voltage in the North Georgia area.

Tricia Pridemore (PSC): [00:36:07] Okay. Mr. Grubb, you mentioned ELG. Why don't we go ahead and define that acronym for those who don't know what it is and where it came from?

Jeffrey Grubb (GPC): [00:36:14] Yes, ma'am. Effluent Limitations Guideline. So it's basically the treatment of all the wastewater on the plant sites. For any more details, panel three can help you. They're a lot more versed on that than I am. But yes, it's wastewater treatment from the scrubbers is really what we're looking at.

Tricia Pridemore (PSC): [00:36:30] Who provided that ELG guidance to the state?

Jeffrey Grubb (GPC): [00:36:34] To the state? So that is a federal rule that we apply through working with the EPD in Georgia. But is a federal rule.

Tricia Pridemore (PSC): [00:36:42] Out of the federal EPA? Yes, ma'am.

Jeffrey Grubb (GPC): [00:36:44] That is my understanding.

Tricia Pridemore (PSC): [00:36:46] All right. Thank you, Mr. Walsh, go ahead.

Daniel Walsh (PIA): [00:36:51] Thank you. Let me finish up discussing on the additional sum. You mentioned that the additional sum is sometimes a disputed issue during these proceedings. But if the company is awarded an additional sum in association with the purchase power agreements, then that will be a cost recovered from ratepayers that will not have been included in the economic analysis. Is that fair?

Jeffrey Grubb (GPC): [00:37:17] That's correct. I don't think it would change our recommendations. And again, you don't know exactly what that value is. We haven't put that in there. But yes, once you are granted the additional sum, it is a cost to customers.

Daniel Walsh (PIA): [00:37:30] You don't know what the value is, but the company has been awarded additional sums previously. Correct?

Jeffrey Grubb (GPC): [00:37:36] On capacity RFPs? Yes, they have.

Daniel Walsh (PIA): [00:37:39] And the decision of whether to include or exclude an additional sum from the modeling analysis could potentially affect the comparison of a combustion turbine with a power purchase agreement or of a combined cycle purchase power agreement, correct?

Jeffrey Weathers (GPC): [00:37:57] Well, I wouldn't say that would be appropriate because really, in the unit retirement studies, what we're looking to do is to evaluate all of the incremental cost and benefits of whatever resource we're looking at. So a coal unit versus the incremental cost benefits of a replacement unit. And so once the additional sum is decided upon, then that's not a, that's a known cost. So that's a cost that you know what it is, is going to occur. The occurrence of that cause won't be dependent upon the retirement of the unit. And so we're looking at costs that are affected by the retirement or the continuation of the operation of the unit.

Daniel Walsh (PIA): [00:38:37] So I understand that your testimony is then that it would be inappropriate to include it. But the question of whether to include it or not could impact the analysis, correct?

Jeffrey Grubb (GPC): [00:38:52] It could. I mean, it's a cost that you're putting in there. I don't know that it changes any of our recommendations. I don't think it would. Commissioners, we're looking at a 30 year study on the unit retirement study. The PPA terms are for ten years or so. You've got a lot more moving pieces in there. So is it a cost that customers pay? Yes, but it's really one that's determined after you've made the retirement decision and looked at what are you going to replace it with.

Daniel Walsh (PIA): [00:39:19] For renewables, how is the company proposing to calculate the additional sum?

Wilson Mallard (GPC): [00:39:25] So for renewable PPAs, the company is proposing a change in the way that we calculate the additional sum. In RFPs past, the additional sum has been calculated based on shared savings and specifically an 8.5% portion of the savings. What we're proposing going forward is to convert those numbers into a more simple dollar per KW amount. So really what we did, Commissioners, is take a look at the average from the last four renewable solicitations based on that 8.5 and then just converted that into $1 per KW, the resulting amount is $7.50 per KW.

Daniel Walsh (PIA): [00:40:01] And is that the same additional sum calculation that the company is requesting in connection with distributed generation projects?

Wilson Mallard (GPC): [00:40:10] Yes, the calculation would be the same for utility scale and for distributed generation.

Daniel Walsh (PIA): [00:40:15] And the Commission has not previously authorized an additional sum for distributed generation projects, correct?

Wilson Mallard (GPC): [00:40:20] One has never been awarded through a certification process. However, the stipulation, the ordering language in the last IRP, did call for additional sum for distributed generation RFPs.

Daniel Walsh (PIA): [00:40:35] And while the IRP Act [stipulation] references an additional sum, it does not dictate how much of an additional sum the Commission should award, correct? [Correct.]

Tim Echols (PSC): [00:40:45] A question for Mr. Mallard. Would that additional sum be applied towards homeowners who were net metering or would it just be on those RFPs?

Wilson Mallard (GPC): [00:41:04] Just the competitive RFPs, Commissioner, just the RFP through which we run a competitive solicitation, utility scale and distributed generation RFPs.

Tim Echols (PSC): [00:41:10] And would it be retroactive or just beginning with future RFPs going forward?

Wilson Mallard (GPC): [00:41:16] The new methodology is proposed for the future RFPs going forward to procure the energy from the 2,300 megawatts as we proposed.

Tim Echols (PSC): [00:41:23] Have you considered requesting an additional sum for net metering and expanding the net metering program?

Wilson Mallard (GPC): [00:41:32] We certainly considered expanding the net metering program, collecting an additional sum. I don't know that I've given that much thought. You would really need a long term purchase power agreement to lock in prices that were beneficial to all customers to consider that. So I'd have to say, no, we haven't really considered that, Commissioner.

Daniel Walsh (PIA): [00:41:52] I'd like to now ask a few questions about Bowen Units 1-4, and the Commissioner's questions earlier have addressed some of my questions. So this should be fairly brief. But the company assumes that Bowen 3&4 will continue to operate past 2028. Is that correct?

Jeffrey Grubb (GPC): [00:42:15] Yeah. We're not only assuming it, we're planning for it and moving down that path. Commissioners, as we said before, when we identify the transmission projects, if we were going to avoid ELG at Bowen 3&4 and retire it, we cannot complete those by the time we would need to comply with the ELG. So yes, we're planning on that, but it's because that's what we need to move forward. So it's not just planning assumptions, is what I'm trying to clarify. [It's OK.] It's a request.

Daniel Walsh (PIA): [00:42:40] And in order to do that, the company is planning to install additional wastewater treatment system for flue gas scrubber effluent. Is that correct?

Jeffrey Grubb (GPC): [00:42:49] That's correct. By the end of 2025. That's correct.

Daniel Walsh (PIA): [00:42:51] Okay. And the wastewater treatment installed for Bowen 3&4 would also address that scrubber effluent from [Bowen] 1&2. Is that correct?

Jeffrey Grubb (GPC): [00:42:59] That's correct. The cost to control wastewater really is a plant wide cost. It's not dependent on the number of units.

Daniel Walsh (PIA): [00:43:06] And therefore, the company would not have to incur incremental capital expenditures to treat Bowen 1&2 scrubber effluent, correct?

Jeffrey Grubb (GPC): [00:43:14] That's correct. And again, Commissioners, In the unit retirement studies, we have shown that. In our unit retirement studies, if you avoid a plant and avoid, if you retire a plant and avoid an environmental cost, we'll show that as a benefit or a cost reduction. We did not do that on Bowen 2, because we aren't avoiding that cost. So the economics reflect that, as you [Daniel Walsh] just laid out.

Daniel Walsh (PIA): [00:43:35] Okay. And just so I understand, if Bowen 3&4 continue to operate, essentially the same environmental costs would be incurred, whether it's just Bowen 3&4 or it's all four units, is that correct?

Jeffrey Grubb (GPC): [00:43:49] For ELG capital projects, that's correct.

Daniel Walsh (PIA): [00:43:54] Given that inflation is running higher than the company anticipated when it conducted its IRP analysis and that natural gas prices are rising, would it provide the company and the Commission with additional flexibility to again wait on finalizing a Bowen 1&2 retirement decision until the next IRP?

Jeffrey Grubb (GPC): [00:44:15] So that is the Commission's decision. Obviously, the company's recommendation, again, is based on a 30 year look. And so when we see current run ups on natural gas prices or inflation, we do not see that changing the long term nature of this decision. So the company's recommendation is investing in the coal units at [Bowen] 1&2 pose risk for future coal rules or carbon costs on those units. And so it's really around that 30 year look that we're making that recommendation.

Jeffrey Weathers (GPC): [00:44:44] And the replacement capacity are power purchase agreements that we know what the price is. They're not subject to inflation. Natural gas prices could impact it, but we don't think that the fundamentals of the natural gas market have really changed because of the short term run up in gas prices that we've seen. So we think we're looking at some...we know that we're looking at known power purchase agreement prices. Now we have assumption on the back end for solar & storage. But that's not in the near term either.

Jeffrey Grubb (GPC): [00:45:15] And I think the other thing, Commissioners, is these are immediate decisions on the coal units, but the retirement dates are several years down the road. So we will have these coal units for the next four or five, six years to help us respond to changes in gas prices just like we have. It's just that long term view. We see more risks on the side of staying in Bowen 1&2 then retired.

Tim Echols (PSC): [00:45:36] But isn't it true that federal policy sometimes goes back and forth, with the example of the Clean Power Plan that didn't ever materialize?

Jeffrey Weathers (GPC): [00:45:46] That's that's correct, Commissioner. It does go back and forth. And really, that's why we look at not just a single planning scenario, we look at a range of scenarios. It takes into account a range of natural gas prices, a range of federal policy with regards to carbon, such as the Clean Power Plan. We looked at that several years ago. That fit within the range of carbon prices. We think that the range of carbon prices we're considering today include the potential scenarios, potential legislation, regulation and policy the federal government has.

Jeffrey Grubb (GPC): [00:46:18] Commissioner, the other thing is that when we look forward on coal units, as we continue to add renewables, flexibility of resources becomes even more important. And so the energy value from the coal units gets harder to achieve because they you've got to commit them. You've got to run them for several days. They're not always in the money as they were five, six years ago. So there's several drivers that, from our standpoint, you just don't see a lot of upside. And this ELG timing, it gives us a chance to transition out that we may not have in the future.

Tricia Pridemore (PSC): [00:46:49] From a cold start, how long does it take to get a coal unit at maximum output?

Jeffrey Grubb (GPC): [00:46:55] So we've, you can help me here, Jeff, but I think we have a minimum commitment time of a week on a coal unit, and I think it's a 24 hour or so start up. And so if you're looking at days ahead or volatility on the system, you really have to commit a coal unit, run it at minimum to have it available to when it does provide value. So it's a lot less flexible. They were designed to run a lot and run a lot of time, and they've served us well for decades. But as you get to where there's more volatility, that flexibility starts to cause issues.

Michael Robinson (GPC): [00:47:28] Madam Chair, I believe for those units, it can take up to two days to get to full maximum output for those units. And they have very complicated starting schemes there. They pull off of each other, have sources internal to the plant that they have to run in certain sequences as well.

Tricia Pridemore (PSC): [00:47:43] Have we seen a limitation in availability of fuel for coal?

Jeffrey Grubb (GPC): [00:47:48] We did some, Commissioner, a few months ago when we were getting ready, when we saw some of the natural gas run up. And we really try to start looking at getting more coal to our coal piles. We had some challenges. And so what we did was we actually wanted to focus on the winter to make sure we had the coal supply available for the winter. We actually didn't run our coal units quite as much that the straight pricing would have shown to make sure that we had the inventory to get through the winter. But so we have. I don't think the coal supply chain is really set up to ramp up a lot and add new mines and add new locomotives. And so we have seen some challenges there.

Jeffrey Weathers (GPC): [00:48:27] Madam Chair, to your point, I mean, that really for us highlighted that the coal generation is not immune from some of the market interactions that we're seeing today with supply chain challenges, transportation challenges, because we did have some limitations on coal delivery and it did impact the way we're able to economically operate those units. They also, as we're talking earlier, have challenges in terms of flexibility because we have more....We have the increasing need for flexibility on the system. As we continue to add solar generation, coal units are not able to provide the flexibility needed in the most economical way to integrate those solar units.

Jeffrey Grubb (GPC): [00:49:07] So Commissioner, just that was that short term run up trying to handle some of that volatility. We do, we will be able to make sure we have supply and coal transportation and coal commodity while we're keeping coal units. I don't want to make it sound like we can't supply our coal units through 2027. We can do that. It was just that short term run up is what we were speaking to.

Tricia Pridemore (PSC): [00:49:29] So I know that we're going to talk more about ELG in forthcoming panels, but I do want to unpack a little bit more about the basis of ELG, because it is the basis for the closure of [Bowen] 1&2, to a great extent. So the January 26 edition of The Wall Street Journal had an article about EPA and their rules to target power plant pollution. And it talked about the fact that the EPA is doing this through their, and I want to quote this, "through the agency's broad powers to oversee air and water pollution as well as wastewater disposal." But they're doing it through rules versus it going to Congress or across the president's desk. It's being done through the rulemaking process at the EPA. Has the EPA, so this was from January, have they issued the guidance on ELG or what's also kind of considered NOPRs [Notice of Proposed Rulemaking] in some cases? Have they issued that to utilities yet?

Jeffrey Grubb (GPC): [00:50:36] I don't think so. And I'm not trying to completely punt to panel three, they need more details. But those are the types of things, Commissioner, that we look at future coal operations beyond just the this ELG rule that we're looking at. They have said they're going to revisit the ELG rule. So if you think back to 2019, the ELG rule is supposed to take effect in 2023 and we're going to have to have compliance by 2030. The reconsideration rule will move that date back to 2025 and also gave us this boiler cessation option in 2028. The new administration, I think, has stated they're going to revisit that. I think the EPA always has the chance to revisit MATS rules [Mercury and Air Toxics Standards] that we controlled four years ago. NOx, ozone. I think they always have that re-...to come back and revisit on it. So those are the pressures that we're thinking of when we say future environmental rules. And a lot of times those rules have timeframes that are shorter than us being able to build transmission. So we aren't we aren't basing our recommendation on Bowen 1&2, on the avoidance of ELG. The ELG is driving the timing of when we make that decision because again, as we've covered, Bowen 1&2 don't cause any incremental ELG. So that article or those those other rules that the EPA can use, that's the things that we see long term posing more risk to the coal units.

Steve Hewitson (GPC): [00:51:57] And commissioners, when Mr. Grubb talks about the time it takes to build transmission, what we're looking at right now of greenfield 230 KV lines that are, for any distance, it's about six and one half years to acquire, design, acquire the right of way and build that transmission. For 500 KV for any distance, it's about eight years.

Tricia Pridemore (PSC): [00:52:21] OK. Thank you, Mr. Walsh.

Daniel Walsh (PIA): [00:52:22] Thank you. You stated that the retirement of Bowen 1&2 is still several years away under the company's plan. Is that correct?

Jeffrey Grubb (GPC): [00:52:32] That's right. We're recommending the end of 2027. We cannot retire those units until we complete transmission work. And those transmission projects are projected to be completed by the end of 2027.

Daniel Walsh (PIA): [00:52:44] So the Commission will have another integrated resource plan from the company in between now and the anticipated retirement date.

Jeffrey Grubb (GPC): [00:52:54] They will, but the decisions before the Commission and the company that we've been working hard on the last several years is again the opportunity to take advantage of the capacity RFP and then the transmission construction. So the ELG compliance is to be done by 2025, if the Commission waits until 2025 and you've waited on transmission in the Capacity RFP, you've just missed that opportunity.

Michael Robinson (GPC): [00:53:19] And Commissioner, one of the projects that's needed for those retirements is a 40 mile 230 kV line that's going to take six and a half years.

Tricia Pridemore (PSC): [00:53:27] Is that part of the North Georgia Transmission plan you spoke of?

Michael Robinson (GPC): [00:53:31] It is not. It is part of the projects associated with the unit retirement studies, and those projects are listed in volume three.

Jeffrey Grubb (GPC): [00:53:40] So that accommodates the retirement of Bowen 2, Madam Chair.

Tim Echols (PSC): [00:53:45] So is the idea of leaving the units in operation, but not using them on a regular basis, just treating them as a big generator for when we have a crisis or a polar vortex or something like that. Is that something you all have considered?

Jeffrey Grubb (GPC): [00:54:04] I believe that's something we'll definitely look at, Commissioner, in terms of the North Georgia plan. Mr. Robinson spoke about synchronous condensers. You may be referring to kind of an inactive reserve. In other words, the plants, Bowen 1&2, aren't there for normal dispatch. But they're there if you have something happen. I don't know if we know all the implications of that from an environmental standpoint, right? Do you have to still control it? Do you have to permit it? How does that work? But I think in terms of how it may help on the power delivery side, that's something we can look at as part of that North Georgia Reliability and Resilience Plan. From a generation planning standpoint, though, we're trying to make decision on do you replace it and do you no longer plan on it for normal energy and capacity service.

Tim Echols (PSC): [00:54:43] And you may not know this off the top of your head, but has there been a time over the last three or so years when we've had to go to the coal unit on the system that wasn't really operational and fire that unit up for reliability for our grid because of weather related events?

Jeffrey Grubb (GPC): [00:55:13] There's two aspects to that. We'll address both. I think just Mr. Weathers will speak to a generation resource adequacy. Mr. Robinson can speak to it from a transmission system.

Jeffrey Weathers (GPC): [00:55:23] Thank you, Mr. Grubb. We have done that in the past, Commissioner. We've had units on inactive reserve, which generally means they're not counted on as firm capacity in the company's resource plans, they're generally available for resiliency needs made with a few days notice. So we have had that occur in the past. So that's something that happens on the system. Now the size of the unit, there's a lot of things that go into...must be taken into consideration when you're thinking about placing the unit on an active reserve. But but it has happened in the past with smaller units, with another operating company.

Michael Robinson (GPC): [00:55:59] And Commissioner, you typically don't see those large units on what we call the reliability commitment list in the wintertime for transmission constraints, because the system is not constrained. We see those units on reliability commitment list as in the spring and fall, the time we're in right now where we have a lot of outages on the system, a lot of projects going on, a lot of generators are offline for maintenance. And so we actually utilize those units and have them run during this period of time and which creates challenges with coal. As we mentioned before, we've been working through that system operations and the transmission operators as far as feathering that as we move forward and making sure we're making the right decisions.

Jeffrey Grubb (GPC): [00:56:37] And Commissioners, Mr. Robinson, when he spoke about not being constrained in the winter, that's on the transmission and power delivery, because that doesn't change the risk we see on the generation side of the reserve margin. I just want to make sure...

Jeffrey Weathers (GPC): [00:56:50] Mr. Robinson, kind of help me with the with the upgrade of the transmission system. When your long range plan is to close down a portion of generation in that area, kind of bring those two together.

Michael Robinson (GPC): [00:57:05] Sure, Commissioner. So you go back and look at the growth in Atlanta of the state of Georgia in the fifties and sixties. The transmission system that we have today was built out in the sixties, seventies and eighties to serve the load in Atlanta from the supercritical plants that we're now retiring. When you flip the state and you've got a lot of solar development in South Georgia, now you've got the megawatts flowing from south Georgia to north Georgia, where the load is now. We submitted a...it's a study that we did looking at just a simple delta between load and generation forecasting out in time. If you look towards potential retirement of Bowen

3&4 and there's a 7,000 megawatt deficit of load versus generation in the Atlanta area, North Georgia area. And so it's very important that we build the transmission to move those megawatts across the state to address those south and north flow issues and eliminate the constraints that we're starting to see in these studies long term.

Jeffrey Weathers (GPC): [00:58:01] In our last NARUC [National Association of Regulatory Utility Commissioners] conference in Washington, I attended a seminar or whatever on transmission and there was talk about the difference between twisted aluminum and composite, as far as the wires are concerned. And I think somewhere between there and where we are today, I asked the question about were we using composite. And I got the answer was no. Is that correct?

Michael Robinson (GPC): [00:58:28] No, Commissioner. We are. We've used a, what's called ACCS (Aluminum Conductor Composite Single), which is aluminum composite. And what the composite is, is it replaces the steel core or all aluminum core in the conductor. You still have to have the metal to be a conductor. But what it allows you to do, that composite material that's in the center, it allows you to operate that wire at a higher temperature. So we actually can reconductor lines that we've got several in the Savannah area that we've done with that technology. And it also uses a trapezoidal conductor. So it gets the metal conductor. You can get more conductor in the space because of the trapezoidal design. But it allows you to operate that line at 200 degrees Celsius versus typically we could only go up to 100 degrees C on a typical steel conductor.

Jeffrey Weathers (GPC): [00:59:21] So you get over 20% more, you get more use out of it. [That's right.] So you can get the same size, basically same size wire. You don't have as much sagging? [That's correct.] The weight of the wire.

Michael Robinson (GPC): [00:59:35] That's correct. And we will look at those. We look at this North Georgia plan that we're currently working with as ITS participants. We will look at that type of technology in the future because we've had success with it in the past. Absolutely.

Daniel Walsh (PIA): [00:59:49] So I was asking about the Commission having another integrated resource plan proceeding in 2025, which is before the date that the company is currently planning for retirement and Bowen 1&2. Is it your testimony that if the Commission were to wait until the 2025 IRP to decide on the Bowen 1&2 retirement decision, that it would be impossible to retire it by the date that the company is currently planning?

Jeffrey Grubb (GPC): [01:00:22] That's all going to depend on what else the Commission approves in this IRP.

Daniel Walsh (PIA): [01:00:27] But it would be possible, depending on what the Commission approves in the IRP.

Jeffrey Grubb (GPC): [01:00:31] With the transmission aspect taken into account. That's really the timing driver and then what the commission decides to do on capacity replacement. So yes, you can, but it depends on what else is approved in the case.

Michael Robinson (GPC): [01:00:45] Yea, commissioners because of the project that I mentioned before, the long 230 KV line, that's greenfield, six and one half years. We would need to go ahead and build that project to leave the contingency open for that further date.

Jeffrey Grubb (GPC): [01:00:57] And then I think as well, and I've said it before, the capacity RFP resources are very, very attractive prices. So that's another consideration.

Daniel Walsh (PIA): [01:01:06] There are considerations, I understand, and one of the considerations would be that not deciding to retire Bowen 1&2 as part of this proceeding would provide the company some flexibility in some matters. Correct?

Jeffrey Grubb (GPC): [01:01:21] Depending on what else is approved in this case.

Daniel Walsh (PIA): [01:01:24] I gotcha. I'd like to move now to a different subject. Gaston 1-4. Is it correct that the company considers that if it were to continue operating Gaston 1-4, it would be preferable to obtain a firm gas transportation contract rather than to incur the cost of environmental upgrades.

Jeffrey Grubb (GPC): [01:01:45] So we modeled that we aren't recommending either for Gaston 1-4, we're recommending to retire Gaston 1-4 and do neither a conversion to handle ELG or to get firm gas transportation. So those are the two options for operation beyond 2028. We think the more appropriate one long-term would be to go get natural gas firm transportation, but that is an expensive option, which is driving our recommendation to retire gas.

Daniel Walsh (PIA): [01:02:17] In obtaining a firm gas transportation contract, did the company assume that it would be necessary to have a firm gas contract every day of the year?

Jeffrey Grubb (GPC): [01:02:27] Yes, we did. And that is because from our fuel policy that we use on the system for a steam unit that is converted, we look to have, I forget the hours, but we look to have firm gas transportation on a daily basis just in a similar manner as we do for combined cycles. You've got to be able to have access to the pipes to be able to generate with that unit. So, yes, it's an annual firm transportation contract.

Daniel Walsh (PIA): [01:02:52] Could the company have identified specific months to have a firm gas transportation contract that would have been cheaper than the option selected by the company?

Jeffrey Grubb (GPC): [01:03:02] Possibly. I think, again, commissioners, we didn't get into those details because when we look at Gaston 1-4 and the replacement generation options that we have in the capacity RFP, it's in the best interests of customers to retire those units. They were built in the 1950s. We don't see it benefiting customers to either comply with the ELG rule there or to do gas transportation when we have the capacity RFP resources that's available in the meantime.

Jeffrey Weathers (GPC): [01:03:32] I'm sorry. I'll just add to that. I'm not a gas procurement expert, but I don't think there really would be savings if you try to eliminate certain days of the year. And so really the gas pipeline capacity, the firm transportation is going to be priced on when it's most valuable to the pipeline. So what are the constrained seasons? We're looking at the winter season and the summer season. If you're purchasing it for those seasons, then I think the cost to have other non-constrained times of the year would be minimal.

Daniel Walsh (PIA): [01:04:00] So did you do that analysis to confirm that belief?

Jeffrey Weathers (GPC): [01:04:04] I did not. But that's my again, I'm not in the procurement part of the company, but that's my, that would be my belief and my expectation of that analysis if it would be performed.

Daniel Walsh (PIA): [01:04:16] Did the company perform it? When I said you, I meant the company and not just you specifically, but did the company perform that analysis?

Jeffrey Weathers (GPC): [01:04:22] I don't think so. But generally we're looking at either you're buying summer FT (firm transportation) or you're buying winter, you're buying annual. And it really covers both seasons. You're not generally buying it for some days of the year and excluding, say, an April day. I think April is just going to come along for the ride. If you're buying winter and if you're buying summer.

Tim Echols (PSC): [01:04:43] Let me ask you about the firmness. I mean, we learned through the Texas situation, right? That cheap gas alone is not enough, right? [That's correct.] But it needs to be cheap and firm.

Jeffrey Weathers (GPC): [01:04:52] It needs to be firm.

Tim Echols (PSC): [01:04:54] Yeah. So and the Transco [sic] [Colonial] pipeline hack was a liquid pipe. But if it had been a methane pipe that had been hacked, how much of our generation would have been idled?

Jeffrey Weathers (GPC): [01:05:11] Well I don't know in terms of percentage. I mean, there's primarily two gas pipelines that serve our generation fleet, the Transco [Transcontinental] pipeline and SoNat [Southern Natural Gas Pipeline]. It is a significant portion that's on Transco. Those are the type of studies that we do from time to time looking at resiliency. What if... We look at the what if's? What if that happens? Then we're looking at utilizing our gas storage. We're looking at re-dispatching our system, running units on oil that have that capability to try to recover from those type of events, you know, as quickly as we can. So I don't have the exact numbers, but it would not be insignificant.

Michael Robinson (GPC): [01:05:48] Commissioner I'm sorry. The transmission team also runs studies looking at the loss of those pipelines, each individual pipeline, to ensure that we have the transmission capability to serve the load throughout the southeastern area. One of the things that's very important in that study is our interface capability to ensure that we can import megawatts from other areas. If we were to have that contingency happen, just to ensure that we can reliably serve a load.

Tim Echols (PSC): [01:06:11] But it would have been a crisis of epic proportions for our grid, right?

Jeffrey Grubb (GPC): [01:06:16] Well I don't know if I would say that, because as Mr. Robinson said, and I was alluding to, we do those type of studies and we're not dependent on a single gas pipeline and we're not dependent on natural gas as a single fuel source either. So we have diversity of fuel sources that diversity of generators in our fleet. And we have gas units that can run on oil, that can pull from gas storage. So we have a lot of diversity that helps with that. It wouldn't be catastrophic, but it is something we look at from a planning perspective.

Jeffrey Weathers (GPC): [01:06:47] And that's where you always have to look back at coal every once in a while, too.

Jeffrey Weathers (GPC): [01:06:51] Yes, sir. We have certainly have coal as well.

Tim Echols (PSC): [01:06:55] And would that be a rationale for leaving these, a unit like Unit 2 at Bowen in an inactive reserve status, because you might be anticipating a hack in the future?

Jeffrey Weathers (GPC): [01:07:09] Well, that would be the type of resiliency situation that if you had a unit like Bowen that wasn't there for reliability anymore, but was there within maybe a few days notice to run for resiliency purposes, that would be one of those situations that it would run for.

Tricia Pridemore (PSC): [01:07:24] Mr. Weathers, could you clarify Bowen as in Bowen Units 1&2 or 3&4?

Jeffrey Weathers (GPC): [01:07:28] Yes, very different. We're talking about Bowen Units 1&2.

Tricia Pridemore (PSC): [01:07:32] Thank you.

Daniel Walsh (PIA): [01:07:37] I'd like to ask you a few questions about capacity expansion analysis. And before I get into the specific questions, I'd like to talk about a couple of terms and make sure that we share the same understanding. Capacity value when you do an analysis. What does that term mean to you?

Jeffrey Weathers (GPC): [01:07:59] Well, we have a term very similar to that we call the Incremental Capacity Equivalency or ICE factor. So my understanding of the term that you just used would be the ice factor in our name...

Daniel Walsh (PIA): [01:08:11] Do you use that term instead of mine because you get to say ICE factor?

Jeffrey Weathers (GPC): [01:08:15] No, but it is a good word to say. But the, real briefly, what the ICE factor is, is the reliability contribution of a unit. This may be energy limited unit or or intermediate unit, variable energy resource unit. They don't have a one for one capacity value as you compare to firm dispatchable units. So we use an ICE factor. Another common term in the industry is the effective load carrying capability or ELCC. Those are both ways to take variable units or demand side units that can't operate all hours of the year and equivalate them to firm capacity units on the system.

Daniel Walsh (PIA): [01:08:59] And are you also familiar with the term nameplate capacity?

Jeffrey Weathers (GPC): [01:09:02] Yes.

Daniel Walsh (PIA): [01:09:02] And what does that what does that term me?

Jeffrey Weathers (GPC): [01:09:05] That's just going to be your normal rating of the unit. So what the unit can operate under normal conditions, usually summer conditions.

Tim Echols (PSC): [01:09:15] Let me ask you a question on the transmission side. You mentioned a six and a half year window to do a 230 kV line and an eight year time period to do a 500 kV window. We've talked before about using old coal plants like Plant Branch, where the switch gear lines are still there. Right? We've closed it. Everything's been torn down, but we still have that equipment there. And we've got, of course, with Bowen with it fully operational. If you self-built a massive solar array at or near these plants with storage, would it have a positive impact on transmission and possibly push those dates where we need the transmission upgrade out further?

Michael Robinson (GPC): [01:10:13] Commissioner, that could be useful. Those technologies are very expensive for the megawatts that we would need, particularly if you're looking at retiring a 760 megawatt unit and replacing that with 760 megawatts of solar plus batteries. It gets pretty expensive. As it relates to Branch, surprisingly, almost all, most of that capacity is gone because of changes in the system around it, because of solar development in South Georgia. The study that we filed in volume three that looks it's called the optimal transmission siting study. It looks at where we can inject 300 megawatts throughout the state and not cause transmission problems. Bowen is not one of those listed there. So we've pretty much eroded all capacity at Bowen, and it's surprising to hear that. But if you look at what's going on in South Georgia, the development of solar, that that capacity, that transmission capacity is pretty much been eaten up.

Jeffrey Grubb (GPC): [01:11:08] So, Commissioner, that this, what Mr. Robinson is talking about is the flows on the overall grid, the physical switchyard and everything at Branch are still there. He's talking about what you deliver to the bulk system, just to make sure there's a clarification. [Thank you.]

Daniel Walsh (PIA): [01:11:26] When the company conducts capacity expansion analyses, does it use the equivalent capacity value or ICE factor for renewables?

Jeffrey Weathers (GPC): [01:11:36] Yes. Well, in in the capacity mix study, all the existing renewables are in there with their appropriate ICE factor.

Daniel Walsh (PIA): [01:11:48] So the company does not use then, what we talked about as nameplate capacity for renewables when it develops its expansion plan, does it?

Jeffrey Grubb (GPC): [01:11:58] Well, we do from an energy standpoint, the commissioners, the way we would model, for example, a 100 megawatt solar PPA is it's going to have a 100 megawatt profile delivered its energy. We capture that in the models. But when we look at the reserve margin and what is able to meet that peak, that's when we use capacity equivalence. 100 megawatts of solar does not contribute to the reliability the same way 100 megawatt CT [Combustion Turbine] does. So we capture, I'm sorry, a lot of stuff on my desk I need to stay closer. So the nameplate or the megawatts of the facility itself are modeled and the generation from an energy standpoint is captured. But the capacity equivalence, that it leads to certain peaks, is where we reduce that.

Jeffrey Weathers (GPC): [01:12:43] Another way to think about that is the resource ledger. When you're counting up your capacity, comparing that to your peak demand, use the equivalence, use the ICE factor. So you only want to count what can contribute to reliability. But when we run our models, as Mr. Grubb said, we model the full unit and there's a profile and it'll dispatch the unit over the course of the day. But that doesn't use the ICE factor that uses the energy profile of the unit.

Daniel Walsh (PIA): [01:13:09] So when the company tests if a purchase power agreement renewables exceeds the 30% purchase power agreement requirement in the Commission rule, the company uses the nameplate value of renewables. Is that correct?

Jeffrey Grubb (GPC): [01:13:24] No, that is not correct. I believe we filed a data request where we look at the 70/30 rule. We haven't talked about it in a long time, but we look at it from a planning megawatt standpoint. And so when we filed either an a DR [Data Request] or some of our testimony or our main [IRP document], I forget where it was, we do the equivalence. So if we've got 5,000 megawatts of solar, we are not putting 5,000 megawatts of PPAs in that calculation. We can do it both ways. But the one that we filed was based on planning megawatts or those capacity equivalence.

Daniel Walsh (PIA): [01:13:59] If you did use the nameplate value of renewables for the testing, that would be reflecting that the renewable resource would be fully dispatchable. Is that, would that be the implication of using nameplate for testing?

Jeffrey Grubb (GPC): [01:14:11] Well, I mean they are, the renewable resources aren't dispatchable and that they operate as they operate. That would just be doing, would be looking at just for lack of a better term, the steel on the ground, the megawatts on the ground. And so when we look at the origins of the Commission's rule on the 70/30, it was a lot around reliability. And so when we do that math, we do it with planning megawatts or the capacity equivalence. If you did use nameplate, well then the PPA amount would exceed 30 a lot faster and quicker than it would look at the capacity equivalence. So it would, if you use nameplate, it would say that that we were over the 30% by much more.

Daniel Walsh (PIA): [01:14:56] I need to ask you a few questions about winter reliability. In this IRP, as in prior IRPs, the company conducted the Economic and Reliability Study of the target reserve margin for the Southern Company system. Is that correct? [Yes.] And the purpose of that study is to determine the amount of reserve or backup capacity or target reserve margin that should be maintained on the system. Is that correct? [Yes.] And you would agree that while reliability concerns are critical, maintaining the capacity reserves at too high of a level can result in exposing customers to significant expense. Correct?

Jeffrey Weathers (GPC): [01:15:35] Yes, absolutely. And that's exactly why we do the reserve margin study, because it is an economics based view of setting the target reserve margin. Because to your point, Mr. Walsh, if you have too much capacity on the system, you may be really, really reliable, but that's expensive for customers. On the other hand, if you have too little capacity in the system, there's significant reliability costs that customers see.

Daniel Walsh (PIA): [01:15:58] It goes each way.

Jeffrey Weathers (GPC): [01:16:00] It's goes each way. So our target reserve margin finds the optimal point and also adjusts that for the risk of outages that the customers see.

Daniel Walsh (PIA): [01:16:07] And the goal for the company is to come up with the least cost reliable system. Is that fair to say?

Jeffrey Weathers (GPC): [01:16:13] Well, that is a point of consideration. The goal is not necessarily to set the target reserve margin at the least cost, but that is a data point. But we go beyond that to look at is there value to customers by increasing the target reserve margin some amount in reducing more risk than the cost that you're increasing? So that's the risk analysis that we do on top of the lowest economic cost.

Daniel Walsh (PIA): [01:16:41] And I think I was careless with my word choice there. Would it be more accurate to say that you go, you look at maintaining a reliable system in a least cost manner? Would that be more accurate?

Jeffrey Weathers (GPC): [01:16:52] Yes, because appropriately considering risk, we do.

Daniel Walsh (PIA): [01:16:55] And it's also fair to say that your analysis involves a large number of detailed assumptions.

Jeffrey Weathers (GPC): [01:17:03] It does. We're modeling the entire Southern company system, all the existing units on the system. We're modeling a range of 58 different weather years looking at weather variability, or the model does random draws of unit outages. So it's a very robust analysis to capture all the variability around reserve margin. So we will make a recommendation. It has all of that analysis behind it.

Jeffrey Grubb (GPC): [01:17:29] And Commissioners, as Mr. Weathers and team are putting that study together, we're using information and sources that are our operators on the system, our senior production officers. So when we're looking at how our generation performs or what our system does, we're using the information from our experts to put that together.

Daniel Walsh (PIA): [01:17:47] And if any of the analyses are found to be erroneous or overstated or contain assumptions that are not realistic, then you run the risk of overstating the target reserve margin, correct?

Jeffrey Weathers (GPC): [01:18:02] Well, potentially, but it is a very robust analysis. And as you mentioned, Mr. Walsh, there are a number of data points that go into it. So there are going to be some that are more conservative than others. But I think the analysis as a whole, again, is modeling our system is modeling the conditions on our system based on our actual experience on the system. So I think the analysis and it has a range of range of results, but we're looking at is what's the best cost estimate? What's the best cost number, on behalf of customers, considering these cost economics, considering risk to customers and also considering reliability needs.

Daniel Walsh (PIA): [01:18:42] And I understand that you're looking at a range like that. I'm just making the point that it's important that the analyses be realistic or else it could have the result of overstating the reserve margin.

Jeffrey Weathers (GPC): [01:18:55] It is important. And that's why we use actual data on our system, because that is realistic. That's data that has happened on our system. And so we're using, we're not making up numbers, we're using actual weather that we've occurred, unit outages we've occurred, load forecast differences that we've occurred, all that data points based on actual conditions on the Southern company system. That's why it's important to use that. To your point.

Daniel Walsh (PIA): [01:19:19] The Southern Company system as a whole or Georgia power company system specific, it's Southern Company as a whole.

Jeffrey Weathers (GPC): [01:19:25] Is a Southern Company system because we operate as a system and as a pool. So it's important we plan as a system. So it's important that we capture the whole system because reliability in Georgia is not different than reliability on the system. The reliability is going to be the same across the system.

Michael Robinson (GPC): [01:19:42] Just like the transmission system is planned as a whole as well, because it operates as a whole.

Daniel Walsh (PIA): [01:19:46] To account for potentially higher outages in the winter, the company suggests that it may require more backup capacity in the winter. Is that correct?

Jeffrey Weathers (GPC): [01:19:57] When you say more as compared to what?

Daniel Walsh (PIA): [01:20:00] Well, I guess is backup capacity greater in the winter than in other seasons?

Jeffrey Weathers (GPC): [01:20:05] The reserve margin target is higher in the winter than it is in summer. And it is in part due to, as you just mentioned, that when we get extremely cold temperatures on the system, that our units have demonstrated that they're more likely to have forced outages. Those have occurred in history. We have assumed that those will occur in the future. Now, we've also assumed that there will be improvements to the historical outages because we have made significant winterization improvements on our unit since 2014. Those improvements weren't captured in our study. Doesn't mean the risk is zero for there to be incremental cold weather outages, but it is smaller than it was in the past.

Jeffrey Grubb (GPC): [01:20:47] And so, commissioners, while the 26% number is greater than the 16 number, they are based on a summer load, weather normal in a winter load, weather normal. So 26% is multiplied against a smaller load. So it's not megawatt to megawatt 10% greater. But the important thing is we've seen those risks move to the winter as we've talked over on the last IRP, last two. And so the winter target reserve margin needs to take into account those different risk drivers. And that's what we've incorporated in the last several studies.

Daniel Walsh (PIA): [01:21:19] I think actually your response about the steps you take, you've taken, leads into the next exhibit that I was going to present you with. Madam Chair, may I approach.

Tricia Pridemore (PSC): [01:21:30] And you can pass to Commissioner Johnson and we can pass down the road. It's a lot easier for us.

Daniel Walsh (PIA): [01:21:46] Madam Chair, I would ask that this next exhibit, STF-JKA-1-1, the company's response to it, be marked for identification of Staff Exhibit number two.

Tricia Pridemore (PSC): [01:21:57] So moved.

Daniel Walsh (PIA): [01:21:59] I'll give you a moment to look at that exhibit. And it's front and back. So you're aware. Let me know when you're ready for questions.

Jeffrey Grubb (GPC): [01:22:50] Yeah. We're ready.

Daniel Walsh (PIA): [01:22:52] This is your response. So I would assume that you'd agree this is an accurate summary of the actions taken by the company in response to the NERC (North American Electric Reliability Corporation) report.

Jeffrey Grubb (GPC): [01:23:04] Correct.

Bubba McDonald (PSC): [01:23:05] Couldn't that be answered in just one word, Diversification?

Jeffrey Grubb (GPC): [01:23:12] I think it's reliability, commissioner. I mean, what we learned after the polar vortex and what a lot of this is talking around is we had gone 10, 11, 12 years before we had, since we'd had a really cold winter. And we learned a lot around resources that we had added in that timeframe on weatherization and winterization. So what this DR is stepping through is what all our generation teams did to improve the performance of units in cold weather.

Bubba McDonald (PSC): [01:23:39] Was not Texas generation mix less diversified than what we have in Georgia?

Jeffrey Grubb (GPC): [01:23:46] Could be. And this, commissioner, talks about...I think there's another one that the attachment, some of these are steps taken at gas units, some of these steps taking it coal units. But yeah, so each resource has its benefits from a diversification standpoint.

Daniel Walsh (PIA): [01:24:02] And this this response talks about the report that NERC published in September 2014, which recommended that utilities review and update power plant weatherization programs, correct? [Yes.] And have there also been other written reports and investigations conducted by FERC as well?

Jeffrey Weathers (GPC): [01:24:26] Well, related to the polar vortex or just in general?

Daniel Walsh (PIA): [01:24:30] In general, as far as what the utilities could do to make them more resilient during cold weather.

Jeffrey Weathers (GPC): [01:24:38] Yeah, I think I think FERC has, I mean, they have, every year there's a there's a winter assessment that they do. But I think this is the primary report coming out of the 2014 polar vortex. Now, there was another one issued after the February 2021 outages that impacted Texas and a lot of the Midwest.

Daniel Walsh (PIA): [01:24:58] And these, the steps that the company has taken, what's the time frame for the actions outlined on JK1-1, just generally the other range of when the company began these steps and when they...

Jeffrey Weathers (GPC): [01:25:16] We don't have the attachment to it, I think, that gives the time frame. But generally, I think these are actions that obviously occurred since 2014 and I think majority of them should have already been completed.

Daniel Walsh (PIA): [01:25:34] And the company also has made significant capital and O&M expenditures recently, including implemented changes to gas fired generating units to be able to withstand low temperature events. Is that correct?

Jeffrey Grubb (GPC): [01:25:47] I don't remember, recall the totals. But again, commissioners, what we've done is we've continued to look at what can we do to make the gas resources specifically more protected from cold weather. So there was a phase of actions that we're talking about here after the polar vortex by Mr. Weathers. I don't have the attachment. I can't remember exactly the dates, but we're continuing to look at that because winter is really where we're seeing our reliability focus now.

Daniel Walsh (PIA): [01:26:16] And you would say that the company has been and is continuing to be proactive and preparing its units for winter cold weather events and has successfully prepared and mitigated the impacts of cold weather events.

Jeffrey Weathers (GPC): [01:26:33] Well, yeah, I would say yes. The company continues to be proactive. The company has mitigated those impacts, but they're not zero. So there are still risks when the temperatures get really cold. There's still risk on our system that the units will have an outage.

Jeffrey Grubb (GPC): [01:26:49] So, commissioners, Mr. Weathers spoke to, as we've done these measures across the fleet, we've improved that assumption in the reserve markets and we'll continue to do that. So as we take actions across the fleet, we will capture that in the next study. But again, the focus has really been around the reliability of those units and our reserve margin study is very robust and looks at 700 something thousand different iterations to recommend that 26% in the winter.

Jeffrey Weathers (GPC): [01:27:19] And these type of things, these improvements that we've made to the performance of our units at cold temperatures is a reason why we expect the system to be more reliable at 26% than it was expected to be three years ago. So the company has made strides forward. Reliability is expected to be improved based on, with the same target reserve margin, that's based on economics for customers, we expect a little bit higher reliability.

Daniel Walsh (PIA): [01:27:46] Would you agree it's appropriate for the Commission to consider the success that the company has had in mitigating the impacts of cold weather events in determining what the target reserve margin should be?

Jeffrey Weathers (GPC): [01:27:59] Yes, and it is a consideration in our analysis. We do consider these type of events, but really our analysis is being driven by economics. So we did a sensitivity, if we were to remove all the cold weather outages from our model and basically assuming that the units are reliability, reliable down to whatever the lowest temperature is that we see, that doesn't really change the economics, it changes the reliability, it makes our system more reliable. And there's benefit for customers to do that. But it does it change the target reserve margin.

Daniel Walsh (PIA): [01:28:33] The company charges customers for the improvements that it's made to generating units, correct?

Jeffrey Grubb (GPC): [01:28:40] Yes. So those costs are recovered for customers, but it has the benefit of those resources being more reliable as well.

Daniel Walsh (PIA): [01:28:46] And a primary benefit, in fact, of the winterization expenditures is less expected outages, correct?

Jeffrey Grubb (GPC): [01:28:54] That would be one of them. That's correct.

Daniel Walsh (PIA): [01:28:57] And customers who are paying for the winterization expenditures shouldn't have to pay the same for backup capacity as if these winterization efforts never took place, should they?

Jeffrey Weathers (GPC): [01:29:07] Well, again...

Daniel Walsh (PIA): [01:29:08] If you can answer yes no, and then you can explain.

Jeffrey Weathers (GPC): [01:29:11] Well, can you ask a question again, please?

Daniel Walsh (PIA): [01:29:13] Customers who are paying for winterization expenditures should not have to pay the same for backup capacity as if these winterization efforts never took place, should they?

Jeffrey Weathers (GPC): [01:29:25] Yes, they should. Because if the target reserve margin were based only on reliability, then it would be true that those actions would have a direct impact on the target reserve margin. But it's not. It's based on economics. So it is economic for customers to carry 26% reserves. Based on our study, based on studying our system, is economically advantageous for customers.

Jeffrey Grubb (GPC): [01:29:54] And Commissioners, also, Mr. Walsh referred to it as backup capacity. I would not qualify it that way. What we're talking about is the resources that we have on the fleet to be available to customers when they need it. Some run less than others, but it's not backup and that we're planning to one and we add some extras. But that's the target to make sure we have the resources there to balance those economics and the reliability to the customer. So as we continue to invest in those units, they become more reliable. It may or may not change whether, to Mr. Weathers' point, the ultimate reserve margin, but it's still a more reliable resource. And as we continue to see winter as the risk, it makes sense to invest in those. And we do study, but 26% captured those impacts.

Daniel Walsh (PIA): [01:30:35] So in summary, the company's position is that even though it has incurred expenses to mitigate the impacts of cold weather events and even though those expenses have been recovered from customers and of those efforts have been successful, that customers are still going to be paying to support the same target reserve margin as it did had these winterization expenditures never taking place.

Jeffrey Weathers (GPC): [01:31:07] Yes. And it's actually a lower cost to customers. When we do our reserve margin study, we look at reliability and we look at economics. So if you were to pick solely based on reliability, which is the general planning criteria, is a one outage event every ten years. So if you're looking at just that number that's actually higher cost, then the 26% reserve margin, because we consider all the cost to customers, the capacity costs, the energy costs and any reliability costs. In addition, you're really looking at having one outage every ten years. So Texas, they had to shed load in 2011. They did it in 2021. That was a very expensive toll on the economy. Not to mention lives were lost during the event last year. So we're not planning on just we're playing for reliability, but the economic reserve margin, it provides additional reliability benefits but at a value to customers to do that. So less, the 26% is a less cost to customers than the one in ten marker in our study is, which would be 20%.

Daniel Walsh (PIA): [01:32:22] You're saying it's the least cost reliable system for customers to maintain the same reserve margin?

Jeffrey Weathers (GPC): [01:32:30] It is least cost for customers considering the risk adjustment that we do and is more beneficial for customers to have the 26% target reserve margin than it would be to only plan for a liability. So your questions were very important questions to consider when you look at cold weather outage improvements, those benefit customers because they make our system more reliable. But it doesn't change our reserve margin recommendation because we're not basing it only on reliability. We're also basing it on economics and primarily on economics.

Daniel Walsh (PIA): [01:33:07] To ask a few questions about hydro modernization. In this IRP the company is seeking approval to modernize plant Burton, plant North Highlands, and plant Sinclair hydro facilities. Is that correct?

Jeffrey Grubb (GPC): [01:33:20] That's correct.

Daniel Walsh (PIA): [01:33:23] The goal of hydro modernization is to keep units running for a very long time, correct?

Jeffrey Grubb (GPC): [01:33:29] Yes. I mean, the real goal of the modernization, as we discussed in the 2019 IRP, is a lot of the hydro facilities are getting, they're well up in age. They were starting to see more forced outage on those units. And so investment in those units to allow them to continue to operate, to make sure we can maintain our FERC license. And yes, it adds those generation resources for another 40 to 50 years.

Daniel Walsh (PIA): [01:33:57] And modernizing these units cost hundreds of millions of dollars in capital investment.

Jeffrey Grubb (GPC): [01:34:03] Yes. And so what we've proposed the next three, that number is trade secret. But it is. but it's the same discussion we had in 2019. As we look at these hydro units, the values they bring to the system, the values they bring to the state and the communities, the risk of not investing those units, not operating, risking the FERC license and what you do with the dams, we just feel like these are resources that we need to continue to invest in. And so we've got the five plants that were approved in 2019. We're recommending the next three, which are the three most in need of maintenance, and they allow us to keep the momentum going that we've gotten from the first five.

Tricia Pridemore (PSC): [01:34:44] Mr. Walsh, can we unpack that for just a minute on page 27 of your pre-filed direct testimony? I'll give you a minute to get there. You talk about the fleet modernization for hydro from the 2019 IRP and you substantially completed projects at plant Terrora?

Jeffrey Grubb (GPC): [01:35:08] Yes, ma'am.

Tricia Pridemore (PSC): [01:35:08] Where's that?

Jeffrey Grubb (GPC): [01:35:09] It is in, all of that's in northeast Georgia. It's in the north Georgia.

Tricia Pridemore (PSC): [01:35:13] Rabun County.

Jeffrey Grubb (GPC): [01:35:15] Up that way. Yes, ma'am. There's six of them in a row up there. That's true.

Tricia Pridemore (PSC): [01:35:18] Okay. So they're all in Rabun. Okay. And then talk to me on line 21 of that same page where the company states, "the integrity of the fleet and allow these flexible, dispatchable and zero carbon resources to operate for at least another 40 years." Explain to me dispatchability on hydro. How long does it take to fire one up? Do you ever shut it down?

Jeffrey Grubb (GPC): [01:35:39] We don't run them all the time because they're energy limited, right, from a water standpoint, but they are super fast to start up. I mean, it's within minutes, I believe. And so they're very flexible. A lot of times the value we see from hydro is using them across the peaks to avoid some of the more expensive generation coming on. But, yes, they're very flexible. As we modernize them, they will become more flexible. The modernization will include putting more AGC on the hydro units as we do those.

Tricia Pridemore (PSC): [01:36:06] AGC define please.

Jeffrey Grubb (GPC): [01:36:09] Automated generation control. But again, yes, Madam Chair, they're very flexible resources, come on in a matter of minutes and can start and stop as they need.

Michael Robinson (GPC): [01:36:19] Madam Chair, we could also use those units in what's called motoring. We can use them as synchronous condensers. As I mentioned before, where you're producing a real power, we use reactive power output to control voltage and help with power system and transmission system reliability in the area.

Bubba McDonald (PSC): [01:36:35] And starting at Like Burton, you use the same water how many times?

Jeffrey Grubb (GPC): [01:36:39] There's six dams in a row.

Tricia Pridemore (PSC): [01:36:43] How will this modernization increase the, increase hydro in the overall generation mix, will it?

Jeffrey Grubb (GPC): [01:36:50] So it's not a real change on the energy side. We don't expect them to generate a lot more, commissioner. What we're facing now is their ability to actually be available and to run. We've got some that they just get to the end of their lives and they can no longer function. So what modernization does is allows us to go into a facility, for example, if there's four units, update all four of those units in a very programmatic fashion as opposed to, one fails, your replace it you wait for the other one to fail. So it's a very structured and methodical way to reinvest in things. And so it's, they will be more efficient. They'll use less water to get those megawatt-hours out. And so it will be more efficient. It won't increase hydro's share of the energy mix. But what it does is allows us to have hydro for the next several decades as we continue to invest.

Tricia Pridemore (PSC): [01:37:43] So it's really to secure the percentage of hydro that's in the generation mix now.

Jeffrey Grubb (GPC): [01:37:47] That's correct. And to remove the risk of losing a FERC license and what do you do with the dams.

Tricia Pridemore (PSC): [01:37:56] Thank you.

Daniel Walsh (PIA): [01:37:58] The company hasn't provided any economic analysis for any decision to upgrade or retire the units, has it?

Jeffrey Grubb (GPC): [01:38:05] On the hydro units, we have not.

Daniel Walsh (PIA): [01:38:08] I'm sorry, if I could clarify my question. Have you performed any studies that are not included in the plan or have you not performed any studies?

Jeffrey Grubb (GPC): [01:38:16] Thanks for that clarification. We did not perform them.

Daniel Walsh (PIA): [01:38:18] Okay. Thank you.

Jeffrey Grubb (GPC): [01:38:19] Yes. So reasons being, we, if you look at just energy and capacity, there's other aspects of the hydro fleet you would need to capture the value that they bring to the system.

Daniel Walsh (PIA): [01:38:31] And the company hasn't prepared any capital revenue requirement analysis either, has it, for these units for..?

Jeffrey Grubb (GPC): [01:38:42] The three additional. [Yes.] So we provided the the cost and the budgets for those hydros in terms of revenue requirements. Those would be captured in any kind of rate base, rate case analysis that we would do. We just provided the budgets in the supplemental information in the filing.

Daniel Walsh (PIA): [01:39:00] Okay. Thank you. I'd like to now talk specifically about the status of existing modernization projects, in particular plant Tugalo. Georgia power has spent, and I'm sorry, I want to be careful about trade secret dollars. Is it trade secret? The amount of money that the company has spent on modernization at Plant Tugalo?

Jeffrey Grubb (GPC): [01:39:36] That we filed in the reports to staff? I do not believe historical spins are trade secrets, so I think we're, future ones would be, but I don't think historical.

Daniel Walsh (PIA): [01:39:45] So has the company spent approximately $26 million on the modernization of this plant through December 2021?

Jeffrey Grubb (GPC): [01:39:53] Subject to check. I don't have the latest report that we filed with staff.

Daniel Walsh (PIA): [01:39:58] Okay. Is it correct that the company submitted a non-capacity amendment at FERC in September of 2021?

Jeffrey Grubb (GPC): [01:40:07] That is correct. And we've stated in the filing for any of the modernization work we've we filed those FERC amendments did so with Terrora as well.

Daniel Walsh (PIA): [01:40:16] And is this plan the same as or similar to the plan and schedule for the modernization program for the Tugalo plant, as was approved in the 2019 IRP?

Jeffrey Grubb (GPC): [01:40:27] The plan that we filed at FERC?

Daniel Walsh (PIA): [01:40:30] Yes. Is the amended plan the same or similar?

Jeffrey Grubb (GPC): [01:40:32] I don't believe the scope has changed on any of the modernization working in the hydro facilities.

Daniel Walsh (PIA): [01:40:39] Is FERC still reviewing the amendment application?

Jeffrey Grubb (GPC): [01:40:41] Yes, that's my understanding.

Daniel Walsh (PIA): [01:40:44] Has Georgia Power started construction on this work?

Jeffrey Grubb (GPC): [01:40:47] Not on the work that is contained in the amendment. We did work to to remove the turbine generator. We've done some site preparation work. There's potential, there's maintenance work that we would have to do on units two, three and four if it came up. But in terms of the work that is in the FERC amendment, no, we have not begun that work.

Daniel Walsh (PIA): [01:41:06] What would happen if the amendment application is not approved?

Jeffrey Grubb (GPC): [01:41:10] In terms of at Tugalo? [Yes.] It would depend on, I'm not a hydro FERC expert, but I guess it would depend on what FERC puts in that license amendment and what they would want the company to do. It doesn't change our plans for the rest of the hydro fleet, but for Tugalo, it would depend on what FERC stated.

Daniel Walsh (PIA): [01:41:30] Would that have any effect on the work that you've completed thus far in the $26 million, subject to check, that you spent on it?

Jeffrey Grubb (GPC): [01:41:39] Yeah, it would, because that's, I think, that's scoping and engineering and all the work getting ready to do that. So it would, but we've always known that we would have to have FERC amendment file for any of the hydro modernization work.

Daniel Walsh (PIA): [01:41:51] Would it put at risk, I guess, is what I'm asking as far as if you, if the application amendment application is not approved by FERC, would that put in jeopardy the work that you've already done at the plant?

Jeffrey Grubb (GPC): [01:42:03] It would if it were forever halted. It would depend on what FERC ruled.

Daniel Walsh (PIA): [01:42:13] I'd like to move now to discuss energy storage systems. The company asserts that it has determined that 1,000 megawatts of energy storage systems resources by 2030 are required for the, to cost effectively maintain reliability. Is that an accurate statement?

Jeffrey Grubb (GPC): [01:42:35] That's right. Based on the renewable integrations, the renewable integration study that we filed with the IRP. That's correct.

Daniel Walsh (PIA): [01:42:50] I apologize. You were so agreeable in the last round, I get a little ahead of myself.

Jeffrey Grubb (GPC): [01:42:56] If that moves us faster, I'll agree to it.

Daniel Walsh (PIA): [01:43:03] Are you familiar with the resource mix study?

Jeffrey Grubb (GPC): [01:43:07] Yes.

Daniel Walsh (PIA): [01:43:09] And it's the company's position, is it not, that the purpose of the resource mix study is to provide information regarding the optimal least cost resource mix or generic expansion plan?

Steve Hewitson (GPC): [01:43:21] That's correct.

Daniel Walsh (PIA): [01:43:24] Did any of the portfolios that the company developed in the Resource Mix study show 1,000 megawatts of battery storage being added by 2030?

Jeffrey Grubb (GPC): [01:43:34] So that's, I'll let Mr. Weathers help me here. The storage that the resource mix is looking at in that study are resources, four hour or eight hour batteries that would be really deployed solely for the provision of energy and capacity to serve loads. The Renewable Integration Study and the 1,000 megawatts is based on a intermittent five minute reliability study looking at our operating reserves system. So again, the generation resource mix is an hourly model. What resources are best to serve energy capacity? The renewable integration study was around operating reserves.

Jeffrey Weathers (GPC): [01:44:14] Mr. Walsh. Just just to add to that, the answer is no. Our resource mix studies did not include, they did not select 1,000 megawatts by 2030. But as Mr. Grubb said, that's not the purpose of those studies. So those studies are selecting capacity and energy in order to meet system needs. Where the 1,000 megawatts comes from, those type of resources were identified in a different study, a renewable integration study. So that study looked at on a five minute level and a five minute basis and identified that there are flexibility issues on the system as renewable generation continues to grow. So those intra-hour flexibility issues are not, they're not discernible in our hourly integrated modeling. So that model would not pick that up. It would not select it. Those issues are resolved by increasing the operating reserves in our system. So basically having more units online at any given point in time, but it's more economically resolved if you add battery storage. So that's where the 1,000 megawatts come from, is to more economically enable the integration of renewable generation on our system.

Daniel Walsh (PIA): [01:45:25] Madam Chair, I would like to present the panel and the commissioners with a trade secret exhibit. It's an attachment to the company's response to STF-JKA-4-12.

Tricia Pridemore (PSC): [01:45:41] So moved.

Daniel Walsh (PIA): [01:45:43] Now I would ask that this document be marked for identification as staff's trade secret exhibit three.

Tricia Pridemore (PSC): [01:45:53] So moved. Be mindful that it is trade secret. So when we break, it breaks with you.

Daniel Walsh (PIA): [01:46:39] I'll give you a minute to take a look at this exhibit. And if you could just let me know when you're ready.

Daniel Walsh (PIA): [01:46:53] OK. There are a number of pages to the exhibit and they each have different headings as far as which expansion plan we're looking at. I don't need you to go through each page, but can you just tell me generally what's indicated by what type of expansion plans you're looking at here?

Jeffrey Weathers (GPC): [01:47:14] Sure. These are the three low gas, sorry, the three $0 carbon cases and then two of our $20 carbon cases.

Daniel Walsh (PIA): [01:47:27] And does this exhibit confirm your testimony earlier that none of the portfolios that the company developed in the resource mix study show 1,000 megawatts of battery storage being added by 2030?

Jeffrey Weathers (GPC): [01:47:42] That's right. And again, as I said earlier, they wouldn't do that.

Daniel Walsh (PIA): [01:47:45] I understand the caveat to your question, to your answer. I just wanted to provide the visual for the commissioners.

Tricia Pridemore (PSC): [01:47:54] And Mr. Weathers clarified that these that the first three sheets are the $0 carbon, and the second two are the $20 carbon. Is that true?

Jeffrey Weathers (GPC): [01:48:03] Yes, ma'am, that's correct.

Daniel Walsh (PIA): [01:48:14] I'd like to move now to ask some questions about the renewable integration study. The Renewable Integration Study was not intended to identify the optimal level of battery storage to accompany the solar resources. Is that correct?

Jeffrey Weathers (GPC): [01:48:32] That was not the purpose of the study. The purpose of the study was to identify the impacts on our system for integrating renewable resources and specifically looking at, not impacts that are not captured by our hourly integrated models, but within an hour at the real time, five minute level impacts.

Daniel Walsh (PIA): [01:48:52] Can I get you to turn to page 14 of your direct testimony?

Jeffrey Grubb (GPC): [01:48:58] Yes. Page 14? [Yes.] Yes.

Daniel Walsh (PIA): [01:49:10] And specifically, I was going to ask you to look at lines 10 and 11 of your testimony. You testified that the Renewable Integration Study supports the company's request for 1,000 megawatts of energy storage resources by 2030?

Jeffrey Weathers (GPC): [01:49:28] Yes.

Daniel Walsh (PIA): [01:49:30] Page two of the Renewable Integration Study, if you could refer to that.

Jeffrey Weathers (GPC): [01:50:12] Okay. We're there. Mr. Walsh.

Daniel Walsh (PIA): [01:50:14] Thank you. Table two on that page shows that scenario C of the study tested 1,150 megawatts of battery storage to help integrate 8,000 megawatts of cumulative solar capacity.

Jeffrey Weathers (GPC): [01:50:38] Yeah, it shows that 1,150 were added in that scenario. The study didn't select those. Those were added through an iterative process in order to mitigate the impacts of the renewables.

Daniel Walsh (PIA): [01:50:52] Is that the scenario that's most closely aligned with the IRP?

Jeffrey Grubb (GPC): [01:50:59] Yes. In terms of when we look at 2030, we looked at the the intermittent megawatts that would be on the Georgia Power system by then.

Jeffrey Weathers (GPC): [01:51:14] Yea, I think, probably most align with these. These are system numbers, not Georgia power specific numbers.

Daniel Walsh (PIA): [01:51:20] Southern Company system numbers.

Jeffrey Weathers (GPC): [01:51:21] Southern Company system numbers. There is a little bit of a difference there. So it would either be that number or possibly between that one and the next scenario.

Daniel Walsh (PIA): [01:51:32] I'm sorry, could, possibly which scenario? I'm sorry.

Jeffrey Weathers (GPC): [01:51:37] Well. So that scenario you're asking about is scenario C, so it contains 8,000 megawatts of solar on the system. And you ask, does that mostly is that most closely aligned with Georgia Power's expected 2030 renewable penetration? And I think it depends on what actions the other operating companies take. Right. So I think it would either be that one or scenario D possibly depending on other operating companies actions.

Michael Robinson (GPC): [01:52:08] As well as the EMCs and municipalities as well.

Jeffrey Weathers (GPC): [01:52:12] That is correct. It does. Those do have an impact on this. This study was specifically for the Southern company system, as Mr. Robinson said. Other solar generation in the region does have an impact on the grid.

Daniel Walsh (PIA): [01:52:26] Would that other impact be relatively minor compared to the other Southern company system, or would it be a significant impact?

Jeffrey Grubb (GPC): [01:52:33] It depends on which system you're speaking through. Mr. Robinson is talking about from a power delivery, distribution, transmission standpoint. But again, Mr. Walsh, well, the 1,000 megawatt request here matches up to Georgia Power's level of intermittent resources that would be on the system by 2030.

Daniel Walsh (PIA): [01:52:50] Did the study test any sensitivities to see whether a different amount of battery storage would produce a different integration cost?

Jeffrey Weathers (GPC): [01:52:59] Well, so the amount of battery storage was really determined through an iterative process and when the study was conducted. So we looked at, through modeling techniques, what is the intermittency impacts on the system because of renewables? So what we saw is there's pressure on the real time balancing of load and generation within an hour. So there's there's adequate capacity on the system for the hour, but it's not flexible enough to respond to the solar ramping and the solar intermittency within an hour. So you either have to increase your operating reserves, which is have more units online that can move and there's a cost to customers to do that or you add batteries. So this amount of batteries were determined to, there was appropriate, to mitigate the impact at a similar level that adding operating reserves would.

Daniel Walsh (PIA): [01:53:58] So would you say that you did or did not test a different amount of battery storage?

Jeffrey Weathers (GPC): [01:54:04] It was tested in the iterative nature of determining the amount. So these were the amounts that were selected to provide the appropriate mitigation back to the level of intra-hour reliability before you added the solar.

Daniel Walsh (PIA): [01:54:21] When you say that you did it in an iterative methodology, are you saying that what, was there another amount of battery storage that you looked at that produced a different integrated integration cost result?

Jeffrey Weathers (GPC): [01:54:41] Well, ultimately, no. I mean, there was one study. The integration costs were calculated based on these numbers, based on numbers that align with a roughly 15% of solar nameplate capacity, which is the 1,000 megawatts by 2030. So that's what calculated the integration cost on. But the level of batteries, the megawatts of batteries was determined to be a sufficient amount to mitigate the impacts of solar to current reliability levels in the system.

Daniel Walsh (PIA): [01:55:14] Did the Renewable Integration Study consider the capital costs of the battery resources in this analysis?

Jeffrey Weathers (GPC): [01:55:21] It did not. This was only, this is only the benefit size. So this is the value that the battery brings in terms of benefits. Now that any specific battery analysis such as the one provided in this IRP for the McGraw Ford facility, that captures all the costs and the benefits.

Jeffrey Grubb (GPC): [01:55:40] And again, Commissioners, Mr. Weathers laid that out exactly right. The model that we're talking about here is a reliability model that doesn't factor in what is the cost to add it. That's why we added the other analysis. But both of those, basically, what we've studied is intermittent reliability. We can save customers money by using batteries instead of the existing resources, coal units on minimum, those types of things. Because that study didn't capture the capital cost, we did another benefit that looks at costs and benefits of the battery that shows it's positive for customers.

Tricia Pridemore (PSC): [01:56:14] But the storage is reliant upon the additional load coming from the solar. And the solar is market procured. What if the company is unable to procure the expected level of solar that's in this IRP?

Jeffrey Grubb (GPC): [01:56:30] So Commissioner, it's a great, great question. There is a certain level of storage that would benefit customers based on what we've planned and committed to now. So the 5,000 or so that we have by the end of 2025 or so, there's amount of storage that would help there. But you're correct, what we did was we studied several tranches of renewables to look at that value. If there's not as many renewables, you wouldn't need as much storage. But we're looking at 2030 and that was the study that we provided, will as all of our other studies, we'd adjust these as we go forward.

Tricia Pridemore (PSC): [01:57:02] For decades, the Georgia Power Company has prided itself in in owning and developing its own generation and all that goes with that. The ability to manage it, the ability to resource plan against it, to control it. What do you see to be any downside to having more generation then that's outsourced, which look, I understand it's part and parcel. It's a trend in the industry. We're seeing other utilities across the country move in this direction. But I'd like to hear from the panel. What do you see, if any downside to that?

Jeffrey Grubb (GPC): [01:57:41] So I think there'll be several of us. You can probably weigh in here, Madam Chair. I think both ownership and PPAs have their benefits. I think that's why prior Commission had a balance of those. That's why the RFP rule is there, to go to the market. Customers can benefit from PPAs. But I think by the fact that the Commission in the past has had that 70/30, they recognized that there are reliability benefits to company ownership, nothing against PPAs. We've had very successful PPAs on the capacity side from gas resources, we've had successful ones from the renewable side, but there is a balance between value from a PPA and company ownership on some resources. And so I think the ability to be able to understand what's coming in the next 20 years, the company doesn't have to lock that down and know it. We can adjust as things change. A PPA, you have to kind of set that and live with it. Our prior capacity RFPs had all the capacity weight in the summers because ten years ago that's what we had. We've now shifted to put an equal balance on summers and winters. That's something we learned, but we couldn't change the PPAs. From a company owned resource, we could respond immediately. So I think they both have benefits. I think the bigger challenge in my point of view would be company ownership gives us the ability to react to changes, whether it be on the cyber security side or the use case of a certain resource, we can adapt to that, through purview with you all and reviewing the cost there as opposed to having a contract that says you can do a reverse.

Jeffrey Weathers (GPC): [01:59:14] In power purchase agreements, they're going to have certain terms and conditions, they're going to have operating procedures, they're going to have predefined maintenance scheduling windows and things that are worked out between counterparties. Ownership provides ultimate flexibility. They provide being able to update to latest maintenance practices, latest cybersecurity measures, outage scheduling flexibility, talking about batteries, changing the use case throughout the course of a day, even within an hour, enabling the system to deploy those resources according to whatever the greatest system needs are. Those are some of the reasons, especially when you're looking at batteries, where the company plans to rely on for operating reserves, which is a very critical real time function on our system. If there's any contingencies in our system, the units that are serving operating reserves, those are the ones that are going to respond. So having those be reliable, having those, having ultimate flexibility in the hands of the system operators are advantages versus a power purchase agreement, which are great for capacity and energy, but for some services, ownership is going to be more appropriate.

Tricia Pridemore (PSC): [02:00:26] The classic 70/30 split that this commission has worked under and the company has worked under for many years now, how does this plan change that? Have we moved to a 60/40 or have we done the analysis yet to determine if we're still within the classic 70/30 split?

Jeffrey Grubb (GPC): [02:00:46] So what we've by looking at what we're recommending on retirement of the coal units and the certification of the six PPAs in 2029 and 2030, we go a little above 30 [percent].. On the PPA side for about two years, but.

Tricia Pridemore (PSC): [02:01:00] Defined a little bit.

Jeffrey Grubb (GPC): [02:01:03] It's 80 megawatts or so and then 180 megawatts or so over. That does not include the storage request, it doesn't include the wholesale to retail. But then shortly thereafter in the summer of 2030, we have about 2,000 megawatts of PPAs are lost so immediately goes back down. So right now we're right at that 70/30 balance when you look at the year of need in this case.

Wilson Mallard (GPC): [02:01:28] Madam Chair, just to just add on to that, cultivating this mix of PPAs and company owned resources is really the best way for us to balance the economic benefits that we can get through PPAs. And we definitely are getting some good ones through renewable PPAs. We expect to continue to get those really good benefits through the capacity RFP, but maintaining company ownership over those critical reliability resources is the most important and that's, outsourcing that responsibility, we don't feel like is appropriate. Thus the requirement for Georgia Power ownership of the battery storage.

Jeffrey Grubb (GPC): [02:02:03] And tying it back to our discussion we've just had on weatherization and cold weather, those are owned units that we're doing that on. We're putting that money in to make those more reliable. If those were PPA resources, they may or may not do that. They would look at, do I risk it from availability percentage? It might be something that the PPA might go, "I don't know that I need to invest that money. Winter's come around every few years. I may not actually go through that extra cost." But we are because we're looking at that reliability aspect of it.

Jeffrey Weathers (GPC): [02:02:32] Or they would want to extract additional payments to do that from our customers.

Tricia Pridemore (PSC): [02:02:39] Mr. Robinson. It's a hot topic. You want in?

Michael Robinson (GPC): [02:02:41] Madam Chair, as a transmission operator, ownership is always preferred. But I understand that you have to balance economics, but very good point.

Tim Echols (PSC): [02:02:50] Question on the battery performance, the batteries, where the Southern Company or Southern Power or Georgia Power, which, whatever you've had access to the performance data. Have you seen a pattern with these utility scale containerized batteries in not performing as they were sold to you or as you, as the warranty stated? Are they underperforming or overperforming?

Wilson Mallard (GPC): [02:03:23] So generally speaking, Commissioner, they're performing within the range. There's degradation that's expected. Some have degraded, that is, produced less energy than what was expected over time. Most battery projects have a planned augmentation to make sure they can maintain the performance that they're committed to. What we've seen more of is changes in technology, changes in safety requirements, fire suppression, for example. So lots of changes that have happened. And we do have access to study across the industry, Southern Company, R&D projects, and of course, as you referenced, Southern Power's experience as well.

Tim Echols (PSC): [02:04:03] From a ratepayer perspective, are we better off financially with PPAs if batteries aren't performing as they're supposed to, where those companies are paying liquidated damages, the contractor or third party whatever? Or are we better off with you owning them where you have larger arrays and you can go to the provider and demand that the product be replaced and perform as it should?

Wilson Mallard (GPC): [02:04:33] I might reframe the proposition just a little bit, Commissioner. Let's think about these differently. These are required for reliability, a little different than what we've maybe thought about our solar renewable resources, where they're providing energy benefits. If they don't perform, it's a loss of economic benefit. Here, we need these resources for reliability. And so it's not just can we collect money back or are we protected? It's can we maintain the reliability that the system needs? That's where we feel like company ownership gives us an advantage and the reliability with ownership will be higher.

Jason Shaw (GPC): [02:05:07] Mr. Walsh. While we're on this line of question on the energy storage, I don't think we really touched on what have we learned from the 80 megawatts from the 2019 IRP? I think, correct me if I'm wrong, but haven't we approved only 65 megawatts at this point?

Wilson Mallard (GPC): [02:05:28] You're exactly right, Commissioner Shaw, and it's not online yet. It was the 65 megawatt project was approved by this commission last October. So not online. Construction's planned to start here in a couple of months, and it's projected to be online by September of next year. So we don't have any operational experience. But that's not to say we haven't learned a ton from these projects, going through the site development, going through the RFP to choose the EPC vendor, developing all of the agreements, the long term service agreements, the purchase power agreements, studying control systems, studying fire suppression, studying safety systems. We really have learned a lot through the development of that project. There are two more projects are being developed, a 13 megawatt project co-located with solar and also a two megawatt distribution project. None of the projects are online, so we don't have the operational experience, but we really have gained lots of knowledge and experience and feel like we're well suited to be successful developing the McGraw Ford Project.

Jason Shaw (GPC): [02:06:31] But we will have the 13 megawatts you mentioned. That's the one at Fort Stewart.

Jeffrey Grubb (GPC): [02:06:35] Yes, sir.

Jason Shaw (GPC): [02:06:36] All right. So would you say, I know Mr. Walsh had mentioned that capital cost was not a part of one of the main studies you've referenced. But would you say that the capital cost portion is something we've learned a lot from the 2019 IRP?

Wilson Mallard (GPC): [02:06:51] Absolutely. As it relates to storage, getting EPC vendors to actually provide firm bids and understanding the dynamics in the marketplace that are driving the cost behind these, both on sort of site preparation, interconnection cost. But then probably what most people go to and think about is the actual cost of the equipment and material. And I can tell you, based on we've already heard comments about inflation and supply chain pressures, all those things, those are absolutely impacting the cost and potential future costs for battery energy storage projects as well.

Jason Shaw (GPC): [02:07:27] Okay, one more one more question. Tell me what how you think this will impact if we end up approving your 1,000 megawatts that you're filed for or a number around that? How will that impact our solar developer community when they're bidding in on these additional megawatts of renewables that will be forthcoming? How will that impact their ability to bid in solar plus battery storage, for instance?.

Wilson Mallard (GPC): [02:07:55] So let me answer that in a couple of ways, Commissioner Shaw. First of all, it's absolutely going to help them because it's going to facilitate our ability to add more solar to the system. We're getting to the point now where we're going to have to curtail a lot of solar. There's just no where to use that excess solar energy on low load days. Having battery energy storage is going to be critical to maximize the value of more storage to the system. Secondarily, we'll absolutely still accept bids of solar plus storage in our RFPs. There's different use cases. There's a smoothing use case, affirming and smoothing use case, and even a scheduled storage use case. Those can still bid in and still have a good chance to compete. Think about it differently, though. The grid connected storage can do lots more things for the entire grid and in fact it receives signals from the whole system and can operate in a way that benefits the whole system as opposed to a solar plus storage is really just mitigating the impacts of that particular solar facility and so it can smooth that particular facility. What it can't do is help with other system conditions that might be created upstream from that generator. So two sort of different use cases. But they both definitely go together and there's definitely still a role for solar plus storage to compete in our RFPs.

Jeffrey Grubb (GPC): [02:09:16] And commissioners, I'm sorry, that would also apply to the capacity RFPs that we do going forward. [Sure.] The last one, we allowed solar plus storage and standalone storage and we completely will allow those in future capacity fees. We want storage to perform well in those as we look forward. So again, you've got the capacity RFPs that we do, you've got the renewable RFPs. Both of those will absolutely allow storage bids from the market. We're speaking about this one particular operating reserve case.

Jeffrey Weathers (GPC): [02:09:45] And Commissioner Shaw. I'll also add that the biggest impact that we saw in our renewable integration study is the ramping of solar. So generally the sun goes up and goes down. All the solar generation in the state is ramping in and out together. And so in order for the system to be able to dispatch and serve and balance load generation, some other units have to respond when solar is ramping all at the same time. So those other units that are responding, that's the operating reserves that we're talking about. That's what the batteries help with. They help mitigate the impact of the system so that it enables renewable generation procure through future RFPs to be able to be integrated economically for customers.

Michael Robinson (GPC): [02:10:27] I think, Commissioner, although we've stayed compliant with NERC standards when we talk about these ramping periods, ramp up and ramp down, we have seen some frequency issues during those periods of time with the amount of solar that we have on the system today. And those batteries will certainly help with mitigating those issues that we've seen.

Tricia Pridemore (PSC): [02:10:48] In the 2019 IRP, this Commission approved the 85 megawatt battery storage program to be a pilot, but allowed the Southern company to be the one to manage the pilot so that the knowledge could be shared across all three OpCos [Operating Companies - Georgia Power, Alabama Power, Mississippi Power]. This 1,000 megawatts of battery storage proposed in this plan, though, is it exclusive to Georgia Power or is the company seeking it to go to the HoldCo [Holding Company - Southern Company]?

Jeffrey Grubb (GPC): [02:11:10] So I'll let Mr. Mallard speak to, Georgia Power is running the 65 megawatts. He can come back to that. But the 1,000 megawatts would be Georgia Power resources. And so when you look at how we handle things in the Southern Pool, it would be a Georgia power resource. So energy and capacity values from that 1,000 megawatts is Georgia Power's in the pool for our customers.

Tricia Pridemore (PSC): [02:11:32] Can I ask you a question? Go ahead, Mr. Mallard.

Wilson Mallard (GPC): [02:11:34] I was just going to add that the 65 megawatt project that's being developed, the large grid scale and the other two projects, they are managed by Georgia Power, but absolutely, with a lot of help and support from our Southern Company partners. And that energy, that information flow goes both ways. We're able to share information with them that we're learning throughout the project. But we also get a lot of information, a lot of the same folks who work on battery projects across the country and other jurisdictions are able to share information with us as well. So it's a two way flow of information.

Tricia Pridemore (PSC): [02:12:07] And if February 2022 article in the Wall Street Journal...Yes, I read other things besides Wall Street Journal, but it is a favorite...It talks through California's situation and how in particular net metered solar has affected the state and affected the state's utilities. But in the name of the of the article is California Solar Power Welfare State. But it mentions that the state sometimes generates so much solar power that it must pay other states to take it to stabilize the grid. [I'm familiar.] Is Georgia in that position with the amount of solar that we've currently procured through

PPAs? Or do you foresee that it could be in a situation such as that if this plan is approved as filed?

Jeffrey Weathers (GPC): [02:12:55] We are not currently in that situation. I don't expect this plan, as filed, to put us in that situation. In our planning cases, we're modeling future generic solar on the system. We do expect there to be curtailment of solar. So it's important that we have the ability to curtail that solar generation to avoid having to over-generate or pay someone to take it. So having that flexibility in our contractual arrangement to curtail it and really ideally, to precisely curtail it with automatic generation control, enables us to more effectively integrated and minimize those opportunities for that to happen like you're describing.

Tricia Pridemore (PSC): [02:13:39] Can curtailing with AGC be absorbed in storage or is that above and beyond storage?

Jeffrey Grubb (GPC): [02:13:47] So that's one of the benefits of storage. Is, if you do have it, where you've got storage on the system, one of the first places you want to go to charge that would be if I'm about to curtail solar now, I can put a load on the system. It's very similar to how we do pump storage hydro, the initial pump storage hydro. I've got nuclear overnight. Let's load up this pump storage pump. So if you have renewables that you're about to curtail, but you've got storage and that's a load you can put that's megawatt hours you can use.

Jeffrey Weathers (GPC): [02:14:15] Like in our renewable integration study we did, we studied two different things. We studied more renewables on the system, only relying on the current system. There is significant curtailments in that situation. There's significant curtailments and it costs more if you're only relying on the current system. As you add batteries, there still will be curtailments, but there will be less curtailments with batteries because their ability to store that generation then release it in other hours. And plus it's a less costly solution because the batteries are able to more effectively provide those reserves cheaper than if you're relying on the rest of the system that's not quite as flexible.

Michael Robinson (GPC): [02:14:55] And Madam Chair, our transmission planning team, to address the issue that you referenced in the Wall Street Journal article, is continually looking at studies out of time, looking at assumptions of generators that may be proposed to be retirement or retired in Alabama, Mississippi, our proposed solar expansion to ensure that we have a reliable system in the future, we don't get into that situation.

Daniel Walsh (PIA): [02:15:19] I'm going to ask a few questions on the renewable integration study. Do you have that available? [Yes.]

Daniel Walsh (PIA): [02:15:26] Renewable integration studies used to calculate the new integration cost component of the Renewable Cost Benefit Framework. Is that correct? [Yes.] Can I get you to turn to page 22 of the study? This is Section 3.5 entitled Integration Cost Calculations. [Yes.]

Daniel Walsh (PIA): [02:15:52] Is it correct that the mitigation cost is based on the change in total system production cost between a case with no additional operating reserves in a case with additional operating reserves to address solar output volatility?

Jeffrey Weathers (GPC): [02:16:10] That is correct. It is the system impact cost that that solar incurred on the system.

Daniel Walsh (PIA): [02:16:17] And key components of production cost. Would that include fuel prices and variable O&M expense? [Yes.]

Daniel Walsh (PIA): [02:16:24] Would it include, would there be any other major components of production cost?

Jeffrey Weathers (GPC): [02:16:31] Those are the major ones.

Daniel Walsh (PIA): [02:16:34] Are natural gas prices a primary element of the change in production cost, driving the mitigation cost calculation?

Jeffrey Weathers (GPC): [02:16:43] Well, they are a primary component. Yes. Fuel costs are a primary component, of which, of that natural gas is a primary component.

Daniel Walsh (PIA): [02:16:53] Yes. And the production cost metric is calculated within the SERVM model. Is that correct?

Jeffrey Weathers (GPC): [02:16:58] Yes.

Daniel Walsh (PIA): [02:17:00] Can I get you to look at page 17 now of the renewable integration study? This is Section 3.1 entitled Established Flexible Violation Benchmark Target. [Yes.]

Daniel Walsh (PIA): [02:17:16] I was going to. Well, first of all, what is a flexible, flexibility violation?

Jeffrey Weathers (GPC): [02:17:22] So a flexibility violation is when, in the SERVM model, so the model we use for the study, we determine that in a particular hour there's enough resources on the system, but the model is not able to balance load and generation and at least one of the five minute increments. So what that means is you've got adequate resources. They're just not flexible enough. So you need more flexible units. So you either have to have more units online or you need to replace the units that are online with more flexible resources.

Daniel Walsh (PIA): [02:17:59] Can I direct your attention to the bottom of the first paragraph under 3.1? The last sentence says, "Therefore, the flexibility violation metric should not be interpreted as actual outage conditions."

Jeffrey Weathers (GPC): [02:18:12] That's correct.

Daniel Walsh (PIA): [02:18:13] Does this mean that even though there are flexibility violations in the base case, it does not necessarily mean that there would be a system outage?

Jeffrey Weathers (GPC): [02:18:21] That is correct. When we study this with there, as you mentioned, Mr. Walsh, within our base case, there is some flexibility violations. It doesn't mean that there's outages in our system. So there's some room within the NERC compliance guidelines for those type of conditions and returning the system to where it should be. So not every not every situation is an outage, but it represents pressure on the ability of our operators to balance load and generation in real time.

Daniel Walsh (PIA): [02:18:49] Could I get you to turn to page 19 of the study? I'm going to ask you to look at the first paragraph under table 13. Does this paragraph state in effect, that for purposes of this analysis, reserves were increased to address flexibility violations?

Jeffrey Grubb (GPC): [02:19:21] Can you say the question one more time, please, Mr. Walsh?

Daniel Walsh (PIA): [02:19:23] Sure. I'm trying to summarize this paragraph under table 13 on page 19, and I'm asking whether it's accurate to say that this paragraph is stating that for purposes of the analysis it's discussing, Reserves were increased to address flexibility violations.

Jeffrey Weathers (GPC): [02:19:47] This, it is true that we did that. I don't see in this particular paragraph where it addresses that. But it does address the, it describes the table which is talking about the flexibility violations, the intrahour pressure on balancing load and generation.

Daniel Walsh (PIA): [02:20:05] I was looking, focusing in one part of the last clause which says higher levels of energy deficiency requiring greater operating reserves to mitigate the flexibility violations.

Jeffrey Weathers (GPC): [02:20:16] Okay. Yes, that is correct.

Daniel Walsh (PIA): [02:20:19] Is it correct that the increase in load following reserves is only based on the SERVM model analysis and not based on Georgia Power's actual system operations?

Jeffrey Weathers (GPC): [02:20:31] Well, the SERVM model analysis is modeling the Company's system. So it is modeling within the system with different levels of renewable penetration, which haven't occurred yet. So it's all, you're all in modeling world. But it is the actual units in the system, the actual operating characteristics of those units, and the actual load forecast that we have, all those things are what goes into the model.

Daniel Walsh (PIA): [02:20:58] Is it based on Georgia Power's experience with integrating solar on its system?

Jeffrey Weathers (GPC): [02:21:04] It is. The results are consistent with it. So we have seen pressure on operational flexibility within real time operations, both from ramping and also from intermittency impacts. The model confirms that. It also projects that to continue in increasing amounts as you add additional solar on the system.

Daniel Walsh (PIA): [02:21:25] I just want to make sure we're talking about the same thing. When you say the results confirm that. I was asking whether the experience, whether the SERVM model analysis was based on the actual Georgia Power Company experience with integrating solar on its system, not whether the results confirmed, but whether the model is based on it.

Steve Hewitson (GPC): [02:21:47] Well...I don't know if it's the way that you're asking. It's not historical looking. It's not looking at actual results, but is using actual units and projecting operations. So it is the units on our system, but it's not backward looking. It's a forward looking modeling process.

Daniel Walsh (PIA): [02:22:09] But as far as what inputs are being included into the model analysis, was that based on actual experience?

Jeffrey Weathers (GPC): [02:22:19] Yes. In terms of the solar generation, the profiles, the intermittency impacts based on weather, all those are in terms of actual data.

Daniel Walsh (PIA): [02:22:30] And the actual data for integrating solar on the system?

Jeffrey Weathers (GPC): [02:22:36] Yes. For our solar generation, we used our solar generators, we modeled those on the system, and then we applied volatility around that based on weather that occurs across our service territory. So it's all based on observed or actual data or units that we have, but it's a model and so it's projecting future operations and it's not going to exactly align with any particular hour in the past. It is projecting the future operations.

Daniel Walsh (PIA): [02:23:07] Is it easier to avoid flexibility violations if you have more flexible resources?

Jeffrey Weathers (GPC): [02:23:13] Yes.

Daniel Walsh (PIA): [02:23:14] Would that mean, like, more flexible resources, like combustion turbines or batteries on the system rather than large coal plants?

Jeffrey Weathers (GPC): [02:23:24] Well, so those are different degrees of flexibility. So certainly large, of those three, large coal plants would be the least flexible. Combustion turbines provide more flexibility because you can start and stop those either within 15 minutes or maybe within an hour, but that the batteries will provide the most flexibility. They can come on nearly instantaneously and respond to these intrahour five minute, and even more real time than that, flexibility issues that we saw in the model.

Daniel Walsh (PIA): [02:23:57] And does the Renewable Integration Study analysis consider that Georgia Power is planning to retire multiple coal units and will be adding more flexible resources.

Jeffrey Weathers (GPC): [02:24:09] It does consider, so it doesn't necessarily consider specific retirements, but really there's a contrast in the model between the existing system being able to provide the flexibility needed to integrate solar, and batteries being able to do it. So a lot of the, when the existing system is providing in the modeling, a lot of that is from natural gas units. So the coal units aren't operating a lot in the model anyway. So what you're doing is you're replacing operating reserves from a variety of resources, but natural gas is a large part of it, with battery resources, will provide that more efficiently and more economically.

Daniel Walsh (PIA): [02:24:54] Well, let me summarize what I think I heard there. The model, the study analysis did not consider that Georgia Power is planning to retire multiple coal units. But you don't believe that coal was operated that much in the model anyway?

Jeffrey Weathers (GPC): [02:25:14] It does consider the retirement of some units. I would have to go back and verify which specific units were in or out of the model. But when. But there is some coal the system. So the model does reflect there is some coal, the system, but it's not only coal providing reserves, gas unit providers provide reserves as well. And there's some base level of operating reserves. It is going to be the same no matter what. So our existing system provides those reserves. So we're talking about here are the additional operating reserves that will be required to mitigate the impact of future expansion of solar. There's value to providing those additional reserves with the battery storage devices, as opposed to continuing to rely on the rest of the system, which doesn't have the same level of flexibility.

Daniel Walsh (PIA): [02:26:06] Does the renewable integration study itself state that it considers that Georgia Power is planning to retire multiple coal units? Or is that reflected somewhere in the company's filing?

Jeffrey Grubb (GPC): [02:26:22] I don't believe that we stated, as Mr. Weathers said. So we have to go back and look at the years that we studied and what basis some of the coal units probably were retired. It's probably not all of them. We'd have to go back and look. [Okay.]

Tricia Pridemore (PSC): [02:26:35] Mr. Walsh, we're going to break at noon to allow...and my question, for you all to receive nutrition and hydration. We want to make sure that you can do so without the folks across the street getting in your way. So let's do a hard stop at noon.

Daniel Walsh (PIA): [02:26:49] Okay. [Thank you.] I'm going to ask a lengthy question. You're going to have only time for a very short answer.

Jeffrey Grubb (GPC): [02:27:00] I can't see the clock so I'm at your mercy. I have no idea what time it is.

Daniel Walsh (PIA): [02:27:05] I'm going to ask you a very hopefully a short line of cross on the ownership of energy storage service. You've testified that the company is proposing to own the storage resources rather than contract for them under third party ownership. Is that correct? [That's correct.] Okay. And you've testified that the company will face many challenges that make company ownership of energy storage service resources essential. Does technology exists that would allow Georgia power to control and dispatch battery resources even if it does not own them?

Jeffrey Grubb (GPC): [02:27:41] Yeah. Mr. Mallard may help me here. I believe there are AGC and other things you can do in batteries. And again, it's not that we couldn't put a contract in place on those batteries, is that we shouldn't, in terms of reliability, resources and these operating reserves. Commissioners, we've been talking about a lot about operating reserves. We're talking about the ones that we will not commit other resources for knowing that these batteries are there to handle unit outages, changes in loads. So it's from a generation standpoint, operating reserves are the reliability backbone of the system. So our position is we need to own that, 20 year assets, making sure that they're reliable, making sure that we're able to have the flexibility to handle the different uses that we may need of it over 20 years. And so their technology to be able to control it, we would deploy that ourselves, I'm sure. So it's not that that's not available. It's it's the ownership piece. And having the party responsible for reliability have ownership of those resources, that's driving our requests.

Daniel Walsh (PIA): [02:28:43] Does the company rely on generating capacity for resource adequacy that it does not own?

Jeffrey Grubb (GPC): [02:28:48] We do in part, yeah.

Daniel Walsh (PIA): [02:28:51] And is it possible that developers could develop battery resources more cost effectively than Georgia Power?

Jeffrey Grubb (GPC): [02:28:58] They're able to be able to bid in the capacity RFP. And as we've mentioned, we totally expect and welcome them to bid into future capacity RFPs where we would have contracts. We have PPAs we're seeking certification here on gas units. Not as new as batteries are. We've got more experience with them. But from a resource that you're supplying capacity and energy out of, we've got experience with gas resources, feel comfortable with those PPAs, would allow stores to bid in there. Again this comes back to the specific resources that are critical to reliability.

Daniel Walsh (PIA): [02:29:32] So the answer, though, is yes.

Jeffrey Grubb (GPC): [02:29:35] They could, I don't know that they can do it cheaper. We'll have to see. We wouldn't know that until we did an RFP, but they could [it's possible] they can develop them.

Daniel Walsh (PIA): [02:29:43] So it's possible it could be less expensive and it's possible.

Jeffrey Weathers (GPC): [02:29:48] But it's also important that, as we said earlier, batteries are very flexible devices. They can operate a wide variety of purposes according to whenever the system needs them and is really difficult to anticipate all the different uses of the system in the terms and conditions of contract and to allow that flexibility to operators. So they need to be able to have assurances the batteries will be maintained according to current system standards, whatever those are and however those evolve over time. And also they have the ability to operate and call those devices as needed for system purposes without the encumbrance of any terms and conditions that may limit that.

Daniel Walsh (PIA): [02:30:30] Is it your testimony that could not be done unless Georgia Power owns it?

Jeffrey Weathers (GPC): [02:30:35] I think any time you introduce a contractual arrangement, there are going to be terms and conditions. And so either there's, the more flexibility you build into the contract, the more expensive it is, because the provider, the seller, will have to anticipate that the company uses it in the way that provides the most wear and tear to the units possible so they recover their cost.

Daniel Walsh (PIA): [02:30:57] Then it would just be a question whether you could build that flexibility at a cost that was more cost effective than Georgia Power owning it, correct?

Jeffrey Weathers (GPC): [02:31:04] Yeah, that would be the question. But I think it's important. As Mr. Grubb said, we're talking about operating reserves and essential reliability services on the system that operators rely on in real time operations. That's something you're not, you don't want to outsource. You want the company to be able to control that it, own that and operate that and know that they can depend on that because without it, there's no other units committed. It's going to cost customers a lot more for the system to react.

Daniel Walsh (PIA): [02:31:38] That completes that line of cross.

Tricia Pridemore (PSC): [02:31:39] Thank you. Very good. Mr. Walsh, want to give you an opportunity to show off that good looking tie in the cafeteria. We're going to break until 1 p.m. See you all back here.

Tricia Pridemore (PSC): [03:29:14] According to my clock, it's 12:59. We'll get started in one minute. Give everybody an opportunity to get settled.

Tricia Pridemore (PSC): [03:30:09] Mr. Walsh. Are we ready? Witnesses? Are we ready? [Yes.] Let's take it from where we left off.

Tim Echols (PSC): [03:30:17] Mr. Walsh, can I jump in? There wasn't time before lunch. On solar, and I'm thinking mainly on the distribution grid, not the transmission grid. So maybe, Mr. Mallard, This would be you. But is it true that as we get more solar on our distribution grid, that we've nudged the voltage up a little bit or not necessarily?

Jeffrey Grubb (GPC): [03:30:39] So it can be. And I'll ask Mr. Robinson to help. It just depends. It's locationally dependent. When solar is producing and creating output, generally, yes, it's supporting the system, but it's the variability, Commissioner, that solar without storage adds to the grid that makes, can make that more challenging.

Michael Robinson (GPC): [03:30:57] Again, Commissioner, part of the interconnection study process that we do is ensure that voltages stay within appropriate levels. So we're not over-voltaging the system or creating situations where we're under voltage as well.

Tricia Pridemore (PSC): [03:31:10] Mr. Robinson, speak into that mike, please. Thank you.

Tim Echols (PSC): [03:31:13] So in the same way, I guess, as you're wanting to have more control over whether it's the battery system or the curtailing the solar arrays yourself, automatically with the automatic controls, is it, does the smart inverters, do they help with that? We don't necessarily require those, do we?

Wilson Mallard (GPC): [03:31:37] So we do. We are, we have upped the requirements on our inverters. Most inverters out of the box these days are smart inverters. Commissioner. What we need on the other side now is a DERMS, a management system for these distributed energy resources so that we can communicate with them and control them. That is under development, for sure. There's some elements of this IRP that support distributed generation management in that way. And that's absolutely a future state that we're moving towards, where we will have better line of sight and better operational control of distributed risk. [All right. Thank you.]

Tricia Pridemore (PSC): [03:32:11] Go ahead, Mr. Walsh.

Daniel Walsh (PIA): [03:32:12] Thank you. Before the break, we discussed the renewable integration study quantifies the change in production costs as recorded in the SERVM model for each scenario to prevent flexibility violations. Has Georgia Power quantified the production costs that it is currently incurring to avoid flexibility violations due to the solar that it is that is already on the system?

Jeffrey Weathers (GPC): [03:32:40] No, it's not really something that is easily done. And so in the model, we're able to do it because we have, we can model with and without the solar. So the difference of those two is the production costs, the integration cost associated with that. In actual operations, you only have actuals. So there's no comparison case to compare that to. So we know that there are impacts from ramping a solar and intermittency of solar, but exactly the cost of those is not determinable.

Daniel Walsh (PIA): [03:33:13] So you can't do any kind of comparison then between the results of the renewable integration study and the actual comparison?

Jeffrey Weathers (GPC): [03:33:21] No. In terms of the integration cost, it's really not something we have in, we can't quantify in actual practice, but that's why we have the model. So the model actually enables us to quantify that, both for the existing level of solar and for increasing levels of solar.

Daniel Walsh (PIA): [03:33:37] Just to be clear, when you say you can't do it, is it an impossibility or is it something that the company believes is not worth doing?

Jeffrey Weathers (GPC): [03:33:45] But, it's an impossibility without the use of a model that presents some other scenario different than reality, because you only have one actual case. So you want to compare that versus an alternate actual case. You're having to introduce modeling elements.

Daniel Walsh (PIA): [03:34:06] I want to ask you a few questions about McGrau. The company is seeking approval to build the 265 megawatt McGrau Ford BESS system, which it states is part of its ESS deployment strategy. Is that correct?

Jeffrey Grubb (GPC): [03:34:22] That's correct.

Daniel Walsh (PIA): [03:34:25] And there's nothing in the company's filing, is there, that shows whether the company examined any alternatives to the McGrau Ford system that could have produced operating reserves at a lower cost?

Wilson Mallard (GPC): [03:34:39] So the company continuously evaluates potential sites for generating resources, renewables, battery energy storage as well. And so as outlined in the company's Battery Storage Procurement Action Plan, the company is continuously looking for these desirable locations. So, yes, we have absolutely evaluated different locations. McGrau Ford is the one that was chosen for this first battery storage project.

Daniel Walsh (PIA): [03:35:04] Is that reflected in the company's filing, that the company examined alternatives to the McGrau Ford system?

Wilson Mallard (GPC): [03:35:12] So I, maybe it's not, I don't, it's not in the the battery energy storage section in the main docket or in the testimony.

Daniel Walsh (PIA): [03:35:25] Few questions for you related to biomass. Is it correct that the company was unable to finalize the purchase power agreement with any of the bidders from the 2022 through 2028 capacity RFP?

Jeffrey Grubb (GPC): [03:35:40] Yes. So the biomass was actually a part of that capacity RFP. But yes, we were unable to procure resources under the aspects and the particulars of that RFP in the proforma PPA. We work with commission staff and the IE [Independent Evaluator] and went through the entire process. But yes, there was some specifics that we could not meet with some of the other resources.

Daniel Walsh (PIA): [03:36:07] Is it also correct that the biomass bids received in response to the capacity RFP were not economic relative to purchase power agreements proposed for certification?

Jeffrey Grubb (GPC): [03:36:18] So the capacity RFP and the biomass RFP were separate solicitations, they were the same schedule and those types of things. But from an evaluation standpoint, the biomass bids competed against other biomass bids. We did not compare them to the capacity RFP, but the prices that biomass bid in were higher.

Daniel Walsh (PIA): [03:36:41] So they were not economic, understanding you didn't do that comparison? Had you done that comparison, the biomass would not be economic in comparison to other purchase power agreements?

Jeffrey Grubb (GPC): [03:36:53] Yeah, biomass prices are higher than what we saw in the capacity RFP.

Daniel Walsh (PIA): [03:36:56] Were the biomass bids more economic or less economic than the most competitive solar plus storage bid in that RFP?

Jeffrey Grubb (GPC): [03:37:05] So the capacity RFP did not have a solar only bid. I think if you look at prices that we've seen on solar for the renewable RFPs, then yes, those prices are lower than biomass. But I think that's been recognized by many parties that biomass is economically different from those others.

Daniel Walsh (PIA): [03:37:27] Did the company's evaluation of the biomass bids show a net benefit to customers?

Jeffrey Grubb (GPC): [03:37:34] From a straight in energy and capacity standpoint, they would not have. But then again, we were just looking to get the best price biomass resources we could. But I think this commission in the past has noted there's other aspects to biomass that they've often included. But from a straight energy and capacity standpoint, they just competed with each other.

Daniel Walsh (PIA): [03:37:55] What was the amount of the net loss to customers from the most competitive biomass bid?

Jeffrey Grubb (GPC): [03:38:01] I can't remember what the total net cost was there. I just can't recall.

Daniel Walsh (PIA): [03:38:06] Can you say whether the net loss is more or less than 100 million?

Jeffrey Grubb (GPC): [03:38:10] I can't recall. We didn't execute the contract, so I don't know. I can't recall the final evaluation there. But a 20 year biomass contract is a lot of money over the life of that customer.

Daniel Walsh (PIA): [03:38:25] I'd like to ask you a few questions about accounting deferrals.

Jeffrey Grubb (GPC): [03:38:29] Okay.

Daniel Walsh (PIA): [03:38:30] The company is requesting several accounting deferrals, primarily related to plant retirements. Is that correct?

Jeffrey Grubb (GPC): [03:38:37] If by accounting deferrals, you mean moving the net book value into regulatory asset? Yes, we are.

Daniel Walsh (PIA): [03:38:44] And the commission is not required by statute to address the company's request for accounting deferrals or amortization periods in an IRP proceeding. Is that correct?

Jeffrey Grubb (GPC): [03:38:55] That is my understanding. I know we've made several of those recommendations in the past for the commission to consider. So we've often requested for the net book values upon retirement to be moved to regulatory asset. In this case, we're asking for that again, but stating that the actual amortization periods and the dates will be determined across the next few rate cases.

Daniel Walsh (PIA): [03:39:19] And the company, in fact, is scheduled to file its next rate case later this year, correct?

Jeffrey Grubb (GPC): [03:39:23] That's correct.

Daniel Walsh (PIA): [03:39:30] And. Will the company will be seeking to establish a new three year rate plan covering the years 2023 through 2025?

Jeffrey Grubb (GPC): [03:39:38] I believe that's the timeframe for the rate case. I'm not involved in the rate case strategy of those developments, but that's my understanding of the timeframe.

Daniel Walsh (PIA): [03:39:45] Okay. And it's your understanding that the company would also be on schedule to file its next IRP and another base rate case in 2025?

Jeffrey Grubb (GPC): [03:39:53] That's correct.

Daniel Walsh (PIA): [03:39:55] Would you agree that since the company filed its 2022 IRP, there have been significant developments that were not known to the company at the time that it made its filing, such as increased volatility in the world energy markets.

Jeffrey Grubb (GPC): [03:40:10] And which markets I'm sorry?

Daniel Walsh (PIA): [03:40:11] The world energy markets.

Jeffrey Grubb (GPC): [03:40:14] Yeah. I mean, there's been a lot going on in the last few months. I think we hit on a little bit this morning. Again, we're looking at 30 year studies, long term decisions. I don't think that would change any of our recommendations. But yes, some things have changed. I think they're more short term in nature than long term in nature.

Daniel Walsh (PIA): [03:40:33] Are all of the units of which the company is seeking early retirement in the current IRP sourced with fuel sources that are produced in the United States?

Jeffrey Grubb (GPC): [03:40:43] Yeah. I mean, I think almost all of our resources are fueled from within the United States. I think the gas, all of our domestic supply, all of our gas supplies, domestic, coal supplies, domestic, I think our uranium may be globally, but almost everything is domestic from a supply standpoint.

Daniel Walsh (PIA): [03:41:06] I want to ask you a few questions about procuring renewables beyond the 2,300 megawatts. [OK.] The company is seeking approval to procure 2,300 megawatts of new renewable projects in the next three years. Is that correct?

Jeffrey Weathers (GPC): [03:41:24] Correct.

Daniel Walsh (PIA): [03:41:26] And this this megawatt target is the result of the analysis summarized in the renewable expansion plan. Is that correct?

Jeffrey Weathers (GPC): [03:41:34] Correct.

Daniel Walsh (PIA): [03:41:35] And also the resource mix study?

Jeffrey Weathers (GPC): [03:41:38] Well, the renewable expansion plan, which is a resource mix study, it's not the same as the IRP base case study, but it is a resource mix study. And those renewables are reflected in the resource mix and resource mix study in all the planning scenarios as well.

Daniel Walsh (PIA): [03:41:58] So did the resource expansion plan analysis indicate that there were market conditions that would suggest that more renewables would provide economic benefits to customers?

Jeffrey Grubb (GPC): [03:42:13] Yes. Are you talking about the, asking about the renewable expansion plan that we filed or the expansion plans in 2022 that included it? I just want to make sure.

Daniel Walsh (PIA): [03:42:26] I'm talking about the renewable expansion plan analysis that was filed.

Jeffrey Weathers (GPC): [03:42:30] Yeah, I mean, it considered a range of scenarios and in those scenarios, represents a range of renewable expansion. So if you have, for example, very high carbon prices, then renewables are more economic and made more, economic to add more earlier.

Daniel Walsh (PIA): [03:42:48] If the Commission were to approve the Company's request for approval of the 2,300 megawatts, will the company continue to monitor market conditions and potentially propose additional procurements if it determines that there would be additional benefits?

Wilson Mallard (GPC): [03:43:01] So absolutely. That's one of the hallmarks of our renewable plan this time, is some added adaptability and flexibility to market conditions that are continuously changing these days. As Mr. Walsh referenced, there's lots of things impacting the supply of the components for renewable resources and batteries...inflation, the supply chain pressures that we're all familiar with. Additionally, the impacts to our transmission system as we integrate more of these. And so having some flexibility, Commissioners, as we go forward on the timing and maybe the total amounts and being able to make some adjustments there based on market conditions, we feel like that's important to ensure that we continue an efficient procurement of renewables.

Daniel Walsh (PIA): [03:43:44] I'm going to be referring to page 1-8 of the main IRP filing. You may be able to answer the question without reference, but it may help to get there.

Jeffrey Grubb (GPC): [03:44:00] You can proceed with your question.

Daniel Walsh (PIA): [03:44:03] Thanks. Do you see where the company says it's proposing a longer plan through 2035, that includes the addition of 6,000 megawatts of renewable resources?

Jeffrey Weathers (GPC): [03:44:14] Yes.

Daniel Walsh (PIA): [03:44:15] If the Commission were to approve the company's IRP, would you consider that to be approval of the company's longer plan to add the 6,000 megawatts?

Wilson Mallard (GPC): [03:44:24] So not explicit approval. And here's the thing. The 6,000 is a long term target, and the models do show that adding that amount of renewable resources is going to be in customers best interest. The only thing that we really need approval of in this IRP cycle is the 2,300 megawatts. That'll get us through issuing the two utility scale RFPs, one distributed generation RFP with two bid periods. And by that time, we will be back in front of the commission in the 2025 IRP. Our expectation is we'll make adjustments to that long term target of 6,000 megawatts based on the current market conditions.

Daniel Walsh (PIA): [03:45:01] So would you characterize that statement about the 6,000 megawatts of renewable resources by 2035 to be less a request for approval and more just an explanation of the company's longer term plans?

Jeffrey Grubb (GPC): [03:45:16] Yeah, I would agree with that. And I think, Commissioner, is one of the things that that longer term plan gives us is the ability to plan for it, both on the generation side and the transmission side. So fast IRPs, we had that one number that we were doing for three years and really no guidance beyond that. This extra guidance allows us to study it from a transmission standpoint as well.

Michael Robinson (GPC): [03:45:36] And, Commissioners, it's going to be very important, but we're looking out in time beyond the ten year window, looking towards that 2035 date. We anticipate the future retirement of Bowen 3&4, an additional 6,000 megawatts of renewables in south Georgia. Hopefully, we're successful in steering some of those to North Georgia with the North Georgia Reliability Resilience Plan we proposed. But we're going to need significant transmission built. That's not in this plan. We're working on that with the ITS participants today to move those megawatts from South Georgia to North Georgia to address those constraints that we're starting to see on the System today.

Tricia Pridemore (PSC): [03:46:08] But since you're not seeking the 6,000 megawatts in this cycle, you're saying that the 6,000 could go up or it could also go down.

Michael Robinson (GPC): [03:46:18] [Correct.] Madam Chair, another thing that's very important is not being the only utility in the state. EMCs and municipalities also have renewable development goals. Their customers are doing the same thing. So you could easily see that 6,000 megawatts be 9,000 megawatts. If you add the EMCs and municipalities into the equation as well.

Tricia Pridemore (PSC): [03:46:38] That's for another day, Mr. Robinson.

Daniel Walsh (PIA): [03:46:43] The company proposes to procure 2,100 megawatts of utility scale renewables in this IRP cycle, and to make all of that capacity available to C&I customers through the CARES program. Is that correct?

Wilson Mallard (GPC): [03:46:56] Yes.

Daniel Walsh (PIA): [03:46:57] When renewable resources are subscribed by a C&I customer, does that mean that other customers do not get the full benefit of that renewable resource?

Wilson Mallard (GPC): [03:47:06] No, I don't think that's the case. I think all customers get all of the benefits of the renewable resources, really. Commissioners, what we're talking about here is on whose behalf the REC is retired, the Renewable Energy Credit or the attribute. And that Renewable Energy Credit is important to a lot of our large customers, especially who have sustainability or carbon or renewable energy goals. The benefits of adding renewables to the system accrue to all Georgia Power customers, regardless of who owns the REC. Additionally, the CARES design will allow those RECs to be sold, if you will, retired on behalf of the subscribing customers and the proceeds will go to the fuel bucket in hopes of putting downward pressure on rates for all customers.

Daniel Walsh (PIA): [03:47:49] So it's your testimony that all customers benefit equally.

Wilson Mallard (GPC): [03:47:57] All customers will benefit from the addition of the 2,300 megawatts of renewable resources as we, as proposed. The same cost benefits, the same environmental benefits, the same renewable benefits do accrue to all customers. What's different is some customers will be able to subscribe to the Renewable Energy Credit. That is, the ability to claim the renewable attribute, to advertise the renewable attribute or to use it for compliance with an internal or external goal. That's really the key to this program, is allowing those renewable energy credits to be assigned to a specific customer.

Daniel Walsh (PIA): [03:48:35] And will those customers that get to subscribe benefit more than those customers that don't get to subscribe?

Wilson Mallard (GPC): [03:48:40] They benefit in the sense that they get access to the Renewable Energy Credit that is important to them. But if that Renewable Energy Credit is not important to another customer, then they have no need for it. They benefit just as much.

Tim Echols (PSC): [03:48:54] Just a question for Mr. Mallard on this. Mr. Mallard, really, since Commissioner MacDonald's motion in 2013, all the solar that we've done at utility scale that's been below avoided costs, it's actually had an accrued benefit for every customer on the system, right?

Wilson Mallard (GPC): [03:49:11] The benefits accrue to all customers. Yes, sir.

Tim Echols (PSC): [03:49:14] And do you anticipate, even with this solar dumping, this dumping policy that's been put in place and solar prices ticking up, do you anticipate us still being able to deliver the savings to the customers?

Wilson Mallard (GPC): [03:49:31] So what we do, Commissioner, and what we're proposing here is is to look at those benefits a little bit differently. Our models are able to choose renewable resources now looking forward where they haven't been able to do that before. That's the output that we've been talking about, where it shows that 6,000 megawatts, if added at prices similar to what we modelled, will be a benefit to all customers. We do expect that to continue. Now, all the things that you're talking about, there's volatility in the solar market. Absolutely. Prices can go up and down. It's our expectation that long term solar will continue to deliver value to customers. But we'll model that and we'll run these RFPs and get a real good idea of exactly what those prices look like. Work with staff, work with the IE, and then ultimately present to the Commission for approval, what portfolio of resources is in the best interest of customers.

Jeffrey Weathers (GPC): [03:50:23] Mr. Echols I'll add also, as Mr. Mallard said, the model is selecting solar. So it's looking at not just one scenario but a cost across a range of scenarios of gas prices and carbon prices. And the only reason the model selects it is because it produces energy savings for customer. It's cheaper to have the solar than to not have the solar. So all the solar that's proposed and been selected by an optimization model that selects it because it produces savings for customers. [Thank you.]

Daniel Walsh (PIA): [03:50:52] I want to go back and discuss this one point. If I understood your last answer, because I was asking whether the customers who have the option to subscribe receive a greater benefit than the customers who don't receive the option, who don't have that option. And I believe you said that if the subscription wouldn't benefit the customer, then nothing's lost when, if they don't have the opportunity to subscribe. But I'm just trying to make the point that if, not every customer will have the opportunity to subscribe, right?

Jeffrey Grubb (GPC): [03:51:24] Not every customer will have the opportunity to subscribe to the CARES program. However, all Georgia Power customers do have options available to them to subscribe to the output of renewable resources.

Daniel Walsh (PIA): [03:51:35] But for this program they would not. And so they don't have every option to receive the full benefit that the customers who have the opportunity to subscribe.

Wilson Mallard (GPC): [03:51:47] I guess my position, Mr. Walsh, is unless an individual customer finds value in having that renewable energy credit retired on their behalf, they're better off under the CARES program because their bill will be lower. And the customer that does find value in the renewable energy credit will also be more satisfied. They will have paid a subscription fee and the REC would be retired on their behalf.

Daniel Walsh (PIA): [03:52:09] But would there be customers who would benefit, but who would not have the opportunity to subscribe?

Wilson Mallard (GPC): [03:52:15] Well, there's, not every customer will have the opportunity to subscribe to the CARES program because we do have subscription levels, minimum subscription levels, and it's targeted for our larger customers. But as I mentioned, we've got a portfolio of programs including simple solar, including community solar. All Georgia Power customers have the opportunity to subscribe to a solar program or a renewable program one way or the other.

Daniel Walsh (PIA): [03:52:38] And I'm asking specifically about the CARES program. So for the customers who don't have the opportunity to subscribe, they may not be able to receive a benefit under this particular program that they would be able to receive if they were allowed to subscribe.

Wilson Mallard (GPC): [03:52:53] The only benefit that they're going to miss out on is if they find value in the Renewable Energy Credit. The cost savings, the environmental benefits, the fuel diversity, all of those things that solar and renewable resources bring to the system, those still accrue to all customers, regardless of the REC ownership.

Tricia Pridemore (PSC): [03:53:09] So on the CARES program, though, it's designed to be able to assist the economic development mission in the state of Georgia, right?

Wilson Mallard (GPC): [03:53:16] Partially, yes, ma'am. Some is also reserved for existing customers, but some is for new load as well. Yes, ma'am.

Tricia Pridemore (PSC): [03:53:21] Okay. And so as the state of Georgia has seen an increasing number of corporations that want to put a second headquarters or an outlet here of some sort. But the corporate entity has, we'll call, an RPS on their corporation, and that is what is allowing Georgia to be competitive with other states, such as North Carolina, Florida, and those that we compete with on a regular basis for jobs. That gives an opening, though, so that, it makes Georgia equally or in my opinion, more attractive than other programs that have been reviewed and implemented in those states. Is that right?

Zach Fabish (SC): [03:54:01] Yes, that's that's definitely the case based on my experience. Almost all, I wish I had a percentage, but it seems like almost all of the customers seeking to relocate or add load to Georgia, the large customers we dealt with in the last couple of years, almost 100% of them have some sort of renewable or carbon goal. And so having this option available definitely helps Georgia be more competitive to bring the load to Georgia and then help Georgia Power be more competitive in the customer choice market as we compete for these jobs.

Tricia Pridemore (PSC): [03:54:31] Okay. Thank you.

Daniel Walsh (PIA): [03:54:33] Can I get you to refer to page 36 of your pre-filed direct testimony? I'm going to be looking at the Q&A that begins on line 20.

Wilson Mallard (GPC): [03:54:46] Can you say the page one more time? [36.] Yes.

Daniel Walsh (PIA): [03:54:50] It's the question where you ask, "Please describe what is meant by best cost procurement."

Wilson Mallard (GPC): [03:54:55] Yes, I'm there.

Daniel Walsh (PIA): [03:54:58] On line 23. You describe it as most valuable or best cost resources. Do you see that? [Yes.] Would you agree with me that calling it the most valuable doesn't give a lot of specifics as to what the company means by best or most valuable?

Wilson Mallard (GPC): [03:55:15] Well, it does. It does to me. And maybe I'm speaking in the world of evaluating renewable resources, but it's creating the most value for our customers. It's based on price and then also based on the generation profile and the associated benefits that each of these renewable resources would bring to the system.

Daniel Walsh (PIA): [03:55:35] Okay. But I mean, in your answer, you just say most valuable, right?

Wilson Mallard (GPC): [03:55:39] Yes.

Daniel Walsh (PIA): [03:55:40] If you could turn to the next page, 37.

Jeffrey Weathers (GPC): [03:55:44] Mr. Walsh, we do talk about, we do further describe that, in that same response further in the next question.

Jeffrey Weathers (GPC): [03:55:52] We didn't limit it to that one term. We also described what that meant in terms of the RCB Framework.

Daniel Walsh (PIA): [03:55:56] And that's what I'm getting to in my next post. [Good. Thank you.] On the next page, still in the same question you say, "Therefore, the company is proposing additional flexibility in how it identifies the portfolio of best resources to fill the company's renewable energy needs.' Again, that doesn't give a lot of specifics about what the company would get approved, what the commission would be approving, if it approved the company's best cost approach, does it?

Wilson Mallard (GPC): [03:56:27] So I'm happy to expound on that for the commissioners. And it goes back to the discussion we were having just a second ago.

Daniel Walsh (PIA): [03:56:34] Well, actually, what I've asked is just if you could say, if you could agree that that answer in your testimony about providing additional flexibility in identifying the portfolio of best cost resources doesn't, that response does not provide a lot of detail as to what the company anticipates in a best cost approach.

Jeffrey Weathers (GPC): [03:56:55] No, I don't know that I could.

Steve Hewitson (GPC): [03:56:57] Well, I think he's going to explain anyway. But I would like the witness to be able to explain their answer before the follow up comes.

Daniel Walsh (PIA): [03:57:03] And I would just say that the, I did not get an answer to my specific question before the further explanation. And that's what I was asking for.

Tricia Pridemore (PSC): [03:57:14] These are technical terms. Sometimes we have to rephrase the way that we ask a particular question or just ask it again.

Daniel Walsh (PIA): [03:57:22] Why don't I skip to this question? Maybe it'll move things along. Will the company be agreeable to working with the staff and the independent evaluator during the RFP development process to work out the specifics of the best cost procurement approach?

Wilson Mallard (GPC): [03:57:37] Yes, definitely. And some of the specifics in the the best cost approach, some of the additional items that will be considered as part of the evaluation process, they are listed in the next paragraph. They're down below about halfway down on page 37. [Line?] Starting about 11, 12 and 13, Madam Chair.

Tricia Pridemore (PSC): [03:58:01] Thank you.

Daniel Walsh (PIA): [03:58:06] I'd like to ask you about the Commission's final order in the capacity and energy payments to co-generators under PURPA in Docket 4822. This was an order issued March 11th, 2021. And I can show you the order if needed. But let me just ask the first question then. If you need to look at the order, I'll provide it to you. Okay. But are you aware that in that final order, the Commission ordered that the support capacity component shall be set to zero until the public interest advocacy staff reviews the internal Southern Company operational data, and the Commission approves the data and methodology used in calculating short term production cost impacts?

Jeffrey Grubb (GPC): [03:58:52] Yes, I recall that for the motion, and that is specific to payments to Qualifying Facilities on a day ahead basis.

Daniel Walsh (PIA): [03:58:58] If the Commission were to adopt the company's proposal to replace the support capacity component with the integration cost component, would that in any way modify the requirement ordered by the Commission in 4822?

Jeffrey Grubb (GPC): [03:59:12] I don't have the exact order, as you just mentioned, but I think our thoughts were always that as the RCB changes, if it's applicable to Qualifying Facilities, that that would be updated as well. So that would be in that docket. We would have to have that discussion on how to incorporate integration calls for Qualified Facilities.

Daniel Walsh (PIA): [03:59:31] I can provide you with a copy of the order, if it would be helpful.

Jeffrey Grubb (GPC): [03:59:34] I'm good right now. Yes.

Daniel Walsh (PIA): [03:59:40] So, just to put a finer point. Are you saying that you believe that it would require an update to what was ordered in 4822?

Jeffrey Grubb (GPC): [03:59:47] If we were going to apply them to QFs, it obviously would. I think the reason that we have support capacity in the qualifying facility payments is because as those QFs deliver intermittently, just like anything else, it does put a cost in the system. Again, the order ended up having that value at zero, and causedsome more discussion with staff. So the company's position would be for the, to benefit customers. That is a cost that a qualifying facility would impose on the system just like others. So we would want to have that discussion under that docket.

Daniel Walsh (PIA): [04:00:18] If the Commission were to approve the integration cost component in this filing, would that mean the company is not planning to provide the operational data to staff?

Jeffrey Weathers (GPC): [04:00:31] Well, the company already provided operational data to staff and reviewed that with staff. So it was never our intention to not do that. The company provided that data. The integration cost component is similar to the support capacity function, is a little bit different in the way that it's calculated and compiled. But it provides a similar function in that you're capturing the reliability impacts of the intermittent resources on the system. It's different because you don't break apart some of the components like you did with the old support capacity. So I think it's conversations the company would need to have those with staff about how to best utilize the integration cost component with the Renewable Cost Benefit framework consistent with the order that you just read.

Tricia Pridemore (PSC): [04:01:27] To be clear, though, that's docket number 4822 that's been heavily discussed here at the commission just as recently as last Thursday. I believe we've got an item before us tomorrow related to it, but that is for PURPA QFs and does not apply to the solar that the company is proposing in this IRP in docket number 44160, correct?

Jeffrey Grubb (GPC): [04:01:48] That's correct. Correct.

Daniel Walsh (PIA): [04:01:52] I'd like to ask you some questions on Plant Held for Future Use. And prior to beginning the questions, I'd like to provide you with the company's response to STF-LA-1-4. Madam Chair, may we provide this to the witnesses?

Tricia Pridemore (PSC): [04:02:12] Yes you may, you may approach.

Daniel Walsh (PIA): [04:02:16] And as it's being circulated, I would ask that this response again to STF-LA-1-44 be marked for identification as staff exhibit 4.

Tricia Pridemore (PSC): [04:02:29] So moved.

Daniel Walsh (PIA): [04:02:54] Please turn to the second page of the attachment that you were just provided. Does this show that as of December 31st, 2021, the company had $106.6 million in plant held for future use?

Jeffrey Grubb (GPC): [04:03:19] Yes, it does.

Daniel Walsh (PIA): [04:03:21] And does that include $22.9 million for St. Joe Timberland in Stewart County?

Jeffrey Grubb (GPC): [04:03:30] It does.

Daniel Walsh (PIA): [04:03:32] The $22.9 million that was spent for land in Stewart County is not currently providing service to ratepayers, is it?

Jeffrey Grubb (GPC): [04:03:42] It is a site that the company has for future deployment of generation, but there's no generation on site at this time.

Daniel Walsh (PIA): [04:03:49] So it's not currently providing service to ratepayers.

Jeffrey Grubb (GPC): [04:03:52] Not from a generation standpoint. That's correct.

Daniel Walsh (PIA): [04:03:56] But you say "not from a generation standpoint." Are you saying that it is providing service to to ratepayers and not...?

Jeffrey Grubb (GPC): [04:04:03] It's not providing electric service. There's value to customers of us having that site for future use.

Daniel Walsh (PIA): [04:04:09] Okay. You're saying there's value, but I'm saying right now it's not providing the service.

Jeffrey Grubb (GPC): [04:04:15] That is correct. Whereas I think that applies for most of the items in plant held for future use.

Daniel Walsh (PIA): [04:04:22] Will the company ask this Commission for authorization to recover from its customers the dollars spent for the land in Stewart County?

Jeffrey Grubb (GPC): [04:04:29] So I think one thing here, Mr. Walsh, is I believe this was all addressed in the 2019 rate case and that the IRP would bring forth reviews on plant held for future use once it had been in that category for 15 years, which none of these apply. So I don't know exactly all the treatment from a rate case standpoint and everything. But again, the plant held for future use discussion in the IRP was really once it has been in that account for 15 years.

Tricia Pridemore (PSC): [04:05:00] Mr. Grubb, for the record, can you go through with the 2019 rate case did to treat Stewart County and the plant held for future use, if you recall that?

Jeffrey Grubb (GPC): [04:05:10] Madam Chair, I don't know the exact wording. I know in our response here we talk about we're complying with the agreed upon time frames and forms for review of plant held for future use, as provided in paragraph 16 of the stipulation approved by the Commission in the 2019 rate case and docket 42516. I don't know exactly what the wording was, but my understanding was it was once something had been in an account whether it was generation transmission for 15 years, then we would bring it forward in the IRP to determine the status st that point.

Daniel Walsh (PIA): [04:05:45] The company does not currently have any commission authorization or plans to build future generations on the Stewart County site, does it?

Jeffrey Grubb (GPC): [04:05:54] Nor any other any other site. We're not building anything right now. That's correct. But again, it's a site that has great value when you look at sites across the state for generation.

Tricia Pridemore (PSC): [04:06:09] Mr. Walsh, are you thinking about buying the site? Tends to come up about every three years. I just wonder, are you looking at anyone? Stewart County. It's pretty down there.

Bubba McDonald (PSC): [04:06:19] We're not through with it yet.

Tricia Pridemore (PSC): [04:06:23] I'm just saying, it's just...

Daniel Walsh (PIA): [04:06:25] I don't quite have the money that's listed in the balance.

Michael Robinson (GPC): [04:06:30] And Commissioners, there are three properties that came off of this list that we've moved out of this account for future projects. Three substation projects believe we answered that in one of the data requests.

Daniel Walsh (PIA): [04:06:41] Why does the company show the projected use date for Stewart County land as later than 2030 and not later than 2040? Does Georgia Power Company plan have plans for that Stewart County land between 2030 and 2040?

Jeffrey Grubb (GPC): [04:06:58] Well, I think there's a lot of things in flux. I mean, the main reason we put [that] in 2030 is if you look at our needs, we don't have we have some needs in 2029 and 2030. We have a lot of PPAs that roll off in 2030. So you're really thinking from a company standpoint, if we were to propose self build generation for company owned proposals, it's likely in that 2030 to 2040 time frame.

Daniel Walsh (PIA): [04:07:21] But you don't have anything specific?

Jeffrey Grubb (GPC): [04:07:24] That's correct.

Daniel Walsh (PIA): [04:07:25] All right. So if Georgia Power sells any timber on the Stewart County land, will all the net proceeds from such timber sales be credited back for the benefit of ratepayers?

Jeffrey Grubb (GPC): [04:07:33] I don't know, the treatment of timber sales in Stewart.

Daniel Walsh (PIA): [04:07:41] For a significant portion of the company's plant held for future use, the projected use dates are 2040 or beyond. Correct?

Jeffrey Grubb (GPC): [04:07:52] Correct. Again, most of these have not haven't fallen in that 15 year window. So we didn't come prepared to speak to every possibility of it. But I think there is value in having these these parcels. But again, I'm not prepared to speak for every one of them.

Daniel Walsh (PIA): [04:08:07] And I have no intention of asking about every one of them. I'm trying to keep the questions big picture. [OK.] But it would be fair to say that the company has tens of millions of dollars of land for which it has no plans to use within the ten year plan. Correct?

Jeffrey Grubb (GPC): [04:08:27] Currently, we, I've spoken to the generation one, I think, from a transmission and distribution standpoint, we're projecting that same time.

Michael Robinson (GPC): [04:08:37] So the commissioners, the South Dahlonega, Clermont properties across the South Dahlonega that were entered into 2008, 2009, there is potential that those properties could be used in the North Georgia studies that we're working on. That's one of the things our engineers continue to look at is the property that we have. There's also property that Georgia Transmission Corporation has that was associated with this original plan in the mid 2000s that we continue to study and could show benefit in this ten year window. It's just not in this plan here because the assumptions that I'm talking about are looking beyond the ten year plan, looking at the year 2035 with additional renewables in South Georgia, potential retirement of both [Bowen units] 3&4.

Daniel Walsh (PIA): [04:09:22] I'm going to ask some questions now about the solar tariff. As part of the IRP, the company has requested changes to the simple solar and community solar tariffs. Is that correct?

Wilson Mallard (GPC): [04:09:36] Yes.

Daniel Walsh (PIA): [04:09:38] And the commission typically reviews and approves tariff changes as part of the rate case. You understand that?

Wilson Mallard (GPC): [04:09:45] So I would say, the history on renewable programs has been that generally the concepts are teed up in the IRP, going all the way back to the Green Energy Program back in 2001 where the concept was teed up and then approved subsequent to the IRP. After that, that's been the general order of operations for renewable programs, where conceptually they're introduced in the IRP and then approved, the tariff and the rest of the program, either in a rate case or in a subsequent filing.

Daniel Walsh (PIA): [04:10:12] And the company filing, as we've talked about, a rate case later this year.

Wilson Mallard (GPC): [04:10:15] That's right.

Daniel Walsh (PIA): [04:10:16] I'd like to now talk to you about tall wind projects.

Wilson Mallard (GPC): [04:10:21] Yes.

Daniel Walsh (PIA): [04:10:26] And I'm going to be referring at some point during these questions to page 51 of your direct testimony.

Wilson Mallard (GPC): [04:10:44] Okay. We're ready.

Daniel Walsh (PIA): [04:10:48] The company proposes to develop two wind turbines up to four megawatts each, with hub heights between 140 and 165 meters. Is that correct?

Wilson Mallard (GPC): [04:10:57] Correct.

Daniel Walsh (PIA): [04:10:59] And those are taller than conventional, conventional onshore land based wind turbines, correct?

Steve Hewitson (GPC): [04:11:03] That's right.

Daniel Walsh (PIA): [04:11:05] The company refers to that as its tall wind demonstration project. Is that correct?

Steve Hewitson (GPC): [04:11:09] Correct.

Daniel Walsh (PIA): [04:11:11] And making wind turbines taller involves additional cost. Is that correct?

Jeffrey Grubb (GPC): [04:11:15] That's right. The cost of the tower and the construction of the tower to reach the higher hub heights, it requires more capital costs, more construction cost.

Daniel Walsh (PIA): [04:11:23] And the company doesn't expect the energy produced by those 12 wind turbines to be economic, does it?

Wilson Mallard (GPC): [04:11:28] No, that's the reason for the demonstration project. We're looking to test the wind resource and test this revolutionary in-field tower spiral welding technology that we're excited about that will allow tall towers to be built without significant additional cost, hopefully making improving the economics here and introducing wind as a viable resource here in the Southeast.

Daniel Walsh (PIA): [04:11:53] No site has been selected for the Tall Wind project. Is that correct?

Wilson Mallard (GPC): [04:11:55] That's right.

Bubba McDonald (PSC): [04:11:55] You said no site?

Wilson Mallard (GPC): [04:11:59] No, no site. We're evaluating several sites. We're looking at a good number of them, but we've not selected a final site at this point.

Bubba McDonald (PSC): [04:12:05] Such as?

Wilson Mallard (GPC): [04:12:06] If it's all right with you. I'd like to not discuss them publicly, sir, because that might make a run on interconnections and property to be purchased in those areas. But we'll present that assuming this is approved. We'll come back to the commission with a detailed filing once we have the site identified and all the particulars.

Tricia Pridemore (PSC): [04:12:24] Are you proposing it on land or on sea?

Wilson Mallard (GPC): [04:12:27] These are land based.

Daniel Walsh (PIA): [04:12:33] And the company does not have any anticipated energy amounts available for the Tall Wind Demonstration Project, does it?

Wilson Mallard (GPC): [04:12:40] That's correct. It's hard to do the estimate without the particular site chosen in the particular profile of the wind resource at that site.

Daniel Walsh (PIA): [04:12:48] And the company is proposing this project at a time when the cost of solar is declining, correct?

Wilson Mallard (GPC): [04:12:53] So the cost of solar has been declining over time, and it is projected to continue to decline out into the future. We're in a period right now where there's some volatility in solar pricing.

Bubba McDonald (PSC): [04:13:04] What is the length of a contract with New Mexico and Oklahoma on wind?

Wilson Mallard (GPC): [04:13:11] So, Commissioner, we've got 20 year wind deals from Blue Canyon in Oklahoma that we're, gosh, six years into now. Mr. Grubb is going to check and tell you how far, but we're not quite halfway through those PPAs.

Bubba McDonald (PSC): [04:13:28] Is that not delivered FOB destination [free on board - meaning Georgia would pay for transmission wheeling from the wind site].

Wilson Mallard (GPC): [04:13:31] I'm sorry. Repeat the question.

Bubba McDonald (PSC): [04:13:33] Is that not delivered to Georgia FOB destination?

Wilson Mallard (GPC): [04:13:36] It's delivered and it's firmed up. That's a really good wind deal. It's the wind delivered with the counterpart taking on the transmission risk and the wind is firmed up with with gas to back it up. So we get a blocked, scheduled wind delivery.

Jeffrey Grubb (GPC): [04:13:49] And so, commissioner. Mr. Mallard was right. It started in 2016. It expires at the end of 2035.

Tim Echols (PSC): [04:13:57] Mr. Mallard, a question about the foundations on these wind turbines. You remember the other wind turbines that we approved back in was it 2013?

Wilson Mallard (GPC): [04:14:08] I do remember the foundation issues we had with those. I do. And I will say we learned a lot from that from that demonstration project. Not all demonstration projects prove the technology works, so a valuable lesson can be learned to prove that. And in this case, what commissioner is referring to is a small wind demonstration project, very low hub heights. That didn't prove to be economical.

Tim Echols (PSC): [04:14:29] So, how will these projects, which are probably going to require even more foundation work, right, because they're taller. How are these going to be viable on the coast? If we couldn't do a small one?

Wilson Mallard (GPC): [04:14:44] Right. So first of all, I wouldn't expect these tall wind turbines to locate at or very near the coast. They could. But that's the whole thing about the new tall wind technology is, wind resource in, say, central and south Georgia, very far inland. If you get high enough, that wind resource is significant and it can create economical wind. So the expectation would be that these resources would be installed. Typical Georgia geography, not necessarily near the coast. I wouldn't anticipate any foundation issues. But again, we won't know that for sure until we pick the site.

Michael Robinson (GPC): [04:15:25] Commissioner, one of the aspects, wind tends to blow in the evening hours at night versus solar being available during the day. So if these sites were in south Georgia, then they could offset the congestion that we see with future continued solar development in that area.

Daniel Walsh (PIA): [04:15:48] Madam Chair, I would like to present the panel with the company's response to STF-DEA-2-30, which I'd ask be marked for identification as staff exhibit five.

Tricia Pridemore (PSC): [04:16:01] You may approach. So moved.

Daniel Walsh (PIA): [04:16:35] I'll give you a moment to review that when you're ready for questions. [Okay.]

Daniel Walsh (PIA): [04:16:49] In this response. If you look near the bottom of the first paragraph, the company states that the hosting capacity tool will provide an annual snapshot of distribution circuit availability capacity in a geographical GIS based format. By distribution circuit, does the company mean individual feeders?

Michael Robinson (GPC): [04:17:13] Yes, that's correct. The 2,356 feeders that we have throughout the state of Georgia.

Daniel Walsh (PIA): [04:17:18] And does this response mean that the only information that will be supplied by the hosting capacity tool is the available capacity, or will it give more specific information?

Michael Robinson (GPC): [04:17:30] So we're still working through the details of that tool. We're working with a consultant to develop the models that would go into the tools that you run to develop the hosting capacity. So the initial development is for hosting capacity. If there were further uses for that information in those models, that could be beneficial in other capacities, we would be looking at those in the future. But initially it would be based on capacity on each individual feeder as it relates to additional solar development, distributed generation.

Daniel Walsh (PIA): [04:18:03] So down the road it might provide something like peak load. Would that be something that that would be in play?

Michael Robinson (GPC): [04:18:08] It could. It could also provide locations for optimal volt-VAR siting. So volt-VAR control where you could put devices at the end of feeders to allow for additional solar development, renewables to be put on the system. So there are many uses for this type of a model, but the initial development and efforts that we'll be taking forward would be for the hosting capacity tool.

Daniel Walsh (PIA): [04:18:31] Have you looked at those other capacities for it yet or is that just been kind of put on the table to get through this phase?

Michael Robinson (GPC): [04:18:38] We're generally familiar with those additional use cases talking to like utilities, talking to Eaton, who is the manufacturer of the CYME software that is the tool that you would use to run this hosting capacity. And so we are generally knowledgeable of those additional uses for the models. But as I said before, the initial deployment will be for hosting capacity.

Wilson Mallard (GPC): [04:19:04] Commissioners, if I could just add, this hosting capacity tool is something that we've heard from the market is something that could be really useful to help locate distributed generation on certain circuits that have the available capacity. As Mr. Robinson stated, what we're proposing here, it really is a first step. It's an opportunity for us to begin that development. What we proposed is to put out a tool that will be useful to the marketplace, will just be updated annually on a snapshot. We've been benchmarking to some other utilities here in the Southeast and other places as to what's best practice and sort of most bang for the buck, if you will. But we'll absolutely be evaluating that as we go, be soliciting feedback from the marketplace, from the users, and certainly have the opportunity to make improvements as we go through time.

Daniel Walsh (PIA): [04:19:51] I'd like to ask some questions about transmission now, and if I could get you to look at Section 13.1 of the IRP document and it's on page 13-91.

Jeffrey Grubb (GPC): [04:20:09] 13-90?

Daniel Walsh (PIA): [04:20:11] 13-91 and it's Section 13.1 entitled Battery Energy Storage System Demonstration Projects. [One?] Yes. Section 13 one. What siting or reliability criteria did the company use to select the McGrau Ford and Fort Stewart sites for the energy storage systems?

Wilson Mallard (GPC): [04:20:41] So let me clarify here. You're asking about McGrau Ford or Mossy Branch that's discussed here at the bottom of 13 nine one?

Daniel Walsh (PIA): [04:20:51] I was asking about McGrau Ford. Is is that not applicable?

Michael Robinson (GPC): [04:20:55] Sure. What's referenced in this paragraph is Mossy Branch and the...

Jeffrey Grubb (GPC): [04:21:03] It's the 80 megawatts from the last IRP. [Correct.] Not that we won't answer McGrau. We're just making sure that we're responding correctly.

Daniel Walsh (PIA): [04:21:09] I will. Well, let me ask you this. Would the reliability criteria be different for each site?

Wilson Mallard (GPC): [04:21:19] So it could be. It's important to remember the 80 megawatts was approved as an early deployment. The siting criteria there was based on ensuring that a location could be the facility could be sited at a location that would allow Georgia Power to test all of the use cases and gain all the different learnings as proposed in that early deployment. So that's, that was really the basis of choosing the Bossy branch site, was to make sure we've got a spot on the transmission system, it minimizes interconnection cost, but also allows for that flexibility to test all the things that we want to test and learn from that facility. The same would be true generally for the Fort Stewart site, although obviously locating that site is limited by where there's a solar facility already. And so choosing to locate that at Fort Stewart, that site made lots of sense based on the land availability and again, minimizing interconnection costs there.

Daniel Walsh (PIA): [04:22:15] Did the criteria includes siting the energy storage service on circuits that had a poor record of reliability.

Wilson Mallard (GPC): [04:22:23] So no. And these are, it's important to note that the mossy branch facility, that's a transmission interconnected facility. It is not interconnected at the distribution level. It's interconnected to the transmission system.

Michael Robinson (GPC): [04:22:36] And none of these battery systems are being proposed for any type of reliability purpose, whether it be transmission or distribution connected.

Daniel Walsh (PIA): [04:22:43] And that would be true for McGrau Ford as well? [Correct, yes.].

Tim Echols (PSC): [04:22:48] Can I ask you about the Fort Stewart facility? So there's no arrangement for the military to tap into that in case they need it?

Wilson Mallard (GPC): [04:22:53] So there's not yet, as you may remember, Commissioner, the original agreements, the easements with the bases, allowed for the base to have access to the energy in times of grid outage. However, there's a good bit of work that has to be done to make that happen, to put all the control and switching equipment in there. I think most of the military bases have indicated interest in doing that at some point. None of the facilities at this point have been converted or configured in that way. So that still remains an option. And siting a battery storage facility adjacent to the solar facility is another tool, if you will, that could be used there at the Fort Stewart location. But as of now, there's, the ability does not exist to turn that power inward, to be used in times of grid outage.

Tim Echols (PSC): [04:23:44] How far is the batteries from the Fort Stewart 30 megawatt array?

Wilson Mallard (GPC): [04:23:47] It's adjacent or maybe even in the same easement. It's very close.

Tricia Pridemore (PSC): [04:23:57] It was part of a project in the last administration [Trump], where the military was attempting to be able to operate off the grid for a ten day period in cases of catastrophic energy or outage. Are you seeing the same level of commitment to these projects now since January of 2020 [Biden]?

Jeffrey Grubb (GPC): [04:24:18] I would say so. It seems like the...

Tricia Pridemore (PSC): [04:24:19] Come on.

Wilson Mallard (GPC): [04:24:19] ...commitment from the military has shifted a little bit from just renewables to more of a resiliency play. That continues to be the feedback that we get. They do want to be able to island, if you will, to be able to operate in times of grid outage for ten, 14 days, maybe even more than that. So I have not noticed a change in that desire. I think they all still have that as a long term goal.

Michael Robinson (GPC): [04:24:45] And Madam Chair, we're in recent discussions with one of our military bases through DOE, DOD and EPRI on this very project. And just as recent as last week, I got a notification about moving ahead with one of these projects. So, yes, we are seeing the commitment.

Tim Echols (PSC): [04:25:03] And Mr. Mallard at the last NARUC I had a conversation with you remember General Aycock, who came down and was responsible, I guess, for really making the pitch for doing this. Southern has now, I think, hired one of his former assistants, and they told me that the administration, the presidential administration was moving towards a requirement that all bases, all federal facilities, including VA hospitals, US VA offices, pick a an acronym, that they were going to be moving towards a requirement that those facilities be provided with a zero CO2 form of energy with what they called a 24 hour match. Are you familiar with that terminology and what they are what they're talking about?

Wilson Mallard (GPC): [04:26:02] Yes, sir, I am. And it's akin to the CARES CFE-ATC program, which is designed to provide customers with carbon free energy around the clock. That's the ATC. So it's developed specifically for needs like what is expressed by the military, but also from some other large customers.

Tim Echols (PSC): [04:26:20] And are you not anticipating this happening within the performance of this IRP, the three year period, are you? Because we're not really talking about it and talking about the requirement.

Wilson Mallard (GPC): [04:26:34] So I do. Feedback from important customers like military, like our governmental customers, like our very large manufacturers and data centers. All of that is absolutely plowed into our plans. That's why the CARES program exists as it is. That's why the request for the R3 program is what it is. It's so that we can help these customers down the path towards meeting their goals.

Bubba McDonald (PSC): [04:26:59] They have learned a lot from Georgia Power,. Their experience over the years because it's three or four years ago I was on the dais with the base commander from Fort Stewart and he said to me, he said, "I'll tell you what, the Georgia power outlawyered the army in developing those 30 megawatt arrays."

Tricia Pridemore (PSC): [04:27:23] Now might be a good opportunity, though, to talk about MUSH, I have questions about mush. Is it part of cares or is it stand alone and describe and define it?

Wilson Mallard (GPC): [04:27:33] Yes, ma'am. Mush is stands for municipals, universities, schools and hospitals. It's just a segment of our commercial customer base. These customers, it's a carve out. It's part of CARES. It's part of the total CARES allocation. But what we found is these customers tend to be smaller. They tend to maybe not be as quick and able to participate in our application, our notice of intent periods. And so creating a carve-out for these customers so that they can participate at a smaller size instead of a three megawatt minimum, it's just a one megawatt minimum. What we find is a lot of our our cities, they can aggregate their load, they can meet the one megawatt minimum, whereas some of them couldn't meet the three megawatt minimum. So it really is CARES. It's just a sub part of CARES specifically allocated for customers in that segment.

Tricia Pridemore (PSC): [04:28:26] Thank you.

Daniel Walsh (PIA): [04:28:29] I want to revisit real quick the question of whether energy storage service sites are ever, ever factor in an issue of reliability. Does the company have any plans for placing small scale energy storage system on circuits with or reliability as a potential non wired alternative to address reliability issues?

Michael Robinson (GPC): [04:28:59] Yes, commissioners, we do. And the seven pilot projects, the local restraints and Local Reliability Constraints program that we've proposed is seven systems that are very much what you had mentioned, deployed for three use cases, the first being wires capacity. So that's the deferment of reconductoring and distribution lines or even at the substation level. The second use case is reliability. So looking at improving reliability for the customers, that would be served off those systems. And then the third is resilience. So that's the ability for those customers served up those systems to withstand long events or multiple contingencies. And so we're very interested in those seven pilots that we have proposed in IRP and how we can deploy future pilots or future systems, not pilots, but future systems as it relates to batteries paired with traditional recips as well as even solar.

Daniel Walsh (PIA): [04:29:58] Does the company consider energy storage systems to be a generation asset or a transmission asset?

Jeffrey Grubb (GPC): [04:30:06] I think it's going to depend on the use case. All right. So the pilots that Mr. Robinson's just covered are assets to use for power delivery aspects. And so they would be driven, they would be controlled and dispatched for transmission and distribution needs. The storage that you're looking at for operating reserves or capacity RFPs or renewable RFPs are generation resources. So it depends on the use.

Daniel Walsh (PIA): [04:30:35] I want to ask you about the ten year transmission plan, what retirements were assumed as part of the ten year transmission plan.

Michael Robinson (GPC): [04:30:44] So the retirements of generation? [Yes.] The retirements in the ten year transmission plan that are included are Wansley 1&2 and Bowen 1&2. The shared decisions had not been made at the time that the ten year plan version of cases was created. So that was an August timeframe. And so the shared decisions or the share recommendations are not in the ten year plan that you have in the IRP.

Daniel Walsh (PIA): [04:31:14] What about plan Gaston?

Michael Robinson (GPC): [04:31:16] Plant Gaston is assumed first two units in, subject to check, 2027, 2028 and the second set in 2030.

Daniel Walsh (PIA): [04:31:36] Were there reasons related to transmission projects that the company's position is that Bowen 3&4 cannot be retired before 2035?

Michael Robinson (GPC): [04:31:47] Yes. So when we looked at the retirement of Bowen 3&4 on top of the other units and the rank order that we use to study those, we saw significant transmission that needed to be completed. So looking at the outage schedule, incorporating those projects into building all of that transmission and making that work so that you could retire Bowen 3&4 along with the same timeline as the other units. The decision was made by the Integrated Transmission System, our participants GTC, MEAG and Dalton Utilities to build strategic transmission, to look at not having to do a piecemeal approach to all of those issues that you have to go fix. So when you retire Bowen 3&4, you have a significant amount of transmission that overloads and needs to be reconductored. And so it's going to be very hard for us as we move forward to get the operational outages to coordinate that work. We're seeing the need for additional transmission, greenfield transmission, if you will. We're working on those studies right now to bring those megawatts from south Georgia up to north Georgia to replace that capacity. That's in north Georgia because most of the load that we're serving is in the Atlanta area.

Daniel Walsh (PIA): [04:33:05] Did you consider any specific alternatives that would permit you to retire the plant before 2035 without jeopardizing reliability in the System?

Michael Robinson (GPC): [04:33:12] Well, we're still working on those studies right now with the ITS participants as it relates to transmission solutions. But we will look at multiple technologies, additional greenfield transmission lines. I mentioned the potential conversion of units to synchronous condensers. We see that as a potential benefit for us in the future as well.

Daniel Walsh (PIA): [04:33:31] So is it possible that the company may, at some future IRP, recommend an earlier retirement date for Bowen 3&4?

Jeffrey Grubb (GPC): [04:33:42] I think that's all going to depend, Commissioners, on what we discover in this North Georgia reliability and resiliency plan. As we've stated, we're going to control Bowen 3&4 to support North Georgia after this IRP and what comes out of this, we'll start looking at that next that next part of that study. What what do we need to do to not keep Bowen forever? We know there's pressure on that unit as well. And so we've said no later than 2035. So it's all going to depend on transmission solutions. What are your generation options? What comes out of this case? So it's something that we'll study. It could, but I think it's going to all depend on what we discover from a generation and transmission standpoint.

Michael Robinson (GPC): [04:34:22] And marry that also with the assumptions that come out of the IRP as it relates to additional renewables, renewable development in South Georgia, hopefully we're successful in the approach. We're targeting North Georgia with additional renewables, but all that has to be incorporated into those future studies. That transmission has to be built to accommodate that date in the future, in 2035, when we look at 6,000 megawatts of additional renewables, retirement of Bowen 3&4, and then as I mentioned before, not being the only utility in the state, we have to look at what the EMC and municipalities are doing as well, as it relates to renewables and decisions on their resources.

Tim Echols (PSC): [04:34:56] And you think we can build utility scale solar, below avoided cost, north of I-20?

Wilson Mallard (GPC): [04:35:05] So what we're going to do is we're going to run the RFP and we're going to see and again, Commissioner, remember we're going to look at evaluating these resources a little bit differently. The model has chosen solar at the 6,000 megawatt mark, moving in that direction, adding those resources at its energy benefit to our customers. And so running the RFP, see what the market delivers, and then evaluating that with staff in the IE. That's, we're going to see what the market can bear.

Michael Robinson (GPC): [04:35:33] And Commissioner, we think it's very important to target North Georgia first, to buy us that time to study, develop and build that transmission to ensure that we can continue developing in south Georgia. I think if we don't develop in North Georgia, I think we're going to end up seeing is transmission constraints that we can't get resolved in time, delaying of CODs [Commercial Online Date] pushing these projects out because we can't get the transmission projects done in time.

Daniel Walsh (PIA): [04:36:00] I'd like to present the witness panel with a page from the IRP filing. And it is a trade secret page. I would like to provide the witnesses and the commissioners with the trade secret version and the rest of the parties here with the redacted version.

Tricia Pridemore (PSC): [04:36:23] Please go ahead.

Daniel Walsh (PIA): [04:36:24] And if I could have it marked with the trade secret mark, I believe, is the next exhibit number six. And the public disclosure as seven.

Tricia Pridemore (PSC): [04:36:32] So moved. You may approach. The quicker we pass the paper, the quicker we get to keep moving. You got it. Trust me on this one. No, he's going to go make a copy. I don't need this.

Daniel Walsh (PIA): [04:37:25] When you're ready for questions.

Jeffrey Grubb (GPC): [04:37:27] I'm ready, Mr. Walsh.

Tricia Pridemore (PSC): [04:37:29] I don't hold my own hymnal. [Laughter.]

Daniel Walsh (PIA): [04:37:31] I wanted to ask you about...hold on a second, I wanted to ask you about some of the projects that were included in the transmission retirement projects. And I believe from your answers, my previous question you identified. I'm sorry, could you could you identify again which projects were included in the ten year [plan]? I don't want to mess that up. I'm sorry for having to ask that again.

Michael Robinson (GPC): [04:38:01] Which are...

Daniel Walsh (PIA): [04:38:04] Which of the generating units?

Michael Robinson (GPC): [04:38:05] So this is transmission retirement projects associated with retirement studies. What's in the ten year plan is a different set of assumptions.

Daniel Walsh (PIA): [04:38:14] Right. I understand that. I was going to ask you a couple of questions on it. But my understanding, I just want to make sure, because I think you mentioned a few of the plants that were included as part of the ten year transmission project. Few of the generating plants. And was that Wansley 1&2 and Bowen 1&2?

Michael Robinson (GPC): [04:38:32] That is correct. And I believe Gaston 1, 2 and 3 & 4.

Daniel Walsh (PIA): [04:38:38] Okay, great.

Michael Robinson (GPC): [04:38:39] And Scherer 4. We assume that, dead last year.

Daniel Walsh (PIA): [04:38:45] Okay. Thank you. Now, turning to the page that I've handed you, would would you be doing any of these transmission retirement projects listed on this page? These transmission projects listed on this page. Absent the retirements that we just discussed?

Michael Robinson (GPC): [04:39:13] There are a couple of these projects that are advancement projects or projects that were already in flight. So yes, there are a couple of projects that we would be doing that are not directly linked to the transmission retirement projects listed here. So either they were advancing in time or they were a project already in flight.

Daniel Walsh (PIA): [04:39:33] Could you identify which ones?

Michael Robinson (GPC): [04:39:36] One is the Arkwright Shoals 115 line. That is a transmission line rebuild. That was a project that was already in flight. And so the project associated with reconductoring the line to a larger conductor was an easy decision to make, but the rebuild of the line was already a project in flight.

Daniel Walsh (PIA): [04:39:55] Were there any others? If you're not aware of that...[None that I'm familiar with.]. Could I make that as a hearing request? For the company to identify which of these transmission retirement projects would be, would still take place absent the retirements?

Michael Robinson (GPC): [04:40:17] Whether they are an advancement of a project or whether they were a project already in flight like the one I just mentioned. [Yes.]

Daniel Walsh (PIA): [04:40:33] I'm going to ask you a few questions about substation capacity. What steps does the company have to take any time it increases a substation's capacity?

Michael Robinson (GPC): [04:40:48] So our area planning engineers are looking at our substation capacity and they're looking at certain criteria for bank loading. And so when we forecast out a bank that's either looks to be 90% loaded in the future based on the assumptions for that area or there's a contingency loading they look at as well, which is 100% of emergency rating. Any time it is forecasted, the substation or bank in that substation is forecasted to hit those. We trigger a study and look at the replacement of those, either upgrading the bank or looking at adding another bank or transformer to the substation, looking at tying that load to an additional feeder or additional source out of the field.

Daniel Walsh (PIA): [04:41:32] And is that 90%? Is that consistent with what other utilities use?

Michael Robinson (GPC): [04:41:36] If...I'm not familiar with what other utilities use, but it is consistent with what our sister companies do.

Daniel Walsh (PIA): [04:41:46] And how much lead time is required in advance of that target percentage?

Michael Robinson (GPC): [04:41:50] Depends on the type of project. If it's just putting a transformer in an existing substation that you already have space for, so you built the space for expansion. It could be 12 to 18 months, 24 months depending on availability at that bank. If you've got to go purchase land to build a new substation, it could be 24 to 36 months. One of the things that we're being challenged with right now is supply chain transformer slots are moving out right now. They're at about two years.

Daniel Walsh (PIA): [04:42:25] I'm sure that's all the questions that staff has. I would ask that staff exhibits 1-7 be admitted into evidence.

Tricia Pridemore (PSC): [04:42:34] So moved.

Daniel Walsh (PIA): [04:42:35] Thank you very much.

Tricia Pridemore (PSC): [04:42:35] Thank you, Mr. Walsh. Before we run through the interveners list, I have a couple of questions. I was just going to let Mr. Walsh finish to make sure that he didn't ask any questions I have. Page seven of your pre-filed direct testimony. I'd just like for you to talk through lines 14 and 15 with me. You say increasing policy and regulatory pressure related to carbon and environmental standards, the significant increase in customer expectations for renewable and other low or no carbon solutions. I want to understand how significant is weighted with customer expectations on reliability and affordability.

Jeffrey Grubb (GPC): [04:43:22] So I think there's two pieces here, Madam Chair, when we think about the coal-fired generation fleet, the pressure we see here is what we talked to some this morning is future coal rules and also carbon. And so when we looked at the unit retirement studies, we did do transmission studies on what those impacts to customers are from...I think the next part is talking as much around the program offers that we do like CARES. So from a unit retirement study, it's absolutely taking into account when we do those transmission studies on the renewable side, it's similar and that we've we know that our pace of procurement that we've mentioned is going to have to have transmission investments there.

Wilson Mallard (GPC): [04:44:07] Madam Chair, the reliability and price are absolutely overarching goals. Adding renewables has got to be done under that umbrella. And as we think about adding renewables for the benefit of all customers, which is what we do when we do the models, we run those, it shows that adding 6,000 megawatts by 2035 does present economic benefits for all customers. So it's then within that plan that that does balance reliability and price that we add renewables and then we're able to respond with our program options to this ever growing contingent of customers that does want to support renewable energy. And yeah, I would say it's that customer count is still relatively small, but the amount of megawatts and total energy sales made by the company, it's a pretty significant amount because it is some of our largest customers, some of the largest segments that are more interested and we continue to work with day after day to try to meet their renewable energy needs, their carbon needs, but to do it in a way that absolutely doesn't violate our renewable energy principles. We don't want to shift any costs. We don't want to raise any rates. We want to do it in a competitive procurement. So we want to make sure that we allocate those costs and benefits accurately. So taking all that into account, that's what really is the backbone of the plan, where we're going to add renewables for the benefit of all customers, but then offer the programs for subscription by a smaller number of customers.

Jeffrey Weathers (GPC): [04:45:36] Madam Chair, I'll add, if I could, just for further clarification to your question. When the 6,000 [megawatts] of] renewables was selected through the optimisation studies, it was only looking at reliability and economics. And so external factors were not considered in the model. And so, as Mr. Mallard said, those are taking into consideration the program design. But as far as the selection of the amount, the 6,000, that was based on the model that only looked at reliability and economics.

Tricia Pridemore (PSC): [04:46:04] Okay. Thank you. And a lot of this is just that these terms are not defined in other places in your testimony. So page 17 line 10, the results of the Aurora expansion planning analysis. What is the Aurora expansion planning analysis?

Jeffrey Grubb (GPC): [04:46:31] So that is the mix study that we spoke about this morning. We had some questions for Mr. Walsh.

Tricia Pridemore (PSC): [04:46:36] Also known as a mix study.

Jeffrey Grubb (GPC): [04:46:38] Mix study. So, Commissioner, that's, those are the models that we run that look at the next 30 years and what's the most economic resources to add. And so what we're noting here is that this is the first IRP that we've proposed here in Georgia that has generic selections for wind and solar and storage as some of those options.

Jeffrey Weathers (GPC): [04:46:58] Madam Chair, I'll add to that if I could. So it's the model, as Mr. Grubb said, the model we call it the mixed study, but we're running a model that optimizes the build out of capacity on the system over time, and they're looking at generic additions. So we're now able to, in that process, we've converted to a new software product called Aurora. And so it's able to incorporate generic solar and wind and battery storage into the optimization process. And that's something that we didn't have in the past with our old model.

Tricia Pridemore (PSC): [04:47:30] It means the same thing. Thank you. That's what I need to know. Page 19, starting on line 19 through 26, if this plan is approved, what will Georgia Power do with the Plant Wansley site because of the, of those in this section, it's in this filing, it's the only one to fully close.

Jeffrey Grubb (GPC): [04:47:50] Yes. So, Commissioner, I mean, we obviously have like we've done with prior plants, Mitchell and Kraft, we will put together a plan on how to do the demolition at the site. I know there's reasons from an ash pond standpoint that we'll need to stay on site and monitor those. So I think it would be similar to Plant Branch that Commissioner Echols mentioned this morning. Once we demolish the plant, we'll have that site, as considerations going forward. I don't know that we've put that, all those plans together, but we would do the same thing, similar that we would do at Mitchell and that we'll also do it at Hammond and others.

Fitz Johnson (PSC): [04:48:26] Yes, Mr. Grubbs. Are there any plans to work with that community? Of those being displaced by jobs or to place folks in jobs as they as you close that plant?

Jeffrey Grubb (GPC): [04:48:38] Yeah, Commissioner, I don't know all the specifics, but I know our generation grew from an employee standpoint at plant Wansley is looking at offering them opportunities at other plants. As we look further down to retirements of Bowen and Scherer, we'll have to consider those. I know that's something we'll be there. That's from an employee standpoint. From a community standpoint, we're obviously going to stay engaged in all of our community development aspects that we do, citizens wherever we serve, and that kind of engagement. In terms of impacts to the county, I don't know that answer, because you do have a tax base loss there, but it's always something that we're considering when we go back with projects, there's a benefit at the plant site, so hadn't figured it all out, but we'll definitely stay involved from a community standpoint.

Michael Robinson (GPC): [04:49:20] And, Commissioner, our new transmission control center is sited in Douglas County, which is on that side of town. We've had a good amount of success and having boiler turbine operators and AEOs or auxiliary equipment operators become transmission operators. We're actively marketing those vacancies that we have and thinking more creatively on how we ca on board those, make it more flexible for those employees to make that jump from generation to transmission.

Fitz Johnson (PSC): [04:49:46] As you know, we close more and more of these plants that become so important, that these communities that you're kind of leaving behind just a little bit, that we work with these communities to make sure and those that are being displaced in their jobs.

Jeffrey Grubb (GPC): [04:50:01] And I think, Commissioner, one of the, that's one of the benefits of a longer transition on these coal units that we've recommended is it's not, other than Wansley, even though we've notified them in the past, I believe it's not an overnight or immediate. And so while it's an impact to the county, they do have several years to plan for it and take that into account as well.

Michael Robinson (GPC): [04:50:20] And we can manage a lot of that change through attrition.

Jason Shaw (GPC): [04:50:20] Mr. Grubb I'll just point out, I've heard from some of our friends across the street that hale from that area around Wansley that, to be specific, the impact to the local schools budget, there in Heard County, 40% of their budget comes from the taxes on Wansley.

Jeffrey Grubb (GPC): [04:50:46] Yes, Commissioner. And I don't mean to sound like it's not a consideration. It's not an impact. We understand that that is. We understand that's something that the commission takes into account, I think. But when we look at coal unit retirements, we've got to step back and look holistically for all the customer base. Very similar to Branch. Branch had a major impact down there as well. But when you look at the entire state and the customer base, that's what we're basing our decisions on. But absolutely...

Jason Shaw (GPC): [04:51:09] I understand that. But these folks aren't calling you. They're calling me.

Jeffrey Grubb (GPC): [04:51:13] I understand? That's why they're recommendations, Commissioner.

Tricia Pridemore (PSC): [04:51:18] Okay. Page 21. Lines 18 to 28 and first line of the following page, is about the potential of retiring Plant Scherer 1&2. To Commissioner Shaw's point, this is an area where commissioners have heard significantly from the majority owner on Plant Scherer 1&2. On line 28 on page 21, as well as the top of page

22, quote: "For planning purposes only, the company has assumed a retirement date of December 31st, 2028." Talk me through how you do that when you're not the majority owner.

Jeffrey Grubb (GPC): [04:51:58] So, Commissioner, that's two things that we'll look at. So from our standpoint, that gives us a little bit of guidance on the generation standpoint, what we might need to do in that 2029-2030 timeframe. But the more important impact, I think, is to the transmission planning side of things. [Yes.] So being able to plan for the retirement of those units, similar to what we talked about this morning, gives us the option that what we've, what we're looking at Plant Scherer 1&2 from an ELG compliance standpoint is two parallel paths. There's the physical chemical bio-wastewater treatment, and then there's the voluntary incentive program, VIP. That's a later compliance date, different type of technology. So the co owners are looking at that. And so as we continue down those parallel paths, ultimately a decision will be made. We want to go ahead and proactively plan the transmission. So if things do shift and it's in customers best interest to retire Plant Scherer 1&2, we have that option.

Michael Robinson (GPC): [04:52:57] And Madam Chair, the exhibit that Mr. Walsh just passed out with the transmission project list, the lower half of that table are all associated with Scherer 1, 2 & 3, with the lead time from 12 months to 54 months for the transmission that needs to be done to retire those units.

Tricia Pridemore (PSC): [04:53:14] Give me the first, give me the first letter of the line that's, you say, lower half. Give me the first letter of the top line. Because it is trade secret.

Michael Robinson (GPC): [04:53:24] M.

Tricia Pridemore (PSC): [04:53:25] M? Thank you. Page 23.

Jeffrey Grubb (GPC): [04:53:43] Yes, ma'am.

Tricia Pridemore (PSC): [04:53:47] Describe the environmental benefits of retiring the oil-fired units from a cost and reliability perspective as well. That's, you can expand on lines 4-10, please. These are oil-fired units.

Jeffrey Grubb (GPC): [04:54:06] Yeah. I'm just real quick. I'm sorry. Just reading real quick. Yeah. I mean, the main decision on the CTs here, Madam Chair, is that two of them are at sites where we're retiring the coal units, and another is at a site by itself. And so there's really no benefit from customers when we study those in the retirement studies. So it's really just a cost standpoint to pretty small seats. And while they help from a liability standpoint, there's just not a lot of benefit to maintaining those as a single unit site. And so we've incorporated that into our plans and just oil-fired. We were able to use them, but just thinking long term, they will likely be continued pressure on oil-firing resources in the future as well.

Tricia Pridemore (PSC): [04:54:48] Are you getting federal pressure on oil-firing resources now?

Jeffrey Grubb (GPC): [04:54:53] I don't think we're getting them oil right now. Other than the potential for carbon pressure, I don't know that there's oil specific rules and we still have a lot of other oil CTs that are crucial to the system. So we're really we didn't study and recommend retiring a lot of oil-fired CTs. It's very important from a reliability standpoint, black start resources as well. But with these three being solo sites, if you retired the coal units, it was just best interest to close this.

Tricia Pridemore (PSC): [04:55:19] Page 26 line ten, $28 million dollars sought in this docket to extend the life of plant Hatch 1&2. What's comprised in the $28 million? Be specific.

Jeffrey Grubb (GPC): [04:55:38] So Madam Chair, the $28 million is the cost, Georgia Power's cost for the five year process to go to to develop our subsequent license renewal and work through that process with the NRC. At the end of that five year, we would have a of a ruling from them on can we extend the lives of Hatch 1&2? So again, we're asking for cost recovery to go forth with getting that option. We would bring back to the commission if we get that license, if we're going to extend the 20 years, this is the $28 million to do that work.

Tricia Pridemore (PSC): [04:56:10] But it's application, legal fees. You're not making technical adjustments to the plant, correct?

Jeffrey Grubb (GPC): [04:56:15] That's correct. It's a five year process to cover all those types of costs. That's correct.

Jason Shaw (GPC): [04:56:21] It's a lot cheaper than building a new one. [Yes.]

Tricia Pridemore (PSC): [04:56:30] Okay, let's see. Page 34. Define economically optimal on line 24, please. Sorry. 26. Can't read my own writing at this point.

Wilson Mallard (GPC): [04:56:48] So I'll start and Mr. Weathers can chime in. We're referring back here to the model, that Aurora model and the ability for us now to have solar and wind and battery storage resources selected in the model in the generic expansion plan. So because of that change, because of that enhancement, we're able to identify and pre-select, if you will, the addition of renewable resources going forward that will provide economic benefits to our customers.

Tricia Pridemore (PSC): [04:57:16] There you go. Confirmed what I thought, page 35. AGC. It is included in the new RCB framework as proposed. But is that a cost to the developer or Georgia Power?

Wilson Mallard (GPC): [04:57:30] AGC is a cost to the developer. There are some costs to Georgia Power as well to be able to communicate with the device, but the developer has to provide communication equipment on site, an RTU. I think we answered the data request. Madam Chair, I can get that for you. I believe we estimated the price of those at about $50,000, so not insignificant. But in the scheme of things, in the development of a large solar site, we think it's a reasonable expense.

Tricia Pridemore (PSC): [04:57:57] OK. Makes sense. The last one I have for you. Page 44. What is BESS? B-E-S-S.

Wilson Mallard (GPC): [04:58:11] BESS is ESS's cousin. So ESS is energy storage system. A BESS is going to be a battery energy storage system. But there's other energy storage systems. You could have a pump storage hydro or kinetic storage or any sort, but a BESS is going to be a battery storage.

Tricia Pridemore (PSC): [04:58:28] So the only place that was referred to in your pre-filed testimony. That's it. It's all I've got. Thank you. Helped me a great deal. Let's go through the list. Americans for Affordable Clean Energy. Commercial Group.

[04:58:49] [Sorry to disappoint.]

Tricia Pridemore (PSC): [04:58:54] Thank you, Mr. Jenkins. You always do a good job of keeping me in the loop. Concerned Ratepayers for Georgia.

Steven Prenovitz (CRG): [04:59:01] No questions, Madam Chairman, for this panel or the other two panels. I do have one housekeeping suggestion, though it might be helpful, since it's like four people on the panel, if they kind of had name plates, nametags on them, kind of like they do in congressional hearings, that would make it easier to follow, at least from a zooming point of view.

Tricia Pridemore (PSC): [04:59:24] Thank you, Mr. Prenovitz. I will take your suggestion to the Executive Secretary's office. [Thank you.]

Tricia Pridemore (PSC): [04:59:29] Cypress Creek Renewables, LLC. George Association of Manufacturers. [I have some questions.] Not surprising, Mr. Jones.

Clay Jones (GAM): [04:59:40] Sorry to disappoint. Thank you, Madam Chair. Good afternoon, panel. It's good to see you. Before I get into my questions, I want to go back to something you were talking about with Mr. Walsh for just a minute on pages 36 to 38 of your testimony, just generally. And actually, let's go to page 38. This is where we're talking, you're talking about best cost analysis versus the avoided cost analysis. And on page 38, lines 10 and 11, you say the company will no longer rely on the MG0 RCB avoided cost threshold as the primary determinant of customer benefit in its evaluation of renewable projects. Is that accurate? [That's right.] So does that mean that you could end up selecting procuring resources at a price higher than what it costs energy that's derived in this IRP?

Wilson Mallard (GPC): [05:00:53] So, yes, it's really a redefining of what avoided cost is and it goes back to the discussion about the Aurora model and the ability to pre-select these renewable resources is beneficial to customers. in times past commissioners, the model hasn't been able to select these resources and so we really depended on that MG0 avoided cost ceiling to ensure that those resources benefited customers. Now that the model is able to select these resources, it's really a different way of thinking about it. If we can go and get resources from the market that are generally priced in line with the assumptions in the model, the model shows that those resources do provide benefits across a range of scenarios for our customers. And so really just a different way of thinking about it, if you will. Mr. Jones. It's a different way of defining avoided cost. But the primary change, and you've hit on it, is to no longer disqualify benefits that might be above that MG0 avoided cost.

Clay Jones (GAM): [05:01:50] So just to put a fine point on it, yes, it could result in higher prices, higher than avoided cost procuring energy at a higher price than avoided cost.

Jeffrey Weathers (GPC): [05:02:01] It could be higher than the MG0 avoided cost. But here's the other thing, is that not only are we looking at across a range of scenarios, as Mr. Mallard said, but the MG0 avoided cost now have all the generic solar already factored into it. And so it is by nature a different number than it was in the past. We didn't have that. And if you can come in below it, you know there's a value. Now the value is determined on the front end through the optimization process. On the back end, looking at after-the-fact MG0 prices alone is not the best measure of being above or below what it cost.

Michael Robinson (GPC): [05:02:39] And Commissioners, there's another benefit, is we mentioned before we're going to become more and more constrained in South Georgia particularly. And so we're seeing more and more transmission costs associated with this. So this gives us flexibility across a portfolio of projects versus just kicking individual projects out because of transmission constraints.

Clay Jones (GAM): [05:02:55] So if you're going to employ this approach in future RFPs, do you think the commission should have the opportunity to review your avoided cost projections you're going to use them as RFPs before you do them?

Wilson Mallard (GPC): [05:03:07] Yes. And the commission does and will and yeah, just to be clear, we're still going to use an avoided cost to compare the bids against. That's still part of the modelling. That's still part of the evaluation exercise.

Clay Jones (GAM): [05:03:19] Well, that was kind of my next question. What role you see envisioning the avoided cost threshold playing? I know you said you're going to use it. How do you how do you envision its importance going forward as part of the process?

Jeffrey Weathers (GPC): [05:03:30] It won't be so much a looked at the MG0 as a threshold, but the MG0 is a component of the Renewable Cost Benefit Framework. So we're going to continue to evaluate all of the bids according to the Renewable Cost Benefit Framework for both the cost the system incurs, but also the benefits. So you talk about the cost of reviewing those. The RCB framework, of course, is filed with each IRP. But what's more important to the amount of solar is not the avoided cost but the optimization. So the renewable expansion plan analysis for this IRP that determined the amount of solar. So when we execute on those in the PPAs, we're still using MG0 as part of our RCP framework, but it's not appropriate to be a threshold anymore.

Clay Jones (GAM): [05:04:21] All right. Let's talk a little bit about the target reserve margin. Maybe you want a drink of some caffeine before we do that.

Jeffrey Grubb (GPC): [05:04:29] We may not need to.

Clay Jones (GAM): [05:04:30] I've got some right here. So the target reserve margin study was conducted at the Southern company level. That's what we said. [Yes.] And then translated it into a target reserve margin for each operating company such as Georgia Power.

Jeffrey Weathers (GPC): [05:04:43] That's correct. Based on the diversity across the system, each operating company's actual target is a little bit lower than the System target.

Clay Jones (GAM): [05:04:50] And in doing that, you develop three different metrics or use three different metrics: Loss of Load Expectation or LOLE, Economic Optimum Reserve Margin (EORM), names where you can shorten them up instead of spell them, and Risk Adjusted EORM or Value at Risk (VaR). These are those familiar terms to you?

Jeffrey Weathers (GPC): [05:05:12] Yes, that's right.

Clay Jones (GAM): [05:05:12] And those are the three different metrics you used in your study. [Yes.] Madam Chair, I'd like to show the witnesses an exhibit, if I may.

Tricia Pridemore (PSC): [05:05:21] You may approach.

Clay Jones (GAM): [05:05:21] Okay, gentlemen, I'm showing you what I've marked as exhibit, and Madam Chair, I'll ask this be marked as exhibit one. I'll give you a minute to look at it. [I'm good. Mr. Jones.] Do you agree that this exhibit accurately reflects the information in your filing? There's a source there for where the information comes from.

Jeffrey Weathers (GPC): [05:06:04] Yes, it looks correct.

Clay Jones (GAM): [05:06:06] Okay. All right. Let's talk about LOLE first. This is considered an industry standard approach to determining target reserve models. You agree with that?

Jeffrey Weathers (GPC): [05:06:15] Yeah, there's no particular standard in terms of, say, a NERC standard or something like that. But it is widely used across the industry and widely accepted as a best practice.

Clay Jones (GAM): [05:06:25] Okay. You say in fact, you even say that in your testimony that it's an industry standard for reliability, I think.

Jeffrey Weathers (GPC): [05:06:32] Yeah, it is an industry standard. But in terms of a specific standard, you can't point to anything that I'm aware of. But it is an industry standard.

Clay Jones (GAM): [05:06:40] And the industry standard is to use what they call a 1 to 10 LOLE, which represents one outage event in ten years.

Jeffrey Weathers (GPC): [05:06:47] That's correct. On the planning basis from reliability perspective. We plan to have no more than one firm load shed event every ten years as related to generation resource adequacy.

Clay Jones (GAM): [05:07:01] And you're familiar with SERC, the Southern Reliability Corporation? [Yes.] And that's the entity that's responsible for ensuring a reliable and secure electric grid across something about 16 southeastern states, central states as well. [That's about right. Yeah. Yes.] You don't have to get the number right. [16. Subject to check.] But the important one is Georgia and Southern Company is included in that region, right? [Yes.] Okay. Would you agree with me that using a 1 to 10 LOLE serves to determine a reference reserve margin of 15% for SERC Southeast?

Jeffrey Weathers (GPC): [05:07:37] I am aware that that has been has been stated for a number of years related to our territory. But I think important to note, that is a, that is more general in nature. So that's not specific, that's not related to a specific reserve margin study for Southern System. So our study is the one that models our specific system to develop a target reserve margin.

Clay Jones (GAM): [05:08:04] And in your study, the LOLE results in a winter reserve margin of 20% in the summer reserve margin, 15.75%, correct.

Jeffrey Weathers (GPC): [05:08:12] Yeah. The 20% would be the minimum reserve margin to satisfy the one in ten LOLE criteria. So as long as, we check, we run our optimization process and as long as it is above 20%, then you're fine. If it were, if it happened, the economics indicate it should be below 20%. We would need to raise it to get to that minimum level.

Clay Jones (GAM): [05:08:37] Okay. So from a reliability perspective, under that metric, a 20% winter reserve margin and a 15.75% summer reserve margin would be adequate to meet the company's reliability needs.

Jeffrey Weathers (GPC): [05:08:50] Well, the 20% would, as a minimum. The 15.75% is really only a summer looking result. So since we obviously, we have the whole year to consider, the summer and the winter. So if you're having a 20, if you only had a 20% winter reserve margin, you would need a higher than that in the summer because in order for the whole year to come out to the one in ten criteria. So it's a little bit confusing because there's presented different results here. But you have to take the combination of those two into consideration when you determine the system target reserve margins.

Clay Jones (GAM): [05:09:31] All right. So...

Tricia Pridemore (PSC): [05:09:32] Do me a favor, Mr. Jones. Speak into your mike a little bit.

Clay Jones (GAM): [05:09:35] I thought I was pretty close, but I guess I need to get closer. Thank you, Madam Chair. So now referring back to the exhibit again, you use two other metrics in your target reserve margin study, right? [Yes.] And you would agree that, as I understand it, EORM is an economic-based metric that balances price to balance, the estimated cost of having too little capacity versus having too much. Is that roughly correct?

Jeffrey Weathers (GPC): [05:09:59] That's correct. In terms of cost to customers.

Clay Jones (GAM): [05:10:01] And then VaR is kind of an extension of that, also economic based, that measures, I want to say, riskiness of financial entities, portfolios of assets that you might already have?

Jeffrey Weathers (GPC): [05:10:10] Well, yeah. It considers the risk of higher cost outcomes and then the value of mitigating that risk. And can you do that in such a way that it provides value to customers?

Clay Jones (GAM): [05:10:22] And again, LOLE is what SERC has relied on in the past and continues to rely on?

Jeffrey Weathers (GPC): [05:10:27] Well, SERC doesn't set the reserve margin for the company. And so that's determined by this commission. So again, LOLE is one of the metrics, but we think it's very important to consider cost to customers. And really that cost to customers and the value to customers is the primary metric that we use.

Jeffrey Grubb (GPC): [05:10:45] And so Commissioners, is what we what we're saying is the looking at the economics is that LOLE is just a measure that you can use in [unintelligible]. We have an LOLE related to any reserve margin. If you just wanted to look at one in ten, you wouldn't have to run any economics. But the company places value in, I can, we can add generation that is more economic than, it's cheaper to add that generation for the value of reliability that you get. So that's what we start looking at beyond the minimum. And then the value at risk is really looking at the probability of those cases. And so it's a balance of, we don't want to just be the minimum, especially if economically the cost of reliability that you avoid is greater than the cost of generation that you add. So that's what the reserve margin study is looking at.

Clay Jones (GAM): [05:11:33] All right. Let's talk a little bit about your unit retirement study. The goal of the unit retirement study is to quantify the impact of continued operation of the existing coal and other steam units with the impact of retiring and replacing those units with a portfolio of new resources, is that a fair summary?

Jeffrey Grubb (GPC): [05:11:52] Some form of replacement generation.

Clay Jones (GAM): [05:11:54] And you considered a number of coal and CT units for retirement, correct?

Jeffrey Grubb (GPC): [05:11:58] We did.

Clay Jones (GAM): [05:11:58] And the replacement portfolio you're comparing it against is comprised of the six power purchase agreements that you sought certification for in this case?

Jeffrey Grubb (GPC): [05:12:05] That's correct. For the portions that that would cover and for the duration that that covers.

Clay Jones (GAM): [05:12:10] I would like to introduce another exhibit to witnesses. I want to caution them that is includes trade, secret information. So I've already discussed that with Georgia Power. I'm going to give a copy to Georgia Power staff, to each of the commissioners, and the panel and then leave it up here.

Tricia Pridemore (PSC): [05:12:27] You may approach.

Clay Jones (GAM): [05:12:28] Thank you. Okay. Now, what I'm showing you here is exhibit GAM-2 marked as GAM-2, which contains trade secret information from your unit retirement study from Appendix A. And I'm not going to mention specific numbers on this chart, and I would caution you not not to either in response to my question. So we in agreement on that? [Yes.] Okay. I'll give you a minute to look at it.

Jeffrey Grubb (GPC): [05:13:30] Okay. So, Mr. Jones, this is MG0 only looking at. [That's right.].. Okay. I was trying to get oriented. [Yeah, we'll get there.]

Clay Jones (GAM): [05:13:42] Okay. Do you agree with me that this exhibit accurately reflects information that's in your filing?

Jeffrey Grubb (GPC): [05:13:49] I was only able to check the unit current study net benefit, but spot checking those they look at accurate, subject to check. [Subject to check.] Yeah. Thank you for that.

Clay Jones (GAM): [05:13:59] Great. Thank you. So this chart shows the results of the unit retirement study under a moderate gas price, zero carbon cost scenario known as MG0 for short, do you agree?. [That's correct.] And as your filing and testimony indicates, you ran several other scenarios as well, right? [That's right.] Low cost gas. High cost gas. And then adding in a carbon adder as well at times.

Jeffrey Grubb (GPC): [05:14:21] That's correct. 7 different scenarios.

Clay Jones (GAM): [05:14:22] Was it fair to say that, sort of, MG0 case would be considered a reference case?

Jeffrey Grubb (GPC): [05:14:28] So I wouldn't say that necessarily. There are places in the IRP where we do model comparisons against the reference case and we pick MG0 for a recommendation to the Commission. We use the scenarios and would say that they are all equally probable when you're looking across 30 years of a company. So we don't put any more emphasis on MG0 for coal unit retirement than we do any of the other scenarios that we look at.

Clay Jones (GAM): [05:14:57] But it's certainly a pretty standard, reasonable, possible scenario. Moderate gas, zero carbon, you look at doing these analyses.

Jeffrey Grubb (GPC): [05:15:04] As all of them would be. It's the case that we base our avoided cost on because it's based on existing rules. But again, for the scenarios that we look at in the unit retirement study, we note that they're all equally probable.

Clay Jones (GAM): [05:15:17] So your testimony is that a $50 carbon tax is just as likely as moderate gas or a carbon tax, you think.

Jeffrey Grubb (GPC): [05:15:23] Over 30 years, and for guiding a unit retirement study, yes.

Clay Jones (GAM): [05:15:29] All right. Now when considering a unit retirement study, the goal is to determine with respect to each units, each unit, the net benefits of not retiring the unit and the net benefits of retiring the unit, right? [That's correct.] And you would agree with me that a negative net benefit, which is shown here in some cases in parentheses, would indicate that early retirement is more economical in the status quo.

Jeffrey Grubb (GPC): [05:15:51] So you say early retirement, we'd just say retire. We're studying at 2025 through whatever. Yes. Retiring it within this IRP timeframe. Yes.

Clay Jones (GAM): [05:16:01] Fair clarification.

Jeffrey Weathers (GPC): [05:16:01] Based on this one scenario.

Clay Jones (GAM): [05:16:02] That's right. So we can agree that under the MG0 scenario, this study clearly supports the retirement of Plant Wansley 1&2 and Gaston Units 1-4. Would you agree?

Jeffrey Grubb (GPC): [05:16:14] If you were to base it just on the negative numbers? Yes. I think another thing that we would need to look at is, like we spoke to this morning, commissioners, there is no future coal risk in these models either in terms of there's carbon, but there's no other change in the MATS rule, change in the ELG. So if you're looking at just negative numbers strictly to guide that decision. Mr. Jones, you're correct. It would say that Wansley 1&2 and Gaston.

Jeffrey Weathers (GPC): [05:16:41] And I know these numbers are trade secrets, so I won't say them. But there are three other cases on here that are very near zero. And if you're struggling to break even with moderate gas prices with no carbon pressure, then you can, then you know that lower gas prices or having any carbon pressure will mean that it's negative.

Jeffrey Grubb (GPC): [05:16:59] Or any other future coal requirement for environmental controls.

Tricia Pridemore (PSC): [05:17:04] Recently I was at Plant Scherer and Unit 4, you know, JEA and FPL decided to shut down last year. But Unit 3, based upon its output and ability, it doesn't operate that frequently. So I mean getting it to near negative is, makes sense.

Jeffrey Grubb (GPC): [05:17:23] Yeah. Madam Chair, we've seen over the last few years the capacity factors in the units run a lot less. There are times that they run for transmission. And so we talked about the need to do that. But yes, there's continued pressure on coal from lower natural gas prices, more renewables, those types of things. And so the capacity factors are lower. This valuation captures that.

Clay Jones (GAM): [05:17:47] So you've been reading my cross? I think I might have put it on the Internet or something. I don't know. But you're, you apparently know what my next question was going to be, which is that the study doesn't show under this scenario any compelling benefits to retirement of Plant Bowen Units 1-2 or Scherer 1-2 or Scherer 3. Right? I mean.

Jeffrey Grubb (GPC): [05:18:08] I think it doesn't show benefits to retirement. It also doesn't show benefits to continue to operate. I mean, the numbers are pretty small. And again, I think there's future risk on the coal side. We have not seen the economics of coal units get better over the last several IRP cycles. And so when you have results that are barely above zero, a few digits of millions of dollars that we're looking at here, that it may not say retire it, but our position would be it doesn't say keep it because you've got future pressures. We think there's a lot more risk than there are benefits.

Jeffrey Weathers (GPC): [05:18:44] And Mr. Jones, I know this is labeled unit retirement studies, but again, as we said, it really only is the MG0 scenario. So I don't think it's, I wouldn't characterize these results as being reflective of the study because the study compared, also considered six additional scenarios. And if you only look at one scenario of the future, and count gas prices as being moderate forever and there not being any carbon pressure, any additional pressures on coal. I think that that's a, disadvantaging customers because you're not looking at, you're not taking risks into consideration. So I think it's a, that's why we look across the range of scenarios.

Clay Jones (GAM): [05:19:22] So if you looked at a higher gas scenario, though, these numbers would be even less compelling for retirement. Is that correct?

Jeffrey Weathers (GPC): [05:19:27] Higher gas, zero carbon scenario is going to be the best case for coal, but lower gas will be worse. And any carbon pressure is going to be worse.

Clay Jones (GAM): [05:19:37] Now certainly the, this particular scenario doesn't show any compelling reason to retire Plant Bowen Units 3&4. Right? And you've elected not to do that in this case or to ask for that in this case?

Jeffrey Grubb (GPC): [05:19:50] Correct. And again, part of that is because we knew we needed to control Bowen 3&4 to maintain reliability. The capacity RFP is not reflected in these economics. But again, I think when you're talking about these levels, it may not be compelling to retire. It's also not compelling to keep. And so to Mr. Weathers's point, if you look at the entire unit retirement study, there's a lot more risk in a lot of these scenarios than there are benefits.

Clay Jones (GAM): [05:20:14] And you would agree with me...

Tim Echols (PSC): [05:20:16] A question on the chart. So we talked earlier today about the inactive reserve. So on Bowen 1&2, if 2 was put in inactive reserve, that number that's listed there, would it go...If it wasn't being used, it would go up or down, that number, at the very bottom, under the net benefit?

Jeffrey Grubb (GPC): [05:20:43] So Commissioner, I'll let Mr. Robinson add in here as needed. The, if we, if you do inactive reserves on a coal unit, we would not project any capacity benefit, any energy benefit, anything here. So it would get a lot worse here because it would have absolutely no value. We'd have to look at the cost. It really then becomes what is the value from a transmission standpoint.

Michael Robinson (GPC): [05:21:09] Right, commissioner. We'd be running it for reliability purposes on the system or for resiliency.

Tim Echols (PSC): [05:21:14] And do you do you quantify that number ever?

Michael Robinson (GPC): [05:21:22] Specifically referring to resiliency? It's very hard to quantify resilience. On reliability, there are re-dispatch costs that we can look at, cost of one of those units as it relates to transmission reliability. But those are also difficult to quantify depending on the time of season, how long you have to run it. If it's a short period of time, can the unit respond and run for that short period of time they come offline.

Tim Echols (PSC): [05:21:50] If there were a reliability issue in North Georgia, would it be better to have a unit like Bowen 2 there, or to buy energy off the spot market out of some surrounding state which which would be better?

Michael Robinson (GPC): [05:22:07] Commissioner, from a transmission perspective, it's always a good thing to have generation close to load, but there are economic decisions that go into that as well. That's why we're thinking about and talking to generation about converting those units to synchronous condensers where we can get the VAR support for voltage support in the area. And that's one of our concerns as well as relates to reliability in North Georgia.

Jeffrey Grubb (GPC): [05:22:26] And Commissioner, to the inactive reserve point, if you've got a unit that's set up in that manner, you're really talking out about events that are multiple days like we talked about earlier with some pipeline disruptions or something. It's not one that you could bring on because you have issues tomorrow. It's days and weeks. And so to be able to have it respond, even though cold units take a little while, you actually have to keep it as it is now. So the inactive reserve is really for those low probability, high impact events that we talk.

Tim Echols (PSC): [05:22:58] And a voltage event, because I've visited the Georgia transmission voltage facility in Winder, voltage events are resolved pretty quickly. Right? That's not something that you're doing over days.

Michael Robinson (GPC): [05:23:13] The SBC that you refer to in Winder. Yes, it's very quick. It's always there. Ready to respond. Come online, synchronous condenser would be the same, so the operators could can manipulate the absorption or production of VARs from that facility. The two static VAR systems that we have proposed in the ten year plan also saying offer voltage support to the North Georgia area and are online and available to act within milliseconds of an event. Yes, thank you.

Tricia Pridemore (PSC): [05:23:42] Does the Georgia power fleet today have inactive reserve that is coal in it?

Jeffrey Grubb (GPC): [05:23:48] No, ma'am.

Tricia Pridemore (PSC): [05:23:48] No? Thank you.

Clay Jones (GAM): [05:23:53] Mr. Grubb, a minute ago you said that, I don't want to misquote you, so correct me if I'm mischaracterizing what you said, but I believe you said, you were looking at these numbers where it didn't give a compelling reason to retire, but didn't give a compelling reason to keep it. Then you went on to say that the coal economics, the coal plants are not getting better. Is that a fair summary?

Jeffrey Grubb (GPC): [05:24:14] Yes, it's not, make sure I hear, I said it does not also, it doesn't compel one to keep it either. So I got you. Okay.

Clay Jones (GAM): [05:24:23] Fair enough. So given that. But the decisions being made here is being made now. Right? So even if you think the economics are going to get worse in the future, we're still looking at a decision point of now and there'll be another IRP three years from now. Correct?

Jeffrey Grubb (GPC): [05:24:36] Yeah, that's correct. I mean, we've talked about the retirement dates are down the road, but the decision is here now. But again, that's when we see the trends. And when we look forward, we just don't see the coal economics getting better. So when you're have, for lack of a better term, marginal results, we would tend to say there's more risk to keeping it than retired.

Jeffrey Weathers (GPC): [05:24:56] And then the opportunity is now in terms of replacement power through the purchased power agreements. So those are really good deals that customers will benefit from. And those deals are not likely to be there certainly at those prices if the decisions were delayed.

Clay Jones (GAM): [05:25:13] We don't know. I mean, there could. We don't, three years from now, we don't know what prices are going to be.

Jeffrey Weathers (GPC): [05:25:17] We don't know. But we've also we know the market is getting tighter than it used to be. We know the region is getting tighter. So our expectation would be that it would not be available, at least at those prices.

Clay Jones (GAM): [05:25:30] Okay. Well, let's talk about a different expectation. You in your scenarios, talk about in various scenarios, carbon taxes of $20 per metric ton and $50 per metric ton, correct? [That's correct.] And you used to look at $10 per metric ton, but you dropped that one for this case, right? [That is correct.] There's no tax on carbon right now, is that correct? [That's right.] And even though we've been talking about carbon tax scenarios down here for nearly a decade, Congress still hasn't enacted a carbon tax, has it?

Jeffrey Weathers (GPC): [05:25:59] They have not. But there are a number of proposals that they have considered, a range of proposals. So we're looking at future decisions in the evolution of the fleet over the next 30 years. So in terms of risk to customers, is a real risk to customers that there will be carbon. In fact, the $50 price very well aligns with some of the recent proposals, potential bills that Congress has discussed.

Clay Jones (GAM): [05:26:26] What about the Build Back Better bill that was proposed last year? In that bill, Congress considered the climate change provisions were more focused on incentives, not on carbon.

Jeffrey Weathers (GPC): [05:26:36] They were more focused on incentives. They were they had the same objective, which was to decarbonize the electric sector and really to to decarbonize the industry. There's a different pathway to get there. The company considered a different pathway in its planning scenario process, which is a lowering of emissions over time. We called it a carbon intensity scenario. But in looking at that, it is very similar to the $50 scenario that it drives the fleet to decarbonize over time. So pressures may come in different forms. It could be carbon tax, it could be some type of clean energy standard. It could be tax incentives or and/or penalties similar to what's in the Build Back Better plan. But we think that the risk of carbon is real and that's why we factored it into our scenario planning.

Clay Jones (GAM): [05:27:27] OK. Now, in making this comparison between the cost of keeping the units instead versus adopting this portfolio. As you said, as you went through it, Mr. Walsh, are also asking for additional sums with regard to those PPAs, correct? [That's correct.] And just confirming, as staff crossed you on, those weren't taken into consideration in your unit retirement study, right? [That's correct.] All right. Let's talk a little bit about cost recovery of the units that you propose to retire. Madam Chair, I'd like to approach the witness with an exhibit.

Tricia Pridemore (PSC): [05:27:57] You may approach.

Clay Jones (GAM): [05:28:03] Again, this does not include trade secret information. I'll represent to you that the chart, as it says, is sourced from information reflected in the responses to data requests STF-LA-1-28 and 1-29, marked as exhibit GAM-3. You see that? [Yes, sir.] And subject to check. Do you agree that this reflects accurately reflects what you had in your responses to those data requests? [I do.] Okay. Thank you. Now, this chart summarizes the proposed plant retirements and remaining net book value as of December 31st, 2021, right?

Jeffrey Grubb (GPC): [05:28:59] That is correct.

Clay Jones (GAM): [05:29:00] So for Wansley 1&2, the 2017 depreciation study. Now, we say that that that was what was used to determine the retirement date in the last full rate case. Is that fair?

Jeffrey Grubb (GPC): [05:29:11] For depreciation purposes.

Clay Jones (GAM): [05:29:13] And for Bowen 1&2 is 2030, and Scherer 3 is 2047? [That's correct.] And the second column has your proposed retirement dates, and the third column has the remaining net book value of those assets.

Jeffrey Grubb (GPC): [05:29:26] At the end of last year, that's correct.

Clay Jones (GAM): [05:29:27] End of last year. All right. Now Georgia Power is seeking recovery of the net book balance of these plants even after they're retired and no longer providing service, correct?

Jeffrey Grubb (GPC): [05:29:37] Yes, that's correct. We're requesting that the net book value upon retirement would be moved to regulatory asset.

Clay Jones (GAM): [05:29:43] And the company would also seek to earn a return on the unamortized balance after the plants are retired. Agree?

Jeffrey Grubb (GPC): [05:29:48] As it goes through rates, not regulatory accounting. Can't speak to all those, but yes, we would we would continue to recover it as we have.

Clay Jones (GAM): [05:29:58] And you would agree with me that in this filing you haven't stated over what period of time you will seek to recover those costs, have you?

Jeffrey Grubb (GPC): [05:30:06] Yes, that's correct. We've stated that that would be discussed in the rate case or future rate cases. We do, though, however, expect the remaining net book value to be less upon the retirement dates than they are right now. But we have not laid those out.

Clay Jones (GAM): [05:30:20] The total would probably be less than 3.1 billion. It would be something less than that. [That's correct.] Would you expect it to be north of 2 billion?

Jeffrey Grubb (GPC): [05:30:27] I don't know. I don't know, Mr. Jones, what our rate case strategy will be in terms of proposed depreciation dates.

Clay Jones (GAM): [05:30:34] I'm sorry, I didn't state the question correctly. Would you expect the remaining net book value, if these retirement dates are approved, to be north of $2 billion? Not what you would request, but what the net book...?

Jeffrey Grubb (GPC): [05:30:44] I don't know, because I think that will depend on two things. One, how much money we spend between now and then and what comes out of this IRP. But the other is what is that depreciation date that's approved in the rate case? I don't know.

Clay Jones (GAM): [05:30:57] So Georgia Power might seek to recover these costs prior to the retirement dates that were established in the last rate case. Right? You would reserve the right to request that?

Jeffrey Grubb (GPC): [05:31:08] I think we have that right. But again, I'm not in those discussions. I don't believe we would request it to be before we retired it, though.

Clay Jones (GAM): [05:31:15] And if you were to seek, say, an accelerated recovery and the commission were to grant that request, that would place upward pressure on rates, wouldn't it?

Steve Hewitson (GPC): [05:31:28] Objection. I think that's been asked and answered. I think the witness just said, he didn't think we would seek it. So asking a hypothetical "If you did seek." It seems to me that...

Tricia Pridemore (PSC): [05:31:37] Sustained.

Clay Jones (GAM): [05:31:38] Madam Chairman, I'll respond to the objection. I mean, I'm asking a question about, he hasn't committed to not, the company hasn't committed to not seeking accelerated recovery. So I'm just asking if they did, what would be the rate impact? I'm not, that's not asked and answered. That's a different question.

Steve Hewitson (GPC): [05:31:53] It would be a great question to answer in the rate case, but that's not part of the IRP.

Tricia Pridemore (PSC): [05:31:57] Sustained.

Clay Jones (GAM): [05:31:58] All right. Your unit retirement study didn't take any of that into consideration, did it?

Jeffrey Grubb (GPC): [05:32:10] By that meaning?

Clay Jones (GAM): [05:32:11] That it was a period of when you would seek to recover these costs.

Jeffrey Grubb (GPC): [05:32:15] That is correct, exactly. As we've done in prior IRPs and unit retirement studies, we look at the incremental cost of maintaining the coal units and running them versus retiring and replace the net book value treatment. Whether you're retired or not, we see being the same the way we've done it in the past. So to us it's a cost that is the same regardless of whether we retire the unit or not. So we do not include.

Clay Jones (GAM): [05:32:42] So back to the additional sums on the PPA. You propose to replace the retired coal units with these six capacity PPAs and the additional sum, those additional sums are considerably higher than the $2.30 per kilowatt year figure used in a lot of prior PPAs. Right?

Jeffrey Grubb (GPC): [05:32:59] Yeah. They are higher. The $2.30 has its genesis about 20 years ago. And so they are higher, really reflecting the great values that we got in the capacity RFP.

Clay Jones (GAM): [05:33:09] And the additional sum, just as a mechanism, acts as a, would you agree, as a proxy for a return on those supply side options which are treated as expenses not included in rate base. Is that right?

Jeffrey Grubb (GPC): [05:33:21] So it's a, it's added to revenue requirements, I think is, if that's what you're asking. Yes.

Clay Jones (GAM): [05:33:27] It's not technically a return, but it's an additional sum that acts as sort of a proxy for that, because you don't get a return on those. So they don't go into rate base. Right?

Jeffrey Grubb (GPC): [05:33:37] I believe that's fair.

Clay Jones (GAM): [05:33:38] And you recover the cost of those PPA typically through the fuel clause.

Jeffrey Grubb (GPC): [05:33:42] That's correct. But I'm not sure additional sum goes through the fuel clause, subject to check that. I believe it's revenue requirements through the rate base. But I'd have to confirm that.

Clay Jones (GAM): [05:33:51] By contrast, rate base costs, you earn a return, including a return on equity for Southern Company, your shareholder, correct? [Correct.] For example, you'll earn a return on the retired generating plants if the commission approves this plan because their rate based assets for as long as those assets are to be recovered. Right?

Jeffrey Grubb (GPC): [05:34:11] Are we, net book value plant service? But yes, we do.

Clay Jones (GAM): [05:34:16] Okay. So and then through the additional sum mechanism, you'll be earning that as well on the PPA, meaning in effect, ratepayers will pay a return on both the capacity of the coal units that are no longer in service and on the capacity of the PPAs to replace them.

Jeffrey Grubb (GPC): [05:34:29] So the additional sum is, is, is allowed by statute. So that's correct. So we would continue to do that again. The what we'd look at the unit retirement decision is the 30 year benefit to customers. And so that's why we're recommending retirement regardless of the rate case treatment over 30 years, it's in the best interest of customers economically to retire.

Jeffrey Weathers (GPC): [05:34:51] And the additional sum is directly proportional to the savings that customers will realize through the power purchase agreements. So that, the reason why it is larger, as Mr. Grubb said, is because there is substantial savings from retiring these units and replacing them with these power purchase agreements instead of alternate company-owned capacity.

Clay Jones (GAM): [05:35:12] And you would assume that in designing the bids for the PPAs, the bidders, the ones you've selected, have factored in a bid price that includes a return to their shareholders.

Jeffrey Grubb (GPC): [05:35:23] I would, I'm not a bidder. It's a fair assumption. I don't know how much or those types of things. That's up to the bidders.

Clay Jones (GAM): [05:35:31] Sure. I think that's all I have. Thank you. Madam Chair. Let me ask you about the trade secret exhibit that I distributed. I know I need to leave one with the court reporter. Mr. Hewitson has said he can keep his and staff can keep theirs. What would you like me to do with regards to the ones you have? Glad to gather.

Tricia Pridemore (PSC): [05:35:46] The commissioners can keep theirs as well. We are privy to trade secret information.

Steve Hewitson (GPC): [05:35:52] Thank you, Madam Chair. I appreciate it.

Tricia Pridemore (PSC): [05:35:53] Thank you, Mr. Jones, Georgia Center for Energy Solutions.

Peter Hubbard (GCES): [05:36:00] Thank you, Madam Chair. Because I plan to offer direct testimony on behalf of the Georgia Center for Energy Solutions, it's my understanding that the Commission rules preclude me from directing [questions to their] direct testimony, so I'll step down from that role.

Tricia Pridemore (PSC): [05:36:20] It's one or the other. Mr. Hubbard. Yeah. Thank you. Okay. Georgia Coalition for Local Governments.

Alicia Brown (CLG): [05:36:37] Afternoon. Commissioners, panel members. [Good afternoon.] Just as a matter of road mapping, we'll be jumping right in with the CARES program, which is one of your big programs for customers like the local governments within our coalition. So the first question is, as currently proposed, that program includes a $5,000, what you're calling NOI fee for pre-administration purposes. Are there any plans to work out alternative solutions for some of the smaller entities that might be taking advantage of that program, like a local government or a school that may struggle to come up with $5,000 for something that may not work out?

Wilson Mallard (GPC): [05:37:15] So certainly we could consider that. And again, commissioners, as we have with prior commission approved programs, really just proposing the concept here with CARES. Now, once approved in this IRP, a more robust and complete program filing will follow much like CRSP, much like C&I REDI before. So the opportunity to consider particular changes like that. Certainly have that chance and can be considered.

Alicia Brown (CLG): [05:37:40] Thank you. And it's my understanding is that CARES is an iteration of the program that's been running since, I believe, the 2019 IRP. In your experience, has that been a premium program, or a cash neutral program, or a money saving opportunity?

Wilson Mallard (GPC): [05:37:56] So it's, I think it's all of the above. What the program offers is the ability to subscribe to the output. And the subscription price is based on the cost of the purchase power agreements, plus the administrative fee to cover the company's cost. Again, try to protect make sure the program is cost neutral to non participants. In return for that, the participating customer gets a credit that's based on the marginal cost to generate electricity as, in hours that the solar energy that they've subscribed to is producing. And so it really just depends on what those actual avoided costs turn out to be over time. So there is a chance that the participating customer could benefit at the end of time, could have paid more. There's a chance a participating customer could have paid less. There's a chance if our forecast is really close to what actuals turn out to be, that it would be cost neutral at the end of the time period.

Alicia Brown (CLG): [05:38:54] So would you say that it's most analogous to a virtual power purchase agreement?

Wilson Mallard (GPC): [05:38:59] I don't know that it's analogous to a virtual power purchase agreement, really. It's the ability to subscribe to the output. Georgia Power is the the deliverer, provider of energy to all of our customers. We procure resources that benefit all customers. And so we make the decision. This Commission approves through the certification process a portfolio of resources that will deliver benefits to all customers during the term of the subscription period. The customers get the RECs, they get the ability to, to benefit. So in that way, they are subscribing to the particular output. So maybe there's some similarities in that respect, but I wouldn't call it analogous to a virtual PPA.

Alicia Brown (CLG): [05:39:46] In your filing for this CARES program, you mentioned a community adder fee. There was only about a paragraph on that. Can you speak to that further?

Wilson Mallard (GPC): [05:39:53] And so that's a concept that we've gotten feedback from some of our interested customers that they would like the opportunity to support community programs in addition to just subscribing to the output of these renewable resources. I will tell you that the, that dimension is really a nod to that concept to show that we are interested in committed to developing a community outreach program like that. But we don't have any of the details developed at this point. It's important to remember the CARES projects are still 4 to 7 years down the road from from coming online. And so if there's interest from CARES customers and participating in that, we'll further develop that option, we'll bring that back before the Commission for approval. Conceptually, though, we're going to collect an adder from the participating customers, and those funds would then be used to support community program related to renewables or energy efficiency or possibly some other options like that. [Okay.]

Tricia Pridemore (PSC): [05:40:57] Mr. Mallard, do you find it in the company's experience, though, that when an entity has some skin in the game, as Commissioner McDonald likes to say, that they've met, that they're making some level of investment to accomplish their goals with these renewable programs that... The arrangement tends to work out better because they are invested in it and they're making some level of of participation to to identify that.

Wilson Mallard (GPC): [05:41:27] Yes. Yes, Madam Chair, I think that's absolutely true. And I think our experience has shown that that collaboration and commitment is much more when both entities are working together towards the same goal and and when, yes, the other entity has some skin in the game.

Alicia Brown (CLG): [05:41:46] So we certainly appreciate the inclusion of a municipal, university, schools, and hospitals carve-out in that CARES program, given that each of us has these renewables goals and may not meet or at one point may not have met that three megawatt threshold. But as you may know, our goal is, most of them are community wide and not just for our city operations. So is there any interest in taking this CARES program and allowing representatives like ourselves who aren't just concerned about our own energy use but are concerned about our communities? Would there be a chance to subscribe on behalf of our community above and beyond our own energy use?

Wilson Mallard (GPC): [05:42:21] So I don't think we've contemplated that in the program designs thus far. I'm not saying it's not something we couldn't consider down the road, but as designed right now, the first step towards a carve-out specifically for the MUSH market, we feel like is appropriate next step to test that market to understand how we can try to satisfy those customer needs. I mentioned earlier, I'll mention again, we do have programs available for customers in all classes and all rates at Georgia Power. And so we certainly could work towards helping to market and expand our programs like simple solar, like community solar, but other program design concepts like you're talking about, certainly something the company would be interested and willing to discuss in more detail.

Alicia Brown (CLG): [05:43:05] We appreciate that. And as far as that MUSH carve-out, I believe it's currently 50 megawatts, is that correct? [That's right.] What is that size based on?

Wilson Mallard (GPC): [05:43:13] So the size is based on the overall amount of subscribable capacity, which is 2,000 megawatts, the demand that we've seen from all of the segments, and then interest that we've seen from potential participants in the MUSH segment. So it's based on all of those things. It's based on direct feedback and interaction from these customers that we deal with and then us using our judgment as we design the program to try to do the most good for the most customers, if you will, and allocate those megawatts for subscription across segments where there's customer interest.

Alicia Brown (CLG): [05:43:50] To that point about customer demand and customer interest. You include in your filing that the simple solar program is going to go from a 1 cent per kilowatt hour premium to a 1.25 cent per kilowatt hour premium based on current changes in REC prices. [That's right.] In your opinion, what is driving that increase in REC prices?

Wilson Mallard (GPC): [05:44:08] So I think what's driving the increase in prices are more customers with voluntary renewable energy goals who are seeking to meet those goals through purchases of voluntary RECs. And so what we've seen are REC prices that have been in the neighborhood of a 10th or 2/10 of a cent per kilowatt hour go all the way up to north of six, maybe close to 7/10 of a percent. They've settled back down now, I think most recently back in the two or 3/10 of a cent range. But those, that volatility and that demand is driven by customers trying to meet their voluntary goals.

Alicia Brown (CLG): [05:44:44] So if an increase in demand is being driven by these voluntary goals, wouldn't it makes sense to provide even further supply than's being proposed to meet that demand?

Wilson Mallard (GPC): [05:44:54] So the amount that we can offer for subscription is based on the total amount of renewable resources that we can procure. As we've talked about, we really spend a lot of time using our models, using our experience here to map out this plan towards adding 6,000 megawatts of renewable resources to benefit all customers. To go faster than that can introduce cost and risks, to go slower than that can introduce cost and risk. Our plan to get to 6,000 and the 2,300 megawatts that we proposed this time is our best, in our judgment, what's best for customers, the best growth of renewable resources. That also takes into account the impacts to our generation system, our transmission system, that takes all of those impacts into account. And it's a pace that we feel like maximizes the benefits for customers.

Alicia Brown (CLG): [05:45:47] So you mentioned the extensive reliance on modeling, and you've mentioned dozens of models throughout today's hearings. And there's been a specific focus on reliability in North Georgia and how certain plants close there's going to be reliability concerns from that. As a part of those reliability studies, have you considered a demand side focused option with demand side solar, demand side batteries as a quicker and more, less space constrained option as opposed to the transmission and utility scale renewables that you focused on?

Michael Robinson (GPC): [05:46:21] What do you mean by demand side solar?

Alicia Brown (CLG): [05:46:24] Like rooftop solar. Behind the meter solar.

Wilson Mallard (GPC): [05:46:27] Sure. We consider all sorts of resources that can help meet generation needs and resource adequacy needs. What you'll see in our proposal for distributed generation procurements is that hosting capacity tool that we've talked about that will hopefully provide information that will guide renewable developers to circuits where there's capacity available. I would expect a good number of those would be in North Georgia, in and around the metro Atlanta area. So in that way, we're absolutely encouraging distributed generation to locate in areas where that, those resources can be integrated to the system with the least cost and provide the most benefits.

Michael Robinson (GPC): [05:47:07] And Commissioners, it's important when you're thinking about transmission constraints and reliability, and you're resolving those with demand side resource as counselor proposes, those resources have to be available online when that contingency happens. And if that contingency happens at 6:00 in the evening, going into the evening hours and solar is not available, that demand side resource does no good for the transmission constraint perspective absent storage.

Alicia Brown (CLG): [05:47:34] And on the subject of Behind the Meter Solar, we've had multiple listening sessions with Georgia Power about new programs that are being developed around income, qualified community solar and of course, extensions of your income qualified energy efficiency programs. But I can't help but notice that there isn't any income qualified option for behind the meter solar, which of course rooftop is the only kind of solar that could provide those customers with resiliency benefits through the addition of storage. So I was just wondering what the rationale was for the lack of income qualified behind the meter?

Wilson Mallard (GPC): [05:48:06] Yeah, we've certainly considered that and evaluated program designs in other parts of the country. In our opinion, it's difficult to do onsite solar on, for income qualified customers based on the quality of the housing stock, based on the integrity of the roofs. Those programs can be done. They require a lot more of analysis of the quality of the housing stock. They require a lot more information from those customers. I think that's something that the company can definitely consider in the future. But it's our position that the income qualified community solar program is really the best way for income qualified customers to get access to solar. We don't have to worry about installing solar on the rooftop. These customers are going to have the ability to subscribe to the output of a community solar facility, which we got eight megawatts worth here in the state, five megawatts we're going to make available for income qualified customers. In that way, these customers can subscribe and they can reap the benefits of solar without the complexity of a rooftop installation at their actual residence.

Alicia Brown (CLG): [05:49:19] We're no strangers to the conditions of low income housing. It's something we work with every day...

Tricia Pridemore (PSC): [05:49:24] Would Georgia Power Seek rate recovery for income qualified behind the meter.

Jeffrey Grubb (GPC): [05:49:29] So if we could design a program, Madam Chair, where costs would not be shifted and the benefits could accrue to all customers and benefit the income qualified customer as well, I think we might, but that's that's a math equation that we haven't been able to solve as of yet.

Tricia Pridemore (PSC): [05:49:49] You just answered my question by asking the same question back to me. So I'm going to ask it to you again. Would Georgia Power seek to recover in rates income qualified behind the meter solar?

Tricia Pridemore (PSC): [05:50:04] Yes. [Yes.] If we could design a program that protected non participants. That benefited the participants and made cost effective sense for all Georgia Power customers, then yes, I think that's...

Tricia Pridemore (PSC): [05:50:16] Mr. Mallard, would that not socialize the cost of solar across the rest of the Georgia power rate base?

Tricia Pridemore (PSC): [05:50:20] So that's the big if there, we're going to make sure we protect other customers...

Tricia Pridemore (PSC): [05:50:25] That's a yes or no, would it not?

Wilson Mallard (GPC): [05:50:29] It depends. So community solar income qualified. We have a third party that's going to sponsor that. They're going to buy down the community solar for the participants. So in that way, we're protecting all of the customers. And there's a corporate sponsor that's going to volunteer to support that program. A similar design could be done for onsite or rooftop solar with a third party who's willing to buy down the program cost.

Tricia Pridemore (PSC): [05:50:57] So if a third party was to buy down the program costs to zero to the rest of the Georgia power rate base for income qualified behind the meter solar, say that five times fast, then that would be a program that Georgia power would not have to seek to recover in rates because a third party, an independent third party would cover the cost of it. Correct?

Tricia Pridemore (PSC): [05:51:23] If we're, if it's going to be Georgia Power that's building and installing the solar, I think we still need certification from the commission to do that. It's just the cost recovery is going to be subsidized by the third party. So that's still a program that we would absolutely bring to the commission and get commission approval. And I could see that working on maybe new construction. So maybe the rebuild of affordable housing, that type of thing, where in new construction solar could be integrated into the initial design and construction, certainly something that we could pursue further. But absolutely we would want to see a design that protected non-participants, Madam Chair.

Tricia Pridemore (PSC): [05:52:01] This third party that's out there that covers the cost of community solar for income qualified recipients. When did that program start? And how long as it been going?

Wilson Mallard (GPC): [05:52:11] It has not it's been proposed for approval here this IRP.

Alicia Brown (CLG): [05:52:15] Thank you. So continuing the line of questioning around behind the meter solar, a hot topic today, as we all know, is probably going to be the monthly netting pilot and how it's reached its cap. You list in the main document that you're continuing to evaluate the rate impacts of that program. When can we expect that study?

Wilson Mallard (GPC): [05:52:37] Well, we still don't have all of the 5,000 customers online yet. We reached capacity last summer with customers who had signed up. We're north of 4,000. I haven't gotten the update today. It's probably on the website, but we're within six or eight weeks of having all 5,000 customers online. Once we have all 5,000 customers online, we really do want to monitor and get a full year's worth of usage to see all the seasons, all the months of the year, and to be able to evaluate those impacts. I can tell you, commissioners, that based on early analysis and customers who already had solar installed and we just moved over as of January of last year, what we're seeing is a cost shift just based on the energy push back to the grid of more than $1.5 Million a year from the 5,000 customers. So it's going to be at least that much. And then once we get all the customers online and can do a more in-depth analysis, we'll have better figures to be able to show the amount of upward rate pressure shift.

Alicia Brown (CLG): [05:53:41] When evaluating that program, with that study, is this looking at just a near-term window or is this looking over the life of the solar asset using the renewable cost benefit framework?

Wilson Mallard (GPC): [05:53:51] So we use the renewable cost benefit framework, but we really just have year to year agreements with these customers. And so it uses the the best view of current cost and benefits, which represents the MG0 that we've talked about. Each year's RCB adjusted avoided cost is calculated and that's the amount of compensation that customers receive for the energy pushback.

Alicia Brown (CLG): [05:54:19] On the subject of that renewable cost benefit framework, my understanding is that involves variable O&M, fuel, fuel handling, line losses and things of that nature. Is that correct?

Michael Robinson (GPC): [05:54:30] Yes, correct.

Alicia Brown (CLG): [05:54:31] When we talk about line losses, it's simple physics that you have greater line losses when it's warmer, when there's more energy going through the line. Does this value that's included in the avoided costs use an average line loss or is that use marginal line loss based on the actual conditions when solar is being produced?

Jeffrey Grubb (GPC): [05:54:52] I haven't dug into the line loss study in a while, but I think it's an average, it's an annual average, zone level.

Jeffrey Weathers (GPC): [05:54:59] Yeah, I think that's correct, subject to check.

Alicia Brown (CLG): [05:55:03] So if we're adequately measuring cost and benefits of solar and we're looking granularly at the energy, would it makes sense to also take a granular look at the line losses?

Jeffrey Grubb (GPC): [05:55:13] So I think when we say granular on energy, I'm not, we don't look at that at each circuit type of level. And I think losses would have to be down to that level. I don't think you would see as drastic of a change, but to have losses for every single account would be quite administratively burdensome. If we could even...

Michael Robinson (GPC): [05:55:31] It would be a significant challenge from a transmission and distribution perspective to calculate those losses on the basis that which you're speaking.

Alicia Brown (CLG): [05:55:38] But could it be hourly, like you do with energy? Across the System.

Jeffrey Grubb (GPC): [05:55:42] Again, I'm not familiar enough with the loss study to know that it's across every hour because I think your losses are...

Michael Robinson (GPC): [05:55:49] We do not have the models to support that type of calculation. It would be significantly costly for the company to develop those models, if they could be developed, to calculate that loss on an hourly basis.

Alicia Brown (CLG): [05:56:05] And final question on the behind the meter side of things. Again, as local governments, we have a few more policy goals than just renewable energy. We're also interested in jobs. We're also interested in the resilience that comes through adding storage. We're also interested in preserving our landscapes. And all of those things come together with rooftop solar in many cases being our best option to uphold all of those goals. With the closure of the monthly netting. The calculations for how large the system should be. What kind of budget that we need to set aside, gets a little more complicated. So in your experience, if we're on the RNR instantaneous tariff that you get put on now that monthly netting is full. What information do you need to make the best decision from a financial perspective?

Wilson Mallard (GPC): [05:56:52] Sorry. Can you repeat that one more time?

Jeffrey Grubb (GPC): [05:56:53] And before you do, you're asking from the customer's perspective?

Alicia Brown (CLG): [05:57:01] Yes. [Okay.] To simplify. Under monthly netting your calculation for when, how much money you need to have and what your payback will be is quite simple. It's the retail rate times what's being produced is how much that you are saving. But under instantaneous netting, it's a little more complicated because most customers don't have a concept of how much energy I'm using at any moment and how much my solar is generating at any moment. So how do we, as customers, and particularly as local governments, make the most informed decision about the solar that we want to put on our sites?

Wilson Mallard (GPC): [05:57:33] So and we're absolutely committed to helping local governments, to helping all customers and to grow rooftop solar, frankly. Gosh, The renewable development team, I think we talked to over 12,000 customers last year alone to help them along their journey to evaluating solar at their home or residents or business and help them make the best decision. And so you're right, it's a more complicated calculation than just your retail rate, but that in itself is not a justification to overpay through monthly netting for that energy that's pushed back to the grid. That energy is only valued at the commission approved RCB avoided cost, which is about 2.7 cents this year. That also really lines up well with what the market can deliver as far as price and value of solar. It's my experience that we can estimate how much solar is consumed on site based on the size of the solar panel and the load of the house. And we can help that customer understand if 50%, two thirds, 75% is consumed on site and thus reducing retail rates. And how much is pushed back to the grid and is credited at that avoided costs? So we're here to help. We've got a team full of folks that can help. But just the simplicity of the retail monthly netting, to me, is, that in itself is not a good reason to overpay for that energy that's pushed back to the grid.

Alicia Brown (CLG): [05:59:00] Yes, but my question is, what information do we need to make sure that we send as little back to you guys as possible?

Wilson Mallard (GPC): [05:59:08] Right. So again, we can help. And we've got we've got a team of folks that can help. We can look at... Sure. If it's a business account, we've likely got more information. If it's over a megawatt, we've got hourly information, we can bump that, your hourly usage up against the solar production curve based on the size of the solar system that you might put on your rooftop or besides your business or residence. We can help a customer estimate how much is consumed on site, how much is pushed back, put values on both of those and help produce a payback analysis for customers that are interested.

Alicia Brown (CLG): [05:59:42] So what if my building is not over a megawatt? What do I have to do to get the hourly information that you need to make this analysis?

Wilson Mallard (GPC): [05:59:50] So if you're on a time of use rate, then we'll have your rates by your usage, by the time of use period. And we can overlay the solar production curve on that as well and estimate how much is going to be credited at the off peak, the on peak, and then how much might be pushed back. For residential customers, it's a little less, we don't have the granular information, but we're still are able to make some assumptions and help customers estimate just how much energy would be consumed on site and how much would be pushed back to the grid. So not as accurate without all of the billing determinants, but still we're able to make a relatively informed decision there. For the most part, if a solar facility is sized correctly, the majority of the energy will be and should be consumed on site, really minimizing the amount that's pushed back to the grid.

Alicia Brown (CLG): [06:00:39] Are you aware that at this point, local governments like the city of Savannah, Atlanta, DeKalb County, the ones in our coalition, are currently being asked to pay $50 per meter per month to have access to hourly interval data?

Wilson Mallard (GPC): [06:00:52] I am not aware of that, but if you're telling me that that's true, I'll accept it. Subject to check.

Alicia Brown (CLG): [06:00:57] Well, I was going to ask you to speak to the cost causality of that. Maybe to find someone else... anyone want to take that question?

Wilson Mallard (GPC): [06:01:04] Yes. So all of our programs, all of the information that we provide to customers, we really do try to assign the cost to the cost cause. And so although I'm not familiar with the $50 a month charge, my expectation is that's been, that amount has been determined based on the cost of the meter and the cost of gathering, the metering information, the cost of interpreting it, the cost of producing it back to the customer. And so those fees are designed to collect the cost from the cost causer and to not shift those costs to the entirety of all Georgia power customers.

Alicia Brown (CLG): [06:01:40] Shifting to community solar and this idea of income qualified. Absolutely thrilled to see that you are offering that. But I'm a little disappointed to see that the standard subscription is going up. And I'm curious as to why that is happening, when, to my knowledge, these sites have already been built. So can you explain the, I believe, it's $3 increase in the standard subscription?

Wilson Mallard (GPC): [06:02:01] Yes. And the subscription price for community solar, commissioners, is calculated based on the same notion that we've talked about a couple of times already, to prevent costs from being shifted. And so as you guys are aware, our residential rate is an energy only rate. And so the entirety of the cost of providing electricity is recovered through those those kilowatt hours. All of the costs are recovered, save the base charge, through the energy charge. And so in order to make sure that community solar participants continue to pay their fair share for their portion of the grid, their portion of the generating plant, the transformer, the wire, the customer service, all those things, we have to design the community solar participation price at an amount that ensures that we still recover the correct amount of cost for those customers. And so it's in anticipation of increases that we've seen in fuel rates and expected increases in base rates that we've estimated that that price needs to be raised by the $3 to make sure that we continue to cover those costs from those participants and costs are not shifted to non participants.

Tim Echols (PSC): [06:03:11] Mr. Mallard. We've had trouble getting subscribers to it. So what you're telling me is your answer to this is let's raise the price $3. Is that whay you're saying?

Wilson Mallard (GPC): [06:03:25] Want subscribers more than anybody. I promise. We meet about this monthly, commissioners, but I do not want subscribers at the expense of shifting costs to non participating customers. So we've got to stay true to that, that principle. And in order to keep from shifting costs, we've got to adjust that amount. Now we're going to continue to market regular community solar. We've actually seen some pretty good growth here lately with north of 2,000 sold just in the last month or two. And then we're really counting on that income qualified community solar pilot to, that's going to use up to 5,000 out of the box to really help grow the subscriptions to the community.

Tim Echols (PSC): [06:04:04] So how many months out of the year are our customers that subscribed cash positive on this? Do you have any ideas at one? Is it one. Is it any months, do you think?

Wilson Mallard (GPC): [06:04:14] It definitely is. It depends on. So in the summer there's an inclining block and bills are more expensive and the other eight months of the year of the residential rate is a declining blocks of bills or less. I can tell you over the course of 12 months, generally, we say a customer is going to end up averaging about $5 in addition on their monthly bill. So they're going to pay what's 24.99 now, is proposed to go up. They'll get to get a credit back. And over the course of a year, they'll end up paying on average about $5 more a month. But there are some months where the credit is bigger, in some months when it's less.

Tim Echols (PSC): [06:04:49] I'm not being snarky here. Does it bother you that the EMCs are able to do this virtual net metering and have it be cash positive more for their for their customers. Companies like Walton, EMC?

Wilson Mallard (GPC): [06:05:06] I'm not intimately familiar, Commissioner. It would depend on the right design that the customers were on. All I can tell you is from a rating program design perspective from Georgia Power renewable development. We just don't want to design a program that depends on shifting costs to non participants to make it work for the participants.

Tim Echols (PSC): [06:05:25] And you are aware of my original motion that created this and shame on me for not being more specific. Right. Back when we did this. Long ago. Thank you.

Alicia Brown (CLG): [06:05:37] So to make sure I'm understanding, when we pay for a subscription price, we're not paying for the price of the solar farm. We are actually paying for the price of the energy that's being offset and it will continue to go up as energy prices go up.

Wilson Mallard (GPC): [06:05:53] So you're, what a participant is paying for is their subscription to the block of community solar energy. And what they get for that subscription price is a credit on their bill at a retail rate. So those kilowatt hours are reduced from their bill at the retail level and the RECs are retired on their behalf. The price, the subscription price is developed based on the relationship to Georgia Power base rates and to ensure that those customers don't shift costs to other customers when those kilowatt hours are reduced from their monthly billing determinants.

Alicia Brown (CLG): [06:06:29] To Commissioner Echols point, I mean, most programs are set up. If they are not immediately cash flow positive, they at least allow you over a period of time to hedge against fluctuations in natural gas prices. So I guess the question is, with this community solar, how is it functionally different than any of the other simple solar programs? You're still purchasing energy at a premium and retiring RECs, is that correct?

Wilson Mallard (GPC): [06:06:54] Yes, it's a premium to retire the REC. It's different from simple solar in a good number of ways. First of all, you're supporting community solar facilities developed here in Georgia. All of our facilities are local facilities, Athens, Augusta, Savannah area. You know exactly where your REC is coming from, where the bulk of energy is being produced. And then additionally, it's as, as we do sell out the program and I am optimistic we're going to new income qualified program is going to increase our sales significantly. We will grow that program by building more community solar facilities here in Georgia. Contrast that to the simple solar program, which is supplied by RECs that are not bundled with energy. We just purchased those RECs in the competitive market, generally try to target solar RECs from Georgia, but there's a limit. It's a limited number of available voluntary RECs here in Georgia. And so those are some major differences between community solar and simple solar.

Alicia Brown (CLG): [06:07:55] One other question is with community solar and with the understanding that your customers do typically expect that a community solar program would provide some opportunity to truly invest and to ultimately not only add more solar to the system, but maybe perhaps again, hedge against changes in natural gas prices like we're seeing right now. Are you considering any creative means of finding additional value streams from those programs, like, for example, reducing arrearages for individuals who might be energy burdened at the moment and ultimately be supported by other customers like Commissioner Pridemore been talking about?

Wilson Mallard (GPC): [06:08:31] Yeah, I haven't considered any designs like that. We analyze community solar programs from across the country as we were developing ours and developing the income qualified portion of the community solar program. It's our position that the rollout of the income qualified community solar pilot is what makes sense. It's a great way to, in a pilot format, grow our community solar, help income qualified customers, allow for these third parties to help sponsor and create a community benefit. And that's what's most appropriate way for us to grow community solar at this point.

Tricia Pridemore (PSC): [06:09:06] All right. Thank you, Ms. Brown. I have a question for you, because I'm just truly interested. So the five commissioners that you're before today were all elected statewide. So we travel across the state. We hear from different people, from different regions, different economic backgrounds, etc. You mentioned at the beginning of your comments what was important to the people that you represent in order, renewable energy, sustainability, and green space preservation. Right?

Alicia Brown (CLG): [06:09:34] Well, I was speaking on behalf of my government. I'm not speaking on behalf of every single...

Tricia Pridemore (PSC): [06:09:38] ...of the coalition, but on behalf of your government. All right. And so in that order that you listed them, I'm interested on behalf of your government. How important is a monthly bill and a tax increase to the people of Savannah?

Alicia Brown (CLG): [06:09:55] We're not proposing any tax increases, commissioner.

Tricia Pridemore (PSC): [06:09:58] I'm not saying you are. I'm asking you a question. How important is that, if renewable energy, sustainability, green space preservation are important, and they are, I'm not saying they're not. Not discounting them. I'm interested, though. How important is that monthly bill to the people of City of Savannah in tax increases?

Alicia Brown (CLG): [06:10:19] We're certainly concerned about the take home income of every citizen in Savannah and the other cities here. And that's one reason that we are here at the commission is to make sure that utility bills are put on downward pressure. And one thing that we're seeing right now, Commissioner, is volatility in fossil fuel prices. Volatility and construction schedules for traditional resources like Plant Vogtle. So we are here advocating as best we know. About how to keep those prices under control as far as tax increases? That is well beyond my pay grade as an energy analyst at the city of Savannah.

Tricia Pridemore (PSC): [06:10:52] Okay. All right. Just interested. All right. Thank you, Ms. Brown. Thank you, ma'am. Georgia Interfaith Power and Light and the Partnership for Southern Equity. Hello Ms. Kysor.

Jeffrey Grubb (GPC): [06:11:01] Is there any way we could have a quick break? I don't know what time it is, but...

Tricia Pridemore (PSC): [06:11:05] I was planning to break at 3:55.

Jeffrey Grubb (GPC): [06:11:08] I have not...

Tricia Pridemore (PSC): [06:11:09] I'm sorry. You all need a clock.

Jeffrey Grubb (GPC): [06:11:12] I intentionally don't have one.

Tricia Pridemore (PSC): [06:11:13] It is 3:42. Do we need to do it now or can we go at 3:55? 3:55 it is. Ms. Kysor, we're going to break at 3:55. [That sounds great. I don't have to finish by 3:55?] No, I was just getting ready to tell you we were going to break at 3:55. But our witnesses have been in that little box together for a while.

Jill Kysor (GIPL-PSE): [06:11:40] Great. Hello, gentlemen. Jill Kysor. And I'm here representing Georgia Interfaith Power and Light and Partnership for Southern Equity. Nice to see you. You all had a long day. I'll direct my questions generally to the panel and anyone can answer. But Mr. Mallard, just a heads up. I think my first couple of lines of questioning will focus on you, and I'm going to start by distributing, if you don't mind, if I approach. [You may approach.] Madam Chairwoman, I have what I have marked for identification as well as GIPL-PSE Exhibit one. And what it is, is Georgia Power's response to staff data requests, DEA-3-37, and there are trade secret components to it. But I haven't included any of those here, so I think everything I've got is public.

Jill Kysor (GIPL-PSE): [06:12:56] Mr. Mallard, are you generally familiar with this data request and response? [I am.] And I've only included the first two summary tables. I don't intend on digging into any of the detailed tables that I have not included. [Okay.] So Georgia Power conducted a preliminary high level analysis of the monthly netting program. Correct? [That's right.] And Georgia Power has not yet performed an analysis on lost revenue due to the energy customers are consuming on site, right? [That's right.] You'd agree with me that customers have the right to buy less electricity from Georgia power, right?

Wilson Mallard (GPC): [06:13:35] Absolutely.

Jill Kysor (GIPL-PSE): [06:13:37] I have a couple of quick clarification questions about the tables just to make sure I understand them. And to recap, does DEA-3-37 still represent all of the studies and analysis that Georgia Power conducted to date on the cost shift topic with RNR monthly netting?

Wilson Mallard (GPC): [06:13:58] I believe it does. This study was conducted based on the customers that were on RNR monthly netting at the time. There are more customers that have been added now, but I'm not aware that the study has been updated.

Jill Kysor (GIPL-PSE): [06:14:10] And Georgia Power has not conducted any cost of service study analyzing customers with rooftop solar?

Wilson Mallard (GPC): [06:14:17] That's right. This analysis is based just on the energy that's pushed back to the grid, just on the energy that's produced in excess of what the customer is using and push back to the grid for compensation.

Jill Kysor (GIPL-PSE): [06:14:31] And has the company conducted any other studies or analysis on its monthly netting program?

Wilson Mallard (GPC): [06:14:37] The company hasn't done any other studies on its own monthly netting program. I can tell you that we've evaluated net metering programs and subsequent programs after net metering has been rolled back and multiple other states that have been evaluating the same topic over the last few months and years.

Jill Kysor (GIPL-PSE): [06:14:59] And if any of the studying you've done has been distilled into an analysis, could I make that a hearing request?

Wilson Mallard (GPC): [06:15:07] Yes, I don't think there's any analysis. It's mainly talking points related to some of the cost shifts that we've seen in places like California of $3 billion dollars I think the utilities have estimated they're. In Florida, something like $700 million in cost shifting. We've got some other figures from states like Louisiana that have rolled back net metering as well.

Jill Kysor (GIPL-PSE): [06:15:29] Chairwoman, could I make that a hearing request if it exists?

Wilson Mallard (GPC): [06:15:32] Sure.

Tricia Pridemore (PSC): [06:15:33] Certainly. You know the state of Florida, just through their legislature, rolled back net monthly netting.

Wilson Mallard (GPC): [06:15:40] Yes, ma'am.

Jill Kysor (GIPL-PSE): [06:15:43] So sadly, we can't see, but it's column B titled "accounts." So do you see where that's labeled accounts at the top? [Yes.] I just want to confirm, is this limited to accounts on our accounts that are on the monthly netting tariff only? It does not include any instantaneous netting.

Wilson Mallard (GPC): [06:16:02] Correct.

Jill Kysor (GIPL-PSE): [06:16:04] And then under generated. KWh Is that roughly equivalent to exported kWh?

Wilson Mallard (GPC): [06:16:12] That would be exported. Kw We don't have line of sight into how much energy is generated on site and then consume how many less kilowatt hours the customer purchased. The only thing we have is what goes back through the meter and is pushed back to the grid.

Tricia Pridemore (PSC): [06:16:27] And you'd agree that monthly netting customers are compensated at the avoided cost rate if they have net excess at the end of a monthly billing period. Correct? [Correct.] And I just want to confirm that the generated kWh number only includes those exported kilowatt hours that occurred during the course of the billing period and that it does not include any exported energy that may have been tagged at the cost rate.

Wilson Mallard (GPC): [06:17:00] My assumption is that that is correct, but I can't say that for sure. Subject to check and I can also can also confirm that for you.

Jill Kysor (GIPL-PSE): [06:17:08] Thank you. And then column L on attachment A, I think sorry, you actually can't see that because I didn't include it, at the very bottom near the far right of the page, there's a number 764,194. [Yes.] I think that number is an error. I think it adds up, I think it's the sum of all the numbers above it. And I believe that the $382,097 is the sum of the ones below it. So I just want to confirm whether that's $764,000 number is an error.

Wilson Mallard (GPC): [06:17:48] My, I do not know. It should be the sum of all of the numbers. In the column. I can't say for sure, Miss Kysor, but I can double check that as well.

Jill Kysor (GIPL-PSE): [06:18:02] Thank you. And then you mentioned the one and a half million when you were talking to the previous intervenor. [Yes.] I'm looking at attachment B, the last page there. It looks like the total there is just shy of $1,000,000. I was curious, is the one and a half million dollars number you referenced, is that a more updated analysis?

Wilson Mallard (GPC): [06:18:26] It's really just based on an extrapolation to try to estimate the total impact for all 5,000 customers. And so you'll see here this analysis is run. We've only got 3,600 customers that were online as of this point. And so we just did some simple math to extrapolate, and that was the estimate for what that would look like when all 5,000 customers get on. Now, obviously, it'll be different depending on the types of customers that sign up. What we've seen is an increase in the average size of of solar panel, both on residential, but then also C&I customers that are installing larger solar installation. So it could actually be higher than that 1.5. Again, we'll know once we get all 5,000 online and we can get a year's worth of analysis on them.

Jill Kysor (GIPL-PSE): [06:19:11] And I'm going to dig into an example here and I'm looking at attachment A specifically. So this table is designed to represent revenue erosion from monthly netting customers, correct?

Wilson Mallard (GPC): [06:19:24] It's really designed to represent the payment difference for the energy pushed back to the grid that would have been compensated at or be avoided cost at 2.7 cents. And instead, those kilowatt hours were rolled back from the customer's bill. And we're actually credited at the retail rate. So that's meant to really isolate that difference. Rough math on the residential rate is $0.12 to $0.03. And so Georgia Power residential rates averaging about $0.12 a kilowatt hour, 2.7. We'll round that up to three. And so it's meant to isolate that difference between RCB avoided cost and what was credited under monthly netting.

Jill Kysor (GIPL-PSE): [06:20:06] And the title says revenue erosion, which is why I use that term. So that's the goal of the table to show that. So non-participating customers won't actually pay more for their electricity than they otherwise would unless there's a rate adjustment by this commission that addresses any alleged revenue erosion. Right?

Wilson Mallard (GPC): [06:20:28] So non participating customers. Yeah, it is, what it creates is a revenue shortfall on base rates. And so through the next rate case rates will be adjusted, redesigned and whether rates go up or down, costs will absolutely be shifted. Costs that were recovered from these customers before they had solar and monthly netting. Now we're no longer recovering those costs from those customers. Those costs still remain to be recovered, and so they would be recovered from all other customers.

Jill Kysor (GIPL-PSE): [06:21:01] The revenue shortfall is just where I was going next. So according to this table, Georgia Power experienced a $382,000 revenue shortfall or erosion in 2020 associated with the monthly netting program, right?

Wilson Mallard (GPC): [06:21:17] Yes.

Tricia Pridemore (PSC): [06:21:19] And subject to check, Georgia Power had a total operating revenues in 2020 of about $7.5 billion.

Wilson Mallard (GPC): [06:21:28] Subject to check. I'm not familiar with that number.

Jeffrey Grubb (GPC): [06:21:33] So it's a lot lower.

Jill Kysor (GIPL-PSE): [06:21:38] And subject to check, And I have some of the ASR documents but subject to check. Georgia Power had a total net return in 2020 of about $1,716,785,000. Does that sound in the ballpark?

Wilson Mallard (GPC): [06:21:55] Subject to check.

Jill Kysor (GIPL-PSE): [06:21:57] So making Georgia Power's return on equity about 11.9% in that year, 2021.

Wilson Mallard (GPC): [06:22:03] Subject to check.

Jill Kysor (GIPL-PSE): [06:22:04] And so are you saying in the absence of the RNR monthly netting program, Georgia Power's net return resulting from the reduced revenue would have been about roughly three hundredths of a percent higher.

Wilson Mallard (GPC): [06:22:16] I'm not even sure that the return would would be different. I think it comes into play in the rate design, in a rate case commissioners, where the total amount of expected revenue from a particular class or rate grouping of customers is analyzed. And what monthly netting does is it reduces the amount of revenue recovered from those customers in the historical year that's been translated into the test year, that then gets translated into rate design into a rate case. And so I'm not even sure if that, how that would impact, I think the company's rate of return is set based on based on commission decision in the rate case. But what I am saying is I think that rates would be differently, the residential rate would be designed differently based on that amount of revenue that was under-recovered from those from those customers with monthly debt.

Jill Kysor (GIPL-PSE): [06:23:09] So given the revenue erosion that you've represented here just under $400,000 for 2020, do you expect that the company would anticipate an actual cost shift that would cause you to adjust rates as a result?

Wilson Mallard (GPC): [06:23:27] Eventually, yes, absolutely. And that's the whole basis behind designing programs that don't shift costs. You really want to make sure your program is designed to protect non-participating customers from the very first customer that signs up from the very first kilowatt hour that's generated. It's a mistake, in my opinion, to design a program that, you know, is going to shift costs with the expectation that one day, once it gets big enough, we will identify that, we'll isolate it and we'll try to come up with an alternative program design. I just really think that's a bad way to go. Commissioners, I look at these other states that are trying their best to unwind net metering and customers who have made their financial decision based on it, solar installers, business people who have built their entire business model around counting on net metering. And then once we see places like California or Florida with really big penetrations of customers, decide that, oh, gosh, this this is now such a large amount, we've got to undo this. That just doesn't make any sense at all to me. You're creating a problem that's going to hurt customers. It's going to hurt the solar industry. It's not sustainable. And so even though the amounts are small now, it's it's my testimony that it's absolutely inappropriate to design a program or to grow a program that creates cost shift even as small as the first kilowatt hour.

Tim Echols (PSC): [06:24:52] Let me just, let me, oh we've got a break. I'll ask you after we get back.

Tricia Pridemore (PSC): [06:24:57] You sure? Yeah, sure. Okay. Okay. All right. Let's take a break. The snack bar in the adjacent building again. Nutrition, hydration. I'm here for you. It is open until 5:00. It requires a staff member to get you in, though, and she takes cards and cash. Let's get back in here at 4:20.

Tricia Pridemore (PSC): [06:47:06] Get started in about 3 minutes. About how warm it is in here. We understand we have consulted the higher powers of the HVAC system to give us provision and assistance to cool it off a little bit. And so they are working hard to try to make it a little cooler in here. It's always a little hotter up here. Makes you feel better. So it's a little warmer up here. A couple of feet up off the ground. Say nothing about politicians and hot air, witness box. Your grin said it all, Mr. Grubb. Heard you loud and clear.

Jeffrey Grubb (GPC): [06:47:57] That was not my intent..

Tricia Pridemore (PSC): [06:47:59] It's too late to backpedal now.

Jeffrey Grubb (GPC): [06:48:02] Yes, ma'am.

Tricia Pridemore (PSC): [06:49:53] I love the wishful thinking going on to my right. Okay, let's get ready to get started. Pick us back up. Before we do another housekeeping matter. If you plan to leave after 5 p.m., you have to have somebody from staff buzz you out. We don't have any control over the door system. And so just look for someone in the executive secretary's office there. They're standing by to assist. Ms. Kysor. Floor's yours.

Jill Kysor (GIPL-PSE): [06:50:42] Thank you. Mr. Mallard. I think this is still going to be directed at you, but switching topics to community solar. Okay. So roughly starting at the top of page 48 of your testimony, I think you start covering community solar and the pricing on the program. So that covers program costs like administrative and labor costs. And I believe I heard you say it also covers costs like lost revenue. I don't think you use that term, but is that...

Wilson Mallard (GPC): [06:51:14] Yeah, I'm sorry. Give me the page reference again, please.

Jill Kysor (GIPL-PSE): [06:51:17] Sorry. Page 48, generally lines three through 11, line six where you talk about the cost of the program.

Wilson Mallard (GPC): [06:51:26] Yeah, I'm there now. Okay.

Jill Kysor (GIPL-PSE): [06:51:28] And does the cost of the program cover labor costs, administrative costs, and also lost revenue?

Wilson Mallard (GPC): [06:51:36] That's right.

Jill Kysor (GIPL-PSE): [06:51:37] And do you know approximately how much of how much of the monthly cost is intended to recover lost revenue versus the programmatic expenses?

Wilson Mallard (GPC): [06:51:46] I don't have that in front of me. I believe a data request has been submitted that provides at least some of that information. I know a request has been provided that shows the administrative cost assigned to the program.

Jill Kysor (GIPL-PSE): [06:52:05] And then I have a copy of it, but I'm hoping not to have to go through the, passing it out because I'm not going to ask about the details. But in response to one of the data requests, you talked about the revenue from the Community Solar program. Do you recall that [Yes.] generally? And then just big picture, what does that revenue number consist of? It's the monthly program, subscription fees and what else would go into it?

Wilson Mallard (GPC): [06:52:32] So the revenues attributed to the the simple solar program or the community solar program?

Jill Kysor (GIPL-PSE): [06:52:32] The community solar.

Wilson Mallard (GPC): [06:52:39] Community solar program. So it is specifically the revenues collected from subscriptions from participants in the program.

Jill Kysor (GIPL-PSE): [06:52:47] And that's it.

Wilson Mallard (GPC): [06:52:48] That's it.

Jill Kysor (GIPL-PSE): [06:52:51] And on the, you had another data response, which I have, but I'll ask you just generally about it and happy to share it with you if you need it. You had another data response that covered the program costs of the community solar program and the expected cost of the income qualified community solar program. Do you recall that?

Wilson Mallard (GPC): [06:53:10] Yes, generally and generally.

Jill Kysor (GIPL-PSE): [06:53:13] Do you recall that the income qualified community solar program, the pilot is quite a bit pricier than the standard community solar program?

Wilson Mallard (GPC): [06:53:25] I don't know that I could I could agree with quite a bit pricier. The the cost for the income qualified community solar program could certainly be higher than the cost per block basis than the regular community solar program.

Tricia Pridemore (PSC): [06:53:38] So I'll put it in front of you. Okay. So, Madam Chairman, [You may approach. Call me Chairman, please.] Thank you. It's a long word, Chairwoman.

Tricia Pridemore (PSC): [06:53:57] What was that from? Don't lie. Jesus is watching you.

Jill Kysor (GIPL-PSE): [06:54:10] Okay. My colleague is handing out what has been marked by identification as GIPL-PSE Exhibit 2 and its Georgia Power's Response to STF-LA-2-30. Do you recognize this document?

Wilson Mallard (GPC): [06:54:27] I do.

Jill Kysor (GIPL-PSE): [06:54:29] Great. On the back side of that handout, it lists projected costs for various programs. And I'm just focused in on the community solar and the income qualified community solar programs. [Yes.] And so I'm looking at mainly 2023 through 2025 because the Income Community Solar Program hasn't been approved yet. So you're anticipating most of the cost hitting after 2023. [right.] So I'm just curious maybe what would drive such a high program cost for that compared with the regular community solar program?

Wilson Mallard (GPC): [06:55:05] So this is, this is subject to check. I don't have the data behind this in front of me, but I believe these numbers include not just the marketing and program administration, but also the cost of the buy down of the blocks that would be recovered from the corporate sponsor.

Jill Kysor (GIPL-PSE): [06:55:26] I'm sorry. Could you say that another way for me? The buy down of the blocks? What do you mean by that?

Wilson Mallard (GPC): [06:55:31] Right. So the income qualified community solar program, the way it's going to work, Commissioners, is the Georgia Power is going to partner with a corporate sponsor who will be responsible for the buy down, the paying down of the price of the block for the participant from the from the retail price down to $7, roughly a discounted price at about 75%. So I think, Ms. Kyzor, this amount right here includes not just the marketing of the program, but also the cost of the buy down that would be recovered from the corporate sponsors.

Jill Kysor (GIPL-PSE): [06:56:04] So is it maybe, and maybe the marketing, do you expect that those costs are higher for the program?

Wilson Mallard (GPC): [06:56:12] I would yes. I think the acquisition cost will be higher. We already started developing a preliminary customer acquisition plan whereby we target customers who would be a good fit. Obviously, they need to qualify for the income qualified portion and that would be under 200% of the federal poverty level. And then additionally, we're going to try to target that in some specific locations. But to procure, to acquire those customers will be a little bit more costly on a per block basis than what we've seen with the traditional community solar program.

Jill Kysor (GIPL-PSE): [06:56:46] And then you expect, y'all submitted a response to a data request that looks like customers would save on average maybe about $15 a month. Does that sound right? [That does.] And that is inclusive of, or nets out the $6 or $6.99 monthly fee?

Wilson Mallard (GPC): [06:57:05] That's exactly right. So that's meant to represent the amount that the customer does pay the non discounted amount of $7 a month. And then is an estimate based on the value of the energy produced by each block and the value of those kilowatt hours on the customer's retail bill.

Jill Kysor (GIPL-PSE): [06:57:22] And is Georgia Power open to having some sort of bill savings assurance built into the program or at least a bill neutrality provision?

Wilson Mallard (GPC): [06:57:33] So as it's designed right now, we don't have a provision like that. But what we do have is the ability to target customers that we believe will save money. We've already pulled a sample of just north of 50,000 income qualified customers to study. What that analysis showed commissioners is, as long as customers have a minimum usage and I don't know that a number of kilowatt hours, but something a little bigger than just a really small customer, they are going to see the savings. They're going to see that solar-produced savings on their bill. It would only be customers with very small monthly usage that might not save as much. And so it's our intent to target customers that do have the larger bills. The community solar income qualified is going to benefit them more and it will ensure that those customers save and don't end up with any months where they're actually a net positive on their bill.

Jill Kysor (GIPL-PSE): [06:58:27] Do you agree that the the extra fee or the extra line item on the bill could be a deterrent if folks don't have any assurance that they could achieve a savings each month?

Wilson Mallard (GPC): [06:58:40] So it could be. Part of the income qualified community solar program, the intent is to educate these customers. It's not just a bill discount, it's the ability to participate in solar and to understand how solar works, how solar production varies month by month, how the customer does pay some towards it and then get that credit back. And so we'd absolutely explain and educate that additionally, on bills of customers that participate in community solar, we identify the amount of kilowatt hours that the community solar produced and save the customer money. So in that way, I would hope that we could educate customers and show that for the $7 a month monthly subscription fee, they're getting much more benefits on their bill.

Tricia Pridemore (PSC): [06:59:23] The $7 a month monthly subscription fee, the sponsor is paying $15 a month per customer.

Wilson Mallard (GPC): [06:59:31] They're paying the difference between 28 and seven. It's $21 a month. They're paying, the sponsor will pay 21. The 15, Madam Chair, is meant to represent the monthly savings on the customer's bill. So they'll actually pay $7. They'll get $22 worth of credit on average. Again, these are these are averaged across customer data set. They would average netting about a $15 savings a month.

Tricia Pridemore (PSC): [07:00:02] Okay. So let's walk this back just because it's late in the day and I need you to repeat yourself. [Okay.] So qualifying customers will pay the $7 a month. [They will.] And the sponsor is paying $21 a month because the cost of the program is $28 a month. [You got it.] All right. The customer is expected to save $15 a month.

Wilson Mallard (GPC): [07:00:27] That's on average. They're going to get the output of one kilowatt of solar. And so it varies, through seasons of the year, through month by month. But on average, we expect that block to produce approximately a $15 net savings for each participant over the course of the year.

Tricia Pridemore (PSC): [07:00:45] Can I further this into just some obvious basic math? It's a program that costs $28 a month. The customer's saving 15. Where are the other net benefits?

Wilson Mallard (GPC): [07:00:58] So the benefits come from the participating corporate sponsor who has amongst their corporate goals to try to help benefit the communities in which their businesses are located. That aligns with Georgia Power's goals as well. We really look forward to offering a program that can help income qualified customers participate, enjoy the benefits of solar, and see a lower bill. But the program is designed such that non-participating customers won't see any bill impacts. They will all be covered by that corporate sponsor.

Bubba McDonald (PSC): [07:01:32] Does the corporate sponsor get a REC?

Wilson Mallard (GPC): [07:01:34] They do. They get the RECs. That's the trade off. So the customers that are participating will not get the renewable energy credit. Commissioner McDonald, the corporate sponsor, will have the RECs retired on their behalf.

Jill Kysor (GIPL-PSE): [07:01:48] My two follow up questions on what the chairwoman was saying. So you noted that the savings is built off the average expected production of the block. And in one of the data responses, you listed that as 165 kilowatts per block per month. I'm just curious, do you know whether that number is based off of the actual actual data on your community solar program production or if it's based on...

Wilson Mallard (GPC): [07:02:20] The general load shape? I don't. But we can find that out. Subject to check.

Jill Kysor (GIPL-PSE): [07:02:26] Thank you. And then I'm looking at your testimony, page 48, lines 26 through 28.

Wilson Mallard (GPC): [07:02:37] I'm sorry. Say it one more time.

Jill Kysor (GIPL-PSE): [07:02:38] Page 48. Actually, lines 27 and 28.

Wilson Mallard (GPC): [07:02:43] OK, I'm there.

Jill Kysor (GIPL-PSE): [07:02:43] And I just want to make sure I understand who's paying for what. So there, there's a sentence that starts, "All other program costs will be recovered from the participating sponsor." And I just want to confirm, does the participating sponsor pay 75% of the monthly fee or more?

Wilson Mallard (GPC): [07:03:06] They pay the fee buy down. Then they're also responsible for the program costs related to the Income Qualified Community Solar Program. So if there's community solar cost to run the program overall and we've talked about those, we design those and bake that amount into the overall price. Additional costs, as we've talked about, the customer acquisition could be a little more complicated, could be a little more costly to qualify these customers to make sure we're targeting the right customers. Any additional costs that are attributed specifically to income qualified community solar will also recover those costs from the participating sponsor.

Jill Kysor (GIPL-PSE): [07:03:46] Do you have any idea, ballpark, how much those additional costs might be?

Wilson Mallard (GPC): [07:03:54] I think we do. I do not have that off the top of my head. I think that exists in the model where we develop the price.

Jill Kysor (GIPL-PSE): [07:04:00] Could I make a hearing request for the information about what a corporate sponsor might pay in, Chairwoman? Can I make that hearing request?

Tricia Pridemore (PSC): [07:04:09] Certainly. Lines 24 and 25. That page. You say the company will seek corporate sponsorships. Does the company have a corporate sponsor that signed up contingent upon this agreement?

Wilson Mallard (GPC): [07:04:22] They're not signed up, but they've indicated strong interest. Assuming the program is approved similarly to what we've designed.

Tricia Pridemore (PSC): [07:04:30] Line 25 makes that plural, sponsorshipS. You have one or many?

Wilson Mallard (GPC): [07:04:35] So interestingly enough, we had one that was the most interested since that time. As we've shared some of the program designs in the IRP, we have received interest from other similar customers. And so I would say their interest is not as as confirmed. But we do have other customers who are interested.

Jill Kysor (GIPL-PSE): [07:04:57] Now I want to go back to one question. I don't think I got a yes or no answer from you on where I asked if Georgia Power would be open to having some kind of bill savings assurance built into the program for income qualified customers. I think you said you haven't done that yet. I'm curious yes or no, whether you're open to having that.

Wilson Mallard (GPC): [07:05:15] So in this current design as put forth in this pilot, I would say we're not, the pilot design is as it is, but certainly we would consider alternative designs as we go forward. That's one of the great things about a pilot is we're going to throw it out there, we're going to see what the results are. And then we can certainly make considered, consider different enhancements and improvements.

Jill Kysor (GIPL-PSE): [07:05:36] And on page 48, lines 17, you note that 5,000 of the existing 8,000 blocks would be available for the income qualified pilot. [Correct.] I'm curious, I know you're changing the community solar program generally to open it up to commercial customers as well. If the 8,000 block program gets eaten up quite quickly and I know you have also asked to expand your community solar, I'm curious if you intend to still keep 5,000 blocks available?

Wilson Mallard (GPC): [07:06:10] No, no, I would say it would be our intent to sell as many blocks as we can. The 5,000 block target here for income qualified. Should we sell more of standard community solar blocks? I think we would work with commission and staff to modify that. I wouldn't want to turn anybody away to sell these blocks that we have to reserve them for, for a particular program.

Jill Kysor (GIPL-PSE): [07:06:36] I'm shifting now to the top of page 52, running through the middle of page 53, where your testimony talks about the DER Local

Reliability Constraints pilot program. [Okay.] You're off the hot seat right now. Mr. Mallard. So I just a simple question. So your testimony addresses the local reliability and constraints pilot and then the DSM panel talks about the customer program. I want to confirm those are separate.

Michael Robinson (GPC): [07:07:13] That's correct.

Jill Kysor (GIPL-PSE): [07:07:14] Correct. And are they unrelated?

Michael Robinson (GPC): [07:07:18] They are unrelated.

Jill Kysor (GIPL-PSE): [07:07:25] Okay. And then I want to understand a little bit more about the pilot program. Will these errors provide backup power to the customers when the grid power is unavailable to wherever the sites are?

Michael Robinson (GPC): [07:07:38] Yes, correct. For the seven sites that we have specified and mentioned, the three buckets of use cases, capacity, resilience and reliability, the reliability and resilience would be targeting the use case of which you speak.

Jill Kysor (GIPL-PSE): [07:07:56] And then would Georgia Power be able to call on those DERs to operate at other times for reliability purposes or any other reason?

Michael Robinson (GPC): [07:08:06] Initially, it would be for those three use cases. If we saw a value in dispatching those for capacity needs in the future. Of course, we would work with commissioners and staff on how we would make that happen. But the important thing is those resources need to be available when those contingencies occur. And so we would need to make sure that those battery systems and those generators that they're paired with are available and online when that reliability need or that resilience need or that capacity need happens.

Jill Kysor (GIPL-PSE): [07:08:38] And so when the DER is operating, would it take some of that customer's load offline or reduce that customer's demand during those times?

Michael Robinson (GPC): [07:08:47] It would not anticipate reducing demand, but it would take those customers off of those distribution feeders. So say you had a car hit a pole on one of these feeders and you had 1,000 customers that were behind, or in the scheme of one of these LRC pilots, that pilot would come online and feed those thousand customers until the system were restored and those customers could come back online.

Jill Kysor (GIPL-PSE): [07:09:14] Will the participating customers or sites pay anything to have the sited there?

Michael Robinson (GPC): [07:09:21] No, they will not.

Jill Kysor (GIPL-PSE): [07:09:22] And what Georgia Power pay, I guess, through the pilot for the capital costs of these units?

Michael Robinson (GPC): [07:09:29] Yes, that's correct.

Michael Robinson (GPC): [07:09:33] Has Georgia Power already selected the sites in these six cities?

Michael Robinson (GPC): [07:09:38] No, we have not. There are six locations or seven locations that have been proposed geographically dispersed throughout the state, looking at attainment areas, non attainment areas, different types of customer base, rural metro. So we looked at see the benefit of, of locating these on the system and where we could do more. And so we have not specifically identified on those feeders where we would put these. Five of those feeders have solar on them currently today. We look to site these as close to the solar as possible to see if we can pair these systems with the solar as well.

Jill Kysor (GIPL-PSE): [07:10:18] And shifting now to some questions about the reserve margin. Mr. Weathers I think it was you that mentioned that your reserve margin study looked at a 58 year period from 1962 to 2019. Is that correct? [That's right.] And so subject to check in at least the last four IRPs, 2013 through this one, the reserve margin study was based on data that started in 1962 and then went to the most current year available.

Jeffrey Weathers (GPC): [07:10:51] That's correct. We've just appended to the data as the actuals have occurred.

Jill Kysor (GIPL-PSE): [07:10:55] So there's a different number of years, weather years studied each cycle when you update the study.

Jeffrey Weathers (GPC): [07:11:01] There is. I mean, again, as additional years occur, that data is added, I mean, the purpose of the weather years is to model weather volatility, the impacts of that on the reserve margin. And so as more years pass, that's just additional data points. So the more data points, the more robust the analysis is in terms of weather volatility.

Jill Kysor (GIPL-PSE): [07:11:25] Have you identified any trends in weather over the years, how weather might change in more recent decades?

Jeffrey Weathers (GPC): [07:11:32] No, not specifically. I mean, there's, there are cold temperatures and there hot temperatures no matter which decade that you look at. But we're really not trying to identify trends in the data. We're trying to capture volatility around the data. So we're not projecting low to the reserve margin study. We take the company's actual forecast and load forecast. We're modeling the volatility around that because the planning reserves are there to compensate for volatility, whether that be in the load itself or on the resource side.

Jill Kysor (GIPL-PSE): [07:12:07] The weather years analyze in the reserve margin study. Those are just looking at the temperatures for each year, right?

Jeffrey Weathers (GPC): [07:12:14] It is the temperature for the years for every hour of the year.

Jill Kysor (GIPL-PSE): [07:12:19] And in the, and I know it's the next panel that talks about the load and energy forecast, but they look at a different set of weather impacts over time, right?

Jeffrey Weathers (GPC): [07:12:30] They do. I mean, they are they're looking at a different set of weather years. And they're looking at it, you can ask them about that, but probably different variables. Again, they're trying to project the company's load forecast going forward. So there's a lot of inputs to that in terms of customer, customer demand growth, technology, things like that. That's not what the Reserve Margin study is trying to do. We're only interested in weather volatility because that's what the planning reserves are in part there to cover.

Jill Kysor (GIPL-PSE): [07:13:01] Gotcha. So the reserve margin weather years are just looking at weather volatility during a certain set of years.

Jeffrey Weathers (GPC): [07:13:07] Yeah, it's the temperature volatility because that's the part of the weather that's most impactful to the analysis that we do.

Jill Kysor (GIPL-PSE): [07:13:15] But you haven't looked at how the temperature volatility may change over time?

Jeffrey Weathers (GPC): [07:13:20] Not specifically. I mean, any changes over time will be captured in the analysis. For example, if there are more frequent occurrences in recent year of a particular temperature, the way that we, we consider all the weather year to be equally probable. So more frequent occurrences of a temperature means in the analysis it occurs more frequently and so is a little bit heavier weighting towards that temperature.

Jill Kysor (GIPL-PSE): [07:13:47] Shifting gears, a couple of questions about the natural gas PPAs, looking at page 24, line 21, roughly. I just want to confirm the natural gas PPAs that you're proposing for certification. They don't have fixed fuel prices included in them, right?

Jeffrey Grubb (GPC): [07:14:09] They don't have fixed fuel prices from the commodity standpoint. We do have firm transportation for delivering that gas that are fixed, but they would be based on daily gas prices just like our company owned units.

Jill Kysor (GIPL-PSE): [07:14:23] So customers would pay for any variability and the gas price over the term.

Jeffrey Grubb (GPC): [07:14:28] They would. [They would go ahead now.] So the capacity prices are set and the F...the firm transportation prices are set. But yes, they would of course, that's taken into account in our dispatch. So if gas prices go up or down, that's factored into how we dispatch the fleet.

Jeffrey Weathers (GPC): [07:14:44] Yeah. And in the analysis, as well, it took into account a range of fuel prices.

Jill Kysor (GIPL-PSE): [07:14:49] And did the 2022 to 2028 capacity RFP that resulted in those PPAs, did it prioritize proximity to North Georgia load and any ability to address the problems raised in the North Georgia Reliability and Resilience Action Plan?

Jeffrey Grubb (GPC): [07:15:08] It did not target those. These were all existing facilities. And so we were able to capture the impacts of that in the transmission studies. Some of are in the north part of the state. And so we would take that into account. When we did our retirement studies and the transmission studies, we captured those. But again, it wasn't specifically targeted, but we do captured in all our analysis.

Jill Kysor (GIPL-PSE): [07:15:34] And just a question about the renewable integration study and the RCB and the relationship between the two. So it seems like the renewable integration study is going to feed in to the renewable cost benefit study, correct?

Jeffrey Weathers (GPC): [07:15:53] That's correct.

Jill Kysor (GIPL-PSE): [07:15:54] Is there any, will they continue operating as separate studies in parallel or updated into one analysis?

Jeffrey Weathers (GPC): [07:16:02] Well, I think it needs to be separate because the, the renewable integration study, that's an actual study. So that's the product of running a model, looking at penetrations of solar and what's the cost to integrate that. The Renewable Cost Benefit Framework, just a compilation of benefits and cost. So it pulls the renewable integration cost from that study. It pulls the energy cost from the company's planning models, the capacity benefit, transmission losses. They're pulled in from different places and compiled in one framework, the RCB framework, to be applied.

Jill Kysor (GIPL-PSE): [07:16:43] Thank you. And just one last clarifying question. Page 15, lines 17 to 19.

Jeffrey Grubb (GPC): [07:16:54] Yes. You said 15, 17 to 19.

Jill Kysor (GIPL-PSE): [07:16:56] Lines 17 to 19, where you mentioned that the company added a CO2 intensity scenario that drives CO2 emissions down to 10% of current levels by 2050. I'm curious if that's, is that scenario intended to address possible carbon pricing, Southern Company's low-to-no carbon goal, or both?

Jeffrey Weathers (GPC): [07:17:23] It's neither one. It's technically a different method of applying carbon pressure. As we've looked across the current landscape of proposals. There are different ways and a lot of them are aimed towards getting to net zero, which is consistent with the Southern goal. But really that's to model a declining ton limit on fleet emissions, not applied by price pressure, but just applied as limits on the annual basis. They both get to a net zero level of of carbon emissions. But it was just a plot to examine through analysis, what if there's a different approach other than price to get there? What impact does that have on the build-out of the fleet?

Jill Kysor (GIPL-PSE): [07:18:09] Thank you, panelists. That's all the questions I have. Chairwoman, could we please, I'd ask that GIPL-PSE exhibits one and two be moved into evidence.

Tricia Pridemore (PSC): [07:18:18] Most certainly. Ms. Kysor, thank you. Georgia Large Scale Solar Association and Advanced Power Alliance.

Brad Carver (GLSSA-APA): [07:18:33] Madam Chair, your fellow commissioners, Grant Carver, on behalf of the Georgia Large Solar Association, Advanced Power Alliance. Good afternoon, panel. Good to see you all again. We start off by asking you all and again, these will be directed to the panel and whoever is most appropriate can answer. To date, how much solar generation does the company have under contract?

Wilson Mallard (GPC): [07:19:04] Online right now is about 2,400 megawatts under contract. On top of that would be another 1,100 megawatts or so.

Brad Carver (GLSSA-APA): [07:19:16] And then up to this point with the RFP, that's, the RFPs that are out now, prior to this IRP, how much would you have online?

Wilson Mallard (GPC): [07:19:27] So we're committed to renewables total of about 5,400 megawatts before the ask in this IRP. Now, some of that is biomass and wind, but the lion's share is solar.

Brad Carver (GLSSA-APA): [07:19:39] So in, through your history 2013, 2016, 2019, Georgia Power has used a variety of programs to grow that solar portfolio. Is that correct? [Yes.] Is it the company's view that the use of competition to procure solar has resulted in better value for the customers?

Wilson Mallard (GPC): [07:20:00] Yeah, one of our renewable principles talked about earlier is using competitive solicitations to procure the best value for customers. So absolutely, we feel really good about the results that have come from our utility scale and our distributed generation solicitations.

Tricia Pridemore (PSC): [07:20:16] Mr. Mallard, did I just hear you say biomass? Is there biomass in this proposal? Because I haven't seen any.

Wilson Mallard (GPC): [07:20:22] No. Mr. Carver asked for the total amount of solar on the system. The number I have in mind includes biomass and wind, which has 5,400. [Good.] Back that out and solar is going to end up being 4,600 or 4,700 without the wind and biomass

Jeffrey Grubb (GPC): [07:20:41] And Commissioner. That's biomass from 2010 and beyond.

Tricia Pridemore (PSC): [07:20:46] Biomass. [Correct.] Thank you.

Brad Carver (GLSSA-APA): [07:20:49] Does the CARES program build on the experience the company has gained through these competitive solicitations?

Wilson Mallard (GPC): [07:20:57] Yes, it does. And just to be clear, the CARES program really refers specifically to the subscription program element of these procurements were really identified the procurements themselves by the years in which the resources are expected to come online. So the utility scale RFP, for example, for right now it's on the street, is for 2022-2023. We call them by that name. The CARES actually refers to the subscription element of those procurements.

Brad Carver (GLSSA-APA): [07:21:25] Gotcha. Is it your opinion that the utility scale solar market is willing and has been able to deliver cost effective solar to Georgia Power's customer at a price that is below avoided cost?

Wilson Mallard (GPC): [07:21:37] Yes, the, it's impressive, the prices that the Georgia market has produced. In my opinion, the Georgia competitive solar market is one of the premier markets for renewable energy in the whole country.

Brad Carver (GLSSA-APA): [07:21:53] The Astrape solar penetration study seems to suggest that the existing solar included in the Georgia Power generation mix is providing value to the ratepayer and has been a beneficial addition to the utility's overall generation fleet. Would that be correct?

Jeffrey Weathers (GPC): [07:22:12] Well, the Astrape, you say renewable integration study? It doesn't directly address the benefits of the solar that has been added. It just includes the solar that has been added and then examines the impacts of it on operations and then the impacts of additional solar. So it's not doing it. It's not producing a cost benefit of that solar. It just assumes it happens.

Brad Carver (GLSSA-APA): [07:22:33] This Commission has opted to increase the total number of megawatts of solar megawatts proposed by Georgia Power in the previous two, actually in the last three IRPs, 2013, 2016 and 2019. Is that correct? [That's correct.] The Commission decided to expand the utility scale solar megawatts. The fact that the Commission decided to expand those megawatts can be validated by the Astrape solar penetration study. Is that correct?

Jeffrey Weathers (GPC): [07:23:13] Again, Mr. Carver, I think that it's two different things. I mean, the value and benefit to customers of that capacity that is, is examined when the RFP is evaluated. The Astrape study assumes that that is built and is there on the system and then is evaluating the impact on real time operations of that generation. So it's not, that study itself is not calculating value. The value had already been calculated at the time the RFPs were evaluated and certified.

Brad Carver (GLSSA-APA): [07:23:51] So in, several of you may recall that in the 2019 IRP, we talked a lot about fuel price volatility, the situation in Europe, liquefied natural gas exports to Europe, and the effect of the Russian pressure on Western Europe. In light of that, when the solar industry talks about fuel price volatility, is it correct to say that that is bad for the ratepayers?

Jeffrey Weathers (GPC): [07:24:23] Is fuel price volatility bad for rate payers? Not necessarily because volatility goes up and it goes down. I mean, we are certainly seeing a recent increase in natural gas prices. We saw that before the Russian Ukraine conflict related to the pandemic and the decreased demand or the pandemic. And then as the demand came back, production was slower to respond. We've seen that with the situation in Europe and the value of exports to Europe. However, if we look at the for natural gas price curve, we expect that those impacts would be relatively short term. The long term fundamentals continue to support gas prices consistent with what's in our filing. In fact, the Energy Information Association, the governmental agency that produces the forecast that we use, the latest forecasts that they produced just last month, continues to show long term natural gas prices similar to what we have in our filing. So we think it's important to consider a range of gas prices because within that range, expect there to be volatility. But if you're considering a range, then you're making sure you're making the best decision for customers, not just on a single price, but on the range of prices.

Brad Carver (GLSSA-APA): [07:25:40] When Georgia Power invests in utility scale solar, does that act as a hedge against fuel price volatility?

Jeffrey Weathers (GPC): [07:25:49] Well, it doesn't impact the volatility of fuels, but it does provide energy that is not subject to volatility itself.

Brad Carver (GLSSA-APA): [07:25:59] These are fixed price contracts for 30 years plus. Right? So there's not volatility with a procurement that happens, a utility scale procurement. It's set at a fixed price contract.

Jeffrey Weathers (GPC): [07:26:13] That's correct. There's no volatility in the price of the PPA. So if you're, if that's...

Brad Carver (GLSSA-APA): [07:26:18] Wouldn't that act as a hedge against volatility you see with other fuel sources, including natural gas?

Jeffrey Weathers (GPC): [07:26:25] Well, I think it's definitely part of diverse portfolio. So any diversity in the portfolio helps with fuel price volatility as you can shift from one generation source to another. So there's benefit from having solar, the company has recognized that, we are planning for that, it's reflected in our models. And so it is a benefit to having a resource that doesn't have the same volatility.

Brad Carver (GLSSA-APA): [07:26:52] That has no volatility.

Jeffrey Weathers (GPC): [07:26:54] That's not in price. In output, it does. So there's different types of volatility. So it's important to see those different outputs in a robust planning analysis.

Brad Carver (GLSSA-APA): [07:27:05] Could you explain the concept of best cost solar projects? Could you also explain how and under what circumstances this evaluation would be used?

Jeffrey Grubb (GPC): [07:27:14] Yeah, I'll be happy to. And really, Commissioners, what we're proposing here with the best cost analysis, the fundamental change is to stop using that MG0 avoided cost number as an automatic disqualifier as we have in the past. As we've talked about earlier, we have some improvements in our modeling. We're now able to pre-select renewable resources through that model and that show that those resources will provide economic benefits to customers long term. And so in the past, the model hasn't been able to select those resources. And so that avoided cost ceiling, if you will, has been used to ensure that we're procuring those resources that will benefit customers. Now, with the new enhancements in the model and the ability to choose renewable resources, our plan has identified this renewable need. And so it's in that way that our our evaluation process will be will be modified. Really, the steps will be more of the same. We're going to continue to choose the resources that provide the most value to customers, including both their cost, their operational characteristics, their interconnection costs, and the benefits they provide customers. But the primary change is that we'll no longer propose to use that MG0 avoided cost bogey as an eliminator of proposals.

Brad Carver (GLSSA-APA): [07:28:38] So in this IRP for the first time, Georgia Power has proposed a regional RFP. North Georgia focusing on North Georgia. Would you agree that when evaluating solar projects participating in this North Georgia RFP, that it is appropriate that the RFP bid evaluation reflect the value of the targeted region, i.e. North Georgia and not a state wide avoided cost.

Wilson Mallard (GPC): [07:29:03] So no, I don't I don't think that's right at all. What will happen is each of these projects are going to get evaluated based on where they choose to locate and a project specific transmission evaluation. It's in that way that each project will be assessed the proper cost for for integrating into the system. The energy itself is, should be valued on a statewide basis. And that's what we'll propose to do. It's the integration cost, the impact to interconnect to the transmission system where projects that locate in North Georgia will see a benefit.

Michael Robinson (GPC): [07:29:38] And Commissioners, the future, the future RFPs that look at, if you look at south Georgia talked about the constraints that we're already seeing and we're getting very full as it relates to South Georgia. We saw that in the last RFP. I think the RFP that's being evaluated right now will show that as well. And I think the cost associated with transmission will be reflected if we continue in South Georgia and not target north Georgia. We need time, as I mentioned before, to build the transmission, those highways, to get the megawatts from south Georgia to north Georgia so that we can continue development in south Georgia. But I think as we go forward, we're going to continue to see more and more constraints as it relates to transmission and transmission cost imputed against future bids in South Georgia in RFPs.

Jeffrey Grubb (GPC): [07:30:29] And that geo...from a generation standpoint, there's value in geographic diversity as well.

Brad Carver (GLSSA-APA): [07:30:37] Georgia power has...

Michael Robinson (GPC): [07:30:39] I'm sorry. Sorry, Mr. Grubb was talking about there's if you've got solar and, all in south Georgia, and you have a thunderstorm come across or you have a hurricane that comes and clips the southern part of the state, and you lose all of that solar. You don't have the benefit of having additional solar in north Georgia at that time. Georgia Power has proposed a significant amount of BESS, battery energy storage systems, in this 2022 IRP. And certainly GLLSA and APA applaud this step to modernize the grid. Do you think it is prudent and appropriate to articulate all the storage use cases that the best procurement will address for the utility?

Jeffrey Grubb (GPC): [07:31:19] Can you repeat the question? I'll make sure.

Brad Carver (GLSSA-APA): [07:31:21] So, do you think it's appropriate to articulate all of the storage use cases that the best procurement will address for the utility?

Jeffrey Weathers (GPC): [07:31:33] I don't know, Mr. Carver, sitting right here, we can identify all of the storage use cases at the best procure. What we've done is we have examined cost and benefits associated with the uses of storage determined by our modelling. So primarily we're looking at the storage being able to replace operating reserves on the system to serve that function instead of the steam units. But it also provides other energy benefits and there's also capacity. So we've considered the ones we've been able to identify and quantify, but there may be others, other uses of it because it's a very flexible resource that we just can't anticipate right now.

Brad Carver (GLSSA-APA): [07:32:21] So we've established earlier that the competitive bid procurement process has worked well for both utility scale and distributed generation procurement. Isn't it safe to assume that such competitive procurement would also ensure that the free market delivers the best value for storage?

Wilson Mallard (GPC): [07:32:44] Yes, and that's that's actually what we're proposing as... The same way that we went to the market for a competitive RFP for our EPC vendor, for the Mossy Branch project, the 65 megawatt project that we talked about, that was approved last August. It's our plan and our intention that for the proposed McGrau Ford Project and for other projects going forward, that the company would procure those EPC services through a competitive RFP. It's really just the ultimate ownership and control and operation that Georgia Power is requesting to own and operate. And again, it's because of the importance of those reliability services and that responsibility to provide that reliability, is why we think that's critical, that Georgia Power own those resources.

Brad Carver (GLSSA-APA): [07:33:32] Witness Mallard mentioned earlier that Georgia Power will accept solar plus storage bids for the RFPs in upcoming procurements. If the bids storage use cases are not valued appropriately, Georgia Power would end up with an inaccurate market response. Is that correct?

Wilson Mallard (GPC): [07:33:51] I would say that's true in every RFP the company has ever run or will run.

Brad Carver (GLSSA-APA): [07:33:55] So back in January, the issue came up for the second RFP from the CRSP program and we had a discussion around the level playing field between storage and storage or, excuse me, solar only and solar plus storage bids. What is Georgia Power going to do going forward that will have a level playing field between, storage, excuse me, solar only and solar plus storage bids?

Wilson Mallard (GPC): [07:34:33] So I will confirm to you and commit to the commission that as part of the RFP evaluation process, the company works very closely with the staff and the independent evaluator to make sure that we are evaluating all of the bids and all the different technologies and use cases appropriately. So we'll absolutely strive and make sure that we do properly value solar only, solar that's required to be on automatic generation control now, and compare that to appropriately other resources like wind or other sources that might be bid in, but also solar and the storage use cases including solar. There's new ones. There's firming and shifting. And there's smoothing. Smoothing, smoothing and firming, and scheduled use case are the three use cases now in the RFP.

Jeffrey Weathers (GPC): [07:35:26] And just to add to that, the mechanism by which we do what Mr. Mallard is describing is the renewable cost benefit framework. And so specifically, if you think of the example of smoothing solar, so smoothing solar has the benefit of not incurring the support capacity costs related to impacting regulating reserves. And so when we give it that credit in the RFP evaluation, another way to accomplish that is with is with AGC on the solar itself. So they're both avoiding the same cost. So they're both getting the same credit in the current way that we do the evaluation. I think as long as we're consistently applying the renewable cost benefit framework in an appropriate way to give the assigned costs where those are due and to give credits for those and benefits where those are due. Also, that's the way that we can ensure fairness across different technology types.

Brad Carver (GLSSA-APA): [07:36:27] The Georgia Large Scale Solar Association, Advanced Power Alliance. We have a lot of renewable energy advocates in this room, but we are the group in this case, in this IRP and have been in the past two IRPs, to be a voice for the utility scale market segment. We also bring expertise in the other 49 states as well. Is Georgia Power open for our input on how to best create those use cases based on the experience we've had in other markets?

Wilson Mallard (GPC): [07:37:06] Yes, certainly we're open to that and we absolutely depend on your members and all the bidders in our RFP to provide us that intelligence and that information for, from their experience and their participation in other markets. In fact, some of the recommendations that was made in the last IRP, including take or pay contracts, including AGC, which was recommended last time, including considering scenarios of carbon and gas. We've taken a lot of those into account and have we've leveraged those. Those are now parts of our program. So we absolutely appreciate that. I'll also point out to the commission that it's appropriate to receive that feedback. It's also appropriate to make sure that the commission staff, Georgia Power and the IE continue to run an RFP that provides the most benefits to our customers. And so while it's important to receive feedback from the market participants, they're motivated to make sure that they can provide the most successful bids they can and do the best for their their commercial enterprise. And so we want to make sure that we take that into account as well as we receive that feedback and then fold it in to our RFPs.

Brad Carver (GLSSA-APA): [07:38:17] And I think that's fair and I appreciate that. So and but you would also say you've said before that the more robust the competition, the better value that we we create for the ratepayers, correct?

Brad Carver (GLSSA-APA): [07:38:30] Yes. Having a robust response to our RFP absolutely ensures really good competition and produces good results for customers.

Brad Carver (GLSSA-APA): [07:38:37] So we're all familiar with the renewable cost benefit framework. Is it possible for us to get a storage cost benefit framework?

Jeffrey Weathers (GPC): [07:38:51] Well, what we've done is we've is the value that storage brings is related to it. And I think if you look at the renewable, the renewable integration study, which is the basis for the integration cost of the renewable cost benefit framework, to the extent storage can mitigate that integration cost, it receives that benefit. So that in the battery storage analysis that we've done is in this IRP, it includes that as a benefit for it. So the renewable cost benefit framework is there to identify the unique benefits and costs associated with variable energy resources that are in addition to the normal cost of benefits for fully dispatchable resources. So battery storage is a fully dispatchable resource. It doesn't have the same intermittency impacts, but we do make sure we consider the unique values that it brings, such as the mitigation cost or the flexibility cost that we included in the battery storage analysis.

Brad Carver (GLSSA-APA): [07:39:58] Shifting to the issue of transmission upgrades, does the ten year transmission plan that Georgia Power has? Does it include the North Georgia action plan?

Michael Robinson (GPC): [07:40:14] It does not include, it does include controls Bowen 3&4. So that assumption is in the ten year plan, it does not include the proposed RFP in North Georgia. The transmission that's being developed currently with ITS participants is not in, that is not in this. That is a transmission plan that's looking, Commissioners, towards that 2035 date of future retirement of Bowen 3&4, 6,000 megawatts of renewables on the system. Add some for the EMCs and municipalities. We've got to plan the system as a whole. So you won't find those in the ten year plan. But there are some aspects of the North Georgia reliability and resilience plan that are in the ten year plan that I laid out.

Brad Carver (GLSSA-APA): [07:41:03] Was renewables integration modeled separately from the coal retirements, the Plant Bowen coal retirements in North Georgia, transmission planning?

Jeffrey Grubb (GPC): [07:41:12] So are you asking about the Renewable integration study? Ask the question again.

Brad Carver (GLSSA-APA): [07:41:17] Well, yes. So, so and again, we're we're talking about transmission upgrades. So was transmission upgrades to facilitate renewables integration model separately from transmission upgrades necessary for the coal retirements?

Michael Robinson (GPC): [07:41:34] The last solar that was added to the ten year plan is the last RFP that was certified. So those solar units are in the studies moving forward. But any anticipated solar that would be approved in the future is not in the ten year plan, but is being anticipated in the studies that are ongoing with the participants.

Brad Carver (GLSSA-APA): [07:41:57] So going now to again BESS battery energy storage system integration. What, you did a 15% storage. What other levels of storage or models?

Jeffrey Weathers (GPC): [07:42:15] Really the other level that was model was really zero. And so the comparison we made was a system that had renewables that only could rely on existing resources on the system, the fossil resources for operating reserves versus one at roughly a 15% level, which was proved to be a lower production cost. So we didn't, we talk about earlier, we did some iteration in the model to decide on the 15%. But once that was decided on being the appropriate amount to mitigate the cost, that was the amount that was studied and compared to having no storage on the system.

Jeffrey Grubb (GPC): [07:42:54] And again, another that we've talked about that, it was done to maintain the reliability at the same level. So it wasn't testing all the different levels of storage, it was what level of storage at that renewable penetration maintains my reliability in the same manner, and now I can compare it to the cost of the existing system.

Brad Carver (GLSSA-APA): [07:43:16] Thank you. So turning to page 14 of your testimony, this is dealing with renewable integration study. You state the 1,000 megawatts being proposed represents a sufficient amount of storage resources to improve the cost effectiveness of solar integration and improve solar reliability. When you say improve cost effectiveness of solar integration, does that mean optimize?

Jeffrey Weathers (GPC): [07:43:46] Well, it's not, it's not necessarily optimized, but it is an improvement. So what we talked about here is that as you increase renewables, you don't have to add batteries at the levels that we're looking at. It's just going to cost more if you don't have the batteries. So the level of batteries that we modeled, as Mr. Grubb just said, it was a sufficient amount to restore the the intrahour reliability back to the pre-solar levels, back to the current levels. And to do that in a more cost effective way, it's not necessarily an optimized amount. It might be 15%, it might be 15 and a half and maybe 14, but it is amount that was determined to be adequate and sufficient to get back to those pre-mitigation levels.

Brad Carver (GLSSA-APA): [07:44:40] So does the amount of storage needed to reduce integration costs depend on the volume of solar?

Jeffrey Grubb (GPC): [07:44:46] Yes. And that's what the renewable integration study is showing, is as you continue to add it, you have to add more operating reserves.

Jeffrey Weathers (GPC): [07:44:55] But the 15%, Sorry. [No, you're fine.] But the 15% was pretty consistent across the range that we studied. So whatever level you studied it, as you get into higher levels of solar penetration, it's a little bit less, but across the range for the foreseeable future, 15% was pretty consistent.

Brad Carver (GLSSA-APA): [07:45:16] Could it mean that if more solar were added, that more storage should be added?

Jeffrey Weathers (GPC): [07:45:22] In terms of megawatts? Yes. So there's additional solar beyond what's contemplated by 2030. Then the 1,000 megawatts would ideally be a little bit higher to accommodate that.

Brad Carver (GLSSA-APA): [07:45:37] So on page 18, now, your testimony lines 14 and 15. You say transmission projects are necessary to accommodate replacement capacity. Is the replacement capacity renewable or non-renewable?

Jeffrey Grubb (GPC): [07:45:57] One second, let me read that.

Jeffrey Weathers (GPC): [07:46:00] What line is that on Mr. Carver?

Brad Carver (GLSSA-APA): [07:46:01] That's on lines 14 and 15.

Jeffrey Weathers (GPC): [07:46:13] Yeah. I think it says the projects are necessary to accommodate the combined retirements and the procurement of replacement capacity.

Jeffrey Grubb (GPC): [07:46:22] Right. That replacement capacity we're speaking about here are the six gas PPAs from existing facilities. And so when we made that final determination of recommending the certification of six PPAs, it was reflected in our transmission models. And as Mr. Robinson said earlier, any planned and committed renewables on the System are included in those evaluations.

Brad Carver (GLSSA-APA): [07:46:48] Okay. Turning to page 29, this is again on the North Georgia plan. 29 lines four through six. You state the existing transmission system is strained by the geographic distance separating South Georgia and load in north Georgia. The long term plan retirement of Plant Bowen 3&4 will exacerbate this geographic constraint. So the system is strained by separation of generation in the south and load in north, south Georgia and load in north Georgia. Is that correct? [Generally, yes.] Did you evaluate transmission improvements in the north south interface to address that strain? [Repeat the question.] Did you evaluate transmission improvements in the north south interface to address that strain? [When you speak of the north south interface, the north south interface in the state of Georgia?] Yes. [The transmission system generally connecting the load in north Georgia to the south.] Correct.

Michael Robinson (GPC): [07:47:54] There were evaluations looking at many different scenarios of retirements and looking at Bowen 3&4. There were significantly more overloads and constraints that were identified when you retired three and four at a future date. What it did not anticipate is additional solar in the South Georgia area or offset by additional solar in the north Georgia if successful in siting there. Those, the studies that I mentioned that are ongoing with the ITS participants, anticipate those needs looking, as I said, looking at that date in 2035, understanding that strategic projects will take time to build. Six and a half, seven to eight years, as I mentioned before, we've got to get ahead of that curve, look beyond the ten year plan and anticipate that data out of 2035.

Jeffrey Grubb (GPC): [07:48:51] And so, Mr. Carver and commissioners, Mr. Robinson correct me if I'm wrong, but right now we're able to serve the System, obviously. So what we're talking about on this is future changes. So Bowen 1&2, you retire it. We've identified those projects. The long term retirement of Plant Bowen 3&4 is what we're talking about. So it's not everything's solved at this point. That North Georgia plan says as we continue to transition the fleet, we need to identify what generation resources take the place of building three and four upon its retirement. And what's transmission in both of those interact.

Michael Robinson (GPC): [07:49:25] Correct

Brad Carver (GLSSA-APA): [07:49:28] So back to storage again on page 31. This would be lines four through seven. That's why it's the company's plan to have company own storage. You state, "The company must maintain a sufficient portion of the energy storage resources on the System under its ownership and control to reliably serve its customers in a cost effective manner." So my question is Georgia Power must maintain a sufficient portion of ESS under its ownership and control to reliably serve in a cost effective manner. Is that true?

Jeffrey Grubb (GPC): [07:50:12] Yes. And this is speaking again to the renewable integration study and operating reserves and the 1,000 megawatts of storage. As you said earlier this morning, storage will still be able to bid into renewable RFPs. It will absolutely still be able to bid into future capacity RFPs. This is speaking specifically about 1,000 megawatts and the renewable integration study and those storage resources, not the entire system, those specific ones.

Jeffrey Weathers (GPC): [07:50:42] The point is, the company doesn't have to own all storage resources, but the ones that we are committing to to serve the operating reserve function. So one of the critical operations functions in the system, those need the flexibility the ownership provides.

Brad Carver (GLSSA-APA): [07:50:59] But there are two elements, right? Ownership and control. Those are two separate elements. Right?

Jeffrey Weathers (GPC): [07:51:06] They can be. But ownership ensures a definitely ensures a robust control across a variety... We talk about use cases earlier, a variety of use cases, some of which we don't even know what they will be today. But ownership provides the ultimate control over the maintenance or the operating procedures and over the performance of the devices.

Jeffrey Grubb (GPC): [07:51:29] Yes. And I think what Mr. Weathers just said is spot on. It's not talking about control in terms of automatic control. It's control over all those different aspects.

Brad Carver (GLSSA-APA): [07:51:46] Along the same line, lines, 31 and 32, same page. "To ensure the best cost, the company will issue competitive solicitations to supply EPC [engineering procurement and construction] services in support of this effort."

Jeffrey Grubb (GPC): [07:52:05] Mr. Carver, we only go through line 26. So you said lines 31 and 32 or do you mean...

Brad Carver (GLSSA-APA): [07:52:11] I'm sorry. I mean pages 31 and 32.

Jeffrey Grubb (GPC): [07:52:15] Just to make sure we're looking at the right spot.

Brad Carver (GLSSA-APA): [07:52:16] Yep. It continues on the page 32. So again, the company will issue competitive solicitations for EPC services, correct? [That's right.] So

Georgia Power will have competitive solicitation for that, but not allow competitive solicitation for third party EPC at sites not owned by the company.

Wilson Mallard (GPC): [07:52:39] Well the ownership of the site could be different. There's some different arrangements there. But ultimately this is an RFP for these EPC services for a battery energy storage system that the company will ultimately own and control.

Brad Carver (GLSSA-APA): [07:52:54] Are you all aware that a large industry has arisen bidding into competitive ESS procurements, including not just EPC but siting and operating such facilities?

Wilson Mallard (GPC): [07:53:04] Yeah, I've studied some of those, a lot of them in California where they were, they use PPA agreements to source their storage.

Brad Carver (GLSSA-APA): [07:53:17] Going to pages 34 and 35. This is dealing with a renewable expansion plan. [Yes.] You state the greater amounts of solar or renewable energy are deemed economically optimal. In scenarios, this is like, excuse me, lines 26 and then continuing on to the next page scenarios with higher fuel emissions cost or lower cost renewable procurements, the model selects higher levels of renewables as optimal with higher fuel and emissions costs. Is that correct? [Yes.] So this is kind of like what we're talking about earlier, price volatility.

Jeffrey Grubb (GPC): [07:53:59] Well, this is specifically aiming towards the evaluations that we did in the scenarios. So the ability of our models to pick across different scenarios. So obviously in a high gas carbon type case, you're going to see a higher prediction of renewables that benefit customers. And so we use that range to come up with that 6,000 megawatt guidance.

Brad Carver (GLSSA-APA): [07:54:20] Have gas prices risen since you ran the model?

Jeffrey Weathers (GPC): [07:54:25] Long term natural gas prices have have not risen in terms of our forecasts. Short term have, that we're looking here about, procurements and evaluation period of multiple years and those have not changed over the long term.

Jeffrey Grubb (GPC): [07:54:42] And these are resources that we're requesting in this IRP that will come online at 2028 and 2029. And so as we continue to go through these RFPs, we mentioned that as we come back in IRPs, we're going to continue to upgrade that. Our models can now pick renewables. And so we're going to have that guidance from every IRP cycle here forward and we can adjust accordingly.

Brad Carver (GLSSA-APA): [07:55:03] And on that short term increase that you're talking about, is that because of events like the invasion of Ukraine and the increased increased demand for LNG in Europe, in the United States?

Jeffrey Weathers (GPC): [07:55:16] It is and I talked through that earlier, that is in part due to that. But we were already seeing some rises in short term natural gas prices due to the pandemic and due to the production, response of production. As demand increased coming out of the pandemic, it was putting upward pressure because production didn't respond as quickly as demand did. And then, as you mentioned, the increase for demand of exports to Europe, those things we do think are short term. The market thinks they're short term. The long term forecast will look at as well, also considers those to be short term dynamics.

Brad Carver (GLSSA-APA): [07:55:57] Okay. So go now to again, the best cost evaluation we talked about before on page 37, which deals with evaluation of criteria, you state that the company will determine the exact excuse me, yeah, "the company working with the commission staff and IE will determine the exact criteria and methods of evaluation, ranking and selection as part of the Commission approved RFP process." Correct? [Correct.] How will the public and stakeholders be involved in reviewing criteria and methods for evaluating in the upcoming RFPs?

Wilson Mallard (GPC): [07:56:37] So as with all of our RFPs, there's a period where we accept comments from interested parties, from bidders. It's usually a two or three week period and all of our evaluation methodologies, our PPAs, the RFP, all of that thing is all of those things are there for comment by again bidders and other interested parties. And we do take that, that feedback very seriously. We file those, those comments, those suggestions as appropriate into the design of the RFP. And we expect that to continue in much the same way. Ultimately the decisions around how to evaluate these resources so they provide the most benefit for Georgia Power customers are the responsibility of the company, the commission staff and the independent evaluators.

Brad Carver (GLSSA-APA): [07:57:25] Prior to the independent evaluator and the bid wall going up, are y'all open to input from stakeholders like the Georgia Large Scale Solar Association, Advanced Power Alliance?

Wilson Mallard (GPC): [07:57:40] Yes, definitely. And some of these improvements, the flexibility, the adaptability that we're proposing in these RFPs, will absolutely allow for that. And it's going to be critical. We're really seeing a dynamic time in the solar and storage market right now. We're going to need to be as flexible as we can be based on those market conditions to receive that feedback. One of the improvements that we're making that's probably not highlighted in here specifically is that we're going to propose to use two separate bid teams. I know some of the market has expressed frustration in the limited amount of time where the parties can speak freely without being constrained by the RFP evaluation and communication guidelines. So we'll one of the proposals we have going forward internally is we'll have two separate teams and so we'll have a separate team running RFP 1, a separate team running RFP 2. RFP 2 team would be available to have those direct conversations with bidders in the marketplace.

Brad Carver (GLSSA-APA): [07:58:41] Thank you. So on page 38 now next page, you say the evaluation team will take additional factors into consideration. What factors other than generation and transmission costs will be considered?

Wilson Mallard (GPC): [07:58:58] Well, those are those are the primary ones. And again, just to reiterate, the value that can be delivered from these projects to our customers, is the primary the primary factor that we will choose these? But as we've talked about a good bit now, interconnection to the transmission system is becoming more challenging. The ability to select the portfolio of projects that can maximize value to customers. What we're seeing is in some of our portfolio analysis, commissioners, these projects interact with each other. And so picking a portfolio of these four projects that are lowest cost may not produce the best net benefit as opposed to these two and two more that we're further down the list because of the impacts of those projects on the entirety of the transmission system, the ability to take that into account and to be responsive to these market conditions that we're talking about. We're hearing from solar bidders in the marketplace that the volatility that we've been talking about is is absolutely there for the ability to be able to procure the solar equipment, battery energy storage equipment. We want to make sure that we are able to be responsive to that and can run the most efficient RFPs that can procure these resources for the benefit of customers.

Brad Carver (GLSSA-APA): [08:00:13] So turning to the next page, page 39, this is dealing with the cadence of the RFPs. So with adding beyond this time horizon, adding 6,000 more megawatts, has the company considered parallel RFPs, one for the North and one for the South, to provide redundancy in case one of the RFP does not yield an acceptable volume of solar?

Wilson Mallard (GPC): [08:00:39] So that's not what we're proposing. We considered a lot of different cadences and timelines for the RFP. What we think makes the most sense is the most efficient for the market, for Georgia Power, for the for the staff to be able to administer, is for the first RFP to be issued starting subsequent to this RFP, if approved. And it will seek resources that will be COD in 2026 and 2027. And then we'll start a second RFP and they'll actually be a little bit more time in between there. We're adding some time for the more complex transmission analysis, so it's a little bit longer timeline, but then the second RFP will solicit resources. We're not sure yet if the first RFP is successful in procuring North Georgia resources, the second RFP could be state wide again. It could be geographically steered to another location. All of those things will be dependent on the results of the first RFP. And so it's that feedback loop, that ability to get that real time information from the market and then craft that into updated RFP timelines and CODs. That's exactly the flexibility that we're proposing that we think makes the most sense given that given the current conditions.

Michael Robinson (GPC): [08:01:51] And I think timing is going to be very important. Commissioners, when you look at particularly South Georgia, we've got to have that time to build that transmission. If we're unsuccessful in the north Georgia and we have to procure all in south Georgia, we're going to need to spread that out. We can't just take that all in one chunk. We've got to strategically build a transmission and we don't have the time from an operational perspective to go onesie twosie doing upgrades here and there throughout the system. We just don't have the, our outage windows are becoming more and more constrained. Resources are constrained. And what that's going to do is put pressure on the market to drive out CODs. We're not going to be able to get those solar renewable facilities online in time because of the need to build that longer term strategic transmission from south to north.

Brad Carver (GLSSA-APA): [08:02:40] So speaking of that, if the North Georgia procurement does not yield 1,050 megawatts, can those megawatts roll over to the statewide or other, the next regional RFP? I think right now you're saying statewide.

Wilson Mallard (GPC): [08:02:57] Certainly that would be the expectation.

Brad Carver (GLSSA-APA): [08:03:00] We are...

Michael Robinson (GPC): [08:03:01] Again, timing would have to be considered in that as well as it relates to transmission.

Brad Carver (GLSSA-APA): [08:03:05] On the stretch run here. Four more questions. Why is the CARES program limited to 2,100 megawatts? The company testified that there are 2,000 additional megawatts of REC demand beyond what is shown in the updated R3 program.

Wilson Mallard (GPC): [08:03:29] So I think I'm following your question, Mr. Carver. What the company proposed is to make all of the resources procured through the utility scale procurements available for subscription. So that's 2,000 megawatts. And then what we've also proposed through the Retail REC retirement program is to make renewable energy credits procured through prior solicitations, both the solicitation and the current ongoing solicitations approved in 2019 to make 2,000 more megawatts available for subscription there. So those numbers are based on the available megawatts and also the demonstrated customer demand that we've seen from customers.

Brad Carver (GLSSA-APA): [08:04:06] Will the first subscription option have a portfolio price that's made up of elements similar to the CRSP portfolio price, i.e. supply costs net present value of net benefits.

Wilson Mallard (GPC): [08:04:23] Ask the question one more time, please.

Brad Carver (GLSSA-APA): [08:04:25] Will the first subscription option have a portfolio price made up of elements similar to the CRSP portfolio price. Supply costs. Net present value of net benefits.

Wilson Mallard (GPC): [08:04:36] So. So the methodology, what we're proposing, is actually two different subscription price calculation methodologies, the first of which is consistent and similar with the way that the CRSP price is calculated, the second of which is a fixed price. We've gotten some feedback from some of these large customers that the volatility, the unknown of the credit that they're going to get back is a barrier for their participation. So we're proposing a second subscription methodology so that we can fix the price for those customers over the term of their subscription.

Brad Carver (GLSSA-APA): [08:05:11] If new load is being procured outside of the 2,100 megawatt cap, as in economic development programs, can customers come to Georgia Power with resources they would like the company to procure? As is the case with Portland General Electric's VRET program, or Duke Energy's, in the state of North Carolina, GSA program.

Wilson Mallard (GPC): [08:05:35] So Georgia Power is going to be guided by those principles that we talked about a good bit already. We're going to procure renewable resources that benefit all of our customers. A particular resource chosen by a particular customer that didn't align with the needs of all Georgia Power customers would not be appropriate. I think we talked about this a minute ago as well. I think Georgia Power's competitive RFPs are some of the best in the country, I think we get some of the best pricing, some of the best projects. I think that is the premier vehicle to procure renewable resources is through Georgia Power's competitive RFP.

Brad Carver (GLSSA-APA): [08:06:14] Why is the MUSH program participation limited to customers under three megawatts of aggregate annual peak demand?

Wilson Mallard (GPC): [08:06:23] So it's a carve out. Most customers have been unable to participate in the CRSP program prior because of the three megawatt participation limit. And so we've got some, much customers smaller than that. And so what we try to do with the program design here is carve out a specific amount of that

CARES capacity just for those smaller municipal, university, school and hospital customers.

Brad Carver (GLSSA-APA): [08:06:50] Gentlemen, thank you very much. Thank you. My questions.

Tricia Pridemore (PSC): [08:06:55] Georgia Solar and Energy Industries Association, Solar Energy Association and Vote Solar. [Thank you. Good evening, Madam Chair. Commissioners. And to the panel.] Do you go by, Ms. Chiles Ottenweller or Ms. Ottenweller? [Ottenweller. That's great. Thank you.] Thank you.

Katie Ottenweller (GSEIA-SEA-VS): [08:07:15] So just to give you a roadmap for your brief time with me, counsel for Georgia Power has agreed to allow my co-counsel and I to split up the question. So my questions are going to be limited to the Aurora modeling and monthly netting, and then I'm going to hand it over to Scott Thompson. Thank you. So I want to start with the Aurora modeling. For the renewable energy expansion plan, did Georgia Power model both fixed and tracking solar.

Jeffrey Weathers (GPC): [08:07:49] No. I mean, it was really based on a tracking solar type profile that we modeled.

Katie Ottenweller (GSEIA-SEA-VS): [08:07:58] And the standalone solar additions in the Aurora model. Those were assumed to have zero capacity value, right?

Jeffrey Weathers (GPC): [08:08:06] The standalone solar additions, the solar. So the incremental solar, yes. It was assumed to have zero capacity value. That's correct.

Katie Ottenweller (GSEIA-SEA-VS): [08:08:14] Does solar have capacity value in the RCB framework?

Jeffrey Weathers (GPC): [08:08:19] Yes. When when we actually evaluate real projects, then the capacity value is assessed at that time. So previous projects that we've added through the RCB framework, the capacity values assigned, but on a going forward basis, we didn't include capacity value. The reason is because the capacity value of solar is trending towards zero. So the more that we add, the less incremental capacity value you have with each additional megawatt. And then we wanted to really evaluate the energy savings. So when the model selects them, they select them for energy savings, not for any capacity value.

Katie Ottenweller (GSEIA-SEA-VS): [08:09:03] Thank you. Does solar have capacity value in the ELCC study?

Jeffrey Weathers (GPC): [08:09:09] Yes, it does. I mean, it depends on the season, but but yes, there's capacity value.

Katie Ottenweller (GSEIA-SEA-VS): [08:09:16] Okay. And are you all counting future solar PPAs towards the 70/30 allocation that you're looking at?

Jeffrey Grubb (GPC): [08:09:25] So the 70/30 is only what's committed to and planned. And so again, we talked this morning around, we use the capacity equivalence part of it, not nameplate, but it's just what we have committed to.

Katie Ottenweller (GSEIA-SEA-VS): [08:09:38] But the plan would include that 2,400 or the...

Jeffrey Grubb (GPC): [08:09:42] No, I think its...I'd have to, subject to check, but I don't think it included our IRP request. Well, I'd have to check. I'd have to go back and look. It's pretty small, though, because the capacity equivalence. Matter of fact, this will answer my question. We wouldn't have been there because we're giving them that zero capacity. So we would have existing gas, PPAs, all the company owned resources and any planned and committed solar that we've truly procured that we have a capacity equivalence on.

Katie Ottenweller (GSEIA-SEA-VS): [08:10:10] Okay. Thank you

Jeffrey Weathers (GPC): [08:10:10] And just just to clarify, just to make sure all the existing projects and projects that we have procured that are real projects, we identified the capacity value. And so whether that's the, what we call the ICE factor in the existing renewable cost benefit framework or the ELCC, which is just a different way of doing it. They have capacity value for... On a going forward basis for incremental solar. we've assumed that the capacity value will be zero because it is turning towards zero. We don't want and, really our primary capacity value is in the winter. So we don't want to give a false assumption of future capacity value that may or may not materialize when this project has come online or they're procured. We'll evaluate the capacity value at that time to assign to it.

Katie Ottenweller (GSEIA-SEA-VS): [08:10:59] Okay. And did the renewable expansion model allow for solar paired with battery storage to be selected?

Jeffrey Weathers (GPC): [08:11:06] It was, look at, just solar. So we looked at what solar, standalone solar, what would be economic for customers across our range of scenarios.

Katie Ottenweller (GSEIA-SEA-VS): [08:11:17] And Georgia Power considered six different scenarios in its renewable expansion modeling, right? And three of those had a carbon price?

Jeffrey Weathers (GPC): [08:11:28] Yes.

Katie Ottenweller (GSEIA-SEA-VS): [08:11:30] And these scenarios form the basis for the company's proposed renewable procurement strategy in this proceeding?

Jeffrey Grubb (GPC): [08:11:37] That's correct.

Katie Ottenweller (GSEIA-SEA-VS): [08:11:41] You may want to refer to your IRP filing attachment F at F-160 for this. [Yes.]. Okay. Georgia Power essentially averages out the outcomes of those scenarios to get to the 2,400 megawatts by 2029. Right?

Jeffrey Grubb (GPC): [08:12:06] So which number did you reference the... You said 20...

Katie Ottenweller (GSEIA-SEA-VS): [08:12:10] At F-160, the 2,400 megawatts by 2029. That's an average of what was selected from those six portfolios. Right? For the six scenarios.

Jeffrey Grubb (GPC): [08:12:21] Yeah. It was really, the six is the long term guidance and I think we just looked at 2,300 is something that we felt like kept us on that path, but we also could physically do from a transmission and the ability to build the solar facility. So I didn't realize that 24 hit right on that, but really that 2,300 is the step towards the six...335.

Katie Ottenweller (GSEIA-SEA-VS): [08:12:43] So would you say that the carbon price does impact the company's renewable energy procurement target?

Jeffrey Weathers (GPC): [08:12:52] It does. It does, yes.

Jeffrey Grubb (GPC): [08:12:55] And so that's why we've stated that the guidance that we're getting in this IRP is looking at these scenarios. We have that ability now. We will adjust that over time based on fuel prices, carbon prices and those other things. So it does it does impact.

Katie Ottenweller (GSEIA-SEA-VS): [08:13:10] Okay. And I just want to follow up with something that I think Mr. Mallard said earlier to Mr. Jones. He was talking about redefining avoided cost. I just want to clarify that that's something that you all are doing for planning purposes, but it's not actually impacting the RCB avoided cost number that's used for compensation purposes, right?

Jeffrey Grubb (GPC): [08:13:34] When you say compensation purposes, you mean through the 4822 or the RNR? [Yes.] Yes. So that's a great clarification. So when we look at pricing something in that manner, then we do use the MG0 because that's a price we're paying. There's not an avoided cost of carbon yet. So we pay RNR QFs under 4822 on, based on a, well QFs are day ahead. But we base it on a non-carbon price. As carbon becomes an impact in a real true cost, we would reflect it there. So here we're looking at the range of resource to procure. We'll actually pay them what they bid in. So it is just a different procurement.

Katie Ottenweller (GSEIA-SEA-VS): [08:14:16] So just to clarify, so you're... There are carbon price assumptions built into your long term planning, but when you're looking at the long term avoided costs, say, for a utility scale RFP, that number will not include a carbon price.

Jeffrey Grubb (GPC): [08:14:37] We haven't traditionally. I'll let Mr. Mallard speak to what we might do going forward. I know on some other solicitations the capacity RFP, we look at a range. And so it's just going to depend on how that develops over time. Right now we have not. We've looked at just that non-carbon case.

Katie Ottenweller (GSEIA-SEA-VS): [08:14:53] The MG0.

Jeffrey Grubb (GPC): [08:14:54] That's right.

Jeffrey Weathers (GPC): [08:14:55] And there's two ways to look at. You can look at a range of avoided costs in your evaluation process or you can look at a range of scenarios, including the avoided costs when you determine how much you are going to procure. So the latter is what we've done. We've done the avoided cost analysis on the front end across a range of scenarios because again, we're looking at procurements for projects that will be 30 years. And so we want to consider potential carbon impacts in that and that sets the amount. And then we do the evaluation. We can continue using the renewable cost benefit framework that has a single set of avoided costs. That's why Mr. Mallard described it's not appropriate to consider that MG0 as the only determinant, or is a price ceiling, because you've considered a more robust range when you selected the renewable procurement amount.

Katie Ottenweller (GSEIA-SEA-VS): [08:15:56] Okay. My next question is about the scenarios that were modeled in the IRP mix study. And those scenarios are listed in the IRP mix study at page 18, if that's helpful. So Georgia Power modelled 11 scenarios for this study, right?

Jeffrey Weathers (GPC): [08:16:15] Yes, that's correct.

Katie Ottenweller (GSEIA-SEA-VS): [08:16:17] I realize that the costs themselves are trade secret, and so I don't want to stray into that. But are you able to say without revealing trade secret information, which scenario was the lowest system cost?

Jeffrey Grubb (GPC): [08:16:32] So which I'm sorry, which are which study were you referring to in looking at the economics?

Katie Ottenweller (GSEIA-SEA-VS): [08:16:37] It's the IRP mix study and the numbers themselves are in trade secret capacity expansion plan spreadsheet.

Jeffrey Weathers (GPC): [08:16:49] I don't have that in mind. I'm guessing it would be the low gas, zero dollar carbon. That's typically the lowest cost. When gas prices are low and when there's no carbon prices.

Katie Ottenweller (GSEIA-SEA-VS): [08:17:02] If I showed it to you that...

Jeffrey Grubb (GPC): [08:17:06] Yeah. Which particular part of the filing? There's, it's in a few places.

Katie Ottenweller (GSEIA-SEA-VS): [08:17:09] Yeah. No it's. [You may approach.] Thank you. Sorry about that, Madam Chair. So are you able to say which scenario was the lowest system cost?

Jeffrey Weathers (GPC): [08:18:18] Yes. It was the low load scenario. [Okay.] If I could explain what that one is. [That'd be great. That's my next question.]

Jeffrey Weathers (GPC): [08:18:27] That's the one, of the 11 scenarios, where we looked at increasing levels of electrification and increasing customer and end use efficiency and resources behind the meter resources for customers. So what effectively what that meant is there is less load for Georgia Power to serve from Georgia Power's resources. So that's why in terms of system production cost, is a lower amount.

Katie Ottenweller (GSEIA-SEA-VS): [08:19:00] I want to turn now to monthly netting, and I'm going to try to avoid handing out exhibits. So I think we could do this without it. But there, I think this question is for you, Mr. Mallard. But do you recall a data response that was asking you about the Cogen Act? [Yes.] Would it be helpful to have a copy of that, to refresh your recollection? [Sure. That probably would be best.] May I approach? [You may approach.]

Katie Ottenweller (GSEIA-SEA-VS): [08:20:06] Does Georgia Power Company count the 5,000 customer monthly netting pilot towards the 0.2% cap in the Cogeneration of Distributed Generation Act of 2001?

Wilson Mallard (GPC): [08:20:20] No, we don't. And as is referenced in this response, we really are only counting behind the meter RNR customers that are outside of the of the monthly netting pilot program approved by the PSC in the 2019 IRP.

Katie Ottenweller (GSEIA-SEA-VS): [08:20:35] Okay. And are there any other programs besides instantaneous netting that you'll count towards the 0.2% cap?

Wilson Mallard (GPC): [08:20:43] No, there's energy offset customers. Some customers choose to install that don't meet the, either the size requirements or don't choose to participate. Additionally, there are some that are so large that they're qualifying facilities, so we actually have some rooftop solar qualifying facilities on top of some large rooftops. But the RNR instantaneous netting is the only one that that we count towards as our as our compliance vehicle for the Cogen Act.

Katie Ottenweller (GSEIA-SEA-VS): [08:21:08] Okay. Thank you. Do you know what the average annual kilowatt hour usage is for residential customers of Georgia Power?

Wilson Mallard (GPC): [08:21:16] I don't know the average. I know we typically say 1000 kilowatt hours a month, but I think the average is probably a little more than that.

Katie Ottenweller (GSEIA-SEA-VS): [08:21:24] OK. So subject to check around 1,000 kilowatt hours. May I approach? [Yes, you may approach] I have a hand out exhibit that I have pre-marked as GSEIA-SEA-Vote Solar Exhibit one.

Katie Ottenweller (GSEIA-SEA-VS): [08:22:06] Now this is a data response that Georgia Power filed concerning customers on the RNR pilot program, correct? [Yes.] And I specifically want to look at the number that's at the bottom of the second page.

Wilson Mallard (GPC): [08:22:24] Well, just to clarify. It's generally about RNR and not specifically about monthly netting.

Katie Ottenweller (GSEIA-SEA-VS): [08:22:29] Okay. So that was one of my first questions is whether this was RNR generally, including instantaneous netting program. Okay. Thank you for that. So customers on the RNR tariff have used on average 1,100 to 1,900 kilowatt hours a month over the last several years. Right?

Wilson Mallard (GPC): [08:22:57] Are we looking at the table under D on page two?

Katie Ottenweller (GSEIA-SEA-VS): [08:23:01] Yes. [Yes.] The numbers at the bottom. [Yes.] And we talked about how the average residential customer uses around 1,000 kilowatt hours. So, the numbers here, is that how much energy they consumed after they installed solar?

Wilson Mallard (GPC): [08:23:19] Yes, these numbers are going to be net of the solar that's consumed behind the meter. We just don't have a way to track that. So really what we see is what's metered, which is the customers usage net of the solar consumed on site.

Katie Ottenweller (GSEIA-SEA-VS): [08:23:30] So these customers with rooftop solar are still using more electricity on average after going solar than the average residential customer is in Georgia.

Wilson Mallard (GPC): [08:23:42] Yes. And so that would stand to reason. A lot of customers that are most interested in rooftop solar customers with large houses, relatively large monthly electric bills, relatively large rooftops where they can fit a significant amount of solar. So, yes, that stands to reason.

Katie Ottenweller (GSEIA-SEA-VS): [08:24:00] And I know you mentioned to Ms. Kysor that you haven't conducted a cost of service study specifically on solar customers. So is there a chance that these customers who are installing rooftop solar are cheaper to serve than the average residential customer?

Wilson Mallard (GPC): [08:24:20] There's a chance, but I don't think that's going to be the case. Introducing intermittent solar behind the meter is going to absolutely add volatility to the customer's load shape. It's going to reduce their overall load factor. And so that makes them more expensive to serve. We end up with a higher peak demand.

Solar does almost nothing to reduce total net demand on a customer's premise, but then we have a lot less kilowatt hours to recover cost from. So my hypothesis would be, generally speaking, customers with behind the meter rooftop solar are generally more expensive to serve than other similarly sized customers.

Katie Ottenweller (GSEIA-SEA-VS): [08:25:03] And you mentioned earlier that you had looked at some studies and analyses that have been done in other places. Are you familiar with a study by Duke Energy that demonstrated the solar customers are in fact, cheaper to serve than similarly situated residential customers?

Wilson Mallard (GPC): [08:25:19] I'm not familiar with that study.

Katie Ottenweller (GSEIA-SEA-VS): [08:25:20] Thank you. So and just so you know where I'm going with this, because I didn't raise it initially. So your testimony on page 49, you identified four concerns with the monthly netting pilot, right? So one of them was cost shifting, which we just touched on. The second concern was an increase in unplanned variable energy resources.

Wilson Mallard (GPC): [08:25:47] Right.

Katie Ottenweller (GSEIA-SEA-VS): [08:25:48] So Georgia Power has about 2.6 million customers, right?

Wilson Mallard (GPC): [08:25:54] That sounds right.

Katie Ottenweller (GSEIA-SEA-VS): [08:25:56] And about 3,400 of those are on the RNR tariff.

Wilson Mallard (GPC): [08:26:02] Yes.

Katie Ottenweller (GSEIA-SEA-VS): [08:26:02] Subject to check. That's about 0.13% of your customer base?

Wilson Mallard (GPC): [08:26:08] Subject to check. I can't do that math in my head.

Katie Ottenweller (GSEIA-SEA-VS): [08:26:11] OK. I couldn't either. So in your testimony, you say this is unplanned, but Georgia Power does estimate behind the meter solar adoption in its load forecast, right? [We do.] And qualifying facilities are variable, too. Right? And generally larger in size than rooftop solar customers. [That's right.] You would also call those unplanned? [That's right.] Would Georgia Power have the same concern with respect to electric vehicles?

Wilson Mallard (GPC): [08:26:44] So electric vehicles is a little bit different. We're talking the difference between load that Georgia Power is obligated by statute and moral obligation to serve and distributed generation which can be valuable to the system. But absent being part of one of our IRP approved programs really is generation that Georgia Power makes sure that we have fair programs that we compensate them accurately, that we maintain the reliability and the safety of the System while we comply with PURPA, with the Cogen Act, and with other requirements for us to purchase this energy from these generators.

Katie Ottenweller (GSEIA-SEA-VS): [08:27:23] So the third concern you identified was that infiltration of solar marketers misinforming customers. [That's right.] What does the company do with a complaint that they receive from a customer with respect to misinformation?

Wilson Mallard (GPC): [08:27:41] Well, at the very highest level, we try to solve it. And we have absolutely been been inundated. One of the things that's been challenging with the monthly netting rollout is just the high volume of applications and then the high volume of players that are new to our market, that don't understand the rules of our programs, don't understand Georgia Power's programs and processes. And so we've been doing a whole lot of education in helping these new participants in the marketplace. Ultimately, commissioners, and I know you are aware of some of these complaints from customers as well, satisfying our customers is our number one objective. And so we do everything we can to help our customers get the best outcome that they can. But a lot of times we find that they've been they've been talked into a deal that is just not the way that the program works. The paybacks they've been promised are never going to be realized. And so we do everything we can to help them maximize their investment, get on the program that makes the most sense for them. And then for some of these more egregious cases, we have actually referred the the offending party to the state attorney general's office for investigation.

Katie Ottenweller (GSEIA-SEA-VS): [08:28:51] Okay. Do you also inform the commission of this? Oh, sorry. [Go ahead. It's a fine question. Go ahead.] I was also, in addition to contacting the AG, do you also inform the Commission about instances?

Wilson Mallard (GPC): [08:29:03] I would say any that arise to that level, we do. We generally work pretty closely with staff and commissioners on some of these complaints. I can't say that they're aware of every complaint that we get and every issue that we try to resolve.

Tricia Pridemore (PSC): [08:29:18] Has the company sent a cease and desist letter to the solar companies out there that are using your likeness, logo and name to market their products?

Jeffrey Grubb (GPC): [08:29:26] We have sent several of those. I don't know how many exactly. And I'm also not sure of the effectiveness of those. But, yes, we've we've sent several cease and desist letters.

Tricia Pridemore (PSC): [08:29:38] Thank you. I'd like a data request. I like those. Thank you.

Katie Ottenweller (GSEIA-SEA-VS): [08:29:42] Can I have that too? Are you aware of consumer protection bills that have been filed at the Georgia legislature?

Wilson Mallard (GPC): [08:29:53] Generally, but not the specifics.

Katie Ottenweller (GSEIA-SEA-VS): [08:29:56] Okay. So has Georgia Power taken a position on any of those bills?

Wilson Mallard (GPC): [08:29:59] No. And I'm only generally aware as I understand them, they would require Georgia Power and or the commission staff to provide some education and support for behind the meter solar in these solar installers. But I'm just not familiar with the details.

Tricia Pridemore (PSC): [08:30:15] They also include the EMCs as well as the municipalities.

Katie Ottenweller (GSEIA-SEA-VS): [08:30:21] But is it your position that the Commission has some discretion to implement consumer protections as part of any program that they might approve?

Wilson Mallard (GPC): [08:30:34] Yes.

Katie Ottenweller (GSEIA-SEA-VS): [08:30:37] Thank you. The fourth concern you cited in your testimony was noncompliance with interconnection rules. Has Georgia Power changed its interconnection requirements since the monthly netting pilot was approved?

Wilson Mallard (GPC): [08:30:50] No. The last change we had was subsequent to the 2019 rate case when Section G was added to the rules and regs, that created some additional requirements. But our RNR program and our other distributed generation programs have their own set of interconnection requirements that are part and parcel of the agreement that the customer signed. So what happens is, for the most part, the customers don't fill out these agreements. They're filled out by the installer. And again, probably owing to the newness of a lot of these outfits to our state and to our processes, we really have seen a lot of mistakes made, a lot of corners cut, both on the the application itself and then the actual installation of the system and how it's interconnected to the customer and into the grid.

Katie Ottenweller (GSEIA-SEA-VS): [08:31:37] Okay. Do you know how long it takes Georgia Power to process an interconnection application so a solar system can be connected to the grid?

Wilson Mallard (GPC): [08:31:46] I don't know exactly. I can tell you that we've been working really hard to get our backlog taken care of, is the monthly netting pilot cost our average monthly interconnection request to go from 30 to 50 a month range to 600 and 800 a month. So we've been playing catch up for a while. I'm really happy to say we processed over 550 just in February alone, so we've made a lot of improvements there and how we can process those and move those along as quickly as possible. But I don't have off the top of my head an average an average amount of time it takes.

Michael Robinson (GPC): [08:32:24] For transmission interconnected to follow the LGIP process, it's 36 to 48 months, from application to COD.

Katie Ottenweller (GSEIA-SEA-VS): [08:32:33] For the smaller scale residential-commercial, could I do a hearing request on that to find out?

Wilson Mallard (GPC): [08:32:42] So say the, say your actual question.

Katie Ottenweller (GSEIA-SEA-VS): [08:32:45] Sure. How long it's taken Georgia Power to process interconnection applications for solar systems that are in the queue for RNR? Thank you. [Yes.]

Katie Ottenweller (GSEIA-SEA-VS): [08:32:58] Just a few more questions for me. In the IRP filing, it talks about how the company is planning to introduce in the rate case a new requirement for all customers installing solar behind the meter to pay a set application fee based on the system size. Do you recall that?

Wilson Mallard (GPC): [08:33:16] Yes, that's in the plans.

Tricia Pridemore (PSC): [08:33:19] Do you, have you determined yet how much that fee will be?

Wilson Mallard (GPC): [08:33:24] We haven't. We're evaluating that and evaluating what those costs look like based on the higher volume that we're seeing these days, which is adding costs, but actually we're gaining efficiencies in how we process those. And so still still doing that analysis.

Katie Ottenweller (GSEIA-SEA-VS): [08:33:39] Okay. And can you talk about what the justification for that application fee based on system sizes?

Wilson Mallard (GPC): [08:33:44] Yeah, it would really just be the general cost causation. We want to make sure that we're recovering costs from those that are causing them, the time and effort that it takes to process the applications, and then also for our billing department, for our metering departments, for all of those folks that work on those projects. And so the cost would really be based on the actual cost that the company realizes to process the applications.

Katie Ottenweller (GSEIA-SEA-VS): [08:34:10] Okay. I want to hand out what I've pre marked as exhibit two of GSEIA-SEA-Vote Solar. If I may approach. [you may approach. We're after 6:00. Thank you to the faithful.]

Tricia Pridemore (PSC): [08:34:52] So this is a survey that Georgia Power included in data response STF-DEA-2-2 attachment A and I want to refer you to page 12. These numbers are a little bit hard to read.

Wilson Mallard (GPC): [08:35:16] I don't see page numbers. Can you tell me what the title is?

Katie Ottenweller (GSEIA-SEA-VS): [08:35:20] Starts with, "Most would prefer to work with pay utility..." So this survey was conducted in November 2021 titled "Marketing research, solar behind the leader." Correct? [Correct.] And as part of the questions about rooftop solar and community solar, Georgia Power asked customers whether they would prefer to work with or pay their utility to install and maintain a solar system or work with pay a solar installer. Correct? [Correct.] And this shows 82% would prefer to work with or pay a utility, 18% work with or pay a solar installer. Right? [I see that.] And then on the next page, it talks about how more specifically customers were asked whether they'd be interested in allowing the utility to lease rooftop space to install a solar system? [Yes.] Does Georgia Power have a plan to offer rooftop solar products in competition with solar installers?

Wilson Mallard (GPC): [08:36:31] No, not at this time. But we're, as part of what we kind of continuously do, commissioners, which is to evaluate the marketplace, evaluate customer needs, look at our program offerings. This research right here is part and parcel to that. By polling these customers, by asking them what their wants and needs are, it does help inform us and help us come up with future programs and potential designs.

Katie Ottenweller (GSEIA-SEA-VS): [08:36:58] Four questions left for me. So one product that Georgia Power does offer today is the community solar subscription program, right? [Yes.] And when a customer signs up for that program, they get a credit based on the electricity that's generated from their block of capacity. [Correct.] Does Georgia Power net that solar generation against the subscribing customer's consumption on a 1 to 1 basis?

Wilson Mallard (GPC): [08:37:19] Yes.

Katie Ottenweller (GSEIA-SEA-VS): [08:37:23] And then my last question. There was some talk earlier about net metering, Florida legislation. Are you familiar with the legislation passed? [Generally.] So do you know if the bill that was passed, you're aware it creates a policy over the next six years known as the glide path?

Wilson Mallard (GPC): [08:37:45] Yes. Step down. Yes.

Katie Ottenweller (GSEIA-SEA-VS): [08:37:47] Do you know if that glide path is more or less generous than Georgia Power's monthly netting pilot program?

Wilson Mallard (GPC): [08:37:56] More or less generous...?

Katie Ottenweller (GSEIA-SEA-VS): [08:37:57] In terms of compensation for rooftop solar customers?

Wilson Mallard (GPC): [08:38:01] Well, so I'm assuming that they're starting at retail compensation now and the glide path is going to glide them down to a compensation rate that's going to be less than that. I think the exact details of that are still, assuming the bill gets signed, are going to be in the hands of the Florida PSC to develop the actual details there. But the compensation is going to go from retail credit, which is what they have now, which is what monthly netting offers down to something less than that. And I can only assume it's going to be something based on an avoided cost methodology similar to what we use in Georgia.

Katie Ottenweller (GSEIA-SEA-VS): [08:38:38] So right now in Georgia, under monthly netting pilot, it's, that policy is not what we would call annual netting, right? It's monthly netting. [That's right.] And you're aware Florida currently today has annual retail net metering?

Wilson Mallard (GPC): [08:38:54] So they'll bank all those kilowatt hours for the entire year. And so you can roll them from month to month. Yes.

Katie Ottenweller (GSEIA-SEA-VS): [08:38:59] And you're aware that the legislation, if passed, would move that down to monthly netting between now and 2028?

Wilson Mallard (GPC): [08:39:07] I'm not familiar, but subject to subject to check. Yes.

Katie Ottenweller (GSEIA-SEA-VS): [08:39:12] Okay. And that the export rate would actually be higher than avoided cost? It would be a percentage of the retail rate from 75% down to 50%.

Wilson Mallard (GPC): [08:39:19] So and that's just part of the glide path until the PSC can come up with a new valuation. I think all that makes sense to me, Commissioners. What I would comment there is they're they're doing the best they can to unwind the policy that has created a huge subsidy. They've got a lot of customers who have made their solar decision based on expected paybacks, based on retail compensation. And they're doing the best they can to glide them down so that the economic impact of those customers is not as significant. That's something that I hope we can avoid here in Georgia and avoid creating a program and a policy that eventually one day puts us in the same place as a state like Florida, where we're really trying hard to unwind the policy to bring it back and compensate that solar energy at the more appropriate price.

Katie Ottenweller (GSEIA-SEA-VS): [08:40:07] But would you agree that between now and 2029, those customers will actually have a more beneficial policy than is offered in the Georgia Power Monthly Netting program?

Wilson Mallard (GPC): [08:40:17] I can't say that for sure. I can't tell you that I don't think that the monthly rollover accounts for very much. If we think about 100% of the output of solar over the course of a year, I can't imagine that the monthly rollover amount is more than than 5% or so of those total kilowatt hours. You're really talking about energy that's produced in addition to more energy that's produced than the home or business uses in the course of a month. And so that part being compensated at a higher rate, I'm not sure if that offsets the glide path pricing that they propose. So I can't say for sure what that studying.

Katie Ottenweller (GSEIA-SEA-VS): [08:40:53] Okay. No further questions for me. I'll hand it over to Scott Thommason. Thank you.

Tricia Pridemore (PSC): [08:41:05] Hello, Mr. Thommason.

Scott Thommason (GSEIA-SEA-VS): [08:41:08] Madam Chair. Gentlemen, good evening. I appreciate your endurance. The good news is I had a lot to cover, but I have been crossing off questions as they were asked, as instructed. And my bingo card is getting pretty full, so a lot less than I originally did. But just as Mr. Carver covered the utility scale procurement. I'm going to start by covering the DDG side of the procurement, some of the improvements that y'all are proposing. But first, I want to make some clarifications about the leftover capacity from the 2019 IRP DG programs. So is it accurate that of the 210 megawatts planned and approved in the 2019 IRP, that not all those 210 megawatts have been procured since...? [Yes. That's accurate.] And do you have a rough number for how much has been procured?

Wilson Mallard (GPC): [08:42:08] So I can tell you the amount procured in the Customer Connected program, which is one megawatt out of the 25 megawatt target. I can give you a rough number on the REDI 2, which is seven projects and in the neighborhood of 14 megawatts or so. What I can't talk about or the results of the ongoing DG RFP, which is on the home stretch but not finished yet, all that information is confidential and protected as part of the RFP.

Scott Thommason (GSEIA-SEA-VS): [08:42:35] But so far, that hasn't been brought to the Commission for Certification. [That's correct.] The total number would be well below 50% of of what's been brought.

Wilson Mallard (GPC): [08:42:46] I just can't comment on the results of that RFP.

Scott Thommason (GSEIA-SEA-VS): [08:42:49] No. The number is not as important as the clarification that, in the IRP on [page] 11-72, the company says that that 210 megawatts is part of the supply side plan. But is it your testimony that leftover capacity is not being rolled over into the proposed 200 megawatts that's part of the new proposals in this IRP. Those are separate, right?

Wilson Mallard (GPC): [08:43:23] So leftover capacity has not yet been proposed to be rolled over. I believe there's language in the order approving the DG RFP that does call for the capacity to be rolled over. But I think the commission would need to act on that and approve the exact form that that would take.

Scott Thommason (GSEIA-SEA-VS): [08:43:39] But the 200 megawatts that you proposed is independent of that? [That's correct.] And just to clarify, while we're talking on the numbers, how does the company determine that allocation of how much is going to be planned for distributed generation as part of the overall performance? So that 200 number out of 2,300?

Wilson Mallard (GPC): [08:44:00] Yeah, it's based on our experience with the prior DG solicitations, based on the amount of interest that we've gotten, based on this commission's longstanding support of distributed generation and the company's recognition of the value that these distributed generation resources bring to the System. And so as we think about the improvements that we're planning to make, hosting capacity probably being the most impactful, that will help these projects locate in areas to minimize their interconnection costs. We're confident looking at the sort of the landscape of bids that we've received in distributed generation solicitations over the last few years, that 200 megawatts is an amount that the market can compete and can produce that amount of resources for the company to procure.

Scott Thommason (GSEIA-SEA-VS): [08:44:50] Did the company consider levels of allocations [of distributed generation i.e. rooftop solar] other than 200, higher or lower than 200 megawatts? And why were those not selected?

Wilson Mallard (GPC): [08:44:58] Yeah, again, it's based on our judgment, our experience, our look at the response to our prior RFP, what the pricing looked like, what the reasons were that projects didn't go forward, our interpretation of the impact that our proposed improvements are going to make. And so it's for all those reasons, we synthesized all that data and determine that 200 megawatts was a reasonable amount and in customers best interest.

Scott Thommason (GSEIA-SEA-VS): [08:45:23] And when I asked earlier, you mentioned the customer-sited programs, the REDI 2 the Customer Connected solar program. [Yes.] The company is not proposing any additional customer-sited capacity in this procurement beyond those two programs?

Wilson Mallard (GPC): [08:45:40] That's right. That's correct. The customer connected program was recently extended by commission action. As I mentioned, 25 megawatts allocated. We just have one customer signed up right now. But and I think we answered this in the DR, we really do have lots of customers that are interested. And what we've learned through through recruiting these customers to participate is a lot of them have a really long timelines to make decisions like this, it's got to go through lots of different approval processes internally. And so what we determined made the most sense for customers is to leave the customer connected program open to maintain the ability for these customers to continue to apply. I think we've got close to 20 customers who have indicated pretty strong interest at this point. So we don't need to add any additional capacity there. We just are proposing to continue the customer connected program with the expectation that some of these customers who have expressed interest will sign up to participate soon.

Scott Thommason (GSEIA-SEA-VS): [08:46:36] And for those reasons, is it also your testimony that the company is not proposing to roll that 25 megawatts into anything else because you want to keep it.

Wilson Mallard (GPC): [08:46:48] That 25 megawatts will remain with the customer connected program. Is that also true for the REDI 2 capacity that's there?

Wilson Mallard (GPC): [08:46:56] REDI 2 capacity is not going to remain available. And I apologize, but I cannot remember what the language is in the order as it relates to rolling the capacity forward. Obviously, it's always commission decision as to what the dispensation is of unused megawatts would be. And so I think that would be a commission decision when the time came.

Scott Thommason (GSEIA-SEA-VS): [08:47:18] And just generally on that last point, I mean, it's still the company's position that the size of that allocation within the overall procurement and the overall size of the procurement are a policy decision for the Commission to make. [Absolutely.] I want to talk about the feedback that you received and the improvements that you're proposing for the procurement process. On page 35 of your testimony on line 11. You mentioned that the company has considered feedback from market participants. How does the company receive this feedback? Did you solicit from market participants or is it part of the RFP process? What channels?

Wilson Mallard (GPC): [08:48:03] Yeah, definitely it's part of the RFP process and we receive lots of feedback through the independent monitor's website. Additionally, we've received feedback through the Public Service Commission staff and the commission directly from the participants in the market. And so that feedback is really important to Georgia Power. We designed lots of elements of this program to procure resources that provided the most value for our customers. But along the way, we identify elements of the procurement processes that can be improved. And so that's exactly the case this time, that feedback from the market participants is invaluable. We've taken that into consideration and are planning some improvements to our processes going forward.

Scott Thommason (GSEIA-SEA-VS): [08:48:49] Could you summarize or mention any highlights that you may remember from the bidder comments specifically in some of the RFP feedback? [Yeah.] About maybe why those procurements were not.

Wilson Mallard (GPC): [08:49:05] Yeah. And and I'm not comfortable speaking about that in detail. That is still an ongoing RFP. The details and the information about that RFP is still protected information and governed by our standards of conduct and communication. I can summarize at a high level that bidders, the process as we designed it, allowed for bidders to bid and also have an interconnection cost assumption that would modify their pricing and added some complexity. Additionally, the actual costs and requirements to interconnect proved problematic for a lot of these projects to move forward. So it's taking into account the process, the feedback on how that went and how we could make that a more efficient process for bidders going forward. That really is the basis for for the improvements that we're considering.

Scott Thommason (GSEIA-SEA-VS): [08:49:57] So interconnection was a major theme of those those comments. Were there other themes? Timing or design of the program or allowance of third party ownership?

Wilson Mallard (GPC): [08:50:10] Yeah, I'm not I'm just not willing to comment on details of the DG RFP.

Steve Hewitson (GPC): [08:50:15] Understood. Okay. So let's talk about the improvements that we're proposing from that feedback. Since interconnection was a theme, without getting into the details of the comments, what's the company proposing as an improvement with regard to interconnection for DG?

Wilson Mallard (GPC): [08:50:36] Well, I would say first and foremost and again, I'll only be able to speak about these at a high level as well, Commissioner. The ongoing RFP is not over. We haven't formalized and synthesised all those comments. We don't have all of the proposals finalized as to what we might do, but we're certainly considering a few things. I would sum it up as this: We want the process to be more efficient for these bidders. We want bidders to, we really want to follow the utility scale procurement process a little bit more. We're going to receive the bids. We're going to evaluate them based on the value that they provide to customers based on their pricing and output. And then we're going to we're going to chronologically go down evaluating the interconnection costs for each of those bids and then selecting bids that provide the most value for customers. The primary improvement is going to be an enhancement to our interconnection guidance process. So we already offer interconnection guidance to these bidders that's available so they can understand the cost to interconnect. But the hosting capacity map is the primary improvement that is going to make the process more efficient. It's going to allow these bidders to select sites that minimize interconnection costs. And we're hopeful it's going to produce a much more efficient and successful RFP.

Scott Thommason (GSEIA-SEA-VS): [08:51:57] And with regard to the hosting capacity mapping, what criteria is the company going to use to determine where the interconnection is more favorable and that mapping?

Michael Robinson (GPC): [08:52:08] So the company is currently discussing with a consultant building the models necessary for all 2,356 feeders that we have throughout the state, using a tool called CYMDIST, which is an Eaton product that has an EPRI 2.0 DRIVE process, ICA capability as far as looking at hosting capacity availability. So those, there'll be a rollout over several years of because 2,300 feeders is a lot of feeders to build models and we've got to staff up for that. But those are the primary tools that we'll be using is the CYMDIST software and the modules available, particularly the EPRI DRIVE 2.0 module.

Scott Thommason (GSEIA-SEA-VS): [08:52:59] So, what's the information that's going to be provided from from that software? I mean, what kind of details is a developer going to see when they go into this online?

Michael Robinson (GPC): [08:53:11] So it's still under development, but what we envision is a GIS based model that would give kind of a red light, green light, maybe yellow light based on feeder location throughout the state, the available capacity that we calculate using this process that we're developing currently.

Scott Thommason (GSEIA-SEA-VS): [08:53:31] And let's assume that we're sort of a red light, green light process. Are those going to be indicative of expected, interconnection costs, or is that purely just a reflection of congestion?

Michael Robinson (GPC): [08:53:46] It will really be more indicative of the amount of capacity that's available on the feeder. We will still need to follow our interconnection process, looking at interconnection cost and ensuring safe, reliable interconnection of those facilities in the future.

Scott Thommason (GSEIA-SEA-VS): [08:54:03] Is the company considering offering any additional information about interconnection costs, such as standardized costs for equipment and components that go into an interconnection study and interconnection costs?

Wilson Mallard (GPC): [08:54:18] So what we are offering is a year round interconnection guidance process. And there's three different levels, commissioners, and they each have a fee associated with them, $1,300 for the basics, $3,500 for the

the mid level, $9,500 that really tells you all the information down to the feeder level that you need to interconnect your facility. That enhanced guidance is being used right now by bidders to evaluate potential future sites. We're optimistic that by using that additional enhanced interconnection guidance, plus the hosting capacity map, is going to allow these bidders to find sites that really do minimize the interconnection cost of the System.

Scott Thommason (GSEIA-SEA-VS): [08:54:59] Does the information that you're describing include, for example, standardized costs or estimates of particular physical components of interconnection that that developer might roughly estimate their own projects?

Wilson Mallard (GPC): [08:55:17] Yeah, I think at the high level, I don't know about standardized costs. Each interconnection is different. But I think at the enhanced level of interconnection guidance provides us a pretty good level of details that can help a bidder understand exactly what those interconnection costs are going to be.

Scott Thommason (GSEIA-SEA-VS): [08:55:33] Does the company provide that information to staff as well for review?

Wilson Mallard (GPC): [08:55:37] Yes. If staff asks for it for review, absolutely.

Scott Thommason (GSEIA-SEA-VS): [08:55:46] Has the company received feedback, whether it is in the RFP process or not, from bidders asking to be able to review interconnection studies and the particulars of interconnection studies when those bidders did not exit?

Wilson Mallard (GPC): [08:56:02] Again, I'm just not going to be able to talk about specifics of the ongoing DG RFP.

Scott Thommason (GSEIA-SEA-VS): [08:56:08] Going forward, for future procurements, would the Company be willing to work with local installers and other stakeholders to talk about access to that kind of information or giving that information to staff?

Wilson Mallard (GPC): [08:56:22] We're absolutely willing to talk with them and work with them. And I personally have talked with and worked with more than I can count over the last six months or so.

Scott Thommason (GSEIA-SEA-VS): [08:56:32] That's fair. Does the company provide any detailed breakouts and interconnection costs, whether they're specifically studies or sort of illustrative interconnection costs, to staff that it doesn't provide to installers?

Wilson Mallard (GPC): [08:56:55] So staff is part and parcel of the development of our distributed generation RFP along with the independent evaluator and independent monitor. And so they're, they work closely with the company as we developed the overall parameters of the RFP and certainly the interconnection processes. So staff has got full insight into how the RFP is developed and what that information looks like in what's provided.

Michael Robinson (GPC): [08:57:22] I also believe there was a data request to provide some of that information as well.

Scott Thommason (GSEIA-SEA-VS): [08:57:28] Does staff also play a role along with the company and the independent evaluator in resolving some of those comments that come up during the RFP process?

Wilson Mallard (GPC): [08:57:37] Oh yes, it's a collaborative process. The comments that are received through the RFP process first come to the company, then feedback from staff, ultimately, the IE or IM evaluates them as well. And then once there's a consensus on the response, the responses are posted through the IE website.

Tricia Pridemore (PSC): [08:57:56] Mr. Thommason, how many more questions do you have?

Scott Thommason (GSEIA-SEA-VS): [08:58:01] I would say I've probably got 10 to 15 more minutes.

Tricia Pridemore (PSC): [08:58:04] 10 to 15 more minutes. Okay. So for the purposes of housekeeping, it is coming up on 6:30. We have present...let's see one...Mr. Carver still here? [Yes.] OK. Two. Mr. Jones. Is he still here? Three. Sierra Club. Are they still here? Four. I'm sorry. Mr. Steven Jones? Yes. I saw him leave. OK, Sierra Club still here. SACE and the All American ABCs of...they're still here. And Mr. Mahan, are you still here? [Yes, ma'am, I'm still here.] Okay. At 8:00, the AC. in this building goes away, and there's nothing that we can do about it. We have tried.

Jason Shaw (GPC): [08:58:56] We can leave.

Tricia Pridemore (PSC): [08:59:00] I like the way that Commissioner Shaw thinks. However, with this number of interveners, we still have to get through this and allow Georgia Power to do redirect if they have any. So let me ask you. If you've answered it. I appreciate the sounds of your voices. Be brief. Just answer the question. We don't need the background on every question. And then if you and all of the other questioners and attorneys would just pick up the pace a little bit, let's act like we've had some caffeine. And if you need some, we'll send someone out to get us some. But it's about ready to get hot in here, so let's just pick up the pace. Thank you, Mr. Thomasson.

Scott Thommason (GSEIA-SEA-VS): [08:59:38] I will wrap up that line of questioning with just, general thing that I think you got at before. But the company is still willing to talk about other improvements to the DG procurement process in addition to just the locational valuations. [Yes.] There were a lot of questions about best cost procurement and how that, I don't want to go back over any of that. But along with this theme, is the company going to offer additional guidance and information in future procurements about how best cost is going to be applied?

Wilson Mallard (GPC): [09:00:15] Sure. Sure. Well, as we roll out the RFP, the evaluation methodologies will be made available. And so all that information will be proposed in the RFP and PPA documents as the RFP is developed.

Scott Thommason (GSEIA-SEA-VS): [09:00:27] And so that will also include how best cost might relate to RCB evaluations as part of procurement and maybe REC treatment?

Wilson Mallard (GPC): [09:00:37] The RECs are assumed to be conveyed to the company on behalf of all customers.

Scott Thommason (GSEIA-SEA-VS): [09:00:46] Let's just skip through a lot. I only have a couple of questions. Didn't get to a community solar. Does the Company have data on how many customers have left the community solar program?

Wilson Mallard (GPC): [09:01:01] I'm sure we do. There's a fairly significant amount of churn. I don't have that information available.

Scott Thommason (GSEIA-SEA-VS): [09:01:06] Has there been any effort to understand what drives the churn or why customers are leaving?

Wilson Mallard (GPC): [09:01:13] Oh yeah. We absolutely study that and understand from customers what their motivations are. I'll be honest, I think the primary driver is customers who are moving locations, have community solar, move locations, file their account, and don't restart at their new location.

Scott Thommason (GSEIA-SEA-VS): [09:01:29] And you mentioned, with the exception of the income qualified scenario, that the customers retire the RECs that they, as part of the community solar.

Wilson Mallard (GPC): [09:01:43] RECs are retired on the customer's behalf.

Scott Thommason (GSEIA-SEA-VS): [09:01:44] Is there a value associated with those RECs in the price that customers pay for that?

Wilson Mallard (GPC): [09:01:49] So there's not. We don't assume a value for RECs that are bundled with energy that the company generates or purchases.

Scott Thommason (GSEIA-SEA-VS): [09:01:58] And a clarification from some of the questions earlier. Has the company evaluated whether benefits accrue to all customers from the Community Solar Program as a whole?

Wilson Mallard (GPC): [09:02:10] Yeah, yes. I would say when the Commission approved the development of the community solar facilities that were built below, the company's projected avoided cost at the time, they were in effect, making the decision that those resources do benefit all Georgia Power customers.

Scott Thommason (GSEIA-SEA-VS): [09:02:29] How does the customer, how does the company recover costs for solar capacity that's not fully subscribed as part of that program?

Wilson Mallard (GPC): [09:02:35] So the cost of the community solar facilities are recovered through base rates.

Scott Thommason (GSEIA-SEA-VS): [09:02:41] And does the company follows the normal IRP or, sorry, the RFP process for other procurements in choosing developers for the community solar projects?

Wilson Mallard (GPC): [09:02:54] So those were all done a few years back. I don't know that we had an established process. Going forward, if we were going to develop more self build community solar facilities, we would certainly envision a competitive RFP for the EPC. I think there was a competitive RFP, but I just can't say for sure.

Scott Thommason (GSEIA-SEA-VS): [09:03:13] But a strong presumption that it would be competitive going forward. [Yes.] A couple other clarifications on RECs. There were some questions earlier about the revenues coming from from RECs. Do any of those revenues go toward compensating solar developers or PPA counterparties from previous solicitations that may not have received much compensation at the time? I think the question is more cut and dry, as I just said. Any of the revenue from selling off the RECs go to counterparties for their existing solar facilities?.

Wilson Mallard (GPC): [09:04:00] So a couple of things. The company doesn't sell RECs. We'll retire RECs on behalf of participating customers for our programs, but we don't sell RECs. Additionally, we don't purchase RECs other than unbundled RECs for the simple solar program. RECs are all conveyed to the company as part of the agreements and the purchase power agreements. The RECs are assumed to be conveyed to the company along with the energy. That's been true for every procurement all the way back to ASI Prime, I believe, which was approved in the 2013 IRP.

Scott Thommason (GSEIA-SEA-VS): [09:04:34] And Mr. Walsh had asked you some questions about whether the benefits of RECs would be distributed unevenly when the company is retiring RECs for specific customers that were previously allocated to all customers. Do you remember that earlier? [I remember.] Do you recall as part of your answer that you mentioned the customers that are receiving the RECs for retirement could use those RECs for compliance purposes as part of the value for them? [That's right.] Is there a value, is there a negative value for all customers who are having those RECs transferred from them, to not having that compliance value? Or is there a sort of avoided compliance cost that, from customers being able to hedge against, or the company being able to hedge on behalf of customers?

Wilson Mallard (GPC): [09:05:29] So I don't think so. There's no compliance value today. And we also anticipate, including language in these agreements, that would make it clear that should the company need any of these RECs for any sort of compliance with federal, state or other sort of carbon or renewable requirement, that we could we could reclaim those RECs. There'll be a clause in the contract that will make sure that customers are protected, should those RECs be needed for any future compliance case.

Scott Thommason (GSEIA-SEA-VS): [09:05:59] Is it accurate that the company tracks RECs associated with simple solar program through the North American Renewables Registry (NARR)? [Yes.] Does the company keep a REC inventory through that NARR for its other programs?

Wilson Mallard (GPC): [09:06:16] No, only the only the unbundled RECs purchased for simple solar to supply that program or tracked through NARR. RECs that we receive that are bundled with renewable energy through purchase power agreements or self build are just tracked on internal company spreadsheets.

Scott Thommason (GSEIA-SEA-VS): [09:06:31] So is that the reason, because you know the source, that you you can account for it yourself?

Wilson Mallard (GPC): [09:06:36] That's right. We get the meter readings. So that's going right to the source for the amount of renewable generation.

Scott Thommason (GSEIA-SEA-VS): [09:06:42] All right. Just a couple more questions about battery storage. [Sure.] I know there were a lot of questions about the 15% and the 1,000 megawatts and how you reach that. I'm not going to cover that again. But independent of the reasons that you settled on the 15% and the 1,000 megawatts, hypothetically, if a higher level of storage were selected higher than 15% or higher than 1,000 megawatts for the existing capacity, would that make integration costs for solar higher or lower? Independent of what the the ultimate balancing decision is, if it were higher, would integration costs for solar be lower necessarily, or does it depend?

Jeffrey Weathers (GPC): [09:07:35] When you say integration costs for solar? Are you referring to the renewable cost benefit framework or are you referring to actual cost on the System?

Scott Thommason (GSEIA-SEA-VS): [09:07:45] More the latter, but I'll take an answer for either.

Jeffrey Weathers (GPC): [09:07:51] OK. So if it's the latter, and your question is, would additional batteries make it less costly to integrate solar?

Scott Thommason (GSEIA-SEA-VS): [09:08:00] Yeah. And a different way of asking is, how does the level of the optimal battery percentage affect the integration cost?

Jeffrey Weathers (GPC): [09:08:10] Sure. Yeah, I think batteries are, they always provide benefits. They're very flexible. They can provide a range of benefits. The reason why the level of batteries that we chose was consistent with the amount that's needed to mitigate the impacts of solar from the levels we saw in the study to current levels. So if you have additional batteries, you can either further increase intrahour reliability. Or you can use those batteries for other purposes. Either way, there's value there. There's value to have batteries in the system.

Scott Thommason (GSEIA-SEA-VS): [09:08:45] But they may be values that don't necessarily reduce the integration costs for solar...at some point.

Jeffrey Weathers (GPC): [09:08:58] They reduce it. They increase reliability. But it's more than the amount in the study. So we studied the current System reliability as being the target. And so I would imagine that the incremental benefits of each additional battery maybe diminish a little bit versus what we studied.

Scott Thommason (GSEIA-SEA-VS): [09:09:17] And a quick clarification about the comparison of company owned BESS to base load facilities, historically. I think you contrasted sort of economic considerations against reliability. And reliability was the key criteria for wanting to own, control it for reliability purposes, not that control results in better economic outcomes. Is that accurate?

Jeffrey Grubb (GPC): [09:09:53] Just to make sure you're. Yeah, I think I'm with you, but I want to make sure.

Scott Thommason (GSEIA-SEA-VS): [09:10:03] So, the primary concern for the company wanting to own BESS is reliability and control, not comparing the economics to a third party. Or not the best cost or least cost that we talked about earlier.

Jeffrey Grubb (GPC): [09:10:19] So, yes, the reliability is the driver for the ownership. As far as the cost comparison between, if you did company ownership versus the market, I don't know that we can speak to that because it goes back to all those use cases. So it depends on how robust, how stringent, how restrictive, how much performance you would put in one of those PPAs. And we don't know all those answers. So I don't know that it would be cost competitive. But to your point, the real request for company ownership is about the need to have that ownership so we can invest in it. Everything we spoke about this morning and earlier today. That's the main driver.

Tricia Pridemore (PSC): [09:11:02] Reliability being the driver for BESS has been asked and answered multiple times.

Scott Thommason (GSEIA-SEA-VS): [09:11:06] The clarification was more about the cost effectiveness. I'll move on. Last question on this is, you talked about using a competitive procurement for EPC for a company to invest. Would it be possible to include in that same competitive solicitation or RFP process, also allow the market to bid in PPA or third party owned contracted BESS without fundamentally changing the RFP process, doesn't the current RFP process allow for that?

Wilson Mallard (GPC): [09:11:45] So I, no, the current RFP for EPC would not allow for that. We'd have to modify it. And again, it's our position that the company needs to own those resources to maintain the reliability our customers expect. So we wouldn't want to entertain allowing third party ownership in that EPC RFP.

Scott Thommason (GSEIA-SEA-VS): [09:12:03] So you can't consider EPC and what we'll call PPAs in the same RFP process?

Tricia Pridemore (PSC): [09:12:08] Talk into that mike, Mr. Thomasson. [Sorry.] Talk quick and in that mike. There you go.

Jeffrey Grubb (GPC): [09:12:12] We would not for this for this application.

Scott Thommason (GSEIA-SEA-VS): [09:12:21] Is the company considering any competitive solicitations for the DER reliability and constraints pilot?

Jeffrey Grubb (GPC): [09:12:28] That's more a panel two question. But I think what we've filed is for company ownership. But Mr. Evans can speak more to that tomorrow.

Michael Robinson (GPC): [09:12:36] So Mr. Grubb... [I was asking about yours. I'm sorry.] spoke to the local reliability constraints. And for these pilots, they would be company owned facilities, we would not...

Scott Thommason (GSEIA-SEA-VS): [09:12:46] So it would be similar to BESS. I mean, could you do an EPC RFP for that as well?

Michael Robinson (GPC): [09:12:48] We will through our generation development team. We will run an EPC. and we would consider third party ownership in the future depending on the results of these pilots and how we, like I mentioned, five of the seven feeders that we've identified have existing solar on those feeders. And how do we interact with those and develop those entity schemes?

Scott Thommason (GSEIA-SEA-VS): [09:13:14] But the company is not open to considering third party owned resources for that pilot?

Michael Robinson (GPC): [09:13:22] Not at this time, for this purpose, for these pilots, until we get more comfort with how we deploy, how we interact, how we engineer, how we operate these in real time.

Scott Thommason (GSEIA-SEA-VS): [09:13:32] That's all I have, Madam Chair.

Tricia Pridemore (PSC): [09:13:33] Thank you, Mr. Thommason.

Steve Hewitson (GPC): [09:13:34] I'd ask that Ms. Ottenweller's two exhibits be entered into the record, as you GSEIA 1&2. [So moved.]

Tricia Pridemore (PSC): [09:13:42] Mr. Moreland. Are you present? No. Ms. Coyle. Georgia Watch.

Liz Coyle (GW): [09:13:50] Short and...I think you referred to it, Chairman Pridemore, as spicy or something along those lines? [That's right. Sweet and spicy.] So good afternoon. Evening. I think mine is relatively short compared to some of the previous interveners. I want I have one follow up question to a conversation you were having earlier, Ms. Kysor And Chairman Pridemoore were asking you questions about the income qualified community solar. And I heard you say that the customer, on average, you expect, would say $15.

Wilson Mallard (GPC): [09:14:40] That's right.

Tricia Pridemore (PSC): [09:14:41] And the cost of the program is $28. $21 of that is paid by the company, and seven of that is by the customer. Is the $15 savings net of that $7?

Wilson Mallard (GPC): [09:14:54] Yes. So the customer would pay the $7. We would estimate their savings to be approximately $22. Again, those are just averages, so, yes.

Liz Coyle (GW): [09:15:01] Thank you. And then going back and just briefly referring to your testimony starting on page seven, that first paragraph answer, summarizing the testimony of your panel. And in your testimony there, you state that, "the plan is a balanced portfolio of resources to supply customers with clean, safe, reliable and affordable electricity." And then you end that same paragraph again, talking about continuing to ensure reliability, service customers across the state in a clean, safe and affordable manner. So my questions, first few questions relate to that. Would you agree that having electricity be affordable is of importance to all your customers and particularly your residential customers, especially those of low to moderate income?

Jeffrey Grubb (GPC): [09:16:00] Yes, I would say I would agree with that.

Liz Coyle (GW): [09:16:03] And as you acknowledged earlier today with Mr. Walsh and others, this IRP will be followed by a rate case. Is that right? [That's correct.] And ultimately, then, do you expect that your customers will have to pay for the plan that is approved in this IRP?

Jeffrey Grubb (GPC): [09:16:22] Yes. Some parts of this plan are not in the next rate case because this is a long term plan. But eventually, yes, the IRP results in impacts to the rate case.

Liz Coyle (GW): [09:16:34] So everything in the IRP has a cost associated with it, whether it's in this next rate case or in a future rate case.

Jeffrey Grubb (GPC): [09:16:39] And benefits. It does have associated benefits, but. Yes.

Liz Coyle (GW): [09:16:45] And. So again, going back to your testimony that the plan is affordable. How do you know that the plan is going to be affordable for your customers, especially those residential customers and the low to moderate income category?

Jeffrey Grubb (GPC): [09:17:12] So when we speak about affordable here, what we're saying is when we look at our 30 year studies and we look at our evaluations here that we are picking what is in the best interest of customers from the cost standpoint. So when we say affordable, we're looking at that long term interest of customers and what's the most cost-effective decision on those resources.

Tricia Pridemore (PSC): [09:17:35] But you made decisions about what to include in this plan that's before us now, based on some assumption that it is affordable.

Jeffrey Grubb (GPC): [09:17:47] Well, and again, that is because what we're looking at is our cost in our models, whether it's the reserve margin study unit, retirement studies, we're looking at that cost to customers. It's the entire customer base, not by class or not by rate, but we're looking at the overall customer costs.

Liz Coyle (GW): [09:18:05] But is it fair to say you want all of your customers to find electricity they purchase from you to be affordable?

Jeffrey Grubb (GPC): [09:18:13] Yes. And again, that's what we're looking at is customer costs in all the evaluations that we're doing.

Liz Coyle (GW): [09:18:19] So in order for you to state testify that the plan is affordable, have you calculated the percent increase in customer rates tied to this plan?

Jeffrey Grubb (GPC): [09:18:31] Not in the IRP. Again, the IRP is a 20 year plan. Some aspects of it are 30 years. And so what we're looking at is that incremental cost. But as you make that decision on incremental costs, the lower incremental cost decision will have lower rate impacts over the time than something that was more expensive. So we don't do rate calculations. We are looking at incremental costs on our side.

Jeffrey Weathers (GPC): [09:18:54] And I think one thing that's important to realize is that when we say affordable, the elements of the plan are less cost to customers than whatever the alternatives were. So you kind of go through the list of things we're looking at, what's the least cost for customers, that attributes to the affordability of it.

Liz Coyle (GW): [09:19:11] And that's actually my last next line of questioning. So thanks for giving us your...

Jeffrey Weathers (GPC): [09:19:15] Trying to speed it up.

Liz Coyle (GW): [09:19:20] Let's be a little spicy, too.

Jeffrey Weathers (GPC): [09:19:24] If only I could, as long as [unintelligible].

Jeffrey Grubb (GPC): [09:19:27] I can't take credit for that.

Liz Coyle (GW): [09:19:30] So then would you say, then, that you've applied certain methodologies to your proposals to evaluate...On page 35 and the whole Section 35 through 37, you talk about, for example, best cost procurement, moving into that as relates to RFPs for, on page 35, line 16 to 18, you're talking about moving to best cost procurement. So you're trying to build more methodologies into this plan than maybe you have in previous IRPs to help you evaluate whether or not, in fact, you are going to have a lower cost option than you're presenting?

Wilson Mallard (GPC): [09:20:21] It's an enhancement to our planning process. As we talked about, the models can select renewable resources and that's what they've done. Now we're going to modify our procurement processes to make sure we can go procure those best cost resources. And just to be clear, Commissioners, as Mr. Grubb talked about, it's maybe, can be less upward pressure on rates. It can also be savings on rates. It could also be downward pressure on the fuel cost bucket based on some of the decisions that come out of this IRP.

Liz Coyle (GW): [09:20:50] And so those, so you mentioned procurement costs, you're looking for avoided cost, building in avoided cost in some scenarios. You always have an eye to, you seem to express a lot of concern about things that might put upward pressure on rates and you're looking for other opportunities to put downward pressure on rates. Is that a fair...?

Wilson Mallard (GPC): [09:21:09] We're looking for the best mix of cost and reliability for our customers.

Liz Coyle (GW): [09:21:14] And so, for example, in your discussion with Chairman Pridemore about your request for $28 million just to apply for a license renewal for Plant

Hatch 1&2, that could take five years before you actually find out from the Nuclear Regulatory Commission whether or not that $28 million was well spent. Is that right?

Jeffrey Grubb (GPC): [09:21:35] That's correct. But I mean, that $28 million is really around the option for 2034 through 2054 and 2038 to 2058, and the value to customers of maintaining Plant Hatch. So again, it comes back to that long term IRP nature and that's what we're looking at...is we feel like, and our numbers show that, it will be advantageous to customers to extend those licenses.

Liz Coyle (GW): [09:21:59] And I believe you said to Chairman Pridemore that it would be cheaper than building new.

Jeffrey Grubb (GPC): [09:22:04] I think that may have been a commissioner comment.

Tricia Pridemore (PSC): [09:22:07] That was a bench comment.

Jeffrey Grubb (GPC): [09:22:10] But I would agree with that. That is a benefit of Hatch is that it's existing.

Michael Robinson (GPC): [09:22:15] Well, and Commissioners, and to that point, one of the reasons we need to take it now and the time that we need to take it is, if we're not successful in that renewal, we're going to need to build a lot of transmission to replace those units down in the Baxley area. So that's an important piece to ensure reliability in the future.

Tricia Pridemore (PSC): [09:22:31] Do you think that the comment from the bench might have been related to Plant Vogtle 3&4?

Jeffrey Grubb (GPC): [09:22:38] That would be my assumption, but I would let the bench speak to that if they need to.

Liz Coyle (GW): [09:22:42] Now, I didn't see and it could be in there and I overlooked it, but I didn't see a reference to Plant Vogtle 3&4 in your testimony.

Jeffrey Grubb (GPC): [09:22:51] It's included in the plans...[But not in your direct testimony.] No, I mean, we aren't asking anything in this IRP on Plant Vogtle. It's included in the plans. It's included in our models. But there's no specific request related to Plant Vogtle.

Liz Coyle (GW): [09:23:07] But, this IRP covers the years 2023-2025, correct?

Jeffrey Grubb (GPC): [09:23:20] That is correct.

Liz Coyle (GW): [09:23:21] And so, and this may again be in your, in the actual filing and not in your testimony, but it struck me. Do you expect that [Vogtle] unit three and possibly unit four might actually begin adding capacity to the mix in that time frame?

Jeffrey Grubb (GPC): [09:23:38] I mean, that's the schedule that we've incorporated is late 2022 and then I think mid 2023. So whatever the latest schedules are, they're in there.

Liz Coyle (GW): [09:23:48] How significant is that? You talked about risk and risk mitigation. If unit three and/or four are not adding capacity to the mix in that time frame, what does that mean for your need to, you talked about just a minute ago, Plan Hatch and your long range planning about transmission? What happens if Vogtle 3&4 aren't online in this three year period where you've got this built into the plan for the capacity?

Jeffrey Grubb (GPC): [09:24:14] Right. So it is, if it were a three year delay, are you're asking? Yes. So you would have to have some replacement capacity. So when you look at our numbers where we have Vogtle coming online at the end of 2022, Vogtle 3 and then Vogtle 4 come on the next year. So our needs reflect that.

Liz Coyle (GW): [09:24:33] Do you model what happens if they're not online, then?

Jeffrey Grubb (GPC): [09:24:35] We do not. Because the expectation is that it will be the end of this year. We've given that guidance and so we're watching that. But it's included on those dates right now.

Liz Coyle (GW): [09:24:45] And just a moment ago, we talked about your concern about looking at its capacity and the choices you make about including sources of capacity in the plan, and want to look at whether or not that particular item in the mix would put upward pressure on rates.

Jeffrey Grubb (GPC): [09:25:07] Something along those, I don't think a 100% followed...

Liz Coyle (GW): [09:25:10] Yeah but we talked about that one of the things you look at in your modeling is to see whether or not something you put into the model results in a sense that it's going to put upward pressure on rates.

Jeffrey Weathers (GPC): [09:25:21] Well, in comparison to the alternative. Right? So the model is either optimizing that, so selecting the least cost or in particular specific evaluations. Often you're comparing something versus the alternative. We pick the one with the least cost or best value to customers.

Liz Coyle (GW): [09:25:36] So something might put less upward pressure on rates? Correct?

Jeffrey Grubb (GPC): [09:25:40] So for example, if you have to add a resource to meet a capacity need, then it's the best cost resource that can meet that need. But it's upward cost because you're trying to add a resource.

Liz Coyle (GW): [09:25:52] And when Vogtle Units 3&4 go into service, whether it's in the next few years or not, how much upward pressure will that put on rates?

Jeffrey Grubb (GPC): [09:26:03] So I can't speak to rate pressures and everything above. I know there's the entire docket where that's addressed. I'm not involved in any of the rate impacts from Vogtle.

Liz Coyle (GW): [09:26:14] None of you have looked, follow along with all the Vogtle fun we have to put, subject to check, would you think roughly 10% is what's been...

Jeffrey Grubb (GPC): [09:26:23] Subject to check. That's my understanding. We didn't study that. That's a different analysis.

Liz Coyle (GW): [09:26:28] And as far as you're as far as you know, because this is your area of expertise. Now, is anything in this IRP, based on your modeling, going to put that much upward pressure on rates?

Jeffrey Grubb (GPC): [09:26:42] That much in reference to...

Tricia Pridemore (PSC): [09:26:43] Into potentially 10% upward pressure? If Vogtle is going to put, 3&4 put 10% upward pressure on rates, you're looking at.,,

Jeffrey Grubb (GPC): [09:26:53] We haven't...

Tricia Pridemore (PSC): [09:26:53] Can I ask the question, where did we get this 10% upward pressure on rate number for Vogtle 3&4. Where's that coming from? [From VCM, previous VCM testimony.] From, I mean when? [Filed by the company.] Filed by the company when? Under which VCM? I said subject to...I think the last two, but I would be happy to, I can provide that information, I said, subject to check. So I would very much like that because that does not track with what this commission is, what we've supported or passed in the past. That's new.

Liz Coyle (GW): [09:27:32] Let me rephrase it. Is there anything in this IRP that's going to put as much pressure of upward pressure on rates as much as expected for Plant Vogtle 3&4?

Jeffrey Grubb (GPC): [09:27:42] Wouldn't expect that. But I think, again, from a Vogtle standpoint, you're looking at a 60 to 80 year resource that, over the life of that, delivers benefits. But again, what we're looking at is that incremental cost of units...

Liz Coyle (GW): [09:27:54] So whether it's on the supply side or the demand side, whether it's for behind the meter solar on affordable housing, as was discussed earlier, or programs to help income qualified customers install energy efficiency measures. You're not talking about percentages and upward pressure on rates. You're talking about, I think you used the word, incremental?

Jeffrey Grubb (GPC): [09:28:14] So depending on if there's a need to add a resource, then you are. But we're doing it in the best cost way. But in terms of that magnitude, I don't expect anything in here to be of that nature. But again, back to the Vogtle, it's a 60-80 year evaluation that's done in the VCM docket and evaluated twice a year.

Liz Coyle (GW): [09:28:36] But generally your goal is to have a plan for capacity, adding capacity or, and retiring coal plants, for example, that is economic and that mitigates rate impact. Is that correct?

Jeffrey Grubb (GPC): [09:28:48] Yes, we're looking at the cost and benefits. So again, there can be benefits that outweigh those costs, but each decision is based on best cost. Looking forward at customers.

Michael Robinson (GPC): [09:29:02] And commissioners, reliability is a huge part of the plan as well. Not just cost, but reliability of the System as well.

Tricia Pridemore (PSC): [09:29:12] So I'd like to ask you some questions. Last line of questioning. I'd like to ask you some questions about your proposed early retirements of coal plants and the coal ash cleanup that's included in the IRP. Did you consider how to handle those aspects of your proposal in the most economic manner?

Jeffrey Grubb (GPC): [09:29:37] In terms of, you mentioned two. The coal ash is a different panel's testimony.

Liz Coyle (GW): [09:29:42] Okay. Well, let's just focus on that. Let's just focus on the early retirement of the coal plants.

Jeffrey Grubb (GPC): [09:29:49] So the question being, did we look at costs to evaluate?

Liz Coyle (GW): [09:29:53] That or how to handle the early retirement of coal plants in the most economic manner? The way we were just talking about, in terms of your modeling things and you're looking at best cost and best option for ratepayers.

Jeffrey Grubb (GPC): [09:30:06] First, I wouldn't, we don't have a set retirement date on coal units, so I wouldn't just determine it as, I wouldn't define it as an early retirement. It's just the retirement of them. But yes, I mean, our evaluation on the coal units is based on, do I, is it best for customers to continue to invest in that coal unit or do I retire and replace? So it is an economics evaluation to that standpoint.

Liz Coyle (GW): [09:30:29] Do, well, use of the term early, I think, is fairly standard in the industry when you have a coal plant that's retiring while it still has what's considered some useful life.

Jeffrey Grubb (GPC): [09:30:40] Well, you mean, as far as like depreciable lives? I mean, that's sometimes used. We've never really set a retirement date in terms of planning.

Liz Coyle (GW): [09:30:50] So speaking of retirement of coal plants, and there were a number of questions from Mr. Walsh and from Mr. Jones about this. Did you consider again in the recommendation to retire certain coal plants, the cheapest cost option for handling your recovery of those costs, the remaining net book value?

Jeffrey Grubb (GPC): [09:31:15] So we have not proposed the treatment of that.

Liz Coyle (GW): [09:31:20] Are you aware that some states, including North Carolina and Florida, have lowered the cost impact of coal plant retirement by recovering those costs through securitized bonds? You know, at a lower financing cost than traditional rate base.

Jeffrey Grubb (GPC): [09:31:36] I'm not an expert on securitization. I don't know what other states have done.

Tricia Pridemore (PSC): [09:31:40] Can I step in here? These are rate case questions. And I know we're looking forward to seeing you back for the rate case this fall. But when we're talking about the financing and costs of projects, it's different. If it's in a Vogtle capacity, that's a VCM. But we're talking about a 20 year strategic plan. So securitization is a is a bonding mechanism. I'm just trying to get as much information as I can to see how much this plan is going to be reflected in the rate case. Thank you.

Tricia Pridemore (PSC): [09:32:15] Thank you, Miss Coyle. Mr. Carver, Interstate Gas Supply. [No questions.] I love the sound of that phrase. Mr. Clarkson, have we seen you yet? No. He's writing something pithy, I'm sure. Restored Chattooga Gorge Coalition. Mr. Jones. Mr. S. Jones. Good to see you.

Stephen Jones (RCGC): [09:32:57] Commissioners. Thank you for the opportunity to appear before you. My name is Stephen Jones with the law firm of Taylor English Duma. I'm here today on behalf of Restore Chatooga Gorge Coalition. I know it's late, I'll be brief. I represent a coalition of entities that have one principal interest in this proceeding, and that is to restore the gorge underlying the lake upstream of your facility known as Tugalo. My questions will relate solely to that purpose and I will address them to you as a panel. Whoever feels that they are best suited to answer the question, please do so. On page 27 of the pre-filed direct testimony, you address the hydro fleet of the company. What is the size of the hydro fleet?

Jeffrey Grubb (GPC): [09:33:59] So about 1,100 megawatts.

Stephen Jones (RCGC): [09:34:02] And what is the capacity of Tugalo?.

Jeffrey Grubb (GPC): [09:34:07] I've got to check. There's a lot of plants. It's, just a second, it is 52 or so.

Stephen Jones (RCGC): [09:34:22] So 1,152, that would put Tugalo at approximately 4 or 5% of the entire hydro fleet. Is that right?

Jeffrey Grubb (GPC): [09:34:35] Subject to check. Yes.

Stephen Jones (RCGC): [09:34:36] And what is the capacity of the entire Georgia Power system?

Jeffrey Grubb (GPC): [09:34:41] So 16. Well, 19,000 or so. Depends on, it changes by year.

Stephen Jones (RCGC): [09:34:48] Okay, I've shown in the territorial base case load spreadsheet. That was for 2022, just over 20,000 megawatts. Can we go with that?

Jeffrey Grubb (GPC): [09:34:57] Depends which year you're looking at.

Stephen Jones (RCGC): [09:34:58] So with those numbers that we've agreed to, that puts Tugalo's capacity at 0.2% of the entire Georgia Power fleet. Is that right?

Jeffrey Grubb (GPC): [09:35:08] That sounds great. Again, that, just because it's 0.2% doesn't mean it doesn't bring value, though.

Stephen Jones (RCGC): [09:35:13] Absolutely. Absolutely. Not...just talking numbers now. [Understand.] Georgia Power is long or has an excess capacity through the year 2029. Is that right?

Jeffrey Grubb (GPC): [09:35:27] I would say it's above target. We don't refer to it as excess because you get value from it. But yes.

Stephen Jones (RCGC): [09:35:31] Yes. You don't show a shortage in capacity until 2030, is that right? [Correct.] And that is, in 2022 you're long on capacity, the company's long on capacity. ABout 800 megawatts, is that right?

Jeffrey Grubb (GPC): [09:35:48] Yes. I don't have it right in front of me, but yeah.

Stephen Jones (RCGC): [09:35:51] Subject to check. [Yes.] Yeah. How old is Tugalo?

Jeffrey Grubb (GPC): [09:35:58] It's...I think it's in the twenties. I think it's a vintage 1920s type of facility.

Stephen Jones (RCGC): [09:36:04] Subject to check. Can we say 100 years? 100 plus years? [Sure.] What's the average life of a dam?

Jeffrey Grubb (GPC): [09:36:12] Well. So I think it depends on components. So what we're talking about in the modernization is the turbines and the generators. And so they're well beyond their lives, which is exactly why in the 2019 IRP, we brought forward the need to invest in those generators and those turbines to maintain those facilities.

Stephen Jones (RCGC): [09:36:30] What about the structure itself?

Jeffrey Grubb (GPC): [09:36:33] The structure itself? I don't deal with that as much, but I think we do everything we need to and those structures are sound and in good shape. So the hydro modernization is really around the generation aspects of the dams. The dams themselves meet all the standards that they need, and we invest in those as we need to.

Stephen Jones (RCGC): [09:36:52] Has the company done any analysis of how the physical structures, what's their useful life? At what point do you, in other words, at what point do you consider decommissioning the entire structure?

Jeffrey Grubb (GPC): [09:37:05] You're referring to the dam. The dam itself? [Yeah. The bricks and mortar.] I don't know what that is, what the record of, or the pattern of, review and those are. Again, I think that what we've noted is that the risk of and the cost of decommissioning those dams would be very high in terms of remediating those dams and removing those dams.

Stephen Jones (RCGC): [09:37:26] Are you aware that there's federal resources and grants available to help decommission aged dams?

Jeffrey Grubb (GPC): [09:37:36] I was not aware of that.

Stephen Jones (RCGC): [09:37:39] What's upstream of Tugalo Dam?

Jeffrey Grubb (GPC): [09:37:42] So there's four other dams upstream from Tugalo.

Stephen Jones (RCGC): [09:37:47] And there's a lake upstream?

Jeffrey Grubb (GPC): [09:37:51] Yeah, above each one of those dams.

Stephen Jones (RCGC): [09:37:52] And there's two rivers, correct?

Jeffrey Grubb (GPC): [09:37:54] That is my understanding.

Stephen Jones (RCGC): [09:37:55] Are you aware that the Chattooga River is a wild and scenic river?

Jeffrey Grubb (GPC): [09:38:00] I'm sure it is.

Wilson Mallard (GPC): [09:38:02] Yeah, I'm aware. I've rafted down it.

Stephen Jones (RCGC): [09:38:05] That, Mr. Mallard's, my next question.

Jeffrey Grubb (GPC): [09:38:08] I have never rafted down it, if that's your next question.

Stephen Jones (RCGC): [09:38:11] But you'd like to.

Jeffrey Grubb (GPC): [09:38:13] One of these days.

Stephen Jones (RCGC): [09:38:14] And underneath, are you aware that underneath Lake Tugalo, there is in fact two more falls, in addition to the five upstream on the Chattooga?

Jeffrey Grubb (GPC): [09:38:26] Wasn't aware of it.

Stephen Jones (RCGC): [09:38:26] I guess now you are. [Yes I am.] Do you know how deep the lake is? [I do not.] Has the company done any studies as to sedimentation of the lake in the past hundred years?

Jeffrey Grubb (GPC): [09:38:40] I can't say that we have or have not. I've been focused on the generation aspects.

Stephen Jones (RCGC): [09:38:46] So, as part of your study as to modernization in the 2019 IRP and this IRP, did you do any studies as to the specifics...circumstances related to each lake and whether each lake has suffered from unique components that might add to the capital cost to operate the dam in the future?

Jeffrey Grubb (GPC): [09:39:14] I need to ask that, when you say suffering, I'm not sure I follow.

Stephen Jones (RCGC): [09:39:18] Yeah, let me rephrase. When the company looks at the cost to operate a dam in the future, does it look only at the dam and the generating resources itself? Or does it look to the cost associated with things such as sedimentation removal?

Jeffrey Grubb (GPC): [09:39:35] I don't know what we do on the side of looking at sedimentation. Again, what we brought forth to the commission and what we're moving forward with is, these are older plants as they start to have outages, the FERC licence to generate from those dams is based on their ability to operate. I need that FERC licence to be able to maintain those dams because in our opinion, the cost of retiring those dams is going to be quite substantial.

Steve Hewitson (GPC): [09:40:01] Understood. Are you, so you're not aware of any sedimentation in the lake outside your knowledge base?

Jeffrey Grubb (GPC): [09:40:08] I personally am not.

Stephen Jones (RCGC): [09:40:10] Any other, in the panel?

Wilson Mallard (GPC): [09:40:12] No, no. What I would say, commission, is that it's interesting to me as we look forward looking at renewable resources, looking at storage resources, these dams and these generators that we have in North Georgia are both of those things. They're 100 years old and they've been providing renewable resources and energy storage all at the same time. I think it just makes sense for hydro modernization for us to go forward with that and keep these resources as valuable resources on our system.

Stephen Jones (RCGC): [09:40:40] But Mr. Mallard, to staff's question, during its cross-examination, the company didn't do any analysis of alternative resources?

Jeffrey Grubb (GPC): [09:40:49] So we did not do an economic evaluation. Again, like we said in 2019, if we were to do it like a unit retirement study and look at retiring the dam and replacing it, you would have to have the estimates of that dam removal and we do not have those because it takes a lot of money to do those studies. We think the cost would be prohibitive. So it makes sense for customers to maintain those dams, invest in them, the generation.

Stephen Jones (RCGC): [09:41:14] And the company's yet to do an environmental impact study?

Jeffrey Grubb (GPC): [09:41:19] At which plant?

Stephen Jones (RCGC): [09:41:22] All of them. Specifically Tugalo.

Jeffrey Grubb (GPC): [09:41:24] I don't know. I mean, I would think that the licence requirements that we have and when we relicensed them would have an environmental study to it. I don't know if, with the amendments, that we're turning those over or not.

Bubba McDonald (PSC): [09:41:35] Mr. Jones, help me just a minute. What is your objective with these questions? In one statement. What is your objective? What do you...

Stephen Jones (RCGC): [09:41:47] Ultimately we want to see the gorge restored so that it becomes a navigable river. We think there's economic benefit to that to the...

Jason Shaw (GPC): [09:42:01] Wasn't the update to the Tugalo Dam part of the 2019 IRP?

Jeffrey Grubb (GPC): [09:42:06] They were commissioner. And so what as we've moved forward, that project, we have to file an amendment to the license at FERC. And so that process is going underway right now. And as I understand it, the association that is represented here today is taking part in that in that permit. So that licensing and impact. So it was, and we were moving forward with it. We've done the scoping and engineering. But before we can replace the turbine and generate work, we have to get an amendment from FERC. That process is taking place and it's being contested.

Jason Shaw (GPC): [09:42:37] I got you. Makes sense.

Stephen Jones (RCGC): [09:42:43] I'm about halfway done, so I'm hurrying. Panel, around the lake, who owns the property along the shoreline?

Jeffrey Grubb (GPC): [09:42:56] As far as the entire lake and our lakes, from the hydro, I'm not sure. I mean, I think there's lakes where it's private landowners. I think there's lakes where we own it. I don't know, around the lake at, above Tugalo.

Stephen Jones (RCGC): [09:43:07] So you don't know if it's owned by Georgia Power or the state of Georgia or the state of South Carolina?

Steve Hewitson (GPC): [09:43:13] Madam Chair, I believe that question has been asked and answered. I also think that we're getting well far afield from the modernization project that is subject to the 2022 IRP.

Stephen Jones (RCGC): [09:43:25] I'm getting there, if you don't mind.

Tricia Pridemore (PSC): [09:43:28] Council withdraws.

Stephen Jones (RCGC): [09:43:30] Thanks, Stephen. Panel, are you aware are there any residential and commercial structures fronting the dam, fronting the lake?

Jeffrey Grubb (GPC): [09:43:40] Our hydro team knows, I personally don't know.

Stephen Jones (RCGC): [09:43:43] But the hydro team hasn't presented any testimony relevant to the modernization efforts in this IRP.

Jeffrey Grubb (GPC): [09:43:49] Other than supportive of what they're doing with us. But we didn't include landowners around the lake in terms of the generation value of those resources.

Stephen Jones (RCGC): [09:44:02] In the 2022 IRP, Georgia Power is proposing solar components and battery components, that's been covered. [Correct.] The FERC license is referred to as a mid term licence, is that right?

Jeffrey Grubb (GPC): [09:44:21] That's right. I think the next licence renewal is in the thirties. So it was an amendment based on the modernisation.

Stephen Jones (RCGC): [09:44:29] And that would be 2036?

Jeffrey Grubb (GPC): [09:44:33] Subject to check. I believe that's correct.

Stephen Jones (RCGC): [09:44:38] And there's...and it's not to belabor the point, but to staff's cross, there's no assurance that FERC will grant that license?

Jeffrey Grubb (GPC): [09:44:46] No, our expectation is that they will, based on a lot of discussions we've had with all the agencies that we actually had discussions with before we filed the amendment at FERC. And so we didn't get any pushback from the agencies that we spoke with, is my understanding.

Stephen Jones (RCGC): [09:45:02] Okay. Is, with respect to just Tugalo and the modernization efforts and the cost reports that have been filed to date in the 2019 IRP. Is that project? Is it on budget? On forecasted budget?

Jeffrey Grubb (GPC): [09:45:22] I don't have the report with me. We're obviously not finished with the project. I think so. Right now it's just scoping in engineering work. I think it's slightly higher, but I don't believe it's that much more than what we did in the IRP. And so we do have a review with staff that we file the commission biannually to keep them up to speed on where we are on those budgets.

Stephen Jones (RCGC): [09:45:43] But it's your belief that it's, at this point slightly over budget?

Jeffrey Grubb (GPC): [09:45:48] I believe it's slightly under budget. I will say that Terrora, which is the first ones that we completed, did come in under budget and the company feels confident in our ability to be successful in the hydro modernization projects, especially as we continue to gain experience.

Stephen Jones (RCGC): [09:46:03] Okay. I'll have one exhibit. I'll mark this is as RCG 1. Madam Chair may I?

Tricia Pridemore (PSC): [09:46:28] You may approach.

Stephen Jones (RCGC): [09:46:56] Gentleman, this is, what I just distributed and labeled as RGC-1 is the biannual hydro modernization report for the period ending December 31, 2021, filed in docket 42310. If you would, please flip to the spreadsheet attached labeled Plant Tugalo at the very top. Panel, would you please identify for me, if you can read it, there's a note section at the very bottom, below the table.

Jeffrey Grubb (GPC): [09:47:41] You're on the specific Plant Tugalo spreadsheet?

Stephen Jones (RCGC): [09:47:45] That's correct.

Jeffrey Grubb (GPC): [09:47:52] Let me review it quickly before I jump down there.

Stephen Jones (RCGC): [09:47:53] It's physical page nine, I counted.

Jeffrey Grubb (GPC): [09:47:59] You say the notes at the very bottom. [Correct.] Yeah. So there's one asterisk that notes that the project forecast, is updated and we fill that out once it's updated and approved. And the final project forecast to be developed was developed in the quarter three 2021. And then we note that we measure against the 2019 IRP budget. Again, that 2019 IRP budget isn't necessarily approved in terms of a cost approval, but it's guidance for the Commission, but we are providing that comparison back to you there. And those are the two notes below the table.

Stephen Jones (RCGC): [09:48:42] And the current estimate of completion on the right hand column, third to the left, projected forecast, the current estimate was the total?

Jeffrey Grubb (GPC): [09:48:51] As 115. So it's around $6 million over the [unintelligible].

Stephen Jones (RCGC): [09:48:56] So construction hasn't started and we're already projecting over budgets and the company's already projecting over budgets, is that a fair reading?

Jeffrey Grubb (GPC): [09:49:02] It's a projection of, I think when you look at the grand scheme of things, that's still within reason, that we could result in something lower than that. Again, the one that we have completed, Terrora did come in under budget. And these are estimates that will change as we continue to get our results on turbines and generators. But yes, so slightly over budget.

Stephen Jones (RCGC): [09:49:26] And last question. I did, I do have two exhibits, so I'm going to mark this exhibit as RGG exhibit two. Madam Chair?

Tricia Pridemore (PSC): [09:49:44] You may approach.

Stephen Jones (RCGC): [09:50:20] Gentlemen, are you familiar? Gentlemen, are you familiar with this document?

Jeffrey Grubb (GPC): [09:50:32] Not very familiar. I know this appears to be the filing of the amendment at FERC. And so I was aware that we did it, but I was, I'm not, wasn't involved in drafting anything. Our hydro services team took care of it. So I knew we filed it, but I haven't spent a lot of time reading it.

Stephen Jones (RCGC): [09:50:52] Are you aware that in this document that the company takes the position that any expenditures not made prior to the 2022 IRP Are not available?

Steve Hewitson (GPC): [09:51:13] Madam Chair, I believe the witness already said he's not familiar with the document.

Stephen Jones (RCGC): [09:51:20] Could I have you then flip to what is the physical page 10?

Tricia Pridemore (PSC): [09:51:37] Mr. Jones, what's the first couple of words on the page that you're referring to, since this...?

Stephen Jones (RCGC): [09:51:47] The first part...It's items three four. Roman numeral two. There's a footnote number four at the bottom.

Tricia Pridemore (PSC): [09:51:58] Got it.

Jeffrey Grubb (GPC): [09:51:59] So I'm sorry. So you said it's on the page with items two, three and four.

Steve Hewitson (GPC): [09:52:03] The footnote four is at the bottom. Yes, sir.

Tricia Pridemore (PSC): [09:52:07] First words on the page are "waived it's 401 authority to the state of Georgia."

Jeffrey Grubb (GPC): [09:52:12] Okay, I miscounted. I counted the letter. Not just the filing. Sorry. So on the page, so what was the...?

Stephen Jones (RCGC): [09:52:23] Would you please just read the third, the second and third sentence?

Steve Hewitson (GPC): [09:52:28] Madam, Madam Chair, this document has been put into evidence. The witnesses have testified they're not familiar with the document. I don't think it's appropriate to have read it into evidence in this proceeding. This is not, this is not a document that was filed with the Public Service Commission. It was filed at FERC. The FERC relicensing amendment is not at issue before this commission.

Stephen Jones (RCGC): [09:52:48] Madam Chair, it goes to the fact of whether or not this commission has the authority to make a decision on the Tugalo Dam going forward in this 2020 IRP. And this is a party admission or representation made to a federal agency about that issue, which is the only issue that the coalition is here on.

Tricia Pridemore (PSC): [09:53:13] Is this an open item that Southern company has before FERC? [Yes.] Sustained.

Stephen Jones (RCGC): [09:53:24] No further questions.

Tricia Pridemore (PSC): [09:53:26] Thank you, Mr. Jones. Sierra Club.

Steve Hewitson (GPC): [09:53:32] Madam Chair, the witnesses have been going for about 3 hours straight. Might we give them a five minute break to stretch their legs?

Tricia Pridemore (PSC): [09:53:38] Absolutely. Let's us...Yes. We'll admit your two exhibits into the record. Thank you, Mr. Jones. Yes. The witnesses will take a five minute break, come back at 7:30.

Tricia Pridemore (PSC): [09:59:26] My friends across the street are still on dinner break now.

Tricia Pridemore (PSC): [09:59:54] Okay, let's get started in one minute. One minute. Let's see. Ah, I've sat down too. Sierra Club. Mr. Fabish. Okay. All right. We've got four witnesses. Let's begin.

Zach Fabish (SC): [10:00:43] Absolutely. So I think I can go pretty quickly here. I hope folks will appreciate that. You guys had a long day already. So with regard to the coal plants, for Scherer Units 1&2, the company is pursuing the voluntary incentives program. [Speak up.] Is that any better? [Yes.] Good. Excellent. We shoot for better. Pursuing the voluntary incentives program compliance pathways, is that the implementation guidelines, right? [That's correct.] And that gives you an extra three years to comply with that, right?

Jeffrey Grubb (GPC): [10:01:20] Right. We're going down the parallel paths of both. But that's what we filed, is not what we're focused on.

Zach Fabish (SC): [10:01:25] And, but what do you mean by that? Parallel paths. Is that preserves that flexibility to make a decision later as to whether or not to install the controls, if that looks like the best option. Or to retire them, or if that looks like the best option. [That's correct.] But you're not doing that with Bowen 3&4.

Jeffrey Grubb (GPC): [10:01:40] That is correct. And my understanding, panel three would have to elaborate on it, is that that's not an option at Bowen 3&4. The VIP option.

Zach Fabish (SC): [10:01:49] On that question for panel three, then. But if it were the option, would that also provide a similar sort of flexibility for Bowen 3&4?

Jeffrey Grubb (GPC): [10:01:58] It would, but my understanding is it's not one. So we had to look at the [unintelligible] on 3&4.

Zach Fabish (SC): [10:02:04] So as part of the IRP, there's a little bit of factoring in some load growth due to vehicle electrification, is that right?

Jeffrey Grubb (GPC): [10:02:19] There is, again, not the expert on the load forecast, but there is some electric transportation assumptions in our load forecast.

Jeffrey Weathers (GPC): [10:02:27] Panel two could probably explain better.

Zach Fabish (SC): [10:02:28] So maybe a lot more questions shouldn't even be asked. But given that, has the company taken a look at what the charging needs will be for the increased number of electric vehicles over the 20 year planning horizon?

Jeffrey Grubb (GPC): [10:02:44] You mean in terms of loads?

Zach Fabish (SC): [10:02:47] In terms of just the physical infrastructure, the Make Ready, the transmission chargers.

Jeffrey Grubb (GPC): [10:02:52] I think that's those aspects are often more in the rate case in terms of our tariffs and our Make Ready programs for electric vehicles. I don't know if Mr. Robinson has anything to add from their standpoint.

Michael Robinson (GPC): [10:03:03] So as we brought forward in the rate case.

Zach Fabish (SC): [10:03:05] Okay, perfect. Thank you. And then there is a hydrogen demonstration project in the IRP. Is that right?

Jeffrey Grubb (GPC): [10:03:11] That's correct. Again, more specific details in panel three. But we are we are proposing that for for several reasons.

Zach Fabish (SC): [10:03:20] And this may be a question for panel three, but what's the source of the hydrogen for that project?

Jeffrey Grubb (GPC): [10:03:26] It would be electrolysis. I do know that part. As far as the source of the actual creating hydrogen, I don't know. But it would be through electrolysis.

Zach Fabish (SC): [10:03:36] Great. Turning back to some of the unit retirements, I think someone testified that, I'm over in the corner so it's hard for me to see who was speaking, testified earlier that the unit retirement study looks at existing environmental compliance requirements, but not potential risks that may be forthcoming. Is that right?

Jeffrey Grubb (GPC): [10:04:01] So in terms of coal rules, if there were revisiting of the MATS Rule or the ELG, that's correct. Until we have a proposed rule, we don't include that in there. So other than carbon in the scenarios, we don't capture anything beyond ELG.

Zach Fabish (SC): [10:04:14] So like you said, not like a stricter potential MATS rule or stricter effluent limitation guidelines rule or potential new requirements for startup-shutdown malfunction or tightened national air quality standards for particulate matter or ozone. That whole list of things wasn't part of the retirement study.

Jeffrey Grubb (GPC): [10:04:39] That is correct.

Zach Fabish (SC): [10:04:41] Would the company agreed that those are potential risks in terms of compliance? And so by retiring those units, those risks are not something that ratepayers are confronted with for those units?

Jeffrey Grubb (GPC): [10:04:52] Right. To our point from this morning, it's not just the carbon risk that we're looking at, it's those futur risks.

Zach Fabish (SC): [10:04:58] Right. So just a couple more questions. Southern Company has a 2050, and I think this is alluded to earlier today, has a 2050 carbon neutrality target that's enunciated, right? [That's correct.] But the planning that's being done in this process is essentially the least cost planning. It's not based on trying to hit that target, correct?

Jeffrey Grubb (GPC): [10:05:24] That's right. I mean, things are trending in a very similar way because the cost of resources, technology, developments and those things are moving that way. But just as we've said in 2019, we still are using the state regulatory process and our models and processes to be. So we definitely take carbon risk into account through our scenarios.

Jeffrey Weathers (GPC): [10:05:43] But the target, the Southern Company goal is not driving the planning in terms of objective function. Not all of our scenarios plan to that. But the planning process drives us to the company goals. And so the goal was developed as a result of the planning process and in coordination and using the vehicle of the planning process to achieve it.

Zach Fabish (SC): [10:06:06] Well, that sort of anticipates my last question, which is going to be, if that goal didn't exist, would there be anything different about the retirement procurements that are in this IRP?

Jeffrey Grubb (GPC): [10:06:16] I would say no, because we're looking at carbon risks, not just that goal driving our decisions.

Zach Fabish (SC): [10:06:25] That's everything I have.

Tricia Pridemore (PSC): [10:06:26] Thank you, Mr. Fabish. Southern Alliance for Clean Energy and Southface Energy Institute. Good evening, Mr. Baker.

Robert Baker (SACE-SF): [10:06:43] Good evening. Chairman, Commissioners, panel, thank you for hanging in there. I'm going to try to, I have a lot of material, cut it back and we're going to get going right now. First question, did Georgia Power work with Southern Power on development of the Garland solar facility battery storage project in California? This is the 88 megawatt 352 megawatt hour energy storage project.

Jeffrey Grubb (GPC): [10:07:10] You ask if Georgia Power worked with them on that? [Yeah.] Not that I'm aware of. [Are you aware of it?] No, I don't think we work on that with a Southern Power...

Wilson Mallard (GPC): [10:07:19] I'm generally aware of a project, but none of the specifics of it.

Robert Baker (SACE-SF): [10:07:23] All right. Well, then you wouldn't know if it's true that Southern Power Energy Storage, that the project is co-owned in partnership with KKR and AIP management.

Steve Hewitson (GPC): [10:07:38] I think they've already answered that. No, they're not aware.

Tricia Pridemore (PSC): [10:07:40] Sustained.

Steve Hewitson (GPC): [10:07:44] Now that you know about the existence of the Southern Power Storage Project in California, it's 88 megawatts. Do you think anybody at Georgia Power might be in communication with them to maybe learn a little bit about.

Tricia Pridemore (PSC): [10:07:56] Sustained, Mr. Baker.

Robert Baker (SACE-SF): [10:07:58] All right.

Tricia Pridemore (PSC): [10:07:59] We have a plan that's been put forward, that's been filed with this commission. We've all spent a lot of time working through. That's a project in California. It's not a part of the plan, but just try to keep us on the rails.

Robert Baker (SACE-SF): [10:08:10] Well, if they're proposing 1,000 megawatts of storage development, they've got to...

Tricia Pridemore (PSC): [10:08:17] But it's by a subsidiary of the holding company, not the operating company. The holding company is not regulated by this body. The operating company is.

Robert Baker (SACE-SF): [10:08:27] I understand that. But they can take up the phone and talk to each other. One big family.

Tricia Pridemore (PSC): [10:08:33] This is a process on the Georgia Power 2022 Integrated Resource Plan.

Robert Baker (SACE-SF): [10:08:41] All right. Well, because Georgia Power has no experience operating large scale solar storage, wouldn't it be more economical for an experienced third party company to manage and operate the storage?

Jeffrey Grubb (GPC): [10:08:52] As we've spoken to this morning, there aren't, there is nobody who has experience with a large battery operating on our system. And again, the request for ownership is all around reliability and our need to own and control operating reserves. And that's what we've talked about several times today.

Robert Baker (SACE-SF): [10:09:09] All right. I'm going to refer to page 32 of your pre-filed testimony. Will the McGrau Ford Battery Facility be operational by 2026?

Jeffrey Grubb (GPC): [10:09:20] You said page 32 [32, line 19.] Mcgrau Ford? [Yes.] Yes, we're there.

Robert Baker (SACE-SF): [10:09:34] But will the facility be operational by 2026?

Wilson Mallard (GPC): [10:09:37] Yes, that's the plan.

Robert Baker (SACE-SF): [10:09:39] Okay. Page 32, line 19, you state...and what is the status of construction at the McGrau Ford Battery facility?

Wilson Mallard (GPC): [10:09:51] So there's there's no construction. The project is conceptual in nature. We're generally following the the battery storage action plan that's listed in the IRP. So the site has been identified. Engineering design work has is underway. Interconnection studies are underway. We're now to the point where we're asking for commission approval. At that point, once Commission does approve, we would go forward with that competitive RFP for EPC vendors. At that point, we could finalize the cost benefit analysis and present that to the Commission for final approval.

Robert Baker (SACE-SF): [10:10:30] What is the projected operation date for the 65 megawatt 4 hour lithium ion battery energy storage system located at Mossy Branch.

Wilson Mallard (GPC): [10:10:41] October of 2023.

Robert Baker (SACE-SF): [10:10:45] And when will the two megawatt standalone battery system be operational?

Wilson Mallard (GPC): [10:10:50] We only have a rough timeline for that yet. That project is not as far along on the development cycle.

Robert Baker (SACE-SF): [10:10:55] Do you have a location, a proposed location for it?

Wilson Mallard (GPC): [10:10:58] We've identified a location of Jekyll Island, Georgia, but final engineering, design and drawings is not complete.

Robert Baker (SACE-SF): [10:11:05] Is the two megawatt standalone battery system related to any of the seven local reliability constraint pilots you're proposing?

Michael Robinson (GPC): [10:11:14] No, it is not.

Robert Baker (SACE-SF): [10:11:17] Is the Fort Stewart Project the one Form Energy is collaborating with Georgia Power to develop?

Wilson Mallard (GPC): [10:11:23] No, that's a that's a separate project. The Fort Stewart project is going to use traditional lithium ion battery storage technology.

Robert Baker (SACE-SF): [10:11:31] It was reported in February and Utility Dive that Form Energy announced a partnership with Georgia Power to test a 100 hour iron air battery. Where is that project going to be located?

Jeffrey Grubb (GPC): [10:11:46] So as we put in the filing, we're still studying that. We aren't specifically requesting that, so that that determination has not been made.

Robert Baker (SACE-SF): [10:12:07] Has Georgia Power company had a NERC citation or violation in the last five years because they did not have enough reserves?

Jeffrey Weathers (GPC): [10:12:15] What kind of reserves, Mr. Baker?

Robert Baker (SACE-SF): [10:12:19] Backup reserves. Adequacy reserves for... Have you had any NERC citation in the last five years?

Jeffrey Weathers (GPC): [10:12:34] In terms of resource adequacy, you said? [Yes.] No.

Robert Baker (SACE-SF): [10:12:36] What about sufficient reserves to meet the generation load?

Jeffrey Weathers (GPC): [10:12:50] Operating reserves?

Robert Baker (SACE-SF): [10:12:51] Yes.

Jeffrey Grubb (GPC): [10:12:55] So we haven't had any loss of load events. We haven't had any shed load events or any of those types of things. So we, I'm unaware of any liability issues that we've had for the last...what was the timeframe? Last five years.

Michael Robinson (GPC): [10:13:08] We did have a NERC alert in October of 2017 that falls within the five years, but that's not a violation.

Robert Baker (SACE-SF): [10:13:24] All right. Were generating reserves used during the winter of 2021, 2022?

Jeffrey Weathers (GPC): [10:13:31] When you say generating reserves, that's a term we haven't used. What do you mean by that?

Robert Baker (SACE-SF): [10:13:36] Well did you have to call upon reserve, generating resources to meet load demand during the winter of 2021 2022.

Jeffrey Grubb (GPC): [10:13:46] The only way to meet demand is with resources. And so we would have supplied those from the fleet. I'm not sure what you're asking about in terms of winter reserves, but.

Jeffrey Weathers (GPC): [10:13:55] Are you talking about operating reserves? [Yes.] I mean, operating reserves are used every every minute of the day, in terms of regulating reserves.

Robert Baker (SACE-SF): [10:14:06] OK. Were any generating assets lost during the winter of 2021, 2022?

Jeffrey Grubb (GPC): [10:14:15] Whether we had any forced outages? I'm not sure. Not saying we didn't.

Jeffrey Weathers (GPC): [10:14:19] But are you asking about specifically due to cold weather or any reasons?

Robert Baker (SACE-SF): [10:14:24] Any reasons and then specifically cold weather.

Jeffrey Weathers (GPC): [10:14:29] Any reasons? Yeah, there's always, I think most every hour of the year, forced outages on the System. Specifically due to cold weather this past winter? I'm not aware.

Jeffrey Grubb (GPC): [10:14:40] But I think we had a DR. But I'd have to, subject to check, on some recent outages that, I can't recall the details.

Robert Baker (SACE-SF): [10:14:49] When Georgia Power testifies it continuously evaluates resource adequacy, how do you define continuously? Daily, quarterly, monthly?

Jeffrey Weathers (GPC): [10:15:02] Through the annual planning process.

Robert Baker (SACE-SF): [10:15:06] Have any major reliability events occurred in Georgia since 2019?

Jeffrey Grubb (GPC): [10:15:13] No, not from a loss of load standpoint.

Robert Baker (SACE-SF): [10:15:22] Is there a NERC criterion that requires balancing of generation and load within a five minute time interval?

Michael Robinson (GPC): [10:15:34] I'm not familiar with the interval, but there is EAL requirements, balancing requirements that require a certain equation to be met to ensure frequency stays within certain tolerance on the system.

Robert Baker (SACE-SF): [10:15:46] Is it a 5 minute standard?

Jeffrey Weathers (GPC): [10:15:48] It's not a five minute standard, but the modelling was performed at a five minute level to approximate that. So we can't go down to the six second level or instantaneous level. So we use five minute to capture intrahour volatility. And it did reveal some volatility concerns.

Robert Baker (SACE-SF): [10:16:07] Well, next question is, why would you use a five minute standard when the NERC standard actually uses a 30 minute interval for system balancing?

Jeffrey Weathers (GPC): [10:16:17] So, yeah, 30 minute refers. Yeah. So the standard does include 30 minutes, but it's measuring the frequency on the system and in terms of staying within certain bounds. And so the five minute interval that we modelled indicates that there's pressure on the ability of the system to meet those requirements for the VAL standard. Doesn't indicate that there's going to be a violation, but there's pressure on the real time balancing. And five minute was the level of granularity we were able to get to in the study.

Robert Baker (SACE-SF): [10:16:49] But NERC Doesn't require... That was your standard. That wasn't NERC standard, is that correct?

Jeffrey Weathers (GPC): [10:16:54] The five minute is not a standard. It's the modeling approach in order to identify the intermittency issues and identify the best way to alleviate those.

Robert Baker (SACE-SF): [10:17:06] So was that Georgia Power's modeling standard, not NERC's?

Jeffrey Weathers (GPC): [10:17:09] That was our modeling approach.

Jeffrey Grubb (GPC): [10:17:13] But again, you've got to be able to study that to understand how you're going to perform in a 30 minute interval. So that's what we're trying to get down to, is that real time operation, because we have the requirement, in real time, to balance load and generation. So that's what we were studying.

Robert Baker (SACE-SF): [10:17:32] By using that five minute modeling standard, doesn't that artificially inflate the integration charge you're proposing for the RCB framework?

Jeffrey Weathers (GPC): [10:17:42] No.

Robert Baker (SACE-SF): [10:17:44] Does the reserve margin study enable calculation of the sensitivity and or proportion of each of these risk factors?

Jeffrey Weathers (GPC): [10:17:55] Will you repeat that one more time. Make sure I get that.

Jeffrey Grubb (GPC): [10:17:58] And you switched to the reserve margin study, was your question?

Robert Baker (SACE-SF): [10:18:01] Yes. Okay. Does the reserve margin study enable calculation of the sensitivity and/or proportion of each of these risk factors?

Jeffrey Weathers (GPC): [10:18:14] When you say "these risks factors," which are you referring to?

Robert Baker (SACE-SF): [10:18:18] The one that is identified in the reserve margin study.

Jeffrey Weathers (GPC): [10:18:22] Oh, quantifying the drivers for seasonal planning. Is that what you mean? [Yes, sir.] Yes. So they're not quantified directly, but the combination of the six drivers for seasonal planning are the reasons why the commission approved the company moving to seasonal planning three years ago.

Robert Baker (SACE-SF): [10:18:48] All right. Is the energy sales forecast impacted by the assumption that technologies such as motor vehicles currently fueled by oil or natural gas will convert to electricity in the future?

Jeffrey Grubb (GPC): [10:19:06] So we just spoke to that. That's more of a panel two load forecast question on the details, but we do include assumptions on EVs.

Tricia Pridemore (PSC): [10:19:24] How many more you got Mr. Baker?

Robert Baker (SACE-SF): [10:19:25] Quite a few.

Tricia Pridemore (PSC): [10:19:26] All right, clip it up, then come up.

Robert Baker (SACE-SF): [10:19:32] All right. Quick question. Are you aware that, returning to the target reserve margin, are you aware that in other cold weather areas of the country that the winter reserve margins are much less than the ones that are being proposed by the company?

Jeffrey Weathers (GPC): [10:19:48] I'm aware that there are some. You have to also look at, are they summer or winter peaking? There's a lot of dynamics that go into it.

Robert Baker (SACE-SF): [10:19:57] You have any information or knowledge about that Kansas uses a 12% reserve margin?

Jeffrey Weathers (GPC): [10:20:06] I do not.

Jeffrey Grubb (GPC): [10:20:08] And some of the other things we don't know, commissioners, is what all Kansas does around their units. I mean, if you have a unit in Minnesota, you probably do a little differently than you do in Atlanta. So that's why it's got to be specific to our system.

Robert Baker (SACE-SF): [10:20:21] Well, there was a series of questions before, I can't remember if it was Mr. Jones or... if Mr. Mr. Jones asked them. But based on the investment made and winterization of the System and facilities, is there a correlation between the winterization and the ability to lower your winter reserve margin?

Jeffrey Weathers (GPC): [10:20:42] Not if you base it on economics, which is what we do. So winterization does help with reliability. It provides benefits to customers. But our target reserve margin, the primary basis is economics. So the 26% winter target reserve margin continues to be economic for customers.

Robert Baker (SACE-SF): [10:21:03] Right. Turning to demand response resources. Why are demand response resources not considered a dispatchable resource within the reserve margin study's dispatchable resource load stack?

Jeffrey Weathers (GPC): [10:21:17] They are.

Robert Baker (SACE-SF): [10:21:19] They are?

Jeffrey Weathers (GPC): [10:21:19] Yeah. They're a resource that reserve margin study optimization can call on those to serve load.

Robert Baker (SACE-SF): [10:21:41] Has the company evaluated any potential cost efficiencies and System reliability benefits that could be gained by improving reserve sharing agreements in the Southeastern Electric Reliability Council planning region?

Jeffrey Grubb (GPC): [10:22:02] So can you ask it one more time. You're asking if we've studied sharing reserves with other entities within the Southeast?

Robert Baker (SACE-SF): [10:22:10] Yes, in the SERC region. Has that ever been considered?

Jeffrey Grubb (GPC): [10:22:16] No. I mean, I think from a reserve margin standard, we don't operate with those other systems. We obviously are neighbors with them. We can have reliability aspects of being able to call them. And we do have some assumptions in the reserve margin study about being able to purchase from those other areas. But we don't operate our system with those other systems. We don't dispatch with those systems. And so we study Southern Company system that serves our customers. And we do have assumptions around purchases that we can get from surrounding areas.

Jeffrey Weathers (GPC): [10:22:46] To Mr. Grubb's point. We don't have formal reserve sharing arrangements with those entities, but we do consider that there is interface capability between our area and other areas. And that when economic, there's the ability to purchase across that interface. And that affects the target reserve margin. That helps put downward pressure on it.

Robert Baker (SACE-SF): [10:23:09] So you buy, you can buy excess power that they have, when you have a need for it. But there is no formal agreement as to that purchase or sale agreement or relationship?

Jeffrey Weathers (GPC): [10:23:21] That's right. If we look at weather diversity across a larger region, there will be opportunities when the Southern company can be a seller and times when it can be a buyer. And those interchange, the economic interchange of power is taking into account the reserve sharing and the reserve margin study.

Robert Baker (SACE-SF): [10:23:41] Has there been an estimate done by Georgia Power Company regarding the rate impacts from the Southeast Energy Exchange Market, by any chance?

Jeffrey Grubb (GPC): [10:23:51] So you said SEEM, the Southeast...? [Yes.]

Jeffrey Weathers (GPC): [10:23:55] I'm not aware of any study about the rate impacts of it.

Robert Baker (SACE-SF): [10:24:03] Would the costs or benefits that can be reflected in Georgia Power ratepayer rates, by any chance? [Current rates?] Or future rates?

Tricia Pridemore (PSC): [10:24:13] Can I ask? That's a question for the rate case. There's a rate, that's a rate case related question, because SEEM is a...let's stick to, let's stick to planning. Strategic planning.

Robert Baker (SACE-SF): [10:24:48] All right. Turning to winter peak demands. Do you know or can you identify the causes of the higher volatility of winter peak demands relative to summer peak demands?

Jeffrey Weathers (GPC): [10:25:07] Well, weather. Weather is going to be the primary driver of that. So in the wintertime, temperatures can can drop pretty low. A normal winter load, maybe something around 19, 20 degrees. They can get as low as five degrees below, zero degrees, even negative. In the summer, your temperatures in relation to your weather normal...the gap is much smaller. So you may be looking at weather normal in the upper nineties. You're not going to get, usually, to 115 in the System. May be more like 100. So there's just the impact of cold weather on the System demand is greater in the winter than it is in the summer.

Robert Baker (SACE-SF): [10:25:47] Is the, is a higher penetration of heat pumps in the market causing this higher volatility in the winter or contributing to it?

Jeffrey Weathers (GPC): [10:25:56] It certainly does contribute to the growth in winter loads as compared to summer. And there could be some volatility associated with that, in terms of strip heating coming on.

Robert Baker (SACE-SF): [10:26:09] Has the company taken into consideration local greenhouse gas laws and local clean energy policies in its carbon pricing forecast?

Jeffrey Grubb (GPC): [10:26:18] You said local?

Robert Baker (SACE-SF): [10:26:20] Yes. Local greenhouse gas laws and local clean energy policies.

Jeffrey Grubb (GPC): [10:26:26] Which kind of greenhouse gas laws are you referring to, in terms of local ones? I'm not aware of local ones.

Robert Baker (SACE-SF): [10:26:34] I would say some municipalities in the state of Georgia they have local greenhouse gas laws.

Jeffrey Grubb (GPC): [10:26:41] So they have goals, as we heard from earlier. But no, our CO2 scenarios are based on what a federal legislative or regulatory approach would be.

Robert Baker (SACE-SF): [10:27:06] When Georgia Power changed its resource mix study for the 2022 IRP by including for the first time solar, battery energy storage, and wind resources, did the company consider including other resources such as demand response, energy efficiency, dispatchable distributed energy resources and DER aggregations in the expansion planning model?

Jeffrey Weathers (GPC): [10:27:36] So in terms of energy efficiency... So there was the DSM study that the second panel can speak to that. Distributed energy resources...not specifically. What we model really generic repeatable utility scale projects in terms of candidate units. And so as you mentioned, we have a new model that allowed us to do that. There's a screening process to help determine which ones would be most economical for customers and repeatable on a commercial basis. And those are the ones that we included in our model.

Robert Baker (SACE-SF): [10:28:23] Regarding the effluent limitations guidelines, has the company included consideration, public policy requirements such as current and forthcoming environmental regulations into their system planning process over the last decade?

Jeffrey Grubb (GPC): [10:28:40] So you're asking around...I think that's the question that Mr. Fabish just asked us around the unit retirement studies. We have the current ELG rule, but not any other future considerations. So if that was your question around future possible rules, then that's what we answered earlier from Sierra Club's counsel.

Robert Baker (SACE-SF): [10:29:02] Well, it was really a, dealing with the broader public policy requirements, other public policy requirements for ELG compliance guidelines.

Steve Hewitson (GPC): [10:29:13] I think that question has been asked and answered.

Tricia Pridemore (PSC): [10:29:15] It has.

Robert Baker (SACE-SF): [10:29:26] Okay. Referring to page 19 of your pre-filed testimony, when examining the flexibility of gas units in the context of intermittent solar resources, in what ways did the company consider the flexibility of wind, hydropower and energy efficiency as alternative solutions?

Jeffrey Grubb (GPC): [10:29:46] Well, so we're not saying that there aren't other resources that have flexibility. We were just using that as an example of the start and stop times on gas units and minimum downtimes are a lot shorter than coal units. We're not saying there aren't other flexibility. It was just an example. More to point to the lack of flexibility of coal units. It wasn't an exhaustive list.

Jeffrey Weathers (GPC): [10:30:07] We also did include solar with storage as replacement resources after the expiration of the power, of the gas power purchase agreements when we did the unit retirement study.

Robert Baker (SACE-SF): [10:30:38] Mr. Weathers, just a clarification question to a prior testimony. You said this morning that the Southern Company plans and operates the entire system as a whole. Is that correct? Is that correct statement of your prior testimony?

Jeffrey Weathers (GPC): [10:30:53] Yes. Through the agreement between the operating companies, they pool their resources and loads together. And it's operated from one centralized dispatch.

Robert Baker (SACE-SF): [10:31:04] And Southern Company reported a significant increase in coal generation megawatt hours in 2021. It went from 17% in 2020 to 21% in

2021. Would that increase also be representative of the 2021 coal generation for Georgia Power?

Jeffrey Weathers (GPC): [10:31:26] I don't have the Georgia Power data, but that's really due to the increased loads versus a pandemic year and also the higher gas prices as we talked about the short term run up in gas prices a little bit earlier.

Robert Baker (SACE-SF): [10:31:45] And Georgia Power is predicting a significant drop in coal generation to 16% this year. Correct?

Jeffrey Grubb (GPC): [10:31:53] I'd have to...subject to check. I don't know what we were last year.

Robert Baker (SACE-SF): [10:31:56] Well, you have the IRP document, page 4-24, figure three. Is that accurate?

Jeffrey Grubb (GPC): [10:32:03] Yes. So for 2022, from an energy standpoint, that'd be correct. I just needed to confirm that number.

Robert Baker (SACE-SF): [10:32:14] There, is that reduction in coal generation due to the retirement of the Wansley units?

Robert Baker (SACE-SF): [10:32:20] That would contribute. I don't know which number you're comparing it to before. Did you compare it to 2021? [21%.] Yes. So it would be. And then. Also, these are weather normal projections, whereas 2021 would have actual generation in there.

Tricia Pridemore (PSC): [10:32:52] [Commissioner Pridemore inappropriately plays music from Jeopardy.]

Robert Baker (SACE-SF): [10:32:52] Referring to pages 23 and 24 of your pre-filed testimony. You discuss the 2022-2028 capacity RFP and the comments and feedback received from bidders and interested parties. Do you know how many commentators participated in the process for the RFP?

Jeffrey Grubb (GPC): [10:33:23] So your on page 23? [23, the bottom of 23, top 24.].

Jeffrey Weathers (GPC): [10:33:34] You're asking if we know how many individuals, people, or entities commented?

Steve Hewitson (GPC): [10:33:41] Approximately. [Inappropriate yawn from Commissioner Pridemore.] Dozens, hundreds, thousands?

Jeffrey Grubb (GPC): [10:33:42] I mean, the IE report has those details, but I mean there were several from from interested bidders just like we see in all of our RFPs. I don't remember exactly the numbers, but I think it was 60 or 70 something comments, somewhere along those lines. Subject to check.

Robert Baker (SACE-SF): [10:34:02] Were third party owned and operated demand response resources and programs evaluated in the RFP?

Jeffrey Grubb (GPC): [10:34:09] You said third party owned demand response?

Robert Baker (SACE-SF): [10:34:12] Yeah, owned and operated demand response resources and programs.

Jeffrey Grubb (GPC): [10:34:16] No, they were not. The capacity RFP was looking at supply side resources in terms of existing gas, new gas, standalone storage, storage paired with renewables.

Robert Baker (SACE-SF): [10:34:31] Do the winning bids for the natural gas PPAs represent the lowest bids in the RFP?

Jeffrey Grubb (GPC): [10:34:37] They do.

Robert Baker (SACE-SF): [10:34:41] Are each of the natural gas PPA winning bids below the company's avoided cost?

Jeffrey Grubb (GPC): [10:34:46] So for capacity RFP, there is no avoided cost hurdle. The avoided cost of the RFP is the RFP itself. And so what you're looking at is, what are the best resources we can add? So there is no hurdle they compete with themselves.

Robert Baker (SACE-SF): [10:35:01] Okay. Turning to page 25 of your pre-filed testimony, you list the additional sums that are being requested for the various PPAs. Can you explain how the additional sums were determined or calculated for each of these units since they vary between each unit?

Jeffrey Grubb (GPC): [10:35:18] Sure. What we did, commissioners, was we looked at the PPAs that we're seeking certification for and compared them across their terms on their annual evaluation compared to the company owned proposal proposed in the capacity RFP. And then the additional sum is based on 20% of that difference.

Robert Baker (SACE-SF): [10:35:44] George Power sought 1,000 to 3,000 megawatts of capacity from facilities size between 100 and 1,200 megawatts. Why wasn't a lower size facility, such as a 50 megawatt facility, allowed to bid in the RFP?

Jeffrey Grubb (GPC): [10:36:00] So that's really around storage. And when we look at retiring, what we're retiring here is 3,500 megawatts of coal units. It's just not in the best interests of the company to have a lot of small storage bids put in. A) From the standpoint, they probably aren't as economical as the larger ones. B) How do you operate it? And then C) just from a standpoint of evaluating all those bids. So 100 megawatts was a level that we felt would result in good storage bids that we worked with the staff and IE on getting approval for that.

Steve Hewitson (GPC): [10:36:43] Do you consider the long duration storage and tall wind technologies mature technologies?

Jeffrey Grubb (GPC): [10:36:50] So I'll speak to the long duration storage. We don't, in terms of, that's why our request isn't for a specific project. But we've noted in the IRP is that that's a very promising and interesting technology. But the reason that we aren't asking for a specific project at this point is it does need to develop. We will study that from a wind standpoint. I think wind itself is. But I think Mr. Mallard's alluded to, our demonstration project really is around the construction to get to the tall wind level.

Wilson Mallard (GPC): [10:37:23] Agree.

Robert Baker (SACE-SF): [10:37:27] Does the company have any experience with long duration storage?

Tricia Pridemore (PSC): [10:37:32] You've asked that, Mr. Baker, you've asked that very question. Does the company have experience with long duration storage? These pauses are taking up the time. We're running out of air, in terms of cool air. I'm going to give you Mr. Baker, until, it's 8:08. So I'm going o give you until 8:11.

Robert Baker (SACE-SF): [10:38:14] All right. Referring to the latest interconnection queue, is the 600 megawatt battery energy storage project in Fulton County affiliated with Southern Company or any of its subsidiaries?

Jeffrey Grubb (GPC): [10:38:28] That's only... No, that's not associated with us. I'm not aware of.

Michael Robinson (GPC): [10:38:32] Not that I'm aware.

Robert Baker (SACE-SF): [10:38:36] You stay the page, 42 lines 20-23, the addition of renewable resources on the system creates additional fuel diversity, environmental benefits, and projects to create long term cost savings for all customers. Would you agree that statement applies to customer owned renewable resources as well?

Wilson Mallard (GPC): [10:38:55] Yes, all renewable resources.

Robert Baker (SACE-SF): [10:39:20] Is the company aware that public interest organization stakeholders submitted requests to Southern Company transmission planners and in the SERTP [Southeastern Regional Transmission Planning] process to study transmission needs driven by public policy requirements, including coal combustion residuals, and other EPA rules that impact coal plant retirements included in the 2022 IRP. [I am not aware.] These were submitted in 2015, 2016 and 2017. [Not aware. No.] Referring to the IRP plan, in the IRP, you mentioned significant increases in interest in behind the meter programs. Is there a significant increase in interest in the RNR monthly netting program?

Wilson Mallard (GPC): [10:40:39] Yeah. So there was. The monthly netting pilot definitely generated significant interest in the program.

Robert Baker (SACE-SF): [10:40:46] Was it a successful program?

Wilson Mallard (GPC): [10:40:48] So we learned a lot. And from that from that aspect, it has generated benefits. We've we've been able to see what high volume of applications does, been able to improve our processes. And we're gathering data as we've already referenced earlier, that will be the basis for more robust analysis on the cost shift, increased cost from monthly netting.

Robert Baker (SACE-SF): [10:41:10] And what specific distributed energy resource technologies will be eligible to be installed in the seven locations that you're proposing?

Michael Robinson (GPC): [10:41:21] Seven locations are a combination of traditional recip engines that could be either diesel or natural gas, and then battery energy storage. But as I mentioned before, we are looking to pair those with solar that's existing on feeders as well.

Tricia Pridemore (PSC): [10:41:38] My clock shows 8:11.

Michael Robinson (GPC): [10:41:41] Well, for the record, I have more questions. I request the opportunity to complete my cross. I've cut it back. I've cut it back.

Tricia Pridemore (PSC): [10:41:50] I recommend that counsel go through his questions ahead of time. And therefore it's these long pauses in this long, drawn out process, Mr. Baker, that it's adding to the time.

Robert Baker (SACE-SF): [10:42:03] I'm going through the questions, trying to cut, I was cutting through those pauses. Madam Chairman, I wasn't delaying.

Tricia Pridemore (PSC): [10:42:08] How much more time do you need?

Robert Baker (SACE-SF): [10:42:12] More than you want to give it. Let me just...could we let Mr. Mahan go and let me just check and see if there's anything remaining, questions I really need to ask for my clients. .

Tricia Pridemore (PSC): [10:42:25] Does counsel have objection to that? Either staff or Georgia Power. [No objection.] OK, work on that list. Check it twice. Find out who's naughty or nice. Mr. Mahan. Southern Renewable Energy Association. He's been with us today on video. He's ill.

Simon Mahan (SREA): [10:42:48] Can you all hear me?

Tricia Pridemore (PSC): [10:42:49] Yes. Mr. Mahan.

Simon Mahan (SREA): [10:42:53] Good evening. Just starting at the top here, across the Integrated Resource Plan, has the Southeastern Energy Exchange Market been modeled.

Tricia Pridemore (PSC): [10:43:12] Please repeat your question, Mr. Mahan.

Simon Mahan (SREA): [10:43:15] Yeah. Across the Integrated Resource Plan, has the Southeastern Energy Exchange Market been modeled?

Tricia Pridemore (PSC): [10:43:24] So we can't understand and the court reporter, the court reporter can't understand. Can you pick up the receiver?

Simon Mahan (SREA): [10:43:33] Yes, I picked it up. I actually tried to call in on my phone because I think I have better reception over there, but it's not piping through that way.

Tricia Pridemore (PSC): [10:43:41] That's a little better. Speak. Speak clearly into your microphone, Mr. Mahan. Mr. Mahan, are we still with you? Still here?

Simon Mahan (SREA): [10:44:02] I apologize.

Tricia Pridemore (PSC): [10:44:05] Let's get moving. Speak clearly into your mic.

Simon Mahan (SREA): [10:44:08] Yes, ma'am. Across the IRP, was the Southeastern Energy Exchange Market modeled or not?

Jeffrey Weathers (GPC): [10:44:16] It was not modeled. The IRP is primarily a capacity planning tool. And the Southeastern Energy Exchange Market does not offer capacity. It is an energy exchange mechanism interhour energy.

Simon Mahan (SREA): [10:44:32] And SEEM doesn't include any transmission planning either, does it?

Jeffrey Weathers (GPC): [10:44:37] It does not. The SEEM is designed to use a new form of transmission, the lowest non-firm transmission available. So it doesn't impact transmission planning at all.

Simon Mahan (SREA): [10:44:50] Let's move on to the transmission plan. You all provide some locational guidance and transmission appendix E-4r and you call it the optimal ITS substation. Is that the extent of the locational guidance you all plan on providing?

Michael Robinson (GPC): [10:45:09] For the purpose of transmission? That is correct. That the study that we did looking at a comprehensive look throughout the state, of busses throughout the state of Georgia, substation busses, injecting up to the 300 megawatts, and those are the sites that did not cause any constraints. They just happened to all be in north Georgia.

Simon Mahan (SREA): [10:45:26] When I read that, I took it to mean that southern Georgia was excluded from the study. Not that it just so happened to be that way. Is that right?

Michael Robinson (GPC): [10:45:35] No. There were tranches, injections done at 100 megawatts, 200 megawatts, 300, 400. We picked 300 because it matched very closely the latest RFPs that we've had bid in. And there were no busses in south Georgia that could accept 300 megawatts without transmission constraints.

Simon Mahan (SREA): [10:45:57] And also in the transmission plan in appendix D-1, this is the ten year transmission plan for the IRP, correct?

Jeffrey Grubb (GPC): [10:46:07] We're flipping to it, Mr. Mahan, just one moment or two. It's a big binder. You said D-1?

Simon Mahan (SREA): [10:46:17] Yeah, I believe so. It's technical appendix volume three. [So ask your question again.] Are you seeking approval of the ten year transmission plan in this IRP?

Michael Robinson (GPC): [10:46:29] No, this is a transmission plan that we develop with the ITS participants as part of the SERTP process as well. We bring this to show our prudency as it relates to planning the System and meeting the transmission plan associated with the resource plan to make sure that we deliver the megawatts from the generation to the load.

Simon Mahan (SREA): [10:46:53] So the commission is not going to approve this ten year transition plan in this IRP?

Michael Robinson (GPC): [10:47:00] It's part of the IRP. We're not asking for explicit approval of a transmission plan. This is a work product of the ITS that also feeds into the SERTP process on an annual basis.

Simon Mahan (SREA): [10:47:13] So I was going to ask this question, but I think you just answered it. How often does the ten year transmission plan get updated?

Michael Robinson (GPC): [10:47:24] Annually.

Simon Mahan (SREA): [10:47:26] Okay. And the transmission upgrades that are identified in the plan. Not all of them are associated with the North Georgia Reliability and Resilience Action Plan. Is that correct?

Michael Robinson (GPC): [10:47:40] None of them are associated with the North Georgia Reliability and Resiliency Plan. I think I answered that earlier.

Simon Mahan (SREA): [10:47:45] I apologize. So when are the North Georgia transmission upgrades going to be put into the ten year plan?

Michael Robinson (GPC): [10:48:02] Those are currently being studied by the ITS participants and we are looking at, as I mentioned before, that timeframe in 2035 where you anticipate the retirement of Bowen 3&4, additional renewables, whatever is approved out of this IRP, in South Georgia on top of what the EMCs and municipalities needs are. And we are working through that process right now, hope to have the plan solidified by this summer and then we will bring that forward in SERTP process as it relates to future ten year plans and the next IRP cycle as it relates to the ten year plan that we file in the IRP.

Simon Mahan (SREA): [10:48:39] With regards to SERTP, I think we're on Appendix E-1 here, because you keep referencing it. You all state the SERTP process did not produce any stakeholder proposed alternatives that were included in the ITS ten year transmission expansion plan for 2022 to 2031. How are these stakeholder alternatives proposed in SERTP?

Michael Robinson (GPC): [10:49:05] So there is a process that's detailed on the SERTP website that allows for stakeholder input into that process on an annual basis for bringing projects for consideration for cost allocation.

Simon Mahan (SREA): [10:49:22] Is that also through, is that through the Regional Planning Stakeholder Group at SERTP?

Michael Robinson (GPC): [10:49:31] Subject to check, I believe that's correct.

Simon Mahan (SREA): [10:49:34] And are you aware that there was a SERTP meeting in March?

Michael Robinson (GPC): [10:49:39] There is a second quarter meeting that, or first quarter meeting, that's scheduled in March, typically on an annual basis, that's correct.

Simon Mahan (SREA): [10:49:47] And are you aware that no Georgia Power nor any Southern Company participants agreed to participate in the Regional Planning Stakeholder Group at that meeting?

Michael Robinson (GPC): [10:49:58] I am not aware of that.

Simon Mahan (SREA): [10:50:00] Okay. Let's move on to the capacity power purchase agreements. Can you describe to me how the capacity benefit is determined in the capacity PPAS additional sum methodology? I think it might have something to do, maybe, with a new combustion turbine or perhaps a value of lost load. If you could explain that, I'd appreciate that.

Jeffrey Grubb (GPC): [10:50:23] I'm not sure I quite followed your question. You're asking around, you started on the capacity benefit in the RFP, but then you switcedh to additional sum. Are you asking additional sum question, how that was determined?

Simon Mahan (SREA): [10:50:37] Well, my understanding is with the additional sum is, the additional sum is based in part off of the capacity benefit value. And the company gets a certain percentage of the total capacity benefit value on a dollar per KW basis.

Jeffrey Grubb (GPC): [10:50:58] Yes. And so I just wanted to make sure I was following your question right. It's like I just said just a little while ago. What we've done for the additional sum was we have the evaluation by year for the PPAs that we're seeking certification and we have the evaluation value by year of the company owned proposal and we took 20% of the difference in those years. So it's not just capacity benefit, it's the entire evaluation in the RFP.

Jeffrey Weathers (GPC): [10:51:24] Right. And add to that, Mr. Mahan, it is the difference between the net cost of the PPA and of the company owned proposal. They both received the capacity benefit. So we're just looking at the difference of those two.

Simon Mahan (SREA): [10:51:41] In the main IRP document, I think this is Chapter 11, page 79, you state that there's a capacity need in 2029. Is that with or without the proposed capacity PPAs in this IRP?

Jeffrey Grubb (GPC): [10:51:58] That includes those. So that reflects the coal retirements we're requesting. And the six PPAs we're seeking certification.

Simon Mahan (SREA): [10:52:07] And also on that same page, you state that the company may monitor and consider issuing a, quote, "all source RFP" to address the capacity needs in the future. Is that all source RFP similar to the capacity RFP that we just went through or is that something different?

Jeffrey Grubb (GPC): [10:52:25] So I lost the page reference, but I can speak to it. So again, it would definitely at least be what we've done in the 2022-2028 capacity RFP to allow standalone storage and storage plus renewables. We haven't really thought through much more beyond that. [10:52:42] In a lot of respects, that is an all resource RFP. [10:52:45] So it's not yet determined, but we will continue to think through that and other other options that we would allow bids.

Simon Mahan (SREA): [10:52:52] OK. And the previous capacity RFP that's led to the power purchase agreements that are being proposed in this IRP, why did the company choose power purchase agreements instead of acquisitions or new build options?

Jeffrey Grubb (GPC): [10:53:08] They were more economic for customers.

Simon Mahan (SREA): [10:53:10] But you all are able to get the flexibility and the firm enough commitments necessary out of those PPAs to serve reliability needs?

Jeffrey Grubb (GPC): [10:53:18] Yes, from the pro forma PPAs for combined cycles and combustion turbines, yes. For capacity and energy needs. Correct.

Simon Mahan (SREA): [10:53:27] With regards to the reserve margin and target reserve margin, the wintertime reserve margin target is higher than the summertime reserve margin target. And is that in part to take into account that natural gas is, the generators have lower capacity accreditation during wintertime?

Jeffrey Weathers (GPC): [10:53:49] No, they don't have lower capacity credit in the wintertime. But it is due, there are several reasons for that. One of the reasons is that they are exposed to cold weather outages, extreme temperatures. But there are other reasons as well.

Simon Mahan (SREA): [10:54:07] So effectively in the models, natural gas resources don't have a different capacity value from summertime to wintertime?

Jeffrey Weathers (GPC): [10:54:21] That is correct. And the way that we do capacity value is what we call the ICE factor. And it's actually comparing against a combustion turbine, a gas fired unit, and other resources are compared to that. So that's the standard that we compare against.

Simon Mahan (SREA): [10:54:39] Thank you.

Jeffrey Grubb (GPC): [10:54:39] Mr. Mahan We do show higher winter megawatts than summer megawatts from a rating standpoint. So Mr. Weathers answered capacity value. But the capacity amounts are seasonal based on winter and summer.

Simon Mahan (SREA): [10:54:55] Thank you. In the IRP, the company is requesting 1,000 megawatts of company-owned energy storage. Is that inclusive of the McGrau Ford site or is the McGraa Ford site in addition to that 1,000 megawatts?

Jeffrey Grubb (GPC): [10:55:11] Yeah, the McGrau Ford would be the initial project in that thousand. So it would count towards that 1000 megawatts.

Simon Mahan (SREA): [10:55:19] And so I think the number then is 735 megawatts. What is the anticipated duration of those battery resources, the new battery resources? Is it one hour or 2 hours? 4 hours?

Jeffrey Grubb (GPC): [10:55:33] So McGrau is a two hour facility. I think we studied that. We would make sure that as we continue to deploy those, that we would re-evaluate if a longer duration storage worked. But McGrau is 2 hours. And our thought is the first few would be 2 hours.

Simon Mahan (SREA): [10:55:51] Okay. And is all that energy storage that the company is planning for expected to be built in north Georgia?

Wilson Mallard (GPC): [10:56:01] Not necessarily. So the company would site those resources based on our evaluation of potential generation sites, and site those around the state where really they could create the most benefits for customers.

Simon Mahan (SREA): [10:56:13] Okay. I'd like to move on to the CARES RFP program. Can you help me understand, I understand CARES is meant to be a full subscription program this go around. But what happens if there are no subscribers? Does the full 2,100 megawatts of utility scale solar and the associated DG solar, does all that still get built?

Wilson Mallard (GPC): [10:56:41] Yes. So the, really, the way this procurement is designed, Mr. Mahan, is that the company is requesting these resources because of the benefits they provide to all Georgia Power customers. Really, the subscription option is an add on or underneath that procurement. And so if approved by the Commission, the company would plan to procure all 2,300 megawatts regardless if they are subscribed to or not.

Simon Mahan (SREA): [10:57:08] That's great news. Appreciate that. The proposed 2023 CARES RFP is intended to focus on North Georgia. Have you all checked the generation interconnection queue lately for North Georgia and the possibility that there's probably not enough facilities to bid into that 2023 RFP?

Wilson Mallard (GPC): [10:57:29] Yes, so I haven't checked it lately. I do believe there are facilities in the queue and then it's our expectation that we've got a really resilient renewable market here in Georgia. It would be our expectation that the market will be able to deliver projects in North Georgia to meet those capacity targets.

Simon Mahan (SREA): [10:57:48] How long does it take to go from first filing in the generation interconnection queue to having a signed generation interconnection agreement? It's 36 to 48 months, that general timeframe.

Michael Robinson (GPC): [10:58:02] That's the COD. That's the construction of facilities to go through the process. It's... I'm sorry. I don't have that information in front of me. The information I do know is that from submission to request to COD is 36 to 48 months. So if you take two years off a construction for that, subject to check, it's somewhere in the neighborhood of a year to go through that process to then begin design and construction of those facilities. Those facilities would be would be done in the 36 to 48 month time frame.

Simon Mahan (SREA): [10:58:56] Let's move on to the generation resource mix study in the Aurora modelling specifically.

Tricia Pridemore (PSC): [10:59:02] Mr. Mahan, before you go any further, I'm going to ask you how much more time do you need? And be mindful of the fact that the room that we're in doesn't have HVAC service anymore. And these witnesses have been on the stand now for 11 hours.

Daniel Walsh (PIA): [10:59:15] Yes, ma'am. 10 minutes.

Tricia Pridemore (PSC): [10:59:17] Can we make it eight?

Simon Mahan (SREA): [10:59:19] Yes, ma'am.

Tricia Pridemore (PSC): [10:59:20] Thank you.

Simon Mahan (SREA): [10:59:23] How are federal tax credits for renewables and energy storage accounted for in the modeling?

Jeffrey Weathers (GPC): [10:59:31] Mr. Mahan, you're referring to the the mix study for the IRP or you're referring to the renewable expansion study?

Simon Mahan (SREA): [10:59:38] Yes, the generation resource mix. I believe that's the one that used the Aurora model.

Jeffrey Weathers (GPC): [10:59:43] Okay. And you asked about how the tax credits are factored in?

Simon Mahan (SREA): [10:59:46] Yes.

Jeffrey Weathers (GPC): [10:59:47] Yeah. So the company has in the resource mix study a couple of different pricing for solar. And so one of them really assumes that a continuation of the existing investment tax credits and one of them looks at what the price of solar would be if those tax credits expire. So we look at both of them.

Simon Mahan (SREA): [11:00:09] And when you ran the Aurora model, did you all place a cap on the amount of solar generation that could be added on an annual basis?

Jeffrey Weathers (GPC): [11:00:19] We did. We had a limit of 1,500 megawatts of solar on an annual basis, but we also looked at a sensitivity without that. And really over the course of the planning horizon, it doesn't matter. It's just a timing of the solar. Either, if you have the cap, you'll add it more evenly over time. If you remove the cap, you'll still add about the same amount of solar over a 35 year period. They'll just be concentrated in a few years.

Simon Mahan (SREA): [11:00:50] And did you allow renewable energy resources to be selected by the model prior to the prior to 2025.

Jeffrey Weathers (GPC): [11:00:59] No. 2025 was the first year.

Simon Mahan (SREA): [11:01:03] Okay. And when you ran the Aurora model, did you include the 2.3 gigawatts of natural gas PPAs?

Jeffrey Weathers (GPC): [11:01:16] Yes.

Simon Mahan (SREA): [11:01:18] Those were hardcoded into the model?

Jeffrey Weathers (GPC): [11:01:22] Yes, those were as well as the coal retirements.

Simon Mahan (SREA): [11:01:29] Finally, here on the integration analysis, did the integration cost analysis account for integration cost of the inflexibility of fossil and nuclear plants because they don't follow load and they're hard to ramp?

Jeffrey Weathers (GPC): [11:01:47] Essentially, yes. I mean, that's what, that's where the value that's attributed to battery storage is derived from, is because they, because the existing fossil fleet is less flexible and that battery storages are very flexible. So they can provide the same operating reserve services to manage additional solar generation more economically than the existing fleet can.

Simon Mahan (SREA): [11:02:16] That'll do it for me. I appreciate it. Thank you.

Tricia Pridemore (PSC): [11:02:21] Thank you, Mr. Mahan. That's the best 8 minutes I've ever heard. Coming in at three. Hello, Mr. Baker.

Robert Baker (SACE-SF): [11:02:28] I have a proposition to make. Could I submit my remaining handful of questions to Georgia Power for a written response?

Tricia Pridemore (PSC): [11:02:39] No.

Robert Baker (SACE-SF): [11:02:41] All right.

Tricia Pridemore (PSC): [11:02:44] How many of you, how much time do you need?

Robert Baker (SACE-SF): [11:02:47] 10 minutes if I call it fast.

Tricia Pridemore (PSC): [11:02:50] You're going to get eight.

Robert Baker (SACE-SF): [11:02:51] All right. Here we go. For the qualified community solar program, the sponsors buy down the credits. [Yes.] And get the RECs. Is this really a solar program for low income customers or just a way to reduce utility bills?

Wilson Mallard (GPC): [11:03:06] So it's definitely a solar program. One of the results we expect to have, reduced utility bills, but we're going to educate those customers and they're going to get to participate in solar by subscribing to a block of that community solar output.

Robert Baker (SACE-SF): [11:03:19] Does the company make it a practice to provide a description of the transmission system need underlying each project as well as economic analysis for each transmission project included in its ten year transmission expansion plan for public comment and feedback?

Michael Robinson (GPC): [11:03:39] Can you repeat your question? That was pretty long.

Robert Baker (SACE-SF): [11:03:41] Does does the company make it a practice to provide a description of the transmission system need underlying each project as well as economic analysis for each transmission project included in its transmission ten year transmission plan for public comment or feedback?

Michael Robinson (GPC): [11:03:57] We do file that in this IRP. We do file that documentation. It is in the ten year plan. All the documentation that you mentioned. And then the ten year plan, as I mentioned before, is also part of the SERTP process.

Robert Baker (SACE-SF): [11:04:09] If the cost of the proposed transmission projects are not reported publicly, how does the company and its integrated transmission system partners solicit and develop cost effective solutions and alternatives?

Michael Robinson (GPC): [11:04:24] Well, as I mentioned before, that information is available through the IRP process. Much of it is trade secret, but it is available. The cost alternatives looked at for the ten year plan. And I do believe is available for public review comment.

Robert Baker (SACE-SF): [11:04:44] Do third party owned solutions get proposed in the process?

Michael Robinson (GPC): [11:04:49] There is an opportunity through the SERTP process, as I mentioned before, to bring projects forward for cost allocation. And that is all explained on the SERTP website.

Robert Baker (SACE-SF): [11:05:01] And could you describe the cost benefit analysis the company uses to evaluate transmission and distribution solutions and alternatives?

Michael Robinson (GPC): [11:05:09] So that's listed and that's also filed in volume three in section eight.

Robert Baker (SACE-SF): [11:05:13] Correct. Thank you. Referring to the CARES Program, the carbon-free energy around the clock, how much battery energy storage is allocated to the program?

Wilson Mallard (GPC): [11:05:29] So what's contemplated is enough battery energy storage to match with 650 megawatts of renewable energy in order to be able to produce a hundred megawatt block around the clock. I think we modeled close to 200 megawatts of batteries to be able to make that happen.

Robert Baker (SACE-SF): [11:05:48] Will battery energy storage have to be operational before the program is offered?

Wilson Mallard (GPC): [11:05:53] Yes. In order to produce the energy around the clock, the battery energy storage would have to be operational.

Robert Baker (SACE-SF): [11:05:57] Will the battery energy storage count towards the 1,000 megawatts by 2030?

Wilson Mallard (GPC): [11:06:02] It would not. It's a different use case, so we wouldn't count it towards the 1,000.

Robert Baker (SACE-SF): [11:06:06] Has the pricing for this carbon-free energy around the clock been established?

Wilson Mallard (GPC): [11:06:11] So preliminary pricing analysis has been done. But what we're looking to do here is to go to the market, solicit the solar resources, and be able to produce final executable pricing in PPAs to offer to interested customers.

Robert Baker (SACE-SF): [11:06:26] Okay. Turning to the Retail Resource Retail REC Retirement Program. [Yes.] If the company originally told the commission these RECs were going to be retired on behalf of all customers, shouldn't that commitment be honored?

Wilson Mallard (GPC): [11:06:37] So the certification language, as I remember it, Mr. Baker, says that the RECs should be used for the benefit of all customers. If the company decides to do something else with those RECs other than retire them on behalf of all customers, we would need commission permission. And so that's exactly what we're requesting here.

Robert Baker (SACE-SF): [11:06:56] How will the corresponding greenhouse gas accounting work for this?

Wilson Mallard (GPC): [11:07:01] So really what we're talking about here is just retiring these RECs on behalf of specific customers rather than all Georgia Power customers. And so we keep track of the RECs and who they're retired on behalf. It really doesn't impact the company's overall carbon emissions as measured at the stack. The ownership of the REC does not impact that.

Robert Baker (SACE-SF): [11:07:23] And are you familiar with the greenhouse gas protocol and the difference between the location based method and the market based method for scope two emissions accounting?

Robert Baker (SACE-SF): [11:07:33] No. All right, Mr. Mallard, your response to cross-examination by Mr. Walsh seemed to indicate that the company does not consider the REC transaction to also convey any emission reduction to subscribers. Is that correct?

Wilson Mallard (GPC): [11:07:49] Ask that question again, please.

Robert Baker (SACE-SF): [11:07:51] I'll slow it down. Your response at cross-examination to Mr. Walsh's question seemed to indicate that the company does not consider the REC transaction to also convey any emission reduction to the subscribers. Is that correct?

Wilson Mallard (GPC): [11:08:10] No, I don't think that is correct. The customer a subscriber who wishes to use that renewable energy to help them meet a carbon reduction or renewable energy goal does need the renewable energy credit retired on their behalf. That's what gives them ownership or title to the renewable energy attribute.

Robert Baker (SACE-SF): [11:08:29] Thank you. Final question. Does the ITS planning process apply a consistent cost benefit methodology or have a threshold cost benefit ratio that it employs to select projects for inclusion in the plan?

Michael Robinson (GPC): [11:08:42] We don't have a specific ratio. We do have a process through the joint planning process where we all as four participants in the ITS review projects, we're able to bring other projects, alternates for consideration. But ultimately, we're making the most economic decision for all customers in the state of Georgia. And we're incented to do that through the parity structure that exists in the ITSs. Thank you, gentlemen, for your time. Thank you, Madam Chairman. Thank you.

Tricia Pridemore (PSC): [11:09:12] Thank you very much, Mr. Baker. Mr. Hewitson. Do you have redirect?

Steve Hewitson (GPC): [11:09:16] I do, Madam Chairman.

Tricia Pridemore (PSC): [11:09:17] How much?

Steve Hewitson (GPC): [11:09:18] I'm going to attempt to do it in 5 minutes or under

Tricia Pridemore (PSC): [11:09:22] Got it. Go.

Steve Hewitson (GPC): [11:09:25] Gentleman, I know it's been a long day, and I'll try not to speak too quickly, but I think you'll be happy if we get through this quick. Mr. Grubb, you were asked several questions about keeping Bowen 1&2 available for use in emergencies. Just to be clear, are Bowen Units 1&2 being proposed for retirement only because of ELG compliance costs?

Jeffrey Grubb (GPC): [11:09:43] No, not just because of the ELG.

Steve Hewitson (GPC): [11:09:45] Does the company have a unique opportunity now with the capacity RFP results?

Jeffrey Grubb (GPC): [11:09:50] Yes, we do.

Steve Hewitson (GPC): [11:09:51] What are the benefits of that and acting quickly?

Jeffrey Grubb (GPC): [11:09:54] So the benefits of that are the pricing that we've got is 40 to 33% lower than contracts we have on hand now. And so the value of those capacity resources is great and we do not feel that we would be able to get comparable deals later down the road.

Steve Hewitson (GPC): [11:10:10] Mr. Walsh asked way back when this morning whether the Company could wait until 2025 to make a decision on Bowen 1&2. If Bowen 1&2 were to be retained as a generation source, these units would have to comply with the ELG right rule. Is that your understanding? [That's correct.] And would that take time to hook those units into the LPLG system at Plant Bowen? [My understanding is yes.] Do you know by when that decision would have to be made or that work would have to be done?

Jeffrey Grubb (GPC): [11:10:41] The work is, my understanding is that that needs to begin this, the latter half of this year for compliance by 2025.

Steve Hewitson (GPC): [11:10:50] To retain Bowen 1&2, in addition to the ELG compliance, would other investments need to be made in these units?

Jeffrey Grubb (GPC): [11:10:57] I think there's some in terms of a piping, as we talked about this morning, it's not massive, but there is work that has to be done, including Bowen 1&2.

Steve Hewitson (GPC): [11:11:06] Do you know if the cost of those investments would exceed the spending limits placed on Bowen 1&2 in the 2019 IRP?

Jeffrey Grubb (GPC): [11:11:12] So non ELG expenses would, in terms of normal capital investment in the units to keep them longer. And O&M would. Yes.

Steve Hewitson (GPC): [11:11:22] Thank you. I have some questions on the renewable integration study. Mr. Walsh asked questions regarding the flexibility violations and how they are not actual outages. Is it true, though, that not addressing the flexibility violations and the pressures that they create on operators may lead to actual outages?

Jeffrey Grubb (GPC): [11:11:42] Yes.

Michael Robinson (GPC): [11:11:43] As well as compliance violations, potentially.

Steve Hewitson (GPC): [11:11:47] Regarding battery storage ownership, you've been asked by a number of people if developers could build storage at a lower at a lower cost than the company could. But to be clear, Georgia Power is still planning to issue an RFP for actually building the battery storage. Is that correct? [Correct.]

Jeffrey Grubb (GPC): [11:12:07] And while it is possible to draft a contract and it includes lots of different contingencies, can you be sure that you know about every issue that could arise, even to include it in a contract for operating battery systems?

Jeffrey Grubb (GPC): [11:12:21] No. We do not.

Steve Hewitson (GPC): [11:12:21] Mr. Walsh asked you a couple of questions about accounting deferrals. And while the timing of recovery is decided in the rate case, is it your understanding that the Commission needs to grant the deferral of the remaining net book value of retiring units in the IRP to preserve the treatment...

Daniel Walsh (PIA): [11:12:39] I'm going to bbject on the leading nature of this question.

Steve Hewitson (GPC): [11:12:41] Just trying to move it along, Madam Chair.

Tricia Pridemore (PSC): [11:12:42] It's okay. Rephrase.

Steve Hewitson (GPC): [11:12:44] Okay. While the timing of recovery is decided in the rate case, what is your understanding of when the decision has to be made in terms of making the decision on the when the accounting treatment will be decided?

Jeffrey Grubb (GPC): [11:12:59] So the request to move to a regulatory asset has been asked in the IRP for prior retirement decisions.

Steve Hewitson (GPC): [11:13:12] Mr. Mallard, you were asked several questions regarding the behind the meter solar, specifically rooftop solar, of course. One of your comments was that Georgia Power is committed to growing rooftop solar in Georgia. Can you expand a little bit on the company's philosophy regarding growing rooftop solar in Georgia?

Wilson Mallard (GPC): [11:13:31] Yeah, sure. The company is committed to growing rooftop solar in Georgia, but doing so in a way where costs and benefits are accurately allocated and where non-participating customers are protected from any cost shifts or cost increases.

Steve Hewitson (GPC): [11:13:46] Gentlemen the exhibit GAM-2 that Mr. Jones, Clay Jones, put in front of you earlier today looked at the MG0 scenario in terms of renewable development. Do you remember that exhibit? [Yes.] If there was any price of carbon in another scenario, that makes the net benefit numbers more negative when you're looking at the exhibit that he put in front of you, is that correct?

Jeffrey Weathers (GPC): [11:14:19] Yes, that's right. The coal units, the economics of coal units would look worse if there's carbon prices in the scenario.

Steve Hewitson (GPC): [11:14:28] Do you think it is appropriate for the company to base retirement decisions only on one scenario, for instance, only on the MG0 scenario?

Jeffrey Weathers (GPC): [11:14:37] No, it's not. To do that would ignore risks to customers that aren't considered in that scenario. The better approach would be to consider a range of scenarios that captures those risks.

Michael Robinson (GPC): [11:14:47] And, commissioners, we have to anticipate the buildout of the transmission system and make sure that the transmission is there to accommodate those future retirements and those risks as Mr. Weathers lays out.

Jeffrey Grubb (GPC): [11:14:56] And then again, as we've mentioned, there's great value, these capacity RFPs that we brought forth in the pricing and to take advantage of those, is a timing decision, now. Thank you, gentlemen. That's all the redirect I have for you. Thank you, Madam Chair.

Tricia Pridemore (PSC): [11:15:12] Care to move into evidence into the record?

Steve Hewitson (GPC): [11:15:15] The only exhibits we have, or I did at the beginning, which were GPC-1, the trade secret version, as well as the public disclosure version.

Tricia Pridemore (PSC): [11:15:22] OK, they're in. I'll ask the court reporter at this time to make all exhibits part of the record. Thank you to the witnesses. You've been great for the last 11, almost 11 and one half hours. A couple of housekeeping matters tomorrow, Mr. Hewitson, I believe we're going to start with the Vale, Phillips, Smith and Evans panel, correct?

Steve Hewitson (GPC): [11:15:41] That is correct.

Tricia Pridemore (PSC): [11:15:42] OK. We're going to do so at 9:30 a.m. immediately upon the conclusion of the administrative hearing upon that adjournment. So thank you very much. We stand adjourned.