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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. UNDOCKETED

REVIEW OF TEN-YEAR SITE PLANS
OF ELECTRIC UTILITIES
_______________________________/

PROCEEDINGS: COMMISSION WORKSHOP

COMMISSIONERS
PARTICIPATING: CHAIRMAN ART JULIE I. BROWN
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER ART GRAHAM
COMMISSIONER RONALD A. BRISÉ
COMMISSIONER JIMMY PATRONIS

DATE: Wednesday, September 14, 2016

TIME: Commenced at 9:30 a.m.
Concluded at 10:48 a.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: LINDA BOLES, CRR, RPR
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P R O C E E D I N G S

CHAIRMAN BROWN: Welcome, everyone. Today is Wednesday, September 14th. If you could kindly silence your phones and electronic devices at this time, that would be much appreciated.

This is the Ten-Year Site Plan Commission workshop. And it's always one of my highlights of being a Commissioner to listen to what the folks are doing, so I'm excited to hear from all of you today, and this meeting is called to order.

Staff, can you please read the notice.

MS. LHERISSON: Yes, Madam Chair. We are here pursuant to notice issued on August 18th, 2016. This time and place is set for the Commission workshop on Florida's electric utilities' 2016 Ten-Year Site Plans. The purpose of this workshop is set out in the notice.

CHAIRMAN BROWN: Thank you so much.

The Florida Reliability Coordinating Council is here today, welcome, and to discuss its 2016 regional load and resource plan and statewide fuel reliability. Duke Energy, Gulf Power, Florida Power & Light, and Tampa Electric are also here today to provide presentations to us. And I do note that Sierra Club and SACE have mentioned that they would like to speak after them.

Following the presentations of all of that, we will have opportunity for public comment as well, and we have a podium dedicated to that over there.

We're going to move to the presentations at this time. And the order of presentations -- we will begin with the Florida Reliability Coordinating Council. Ms. Stacy Dochoda, who is president and CEO of the FRCC, will be giving her presentation to us. So I'd like to welcome you.

MS. DOCHODA: Let me just see if the mic is on. Yes.

Good morning, Chairman Brown, Commissioners. Thank you for having me today. I will help you a little bit with my name. I know it's a real struggle. The C in my last name is completely silent. It's Dochoda, Stacy Dochoda. Thanks so much.

I am the president and CEO of the Florida Reliability Coordinating Council, and we're so pleased to be able to come again and present the Ten-Year Site Plan.

I'll address traditional Ten-Year Site Plan topics of the load forecast, generation additions, reserve margins, and fuel mix. In addition, I'll provide an overview of the utility's integrated resource plans and how those plans fit into the FRCC resource planning process and Ten-Year Site Plan report. I'll also address today FRCC fuel reliability and the reliability in the FRCC region.

The mission of the Florida Reliability Coordinating Council is to promote and assure the reliability of the bulk power system in peninsular Florida. Based on the Ten-Year Site Plans, planned reserve margins are expected to be greater than 20 percent over the ten-year horizon. Demand-side management will continue to be a significant component of projected reserves. Renewables are projected to be about 2 percent of energy served by 2025. Natural gas as a percentage of energy served is projected to be approximately 65 percent over the next ten years. And, finally, the EPA Clean Power Plan effects, those will be addressed in future Ten-Year Site Plans once the litigation over that plan is resolved.

So I'll begin with the load and resource plan. In Florida, each utility does its own integrated resource plan. The utility will prepare forecasts of electric demand and energy usage considering drivers such as customer growth, impacts of energy efficiency, and also average weather.

The utility will also develop a fuel and resource price forecast. Utilities consider the available demand and energy that can be produced by their existing resources, and they also factor in any plans for modifications like upgrades or efficiency improvements, and also consider the impact of any resource retirements that they have planned or the expiration of purchased power agreements. So they look at both their forecasts on load and demand and energy and the resource requirements -- resource availability.

They compare those demand and energy needs and the resource availabilities to their target reserve margin criteria and other reliability criteria, and where there is a gap or shortfall, then the utility will consider the options for meeting those reserve margin targets. The options can include supply-side resources such as new generation or purchased power, or they can include demand-side options such as load control. So the costs of -- the costs in the operating criteria of those options would then be used to evaluate the alternatives, and the result of that analysis taken together forms the utility's integrated resource plan.

So then at FRCC, the individual utility integrated resource plans are brought together to create the FRCC load and resource plan that we provide to the Commission. In addition, at FRCC we use the load and resource plan data to conduct reliability assessments of generation adequacy and transmission reliability.

Now I'll discuss the load forecast. Now while economic factors are a positive driver of the load forecast over the next ten years, increasing impacts from energy efficiency codes and standards are causing the per-customer usage to decline, and so that, put together, the forecasted energy sales and peak demands for the 2016 Ten-Year Site Plan is lower than the 2015 Ten-Year Site Plan.

And this chart shows the impact of the energy efficiency codes and standards in the load forecast. As a point of reference, those codes and standards are projected to reduce summer peak and energy usage by over 3.5 percent by 2025. For summer peak demand, this year's Ten-Year Site Plan has an average growth rate of 1.13 percent compared to 1.46 percent in 2015. The drivers to the flattening demand include lower usage per customer, as I mentioned before, and the increasing impact of energy efficiency codes and standards.

This is the winter firm peak demand forecast. 2016 starts a little lower than last year's Ten-Year Site Plan and then approaches last year's forecast. We've had very mild winters in many recent years, and those have impacted the weather averages that are used to develop the winter forecast.

The 2016 energy forecast has a compound annual growth rate of 1 percent. On average, this 2016 energy forecast has shifted downward about 2.7 percent from the 2015 forecast. The main drivers are lower usage per customer and also the increasing impact from the energy efficiency codes and standards and, to a more modest degree, customer self-generation, including the impacts of distributed solar.

This graph shows the current forecast demand compared to the trend line of the actual demands from 1990 to 2015. Again, you can see that the current forecasts are shifted down somewhat from what a historical trend line would predict.

On slide 14, on this graph we have the red line, which is projected summer firm peak demand. The upper yellow line is demand without demand response and energy efficiency programs. Demand response lowers the demand forecast by 6.3 percent by 2025. Utility energy efficiency programs are projected to reduce demand by 1.4 percent by 2025.

Here we have the compound average annual growth rate for firm peak load summer and winter. The 2016 Ten-Year Site Plan summer compound annual growth rate is 1.13 percent and winter, 1.02. This chart, you can really see the decline in forecasted growth rates from around 2 percent in the early 1990s to around 1 percent today.

Okay. Now I'm going to switch from the load forecast to resource capacity. This bar chart shows the available capacity over the ten-year horizon. It includes the impact of new builds and retirements. A net of 8,300 megawatts of additional generation is planned for the FRCC region over the ten years. There's about 9,700 megawatts of combined cycle planned, 2,400 megawatts of combustion turbine, 1,100 megawatts of nameplate solar, and then there are also about 4,300 megawatts of planned retirements, which are coal and less efficient steam and combustion turbine units.

On slide 17, using the forecasted firm load and the projected available resources, we've calculated the reserve margin over the ten-year period. We project that reserve margins based on the firm load to be above 20 percent over the forecast period.

On slide 18 here we have reserve margins excluding demand response and utility energy efficiency programs. This summer, generation only reserve margin declines from about 15 percent in 2016 to 13 percent in 2018, and then remains at approximately 15 percent for the remaining years. The FRCC region continues to have the most significant portion of reserves coming from demand response compared to the rest of North America.

So to summarize the reserve margin review, based on the 2016 Ten-Year Site Plans, reserve margins are planned to be greater than 20 percent over the ten-year horizon, and demand response is projected to continue to be a significant portion of our reserves.

Now I'll move to a discussion of fuel mix. These pie charts show the fuel mix on an energy basis. Natural gas continues to be the largest fuel source at between 61 and 64 percent. Renewables grow from 1 percent in 2016 to 2 percent in 2025. And just as a point of reference, it takes about a thousand megawatts of nameplate additional solar generation for solar to provide about 1 percent of energy in the FRCC region.

This is the fuel mix in installed capacity. Natural gas-fired capacity is between 71 and 74 percent on a megawatt basis over this time period.

This pie chart breaks down our current renewable resource capacity. Out of 1,583 megawatts currently, the largest percentage comes from biomass at 37 percent and municipal solid waste at 28 percent. Solar is 11 percent of current renewable capacity.

Planned additions of renewables over the ten years include 278 megawatts of biomass and 1,167 megawatts of nameplate solar. For nuclear capacity, we currently have about 3,600 megawatts, with 40 megawatts of planned upgrades during the ten-year horizon.

Moving to the Clean Power Plan, the Clean Power Plan remains stayed, with oral arguments currently scheduled for September 27th. So impacts of the Clean Power Plan would be addressed in future Ten-Year Site Plans.

So summarizing the load and resource plan, the region is projected to have adequate planned reserves over the ten-year period. Demand response and the effective energy efficiency codes and standards will continue to be a significant component of our reserves. Natural gas will be about 65 percent of energy, and renewables are projected to be 2 percent of energy by 2025.

So now I'll discuss fuel reliability in the FRCC region. FRCC has a Fuel Reliability Working Group which reviews existing interdependencies of fuel availability and electric reliability and also coordinates regional responses to fuel issues and emergencies in real time.

In the FRCC region, energy production from natural gas has increased significantly from the year 2000 to today and is projected to continue to increase.

So looking at the ways that the region has mitigated the reliance on natural gas as a region, we have a significant portion of natural gas-fired units that can also burn alternate fuels such as fuel oil. Dual fuel capability is expected to remain between 70 and 75 percent of the total megawatts of natural gas capacity over the ten-year period.

As to natural gas delivery infrastructure, Florida currently has two major natural gas pipelines. The Florida Gas Transmission has capacity of 3.5 Bcf a day, and Gulfstream has 1.3 Bcf a day. Since about 65 percent of our energy production is from natural gas-fired generation, the natural gas delivery infrastructure is very important for electric reliability.

There is a third natural gas pipeline under construction with an expected in-service date of mid 2017. The new system includes the Sabal Trail pipeline and the Florida Southeast Connection, which connects to the Sabal Trail at the new Central Florida Hub. The new pipelines will provide increased fuel supply flexibility. The Central Florida Hub interconnection provides increased operational reliability by connecting the two existing pipelines with Sabal Trail and Florida Southeast Connection, and it allows the capability to transfer gas between the pipelines. So with the new pipelines there will be improved delivery diversity by adding that third pipeline.

Additional fuel flexibility is available through contracts the utilities have with natural gas storage facilities out of state. This storage can yield about 1 Bcf a day of natural gas.

So summarizing our review of fuel reliability for the region, we have enough existing and planned pipeline capacity to support electric generation. We have additional flexibility from gas storage contracts and significant dual fuel capability. The third gas pipeline will be an important increase in natural gas supply diversity, capacity, and reliability for the region.

So to conclude my discussion today, again reserve margins are projected to be above the target of 20 percent for the next ten years, natural gas will be about 65 percent of energy production, and the third pipeline, dual-fueled units, and out-of-state gas contracts support reliability in the region. The effects of the Clean Power Plan will be discussed in future Ten-Year Site Plans. So with that, I'd be happy to answer any questions that you have.

CHAIRMAN BROWN: Thank you, Ms. Dochoda. I appreciate the presentation.

Commissioners, I do have a couple of questions, so if you'd just hold off on yours for a second. Can you please turn to page 15 of your report?

MS. DOCHODA: Sure.

CHAIRMAN BROWN: Oh, I'm sorry. Page 17.

MS. DOCHODA: Okay.

CHAIRMAN BROWN: And it's also discussed on page 18 for the year 2018. Can you explain what's happening in the 2018 year for firm load in the summer?

MS. DOCHODA: Let me make sure I'm on the same page. 17 or 18?

CHAIRMAN BROWN: Yes, 17.

MS. DOCHODA: 17. Okay. And, I'm sorry, the question?

CHAIRMAN BROWN: I like to confuse you.

MS. DOCHODA: Thank you.

CHAIRMAN BROWN: For the year 2018 on page 17, what's happening in 2018 for firm load in summer?

MS. DOCHODA: In -- are you asking, like, the firm load is approximately steady? Is that --

CHAIRMAN BROWN: It's lower. It is lower than the other years as well on page -- 2018 without demand response, it looks to be lower than the other years for the summer.

MS. DOCHODA: You know, I'm afraid I don't have that at hand, but I bet my folks here can help me come up with an answer, and perhaps I could answer at the -- toward the end of the day.

CHAIRMAN BROWN: That sounds great. Also on your presentation you talk about population growth remaining strong. Do you have what the projected rate of growth is for population throughout the state over the ten-year period?

MS. DOCHODA: I think I do. Let's see. We do have that. Denise, do you have that handy?

We haven't reduced it to a rate of growth, but we show a change that has occurred historically from, like, 18.8 million to about 20.3 million is the change over a five-year period. And, again, we could follow up with a little bit more detail, if you'd like.

CHAIRMAN BROWN: Okay. Thank you. Appreciate that.

MS. DOCHODA: Sure.

CHAIRMAN BROWN: Commissioners, any questions for Ms. Dochoda? Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Madam Chair.

Good morning.

MS. DOCHODA: Good morning.

COMMISSIONER EDGAR: Thank you so much for being here. The work that you do has always fascinated me, so thank you.

A couple of times in your presentation you mentioned that the impacts of the Clean Power Plan would be assessed in a future planning period, which I found a little confusing because you also mentioned that there are some, you know, coal plants that have closed, and my understanding is that many of our utilities have taken steps, a variety of measures to reduce carbon or to be more efficient or to -- so when you say the Clean Power Plan will not be taken into account, can you just elaborate as to what you mean by that?

MS. DOCHODA: Sure.

COMMISSIONER EDGAR: Thank you.

MS. DOCHODA: No, I'd be happy to. I think, frankly, there's numerous things that affect, you know, a retirement, and I don't know that they could be necessarily attributed to any one particular driver. So certainly perhaps some of the retirements are influenced by the Clean Power Plan. But I do believe that, and the utilities may want to speak to it more specifically, but I believe that the MATS regulation also heavily influenced some of the decisions that were being made, and then also just the simple economics of the current -- the current economics of the gas and coal.

So I think all of those drivers are impacting the retirements that we're seeing.

But I do believe, in terms of any further impacts that might be from the Clean Power Plan, it is possible we would see further impacts in future Ten-Year Site Plans that we don't see today.

COMMISSIONER EDGAR: Thank you.

CHAIRMAN BROWN: Thank you.

Commissioners, any further questions?

Thank you very much for your presentation and for coming up to Tallahassee.

MS. DOCHODA: Thank you so much.

CHAIRMAN BROWN: All right. Moving on to the Florida investor-owned utilities. We have before us -- the order will begin Duke Energy, Gulf Power, Florida Power & Light, and then Tampa Electric.

And from Duke Energy we have Mr. Ben Borsch here. He's director of integrated resource planning. And welcome.

MR. BORSCH: Thank you. Good morning, Commissioners.

CHAIRMAN BROWN: Good morning.

MR. BORSCH: Thank you for the opportunity to present and update on the DEF resource planning process. Although our overall process has not changed significantly, DEF, like the other Florida utilities, continues to update our processes to accommodate changes in generating technologies and in customer behavior and in technology adoption.

Florida Statutes define the obligation of the utilities to provide sufficient, adequate, and efficient service at rates that are defined to be fair and reasonable. At Duke Energy, we express this as a mission to provide our customers with electricity that is safe, reliable, affordable, and increasingly clean. To this end, we work within a planning process that focuses on developing plans for reliable and sufficient generation, and then selects among those options for cost-effective generation and improving environmental impacts.

At a high level, the generation planning process is driven by a balance of customer consumption with the available resources. DEF forecasts future system needs, taking into account both the demands of the customer and the needs of the system for reliability, and then weighs that system demand against the available resources accounting for unit conditions, potential retirements, contract terms, and other operating factors. This evaluation determines our need for additional resources in the future.

The load forecast is one of the most important elements in long-range planning. In the past, the DEF load forecast has focused on three principal types of variables: Economic growth, numbers and classes of customers, and weather.

As we project into the second half of this decade, into the 2020s and beyond, we are also focusing on three additional and interrelated areas: Organic energy efficiencies, distinct from utility-sponsored programs, which appears principally in the form of mandated updates to efficiency codes and standards; customer behavior; and behind-the-meter generation, predominantly in the form right now of customer-owned solar. Collectively these three elements have combined to result in an increasing reduction in DEF's long-term expectation of the growth in both energy and capacity needs, and this is evident in the trends shown statewide on slide 12 of the FRCC presentation. These also have an impact on the load shape, which in turn affects both the capacity need and the system support requirements.

DEF then reviews the existing fleet of resources. Units are reviewed for reliability, for remaining life and potential risks, for functions within the portfolio. As we look to the future and the introduction of more and more intermittent resources, there is a particular focus on fleet flexibility and on maintaining system reliability not only in terms of generation but also power quality.

DEF then looks at new resource alternatives and options. DEF renews alternative technology options for commercial and technical feasibility; for portfolio fit, that is the way in which a technology works within the portfolio to serve the demand; and cost, considering the life cycle cost of the system.

Economic comparisons of technologies depend on all different factors: Fuel price, capital cost, any other operating assumptions, and utilization rates are also a key factor in how a particular unit may fit within the system. So we perform detailed modeling to make sure that there's a balance in the way that different units are operated.

So the single element of technology cost can't be reviewed in a vacuum. It has to be reviewed in the context of the whole system comparison. Often times you'll see comparisons of technologies strictly on a levelized cost basis, which is indicative of how they might fit in an overall stack, but it's not by itself sufficient for planning because you have to have that balance of understanding how units will perform in an overall system. That -- excuse me.

So DEF evaluates technologies in three different categories, what we call emerging, developing, and mature technologies.

Emerging technologies are considered to be undergoing considerable technological or commercial change and are evaluated but typically not considered in a given year's resource plan. Duke Energy's Emerging Technology Office meets regularly with the developers of a wide range of technologies that are currently in development to perform evaluations and understand the potential for these technologies to be utility ready.

Mature technologies are those that are well known, widely deployed, typically stable in their technology development and in their costs. Duke Energy works with engineering consultants who provide costs for current installations of these technologies and projections of cost changes and incremental improvements based on discussions with the manufacturers and with their own EPC experience.

Developing technologies are those which are commercialized and are receiving wide deployment but which are also expected to undergo significant commercial or technical change in the next five years. PV solar remains in this category as Duke Energy expects to see ongoing improvements both in unit efficiency and most especially in installed cost. In this regard, Duke utilizes a combination of our current experience from recent RFPs, from installed project costs, with consultant expectations of future price and technology changes. Developing technologies are expected to have levelized costs with declines exceeding 20 percent over five years.

Technology costs are made up of different components. And while I talked a moment ago about the insufficiency of levelized cost comparisons, they do provide a useful indicative measure. Levelized cost comparisons can show you the elements of different technology costs and their relative prices, although they're not by themselves sufficient for planning because they don't give you hourly performance and detailed unit behavior. Levelized costs can then be used to develop busbar curves, which again are an adequate screening tool but not definitive for planning. This view begins to give us a comparison of how these technologies will perform in terms of their effective capacity factors and their overall use.

We develop definitive data and detailed data for each technology that we evaluate. Detailed data includes data on equipment purchase and construction, fuel use, dispatch and operating costs, capital maintenance and parts requirements, emissions costs, as well as performance and affected -- expected efficiency degradations and outage cycles.

These are incorporated into our detailed production cost models and evaluated for different portfolio costs and feasibility. Recognizing that this is a process that DEF performs more than once a year, DEF generally anticipates need several years in advance of the actual need and of the time frame in which specific action must be taken. As a result, while a particular unit may appear in the plan, that unit, if it's farther in time than the time required to permit, construct, and engineer a project, the unit becomes essentially a placeholder representing an identified need which will continue to be evaluated until it becomes the next planned generating unit. During that period, DEF begins to evaluate specific options that would influence a final selection, including technology options, locations, and grid impacts. As well during this evaluation, the resource need, the technology, performance, and costs and other factors like environmental regulations or fuel prices may change, resulting in an alternative choice before the selection of a specific project.

So finally we reach DEF's 2016 plan. The current resource plan includes several units selected through the need process in recent years which are committed and coming into service in the next 24 months or so. The next new unit need is not projected until 2024. The selected combustion turbines will continue to be evaluated over the next several years. DEF has also projected that construction costs, fuel costs, and environmental policy will favor the installation of a significant amount of solar generation over the next ten-year period, while this too will continue to be evaluated.

CHAIRMAN BROWN: Mr. Borsch, not to -- my apologies for interrupting you.

MR. BORSCH: That's okay.

CHAIRMAN BROWN: But on this chart, the red, those are retirements?

MR. BORSCH: Yes. Yeah, the red are units which either represent retirements, contract expirations, or unit derates, which are -- so effectively all of those reds are elements which would reduce our generating capacity.

CHAIRMAN BROWN: And, conversely, the blue?

MR. BORSCH: And, conversely, the blue are additions.

CHAIRMAN BROWN: Thank you.

MR. BORSCH: And that actually is a perfectly timed question because I'm at the end. So thank you.

CHAIRMAN BROWN: I planned it that way.

Commissioner Brisé.

COMMISSIONER BRISÉ: Thank you, Madam Chair.

Thank you for your presentation. So you mentioned the process of determining which new technologies that Duke would take into account. Are you in a position to share some of those technologies that are considered emerging now that Duke is exploring?

MR. BORSCH: Well, I think we can -- yeah, I mean, I think we're not doing anything that's completely secret here. So even on the slide, if I could find it, which I may --

CHAIRMAN BROWN: It's page 8.

MR. BORSCH: Yeah, there we go. We have -- you know, we're looking -- there's just a few examples. Certainly there's a wide range of things. And our technology evaluations include not only things that would be considered conventional generating technologies like wind or, you know, for instance, small modular nuclear or any number of things, but also things which are grid tied or demand-side technologies. We're looking at a variety of arrays of new demand-side technologies, evaluating how the utility might participate in the deployment of, you know, for instance, programmable water heaters and, you know, as well as smart grid technologies. So there's a pretty wide envelope of different kinds of things that we're keeping an eye on.

COMMISSIONER BRISÉ: I think at one of the NARUC meetings I went to there was a conversation around underwater hydro. So is there any conversation at Duke surrounding that?

MR. BORSCH: Well, I think you're probably referring, for instance, to, you know, tidal hydro.

COMMISSIONER BRISÉ: Uh-huh.

MR. BORSCH: It's on our list. I know that, you know, when the emerging technology guys publish their large list of technologies that that does appear on the list. I haven't been given an update on their findings on that recently.

COMMISSIONER BRISÉ: Sure.

MR. BORSCH: But it is in the envelope.

COMMISSIONER BRISÉ: Okay. All right. Thank you.

CHAIRMAN BROWN: Thank you, Commissioner Brisé.

Commissioners, any further questions?

Just one quick question about the percentage of Duke's customers using behind-the-meter generation such as solar. Do you have a number?

MR. BORSCH: I don't have a number, but it's quite small. I know that it's less -- well less -- significantly less than 1 percent at this point. So it's, you know, it's -- on the other hand, it's also growing very rapidly. I think we've seen more than a doubling in the last year. So it's kind of on -- you know, we're still sort of in the infancy, but we are anticipating and already experiencing a very rapid growth rate.

CHAIRMAN BROWN: Thank you. Thank you for your presentation.

All right. Moving on to Gulf Power. We have with us today, from Gulf Power, Sybelle, Sybelle Fitzgerald.

MS. FITZGERALD: Sybelle.

CHAIRMAN BROWN: Sybelle. It's spelled uniquely.

Ms. Fitzgerald is manager of generation resource planning for Gulf Power. And welcome.

MS. FITZGERALD: Thank you.

CHAIRMAN BROWN: You're welcome.

MS. FITZGERALD: Good morning, Commissioners.

CHAIRMAN BROWN: Good morning.

MS. FITZGERALD: My name is Sybelle Fitzgerald. I'm the generation resource planning manager for Gulf Power, and I'll be going over today's presentation.

We're going to start off with an overview, and I'm going to be talking about the load forecast, the factors considered for our next resource need, our need year driver, as well as Gulf's generation energy source mix. Then I'll be moving to our next resource need as is pointed out in our Ten-Year Site Plan, and then what we considered for our site and technology selection.

So this slide goes into our retail energy sales. And the story behind this graph is just to show that our energy sales have remained flat, and that's due primarily to our customers using less of our product. You can see that there's a few, you know, bumps in the line there, and that's mainly just due to, you know, your fluctuations in weather and then lower usage by our customers, depending on residential customers or industrial customers.

So this slide just simply depicts the Gulf Power service territory footprint in red, just to remind everybody that we're located in Northwest Florida and we're in the SRC -- SERC, SERC.

The next slide, we go over our factors

considered for our next resource need. And like everybody else that we hear from, we consider technology such as cost and time to construct, cost to operate, and whether the technology is dispatchable. We look at fuel, pipeline infrastructure, and the proximity to that, and the commodity, the type of fuel that will be needed for the technology. We also look closely at transmission, what are the interconnection requirements: Is it going to be to 115 or 230, is that within our site, how far is it from our site, and the system impacts that that type of generation has on the performance of our transmission grid.

Site factors, some things that are very important to us is the consideration of the environmental factors: Whether it is wetlands, are we going to have to do any mitigation, is there any endangered species on the site?

We also consider the elevation of the site. You know, we're primarily a coastal company, and we like to, you know, look at siting away from, you know, the impacts of hurricanes and those sort of things. We look at any easements that may need to be acquired and the impacts on the public from that, and acquiring new right-of-way. And then lastly performance, of course, the performance of the unit that is chosen or the technology and the value that's provided to the system and the customers, because reliability is one of the most important things to us.

Our next slide here talks about our need year driver. So in 2023, we have the expiration of our largest purchased power agreement. That's with Central Alabama. It is for 885 megawatts. So you can see that we fall severely below our target reserve margin, so in 2023 we're going to have to look at adding some new capacity.

My next slide here talks about our generation energy source mix. And in 2015, 1 percent of our customers -- 1 percent of our customer load was served by renewables. And that was made up of our municipal solid waste facility that's located in Panama City, which is 11 megawatts, that's a purchased power agreement, and also our own Perdido landfill gas unit, which is approximately 3 megawatts.

But we're proud to say that we recently signed a new purchased power agreement for our Kingfisher 1 facility, which is a wind product, and that increased us to 6.2 percent for renewables.

And then looking at 2017, we increase to 11 percent, and that's through the addition of a second wind contract which is under consideration by the

Commission now. That'll add another 94 megawatts of wind. The first deal is 178 megawatts of nameplate capacity. And then our three large-scale solar military projects that are under a purchased power agreement will be 120 megawatts, and those are scheduled to complete construction next year.

So the next slide, I want to discuss our next resource need. Our next resource need is a strong capacity need. We feel that we need a dispatchable resource for that. So, as such, we considered the technologies of the combustion turbine and the combined cycle. Now they both have their pros and cons, such as the CT has a lower installed cost but yet a higher energy cost to operate. A combined cycle is better efficiency but yet a higher installed cost to operate than a CT. The components that we look at are the capital costs, operations and maintenance, and your energy and capacity value.

So moving to our site and our technology selection, as I mentioned before, we looked at CCs and a CT across six site locations, and we determined that, per our 2016 Ten-Year Site Plan, that the technology of choice right now is for a combustion turbine, multiple combustion turbines to meet our need, although additional studies are required to finalize the technology. We will be running more studies.

And our anticipated sites are our North Escambia site and our Smith Plant site. We might be splitting CTs across those two sites. Preliminary studies show these sites to be economically favorable because they're in close proximity to electrical transmission, gas pipeline, and water supply. But, again, we are doing more studies before we finalize the site selection, but that's how things are looking right now based on our latest studies.

So, Commissioners, this concludes my presentation. Do you have any questions for me?

CHAIRMAN BROWN: Thank you, Ms. Fitzgerald.

Yes, I do have some questions. On page 6 of your presentation, you talk about the expiration of the 2023 purchased power agreement, and you mentioned something about looking at adding new capacity.

Has Duke -- has Gulf, pardon me, contemplated extending that PPA or entering into another PPA or -- rather than new generation?

MS. FITZGERALD: That's a good question. We don't know what the situation for the Central Alabama combined cycle unit will be, you know, at the time that we move forward with an RFP, and we don't know what the pricing will be or, you know, just what the situation will be with that. But, of course, we will evaluate it to see if it'll meet our needs.

CHAIRMAN BROWN: Thank you. And then on your Gulf generation energy sources, page 7, you mentioned some of the wind projects in 2016 and 2017.

MS. FITZGERALD: That's right.

CHAIRMAN BROWN: Taking out the wind projects, what would the percentage of renewables be for 2016 and 2017, if you can do that?

MS. FITZGERALD: Yeah. So the wind project was 8.6 percent. So the remaining of that, the solar is 2 percent and the MSW and the landfill gas that we have at our Perdido facility, which is about 3 megawatts.

CHAIRMAN BROWN: Thank you. Appreciate it.

MS. FITZGERALD: Sure. We'll have a total of 406 megawatts of generation from renewables in 2017.

CHAIRMAN BROWN: Great. Thank you very much for your information, your presentation.

Commissioners, any further questions? Have a great day.

MS. FITZGERALD: Thank you. Appreciate the opportunity.

CHAIRMAN BROWN: Thank you.

Moving on to Florida Power & Light, and with us today is Dr. Steve Sim, who is the senior manager of resource assessment and planning at FPL. Welcome, Dr. Sim.

DR. SIM: Good morning.

CHAIRMAN BROWN: It's been a long time.

DR. SIM: It has been.

Well, Madam Chair and Commissioners, it's good to see you again, and it's a pleasure being here to discuss this subject.

Let me start out by saying that we're all aware that the 2016 site plan was filed in April of this year, which is roughly six months ago. And what I'd like to do is take you back 12 months before that and start with where we were with our 2015 Ten-Year Site Plan, summarize that, and then move forward taking a look at some of the key forecasts or assumptions that we used in coming up with the 2016 site plan and show how the two site plans differ. So that's the approach here.

All right. This is how I would summarize the 2015 site plan. In 2016, we had, in our site plan, showing the completion of modernizations of some of our combined cycle and combustion turbine projects, the Port Everglades modernization, the removal of a bunch of 40-plus-year-old gas turbines, and the replacement with some brand new and more efficient combustion turbines. We also showed, for 2016, that we would be taking advantage of three highly advantageous sites and putting in about 224 megawatts of photovoltaics.

And then let me ask you to skip down, please, to 2019. The other thing that we showed in our 2015 site plan was a significant resource need in 2019 that was projected, and we had in our site plan as a placeholder at the time an Okeechobee combined cycle unit that we were projecting as our best self-build unit. And it was the next planned generating unit in a capacity RFP we had sent out and was the basis of our need determination filing for that unit.

And then finally, down in 2023, that was the date or the year in which we had our next significant resource need projected at the time, and as a placeholder we had an unsited combined cycle.

Now after April of 2015 when we filed the site plan, we focused largely, in our resource planning work, on our post-2019 resource needs and on the options which could address those needs. And before I leave this slide, let me point out that in all of our resource planning work and certainly what is shown in our annual site plans, we take into account the DSM goals that the Commission has set for FPL. We assume those will be achieved, and we fully account for those in all of our resource planning work.

Now in our resource planning work, I'd say there are three primary forecasts or assumptions that tend to drive the outcome of the resource planning analyses, and the first of these is our peak load forecast. Now on this graph, the black line shows what the peak load forecast was in our 2015 site plan. The red line is what the peak load forecast was in our 2016 site plan. And as the graph shows, the more current load forecast is considerably lower, especially from about 2020 to on compared to the prior load forecast. And what this means is this tends to reduce and defer our projected resource needs into the future.

The second such forecast is our natural gas cost forecast. Again, black line is the 2015 site plan, red line, 2016. It shows that our projected natural gas costs were noticeably lower than what they were in 2015, and this tends to improve the economics of gas-fired resource options when we analyze them versus non-gas-fired options.

And the third of these key assumptions or forecasts is our CO_2 cost forecast. Once again, black line is 2015, the site plan, red line, 2016. And as we -- as the graph shows, the 2016 numbers are lower in every year in regard to where we were a year before. And what this does is that the lower CO_2 projected cost tends to reduce the cost-effectiveness of any non-CO_2 emitting resource options such as solar, such as DSM, all else being equal.

So with those forecasts in mind, the analyses that we conducted from April of 2015 that culminated in the 2016 Ten-Year Site Plan filing was one that focused primarily on combined cycle, combustion turbine, and photovoltaic options. During that time period, the Commission approved the Okeechobee combined cycle as the best option with which to meet our 2019 resource need. And then due to the lower load forecast that we just addressed, our next significant resource need moved back a year from 2023 to 2024. So no decision is needed regarding that resource option until at least three years, probably around 2019, and that's because there's about a five-year time frame in which to complete the regulatory permitting and construction of a combined cycle unit. If we decide to build something other than a combined cycle, the odds are that that decision need can be postponed even further.

In regard to the three options, my opinion is there's more certainty regarding the cost and the firm capacity contribution of combined cycle and combustion turbines than there is for PV. But the more we study PV, the more we've become convinced that it is becoming increasingly competitive. And, in fact, over the next ten years, we see combined cycles and photovoltaics as being the competitive options.

And, therefore, my last slide ends up with the summary of the 2016 Ten-Year Site Plan. And what I've done is in red I've tried to show what I think are the more significant changes from the 2015 site plan. First of all, on the 2019 row, as mentioned earlier, the Commission approved the Okeechobee combined cycle unit to meet the 2019 need.

In 2020, what I'm showing is there is a loss in terms of reserve margin of 382 megawatts of coal capacity from the St. Johns PPA that we have. Now that PPA has an IRS regulation that applies to it that allows us to only take up to a certain point in the amount of megawatts, megawatt hours that we can receive. And in the 2015 site plan, we assumed or were projecting that that limit would be met by second quarter of 2019 because of lower gas costs, less coal is being used. So by the time we got to the 2016 site plan, that projected limit had slid from second quarter to fourth quarter of 2019.

We were seeing projected decreases in solar cost. We were finding certain sites that we thought were advantageous sites for solar and, therefore, in our

2016 site plan we show 300 megawatts of additional PV coming in -- in the text, we said by 2021. For planning purposes, we show it here coming in at 2020.

And then finally, as mentioned earlier, our next planned generating -- our next planned significant resource need is moved from 2023 back to 2024. And as a placeholder, we've put in an unsited combined cycle there, but no decision has been made for that year.

That completes my presentation. I would like to pick up on a point that Stacy made earlier, if I may. She mentioned that in terms of the FRCC region, it would take 1,000 megawatts of nameplate PV in order to supply 1 percent of the total energy mix for peninsular Florida through photovoltaics. For FPL, because we're a smaller system, that walking around number is probably about 525 megawatts of PV that would move our fuel mix by 1 percent. And I think that's useful, both the 1,000 for FRCC, the 500-plus for FPL, because it shows that it will take large blocks of photovoltaics in order to move the needle in terms of energy mix for the state.

And that's driven by primarily two things. Number one, the size of FPL -- excuse me -- of Florida's utility systems, and the second is that the photovoltaics capacity factor is relatively low in terms of resource options, at about 25 percent is probably a rough average for the various utilities. So on that note, let me try to answer any questions you may have, and thank you.

CHAIRMAN BROWN: Thank you, Dr. Sim. Thanks for your presentation.

Commissioners, any questions? Commissioner Brisé.

COMMISSIONER BRISÉ: Good morning, Dr. Sim.

DR. SIM: Good morning.

COMMISSIONER BRISÉ: Similar question to what I asked Duke. What is your process to evaluate new technologies, and what are some of the new technologies for generation that FPL is looking at?

DR. SIM: There's one department in FPL, our project development department, that has the lead in examining a number of, let's say, emerging or future resource options. In terms of those, we are looking at with more of a near-term focus. Solar is obviously number one. Not a day goes by but we don't have another solar analysis, it seems, that we wish to run. And as of late, battery storage is getting a lot of attention in our planning efforts.

CHAIRMAN BROWN: Dr. Sim, I asked, I think it was Duke, a question about what percentage of customers, of FPL's customers, though, are behind the meter. Do you have a number?

DR. SIM: Yes, Madam Chair. I believe the number as of year end 2015 was roughly 4,250.

CHAIRMAN BROWN: You're seeing an increase?

DR. SIM: It is a steady increase, yes.

CHAIRMAN BROWN: Okay. Thank you. Thanks for your presentation.

DR. SIM: Thank you.

CHAIRMAN BROWN: All right. Moving on to Tampa Electric Company. And with us from Tampa Electric is Mr. Jim Rocha, who is the director of resource planning. Mr. Rocha, welcome.

MR. ROCHA: How are you?

CHAIRMAN BROWN: How are you?

MR. ROCHA: Terrific.

CHAIRMAN BROWN: How are folks down in Tampa?

MR. ROCHA: We're doing good. We got most of the limbs out of the way. Everybody is returned to service, even my friends who call me and think they can get ahead of the line with folks working 16-hour days, you know.

CHAIRMAN BROWN: I do. I know that. I do know that.

MR. ROCHA: I'm really excited about everybody wanting to hear about generation planning because when I give these presentations at work, I tell everybody it's the center of the known universe, and I never understood why nobody agreed with me. So let's see if I can figure out this thing.

So starting with the obvious on the first two bullets, but starting out at a very high level, 30,000 foot, what are we trying to do? We're trying to compare demand-side and supply-side resources on a consistent and comparable manner so that we get the most cost-effective and reliable system that we can build in the future.

On top of that, we then have this reliability analysis that I'll go into a little bit as we go forward where we look at different alternatives, compare them to future forecasts of both fuel and capacity and demand needs, and pick the source, the top sources.

So this is my little picture of our flow diagram, and it starts with the demand and energy forecast. And we go out 30 years with that demand and energy forecast, and it includes all existing and future demand and conservation programs that we have. This is used to determine reliability needs in the future and when it would occur and the magnitude of megawatts that would be needed for customers.

The first step is, as Ben pointed out, we do look at levelized cost curves. Those are the ones that always end up in the paper because it's a very nice number to compare. They're good for being informative, and I'll show you some of those a little later.

The -- then we take the candidate alternatives, and to your point, Commissioner, we go out -- in order to get that consistent basis, you go out in the Google search and you'll see, even on gas turbines you'll see dollars per KW at 59 degrees Fahrenheit and you'll get a lower heating value and a higher heating value on solar. It'll be DC or AC and panel loading factors. So I'm trying to get numbers and operational and cost numbers that will be consistent across all of those when I put them in our expansion plan models.

So we hire an engineering firm, a big firm, and they'll include distributed generation like micro turbines and diesel generators, and then renewables, biomass and solar and wind. Also to your point, we're excited. Our new parent company has lots of expertise and title power in Nova Scotia, lots of experience with wind, and we'll be trying to add that expertise to our future look at intermittency and how to incorporate them into a balancing area.

So we put all these together and we put them into what I'll describe in the next page of what the software is, but it looks out 30 years for net present value revenue requirements and compares them all in all kinds of -- a gazillion combinations of those.

We take the top plans and then put them into our detailed models -- a lot of folks use PROMOD, we use a product called Planning and Risk -- and have detailed dispatch out to 30 years and add all the revenue requirements to it and come up with the most cost-effective plans to include the fuel.

And then at the end, all that goes back through to complete the whole cycle of determining our avoided unit and what are the next -- cost-effective demand alternatives to that avoided unit.

So here's the levelized cost curve. Again, I have not yet included carbon costs in this picture. We have scenarios that -- we always look at lots of scenarios, as Steve said, Dr. Sim said, that we'll look at all these scenarios with carbon, without carbon. And we've got solar folks coming in all the time. I go to lots of meetings for presentations. We get lots of traditional generation folks coming in all the time. So it works in all directions.

And what you see here is essentially a low capacity factor -- it's hard to see on this one because

I blow it up for my eyes -- is that a CT at very low capacity factors, then a combined cycle, and then you can see where we have -- with these numbers on where solar and a new -- an IGCC would come out.

Our two software products are both by Bentex (phonetic) ABB. It's a system optimizer. Some folks use Strategist. We now use System Optimizer to look at all those combination of things that I've already described, and then we put those top plans into planning and risk.

I'm going to come down. So what was the plan we came up with? Well, we've already got the need for our Polk 2 combined cycle. I was pleased to put the picture of that on our Ten-Year Site Plan, and that was nine, ten months ago. So the whole thing is out there. We're doing lots of testing and things are going well. But that's that first number in the summer reserve margin that -- because we added in January. And then as you can see, we grow about 55 megawatts a year in summer demand. And so we add a peaker in '20 and in '23, and kind of lumpy additions gets us above the 20 percent reserve margin. And with that, that's my presentation.

CHAIRMAN BROWN: Thank you. Nice and succinct.

Emera does -- the new parent company does seem to be a proponent of utility scale solar and the transition has already occurred. And I'm curious what Tampa Electric's plans are for deploying more utility scale solar in -- for its territory.

MR. ROCHA: So, again, we have lots of developers. All of them have been in offices -- I attend lots of meetings. Our corporate plan is to be a sustainable and a greener utility, and -- but there will -- we wanted to do that in a reliable and cost-effective manner.

So what I can tell you to this point is we are -- my group is doing lots of analysis all the time on a million scenarios, including our existing fleet, our future fleet, and then trying to judge where those same costs will be. In fact, I'm updating now with our engineering firm all of those numbers, and then trying to get a better handle, like five years from now, ten years from now, how do those numbers change, so I don't just have a static number, what is that cost today.

But what I can tell you is, yes, Emera is pushing hard for us to get to the place that you're describing.

CHAIRMAN BROWN: That's what I figured.

And then on the supply side, the residential supply side, what is the percentage of customers?

MR. ROCHA: Well, what I can remember is there's about -- we had in the rebate program on solar about 300 customers use the rebates. About -- on the solar water heating there was about 250-ish. So overall we probably -- it's, subject to check, around 700.

CHAIRMAN BROWN: Yeah. Not a lot. Thank you.

Commissioners, any further questions?

Thank you, Mr. Rocha.

MR. ROCHA: You bet. Thank you.

CHAIRMAN BROWN: Safe travels back to Tampa.

All right. Moving into the public comment portion, we will be hearing from Sierra Club, Ms. Csank, first. If you'd like to sit there or go up to the podium, it's your pleasure. And welcome back.

MS. CSANK: Thank you, Madam Chair. Good morning. Actually if you agree, then --

CHAIRMAN BROWN: SACE go first?

MS. CSANK: -- I think Ms. Shenstone will go first. Yes.

CHAIRMAN BROWN: Okay. That's no problem. And welcome, Ms. Shenstone. Yes.

MS. SHENSTONE: Thank you. Good morning, Commissioners. Thank you for the opportunity to address you today and speak regarding the opportunities that the Southern Alliance for Clean Energy sees in providing additional customer value.

SACE is a non-profit, non-partisan clean energy group that advocates for lower-cost, lower-risk resources in meeting electricity demand. That includes moving away from high-risk, high-cost choices such as coal and diversifying the energy mix into resources with vast potential such as capturing more energy efficiency and integrating higher levels of clean, abundant, and low-cost solar power.

SACE supports policies and plans that meaningfully increase rooftop solar, larger commercial installations, and utility scale solar. All are part of a healthy solar market.

All forms of solar are seeing continuing price drops, with utility scale power purchase agreements now being signed at three to five cents per kilowatt hour. As it relates to utility scale solar, there's a significant and growing opportunity to expand and bring Florida to the forefront of the industry where it belongs.

SACE recommends that the Commission encourage more market entry for supply-side solar projects. To that end, we offer several recommendations now and will provide additional details in written comments.

We recommend the establishment of a

solar-specific Standard Offer Contract, including a contract avoided cost rate for solar qualifying facilities with a capacity of up to 5 megawatts. Florida rules and utility practice effectively excludes small solar projects from realizing the benefits of the Standard Offer Contract available to other small power generators under PURPA. PURPA is meant to increase energy independence in the U.S. by requiring states to establish the prices retail utilities must pay to third-party renewable energy developers, thus giving small developers a market for their power. Yet in practice in Florida, solar qualifying facilities are ineligible for any capacity payment due to the minimum performance standards for the delivery of firm capacity.

The system size in the Standard Offer Contract is limited to a mere 100 kilowatts. Developers tell us that there's great interest for projects larger than this limit, and, in fact, it's not unusual for business customers to install larger systems either through a developer or with their own financing; however, these customers may not wish to enter into expensive negotiations with the utility and would desire a streamlined process such as a meaningful Standard Offer Contract would provide.

If a solar developer does wish to negotiate a contract for a solar project over 100 kilowatts, such contracts are entirely at the utility's discretion. There's limited legal basis for any party to challenge a utility's decision to refuse a contract even if it's at the same time negotiating a similar contract at a higher price.

Moreover, Florida rules do not currently provide for any specific competitive solicitation process for projects less than 75 megawatts. A competitive solicitation process is key to encourage more solar development and ensure that customers are getting the most bang for their buck.

Policies like these will help Florida realize more solar potential at the utility scale. FRCC's presentation shows solar expanding in Florida by only 1,167 megawatts in the next ten years. By comparison, Georgia Power already has more than half of that amount on its system and by 2021 may add up to 1,900 megawatts more of renewable energy including solar. Florida has greater solar potential than our neighbor to the north, and we ought to ensure that the state's policies do not create unnatural barriers to taking advantage of that potential.

Moving on to our concerns about coal-fired power plants, we noticed that the Ten-Year Site Plans assume that nearly all coal-fired power plants will stay online throughout the planning period. This assumption is worth taking another look at, as keeping coal plants online is actually subject to a number of risks. There's good reason to plan for the case that the end of a unit's useful life does occur in the next ten years. Utilities should demonstrate to this Commission and to the public that they have factored these risks in and investigated alternatives.

First, as mentioned earlier, coal is becoming a more costly choice. As I'm sure you're aware, coal-fired power plants are being dispatched less frequently as gas is more competitive, which means that the per unit cost of running the coal plants is actually higher and again makes them less competitive. We see this playing out in the case of the two smaller coal plants that FPL has purchased with the intention or expectation of bringing them offline. The specifics are going to be different for other plants, but this is a notable cautionary tale, especially since one of those plants is only 21 years old compared to other Florida plants that are mainly in their 30s, 40s, and 50s.

Adding to these costs are regulatory compliance liabilities. We see these regulations as providing much needed public health and environmental protections. And in order to comply with these standards, many plants are going to need expensive upgrades. For example, Gulf's Crist Units 4 and 5 and JEA's Northside units use ones through cooling systems that suck massive amounts of water from the river and return most of it at a higher temperature. Both should anticipate that in the next water permitting cycle, they'll need to make provisions to reduce thermal impacts, likely by adding a cooling tower, which can cost hundreds of millions of dollars. The cooling tower would also help meet modern standards for prevention of fish, fish eggs, and other wildlife being sucked in or trapped in the intake, which is another regulatory obligation.

Tampa Electric has already applied for cost recovery of nearly half a million dollars just to study what will be needed to comply with -- at its Big Bend plant with the new effluent limitation guidelines, which will come into play, again, in the next water permitting cycle. With such significant costs just for the studies, one can safely anticipate that the cost of actually converting to dry ash handling and controlling heavy metals in the discharge water will be significant, possibly enough to make retirement a more appealing option.

Coal risks are further compounded by the need to comply with the Federal Coal Combustion Residuals Rule or Coal Ash Rule, which is going to be a particular challenge for Florida. By 2018, operators will need to show their ash storage is not compromised by locational factors such as being located in a flood plain, near sinkhole-prone geology, or proximity to aquifers. Many Florida plants may be unable to comply due to Florida's geology and face an expensive alternative of shipping coal ash out of peninsular Florida.

And finally, it's worth keeping the Clean Power Plan in mind as another risk that utilities should factor in, and we would hope to see utilities factoring that in as soon as possible, especially as far as there are no regrets options that they can take now that will prevent additional costs from accruing later.

By thoroughly investigating all of these risks now and researching alternatives, utilities will avoid piecemeal decision-making that could needlessly expose Floridians to higher priced power while robbing them of the opportunities for cleaner water and the benefits of clean energy resources that are at record low prices.

And, again, we'll provide more detail in our written comments, but thank you very much for the opportunity today.

CHAIRMAN BROWN: Thank you, Ms. Shenstone. I was just going to suggest that you submit some of these written comments.

MS. SHENSTONE: Absolutely.

CHAIRMAN BROWN: Thank you.

Commissioners, any questions?

I appreciate you coming down.

MS. SHENSTONE: Thank you.

CHAIRMAN BROWN: Thank you.

Ms. Csank.

MS. CSANK: Madam Chair, if I may just stay right here and provide --

CHAIRMAN BROWN: You may.

MS. CSANK: -- address you this way. Great.

CHAIRMAN BROWN: I hope you got back safely to Washington.

MS. CSANK: Yes, I did. Thank you.

So good morning, Madam Chair, Commissioners. Diana Csank here on behalf of the Sierra Club.

As you know, Sierra Club has an abiding interest in resource planning. We appreciate the focus here today on the planning process as well as the options for electric utilities in today's energy market. Due to the rapid changes in the market, robust options analysis is more important than ever. To promote this analysis and ultimately prudent decisions on behalf of customers, we respectfully urge the Commission to continue to take steps to create space in the Ten-Year Site Planning process where utilities, staff, stakeholders, and ultimately the Commissioners, you, yourselves, can have intensive discussions about what's ahead and the best options for protecting customers as we navigate the way forward. Today I'll share a bit of what this could look like, and Sierra Club will also provide more detailed comments following the workshop.

So in particular, I'd like to focus on the minimum filing requirement for the utilities to provide in their annual plans, quote, sufficient information to assure the Commission that an adequate and reliable supply of electricity at the lowest cost possible is planned for the state's electric needs.

The plans filed by the utilities, however, have not historically provided sufficient information. After the plans are filed, the Commission staff data requests help develop the record over the summer and through the fall. We commend staff. This is very helpful. The FRCC statewide summary also helps. And this year we have the benefit of the utilities' supplemental presentations at this workshop. But as Sierra Club appears before commissions across the country, we see that there is a real value added from the type of exchange that can occur when stakeholders have access to the inputs and more detail about the actual cost-effectiveness screening that the utilities are doing at the planning stage, and this is particularly true with respect to electric utilities because of these complex, long-term projects.

You heard today from, for example, Dr. Sim, a new combined cycle plant can take up to five years from inception to get online. And so once a utility is down that road and is on its way through the planning process of selecting a particular resource and comes to you in a docketed manner to seek approval, it's often very difficult or, you know, the -- at that point to meaningfully go back to the drawing board and make sure all the options are properly considered.

So, again, we will submit written comments to further identify particular suggestions of what this could look like. Certainly the RFP process, as my colleague from SACE alluded to, is a very important one, and the Bid Rule -- and it provides contours for that and for certain resource selection types of situations. But we submit that that's something that could be used to great effect more broadly.

So, again, thank you very much for your

attention. I'll reserve the remainder of my time for questions.

CHAIRMAN BROWN: Thank you, Ms. Csank.

Commissioners, any questions?

Thank you both for appearing.

Opening up this forum to the public, is there anybody from the public that would like to address the Commission on this in this workshop proceeding?

(No response.)

Seeing none, are there any additional matters that need to be addressed?

(No response.)

Commissioners, any concluding comments?

Staff, any concluding comments?

All right. This workshop is adjourned. Thank you all for coming.

(Proceeding adjourned at 10:48 a.m.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, CRR, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 22nd day of September, 2016.

Linda Boles

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