

1                                   BEFORE THE  
2                                   FLORIDA PUBLIC SERVICE COMMISSION

3                   In the Matter of:

4   DOCKET NO. UNDOCKETED

5                   REVIEW OF TEN YEAR SITE PLANS  
6                   OF ELECTRIC UTILITIES.

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11                   PROCEEDINGS:                   WORKSHOP  
12                   DATE:                                   Tuesday, October 3, 2017  
13                   TIME:                                   Commenced at 1:30 p.m.  
14   Concluded at 2:46 p.m.  
15                   PLACE:                                   Betty Easley Conference Center  
16   Room 148  
   4075 Esplanade Way  
   Tallahassee, Florida  
17                   REPORTED BY:                   LINDA BOLES, CRR, RPR  
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APPEARANCES:  
  
STACY DOCHODA, FRCC  
BEN BORSCH, Duke Energy  
JUN PARK, Gulf Power  
SYBELLE FITZGERALD, Gulf Power  
STEVEN SIM, FPL  
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ORLANDO WOOTEN, Commission staff  
PHILLIP ELLIS, Commission staff  
TAKIRA THOMPSON, Commission staff  
STEPHANIE CUELLO, Commission staff

**P R O C E E D I N G S**

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2           **MR. WOOTEN:** Good afternoon. Welcome to the  
3 Commission workshop on the 2017 Ten-Year Site Plan. My  
4 name is Orlando Wooten with the Commission staff. We  
5 also have Phillip Ellis from Commission staff and Takira  
6 Thompson from Commission staff. My bad. Stephanie  
7 Cuello from legal as well. We'll begin this workshop by  
8 having Stephanie read the notice.

9           **MS. CUELLO:** Good afternoon, everyone. We are  
10 here pursuant to notice issued on September 7, 2017.  
11 This time and place is set for the Commission workshop  
12 on Florida's electric utilities' 2017 Ten-Year Site  
13 Plans. The purpose of this workshop is set out in the  
14 notice.

15           **MR. WOOTEN:** The Florida Reliability  
16 Coordinating Council is here to discuss its 2017  
17 Regional Load & Resource Plan and statewide fuel  
18 reliability. Duke Energy, LLC, Gulf Power Company,  
19 Florida Power & Light Company, and Tampa Electric  
20 Company are also here to provide presentations.

21           Following the presentations, we will have an  
22 opportunity for public comments. At this time we will  
23 hear the presentations. First we have Stacy Dochoda  
24 from the FRCC.

25           **MS. DOCHODA:** Good afternoon. My name is

1 Stacy Dochoda. I'm the president and CEO of the Florida  
2 Reliability Coordinating Council. Today I'm going to be  
3 providing an overview of the utilities' integrated  
4 resource planning processes and how those fit into what  
5 we do at FRCC in developing the Ten-Year Site Plan  
6 report.

7 I'll also address the traditional topics of  
8 load forecast, generation additions, and fuel mix, and  
9 then I'll discuss natural gas infrastructure in Florida.  
10 And, finally, I'll describe one of the reliability  
11 assurance processes that we have in Florida for the  
12 electric system and how it was utilized this year.

13 The vision of the Florida Reliability  
14 Coordinating Council is to maintain a highly reliable  
15 and secure bulk power system for peninsular Florida.

16 The key points for the 2017 Load & Resource  
17 Plan are that demand and energy forecasts are very  
18 similar to last year's Ten-Year Site Plan. We have  
19 9,200 megawatts of new firm generation, with 12 percent  
20 of that coming from new solar. Overall, resource  
21 adequacy remains reliable with a planned reserve margin  
22 at or above 20 percent over the ten-year horizon. I'll  
23 note that demand-side management continues to be a  
24 significant portion of reserves.

25 The FRCC region's generation fuel mix will see

1 increases in the percent of natural gas and a decrease  
2 in coal. Regarding natural gas infrastructure, with the  
3 third major natural gas pipeline in service in July of  
4 2017 and other increases in planned capacity for natural  
5 gas pipelines, that capacity is projected to increase  
6 24 percent from 2016 to 2021.

7           So I'll begin the FRCC Load & Resource Plan  
8 and talk about how the data is developed. In Florida,  
9 each utility develops its own Integrated Resource Plan  
10 to look out into the future to forecast customer demand  
11 and how to reliably serve that demand. The utility will  
12 prepare forecasts of electric demand and energy usage  
13 considering drivers such as customer growth, impacts of  
14 energy efficiency, and average weather. Fuel and  
15 resource price forecasts are also developed.

16           The utility will consider its available demand  
17 and energy that can be produced by its existing  
18 resources and factor in plans for modifications like  
19 upgrades in output or efficiency and additions that are  
20 planned. And it will also consider the impact of future  
21 resource retirements or the expiration of purchased  
22 power agreements.

23           The forecasted demand and energy are compared  
24 to the resources and compared to the target reserve  
25 margin. And where there's a shortfall, the utility will

1 consider options to meet the reserve margins. These  
2 options include supply side such as new generation or  
3 purchased power and also demand-side options such as  
4 load control.

5 The cost and operating criteria of these  
6 resources are used to evaluate the differences, and then  
7 the result of the analysis is the utility's Integrated  
8 Resource Plan.

9 The individual utility IRPs are brought  
10 together by FRCC to create FRCC's Load & Resource Plan.  
11 In addition, at FRCC we use the Load & Resource Plan  
12 data in planning models to conduct reliability  
13 assessments on generation adequacy and transmission  
14 reliability.

15 Turning to the FRCC Load & Resource Plan where  
16 we've consolidated all of the utilities' IRPs, I'll  
17 begin with the load forecast information. The 2017 data  
18 projects that firm summer peak demand grows at  
19 1.1 percent per year, and forecasted energy sales grow  
20 at just under 1 percent per year over the ten-year  
21 horizon. The forecasted demand is slightly lower than  
22 the 2016 Ten-Year Site Plan, and the forecasted energy  
23 sales are very similar to the 2016 Ten-Year Site Plan.

24 Demand-side management, which includes demand  
25 response like load control and pool pump programs,

1 utility-sponsored energy efficiency and conservation,  
2 has a material impact in dampening the growth of peak  
3 demand. Demand response reduces peak demand by  
4 6.3 percent over the ten-year period, and  
5 utility-sponsored energy efficiency programs reduce peak  
6 by 1.4 percent by 2026.

7 Another significant factor is energy  
8 efficiency delivered through mandated codes and  
9 standards, and that's projected to decrease peak by at  
10 least 4.1 percent by 2026.

11 Next I'll be discussing the load forecast.  
12 Now while economic factors are a positive driver of the  
13 load forecast over the ten years, increasing impacts  
14 from energy efficiency codes and standards are causing  
15 per customer usage to decline. And other factors that  
16 impact the load forecast include unemployment, which has  
17 decreased from 7.3 percent in 2013 down to 4.5 percent  
18 in 2017, and population, which has grown by 1.5 million  
19 since 2011.

20 Energy efficiency codes are expected to  
21 decrease summer peak demand by 2,100 megawatts, or  
22 4.1 percent, and reduce energy by 9,000-megawatt hours  
23 by 2026.

24 This chart shows the 2016 Ten-Year Site Plan  
25 forecast and the 2017 Ten-Year Site Plan forecast. The

1 2017 is shown in the red. This year's Ten-Year Site  
2 Plan has average growth of 1.1 percent compared to 1.13  
3 in 2016. So the slope of the lines, the growth rate are  
4 very similar, but the 2017 does begin slightly lower  
5 than the 2016 forecast.

6 This is the winter firm peak demand forecast,  
7 and the 2017 Ten-Year Site Plan here is in blue and is  
8 2.8 percent lower than the 2016. The main cause for  
9 this shifting downward of the curve is that the actual  
10 winter peak last year was 19 percent below the forecast.  
11 We've had very mild winters for the last several years,  
12 and that has impacted the weather averages that are used  
13 to develop the forecasts.

14 Now this is the energy forecast. The 2017  
15 energy forecast has an average growth rate of just under  
16 1 percent, and it's lying right almost on top of the  
17 2016 Ten-Year Site Plan. So they're very similar.

18 This graph shows the current forecast demand  
19 compared to the trend line the last 20 years. Current  
20 forecasts are just slightly below what a historical  
21 trend line would predict.

22 On this graph the red line is projected summer  
23 peak demand. The upper yellow line is without demand  
24 response and energy efficiency. So you can see the  
25 demand response lowers the demand by 6.2 percent by



1 2026, and utility energy efficiency programs are  
2 projected to reduce demand by 1.4 percent by 2026.

3 Here we have the compound average annual  
4 growth rate for firm peak load summer and winter from  
5 previous Ten-Year Site Plans, up to and including this  
6 year's. The 2017 Ten-Year Site Plan, again, has a  
7 summer growth rate of 1.1 percent and a winter at just  
8 less than 1 percent, and these are very close to the  
9 2016 plan year numbers. But the chart does show a  
10 decline in forecasted growth rate from around 2 percent  
11 back in the '90s to around 1 percent today.

12 Now I'm going to move from the load forecast  
13 to the resource side of the equation. This bar chart  
14 shows the available capacity over the ten years. It  
15 includes the impact of planned new builds and  
16 retirements.

17 We've about 9,200 megawatts of additional new  
18 generation that's planned for the FRCC region over the  
19 ten years. 6,600 megawatts of that is combined cycle,  
20 1,400 megawatts of combustion turbine, and 1,100  
21 megawatts of firm solar are added over the ten years.  
22 And then there are about 3,400 megawatts of plant  
23 retirements, which are coal and less efficient steam and  
24 combustion turbine units. For nuclear capacity we  
25 currently have about 3,600 megawatts with 40 megawatts

1 of planned upgrades during the ten-year horizon.

2 Using the forecasted firm load and the  
3 projected available resources, we've calculated the  
4 reserve margins over the ten-year period. We do project  
5 the reserve margins to be at or above 20 percent over  
6 the forecast period.

7 Here we have the reserve margins excluding  
8 demand response and utility energy efficiency programs.  
9 The summer generation only reserve margin declines from  
10 about 15 percent in 2017 to 13 percent in 2018, and then  
11 ranges -- bumps up and down a little bit below  
12 15 percent for the remainder of the period.

13 This is a chart of demand response as a  
14 percentage of peak demand for FRCC and other areas of  
15 North America, and you can see that the FRCC region  
16 continues to have the most significant portion of our  
17 reserves coming from demand response compared to other  
18 areas.

19 These are pie charts of the fuel mix, and this  
20 is summer capacity in megawatts. The natural gas-fired  
21 generation, you can see, goes from 72 percent in 2017 to  
22 75 percent in 2026.

23 And these pie charts are the fuel mix on an  
24 energy basis. Natural gas continues to be the largest  
25 fuel source. Here it ranges from 63 percent in 2017 to

1 67 percent in 2026. And renewables grow from just under  
2 2 percent of energy mix in 2017 to almost 5 percent in  
3 2026.

4 Now these pie charts are zeroing in just on  
5 the renewable mix, so we show 713 megawatts of firm  
6 capacity in 2017 of -- from renewables. And here you'll  
7 see a dramatic difference in the charts between '17 and  
8 '26 and also compared to previous Ten-Year Site Plans  
9 that I've brought you.

10 In 2017, the largest percentage comes from  
11 municipal solid waste at 35 percent and biomass at 30,  
12 with solar at 21 percent of the renewable mix. But as  
13 you move to 2026, out of the 1,800 megawatts of firm  
14 renewable capacity, the largest percentage now comes  
15 from solar at 69 percent, which is an increase of about  
16 1,100 megawatts over the ten-year planning horizon.

17 The contribution from biomass and municipal  
18 solid waste are relatively stable on a megawatt basis,  
19 but because of the growth in the solar, the percentage  
20 of those two show a decline.

21 So now here's the same chart for renewable  
22 only but on an energy basis. And here again you can see  
23 that the solar portion of renewable energy is increasing  
24 substantially from about 25 percent in 2017 to 69  
25 percent in 2026.

1           Now I'm going to move on to discuss Florida's  
2 natural gas infrastructure. There are three major  
3 pipelines that serve Florida: The Florida Gas  
4 Transmission system, Gulfstream, and Sabal Trail/Florida  
5 Southeast Connection.

6           The Sabal Trail/Florida Southeast Connection  
7 began commercial operation in July of this year. With  
8 the current pipelines and the planned capacity  
9 additions, gas infrastructure is on pace with generation  
10 additions over the future horizon; however, the  
11 continued operation of the Sabal Trail Pipeline is being  
12 challenged in the courts. Without Sabal Trail, the  
13 pipeline capacity would have been projected to fall  
14 short to supply peak demand this year.

15           The majority of the gas generation capacity in  
16 Florida is dual fuel, and that remains to be between  
17 64 percent and 68 percent during the ten-year horizon.

18           At FRCC we have a group called the Fuel  
19 Reliability Working Group that works together, from  
20 members of the utilities across Florida, to review  
21 existing interdependencies and fuel availability and  
22 electric reliability, and they coordinate regional  
23 responses to fuel issues and emergencies. In the FRCC  
24 region, energy production from natural gas has increased  
25 dramatically since 2000 and is projected to continue to

1 increase.

2 This chart shows the natural gas alternate  
3 fuel capability. As a region, we do have a significant  
4 portion of our natural gas-fired units that can burn  
5 alternative fuels such as fuel oil. The dual fuel  
6 capability is expected to remain between 64 and  
7 68 percent of the total megawatts of natural gas  
8 capacity between now and 2026. Of the 8,000 megawatts  
9 of new natural gas generation that we have projected,  
10 5,600 megawatts includes alternate fuel capability.

11 The third major pipeline system that I  
12 mentioned before began operation, commercial operation  
13 in July of this year. The new system includes the Sabal  
14 Trail Pipeline and the Florida Southeast Connection,  
15 which connects the Sabal Trail Pipeline at the new  
16 Central Florida Hub. The new pipelines provide  
17 increased supply flexibility for Florida, and also the  
18 Central Florida Hub interconnection provides increased  
19 operational reliability by connecting the two existing  
20 pipelines with the Sabal Trail and Florida Southeast  
21 Connection, allowing the capability to transfer gas  
22 between the systems.

23 We also have additional fuel flexibility in  
24 the area through contracts the utilities have with  
25 natural gas storage facilities out of state. This

1 storage can yield about 1 Bcf a day of natural gas. And  
2 if you do the equation, that could support about  
3 12 percent of customer energy needs on an average summer  
4 day.

5 The last topic that I plan to cover is to talk  
6 about one of the FRCC region's reliability processes and  
7 how it was used in April of this year. One of our  
8 long-standing processes is the Generating Capacity  
9 Shortage Plan. This process was revised by FRCC  
10 recently and adopted by rule by the Commission in April  
11 of 2017.

12 The new version of this process is better  
13 aligned with the revised NERC reliability standards, and  
14 it provides improved situational awareness. The new  
15 process includes the NERC reliability standard concept  
16 of energy emergency alerts.

17 A generating capacity advisory will be  
18 declared by the FRCC reliability coordinator when there  
19 are specified low temperatures or when a realtime  
20 operating margin of generation is less than two times  
21 the largest generating unit running, or if there are  
22 statewide fuel and supply and delivery issues.

23 The Commission is notified when a generating  
24 capacity advisory is declared. Now when we declare an  
25 advisory, it does not necessarily indicate an imminent

1 threat of an energy emergency. We have another process,  
2 though, that is a little more directly tied to energy  
3 emergencies, and these also fall under the Generating  
4 Shortage Plan.

5 We have the energy efficiency -- energy  
6 emergency alerts that have three different levels. When  
7 an alert is issued, operating entities, the utilities in  
8 Florida, may issue public appeals, they can exercise  
9 demand response, or if necessary to preserve the bulk  
10 electric system, they can shed firm load. When an EEA  
11 is issued, all the operating entities in the state are  
12 notified so that they can assist one another.

13 So we have the three levels of the alerts.  
14 Level 1 is saying that all available resources are in  
15 use, and then you range down to Level 3 indicating that  
16 firm load interruption is imminent or is in progress.

17 In 2016, last year, there were no EEAs  
18 required to be declared by FRCC. This year, in 2017, we  
19 did have an EEA-1 in April, and I want to walk through  
20 what that was about. We had a -- the FRCC, on April  
21 28th at 12:43, declared an EEA-1 on behalf of one FRCC  
22 entity due to an unexpected loss of generation and  
23 higher than normal forecasted peak loads. Additional  
24 generation became available prior to the peak, and at  
25 17:00 the FRCC declared that they could return to normal

1 operations without any further action being required and  
2 with no loss of load.

3 Pursuant to the procedure, FRCC did notify the  
4 Commission of the EEA-1 when it was issued and also the  
5 return to normal operations. Again, this reliability  
6 process is one that is related to situational awareness  
7 that's used by the FRCC RC and all the operating  
8 entities to ensure reliability of the bulk power system.

9 Now since I prepared this presentation and  
10 initially submitted it, we have had one other EEA that  
11 was issued in FRCC, and that was on September 13th  
12 during the restoration after Irma. We had one operating  
13 entity that had a generator trip. An EEA was called,  
14 and the utility was able to replace the lost capacity  
15 and returned to normal service within about two hours.  
16 And, again, the Commission was notified when the initial  
17 EEA was issued and then when it was restored to normal  
18 operation.

19 So those are the topics that I had to cover  
20 today. I'd just like to summarize the Ten-Year Site  
21 Plan presentation by saying that the region does  
22 continue to project reliable resource adequacy with  
23 reserve margins at or above 20 percent over the ten-year  
24 horizon, and the other key findings are that energy  
25 projected to be supplied by natural gas continues to



1 grow, ranging from 63 percent in '17 to 67 percent in  
2 2026.

3 Also, renewable generation driven by new solar  
4 is increasing on an energy basis from 2 percent to  
5 5 percent. And then also with the addition of the third  
6 major natural gas pipeline into Florida, gas  
7 infrastructure capabilities are now on pace with  
8 generation additions. And with that, I'd be happy to  
9 answer any questions that you have.

10 **MR. WOOTEN:** Thank you, Stacy. In your  
11 presentation on Slide 29, you mentioned a -- let me see  
12 if I can get to it -- over the ten-year forecast there's  
13 going to be a -- between 64 and 68 percent dual  
14 capability generation, and I was curious about how you  
15 felt about that, how the FRCC felt about that, that  
16 amount.

17 **MS. DOCHODA:** So we're very pleased that we  
18 have such a significant portion of dual fuel capability.  
19 So I think it puts Florida in a good space in terms of  
20 having that option. You know, it's one of several  
21 features that we have in terms of resiliency on the  
22 natural gas front between having the multiple pipelines  
23 now, having the additional out-of-state storage, and  
24 then the dual fuel storage -- I mean, dual fuel  
25 capability.

1           **MR. WOOTEN:** Thanks. Another, another point  
2 in there, I think it was also Slide 29, you brought up  
3 Sabal Trail. And I was personally a little curious  
4 about how you feel -- how it's alleviated any sort of  
5 stress that the other pipelines were going through.

6           **MS. DOCHODA:** Sure. The timing of Sabal Trail  
7 was very fortuitous in terms of coming in as we're  
8 having such a huge increase in natural gas production,  
9 and the analysis does show that that third pipeline is  
10 very important to continue to have that capability and  
11 being able to keep up with the capability of the  
12 additional natural gas generation that's planned in the  
13 future.

14           **MR. WOOTEN:** And actually continuing on the  
15 Sabal Trail thing, do you see there to be any sort of  
16 new need for a new pipeline or --

17           **MS. DOCHODA:** I'd say that's outside of my  
18 area of expertise on the natural gas side, but the  
19 analysis we've done to date shows that over the next  
20 several years the capacity that's been added, which is  
21 very important to be able to keep up, and the additional  
22 planned expansions that are planned by those existing  
23 pipelines put us in good shape for the next several  
24 years.

25           **MR. ELLIS:** Good afternoon.

1           **MS. DOCHODA:** Good afternoon.

2           **MR. ELLIS:** Skipping forward a little bit in  
3 your presentation to -- I believe it's Slide 39  
4 associated with the alert levels, you mentioned, I  
5 think, in the April example as well as the September  
6 example you provided that it's a single entity that  
7 you're looking at. So the three alert levels, all  
8 resources in use, load management in use, firm, that's  
9 referring to the individual entity, not the FRCC as a  
10 whole; correct?

11           **MS. DOCHODA:** That's an excellent question.  
12 Yes, the way energy emergency alerts work, they apply to  
13 a balancing authority, so the individual balancing  
14 authority in that utility. And so if that balancing  
15 authority has all of its available resources in use, it  
16 would -- could request to have an EEA-1 called for. And  
17 that does then -- all the other operating entities learn  
18 of that and know that if they need to, they can come to  
19 the aid of that balancing authority.

20           **MR. ELLIS:** And that's the same for the  
21 generating capacity advisory, it's going to just those  
22 local levels, those balancing authorities, not at a  
23 statewide level.

24           **MS. DOCHODA:** That's correct.

25           **MR. ELLIS:** All right. Thank you.

1           **MR. WOOTEN:** Seeing as there's no further  
2 questions, we'd like to thank Stacy for her  
3 presentation.

4           And next we'd like hear from Ben Borsch from  
5 DEF.

6           **MR. BORSCH:** Good afternoon. I'm going to  
7 talk this afternoon about the development of DEF's 2017  
8 Ten-Year Site Plan.

9           (Technical difficulties.)

10          **MR. ELLIS:** Some technical difficulty. Sorry.

11          **MR. BORSCH:** So this is our 2016 ten-year  
12 resource plan, last year's plan. And just by way of  
13 refresher where we were last year, our plan last year  
14 focused primarily on a number of near-term activities  
15 especially around our preparation for the retirement  
16 of our two coal-fired units, Crystal River Units 1  
17 and 2, and their replacement with the new Citrus  
18 combined cycle generating facility and the opportunity  
19 to shift ourselves to a much cleaner and more efficient  
20 generating footprint.

21          Following the in-service of the Citrus plant,  
22 we were actually in good shape for capacity for a number  
23 of years, and you can see right at the end of the plan  
24 we had identified a need for a total of five simple  
25 cycle combustion turbines spread across '24 and '25.

1 I'll take the next one. Moving on towards the  
2 transition from the 2016 to 2017 plans, this is a  
3 projection of our system energy requirements for 2016  
4 and 2017. And in this forecast, we projected a small  
5 drop, about 1 percent, in the forecast of the energy  
6 served, but we project that we will see a continuing  
7 upward trend at about a 1-percent-a-year rate in the  
8 energy served. And primarily that's driven by an  
9 ongoing increase in our number of customers.

10 Our new meter sets for this year are just  
11 about back to the 2008 level, and we are projecting a  
12 continuing increase in the number of customers over the  
13 next ten years. The energy growth is, of course,  
14 mitigated somewhat by our expectation of increasing  
15 customer efficiencies. So the actual rate of increase  
16 of the energy is slightly lower than our projection for  
17 the actual rate of increase in the number of customers.

18 This shows the comparison -- this is a  
19 somewhat confusing slide, but it shows the comparison  
20 between our 2016 and 2017 projections of the peak loads  
21 for winter and summer. Again, there's a big sort of  
22 jump in these, which is really related to a change in  
23 wholesale contracts and not related to our ongoing  
24 expectations of the retail load.

25 But one of the things that starts to happen,

1 and it's in part because of the change in our  
2 expectation of the wholesale obligations, is that we are  
3 transitioning from traditionally having been a winter  
4 peaking utility. And although we are physically still a  
5 winter peaking utility, we're expecting that there's  
6 going to be a significant focus going forward on our  
7 summer planning above our focus on meeting the winter  
8 peak. So this is changing a little bit our level of  
9 emphasis going forward.

10 This year we decided to give a publication of  
11 our projection in the range of energy forecasts both for  
12 energy and demand. This shows our range of forecasts  
13 for the energy compared to the actual historic energy  
14 usage. And what this does, the blue line there is our  
15 base forecast. And as I mentioned before, that is  
16 accelerating modestly with an expectation of continued  
17 customer growth mitigated by ongoing customer  
18 efficiency.

19 In the green line scenario, essentially what  
20 we did was to look at the possibility of expanded  
21 customer use, an even more robust economic development  
22 scenario, and the possibility of some more extreme  
23 weather than we have seen in the last few years. So  
24 that gave us what we thought was a reasonable upper  
25 bound for the energy use over the ten-year period, and

1 similarly we produced load forecasts on the other side.

2 This slide shows the same projection  
3 essentially for our summer peak demand. And the key  
4 here is that we were using this projection to test the  
5 robustness of our plan, whether the base plan, which was  
6 built around that center line, would be able to adapt to  
7 the demands particularly of an increased megawatt need.  
8 And we found that we were able to project, through a  
9 combination of changes in our contract structures and  
10 the changes in our build plan, the ability to respond to  
11 any of these scenarios building off the base plan that  
12 we have today.

13 And finally this is the 2017 Resource Plan.  
14 And basically, again, our focus is still in the near  
15 term here on the retirement of the two large coal units  
16 and their replacement with high efficiency natural gas  
17 combined cycle. Because of the slight decrease in the  
18 load projections, we are projecting a decrease from the  
19 five combined -- five CTs in 2024 and '25 to a total of  
20 three spread across the period from '24 to '26.

21 And lastly, as we have recognized, the  
22 expectation that we're going to continue to see greater  
23 and greater cost-effectiveness in PV generation. We  
24 have incorporated into the plan an expectation that  
25 there will be considerable growth in the amount of PV,

1 utility scale PV generation on the DEF system. This is  
2 reflected here and in our energy use projections  
3 throughout the plan. And that is actually all I had to  
4 present today, so if there are any questions.

5 **MS. THOMPSON:** Good afternoon. Takira  
6 Thompson with staff.

7 I have a few questions. Referring to Slide  
8 5 --

9 **MR. BORSCH:** Uh-huh. I don't know if you want  
10 to put Slide 5 back up. I can't do it, so. 1, 2, 3, 4,  
11 5, yeah, uh-huh.

12 **MS. THOMPSON:** What affected or controlled how  
13 the high and low cases were developed?

14 **MR. BORSCH:** Principally what we looked at  
15 were three independent variables: Economic activity,  
16 weather, and customer growth. And based on the metrics  
17 that we developed for each one of those variables, we  
18 took a -- one standard deviation from the base case on  
19 the high side and one standard deviation from the base  
20 case on the low side for each of those variables and  
21 used those to project load and energy needs in these  
22 bands that you see here.

23 **MS. THOMPSON:** Okay. Referring to Slide 8 --

24 **MR. BORSCH:** Uh-huh.

25 **MS. THOMPSON:** -- how many of the projected



1 solar facilities will the utility own and how many will  
2 be third-party owned?

3 **MR. BORSCH:** That remains to be seen.

4 **MS. THOMPSON:** Okay.

5 **MR. BORSCH:** We looked at this and really  
6 basically did an economic slice of what we thought might  
7 be potentially cost-effective across the number of  
8 utility scale PV projects that would be available. In  
9 this plan, we didn't directly take a position on whether  
10 those would be utility owned or third-party owned. We  
11 expect that there will be some division of the two, some  
12 of each, but we didn't apply a specific ownership  
13 percentage.

14 **MS. THOMPSON:** Okay. Well, that's all. Thank  
15 you.

16 **MR. WOOTEN:** I have a quick question.

17 **MR. BORSCH:** Oh, all right.

18 **MR. WOOTEN:** How do you think the increase,  
19 the increase in developing solar impacted your actual  
20 2017 resource plan?

21 **MR. BORSCH:** Well, as I said earlier on, we  
22 have historically had a focus on DEF as a winter peaking  
23 utility. So up through the position of our 2017 plan,  
24 we were not ascribing a summer capacity value to the PV  
25 solar. So this solar impacts the plant on an energy

1 basis. It provides a substantial amount of PV energy,  
2 but we did not ascribe to it a firm capacity.

3 We are currently, as the Commission is aware,  
4 we have a number of small scale demonstration projects  
5 that we have built over the last year or two, and we  
6 have been evaluating the generation from those projects  
7 as we look ahead, and expect that we'll be assigning a  
8 future capacity to those projects.

9 **MR. WOOTEN:** All right. Thank you.

10 I see there's no more questions, so I want to  
11 thank you for your time, Mr. Borsch.

12 And I think we're going to move on to Jun Park  
13 and Sybelle Fitzgerald from Gulf Power.

14 **MR. PARK:** Good afternoon. My name is Jun  
15 Park, and I'm Gulf Power's forecasting supervisor.  
16 Today I'll be presenting an overview of the economic and  
17 retail sales outlook for Gulf Power. I'll then turn it  
18 over to Sybelle Fitzgerald, who is Gulf Power's  
19 generation and resource planning manager, for an  
20 overview of fuels, renewables, and the next resource  
21 need.

22 Starting with the economic outlook, Gulf  
23 Power's service area covers portions of eight counties  
24 in Northwest Florida. The economy in Gulf's service  
25 area has seen steady growth over the past few years

1 since the end of the "Great Recession." This economic  
2 recovery has been seen in many aspects of the economy.

3 For example, what's shown here on the chart is  
4 the number of households in Northwest Florida. Over the  
5 past few years, households have grown between 1.5 to  
6 2 percent per year, and households are projected to grow  
7 at over 1 percent per year over the next few years.

8 This growth in the number of households  
9 translates to growth in the number of customers. On  
10 this chart, the red line represents Gulf's residential  
11 customers. Excuse me. And historically the household  
12 growth has tracked very closely with -- excuse me --  
13 customer growth has tracked very closely with household  
14 growth, and so over the past few years residential  
15 customers have grown over 1 percent, and residential  
16 customers are projected to grow at more than 1 percent  
17 over the next few years.

18 However, use per customer has not been  
19 growing. In fact, the amount of energy on average per  
20 residential customer has been declining. As shown on  
21 the blue dotted line, residential use per customer has  
22 declined in excess of 1 percent per year over the past  
23 few years, and this decline in use per customer is  
24 projected to continue.

25 The combination of the growth and the number

1 of customers, along with a decline in the average use  
2 per customer, results in retail energy sales that are  
3 projected to be flat to slightly growing. Over the next  
4 few years, retail sales are projected to grow at less  
5 than 1 percent per year.

6 Now I'll turn it over to Sybelle Fitzgerald.

7 **MS. FITZGERALD:** Good afternoon. My name is  
8 Sybelle Fitzgerald. I'm the generation resource  
9 planning manager for Gulf Power Company, and I'm going  
10 to start with our fuel forecast outlook.

11 So overall between 2017 versus 2016 in our  
12 fuel price forecast we've seen coal prices and natural  
13 gas prices and the rate of price increase over the  
14 ten-year period has declined for both coal and gas  
15 prices. For 2016, you can see the rate of price  
16 increase over the ten-year period was only 3.9 percent,  
17 but for 2017 it was even less, 1.6 percent for coal.  
18 And primarily that's because of the competition with  
19 natural gas pricing is what we're seeing.

20 For natural gas, it was 10.4 percent versus  
21 5.2 percent for 2017. And that's overall for natural  
22 gas due to the availability of natural gas and the lower  
23 price to drill and lower environmental cost.

24 So I'm going to turn next to give you an  
25 update on Gulf Power's solar projects. These are energy

1 purchase agreements that we have with two of our  
2 military customers. One solar plant is located on Air  
3 Force property at Eglin Air Force Base, and the other  
4 two are located on Navy property. Both of them went  
5 online in just the last few months, so we're proud of  
6 these projects.

7 Overall these projects deliver about -- the  
8 energy equivalent to serve approximately 18,000 homes  
9 overall. And you can see the breakdown on the slide per  
10 project. The Saufley project located in West Pensacola  
11 is about 50 megawatts, and that's located on Navy land  
12 that Gulf Power leases. And the Holley project,  
13 40 megawatts, is located in Navarre, also located on a  
14 Navy outlying field that Gulf Power leases. And then  
15 the Air Force project is located at Eglin, 30 megawatts,  
16 that also Gulf Power leases the land. And we have a  
17 third party that we have an energy purchase agreement  
18 with.

19 Just to give you a quick visual of the  
20 project, the smallest project for Eglin, 226 acres. And  
21 then here for the Holley project of 40 megawatts, it's  
22 just a -- 330 acres is the span of that project. And  
23 then our largest project in West Pensacola covers  
24 438 acres.

25 And an update real quick on our wind projects

1 that we have at Gulf Power. The first one went online  
2 January 16th. It had 89 turbines, they're 2 megawatts  
3 each, for a total of 178 megawatts of capacity. For  
4 Kingfisher II, that went online this year in February,  
5 47 turbines, 2 megawatts each, for a total of  
6 94 megawatts. And these projects combined, they deliver  
7 about 77 -- the energy equivalent to serve 77,000 homes.

8 And moving to our mix of generation that we  
9 have, this is the percent of energy that we serve our  
10 customers from renewables. That's what we're trying to  
11 show on this slide is how it's increased over the years.  
12 You see in 2016 it was 6.3 percent. That 6.3  
13 percent was mainly made up of our first wind agreement.  
14 And then 2017, you can see the jump to 10.2 percent was  
15 when we brought online our second wind agreement as well  
16 as our solar farms.

17 But keep in mind, the solar farms are only  
18 online for part of the year in 2017. So you'll see a  
19 little bit more increase to 11 percent overall from  
20 renewables in 2018 as we see more generation output  
21 coming in from the solar farms.

22 So this slide here is just to show and to talk  
23 about Gulf's next need in 2023, and you can see that we  
24 have a sharp decline and our reserve margins go negative  
25 to negative 6.3 percent in 2023. And this is due to the

1 expiration of the Central Alabama purchased power  
2 agreement that Gulf has for 885 megawatts.

3           So as we take a look at what we're going to do  
4 about our next resource need, some of the factors that  
5 we consider: technology type, fuel, transmission, site  
6 factors and performance, and dispatchable resources. Of  
7 course, the technologies that we have under  
8 consideration for our next resource need, the usual:  
9 Combustion turbine, CTs, or combined cycles. Of course,  
10 they both have their pros and cons.

11           CTs have a lower install cost but a higher  
12 cost to run. Combined cycles are more expensive to  
13 install, but they have a lower energy cost and, you  
14 know, they're more economical to run. The evaluation  
15 components for those included capital costs, operations  
16 and maintenance costs, energy and capacity value.

17           And then moving to my last slide here, talk a  
18 little bit about technology and site selection. So we  
19 had, of course, the two technologies that I just  
20 mentioned, well, combined cycles and CTs, we looked  
21 across six site locations. And we have done some  
22 preliminary screening, and it showed that North Escambia  
23 and our Smith plant facility was the most favorable  
24 sites to locate a CT. For a combined cycle, at that  
25 screening the most favorable site was at North Escambia.

1           So updated studies are underway to identify  
2 technology and the site for our next self-build, and  
3 those studies are not yet complete. But we anticipate  
4 selecting a site and the technology type in 2018. Are  
5 there any questions?

6           **MR. ELLIS:** Yes. Going back to Slide 13 where  
7 you're discussing the Gulf Power reserve margin, Gulf  
8 Power is the only utility that is not a member of the  
9 FRCC with the Ten-Year Site Plans. And could you go in  
10 a little bit to how the target reserve margin is  
11 established. I know with the other utilities that  
12 there's a stipulation between three of them with the PSC  
13 and there's also the FRCC requirement for generation --  
14 for a 15 percent reserve margin and an LOLP requirement.  
15 How was the target reserve margin established for Gulf?  
16 Is it something voluntarily you did? Was it through  
17 your reliability group, things of that nature?

18           **MS. FITZGERALD:** Sure. Southern Company  
19 has -- you know, Gulf Power is a member of Southern  
20 Company, and we have a coordinated planning process.  
21 And with the expiration of the Central Alabama PPA, it  
22 drove Gulf Power to be -- you know, go well below its  
23 target reserve margin, which unlike FRCC, our target  
24 reserve margin for actually Gulf Power is 14.74 percent.  
25 The Southern Company long-term target reserve margin is



1 16.25 percent. So Gulf Power's contribution to that is  
2 14.74 percent.

3 And so as we study the system on a  
4 coordinated -- you know, as a coordinated planning  
5 process, Gulf Power got allocation for needing to, you  
6 know, build a new power plant or, you know, whatever  
7 technology ends up -- you know, the screening, how it  
8 turns out.

9 **MR. ELLIS:** Thank you.

10 **MS. THOMPSON:** Good afternoon. Did the  
11 utility consider pursuing another purchased power  
12 agreement for its 2023 resource need?

13 **MS. FITZGERALD:** Yeah. As we go through the  
14 screening process, all types of technology will be  
15 reviewed, you know, potential for future purchased power  
16 agreements, self-builds. It'll be the typical screening  
17 process.

18 **MS. THOMPSON:** Referring to Slide 16, what  
19 types of preliminary screening studies were conducted to  
20 determine which sites would be favorable for a  
21 particular technology type?

22 **MS. FITZGERALD:** So we, so we work in  
23 conjunction with Southern Company Services, and the  
24 types of screenings that we do takes into account  
25 several factors. And one of them being, you know, we

1 look at transmission, we look at fuel, where is the  
2 availability of fuel, we look at the technology type,  
3 and they run that all in an economic model, and then it  
4 gives you the results that come out. That's how we do  
5 it.

6 **MS. THOMPSON:** Thank you.

7 **MS. FITZGERALD:** You're welcome.

8 **MR. WOOTEN:** Quick question. I see also on  
9 this slide that there's six sites being considered. Are  
10 these -- can you list these sites, or is that something  
11 you don't know yet, or what's going on?

12 **MS. FITZGERALD:** Yeah, sure. Those are sites  
13 that we have in plant held for future use. So it would  
14 be our existing sites like the Smith plant location in  
15 Panama City, the Scholz power plant that, you know, was  
16 recently retired. We have some land at Shoal River. We  
17 also have the Crist plant location in Pensacola. We  
18 also have the North Escambia property, the approximately  
19 2,702-acre site there in North Escambia that we're  
20 looking at. So those are the sites.

21 **MR. WOOTEN:** All right. I think -- do we have  
22 any other questions?

23 Thank you for your time. I appreciate it.

24 I think next on the list we have Dr. Steve Sim  
25 from FPL.

1           **DR. SIM:** Good afternoon. My name is Steve  
2 Sim. I represent the resource planning area at FPL, and  
3 it's a pleasure to be here today.

4           Let me start off with where we were last year  
5 with our 2016 site plan. What that site plan showed a  
6 year ago was that we were finishing up the modernization  
7 at Port Everglades with a new combined cycle unit. We  
8 were also finishing up the replacement of some old  
9 peaking unit gas turbines with some new, far more  
10 efficient peaking units, combustion turbines.

11           We also showed that we were adding, by the end  
12 of 2016, three roughly 75-megawatt PV facilities in the  
13 southwest area of our service territory. We showed in  
14 2019 the Okeechobee combined cycle that had been  
15 approved by the Commission. And finally we also showed  
16 that we were projecting another 300 megawatts of  
17 additional PV by the year 2020. And lastly on this  
18 slide, we were showing our next resource need was in  
19 2024, which we were showing having an un-sited combined  
20 cycle as a placeholder to meet that need.

21           Now at the time the 2016 site plan was filed  
22 with the Commission, we were well underway with our  
23 planning for 2016 leading to the 2017 site plan. And  
24 with all resource planning, as you've seen with the  
25 prior presentations, there are several key forecasts

1 that drive much of the resource planning process. So  
2 let me walk you through those.

3 First was a peak load forecast. We're summer  
4 peaking, so I'm comparing here in the black line the  
5 2016 summer peak load forecast with the red line, which  
6 was what we used in later 2016 and which led to our 2017  
7 Ten-Year Site Plan. Nothing too surprising here. It's  
8 a little bit lower than what the 2016 peak load forecast  
9 was. A primary reason for that was we were projecting a  
10 bigger impact from the energy codes and standards,  
11 energy efficiency codes and standards. But it still  
12 shows significant growth over the ten-year period,  
13 roughly 2,500 megawatts. So, again, not too much  
14 different than what we were looking at in the 2016 site  
15 plan.

16 That's much the case also when we come to the  
17 fuel cost forecast. The black line shows the natural  
18 gas fuel cost forecast in the 2016 site plan. The red  
19 line shows what we were showing in the 2017 site plan.  
20 A little bit lower, but again not surprising. The past  
21 several years we have consistently seen that the new gas  
22 cost forecast was lower than the prior year's natural  
23 gas cost forecast.

24 There was a significant change, though, in  
25 regard to the CO2 cost or compliance cost forecast. It

1 is significantly lower than what we were using in our  
2 analyses in 2016. Now, our CO2 compliance cost forecast  
3 comes from the consultant, ICF, and there are primarily  
4 two reasons why this forecast is significantly lower.

5 First of all is the change in the new federal  
6 administration. They were anticipating, and I think  
7 correctly, that the Clean Power Plan was going to be, if  
8 nothing else, put on hold for four years and would  
9 probably take a couple of years after that for any  
10 replacement to the Clean Power Plan to resurface. So it  
11 was a, roughly a six-year start to where compliance  
12 costs became non-zero.

13 The second reason why it's so much lower is  
14 they were looking out and seeing the general trend in  
15 the industry of coal being replaced by natural gas in  
16 large part due to the prior slide with the lower cost of  
17 natural gas, and they were also seeing a good bit of  
18 solar activity across the country and in the southeast  
19 and in Florida due to the lower cost of photovoltaics.  
20 So those combinations resulted in lower projections of  
21 CO2 emissions and CO2 emission rates. Therefore, they  
22 thought that whatever the replacement was, assuming  
23 there is a replacement for the Clean Power Plan out in  
24 six years or so, it would cost less to meet those  
25 targets.

1           Now in the analysis itself, during the latter  
2 portion of 2016 what FPL focused on was not only, as  
3 usual, our system resource needs, but we also focused on  
4 regional needs, primarily that for Southeast Florida,  
5 which is made up by Broward County and Miami-Dade  
6 County. The reason for the emphasis on that, well, it's  
7 something that we bring up each year in our Ten-Year  
8 Site Plan as one of the factors that we always look at.

9           Those two counties make up the biggest portion  
10 of our load, roughly 44 percent of our total load. And  
11 to put it in perspective, those two counties' electrical  
12 load is roughly equivalent to the entire electric load  
13 for Duke Florida. It's an area that is bounded on the  
14 east by the Atlantic Ocean, on the south by the Gulf of  
15 Mexico and the Keys, the west by the Everglades, on the  
16 north by highly developed Palm Beach County, and the two  
17 county areas themselves are highly developed.

18           So it's a tough area to try to build  
19 generation in. It's a tough area to try to bring new  
20 transmission lines into the area. And we want to  
21 maintain or need to maintain a balance between load and  
22 generation in order to ensure that that transmission  
23 system down there in the two counties remains stable.  
24 So it's a very important consideration that we  
25 periodically look at.

1           And in our 2016 analysis we were forecasting  
2 that not only would we have a system resource need in  
3 the 2024 time frame, as shown by our 2016 site plan and  
4 the very first slide I showed you, but we were also  
5 projecting that the Southeast Florida area was projected  
6 to go out of balance at roughly the same time frame.

7           So we looked at our analyses on the second  
8 half of 2016 of trying to solve for both problems. We  
9 focused on three types of resource options. We focused  
10 on CC units. As we have seen, projected gas costs are  
11 lower than they were previously, CO2 compliance costs  
12 are lower, and the CC unit capital cost projections were  
13 dropping and fuel efficiencies for the units were  
14 increasing.

15           We also looked at PV. Capital costs have  
16 steadily been declining, and FPL has identified a number  
17 of advantageous sites virtually, without exception,  
18 outside of the Southeast Florida region for PV.

19           Storage, we want to take a look at it. We  
20 have a lot of interest in it. There are high capital  
21 costs currently for storage, but they're declining. We  
22 view they will continue to decline, so we've actively  
23 looked at those.

24           And the last slide here shows where we ended  
25 up in the 2017 site plan. And let me ask you to focus

1 on the black line entries here, or black font. Those  
2 represent what were carryovers from the 2016 site plan.  
3 We see the Okeechobee combined cycle unit in 2019 coming  
4 in, and we saw the un-sited solar of roughly  
5 300 megawatts in 2020.

6 Everything else that's in red font is new to  
7 the 2017 site plan. Taking advantage of the SoBRA  
8 agreement, we have roughly 300 megawatts of additional  
9 PV coming in in '17, '18, and '19, and we were  
10 projecting that those roughly 300 megawatts of PV  
11 additions would continue to be cost-effective and we  
12 would continue to add them through 2023. So about  
13 1,800 megawatts of additional PV beyond what we were  
14 showing in 2016.

15 In 2018, another new thing is we're projecting  
16 the retirement of our existing Lauderdale Units 4 and 5,  
17 and we are replacing that capacity with a new combined  
18 cycle at the same site called the Dania Beach Energy  
19 Center in 2022.

20 And the last big change was -- is shown in  
21 2019 where we are retiring roughly 970 megawatts of  
22 existing coal units, both owned and purchased. And the  
23 last item I'll point out here is that if you look at the  
24 last column and the last row, we do not have another  
25 resource need projected with this resource plan through



1 the reporting period of 2026. Our next resource need  
2 would pop up in 2027. And with that, it concludes my  
3 presentation, and happy to try to answer any questions  
4 you may have. Thank you.

5 **MS. THOMPSON:** Okay. Referring to Slide 6,  
6 why was storage found to be the least favorable resource  
7 option of the three types mentioned?

8 **DR. SIM:** I'm sorry. Could you repeat,  
9 please?

10 **MS. THOMPSON:** Why was storage found to be the  
11 least favorable resource option of the three types  
12 mentioned?

13 **DR. SIM:** Primarily due to the high capital  
14 cost of it. The prices have not come down at the same  
15 level as PV and, therefore, it was disadvantaged for  
16 that reason.

17 **MS. THOMPSON:** Okay. Is the utility's  
18 generation only reserve margin a controlling factor for  
19 any plant unit additions?

20 **MR. SIM:** No. I think what you'll see in our,  
21 in our projections is that both the, what I'll call the  
22 total reserve margin, which is the traditional one that  
23 includes DSM, and the generation only reserve margin,  
24 what we have consistently seen is the year of resource  
25 need is identical regardless of which of the two reserve

1 margin criteria we use, and the amount of capacity that  
2 we need in that year is roughly the same.

3 And what we've seen in some years, we have a  
4 higher number with a total reserve margin criteria, and  
5 in other years we may have a somewhat higher number in  
6 the generation only reserve margin. But they're fairly  
7 comparable.

8 **MS. THOMPSON:** Okay. Thank you.

9 **MR. WOOTEN:** Thank you, Dr. Sim. I appreciate  
10 it.

11 **MR. SIM:** Thank you.

12 **MR. WOOTEN:** Last, but not least, is Chris  
13 Steele from TECO.

14 **MR. ROCHA:** Hi. Well, I'm not Chris. He's  
15 better looking than I am. He got a great opportunity at  
16 the Bayside combined cycle station. He's managing the  
17 maintenance level activities there. So the greatest job  
18 in the utility world of manager of resource planning,  
19 we're looking for that right now, so. Only a utility  
20 planner would have liked that joke.

21 So it's the right arrow, Ben? Oh, there we  
22 go. All right. So this -- the big picture, we're  
23 designed to evaluate -- want to evaluate both the  
24 demand -- I'm Jim Rocha, by the way, the director of the  
25 department -- demand side and supply on a comparable and

1 consistent basis. We wanted to be cost-effective and  
2 reliable. And so to do that, we're going to look at all  
3 our future needs, we're going to survey the market, and  
4 we're going to do an economic analysis and meet all of  
5 those requirements.

6 Here's kind of the flow sheet. It's very  
7 similar to things that Stacy put up. But our first  
8 step, and it's a giant circle, so you could start on any  
9 one of them, but we start -- I started with the demand  
10 and energy forecast and any potential demand  
11 alternatives that were cost-effective and to  
12 determine -- that way we can determine our reliability  
13 and the needs and timing of additions of capacity or  
14 demand reduction.

15 We do an initial screen, which I'll show you  
16 some of those. This is just to narrow down all the  
17 gazillion options that we could possibly put forward,  
18 and some of them you want, as Sybelle said, a little bit  
19 lower energy cost versus a cheaper capacity cost.

20 Then we put these into our expansion plan  
21 models, and I'll talk a little bit about that. And then  
22 finally we put -- a lot of times folks use PROMOD or  
23 some of the others. We use an ABB model called Planning  
24 and Risk. And then lastly we -- with the avoided unit  
25 that we identified for the standard offer, we go back in

1 and determine cost-effective demand-side programs.

2 This is a comparison of our demand forecast.  
3 The very first number is because that's an actual number  
4 from winter of '16, and we heard that, that it was a  
5 fairly low, low number. It's about a 1.4 percent over  
6 the ten-year period increase of demand on our system.  
7 Very little difference between '16 to '17 on our system.

8 Oh, by the way, on the energy side, I guess I  
9 didn't have that graph, it's about 1.2 percent energy  
10 growth for our system. So we're slightly growing more  
11 lower load factor.

12 This is kind of busy and I'll try to show you  
13 the peaking side. This is our screening curve, and it's  
14 a very gross rough estimate of technologies where you  
15 levelize over, say, a 30-year life, and the slope is the  
16 variable cost and the fixed cost is the Y intercept.

17 And right off, the first thing you notice is  
18 combined cycle with the current projections that we  
19 heard from Dr. Sim of natural gas prices is the lowest,  
20 combustion turbine next. Our utility scale solar, you  
21 can see it starts to cross over somewhere higher  
22 capacity factors right now. I want to point out that  
23 these numbers are all based upon our once-a-year survey  
24 of the market. We go to a big engineering firm and all  
25 the different technologies that give us the variable

1 costs, the fixed costs, and the maintenance costs, and  
2 then we do a new fuel forecast.

3 And so as we will talk about a little bit  
4 later and maybe some of our other press announcements,  
5 there have been changes in the market since. But this  
6 puts them all on the same basis.

7 Small scale solar right above that, and then  
8 the aero type peaking. You might want to call that  
9 quick start peaking. Sometimes folks will pick that  
10 technology for that.

11 Here is a result of our reserve margin. Of  
12 course, it bumps up when we add additions. And once  
13 again, our plan that was filed on April 1 is very  
14 similar to last year in that we have two frame peakers  
15 in '21 and then in '24. And we are somewhere -- less  
16 than 25 but more than the 20 percent. And you can see  
17 it's pretty clear we build at the 20 percent level.

18 The Polk 2 combined cycle went in and has been  
19 operating great. It's a very high capacity factor, even  
20 higher than we had thought. Gas prices are low. And  
21 then the Big Bend solar plant, we had been calling it  
22 18 megawatts nominal. When we went out and bought the  
23 equipment, the inverters are going to be rated at 2.0  
24 megawatts. They were, as built, 2.2, so they're a  
25 little bit over 19. So the rating is 19.4 megawatts AC.

1           This is a picture of -- in the back you can  
2 see our Big Bend power plant and the beautiful Tampa  
3 Bay, not the picture that Ben showed of downtown  
4 St. Pete, but I think this is beautiful. And there's  
5 our 19.4 megawatt solar system that we installed --  
6 put into service in February of this year. And the  
7 Polk 2 combined cycle came in in January.

8           And it's -- I've got some graphs I think you'd  
9 find interesting of actual data. I've been doing  
10 everything on forecast data and vendor-supplied  
11 forecasts. And so as we look forward and some other  
12 things that have hit the press, we're going to start  
13 doing a lot more because gen planners don't just work  
14 through the Ten-Year Site Plan. We keep working all  
15 year long, all year long, and we'll be looking at some  
16 of the -- how to integrate larger amounts. And then I'm  
17 always continuing, like every October we look at all of  
18 our power plants and see if they're still -- the net  
19 present value is the right thing for our customers.

20           Here is actual data, and I'm going to finish  
21 up with just our Big Bend solar plant. And you can  
22 see some -- this is a day, one day in May. I wasn't  
23 aware, but May is a very good day for, at least in  
24 Florida, for -- month for solar incidents. And so you  
25 can see we got very flat at the top, maybe a few clouds

1 came in at some of those times or even rain, and you can  
2 even see that at the end of the day. Our coincident  
3 peak is about 5:00 o'clock in the afternoon. So with  
4 these tracking systems, we do a little bit better out  
5 there so we can calculate a more firm coincidence of the  
6 solar at the Big Bend site.

7 Here is a July number, and you can see the  
8 magnitudes are down and they're a little more variable,  
9 but it's consistently performing up at a higher level,  
10 not at the 19 megawatts. But these are actual data, and  
11 we're going to continue to collect a lot of that. And  
12 with that, I'd like to ask if there are any questions.

13 **MS. THOMPSON:** Good afternoon.

14 **MR. ROCHA:** Good afternoon.

15 **MS. THOMPSON:** Does the utility anticipate  
16 including additional solar capacity in its 2018 Ten-Year  
17 Site Plan?

18 **MR. ROCHA:** Next year?

19 **MS. THOMPSON:** Yeah.

20 **MR. ROCHA:** So we announced something  
21 recently. I can tell you that these analyses go on a  
22 long time and a lot of things have been -- a lot of  
23 things we've been through at Tampa Electric over the  
24 summer, it will be in the Ten-Year Site Plan next year.  
25 Of course, we're going to first give an opportunity for

1 this body to see that SoBRA that will be filed or voted.

2 **MS. THOMPSON:** Referring to Slide 7.

3 **MR. ROCHA:** Okay.

4 **MS. THOMPSON:** Are there any studies underway  
5 to address the planning considerations mentioned in your  
6 solar updates?

7 **MR. ROCHA:** Oh, yes. We're doing a lot of  
8 things on this. And, you know, one of the probably  
9 simplest is you start adding enough solar or anything  
10 really to see where you start having dump energy, and so  
11 that's one thing that you've got so many constraints  
12 that that's starting to happen.

13 And then also we do a lot of studies with the  
14 Transmission Planning Group on trying to understand  
15 their requirements. And I'm finding that though we're  
16 in different places now, back in the old days when we  
17 were both closer together might have, might have been a  
18 better way to handle that.

19 Also on storage, we continue to look at it.  
20 As we heard, it's over \$2,000 a kW probably on storage.  
21 But when you have a higher loading factor -- so we keep  
22 trying to find ways to load up the storage with that and  
23 then use it maybe at the coincident peak but just  
24 haven't been able to make the numbers work. And it's  
25 constant working on it with generation planners.



1           But we're also -- instead of -- not just our  
2 long-term models. This is more, you know, you have to  
3 look, really look at the volatility and what could  
4 happen in those hours, and so we've been doing more  
5 studies on spinning reserve and quick start, taking a  
6 look at we might need to do more of that. And go ahead.

7           **MS. THOMPSON:** Is that it?

8           **MR. ROCHA:** Yes, that's it.

9           **MS. THOMPSON:** Well, that's all. Thank you.

10          **MR. ROCHA:** All right.

11          **MR. WOOTEN:** I don't think there's any other  
12 questions. I want to thank you -- what was, what was  
13 your name? I didn't catch it.

14          **MR. ROCHA:** Jim Rocha.

15          **MR. WOOTEN:** Jim Rocha. Okay. Thank you.

16                 At this time we would also like to open up  
17 comments to the public. Is there anyone that would like  
18 to provide comments?

19                 All right. Seeing that there's no one making  
20 comments and there's no other matters to discuss, I'd  
21 like to move to conclude the workshop and declare it  
22 adjourned. Everyone have a good afternoon.

23                         (Workshop adjourned at 2:46 p.m.)  
24  
25


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

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 10th day of October, 2017.



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