ALABAMA PUBLIC SERVICE COMMISSION

MONTGOMERY, ALABAMA

A.P.S.C. DOCKET NO 32953

Ala. Solar Ind Assn's EX. No. 01

WITNESS: Kelley Goss

IN RE:

ALABAMA POWER COMPANY DOCKET NO. 32382

PETITION FOR A CERTIFICATE OF CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OR ACQUISITION OF RENEWABLE ENERGY AND ENVIRONMENTALLY SPECIALIZED GENERATING RESOURCES AND THE ACQUISITION OF RIGHTS AND THE ASSUMPTION OF PAYMENT OBLIGATIONS UNDER POWER PURCHASE ARRANGEMENTS PERTAINING TO RENEWABLE ENERGY AND ENVIRONMENTALLY SPECIALIZED GENERATING RESOURCES, TOGETHER WITH ALL TRANSMISSION FACILITIES, FUEL SUPPLY AND TRANSPORTATION ARRANGEMENTS, APPLIANCES, APPURTENANCES, EQUIPMENT, ACQUISITIONS AND COMMITMENTS NECESSARY FOR OR INCIDENT THERETO

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TESTIMONY AND PROCEEDINGS before the Honorable Scott Morris, Administrative Law Judge, at the Carl L. Evans Chief Administrative Law Judge Hearing Complex, RSA Union Building, 100 North Union Street, Montgomery, Alabama, on Wednesday, August 12, 2015, commencing at approximately 9:05 a.m.; and reported by Kim Pruitt, Registered Professional Reporter and Commissioner for the State of Alabama at Large.

EXHIBIT

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PENGAD 800-631-6989

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Mr. Jeremy H. Oden
Mr. Chris "Chip" Beeker

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EXAMINATION INDEX

NOEL CAIN

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ALJ MORRIS: On the record. Today's date is Wednesday, August 12, 2015, and we're here for a public hearing on Docket 32382. The petition is Alabama Power Company. The petition is for a certificate of convenience and necessity for the acquisition of renewable energy and environmentally specialized generating resources and the acquisition of rights and assumption of payment obligations under power purchase agreement arrangements pertaining to renewable energy and environmentally specialized generating resources, together with all transmission facilities, fuel supply and transportation arrangements, appliances, appurtenances, equipment, acquisitions, and commitments necessary for or incident thereto. And before we get into any of the preliminaries, we are going to turn it over briefly to Commissioner Chip Beeker for a word of thanks and a word of prayer.

(Invocation.)

ALJ MORRIS: I am Judge Scott

Morris. I'm joined here on the bench by Commission President Twinkle Andress Cavanaugh, Commissioner Chris "Chip" Beeker, and Commissioner Jeremy H. Oden.

Getting back to the matter at hand, this application was filed on or about June 25, 2015, and notice of today's hearing was served on July 14, 2015. Also in that notice it established a deadline for intervention. Petitions to intervene were received on behalf of the Alabama Industrial Energy Consumers, the Attorney General of Alabama, the JobKeepers Alliance, Alabama Environmental Council, Alabama Property Rights Council, L.L.C., the Southern Alliance for Clean Energy, and Gulf States Renewable Energy Industries Association.

On or about August 3, 2015, Alabama Power Company filed an objection to the intervention of the Alabama Property Rights Council, the Southern Alliance for Clean Energy, and the Gulf States Renewable Energy Industries Association. Pursuant to procedural ruling, on August 4, 2015, the parties were notified of these objections and given an opportunity to respond. Also in that ruling the petitions for intervention of the Alabama Industrial Energy Consumers, the Attorney General, and JobKeepers Alliance were granted.

Responses were received from the Southern Alliance for Clean Energy and Gulf States Renewable Energy Industries Association. Subsequent to that Alabama Power on August 7, 2015, filed withdrawing their objection to the intervention of the Southern Alliance for Clean Energy and the Gulf States Renewable Energy Industries Association. Also on August 7, 2015, the Commission issued a subsequent procedural ruling granting the petitions of the Southern Alliance for Clean Energy and the Gulf States Renewable Energy Industries Association. And the petition for the Alabama Property Rights Council was -- for intervention was denied.

Furthermore, in the August 4th

procedural ruling the parties were instructed to file a notice soliciting any potential -- or any witnesses that they planned to call and a brief summary of the testimony that they intended to give. A notice was filed by Alabama Power Company listing their witness. Also we note for the record that the Gulf States Renewable Energy Industries Association filed electronically a notice of a witness, but they failed to complete the process. The Commission rules require a follow-up of a hard copy within twenty-four hours, and they did not do that. I believe Mr. Canton, who was the witness, is here, is present. It is my understanding, at least according to the electronic filing, they did file a certificate of service. And I did want to make sure that everyone did actually receive a notice of that witness.
Mr. McCrary, did the company receive a --

MR. McCRARY: Yes, sir, we did.

ALJ MORRIS: You did? The other intervenors -- Ms. Martin?

MS. MARTIN: Yes.

MR. McLEMORE: Yes.

ALJ MORRIS: Everyone?

Okay. So since this is of a technical nature, I'm inclined to allow the testimony unless there is some objection.

But, Mr. Canton, this is the second time this has happened. In your original petition I think you were late and you had some issues. If you're going to participate in this hearing, we need you to follow the rules. And I just want to put you on notice that any further deviation from our rules is not going to be tolerated. We're going to allow you to appear today and to offer your testimony, but we are putting you on notice that if you're going to be here and participate in the process, then you need to follow the rules that everyone has taken the time and the care to follow.

MR. CANTON: Okay.

ALJ MORRIS: All right. With that, let's begin by taking appearances.

First on behalf of the power company.

MR. McCRARY: Yes, sir. Your Honor, thank you, and commissioners. My name is Dan McCrary of the law firm Balch & Bingham. I'm representing Alabama Power Company. With me here today is my partner, Scott Grover. Our contact information is already reflected in the pleadings, but we've also provided it to the court reporter for the record.

ALJ MORRIS: Thank you, Mr. McCrary.

For the staff.

MR. FREE: Yes, sir, Your Honor. My name is John Free, director of the Commission's electricity policy division. And with your permission, I'm here today to ask clarifying questions of the witness concerning her testimony and the company's filing.

ALJ MORRIS: Okay. Thank you, Mr. Free.

MR. BENTLEY: Luke Bentley,

commission staff.

ALJ MORRIS: Thank you, Mr. Bentley.

And for Alabama Industrial Energy Consumers.

MR. McLEMORE: Yes, sir. I'm Jimmy McLemore, a local lawyer here with Capell & Howard. I represent the Alabama Industrial Energy Consumers. We've intervened in the proceeding and participate as we see appropriate.

ALJ MORRIS: Thank you, Mr. McLemore.

And for the Attorney General.

MS. MARTIN: I'm Olivia Martin. I'm here on behalf of the Attorney General.

ALJ MORRIS: Thank you, Ms. Martin.

Let's move down our line for -- I'm doing this really on order of intervention. Next will be JobKeepers Alliance, and I believe that's Mr. Cagle.

MR. CAGLE: My name is Patrick

Cagle, executive director of JobKeeper Alliance.

ALJ MORRIS: Thank you, Mr. Cagle.

Alabama Environmental Council.

MR. JOHNSTON: My name is Keith Johnston. I'm managing attorney of the Southern Environmental Law Center in the Birmingham office. And here with me is my colleague Christina Andreen from the Southern Environmental Law Center. And we are representing the Alabama Environmental Council.

ALJ MORRIS: Thank you, Mr. Johnston.

Next is Southern Alliance for Clean Energy.

MS. SHENSTONE: Your Honor, I'm Amelia Shenstone. I'm the campaigns director with the Southern Alliance for Clean Energy.

ALJ MORRIS: Thank you, Ms. Shenstone.

And for Gulf States Renewable

Energy Industries Association.

MR. CANTON: My name is Jeff Canton, president of Gulf States Renewable Energy.

ALJ MORRIS: Thank you, Mr. Canton.

With that, I believe we are about ready to begin. Are there any preliminary matters that we need to address before we start? Do you have anything, Mr. McCrary?

MR. McCRARY: Yes, sir, Your Honor, just one preliminary matter. I assume that for purposes of this hearing we'll be following the customary rules regarding friendly cross-examination, prohibiting friendly cross-examination?

ALJ MORRIS: Yes.

MR. McCRARY: That's all we have, Your Honor.

ALJ MORRIS: Okay. With that, Mr. McCrary, I believe you have a witness.

MR. McCRARY: Yes, sir, we do.

I would call Ms. Noel Cain to the stand.

ALJ MORRIS: Ms. Cain, if you would have a seat up here, but before you do that I need to swear you in.

Mr. McCrary, are you ready to proceed?

MR. McCRARY: Yes, sir. Thank you.

NOEL CAIN,

having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. McCRARY:

Q. Would you state your name and business address for the record, please?

A. Yes. My name is Noel Cain. I work at 600 18th Street North in Birmingham, Alabama.

Q. And by whom are you employed Ms. Cain?

A. Alabama Power Company.

Q. What's your position with Alabama Power?

A. I'm the regulatory policy manager.

Q. Could you please briefly overview your primary responsibilities as regulatory policy manager?

A. Yes. Alabama Power, as a regulated utility, has oversight and regulation from numerous federal and state agencies. My role as regulatory policy manager serves as one of a few main points of interface between the company and the Commission staff, primarily focused on items of state and national policy as they affect our industry and our company.

Q. How long have you served in this role?

A. Since June of 2014.

Q. Would you briefly review your educational and professional background prior to that time?

A. Sure. I have a degree in electrical engineering from the University of Alabama at Birmingham. And I began with the company in 2001 in Southern Company services. I've had various positions of increasing responsibility across, namely, the operations organization, including wholesale analysis, market structuring, engineering and construction services, mostly across that operations organization.

Q. Ms. Cain, are you familiar with the petition filed by Alabama Power in this proceeding on June 25, 2015?

A. I am.

Q. And are the representations in that petition true and correct to the best of your knowledge, information, and belief?

A. Yes, they are.

Q. Would you generally describe what the company is requesting from this commission through its petition?

A. Sure. The petition is requesting authorization for the construction or the acquisition through either a PPA or a purchase of an asset of renewable or environmentally specialized generation resources in order to meet customer interest in renewable energy.

Q. And I see the petition also includes a reference to various things, support facilities and so forth, and appurtenances. Could you explain what that term generally refers to?

A. Appurtenances would be sort of everything else associated with the delivery of that electricity. So outside of just the generator itself you have procurement of land and right-of-ways and transmission facilities. The actual delivery of that electricity requires more than just the generator itself.

Q. Would the interconnection facilities associated with a project fall within that category?

A. Yes, they would.

Q. How does Alabama Power propose to handle the construction, ownership, and maintenance related to interconnection facilities for these projects?

A. Under Alabama law Alabama Power Company has the right to own any transmission facilities that interconnect to our system. So on a self-build asset, obviously, we would own that interconnection. On anything that was a third-party ownership, a PPA, Alabama Power has the right to own that interconnection facility but may also waive that right if it's in the best interest of the customers, subject to commission approval.

Q. So would Alabama Power choose to elect or would Alabama Power want to elect whichever alternative in that situation was most beneficial to customers?

A. That's correct.

Q. Are there any conditions associated with the company's requested authority in its petition?

A. Yes. Obviously, we're talking about renewable or environmentally specialized generation. So that's item one. I failed to mention that the company is seeking authorization for smaller scale renewable projects. So there's a limitation on the size of each individual project and can only be up to 80 megawatts.

Other restrictions are a limit on the total amount that we're requesting an authorization for. That would be up to 500 megawatts.

And then each and every project under this certificate authority would be required to demonstrate projected positive economic value for customers in terms of electricity price.

Q. And, again, would the authority requested here be limited just to self-build projects for the company?

A. No, there wouldn't be a limitation on self-build. It would be self-build or PPA on a case-by-case basis.

Q. And you've mentioned a couple of megawatt limitations, the 80 megawatts per project up to and then the 500 megawatt aggregate total. Is that size measured in AC or DC?

A. That would be AC.

Q. Are there timing limitations incorporated in the petition in the requested authority from the Commission?

A. There are. The -- upon granting of the authority, the company would need to initiate action on the first project within one year of the granted certificate. And then within six years the company would have that amount of time to exercise the full amount. Should 500 megawatts worth of projects not materialize within that six-year window, then any unused portion of the certificate would expire.

Q. What about any exercised authority under the petition? What would be the term for those projects?

A. Once those projects were approved under the certificate within that six years, they are certificated for the life of the project. So on self-build that would be the life of the asset. For a PPA it would be the term of a contract.

Q. All right. Ms. Cain, now that we've kind of taken a general overview of the company's petition, let's spend a little bit of time looking at the circumstances that led to the company's filing. Are you familiar with those?

A. Yes, I am.

Q. What's the primary factor that prompted Alabama Power to seek the authority requested in this -- in the petition?

A. What brings us here today is primarily driven from customer interest, namely military requirements for renewable energy, but we've also seen interest in the private sector as well. Along those lines, in order to meet that interest, the company's identified a need for -- for these smaller scale projects to have a kind of structured efficient process that we can transact quickly to meet these customer requests.

Q. Can you identify any secondary benefits that might potentially attach to the authority under the certificate?

A. Yes. While not the primary driver, the certificate request is really a function of customer interest in that renewable energy, but there is a secondary benefit that the renewable energy could help with environmental compliance in the future.

Q. Now, Ms. Cain, let's go back to the primary driver, the customer interest that you identified a moment ago. Is that interest in the governmental sector, is it in the private sector, or both?

A. It's both. Both sectors.

Q. As far as Alabama Power is concerned, initially what's the -- has the interest primarily surfaced in the governmental arena or in the private arena?

A. Well, primarily we're here about the governmental arena, the military requirements that I mentioned.

Q. And what's your understanding of the reasons for the military's interest in renewable projects?

A. That requirement that the military has actually dates back to the National Defense Authorization Act of 2007 where that law actually required the Department of Defense to set goals and targets for themselves that they would use 25 percent of their energy consumption from renewable resources by 2025. After that act there was a series of executive orders that sort of reinforced that, the most recent being in March of this year.

And that executive order actually went beyond just the Department of Defense and applies to all federal agencies. It set an interim goal in addition to that 2025 time frame of about 10 percent by 2016 or 2017 for all federal agencies. So the military is working in response to those mandates from the federal government.

That executive order -- it's interesting to note that it actually even references suppliers of those federal agencies, which is another example of reaching into that private sector.

Q. Now, Ms. Cain, I would assume that the interest Alabama Power has seen from the military has been with respect to military installations within its service territory; correct?

A. That's correct.

Q. To your knowledge is there similar interest being exhibited by other military installations across the southeast?

A. Yes, definitely. We've seen military installations across Georgia, Florida, Mississippi, the Carolinas where the military bases in those states have worked with utilities to exercise renewable projects.

Q. To your knowledge how have those installations worked with their jurisdictional utilities to meet their needs?

A. They're a combination of PPAs and self-build. Our understanding is that some of those applications actually require the utility to be the owner and operator of the renewable generation, primarily from a timing requirement in order for the Army to meet their time line. Many of those contracts have been implemented under the General Services Agreement with their jurisdictional utility, and that agreement requires the utility to be the owner and operator.

Q. Now, you also mentioned that there was interest in renewables in the private sector, did you not?

A. That's correct.

Q. Is there publicly-available information that you can point us to that would demonstrate that interest in the private business sector?

A. Certainly. There are a number of pieces of evidence that sort of support that. One that comes to mind is that nearly half of the nation's Fortune 500 companies actually have renewable mandates or goals of some kind. One example is just February of this year there was what's called a corporate renewable buyers guide, which was sort of a conglomerate of about twenty-five-trillion-dollar-worth-of-revenue companies across several industries, manufacturing, retail, technology that have basically documented their commitment to renewable energy. Some companies have actually said they want to be 100 percent renewable, like Google and Wal-Mart.

Q. Can you give some examples of private companies acting on these goals in other parts of the country?

A. Again, there are several examples of that. I'll give you a couple that come to mind. In Iowa MidAmerican Energy has worked with Facebook and Google to build in a partnership over 500 megawatts of wind energy that supplies that wind energy to brand new data centers, that those companies cited renewable energy being a main factor in their choosing to locate those facilities in Iowa.

Another example is Apple has a

couple of agreements with jurisdictional utilities to serve their data centers. The Salt River project in Arizona had a 70-megawatt solar deal with Apple. Sierra Pacific is another utility that worked with Apple to bring renewable energy to their portfolio. And that one was in Nevada.

Amazon is another good example. They recently announced an 80-megawatt facility in Virginia. Those are a few examples that come to mind.

Q. And what about closer to home? Can you identify any examples in the southeastern region?

A. Yeah. Even here in the Southeast we've seen some examples of private sector companies who are demonstrating that they're willing to put their money where their mouth is so to speak. And just north of us in Chattanooga is a good example where the Volkswagen facility has built about a 10-megawatt solar installation there at their manufacturing facility.

And closer to home even is the Google announcement in North Alabama just a few weeks ago where Google cited the renewable energy option where they're working with TVA, the local provider, to -- as a major factor in deciding to locate their facility in Alabama.

Q. How do these private companies such as those you've just been discussing, how do they undertake to achieve their goals?

A. Well, many of them prefer to work with their jurisdictional utility. They have a relationship there, a history of that utility providing their reliable electric service, and many have come out and said they have no desire to be in the energy management business. That's what the utility does. That's their expertise. And they would rather focus their resources on their own products. So they certainly prefer to work with the utility companies.

Q. You mentioned related to customer interest a need to move quickly and efficiently to respond to this interest. Why is that an important consideration here?

A. Well, as I mentioned, most -- the reason we're here is in response to customer interest, and we have a need to be able to move quickly and efficiently. If we are certificating individual small-scale projects, there are costs associated with that and resources that are utilized, so it just makes sense -- it's economical to have a process that's less costly and burdensome.

It also makes sense for it to be able to offer it quickly in order to respond to those customers. Those customers are not regulated utilities. That's kind of a brand new world for them. They would prefer to be able to make decisions and move forward. So to the extent that there are delays caused from the regulatory process they may choose to locate their expanded operations or new data centers elsewhere where there may be less of a timing constraint.

Another reason is from a market

conditions standpoint. The renewable industry is an ever-changing market and -- for instance, the federal tax credit that is -- currently allows for a 30 percent reduction in costs would drop to a 10 percent credit if any projects can't be in service by the end of 2016. So there's a need there to move quickly to effectively take advantage of certain market conditions.

Q. What's the effect of an uncertain time frame as it relates to, for example, vendor offers with respect to a project?

A. That's another -- again, an example where moving quickly is beneficial to customers as a whole, as well as the customer-specific application where vendors are hesitant to quote pricing that is sort of evergreen or out -- you know, hanging out there as long as the company may need. And to the extent that that -- an original offer from a vendor expires, they certainly can come back with a higher price. Or if we are to negotiate with a vendor and try to get them to quote a firm price for an extended period of time, they're going to price a certain amount of risk into that bid or quote and, therefore, increasing the ultimate cost in that market environment.

Q. Ms. Cain, how would an inability to move quickly in these kinds of circumstances potentially harm retail customers?

A. Well, again, there would -- there could definitely be some repercussions on the cost basis, but another problematic situation is that if these customers who we are trying to work with on projects were interested in expanding operations in our state or locating some new operations in our state, typically we're competing for that growth in our economy with some other jurisdiction or some other state or even another country. Some operations may be exploring in Canada, for example. So to the extent that there are delays or uncertainty in that process those companies view that as a risk, and all things being equal, they -- that could deter them from wanting to locate and work with Alabama Power if there's an easier option elsewhere and all things are equal.

Q. Now, lastly, you mentioned that the requested authority could help the company comply with environmental laws and mandates. How would the authority enable the company to accomplish that goal?

A. Renewable energy added to our generation would necessarily reduce some other form of generation. So to the extent that any renewable energy is generating in a given hour it may be offsetting some other generation. So that reduction in generation could help to reduce emissions in further environmental regulations.

The Clean Power Plan is another great example. Obviously, the company hasn't worked through the details of that plan since it's well over fifteen hundred pages and was just finalized last week. Additionally, the state implementation of that plan is yet to be determined. But it's safe to assume that renewable energy will help in some way with that -- with compliance with that plan.

Q. Ms. Cain, let's turn to the specifics of the company's petition. Why does the company seek authorization to both construct facilities as well as enter into PPAs?

A. The company needs to have the flexibility to do whichever thing is the best application for our customers. So on specific customer needs where we have been approached by a customer who's interested and places a priority on that renewable generation like some of those military applications, there could be a requirement that the company own and operate it. So self-build would have to be an option there.

There could be other instances where due to certain timing or siting restrictions that self-build or PPA may be the only viable option that will meet that customer's needs. And -- but in cases where there aren't limitations there needs to be the flexibility to do whichever option is in the overall best interest of all customers.

Q. In either case, Ms. Cain, whether it be self-build or a PPA, would the project be held to the same requirements set forth in the petition?

A. Absolutely. Regardless of whether a project is self-build or PPA, ultimately, in order to qualify under the petition, every project has to be demonstrated to provide projected economic value to all customers.

Q. Now, the company is proposing an 80-megawatt limitation -- an up to 80-megawatt limitation on individual projects; correct?

A. That's right.

Q. What's the basis for that?

A. 80 megawatts has long been sort of the standard of small-scale generation.

That was sort of solidified by the PURPA rules of 1978. It meets that definition under those requirements for small scale.

It also is a reasonable size based on interest that we've seen and projects that have been transacted in other jurisdictions in other parts of the country.

Q. A similar question with respect to the 500 megawatt total cap. What was the basis for that?

A. Again, it's just a reasonable amount given the customer interest that we've seen thus far. And based on, you know, with our existing customers that have come to us and said they're interested in renewable energy, we've identified potentials of around that amount, that range.

And in addition, given the fact that it could attract new customers to the state, we think 500 megawatts is a great starting point at least.

Q. Now, is the company obligated to utilize that full authorization, 500 megawatts?

A. Not at all. It's an up-to amount. So any projects that meet that criteria that was set forth may be brought forward for approval, but to the extent that, as I mentioned earlier, 500 megawatts worth of qualifying projects don't materialize, the company wouldn't transact on something that didn't meet that criteria.

Q. And I think you touched on this earlier, but just since we're walking through the specifics, how long would the requested authorization and certificate last?

A. That would be six years.

Q. And is that with respect to projects under the certificate or just the authorization to transact?

A. The authorization would be six years. Any projects that were approved under that authorization and certificated through this process would be certificated through their life.

Q. And after six years what would

happen to any unexercised authorization?

A. That would expire. And in order for the company to do anything further at that point it would require a brand new authorization.

Q. Now, Ms. Cain, apart from the size and time limitations, could you discuss the criteria for a project to qualify under the certificate related to positive benefits?

A. Yeah. Those positive benefits would be quantifiable calculations based on aggregating the total expected cost of the facility and comparing all of those total costs to the total benefits the company would realize and pass along to customers. So those benefits would be in terms of the avoided costs that the renewable generation entails, as well as any other benefits that are able to be quantified in terms of electricity price savings. So that can be customer contributions based on that specific project. It may be in terms of a fee or a direct payment stream from a customer who's willing to pay an extra price. Or if it's an amount that can be quantified from benefits of retaining load that was maybe at risk of, as I mentioned, locating to some other state or operation or attracting new load and growth to our territory, that would help to put downward pressure on rates. Other benefits could include, as I mentioned, environmental compliance once we see how that shakes out.

Q. Now, a moment ago you mentioned avoided costs. Could you provide a little more detail about what you mean by that?

A. Yeah. The avoided costs would be all of the costs that are -- that the company would otherwise incur but for the generation that's being analyzed. So to the extent that it displaces energy in the stack every hour that the unit is running would be an hour of reduced energy from some other unit. So the marginal price, the dispatch cost of that unit, would be an avoided energy component.

There is avoided capacity costs. However, those are quite small relative to the energy value since Alabama Power has sufficient capacity to meet its reliability needs until 2030.

Furthermore, to the extent that any of this renewable energy is intermittent in nature, that would further diminish the avoided capacity cost value.

Any other avoided costs that the company could directly identify and attribute to the actual renewable project being evaluated would also be included.

Q. Now, you mentioned a moment ago that other quantifiable benefits would include load growth and load retention; correct?

A. That's right.

Q. How does load growth and load retention benefit all customers?

A. Well, let's start with load growth. As I mentioned, if we were able to attract new load to the state, new operations, that load, aside from just being great for the state's economy and creating jobs in the state of Alabama potentially from an electricity price standpoint, the company would calculate the incremental costs of serving that load. And to the extent that the company has already invested in fixed cost assets, transmission, generation, distribution, but may not change or only increase marginally to serve that additional load, then those incremental costs would likely be less than the incremental revenues expected to be received from that customer. Therefore, they would -- that customer would be helping to spread out those fixed costs across a greater amount of electricity sales, which, therefore, puts downward pressure on everybody's rates. So it's a good thing for electricity price in terms of all customers benefiting.

The same is true for retaining load. If a certain amount of load is at risk of maybe relocating operations into another state, that -- the removal of that load, that energy would, therefore, no longer be helping to contribute toward recovery of those fixed costs. And that fixed cost would get shifted to other customers, which would be -- you know, it would go the other direction. So retaining that load helps keep downward pressure on rates.

Q. How would Alabama Power seek to estimate these growth and retention benefits?

A. Well, again, for a -- for an existing customer we have historical information that helps us understand their operation profile and their energy needs and how much that customer is contributing to the cost base for that electricity price calculation.

For a new customer we would work with that customer to understand those energy needs based on design parameters of that operation or similar facilities or things of that nature to project that estimated energy need and, therefore, project those incremental costs and revenues that would ultimately result in that downward pressure.

Q. What kinds of showings and underlying information would be reflected in the company's analysis of those various factors and considerations?

A. Each project, upon submittal for approval, would be given to -- all the analysis and underlying information in that economic analysis would be given to the Public Service Commission staff and the Office of the Attorney General as that representative for the using and consuming public. The company would submit information of that analysis, along with all the supporting details and documentation behind any major assumptions. You know, that would include all of the calculations of total costs and total benefits and all the supporting information that went into quantifying those costs and benefits.

Q. Can you discuss a little bit about the nature of the information that

would be incorporated in those showings by
the company?
A. Right. That information, in terms of the costs and the benefits, would necessarily contain highly-sensitive and proprietary information for both our business as the power company, as well as that specific customer we may be working with on that project. So, therefore, it would be very detrimental to either company for that information to be released. On the customer specific application it could give away information about their business plans or their siting projections and things of that nature, that when working with the power company, that customer is expecting that information to be held confidential.
Q. Ms. Cain, would either the Commission staff or the Attorney General be required to accept the company's analysis of a project?
A. Not at all. The information the company would present to the staff and the

AG's office would support the economic analysis that the company has performed, but it would be up to them to review the information and ask any detailed follow-up questions that the company would respond to. And ultimately they would present their review of that information to the Commission with their recommendation of approval.

Q. In closing, Ms. Cain, in your opinion is the proposal as set forth in the company's petition an effective and reasonable means of meeting the goals that we've been discussing here today?

A. Yes. This petition is a -- is a way to allow Alabama Power Company to respond to that customer interest that we've seen in renewable generation in a way that doesn't create any subsidies across customers who maybe aren't as interested in renewable or certainly don't put the cost priority on it that other customers do. So it's a smart way forward for Alabama Power in bringing more renewable energy options to our customers.

MR. McCRARY: Judge Morris, I believe that completes our direct testimony. We would respectfully reserve the right to recall the witness for redirect as need be.

ALJ MORRIS: Okay. Thank you, Mr. McCrary.

I'm going to start with Mr. Free and Mr. Bentley on behalf of the staff.

MR. FREE: Thank you, Your Honor.

CROSS-EXAMINATION

BY MR. FREE:

Q. Good morning, Ms. Cain, thank you for being here today. We appreciate your testimony. We have several questions to follow-up with concerning the company's petition and your testimony.

And we'll start with the basis for the actual filing. You stated earlier, I believe, that it's not expected -- the projects that you would file under this authority, it's not expected to have a huge capacity benefit. And so -- is that

correct --
A. Yes.
Q. -- first of all?
A. That's true.
Q. So the authority that Alabama Power is requesting is not based on a need for additional capacity or some reliability need but rather is driven by customer requests, preferences of that nature; is that correct?
A. That's correct.
Q. Okay. Speaking to the broad authority of the request, is Alabama Power aware of any regulatory approvals elsewhere in the country that involve renewable energy -- renewable certificate authority similar to what the company has requested here which focuses on an aggregate megawatt hours or the 500 megawatts rather than project-specific approvals?
A. Yes. One example references the example that I used with Mr. McCrary of the 500 megawatts of wind energy in Iowa. Those

two projects with Google and Facebook were actually the result of a bigger block of generation that MidAmerican Energy had secured with their authority of, actually, up to 1000 megawatts of unidentified wind projects that were intended to serve as -- as, at least in some part, an economic development action for the state.

Another good example is in Georgia. There have been a couple of sort of block approvals, if you will, of unidentified solar projects that the company has transacted on.

Q. Thank you.

Let's talk about the certificate parameters just for a minute. In this petition Alabama Power is requesting certificate authority to construct, acquire, or purchase renewable energy and environmentally specialized generating resources. Can you please clarify the types of resources that would qualify as renewable or environmentally specialized?

A. Yeah. Renewable resources are actually defined under Alabama Code, so I may not get all of them, but it refers to wind, solar, hydroelectric, geothermal, biomass. Those are renewable energy per the Alabama Code. I think there are applications of tidal currents. I may not have listed all of them, but those are the mainstream.

The environmentally specialized basically refers to resources where they are recycling in nature. So landfill gas or combined heat and power applications where you harness the waste heat from maybe an industrial process and then use that waste to -- heat to create actual electricity production.

Q. Okay. So in the context of Alabama Power's proposed certificate authority what is the company's position concerning battery power installations and how -- or if such installations may be employed as part of a renewable and/or environmentally specialized generating resource?

A. Well, a battery in and of itself is not really a generator. It stores and discharges electricity. So it's really one of those otherthings that may go along with a power production facility. So to the extent that certain projects may combine with a battery, that would sort of be a part of the project, but batteries themselves wouldn't be a generator. So they wouldn't fall under that --

Q. So it's your testimony that the battery would not qualify on a stand-alone basis but might could be grouped with other renewable projects to make a complete project?

A. Potentially --

Q. Potentially?

A. -- that could be a use.

Q. In its petition also Alabama Power is proposing that no single project should exceed an installed capacity of 80 megawatts. Is the company proposing a minimum size for any project to qualify under the proposed certificate authority?

A. There wouldn't be a limitation on the minimum amount of megawatts. Each project would just be required to provide positive economic value.

Q. Okay. And also in the petition, as you stated earlier, Alabama Power is proposing certificate authority for up to 500 megawatts, a small scale renewable and environmentally specialized generating resources over a six-year period. Is the company proposing a maximum amount that can be submitted and approved for any given year?

A. No. Just the six-year window is the only timing constraint.

Q. So you could have 400 approved in one year and 100 in another or vice versa, a variety of approvals?

A. That's correct. So long as the projects meet that economic benefit criteria, it would be in the best interest of customers for the company to transact on them.

Q. And having that flexibility would be a good thing?

A. That's correct.

Q. Does the certificate authority that you've requested here restrict the type of customer that might be involved in a project?

A. The petition would not limit the type of customer; however, the company thus far has seen interest from the larger scale customers in order to make those project economics work.

Q. Yes. Thank you.

Moving to the self-build acquisition or purchase power decisions, how would the company determine whether to pursue a project as a self-build option or a power purchase agreement? You may have touched on this earlier, but can you explain that further?

A. Yeah. As I mentioned first, when a customer interest is brought to the company, we would need to understand any siting restrictions or timing limitations or parameters that -- that from that customer's standpoint would restrict or limit the type of application able to be used. So that could set the stage for whether there was a self-build or a PPA type project.

To the extent that there weren't any limitations that drove the company in one direction or another, then all options would be considered and determine which option best fits that need and is in the best interest of all customers.

Q. Which option best fits that need. When all the options are available and they're on the table, how would that decision be made?

A. In general the lowest cost option.

Q. Right.

A. But there can be reason -- you know, credit quality or any reliability risks or things of that nature where, you know, all things being equal, you would go with the --

Q. The economic decision?
A. -- you would go with the economic decision. But I'm hesitant to say we would always go with the lowest price if there were -- you know, if there were some counter-party risks associated with those.
Q. Exactly. Everything has to be evaluated at the same time?
A. Exactly.
Q. Okay. So how will the company know that the costs of a plan project are reasonably consistent with market-related alternatives that might be viable for that particular application?
A. The company would have a gauge on the market, if you will. That may come from unsolicited offers if we've got a true gauge of the market, because there are a number of unsolicited offers on the table, and, you know, if they are obviously set in the range, they're not skewed one direction or another, then it's reasonable to assume that that's a good representation of the

market. To the extent that the company doesn't have good market data, that information could be attained through an RFP or other market indications.

Q. The next couple of questions are related to intermittent resources. Are there unique challenges, you know, associated with some of these renewable-generating facilities that are intermittent in their output of generation? Are there challenges there for the company to integrate these type of resources into a system?

A. Yes. You know, renewable intermittent resources, solar and wind basically, are newer applications, and across the industry experts are still trying to understand exactly what that means for operating a system. So to the extent that there are large magnitudes of renewable intermittent energy added to a system there are certainly implications there. And to the extent that those can be quantified and attributable to a specific project, these would be included in that ultimate aggregating of the total cost.

To the extent that maybe some small project is insignificant in that regard, then there would be no -- there would be no significant challenge associated with that intermittency.

Q. So to summarize, there may or may not be costs associated with integrating intermittent resources?

A. There are essentially costs associated with integrating intermittent resources to some extent. The threshold is really still under evaluation. At what point does that cost become material and quantifiable?

Q. And to the extent you can identify those and they are material, they would certainly be included in the project evaluation?

A. That's correct.

Q. Does Alabama Power anticipate that each project submitted under the requested authority will be located in the company's service territory? And I guess I ask that question because it was contemplated that the projects would have a close nexus with Alabama Power customers. And so I'm asking the question as if anticipated that they would be located within your service territory, the projects that are submitted under this proposed authority.

A. Many of them may be. That's a great question in that in response to specific customers, they may want generation on their site or very close to their operations or in the state of Alabama so that they can see it and feel it and know that it's there, but the petition itself wouldn't limit projects to only being located in the state of Alabama.

Q. So you don't want to preclude projects such as PPA projects located outside of your service territory; you would like to retain the flexibility to enter into PPAs; is that correct, for those type situations?

A. Yeah. To the extent that it meets the needs of that customer and meets their interest in renewable generation and passes the qualifying test of applying under this certificate authority --

Q. Right.

A. -- then it would put downward pressure on rates and produce positive value for customers, and, therefore, it would be in their best interest, so there's no need for a limitation in the company's opinion.

Q. Is it correct that if it was an out-of-state project or even a project just outside your territory that it would necessarily involve one or more transmission agreement -- service agreements to get the power to your service territory?

A. To the extent that any projects brought forth under this authority were not located within our transmission territory, the contract protections would be in place such that that energy would be delivered to the company's -- to the company's network and avoid any transmission risks being placed on the company, on our customers.

Q. Through the terms of the contracts?

A. Right.

Q. But they probably would become part of the total cost of the project for the party -- the third party you're contracting with?

A. That's correct. That would be up to that counter party to price in their cost recovery for actually getting the energy to our network.

Q. Generally speaking, are -- and you touched on this a little bit in your earlier testimony, but generally speaking, are interconnection facilities between the generator and the grid, are they generally considered part of the transmission system?

A. Yes. The Alabama law that I referred to actually defines transmission as anything over, I believe, 35,000 volts, 35 kV. So interconnection facilities are at that level or above and connect to our system; therefore, they're -- they are a part of --

Q. Technically -- yeah. Technically considered transmission facilities?

A. Right. Right.

Q. Is it the company's view that a waiver of its right under the law to own, construct, and operate and to maintain interconnection facilities will be in the best interest of customers?

A. A waiver would -- for these types of interconnection facilities where it's basically acting like an extension cord to the system, certain applications may be more impactful to the reliability of our grid than others. So to the extent on a project-by-project basis the company determines that it's in the best interest of customers for the company to have the right to own that facility versus waiving that right and allowing the third party to own it would need to be explored for each project. So in cases where it makes more sense for the third party to own it the company would request a waiver for that right of ownership.

Q. Okay. So it's, I guess, a fair statement that the company -- they seek waivers, but they may not apply in all situations?

A. That's correct. The company would choose the option that makes the most sense for customers and is in their best interest.

Q. You talked a little bit earlier in your testimony with Mr. McCrary about the projected avoided cost calculations?

A. Uh-huh.

Q. Can you explain the process the company goes through to calculate its projected avoided costs?

A. The energy projected avoided costs are based on a complex process that actually calculates the hourly dispatch price of the system in each hour of the year. It's

8,760 hours worth of data for each year of the analysis. That projects that marginal unit, the last unit in the dispatch stack that is set in the margin. It's made up of -- it's a simulation engine that basically mimics realtime operations. So it has data associated with fuel price, heat rates, unit characteristics, maintenance outages, things of those nature, load projections to develop and create that marginal dispatch price in an hour.

On the avoided capacity side of the equation the capacity costs on -- the capacity costs rate that would be avoided is based on market analysis. And as I mentioned, since the company is in a position that it has enough capacity to reliability meet its needs until 2030, that amount is very small in the near term years and is much less significant than the energy component.

Q. So fuel prices are a part of that calculation?

A. That's correct.

Q. If we pulled out a couple of those, such as your projection of coal prices or projection of natural gas prices, can you tell us a little bit more detail on how you would pursue those estimates and arrive at those estimates?

A. Yeah. So for the fuel price component -- those are all fuels, so the company utilizes a third-party vendor to run what's called macroeconomic models where it takes into account the GDP and what's going on in the economy and the interface of how those -- how a projected gas price in the future would impact that economy, so it has that feedback we've taken into account. So those fuel prices are natural gas. And it's basically estimated at the Henry Hub in Louisiana and is -- is utilized, you know, for many applications. There's not a lot of variability in that commodity in terms of its heat content and its quality, wherein on coal pricing and coal forecasting, those can vary drastically from one type of coal to another.

So those are quantified at each basin, each mine now. And then the company takes that third-party information and uses their expertise to calculate and quantify the transportation adder on each of those fuels. So from each basin to each plant that burns that type of fuel -- and from that Henry Hub they use a pipeline basin adder to calculate the transmission -- transportation cost that ultimately result in a delivered-fuel forecast for each and every plant.

Q. So the energy budget is broken down into a short-term projection and a long-term projection, and these fuel prices fall into both of those categories. The third-party consultant that you use, can you tell who that is, or is that confidential?

A. The -- much of their work is confidential, but the name itself, the vendor is called Charles Rivers Associates.

Q. And they are highly respected in the industry for putting together these type of analyses?

A. Absolutely. They're well known in the industry and have been working with us for years.

Q. Has the calculation process that you just described, projecting avoided costs, has that been developed specifically for the purpose of evaluating projects under the proposed certificate filing?

A. No, not at all. That's a good question. This avoided cost process, this complex simulation model, is the result of months worth of work across numerous departments and a lot of analysis, analysts and engineers. And that process has been in place for years and years. It's the means by which we evaluate numerous business decisions in terms of fuel budget or, you know, procurement and generation decisions, all aspects of business operations in which, you know, the price of electricity is concerned. So it's -- it's a process that's well established and has been utilized by the company for decades.

Q. Thank you.

I believe in the -- your testimony and also in the petition we've mentioned that Alabama Power will compare the cost of each project to the company's expected avoided costs, plus other project-specific benefits to determine the value of each project. In this comparison what will be included as part of the project costs?

A. The project costs themselves will depend on what the application is. So for a self-build project that would include all of the projected revenue requirements associated with the installation and ongoing operation of that facility.

For a PPA application that would include all of the projected contract payments under that PPA. So any energy payments or fees or O&M streams that are ascribed under that contract would be evaluated and considered in the total cost, as well as any other quantifiable cost parameters, such as the intermittency that we discussed previously. To the extent that additional costs to the company are identified associated with that particular project, those costs would be included as well.

Q. If it's under a PPA arrangement, is it anticipated that the cost streams that are part of that contract will be hardwired into the contract, or will there be any guesses on escalation rates and things of that nature?

A. The specific terms of a contract are negotiated on a case-by-case basis. They will depend greatly on the different counter parties and the types of generation that we're discussing. Some providers may be willing to lock in a rate and to just charge an energy payment for the entire stream. Some may have an O&M stream as I mentioned. It could depend whether it was an intermittent resource or if it was environmentally specialized or biomass. So it would be negotiated on a case-by-case basis. But in all aspects the company strives to negotiate the lowest price and least risk as possible.

Q. Okay. In the complete equation to do this there's the block for other project-specific benefits. So under that falls customer loads, you know, retaining those loads, retaining expansions or losing loads. So how would the company quantify the value of retaining or growing customer load for that part of the evaluation?

A. Well, retaining and growing load helps contribute to fixed costs of the company where we've incurred, in our long-term business -- invested in large assets like generation and transmission and distribution facilities. So to the extent that that load is retained or we grow additional load, it helps contribute to those fixed costs. As long as the marginal incremental cost of serving that new load or continuing to serve the load that exists today that may be at risk, as long as that cost is smaller than the additional revenues that the company would receive from keeping or growing that load, then it helps contribute to those fixed costs and, therefore, puts downward pressure on rates. You kind of think of it as cost in the numerator and energy sales in the denominator. So any project that raises the denominator by more than it raises the numerator, then that rate would -- would decrease.

Q. Earlier y'all were discussing in your earlier testimony the -- some of the data that would be provided to the staff in support of your filings under this requested authority. In the past we've kind of referred to those as minimum filing requirements in certain cases. Can you elaborate on, at this point, you know, what you would plan to include in the minimum filing requirements for projects submitted under this petition?

A. In general, it would be all of the information that went into that calculation, the total cost and total benefits. So those would, at the least, be broken down in terms of what's going into that fixed cost or the total cost of the project. So if it were revenue requirements on the actual installation of a self-build or projected contract payments under a PPA, those details would be broken down in that calculation,.

Now, on the benefit side there would be the avoided costs benefits, as well as the other quantifiable benefits, and then any of the major assumptions supporting that information. The fuel forecast is one of those major assumptions that you brought up. So supporting documentation behind the company's fuel forecast that went into that analysis would be provided along with those details.

The other benefits that we've discussed, that will necessarily have a lot of assumptions and documentation behind it to demonstrate that those are prudent, reasonable assumptions associated with that load benefit.

Q. And together with that you would be able to provide the source of the information provided?

A. That's correct.

Q. Just a couple more questions.

Currently Alabama Power has a renewable energy credit program that provides customers the opportunity to participate in the purchase of renewable energy. With this program in place why does the company need an additional renewable offering such as the requested 500-megawatts certificate authority?

A. We do have a program under rate OPS. We will sell renewable energy certificates to any customer who signs up for them. That is a cost effective way of customers procuring renewable energy on their behalf. However, some customers want more than that. They don't -- they don't view the REC market as tangible, if you will. They may prefer having an actual, you know, hard physical asset on the ground that they can point to and say, you know, I caused that to be built, where the REC program is more of a tradable commodity market, and so it meets the needs for some customers as a cost effective way to gain access to renewable energy, but other customers want more options.

Q. Okay. So if the requested certificate authority of 500 megawatts is approved, the company does plan to continue to offer the REC program; is that correct?

A. Yes, that's correct.

MR. FREE: Your Honor, that's all I have at this time.

ALJ MORRIS: Okay. Mr. Bentley, did you have --

MR. BENTLEY: I do have a few follow-ups.

ALJ MORRIS: Okay.

CROSS-EXAMINATION

BY MR. BENTLEY:

Q. Good morning, Ms. Cain.

A. Morning.

Q. I'd like to start with a few questions about what you referred to as the primary factor in making this filing, and that was the customer interest. And you said it was mainly the military interest?

A. That's right.

Q. So have representatives from Alabama Power met with any representatives from the Department of Defense regarding the construction of renewable generation facilities at military bases in Alabama?

A. Yes. The company has been in discussions with the military bases in our service territory.

Q. What bases?

A. We have -- we serve Anniston Army Depot, Ft. Rucker, and the Maxwell-Gunter Air Force Bases.

Q. And there have been

conversations already about all three of those bases?

A. There have, yes.

Q. Is there any -- is there a written agreement that reflects those conversations or reflect any agreements that have occurred between Alabama Power and any of those bases?

A. There's no agreement in terms of there's no -- there's been no commitments made. I am aware of an MOU between the company and the military, but my understanding is that that's -- that's sort of an agreement to have discussions, if you will. It's pretty customary when entering into conversations with a counter party that the parties may enter into a memorandum of understanding, an MOU.

Q. Do you know who the parties to that MOU are?

A. Honestly, I haven't -- I haven't seen it. I assume that it's Alabama Power and that military base.

Q. Could we get a copy of that MOU?
A. The agreement is between the company and the customer, so I don't think it was entered with the intent to be shared, but I would -- I would ask my legal counsel.
MR. McCRARY: Your Honor, we're not in a position right now to say whether it can or can't be. So if that's important, we can pursue that, but we're not in a position right now to indicate whether we can or can't share the MOU.
ALJ MORRIS: Okay. We'll have that as a potential follow-up item. You can get back with us once you've had an opportunity to research that.
MR. McCRARY: Yes, sir. Thank you.
ALJ MORRIS: Thank you.
Q. (BY MR. BENTLEY) And earlier you mentioned several federal requirements or federal mandates related to renewable energy that apply to the DoD and other federal agencies. You mentioned the National Defense

Authorization Act, executive orders, particularly the one that was -- the recent one in March of this year. And in your opinion would granting the certificate assist the DoD in meeting these goals and requirements in Alabama?

A. It will. It would be able to meet that mandate in a timely manner for those bases, which will help better situate them in our state to remain viable and operating in the future.

Q. Would they meet these requirements by receiving the RECs? Is that one way to meet the requirements?

A. Yes.

Q. In that March executive order of the things that was mentioned was making federal facilities more resilient and energy security. Do you anticipate that any of these projects would contribute to making military bases in Alabama more resilient or to energy security -- improving energy security?

A. Alabama Power is responding to that customer's request of adding the renewable generation to their site. Having energy there at the base would -- it certainly takes, you know, part of the delivery out of the equation. Solar, if that is the path forward for the military -- and across the Southeast that has been the type of renewable installation that the military bases have chosen -- is intermittent in nature as we've discussed. So the energy would only be as secure as the sun shines.

Q. Do you anticipate that part of the deal or part of the agreement would be that the military installation could have exclusive use of that generation facility?

A. The facility would be interconnected to our system under normal -- under our standard interconnection processes. So currently it would not be treated differently than any other company-owned asset, to my knowledge.

Q. In the Alabama Power petition

there was indication of the possibility of another round of base closures or the base realignment and closures with the BRAC process. In your opinion how would this proposal affect the BRAC process in Alabama?

A. We believe that it helps make those bases in our territory more viable. There's mandate. And many of the military installations across the country are working to meet that mandate. So particularly in the Southeast, when you look around at the other states in the Southeast who have secured some amount of renewable generation, it's reasonable to assume that those bases would be looked upon more favorably in BRAC than bases that have not met the mandate. Therefore, Alabama Power must strive to do anything reasonably practical and to the benefit of all customers to use whatever means possible to help preserve those bases' viability.

Q. Okay. Like I say, I was asking that line of questions because you did list a

primary factor in the --
A. That's correct.
Q. -- military interest.
Now, skipping to what you refer to as the secondary factor for this filing, and this is potential to assist in meeting the environment compliance. And you also reference the Clean Power Plan, which we all know is a -- came out just last week. So I have a few questions about that, and I don't expect you to know the details of that long document. There was discussion about PPAs and discussion about PPAs with generating source outside of Alabama. Can you speak to whether that having a generation -- a PPA with a generation source outside of Alabama would contribute to Alabama's compliance with the Clean Power Plan compared to having a generation on-site in Alabama?
A. My very brief understanding -- and this is very brief -- is that the EPA in their final rule did potentially allow some form of credit of that nature for

out-of-state resources, but I would caveat that with those details are still very fuzzy, and it's still up to the state implementation plan.

To the extent that the company across this six-year period that that -- that those guidelines and requirements in that state plan take shape, the company would only be quantifying those renewable -- or those environmental compliance benefits to the extent that they were known and able to be evaluated. So in the current state the company's economic analysis would not be able to quantify that economic compliance value until there's a little more clarity around how that compliance would work.

It would, however, regardless of the in state versus out of state, to the extent that that renewable energy offsets some other generation, even from an out-of-state perspective, it could lower the generation actually coming out of our current resources.

Q. And I believe there was also a new portion of the -- that was in the file on Clean Power Plan that wasn't in the close version that rewards quicker or faster compliance of some of the renewable energy goals. Would the projects contemplated in this filing contribute to helping Alabama or improve compliance by having renewable faster than anything required by the Clean Power Plan? I know that was an awful question. If you do it -- the Clean Power Plan now says you can be rewarded for having renewable generation faster. Do you anticipate that this filing will help Alabama have renewable generation faster?

A. This filing will definitely help Alabama Power to move quickly toward meeting customer needs and, again, transacting on that federal tax credit that is drastically reduced at the end of 2016. Any additional benefits associated with the Clean Power Plan compliance, to the extent that the final implementation at the state level of that rule passes along those benefits, then there's potential that it could -- that being an early mover could be helpful, but we'll have to see how that shakes out.

MR. BENTLEY: That's all I have for now.

ALJ MORRIS: We'll move next to Ms. Martin on behalf of the Attorney General.

CROSS-EXAMINATION

BY MS. MARTIN:

Q. I have a few questions just based on your prior testimony. You mentioned that Georgia and Iowa had done -- you mentioned -- just going back to some of your prior testimony you mentioned that Georgia and Iowa had developed a procedure similar to the one you're requesting here. What about the state of Florida? How are they handling these projects?

A. Those two examples came to mind. I wouldn't say that we've done an exhaustive search in all jurisdictions, so I'm not aware of something similar in Florida. That doesn't mean there's not one. We just haven't come across it.

Q. But they are adding these customer-specific projects, similar to ones that you're asking for, but they're not asking for the same type of process that you're requesting. Are you aware of any projects in Florida?

A. I'm aware of their military bases. They have -- I believe that they're Air Force bases. They've done two projects, and they -- they had known projects that were requested for certification. That's my -- that's my understanding of it.

Q. Well, you mentioned Florida, so -- but didn't include them in this type --

A. That's right.

Q. -- of process, so I was curious as to how they were handling it.

Just for comparison purposes, would you tell us the total number of megawatts that Alabama Power has in its system?

A. I want to say about 12,000.
Q. And when you're doing a project of this kind, what is the construction time frame that you have? How long does it take to build a project?
A. The actual construction of the project, I'm actually not sure, because there are so many processes on the front end. So I mentioned we need to move quickly for the tax credits. And basically every day wasted is a day that a new project may or may not be able to meet that tax credit. It depends on how quickly all of the other approvals that go along with a project can be implemented, the agreements worked out with the vendors, the interconnection agreements, the permitting requirements from an environmental perspective. So it would be difficult to say an exact timeline, but probably somewhere in the twelve- to eighteen-month range.
Q. So if you're looking at a two thousand --
A. I'm sorry. Maybe eight- to

eighteen-month range.

Q. So if you're looking at a 2016 deadline, you don't have any extra days, do you?

A. We will -- for projects to meet that 2016 timeline we will be needing to move quickly.

Q. So if you're going to try to meet that deadline and it's going to take you approximately eighteen months to get all of the agreements and contracts and suppliers and things together, you have already identified projects that would immediately go into -- you would begin immediately working on this once approval is granted?

A. That's correct.

Q. And so how many of those projects do you have that are known today?

A. Well, I wouldn't say any projects are known with any certainty. I mentioned with Mr. Bentley's line of questions that the military has been in discussions with Alabama Power. So there's nothing firm and known about those projects, but it's anticipated that they would -- that they would probably be the first projects out of the gate.

Q. And how many megawatts would those projects be?

A. That's uncertain at this time.

Q. Is there a range that could be contemplated?

A. I would say less than 15 megawatts.

Q. And we're talking about three bases, three military bases?

A. Three bases in total. Actually, Maxwell and Gunter Air Force Base are two bases, but we would be looking more at the Maxwell side.

Q. And have you had any requests from any other federal agencies?

A. We have had some interest from some other federal agencies. And, again, that's in conjunction with that executive order.

Q. And could you give us a number of how many?

A. I don't have a number, but we do serve a number of federal agency buildings, VA hospitals, the Social Security Administration, areas of those nature. All federal agencies are affected by the executive order I mentioned.

Q. Have you had any interest from suppliers of federal agencies?

A. In the private sector we have seen interest from a number of parties. To my knowledge they haven't specifically cited, you know, the executive order itself. Some of them are companies, as I mentioned, that fall into that category of wanting renewable options like the Fortune 500s and the conglomerate of the companies that release the corporate -- corporate buyers report.

Q. Your petition says that to qualify under the petition the project has to have projected economic value to all customers. And so could you talk a little bit more about that? I know you talked about avoided costs, but I'm primarily interested in how we would -- how rate payers who would be sure that this would be a positive economic value. And specifically what I'm interested in is would rate payers under any of these conditions be required to pay for their electricity?

A. Well, under every project the projected economic savings would have to be there. They are projections, and necessarily in a long-term business, such as the utility investments require, those forecasts are based on the best information that's available at the time. So they will vary necessarily, up and down. So the company utilizes these processes that I mentioned to Mr. Free that have been in place for decades and utilizes expertise from third-party vendors and, you know, analytical and economic -- econometric information that inform those decisions. So I guess to directly answer your question there's not a firm protection that those forecasts may not vary.

However, the interesting thing in forecasting and making decisions off of the best information available is if projects demonstrate, based on those calculations, that there would be economic value for customers, not acting on those decisions, it would be a decision -- it would be a decision to forego those expected benefits. So every decision that the company makes or doesn't make impacts the long-term price of electricity.

Q. You mentioned on the processes that the company has to project these benefits or analyzing prior to the time of the project. Do you also have a process in place to look back at a project and see if those positive economic benefits were actually incurred?

A. We could always compare the avoided cost metrics that were used to -- there is an actual avoided cost that is documented for each hour of operation on our system. Those -- those energy avoided costs can be compared. And some assumptions can be made associated with, you know, whether assumptions came to fruition or not. There are others that -- to use a good analogy, you can't unscramble an egg. So sometimes whatever happened in reality was a result of numerous decisions. So you -- there are certain metrics that may not be able, you know, to be quantified against reality because you don't know exactly which variable led to that outcome.

Q. Okay. But my question really is -- you said you could do this, but I'm curious whether the company does do this when you do you a project like this where a lot is unknown, both to you and to us, but is there a process that is already in place where you would go back and check and have a periodic check on how projects were going, did they meet your -- sort of an evaluation of a project, you know, after it was begun and started and you had some experience with it, was it -- is there a process already in place for doing that at the company?

A. There is on other renewable projects that we have.

Q. And what is that process?

A. Once a year we look at that actual realized avoided energy costs on the system and compare it to the contract payments under those renewable energy contracts, PPAs.

Q. And there's more than just the avoided energy costs that goes into a project. So there are the other factors that you mentioned?

A. Right. Right.

Q. So those were not -- are not evaluated on an annual basis?

A. No. They are. Those specific renewable contracts, namely, quantified the energy benefits and some capacity cost benefits. So those are evaluated on a historical basis and compared to all the costs of that contract. So for the wind contracts in Oklahoma and Kansas those did have some transmission payments. So those payments are quantified there in the total cost analysis. And those payments and benefits are compared historically.

Q. Does the Public Service Commission have access to those analyses that you do?

A. Yes. Every year we sit down with Mr. Free and the staff and discuss the performance of those PPAs.

Q. Is that a part of the RSE or the ECO evaluation every year, or does that take place -- it's a particular meeting that you have, or does it just happen informally every year?

A. It does not happen in that RSE process. It's -- it's been done in February of each year, and it's in a meeting.

Q. So there is a time that that is done and the Commission staff has that information?

A. That's correct.

Q. Has there been any study that if you do the 500 megawatts about what generation might be displaced if the total amount is used?

A. We have -- I'm sorry. Ask me that question again.

Q. Well, has Alabama Power done any studies that if they add this 500 megawatts in renewable generation about what other generation might be displaced?

A. Since the exact projects under that 500 megawatts are unknown, there's not been something to evaluate. It depends on, you know, how these projects take shape and form. So as I mentioned, the process of calculating that avoided cost is constantly under development and takes into account all of the assumptions known at that time and all of the information that goes into those unit operations and characteristics. But the projects then compared to those avoided costs are unknown at this time, so to directly

answer your question, no.
Q. Okay. I guess one of the questions I have is why you want to ask for this much generation when a lot is unknown to you and a lot is unknown to the people here today when you could have asked for an expedited process before the Public Service Commission. And did you consider asking for an expedited process before the Public Service Commission?
A. There are a number of reasons that we chose to petition for this requested authority for up to the 500 megawatts. Number one, as I mentioned, is the customer requests and the inquiries that we've had associated with these specific projects, that we need to be able to move quickly. Again, with the potential eighteen-month timeline we may be behind the eight ball if we don't get moving right away and end up more on the smaller end of that eighteen-month timeline. So the efficiency and the speed at which we're able to accommodate those requests was

a major driver.

But it's also costly to go through an individual certificate process one project at a time when we're talking about very small-scale projects. So the -- you know, in general it's the avoidance of costs that helps with sort of bundling that package together as much as the speed and efficiency that we discussed.

Another reason is the customer aspect of these projects. So we're talking about working specifically with individual customers and their information and their data and their proprietary business plans that make the nature of the proceeding and the showings around that documentation highly confidential. And this authority process helps protect that information and make the projects more viable to the state of Alabama rather than those companies taking that development elsewhere.

Q. So do you believe that a major driver of this project is competition with other states?

A. To the extent that customer interest is in those load growth and load retention applications we would be competing for data centers like Google and shipping facilities like Amazon has built in other territories. So, yes, I think the better we can -- we -- Alabama Power can situate the state of Alabama to compete with those other jurisdictions, the better off our customers and our state will be.

Q. Do you have any concerns about the Public Service Commission being able to keep information confidential and proprietary?

A. As a regulator they and yourself in the petition that we've -- that we've submitted necessarily have to see that information. We are regulated by the Alabama Public Service Commission, and we do -- we do request protections of that confidential and proprietary information and will seek that that information remain confidential.

Q. But have any of your customers expressed concerns about this, the confidentiality of the information?

A. Our customers in general aren't familiar with that entire regulatory process, so it's -- those delays and uncertainties are sort of unfamiliar to them.

Q. So there haven't been customer concerns about that that you know of?

A. They've not specifically -- that I know of. And I'm not the one who actually meets with many of those customers. But that I know of they've not specifically expressed the concern with sharing with the commission, but absolutely they are very protective of their data and don't expect it to be shared with outside parties.

Q. You mentioned in your testimony that you would expect -- after sharing this information with our office and with the Public Service Commission staff, you would expect the staff to make a recommendation of approval to the Commission. And how do you anticipate -- what form would that recommendation take?

A. Our petition mentions that the staff would report that information to the Commission. As far as the company is concerned, that's up to the Commission to decide how that reporting would take place.

Q. Would you consider that that would be confidential and -- because of the proprietary nature of the project, or would it be a public recommendation?

A. The information contained in the documentation and the supporting information would be confidential. What the Commission chooses to do with the recommendation would be up to them.

Q. Do you anticipate there would be a Commission vote on this issue?

A. In the company's petition it didn't specifically require a vote. We feel that the report of that information to the Commission and the Commission would vote to disapprove a project, so there would be the engagement there. We feel that that's sufficient, but, again, the Commission can choose to operate how they see fit.

Q. This is just a question I had. I sort of finished my questions. But when you were talking with -- I think it was Mr. Free -- about the interconnection to your service territory, how you have a contract that would specify that people would, I think, bring the electricity to your service territory, are those contracts filed at the Public Service Commission?

A. I'm --

Q. The interconnection contracts, would they be filed? Did I understand that correctly?

A. The inter -- we had a couple of conversations about --

Q. If you have -- if you have a resource that's located outside your territory --

A. Uh-huh.

Q. -- and you said the contract

would provide that they would bring it to
your territory?

A. Right.

Q. Are those contracts for
transportation --

A. Uh-huh.

Q. -- or transmission or
interconnection, are they filed at the Public
Service Commission?

A. They would be -- the terms of
that contract would be submitted as part of
that -- as part of supporting documentation
there that would be submitted along with that
approval package, but it would be highly
confidential and protected.

Q. But they -- but the PSC staff
would have access to that information?

A. That's correct.

MS. MARTIN: I have no further
questions.

ALJ MORRIS: Thank you,
Ms. Martin.

All right. We're going to move

next to Mr. McLemore.

MR. McLEMORE: Thank you, Judge, Commission.

CROSS-EXAMINATION

BY MR. McLEMORE:

Q. Good morning, Ms. Cain.

A. Good morning.

Q. I'm Jimmy McLemore. I represent the Alabama Industrial Energy Consumers.

I'll try not to tread on Ms. Martin's questions, but I want to go into the review process a little bit. You're familiar with the fact that the Alabama Power Company has previously approached the Alabama Public Service Commission for approval of a block of authority of 25 megawatts for renewable energy PPAs about five years ago in what we've called the Westervelt Project. Are you familiar with that?

A. I'm familiar with it.

Q. Generally?

A. Uh-huh, generally.

Q. Okay. It's similar to this

proceeding in the sense that in that petition the company was looking to get pre-approval or authority for a block of authority for which it would then fill up with later projects; right?

A. Yes, that's my understanding.

Q. And we participated in that, along with Ms. Martin. And I think we were breaking the ice on changing the procedure about how some projects can be reviewed before the Commission. And in that Docket Number 31301 the Commission did order that that procedure was consistent with Alabama Code Section 37-4-28, but that nonetheless, it was a different -- as it described, a novel and innovative alternative to the more traditional processes, which was caused by, as the Commission ordered, environmental concerns, changing federal statutes, and a new environment generally in the area of utility rate making. Isn't that correct?

A. That's my understanding --

Q. That's your --

A. -- in general.

Q. -- understanding. And in this instance, coming before the Commission today, the company is seeking for the Commission to approve a bit of a modified procedure than traditional processes because of the unique circumstances that we're facing in the changing federal statutes and the executive proclamations; isn't that right?

A. Primarily it's driven from that customer interest, which has sort of resonated in part from the executive orders and federal directions. There is environmental compliance benefit, but that's, I would say, secondary to the customer interest.

Q. When I say the developing concerns, the Clean Power Plan, the concern about the military installations' stability in the state of Alabama, those are driving influences too?

A. I would kind of separate -- I agree with you, but I would separate the military requests from the Clean Power Plan --

Q. Right.

A. -- in terms of customer interest versus environmental compliance.

Q. That's right. Those are different. I don't mean to lump them all together --

A. Right.

Q. -- except to say that those are concerns --

A. Yes.

Q. -- that, as you've testified and this petition says, require us to look closer to the needs for efficiency, expediency, customers' concerns for a quicker approval of this process.

A. Correct.

Q. So the power company is seeking, by this 500 block -- 500-megawatts block of authority, a specific procedure tailored to these particular circumstances; correct?

A. That's right.

Q. That's right. And I say that because the next time the power company comes with another block of authority I may take a different position about things. So I appreciate the concerns that you've testified to, and we applaud the company's going into this venture at this particular time, but that doesn't mean we're always going to be in that situation.

A. I understand.

Q. Let me ask you this, because this procedure is different than the Westervelt procedure. And go back to Ms. Martin's questions a little bit. You say that as part of this procedure you will submit to the Public Service Commission staff and to the Attorney General, as the representative of all consumers of electricity, the information -- all of the information that the company submits in support of the project. Is that correct?

A. Correct.

Q. Am I clear that the Attorney

General will be getting all of the same information that's being made available to the Public Service Commission staff?

A. That's right.

Q. Okay. The staff will then make a recommendation with Ms. Martin's or the Attorney General's office participation to the Public Service Commission itself, the three commissioners, as to whether to approve or disapprove a particular requested project; correct?

A. That's correct.

Q. You were a little unclear on what you anticipate that the Commission may do with that. You suggested they can decide to do with it what they want. But the petition itself specifically contemplates that the Commission is going to take some action because the staff is required to make a report to the Commission; correct?

A. That's correct. The staff -- in our petition the company feels that -- has proposed what we feel is an adequate means toward -- toward reaching that approval process, and the Commission staff and the Attorney General would make the recommendation to the Commission.

Q. Right.

A. And the Commission, absent a disapproval vote, the project -- the project would be approved.

ALJ MORRIS: Let's take a little short break. Let's see if we can get your microphone fixed here.

(Off-the-record discussion.)

A. So a Commission report would take place, and a vote would be required for the Commission to disapprove the project.

Q. I've got you, but the petition of the company contemplates that the report being made to the Commission, that the Commission will, in fact, deliberate on whether or not that project is acceptable to it. And it may not vote affirmatively to approve it; it certainly has the authority to vote to disapprove it?

A. That's correct.

Q. But even if it doesn't disapprove it, your understanding is that the Commission will have reviewed it, deliberated it, and make a determination whether it's acceptable or not?

A. That's the contemplation under our request.

MR. McLEMORE: That's all I have.

ALJ MORRIS: Thank you, Mr. McLemore.

I'm sorry. Let's move ahead. I'm just at this point going down the list in order of intervention. So next on the list would be Mr. Cagle on behalf of JobKeepers. And if you would, Mr. McLemore, if you could pass that microphone back to the table behind you.

MR. McCRARY: Your Honor, excuse me. I'm sorry. The witness has been on the stand now for --

ALJ MORRIS: Would you like to

take a break?

MR. McCRARY: Well, I know I would, and I'm guessing that she might.

ALJ MORRIS: Let's take about a ten-minute recess.

MR. McCRARY: Thank you, Your Honor.

(Brief recess.)

ALJ MORRIS: Okay. Let's go back on the record. I believe next up is Mr. Cagle on behalf of JobKeepers Alliance.

CROSS-EXAMINATION

BY MR. CAGLE:

Q. My only question, briefly, is related to the economic development aspect of this filing. You've stated that the purpose of this is -- one of the benefits of this is to support economic development and industrial recruitment; is that correct?

A. Right. The primary driver for the petition is the customer interest in renewables. And the economic evaluation considers the electricity price impacts of that potential load growth or retention among other things, which, as we quantified in our economic evaluation, it's about electricity price, but certainly any load additions to the state likely will come with jobs and boost to the economy for the state of Alabama, which is a good thing for customers.

Q. Well, as you know, any industrial recruitment effort is highly competitive and confidential. You know, its projects generally are not discussed, you know, under an agreement until they're executed and made public. Under the type of process that Ms. Martin was asking about, an expedited process or some process other than what this filing contemplates, would that require a public notice and new docket to be created?

A. It's difficult to say exactly what that process would look like. We really can only talk about what we're petitioning here today. And the company feels that what we've requested protects the interest of those customers and customers as a whole to the extent that it facilitates these projects being completed, which would by definition be good for all customers.

Q. Under any, I guess, theoretical process other than what's contemplated, could you -- would listing any -- even if the company name that's involved is redacted, location, capacity, could that hurt Alabama's industrial recruitment efforts as far as if we were competing with Mississippi and I knew Alabama -- you know, I'm an economic developer in Mississippi and knew that Alabama was competing for a project, even disclosing what kind of capacity -- if they were able to figure out that this is related to that?

A. The predicament there is that even with a redacted filing, so much information would be redacted in order to preserve the proprietary nature around all the data that if there are any hints in there of being able to infer that business, there are people who for a living try to glean and gather all of the competitive information intelligence that they can. So to the extent that everything that would be pertinent to that competitive information is redacted, you are really left with nothing.

Q. And the process requested by the certificate that the company's requested alleviates that by producing those filings to the Commission and to the Attorney General's representative; correct?

A. That's correct.

MR. CAGLE: That's it. Thank you.

ALJ MORRIS: Thank you, Mr. Cagle.

Moving next to Mr. Johnston.

CROSS-EXAMINATION

BY MR. JOHNSTON:

Q. Hey, Ms. Cain, how are you?

A. Good.

Q. Thank you for your testimony. I'm Keith Johnston with the Southern

Environmental Law Center, and we're here today representing the Alabama Environmental Council.

I just want to follow-up on some of those questions about the Westervelt Project of 25 megawatts of renewables. Are you aware that at the end of that process there was an agreement among all the parties involved that there would be a competitive bidding process that would be part of that?

A. I'm familiar with the Commission-approved RFP guidelines associated with that.

Q. And so with that be competitive bidding process, do you foresee that being a part of entities' projects here?

A. To the extent that the company utilizes an RFP process to gather that market information that I discussed with Mr. Free, we would reference those RFP guidelines.

Q. And so do you have -- or can you say at this point which projects will be part of the RFP process or some sort of competitive bidding process?

A. At this point I can't say specifically which ones, but what I can say is that to the extent that the company doesn't have enough market information from maybe these unsolicited offers, then we would certainly procure that market information through an RFP process.

Q. Okay. Is there going to be any sort of public notice as these projects roll out?

A. There would likely be the announcement of a project if we're moving ground on something, in those terms, but just as I answered Mr. Cagle, typically if we're talking about these economic development projects, those are not announced until, you know, both parties are ready to go public with that information.

Q. Again, so it would be safe to say at that point it would sort of be a done deal before the public found out about these projects as they rolled out?

A. Yeah, essentially. The announcement would be when there was an agreement with the company.

Q. I want to talk a little bit about the military installations. So it seems like -- because it seems like those may be some of the first projects that are going to be rolled out potentially. And I just wanted to clarify something that I wasn't quite understanding. You said that those projects are going to be the same projects that you typically do, I guess, in those instances; is that correct? Like is there -- as far as they were connected to the grid?

A. I'm sorry. I --

Q. Let me rephrase that. That was a complicated question. Are the projects for the military installations, as much as you know now, will they provide energy to -- directly to the military installation?

A. Under this certificate the generation would be part of Alabama Power's either owned or contracted generation. So it wouldn't deliver that specific energy to that specific customer. It would all be delivered to the grid in terms of every -- you know, any other generation project.

Q. So it -- that answered my question. Thank you. So does that provide energy security for the military installation?

A. It can to the extent that that's what -- you know, to -- I answered Mr. McLemore's question, I think it was, along these lines in that we are working -- we're in discussions with the military in order to help them meet the renewable aspect of their mandate. It's the federal government that deemed that the renewable energy adds the security to the base. So it -- to a certain extent electrons flow where they want to flow. You know, if you spill water on the table, it's going to go wherever the water wants to go, wherever it's not blocked. So to the extent that that generation is located on the base, then those electrons will -- you know, at least some amount of that energy will be there on the base before it transmits to other areas. It's not necessarily the company's -- the security aspect of the renewable generation is the mandate from the federal government. The company is coming at the projects with the aspect of working with the customer to secure their renewable energy needs.

Q. And are those facilities going to be owned or leased by the military? Are they going to be owned or leased by Alabama Power? How does that work?

A. I mentioned in my previous testimony that on the Army customers, the Army base customers, under the General Services Agreement there is a constraint that in order to execute the agreement under that General Services arrangement, it requires the utility, the jurisdictional utility to be the owner and operator of that equipment. That's not necessarily the case for every single base and nor for every customer under this certificate authority. Whenever there's not a restriction of that nature the company will explore whichever is in the best interest of all customers.

Q. I want to talk a little bit about -- you had discussed sort of the general benefits of this renewable petition and what flows out of it. And I want to talk some -- a little bit about some of the other benefits that I don't think you mentioned. And is there a benefit to the company having increased energy diversity, sort of increased energy portfolio?

A. There -- the company has always -- at least in my tenure with Southern Company Services and Alabama Power has been in favor of diversity, diversity as to the reliability and cost effectiveness of the fleet. To the extent that any value can be attributable to that diversity, it's quantifiable in the form of the economic evaluation. When we look at the avoided costs and the fuel price forecast that I discussed with Mr. Free, if there are any sensitivities to that fuel forecast, the changes in the economics of the project and how it impacts overall price of electricity, that's where that value is sort of quantified.

Q. So you do have those -- you do have those benefits that you can quantify in certain instances?

A. In the form of sensitivities associated with the analysis.

Q. One other thing that Mr. Free touched on during his cross-examination was the intermittency of the power and the problems that presents with solar power in this instance. Let's just take that for example. Are there other benefits that may offset that in some ways? For instance, if the sun is shining and it's most intense --

(Brief interruption.)

Q. So basically the other benefits that are associated with some of these renewable sources such as solar ware, maybe at the time of generation in the hottest part of the day solar may be working the hardest, are there benefits there?

A. Yes. Those are quantified, somewhat in terms of that avoided energy cost calculation. To the extent that the expected profile of the generation output from that solar facility occurs during that peak part of the day, well, that's when generally prices of electricity are the highest, that marginal price that it displaces. So it receives benefit there from the energy -- avoided energy cost evaluation.

As well as I did mention capacity costs, avoided capacity costs. Since we're in a period where the company has enough capacity to reliably meet its demand, that capacity component is small through that 2030 time frame, but there is some value there. And I also mentioned intermittency reduces that value, but, again, there is still some value there. So how the company determines that avoided capacity cost value is sort of a problematic approach to what are the chances that when we need the reliable output that the sun is shining and that generator is producing. And, therefore, an equivalent capacity is calculated, and that's where some small capacity component is introduced into the mix.

Q. But that would go into your --

A. Yes.

Q. -- avoided costs, those sorts of -- and is there -- I guess this added diversity, as I'm framing it, to your portfolio, does that -- is there a benefit there for customer choice just generally?

A. The -- well, that's one reason we're here today, is that we're trying to respond to customer interest in the renewable generation, but the policy of our company and this Commission is to offer those renewable resources to customers who want them without being subsidized from customers who are not willing to place that priority or that premium on those resources. So this petition does just that. It allows those customers who want to choose renewable energy to commit to that resource in a manner that doesn't cause subsidization to other customers; it benefits everyone.

Q. And are you going to look at the avoided costs of these projects and make sure they come in below -- the avoided costs would be below your normal costs?

A. Again, as I mentioned to Ms. Martin, the Commission currently regulates, you know, many aspects of our business and evaluated what our avoided cost realities are relative to our projections. It's just one of those many areas of oversight. So we'll continue to do that. There is no guarantee that those projects exactly hit that mark. There can be upsides and downsides, and that's just a part of forecasting.

Q. And I guess going back to what you testified about some of the research you had done on the businesses that need this type of energy resource or demanding it at this point, some of your customer demand, would it be fair to say that if you didn't have these opportunities in Alabama, it could hurt business development and economic development in the state?

A. We've not had any customer or potential customer to my knowledge say, we don't want to locate in Alabama because you don't offer renewables, but what we have seen is several examples such that I quoted, you know, Google being one, Apple, Amazon, companies that have said renewables are very important to them. So it's one of many offerings that Alabama Power Company can make utilizing this process that will help all customers and better situate the state to have more arrows in the quarter so to speak.

Q. And I want to address the 500 megawatt request. I think you ID'd that there were existing customers that were interested -- the reason -- or the reason you came up with 500 megawatts is because you've

ID'd customers that may be interested, or you had discussions with those customers, and their aggregate load actually exceeded 500 megawatts and that that didn't actually take into account businesses that may bring -- or customers that may bring it to the state. Considering that and sort of those statements in the petition and you went -- you have responded to our interrogatories about, would there be room for more than 500 megawatts?

A. The certificate authority would be up to 500.

Q. Right.

A. Nothing would prohibit us from asking for more if that entire amount is exhausted. There would be another proceeding at that point.

There's also nothing that prohibits us from doing a project outside of this certificate authority. It just would be, you know, its own -- its own request, its own docket. Does that answer your question?

Q. That did. Thank you.

Did the company in the evaluation of this 500 megawatts, when you pinned that down, did they evaluate different alternative scenarios, like, let's say, a gigawatt of renewable power or 200 megawatts of renewable power?

A. We arrived at the 500 based, as I mentioned, on customer interest. It just seems like a reasonable amount. And since it's not a requirement, the 200 falls lower than that, and since there's no -- there's nothing to prohibit us from requesting more, 1,000 can be something that we explored later, so it's a -- it's really gauged on that customer interest.

I mentioned that we've identified customers whose load is in excess 500 megawatts in the aggregate. The reason that that doesn't exactly translate to needing to secure more than the 500 at this time is that that's a -- you know, that would assume that every single megawatt that we've identified is executed. And I mean, just sales and marketing 101, that may not be the case.

Q. And I know that you put a cap of 80 megawatts per project in this petition. Is there a -- is there an advantage to having smaller renewable blocks of energy like that?

A. In regards to this application --

Q. Right.

A. -- where we're working with specific customers?

Q. Right.

A. If the projects -- they're envisioned to be smaller scale under that 80-megawatt threshold because that -- something much larger than that may start exceeding the customer's interest. So, for example, these military applications, you know, I mentioned that those projects would, based on current discussions, be no greater than fifteen megawatts each. So to the extent that most applications are in that range, it makes sense to limit that scenario in some way.

Also, part of the reason for having this authority sort of bundled together is the efficiencies of the process in that requesting certificates for individual small projects over and over -- I mentioned to someone at this table about the cost of doing that, the cost and resources it takes to continue seeking certifications. Part of that is due to the smaller size. So once we -- you know, if there are larger projects than 80 megawatts, as I just said, this petition wouldn't prohibit us from seeking approval for those projects; it just wouldn't be a part of this.

Q. So you would go through another -- you would petition for another certificate --

A. That's correct. If there's --

Q. -- for a specific project?

A. If there's a larger project identified that created value for customers, we would consider that under a separate process.

Q. And are you aware of other projects that are greater than the 80-megawatt threshold that you guys are seeking here? Are you aware of other projects?

A. There have been some -- I referenced some in my example, the wind deals in Iowa, the MidAmerican Energy, those are both greater than the 80-megawatt threshold.

Q. And you state -- or I think this was in the petition actually -- about a notable example of renewable energy development has been next door in Georgia where they're seeking 1000 megawatts through various programs at the PSC there. Are you aware of why those programs in Georgia have sought such a higher total megawatt capacity for this, renewables?

A. I'm familiar that they have. I can't really speak to why -- you know, what's driving their decisions versus ours. What we are doing here today is in the best interest of our customers and working under our legislative and regulatory environment.

Q. And are you aware if those projects were open to competitive bidding?

A. I remember that there was some portion of it that was, but I don't know -- I'm not familiar with the details.

Q. To your avoided costs, some of your testimony on avoided costs, I think you had testified to this in Mr. Free's questions or potentially in some of your other testimony, but did you talk about how fuel costs as far as renewables would be calculated there, in your avoided costs?

A. The cost of the actual renewable generation that's being evaluated?

Q. Right.

A. Would go into that total cost bucket. And then the avoided energy cost is offsetting part of that process. The extent that there is a fuel payment, if we're talking about a biomass, you know, for instance, then there would be a fuel cost associated with the generating of that electricity. And part of that -- that would go into that total cost bucket that's compared to the avoided cost savings benefit.

Q. If there was a solar project, for example, would there be -- what would be the fuel cost for the --

A. There is no fuel cost. The total cost bucket would be all of the fixed costs of installing and maintaining those panels.

Q. And the same for a wind project; correct?

A. Uh-huh.

Q. And the company plans to recover costs through the rate recovery mechanisms, ECR and CMP and RSE, but you also talk about in the petition customer-specific projects. So are there -- in those customer-specific projects will the costs be recouped through those rate bases, or will there be specific contracts just with those customer-specific projects?

A. Will you ask me that one more time so I can be sure I --

Q. I'm sorry. That was a complicated question.

For the customer-specific projects that you mentioned in the petition, how will those costs be recouped?

A. If there are customer-specific benefit, then it's actually -- it's actually not a cost for the company to recoup; it's a benefit coming from the customer to the company that gets distributed to the other customers. So it's -- we can't say exactly at this time because there's not a specific project. There are a couple of examples of how those customer specific contributions could happen. And to the extent that there is a customer contribution being counted in that economic evaluation, the company will utilize -- will seek a contract with that specific customer. So to the extent that it was a dollar payment stream from the customer to the company, there would be a contract there. If it were a load growth application, we would generally seek to try to implement some sort of minimum build provision that would ensure revenues from that specific customer application that are helping to contribute to the overall cost of the company that help all other rates.

Q. And in that scenario you describe, would that be considered a premium for that electricity?

A. It would take many different forms. For instance, there may be customers who are willing -- if they're not -- if a customer comes to us seeking renewable energy and is a customer whose load is not going to grow based on this renewable application or they're not at risk -- the company is not at risk of losing that load with or without the renewable generation, then there wouldn't be those load growth and retention benefits to speak of. So any customer contribution in that case would be that that customer places a priority on the renewable energy and is willing to compensate the project enough to get it to meet that hurdle of providing the positive economic value.

Q. But if there are load growth or retention advantages there, that would go -- that would be recouped through your normal rate -- through your normal mechanisms, through your normal cost recovery mechanisms?

A. There wouldn't necessarily be a direct payment stream from every customer contribution. Those contributions could be in the form of downward pressure on rates to the extent that the information and the data supports those assumptions.

Q. I'm checking off the questions that you've already answered.

You may have answered this, and I'm sorry if I'm repeating here, but the RECs that are going to be created by this, are they included in the avoided costs?

A. That actually would depend on the type of arrangement with each specific customer on a case-by-case basis. So if a customer that we're working with on a project says, I, you know, want to partner with you and cause this renewable project to be built and I want to retain the RECs, then -- then one of two things could happen. Either the market value of those RECs would go over in the benefit bucket, but then you would have an offsetting cost in the cost bucket because the company wouldn't retain the value of those RECs, because the contractual agreement with the customer would be giving them to that customer.

Some customers may say, I just want to see that this renewable energy is built, you do what you want with the RECs. In that case the company may quantify a market value of those RECs in that benefit bucket of costs, of the analysis. And on the cost side the costs were just the cost of the contract or the facility, so it could add some value if the company were retaining those RECs. Did that answer your question?

Q. So in --
A. It's going to depend on a case-by-case situation.
Q. So it's a project-by-project call whether the RECs are going to be included in the --
A. Right.
Q. -- avoided costs?
A. Right. If the company passes on the value of those RECs to the specific customer, then it would be double counted if it tried to count those benefits in the analysis. But if the company retained access to those RECs, then the proper value would be ascribed.
Q. And has the company completed anything such as a REC utilization plan which would forecast or provide the model for how you're going to treat these RECs?
A. Will you ask me that again?
Q. Has the company completed a REC utilization plan which provides sort of a model on how the company will treat these

RECs under this petition?

A. We do have a REC program. I mentioned under that -- under rate OPS that the company offers REC purchases to any customer who chooses to sign up for it. In terms of any excess RECs they do have a shelf life. So to the extent that the company has any excess RECs they do go and try to optimize their value in the market.

Q. And we talked a little bit about the competitive bidding process and how that may play out under this petition. In the event that there is some sort of competitive bidding process for these projects, is there any sort of third-party evaluator who looks at these competitive bids and determines, you know, which one is the best value for the customers?

A. The Commission-approved RFP guidelines don't require an independent evaluator as the Commission and the staff does oversee that process.

Q. So there won't be a third-party

evaluator?

A. It wouldn't be required.

Q. And in your experience do competitive bidding process usually -- competitive bidding processes usually result in the best deal for the customer?

A. In my experience I don't have any evidence of that, actually. The market -- to the extent that the company has market information that seems to be good proxy of the market, there's no guarantee that an RFP would produce lower cost results than that. And in fact, there is a cost associated with performing an RFP; therefore, the company would evaluate that benefit at the time to determine whether an RFP would result in value for customers.

Q. You said there was a cost in even going through the RFP process?

A. That's correct. There is a number of resources required on the company's behalf to conduct and evaluate the terms and put together the bid package and host workshops and things of that nature. There is resources that are utilized to go through an RFP process.

Q. But would it be fair to say that customers could save money on the back end of that going through the RFP process if you spend the money on the front end to do that process?

A. Not necessarily.

Q. And some of these customer-specific projects that you talk about and the close nexus, I think that you mentioned in your petition, would community solar projects fall under that? Are you familiar -- I guess, first, are you familiar with community solar projects?

A. I am. I'm sure they can take many shapes or forms, but that is certainly an industry topic that I'm aware of.

Q. And would those fall under this petition? Is that -- is there a potential there?

A. Nothing in the petition would

prohibit that at this time. Currently we envision it to be focused on a little larger-scale customers, but community solar could be an option.

Q. And I think you've testified and the company has said there's not specific projects in mind at this time, although there's been discussions with military installations or DoD about particular projects, but are there any size, new load, or any other sort of restrictions dictating how customers can actually participate in this -- in a project falling under this certificate? So what are the --

A. Any size limitations?

Q. Are there other parameters besides the ones that we've mentioned limiting customers' participation?

A. The only limitations would be those that we've discussed.

Q. Yeah. Okay. As far as the wind projects that you've mentioned that Alabama Power has entered into PPAs for, Chisholm

View and Buffalo Dunes, are those typical projects -- are those projects typical projects that might fall under this certificate? I guess they're above the megawattage, but --

A. Yeah. I was going to --

Q. -- is that the only limiting factor there?

A. To the extent that -- that some future wind project is available and meets the criteria that we've discussed, then it would certainly be considered under the evaluation. So those specifically are too large for this project, but under an 80-megawatt threshold where they provide positive economic value for customers, then they would be eligible.

Q. Have those projects provided positive economic value for customers in Alabama?

A. Well, we're a couple of years into a twenty-year contract, so it's difficult to say exactly -- you know, I mean, until you look at the meat of the life of that project then it's hard to say that they -- the delivered energy price under those contracts has produced energy savings for customers on that avoided energy cost basis.

Q. And do you anticipate renewable projects of that nature producing those sort of savings for customers across Alabama in your territory?

A. Any projects that are brought forth under this petition, yes, they would be expected to provide savings.

Q. And you said under the -- you've done some -- or -- well, you've talked about the Clean Power Plan and how those federal mandates may affect how the company is reacting and what they're doing now. And the company -- I guess you've testified or the company has said they haven't developed a compliance plan yet; is that correct?

A. For the Clean Power Plan, no.

Q. For the Clean Power Plan. But is the company running scenarios about potential compliance with the Clean Power Plan and how that will happen?

A. My understanding is that the company is still kind of -- I mean, the rule was finalized -- what was it -- last Monday.

Q. Right.

A. Maybe the week before. They're still, you know, processing and absorbing the information and talking with state environmental regulators, you know, gathering their thoughts. So they're not in -- they're still processing the rule.

Q. But a petition like this or a certificate of this nature would help in compliance of the Clean Power Plan, assuming that that --

A. That's a logical assessment.

Q. And does the projects -- do the projects that come under this petition or certificate, would they assist in compliance with other environmental laws such as NACS or MATS rule?

A. They certainly could. I think I

mentioned in my direct testimony any benefits would be quantifiable to the project to the extent that they can be isolated. But definitely, at the very least, any renewable energy that is offsetting other generation overall reduces emissions from that generation. So it's helpful in that regard in the least.

Q. And you -- I mean, the petition asks for renewable energy resources, and I think you have testified to the fact that in the statute that includes numerous things, biomass, black liquor, small irrigation projects under the statute. So could any of those projects, biomass, black liquor, small irrigation, that fall under that definition, could those projects come under this petition?

A. They would meet the criteria under the petition in terms of the definition of renewable resources, but they must also meet that criteria of positive economic value. So to the extent those meet that threshold they could be part of this certificate.

Q. Can you explain to me what black liquor is because I really want to know?

A. I understand it is basically biomass. It's like the leftover pieces of pulp in paper mill processes, but I'm not an expert on that by any means.

Q. Okay. Thank you. I appreciate that.

So would you agree that the additional -- the addition of renewable resources to Alabama Power's portfolio adds to energy diversity?

A. Yes.

(Brief interruption.)

A. So your question was do renewable resources add diversity?

Q. Would the projects under this petition add to energy diversity?

A. Yes. Any -- any variety in fuel sources would add to energy diversity in our fuel mix.

Q. And security, energy security?
A. To the extent that -- to some extent, yes.
Q. Yeah. And customer choice?
A. Yes.
Q. And the ability to promote economic growth?
A. Yes.
Q. In addition to helping the environment?
A. Yes.
Q. One last question, and then I'm done.
A. Okay.
Q. Will any of the projects under this certificate be for the general public and added to the general rate base?
A. Ask me that again.
Q. So will any of the projects that come under this certificate, will those be available for the general public and added to the rate base?
A. All of the --

MR. McCRARY: Could I -- excuse me. Could I ask a clarification by what available -- what does available to the general public mean? Could I ask for a clarification to your question?

MR. JOHNSTON: That the public can participate in the renewable program.

Q. So as Alabama Power has a REC program now that the general public can participate in -- correct? Is that correct?

A. Yes.

Q. -- are there projects under this petition and certificate where the general public will be able to participate in and then that gets -- you get compensated through the rate base, through --

A. All of the projects under this -- under this petition will be serving and useful to the entire rate base. That's where the avoided cost calculations come into play. And all of that energy from these resources is served to Alabama Power customers as a whole.

In terms of a generic rate that any customer could sign up for under this program, each project brought forth under the certificate would have to meet that -- that positive economic value threshold. So as I mentioned right now, we envision that to really require a larger kind of anchor in it, if you will, but there's no limitation on the size of those projects. So to the extent that projects come forward that -- you know, I mentioned the community scale could -- would not be prohibited under this authority.

Q. Okay. I think that's it. Will you give me one second just to make sure that I've covered everything?

A. Sure.

Q. We're done. Thank you very much.

ALJ MORRIS: Thank you, Mr. Johnston. If you would, pass the microphone across to Ms. Shenstone.

CROSS-EXAMINATION

BY MS. SHENSTONE:

Q. Good morning. I'll try to wrap it up while it's still morning. My name is Amelia Shenstone. I'm with the Southern Alliance for Clean Energy. And I want to applaud the company for this petition to bring more renewable energy online and to do it in a very cost conscious way.

So I just wanted to ask just to clarify. My understanding is that it's impossible that any project undertaken under this petition could put upward pressure on rates; is that correct?

A. The projected economic benefits would have to result in positive value. I mentioned a couple of times we can't guarantee any forecast, but from a forward-looking perspective no projects would place upward pressure on rates.

Q. So maybe impossible is the wrong word, but the program is designed so that there would be no upward pressure on rates?

A. That's correct.

Q. Is it possible that projects

under this program could put downward pressure on rates?

A. That's the intention, yes.

Q. Excellent.

Could you envision that some of the projects you've mentioned, that there may be a customer contribution in order to make those feasible in a way that the net effect is a positive one? Is it possible that some of those projects may not require a customer contribution in order for the economics to work out favorably?

A. That is possible. And, obviously, those wouldn't be excluded because that would meet the criteria.

Q. Thank you.

Are you at all familiar with the Advanced Solar Initiative at Georgia Power, our neighboring sister utility?

A. I'm familiar with it. I doubt I'll be able to speak in much detail.

Q. I wondered if you're familiar with the request for proposals process there whereby parameters are set for what would be a reasonable proposal and then the market is basically set free to assure not just a net positive value to the protect but the most value for the project. I wonder if that might be considered as a model for selecting projects or carrying the projects out under this program.

A. Our company's position -- and so I don't want to speak to details of that program that I'm not familiar with. But our company's position is to negotiate the best possible price on any given project so that customers will benefit from all the savings that were available to be attained.

As I mentioned in the previous testimony the company would utilize the Commission-approved RFP guidelines to the extent that an RFP is the best approach to gaining that market information. There can and will be times that -- as I mentioned, we're under the gun here to meet that 2016 tax credit. So an RFP takes time. We wouldn't necessarily have an RFP to the extent that we have enough market information to have a gauge on what a reasonable price is. So we would utilize a combination of those processes to ensure that the projects we're entering into are providing the most economic value possible to our customers.

Q. And I'm imagining that if this is approved there could be many customers coming to you and saying, we would like to have renewable projects under this certificate. How will you prioritize which projects to devote the company's attention to most expediently? Will it be first come, first served or in order of size or a case that the customer brings to you and suggesting that it will have a good positive value? How will that be prioritized?

A. The company will use all the resources available to ensure that we're meeting the needs of all the customers. So I'll have to say I don't know. The priority will be associated by many factors, I'm sure.

Q. Thank you.

ALJ MORRIS: Mr. Canton, do you have any questions of the witness?

MR. CANTON: Just a couple. I'll make them quick. I know we're all ready to move on.

EXAMINATION

BY MR. CANTON:

Q. I guess being a trade association, we're obviously very happy to see Alabama Power looking into renewables and good job opportunity for the state and the customers.

Specifically to the benefits to -- the program is going to provide to Alabama, you know, downward pressure on the rates, economic opportunities, specifically the idea of whether projects need to be sited in Alabama or not when we're talking about what the economic benefits are to Alabama -- I'm still here. Okay -- specifically to the access to perform some of the work in -- that would be involved in these projects by

Alabama companies and workers. So if there's a chance that projects are out of state, obviously, it makes it harder for these companies and workers to participate. So as much as we have the economic development potential of these companies that were retaining -- the corporations retaining and attracting possibly to Alabama, what is being done and what is -- what can be done to provide opportunity for the workers and companies of Alabama who actually participate in the deployment of these projects?

A. Okay. I think you asked what this petition will do for the state of Alabama to ensure that some of that economic value is retained in the state. Is that a fair assessment?

Q. Well, specifically to Alabama workers being able to perform the construction, maintenance, design of the projects themselves.

A. As the utility provider, our mission is to provide reliable cost effective electricity to our customers. So to the extent that a project under this certificate meets that criteria of provided value for customers, then it would qualify for approval under the certificate as we've requested it.

As an occupant of the state and a company who's been dedicated to the state of -- and to the economy and the -- and the good of the state of Alabama for a hundred years, we believe that this petition helps better position our state for some of the opportunities that you and Mr. Cagle have discussed, growth and jobs and that type thing. But as written, the petition doesn't require the construction of those facilities to be in Alabama. In that -- as long as it's in the best interest of our customers from an electricity-price standpoint, then it's something that should be pursued.

Q. Okay. And just the example would be similar to Georgia next door that has several thousand jobs that are associated with their Advanced Solar Initiative program, you know, their effort to bring renewables into the state, I don't believe it was tied specifically to job creation, but it did have the benefit of encouraging local job growth, specifically in those construction industries. So I guess this isn't specifically written for that, but it -- it does anticipate -- is there a sense of some percentage of the projects will be based in Alabama, where the work will be conducted here versus we're buying PPAs from Kansas or from out of state?

A. There wouldn't be a requirement for that under this petition, but there's -- in my opinion there is a likelihood that many of those projects would be located in the state. For instance, the military bases are the -- you know, one of the reasons that we're here. And those projects would be located on the bases in the state of Alabama. So my opinion is that many other customers may have this similar type siting restriction as well.

Q. So it would be kind of customer specific?

A. That's right.

Q. We'd like it on our property or the vicinity of our property?

A. That's right. Or if -- or if they don't restrict it to we want it to be on our property, if there is some other site in Alabama that provides the most cost effective resource, then that one would compete and would be chosen as well. So there's not a preference by any means for it to be outside of the state. Outside of that customer-specific preference and meeting that customer's interest and needs, the company would utilize the most effective resource from a cost and reliability perspective.

Q. And I guess similarly the process of acquiring a contractor or somebody to perform the actual work, as I understand it now, there's an agreement made with -- a customer of Alabama Power that would approach the company and ask, we'd like to do renewables under this program, we imagine it's going to be this size, there's some agreement that's come to, and then the project is announced, and then there's an RFP process, either internal, external, or possibly no RFP process to actually acquire the power itself, the -- either the facility or the PPA? Does that make sense? So I'm trying to understand the steps that are going to be involved from a customer's perspective. I'm a giant Wal-Mart or a series of Wal-Marts, and I want to put solar in our facilities. I approach the company and ask we'd like to be able to do this on some number of our facilities. And the company is going to come back. We might negotiate terms of that, and in that process Wal-Mart has typically wanted it on their facilities. And so they need to deploy 5 megawatts worth of actually on-site solar PV generation. The process for the company to actually deploy that would be -- be possibly an RFP but possibly just using resources that they've already identified?

MR. McCRARY: Your Honor, if I might interpose an objection and a request. There was a lot in that, and I lost count on how many questions there were. If you could -- if you could sort of narrow the focus of your question and serve up one question at a time for the witness, I think that would be helpful for the record.

MR. CANTON: Okay.

Q. I'm sorry. I was thinking more of it from a customer's perspective what are they going to experience when they do this, because, you know, we're trying to represent some of the folks that are members of our organization. How -- if a facility -- a customer of Alabama Power has decided with Alabama Power to deploy generation under this program, how will, say, a contractor be chosen by Alabama Power to perform the work? I believe that may have been answered in part by an RFP process, but it may be --

A. It's difficult to answer

directly because it will vary, you know, on a case-by-case depending on the level of customer interest and their limitations. They could have size or timing or site restrictions. So to the extent that the company is working with a customer there wouldn't necessarily -- the company would examine what tools they have in the toolbox to meet that customer's needs. And those tools could be that we already have information in hand that it's a good gauge of the market for maybe a generic site. So if we were aggregating in several Wal-Mart's loads and meeting their needs off-site, that may be one approach. If some store requested, like the military, that, you know, this needs to be on my site and for some reason, like the General Services Agreement it has to be a self-build on that site where the company has to own and operate and maintain that equipment themselves -- ourselves, there still would be a bidding -- a procurement process. The company has procurement processes surrounding, you know, all types of activities or things that we secure, you know, from office supplies to -- you know, supply chain management. So that bid process would be followed and adhered to under a self-build application.

And under the PPA application, again, we would choose from either the market data that we have on hand from unsolicited offers. Or to the extent that those offers don't give a good representation of the market we would go through the RFP guidelines as approved by the Commission.

Q. As far as participation, it sounds like you anticipate larger customers participating. Is there the opportunity for smaller and mid-size, say, companies and other customers to participate, and what would their process be? What would they do?

A. There's nothing in the petition that limits the size of the customer. So the hurdle, if you will, is the economic value screen. So to the extent that a smaller customer is -- that we're able to work with a customer to identify a project that meets their needs and passes that economic evaluation, then it would not -- there would be no limitation on that size under the certificate authority.

Q. And sometimes on a smaller scale, multiple installations -- say, if it was something in the sense of a PV system, multiple installations can make the economics work better, so perhaps a one-by-one rather than that. Is there the possibility of a program that makes a certain cookie cutter system available to multiple mid-size and smaller customers that allows them to take advantage of the program but keeps it cost effective for everyone?

A. As I mentioned in answer to Mr. Johnston's question, I believe, on community solar, to the extent that we aggregate enough interest and line the stars all up just right, that we could bring a project that had interest from multiple customers all packaged together, you know, as long as that project met the criteria, then it would be a viable project under the certificate.

Q. Is that something that an outside group could bring an opportunity, like an aggregation of customers and say, here's a chance that we may be able to make something work under the program, that this many customers that are interested in, similarly to a community solar, but Alabama Power may not want to put together a community solar program?

A. I don't think I can exactly speak to that hypothetical because there would be, you know, a lot of complex details, I imagine, with that. So, you know, as long as the -- as a project met the criteria outlined here, where it was small scale, up to 80 megawatts, and provided positive economic value for customers, then it would not be prohibited.

Currently, the customer (sic)

envisions working with the larger customers, but over this six-year process other packages may be designed that meet that criteria.

Q. And just one last kind of question and a half on the capacity side of renewables and the intermittency and storage. The question had been asked before about storage, and, you know, by itself it's not a renewable product, but the market for that is changing extremely rapidly. And as renewables are deployed, right now they're primarily a fuel offset, but as your access to storage and combined storage and renewable projects improves, you can deploy -- you know, what is perceived in the market is you can deploy renewables in a way that does have a higher capacity value because the storage evens out the ups and downs of the power. So whether it's in straight-up new projects that are renewables, do you anticipate over time in this program actually being able to add some capacity value to these projects as they go out, or will it just be, you know, we're putting it out and not giving really any capacity value to it?

A. The capacity value is determined -- I think I covered this a little bit, but I'll elaborate. Capacity value is determined by that probability basically that that -- that generation will be available when you need it. So to the extent that resources are intermittent, wind and solar for example, there's a certain amount of generation that you could assume is going to occur during hours that you need it but not necessarily to its maximum. So outside of just battery storage, which you've asked about, but any parameter of the design of that facility that helps optimize or increase the probability that that generation will be flowing at the optimal level when you need it, then it increases the evaluation of that capacity value.

There are a number of ways to do that, specifically with solar and with wind, based on -- for wind, you know, how tall the mast is -- that the blades are spinning on or angle of the blades, and the solar, you know, the tilt and whether it attracts the sun or doesn't attract the sun, which way it's facing. I've heard of clipping where the inverter, you know, behaves differently. Batteries are just another component of the design features of each generating facility that is evaluated individually based on it's likelihood of being there when you need it.

Q. And in that specific case, too, you have the -- where the renewables, they're implemented as -- with some level of intermittency with a fairly low capacity factor, and over time, as the Clean Power Plan comes online, is there the possibility of additional retirements as a result of the Clean Power Plan that are not foreseen right now?

A. Well, the --

Q. And would that -- I guess I'm translating that into would that benefit from the additional capacity that you can have by adding storage to the renewable projects that have been deployed already?

A. The company's environmental compliance plan is really an evergreen process, and we actually have a meeting here every December to discuss the company's plans to meet environmental compliance. And as I mentioned, the Clean Power Plan is still taking shape. So I can't -- I can't exactly speak to what that will mean for our generating resources. But to the extent that it starts to become clear and any environmental compliance value associated with these renewables can be identified and captured in the analysis, then it will be.

Q. That's all I have. Thank you.

ALJ MORRIS: I've just got a few from the bench, and then, Mr. McCrary, I'll let you do any redirect.

CROSS-EXAMINATION

BY ALJ MORRIS:

Q. First of all, one of the quick questions we have is a -- really a timing issue and kind of what start days and all that. And I know we've got a couple of things in there we're about. You have the one-year period after the approval of this or after the approval of a project to actually begin construction. You've got your tax credit 2016 in operation. Can you give us just a little bit more details about what that means specifically in terms of the commission-imposed one-year deadline? Is that met when the first dirt is turned, when the first contract is signed? What is kind of the key that starts that process? And then on the other hand, on the tax credit issue, is it operation, is it construction? What is the -- kind of the deadline there?

A. Those are good questions. The one-year initiation of a project, it's basically dirt being turned. If it's a cell-phoned asset, then it would be us getting out there and turning the dirt. If it was a PPA, it would be the counter party turning dirt. And, of course, there are definitions around what turning dirt means, but it's physical initiation of construction.

Q. Okay.

A. The tax credit deadline, a facility has to be in commercial operation in December 2016 to receive the tax -- the 30 percent.

Q. The 30 percent. And after that it goes to 10 percent --

A. It goes --

Q. -- correct?

A. -- down to 10 percent.

Q. Okay. Another question. This is regarding the federal agencies and their procurement policies. And I know DoD is kind of its own animal, DoD and in many cases the services to their own procurement, but for the other agencies are they doing it individually, or are they it doing through GSA, Governmental Services Administration?

A. So far interest in discussions with those customers has been individually.

Q. Okay. Another one, we talked a

little bit about the security and the ability of -- I guess to isolate a particular location. I know we've talked about this initially in terms of the military bases, but in the event of emergencies in -- you know, a military base under this project would be a good example, but it would not be the only example. You know, a hospital or large medical complex, like, you know, the downtown Birmingham medical complex, if there was a project supporting that -- and I know a lot of times there are, you know, distribution and transmission topography issues that govern this, but is it possible in the event of an emergency, if there is a local or on-site generation source to island those particular critical facilities and perhaps give them more security in terms of their energy flow than just a normal facility?

A. I'm going to have to say I don't know to that. I do know that in storm restoration processes priority is given to customers like, you know, hospitals and areas that have a high need to serve the public and be there and able to run. I'm not sure about islanding practices, actually.

Q. Okay. Yeah. So it gets into the weeds a little bit.

A. Good follow-up.

Q. Just one final for me, and then I'll turn it over to the Commission up here if they have anything.

Since this -- I guess this petition has been announced and made public, has the company received any new inquiries or interest about pursuing one of these projects if this were approved?

A. Yes. The company, since the notice of this petition was made public, have had an increase in inquiries on top of these we already had received from several customers, as well as developers. So those unsolicited offers and gauge of the market that I spoke of, those have increased as well.

ALJ MORRIS: Okay.

Commissioners, any questions?

Mr. McCrary?

MR. McCRARY: Yes, sir, Your Honor. Thank you. I do have a few scattered redirect questions. I'll try to be brief.

REDIRECT EXAMINATION

BY MR. McCRARY:

Q. Ms. Cain, I believe Mr. Free and Mr. Johnston both asked you about the REC program and asked you about RECs that might be -- that would be produced under projects pursuant to this certificate. Do you recall those questions?

A. Yes.

Q. To the extent that the RECs were not transferred to a counter party, to the customer under a separate agreement, would the company then hold the RECs produced by the project?

A. Hold them and use them in the best interest of the customers.

Q. Right. And specifically, would the company retain the right to either sell the RECs or retire the RECs, depending on what's best for customers?

A. Correct.

Q. Because that --

MR. McCRARY: And, Your Honor, just for the sake of the record, I would not want this dialogue to inadvertently result in a retirement of the RECs because the record is not clear. The company receives RECs and retains the right under its PPAs and under this program, I believe, to either retire the RECs for the benefit of local load service or to separate the RECs from the energy and to market the energy separately from the RECs or the RECs separately from the energy. So we do not want the record to suggest that we are in any way retiring the RECs associated with these projects or any other projects of the company absent an intentional decision to do so.

Q. Ms. Cain, in response to some questions from Ms. Martin you indicated that the military base projects would be something in the order of 15 megawatts, give or take; is that right?

A. They would be less than 15 megawatts each.

Q. Okay. But that's not in the aggregate; that was the part that was --

A. Right. And I don't think I added the word each.

Q. And also in response to some questions from Ms. Martin, when she was asking you about what the Commission might choose to do with the report that it would receive from the staff and from the Attorney General indicating whether they felt that a project met the criteria established by the Commission or not. And you indicated that the Commission would decide what it would do with that report; correct?

A. Yes.

Q. All right. Did you mean to suggest in your response that that would also apply to the underlying details and analysis associated with a given project?

A. No. The report was what I was calling the sort of assessment by the AG and the Commission staff that says, you know, we've reviewed this information and we recommend approval or disapproval. That would be the report in the form that the Commission could do what they want with.
Any of the confidential information that was given to the staff and the AG would remain confidential. That needs to be clarified.
Q. Now, in response to some questions from Mr. Johnston, I believe, he was asking you about the possibility of community solar projects; correct?
A. Uh-huh.
Q. And you indicated that community solar might potentially fall within the petition or, at the very least, it's not prohibited by the petition?
A. Correct.
Q. Is it correct that whatever project might fall within the parameters,

that project would have to satisfy the same criteria as every other project as set forth in the petition?

A. That's right.

Q. Similarly he was asking you about the diversity benefits associated with renewable generation. Do you recall those questions?

A. Yes.

Q. And did I understand you correctly that whatever diversity benefits there are relative to renewables or any other form of generation are captured in the company's quantifications that you've described here today?

A. Yes.

Q. Would you please explain?

A. As I was mentioning, the value of diversity, not just renewables but with any fuel source, is that you're spreading your portfolio, just like you would, you know, maybe your financial portfolio. And so the quantification of that diversity value is seen in sensitivities performed on those avoided cost calculations. A well-diversified project is more isolated from swings and things like fuel forecasts and operational parameters. So these would be captured through those sensitivities on the analysis.

Q. Okay. Mr. Canton, I believe, asked you about what effect pairing storage technology with a solar resource, for example, might have on the capacity of that resource. Do you recall those questions?

A. Yes.

Q. Would that pairing impact the value of the capacity associated with that resource, or would it impact the amount of capacity that would be deemed associated with that resource?

A. The value in terms of a rate, dollar per kilowatt year value of the capacity, is determined based on the market conditions. It would be the amount of capacity that can be counted as what we would call equivalent capacity value. So if a resource is capable of delivering the full 80 megawatts under the small-scale size limitation but may not be expected to deliver that 80 megawatts during hours when you need it, perhaps only 10 percent of that capacity is counted and quantified as value. So a battery or some other design feature of a project that boosts the reliability of that generator would increase the amount of the equivalent capacity value, not the market condition or the rate that that capacity has presented value.

Q. And finally, in response to some questions from the bench, Judge Morris was asking for some clarification about what would constitute an exercise of authority under the certificate through a given project. Do you recall those questions?

A. Yes.

Q. And you indicated with respect to the -- a company facility, that would be turning of dirt so to speak?

A. Right.

Q. In the context of a PPA would the execution of a binding PPA by the company represent an exercise of the authority under the certificate by the company?

A. I believe it would. That would be a company-initiating action, but I would follow-up with my counsel to see if that meets the code definitions. Some of those PPAs may be in terms of projects that are already on the ground, so there would be no turning dirt.

Q. Thank you.

MR. McCRARY: That's all we have, Your Honor.

ALJ MORRIS: Yes, Ms. Martin.

RECROSS-EXAMINATION

BY MS. MARTIN:

Q. I would just like to clarify with respect to the confidential and proprietary information. With this project we're talking about a lot of information that no one knows. And I just want to make sure that the company will still mark as confidential and proprietary anything that it considers confidential and proprietary. It's not that everything associated with this project is confidential. You know, we're not deciding today that that's confidential and proprietary. But you will continue to mark that information?

A. Yes, ma'am, of course.

ALJ MORRIS: Any other re-cross? Mr. Bentley?

RECROSS-EXAMINATION

BY MR. BENTLEY:

Q. And to follow-up with Ms. Martin's question. Some of the other questions that addressed proprietary and then the question about notice, particularly with the form -- how you present projects to the Commission, how -- for the individual projects, how would they be presented to the Commission staff? Not the substance of what's in there but the form. Is it a filing? Is it just submitted to the staff?

At least how is that contemplated in the --- in your petition?

A. In the request we would submit the information, and it would likely be a summary packet or a binder of information that has the overall economic evaluation assessment and then all of the supporting materials behind that in the submission.

Q. Is there a piece of that that's a public filing? As I understand it, in your petition you have -- there's thirty days -- the Commission has thirty days to decide to disapprove it. What's available to whom when you make the initial proposal?

A. As requested, it would not be a public filing. It would be a submission to the Attorney General and the Public Service Commission staff.

ALJ MORRIS: Anybody have anything else?

If not, Ms. Cain, thank you very much. You're excused.

THE WITNESS: I thank everyone.

ALJ MORRIS: I believe next is Mr. Canton. I believe you have some testimony that you would like to present to the Commission or --

MR. CANTON: I have been advised to put that in the form of a question, so I pretty much got everything I need on there. I appreciate that.

ALJ MORRIS: Okay. So you're -- with that, then it appears that we have reached the end of the portion where we take evidence in this.

I am anticipating getting this on the September docket, which would mean -- let's see. The meeting is on the 8th, so our agenda is due on the 1st.

I'm assuming the company is willing to pay the cost for an expedited transcript on this, or do you request one, or are you -- it is a timing issue for us generally.

MR. McCRARY: Yes, Your Honor. I think it's clear from the testimony and from the petition that we do need to move forward as quickly as we can. And I'm told that the company would bear the cost of the expedited transcript.

ALJ MORRIS: Okay. Because that can become an issue as we get close to these commission meetings, and that just makes it a lot easier.

Normally -- okay. Well, the Commission -- that even makes it even more imperative. The Commission meeting is on the 1st. I was under the impression -- and I guess I was wrong -- it was on the 8th. So it's on the 1st. And what is my date? Oh, yes, that moves things up considerably. Yes. If anyone has any filings that they wish to make -- I'm certainly not requesting them. I think we probably have all the information we need. But if anyone feels compelled, we are on a very tight schedule. So I would say that if anyone wishes to make any post hearing filings that those would need to be done within probably the next seven days.

And any replies after that would probably even need to be in a more expedited schedule. Let's see. Probably be due by the 24th. So the 19th for any post hearing briefs. And the 24th for any replies to those briefs.

And with that, we will take this -- Commissioners, do y'all have anything else before we conclude?

Mr. McCrary?

MR. McCRARY: Yes, sir. Just to be clear, you're not directing the parties --

ALJ MORRIS: No.

MR. McCRARY: -- to file anything --

ALJ MORRIS: I'm not directing the parties to file anything. I am leaving -- of course, the rules leave that option open to any party, so -- but I do need to put some time constraints on that because of the nature of getting this before the Commission at the next commission meeting. So I'm going to ask that any comment or any initial briefs or comments be filed by the

19th and any replies by the 24th.

MR. McCRARY: Yes, sir. Thank you.

ALJ MORRIS: And with that we will take this under advisement, and this hearing is concluded. Thank you very much.

(Adjourned 12:30 p.m.)

C E R T I F I C A T E

STATE OF ALABAMA)
MONTGOMERY COUNTY)

I hereby certify that the above and foregoing proceedings were taken down by me in stenotype, and the questions and answers thereto were transcribed by means of computer-aided transcription, and that the foregoing represents a true and correct transcript of said proceeding.

I further certify that I am neither of counsel nor of kin to the parties to the action, nor am I in any way interested in the result of said cause.

I further certify that I am duly licensed by the Alabama Board of Court Reporting as a Certified Court Reporter as evidenced by the ACCR number following my name below.

KIM PRUITT, ACCR #280

WORD INDEX

A.P.S.C. DOCKET NO 32953

Alabama Solar Industry Assn

EX NO 2

WITNESS 16/1/27-Cross

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2018

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition Period from to

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-3526	**The Southern Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-0690070
1-3164	**Alabama Power Company** (An Alabama Corporation) 600 North 18th Street Birmingham, Alabama 35291 (205) 257-1000	63-0004250
1-6468	**Georgia Power Company** (A Georgia Corporation) 241 Ralph McGill Boulevard, N.E. Atlanta, Georgia 30308 (404) 506-6526	58-0257110
001-11229	**Mississippi Power Company** (A Mississippi Corporation) 2992 West Beach Boulevard Gulfport, Mississippi 39501 (228) 864-1211	64-0205820
001-37803	**Southern Power Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-2598670

EXHIBIT

PENGAD 800-631-6989

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1-14174	**Southern Company Gas** (A Georgia Corporation) Ten Peachtree Place, N.E. Atlanta, Georgia 30309 (404) 584-4000	58-2210952

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Securities registered pursuant to Section 12(b) of the Act:(1)

Each of the following classes or series of securities registered pursuant to Section 12(b) of the Act is listed on the New York Stock Exchange.

Title of each class	Registrant
Common Stock, $5 par value	**The Southern Company**
Junior Subordinated Notes, $25 denominations	
6.25% Series 2015A due 2075	
5.25% Series 2016A due 2076	
5.25% Series 2017B due 2077	
Class A preferred stock, cumulative, $25 stated capital	**Alabama Power Company**
5.00% Series	
Junior Subordinated Notes, $25 denominations	**Georgia Power Company**
5.00% Series 2017A due 2077	
Senior Notes	**Southern Power Company**
1.000% Series 2016A duc 2022	
1.850% Series 2016B due 2026	

Securities registered pursuant to Section 12(g) of the Act:(1)

Title of each class			Registrant
Preferred stock, cumulative, $100 par value			**Alabama Power Company**
4.20% Series	4.60% Series	4.72% Series	
4.52% Series	4.64% Series	4.92% Series	

(1) At December 31, 2018.

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Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Registrant	Yes	No
The Southern Company	X	
Alabama Power Company	X	
Georgia Power Company	X	
Mississippi Power Company		X
Southern Power Company	X	
Southern Company Gas	X	

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒ (Response applicable to all registrants.)

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Registrant	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company	Emerging Growth Company
The Southern Company	X				
Alabama Power Company			X		
Georgia Power Company			X		
Mississippi Power Company			X		
Southern Power Company			X		
Southern Company Gas			X		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒ (Response applicable to all registrants.)

Aggregate market value of The Southern Company's common stock held by non-affiliates of The Southern Company at June 29, 2018: $47.0 billion. All of the common stock of the other registrants is held by The Southern Company. A description of each registrant's common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at January 31, 2019
The Southern Company	Par Value $5 Per Share	1,034,564,279
Alabama Power Company	Par Value $40 Per Share	30,537,500
Georgia Power Company	Without Par Value	9,261,500
Mississippi Power Company	Without Par Value	1,121,000
Southern Power Company	Par Value $0.01 Per Share	1,000
Southern Company Gas	Par Value $0.01 Per Share	100

Documents incorporated by reference: specified portions of The Southern Company's Definitive Proxy Statement on Schedule 14A relating to the 2019 Annual Meeting of Stockholders are incorporated by reference into PART III. In addition, specified portions of the Definitive Information Statement on Schedule 14C of Alabama Power Company relating to its 2019 Annual Meeting of Shareholders are incorporated by reference into PART III.

Each of Georgia Power Company, Mississippi Power Company, Southern Power Company, and Southern Company Gas meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format specified in General Instructions I(2)(b), (c), and (d) of Form 10-K.

This combined Form 10-K is separately filed by The Southern Company, Alabama Power Company, Georgia Power Company, Mississippi Power Company, Southern Power Company, and Southern Company Gas. Information contained herein relating to any individual company is filed by such company on its own behalf. Each company makes no representation as to information relating to the other companies.

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DEFINITIONS

When used in this Form 10-K, the following terms will have the meanings indicated.

Term	Meaning
2013 ARP	Alternative Rate Plan approved by the Georgia PSC in 2013 for Georgia Power for the years 2014 through 2016 and subsequently extended through 2019
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
AMEA	Alabama Municipal Electric Authority
AOCI	Accumulated other comprehensive income
ARO	Asset retirement obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Atlanta Gas Light	Atlanta Gas Light Company, a wholly-owned subsidiary of Southern Company Gas
Atlantic Coast Pipeline	Atlantic Coast Pipeline, LLC, a joint venture to construct and operate a natural gas pipeline in which Southern Company Gas has a 5% ownership interest
Bcf	Billion cubic feet
Bechtel	Bechtel Power Corporation, the primary contractor for the remaining construction activities for Plant Vogtle Units 3 and 4
Bechtel Agreement	The October 23, 2017 construction completion agreement between the Vogtle Owners and Bechtel
CCR	Coal combustion residuals
CCR Rule	Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in 2015
Chattanooga Gas	Chattanooga Gas Company, a wholly-owned subsidiary of Southern Company Gas
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
COD	Commercial operation date
Contractor Settlement Agreement	The December 31, 2015 agreement between Westinghouse and the Vogtle Owners resolving disputes between the Vogtle Owners and the EPC Contractor under the Vogtle 3 and 4 Agreement
Cooperative Energy	Electric cooperative in Mississippi
CPCN	Certificate of public convenience and necessity
Customer Refunds	Refunds issued to Georgia Power customers in 2018 as ordered by the Georgia PSC related to the Guarantee Settlement Agreement
CWIP	Construction work in progress
Dalton	City of Dalton, Georgia, an incorporated municipality in the State of Georgia, acting by and through its Board of Water, Light, and Sinking Fund Commissioners
Dalton Pipeline	A pipeline facility in Georgia in which Southern Company Gas has a 50% undivided ownership interest
DOE	U.S. Department of Energy
Duke Energy Florida	Duke Energy Florida, LLC
EBIT	Earnings before interest and taxes
ECM	Mississippi Power's energy cost management clause
ECO Plan	Mississippi Power's environmental compliance overview plan
Eligible Project Costs	Certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the loan guarantee program established under Title XVII of the Energy Policy Act of 2005
EMC	Electric membership corporation
EPA	U.S. Environmental Protection Agency
EPC Contractor	Westinghouse and its affiliate, WECTEC Global Project Services Inc.; the former engineering, procurement, and construction contractor for Plant Vogtle Units 3 and 4

DEFINITIONS
(continued)

Term	Meaning
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FFB	Federal Financing Bank
Fitch	Fitch Ratings, Inc.
FMPA	Florida Municipal Power Agency
GAAP	U.S. generally accepted accounting principles
Georgia Power	Georgia Power Company
Georgia Power 2019 Base Rate Case	Georgia Power's base rate case scheduled to be filed by July 1, 2019
Georgia Power Tax Reform Settlement Agreement	A settlement agreement between Georgia Power and the staff of the Georgia PSC regarding the retail rate impact of the Tax Reform Legislation, as approved by the Georgia PSC on April 3, 2018
GHG	Greenhouse gas
Guarantee Settlement Agreement	The June 9, 2017 settlement agreement between the Vogtle Owners and Toshiba related to certain payment obligations of the EPC Contractor guaranteed by Toshiba
Gulf Power	Gulf Power Company
Heating Degree Days	A measure of weather, calculated when the average daily temperatures are less than 65 degrees Fahrenheit
Heating Season	The period from November through March when Southern Company Gas' natural gas usage and operating revenues are generally higher
HLBV	Hypothetical liquidation at book value
Horizon Pipeline	Horizon Pipeline Company, LLC
IBEW	International Brotherhood of Electrical Workers
IGCC	Integrated coal gasification combined cycle, the technology originally approved for Mississippi Power's Kemper County energy facility (Plant Ratcliffe)
IIC	Intercompany Interchange Contract
Illinois Commission	Illinois Commerce Commission
Interim Assessment Agreement	Agreement entered into by the Vogtle Owners and the EPC Contractor to allow construction to continue after the EPC Contractor's bankruptcy filing
Internal Revenue Code	Internal Revenue Code of 1986, as amended
IPP	Independent Power Producer
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ITAAC	Inspections, Tests, Analyses, and Acceptance Criteria, standards established by the NRC
ITC	Investment tax credit
JEA	Jacksonville Electric Authority
KUA	Kissimmee Utility Authority
KW	Kilowatt
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LIFO	Last-in, first-out
LNG	Liquefied natural gas
Loan Guarantee Agreement	Loan guarantee agreement entered into by Georgia Power with the DOE in 2014, under which the proceeds of borrowings may be used to reimburse Georgia Power for Eligible Project Costs incurred in connection with its construction of Plant Vogtle Units 3 and 4

LOCOM	Lower of weighted average cost or current market price
LTSA	Long-term service agreement
Marketers	Marketers selling retail natural gas in Georgia and certificated by the Georgia PSC

DEFINITIONS
(continued)

Term	Meaning
MEAG	Municipal Electric Authority of Georgia
Merger	The merger, effective July 1, 2016, of a wholly-owned, direct subsidiary of Southern Company with and into Southern Company Gas, with Southern Company Gas continuing as the surviving corporation
MGP	Manufactured gas plant
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MPUS	Mississippi Public Utilities Staff
MRA	Municipal and Rural Associations
MW	Megawatt
MWH	Megawatt hour
natural gas distribution utilities	Southern Company Gas' natural gas distribution utilities (Nicor Gas, Atlanta Gas Light, Virginia Natural Gas, Elizabethtown Gas, Florida City Gas, Chattanooga Gas, and Elkton Gas as of June 30, 2018) (Nicor Gas, Atlanta Gas Light, Virginia Natural Gas, and Chattanooga Gas as of July 29, 2018)
NCCR	Georgia Power's Nuclear Construction Cost Recovery
NDR	Alabama Power's Natural Disaster Reserve
NextEra Energy	NextEra Energy, Inc.
Nicor Gas	Northern Illinois Gas Company, a wholly-owned subsidiary of Southern Company Gas
NO_x	Nitrogen oxide
NRC	U.S. Nuclear Regulatory Commission
NYMEX	New York Mercantile Exchange, Inc.
NYSE	New York Stock Exchange
OCI	Other comprehensive income
OPC	Oglethorpe Power Corporation (an Electric Membership Corporation)
OTC	Over-the-counter
OUC	Orlando Utilities Commission
PATH Act	Protecting Americans from Tax Hikes Act
PennEast Pipeline	PennEast Pipeline Company, LLC, a joint venture to construct and operate a natural gas pipeline in which Southern Company Gas has a 20% ownership interest
PEP	Mississippi Power's Performance Evaluation Plan
Piedmont	Piedmont Natural Gas Company, Inc.
Pivotal Home Solutions	Nicor Energy Services Company, until June 4, 2018 a wholly-owned subsidiary of Southern Company Gas, doing business as Pivotal Home Solutions
Pivotal Utility Holdings	Pivotal Utility Holdings, Inc., until July 29, 2018 a wholly-owned subsidiary of Southern Company Gas, doing business as Elizabethtown Gas (until July 1, 2018), Elkton Gas (until July 1, 2018), and Florida City Gas
power pool	The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations
PowerSecure	PowerSecure Inc.
PowerSouth	PowerSouth Energy Cooperative
PPA	Power purchase agreements, as well as, for Southern Power, contracts for differences that provide the owner of a renewable facility a certain fixed price for the electricity sold to the grid
PRP	Pipeline Replacement Program, Atlanta Gas Light's 15-year infrastructure replacement program, which

	ended in December 2013
PSC	Public Service Commission
PTC	Production tax credit

DEFINITIONS
(continued)

Term	Meaning
Rate CNP	Alabama Power's Rate Certificated New Plant
Rate CNP Compliance	Alabama Power's Rate Certificated New Plant Compliance
Rate CNP PPA	Alabama Power's Rate Certificated New Plant Power Purchase Agreement
Rate ECR	Alabama Power's Rate Energy Cost Recovery
Rate NDR	Alabama Power's Rate Natural Disaster Reserve
Rate RSE	Alabama Power's Rate Stabilization and Equalization
registrants	Southern Company, Alabama Power, Georgia Power, Mississippi Power, Southern Power Company, and Southern Company Gas
revenue from contracts with customers	Revenue from contracts accounted for under the guidance of ASC 606, Revenue from Contracts with Customers
ROE	Return on equity
RUS	Rural Utilities Service
S&P	S&P Global Ratings, a division of S&P Global Inc.
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
SEPA	Southeastern Power Administration
Sequent	Sequent Energy Management, L.P.
SERC	Southeastern Electric Reliability Council
SNG	Southern Natural Gas Company, L.L.C.
SO_2	Sulfur dioxide
Southern Company	The Southern Company
Southern Company Gas	Southern Company Gas and its subsidiaries
Southern Company Gas Capital	Southern Company Gas Capital Corporation, a 100%-owned subsidiary of Southern Company Gas
Southern Company Gas Dispositions	Southern Company Gas' disposition of Pivotal Home Solutions, Pivotal Utility Holdings' disposition of Elizabethtown Gas and Elkton Gas, and NUI Corporation's disposition of Pivotal Utility Holdings, which primarily consisted of Florida City Gas
Southern Company system	Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SEGCO, Southern Nuclear, SCS, Southern Linc, PowerSecure (as of May 9, 2016), and other subsidiaries
Southern Holdings	Southern Company Holdings, Inc.
Southern Linc	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
SouthStar	SouthStar Energy Services, LLC
SP Solar	SP Solar Holdings I, LP
SP Wind	SP Wind Holdings II, LLC
SRR	Mississippi Power's System Restoration Rider, a tariff for retail property damage reserve
STRIDE	Atlanta Gas Light's Strategic Infrastructure Development and Enhancement program
Subsidiary Registrants	Alabama Power, Georgia Power, Mississippi Power, Southern Power, and Southern Company Gas
Tax Reform Legislation	The Tax Cuts and Jobs Act, which became effective on January 1, 2018
Toshiba	Toshiba Corporation, parent company of Westinghouse

traditional electric operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power through December 31, 2018; Alabama Power, Georgia Power, and Mississippi Power as of January 1, 2019
Triton	Triton Container Investments, LLC

DEFINITIONS
(continued)

Term	Meaning
VCM	Vogtle Construction Monitoring
VIE	Variable interest entity
Virginia Commission	Virginia State Corporation Commission
Virginia Natural Gas	Virginia Natural Gas, Inc., a wholly-owned subsidiary of Southern Company Gas
Vogtle 3 and 4 Agreement	Agreement entered into with the EPC Contractor in 2008 by Georgia Power, acting for itself and as agent for the Vogtle Owners, and rejected in bankruptcy in July 2017, pursuant to which the EPC Contractor agreed to design, engineer, procure, construct, and test Plant Vogtle Units 3 and 4
Vogtle Owners	Georgia Power, Oglethorpe Power Corporation, MEAG, and Dalton
Vogtle Services Agreement	The June 9, 2017 services agreement between the Vogtle Owners and the EPC Contractor, as amended and restated on July 20, 2017, for the EPC Contractor to transition construction management of Plant Vogtle Units 3 and 4 to Southern Nuclear and to provide ongoing design, engineering, and procurement services to Southern Nuclear
WACOG	Weighted average cost of gas
Westinghouse	Westinghouse Electric Company LLC

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulated rates, the strategic goals for the business, customer and sales growth, economic conditions, fuel and environmental cost recovery and other rate actions, projected equity ratios, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plans, postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects, completion of announced dispositions, filings with state and federal regulatory authorities, federal and state income tax benefits, estimated sales and purchases under power sale and purchase agreements, and estimated construction plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "would," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws and regulations, and also changes in tax (including the Tax Reform Legislation) and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- the extent and timing of costs and liabilities to comply with federal and state laws, regulations, and legal requirements related to CCR, including amounts for required closure of ash ponds and ground water monitoring;
- current and future litigation or regulatory investigations, proceedings, or inquiries, including litigation and other disputes related to the Kemper County energy facility;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate, including from the development and deployment of alternative energy sources;
- variations in demand for electricity and natural gas;
- available sources and costs of natural gas and other fuels;
- the ability to complete necessary or desirable pipeline expansion or infrastructure projects, limits on pipeline capacity, and operational interruptions to natural gas distribution and transmission activities;
- transmission constraints;
- effects of inflation;
- the ability to control costs and avoid cost and schedule overruns during the development, construction, and operation of facilities, including Plant Vogtle Units 3 and 4 which includes components based on new technology that only recently began initial operation in the global nuclear industry at this scale, including changes in labor costs, availability, and productivity; challenges with management of contractors, subcontractors, or vendors; adverse weather conditions; shortages, increased costs, or inconsistent quality of equipment, materials, and labor; contractor or supplier delay; non-performance under construction, operating, or other agreements; operational readiness, including specialized operator training and required site safety programs; engineering or design problems; design and other licensing-based compliance matters, including the timely resolution of ITAAC and the related approvals by the NRC; challenges with start-up activities, including major equipment failure and system integration; and/or operational performance;
- the ability to construct facilities in accordance with the requirements of permits and licenses (including satisfaction of NRC requirements), to satisfy any environmental performance standards and the requirements of tax credits and other incentives, and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of the employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- the ability to control operating and maintenance costs;
- ongoing renewable energy partnerships and development agreements;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to ROE, equity ratios, and fuel and other cost recovery mechanisms;

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION
(continued)

- the ability to successfully operate the electric utilities' generating, transmission, and distribution facilities and Southern Company Gas' natural gas distribution and storage facilities and the successful performance of necessary corporate functions;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions;
- under certain specified circumstances, a decision by holders of more than 10% of the ownership interests of Plant Vogtle Units 3 and 4 not to proceed with construction and the ability of other Vogtle Owners to tender a portion of their ownership interests to Georgia Power following certain construction cost increases;
- in the event Georgia Power becomes obligated to provide funding to MEAG with respect to the portion of MEAG's ownership interest in Plant Vogtle Units 3 and 4 involving JEA, any inability of Georgia Power to receive repayment of such funding;
- the inherent risks involved in operating and constructing nuclear generating facilities;
- the inherent risks involved in transporting and storing natural gas;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, including the proposed disposition of Plant Mankato, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Southern Company system's business resulting from cyber intrusion or physical attack and the threat of physical attacks;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- access to capital markets and other financing sources;
- changes in Southern Company's and any of its subsidiaries' credit ratings;
- the ability of Southern Company's electric utilities to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events, or other similar occurrences;
- the direct or indirect effects on the Southern Company system's business resulting from incidents affecting the U.S. electric grid, natural gas pipeline infrastructure, or operation of generating or storage resources;
- impairments of goodwill or long-lived assets;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the registrants from time to time with the SEC.

The registrants expressly disclaim any obligation to update any forward-looking statements.

PART I

Item 1. BUSINESS

Southern Company was incorporated under the laws of Delaware on November 9, 1945. Southern Company owns all of the outstanding common stock of Alabama Power, Georgia Power, and Mississippi Power, each of which is an operating public utility company. The traditional electric operating companies supply electric service in the states of Alabama, Georgia, and Mississippi. More particular information relating to each of the traditional electric operating companies is as follows:

Alabama Power is a corporation organized under the laws of the State of Alabama on November 10, 1927, by the consolidation of a predecessor Alabama Power Company, Gulf Electric Company, and Houston Power Company. The predecessor Alabama Power Company had been in continuous existence since its incorporation in 1906.

Georgia Power was incorporated under the laws of the State of Georgia on June 26, 1930.

Mississippi Power was incorporated under the laws of the State of Mississippi on July 12, 1972 and effective December 21, 1972, by the merger into it of the predecessor Mississippi Power Company, succeeded to the business and properties of the latter company. The predecessor Mississippi Power Company was incorporated under the laws of the State of Maine on November 24, 1924.

On January 1, 2019, Southern Company completed its sale of Gulf Power to NextEra Energy for an aggregate cash purchase price of approximately $5.8 billion (less $1.3 billion of indebtedness assumed), subject to customary working capital adjustments. Gulf Power is an electric utility serving retail customers in the northwestern portion of Florida. See Note 15 to the financial statements under "Southern Company's Sale of Gulf Power" in Item 8 herein for additional information.

In addition, Southern Company owns all of the common stock of Southern Power Company, which is also an operating public utility company. The term "Southern Power" when used herein refers to Southern Power Company and its subsidiaries, while the term "Southern Power Company" when used herein refers only to the Southern Power parent company. Southern Power develops, constructs, acquires, owns, and manages power generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Power Company is a corporation organized under the laws of Delaware on January 8, 2001. On May 22, 2018, Southern Power sold a noncontrolling 33% equity interest in SP Solar, a limited partnership indirectly owning substantially all of Southern Power's solar facilities, for approximately $1.2 billion and, on December 11, 2018, Southern Power sold a noncontrolling tax equity interest in SP Wind, a holding company owning a portfolio of eight operating wind facilities, for approximately $1.2 billion. Southern Power also sold all of its equity interests in Plant Oleander and Plant Stanton Unit A (together, the Florida Plants) to NextEra Energy on December 4, 2018 for $203 million. On November 5, 2018, Southern Power entered into an agreement to sell all of its equity interests in Plant Mankato (including the 385-MW expansion currently under construction) for approximately $650 million. The transaction is subject to FERC and state commission approvals and is expected to close mid-2019. The ultimate outcome of this matter cannot be determined at this time. See "The Southern Company System – Southern Power" herein and Note 15 to the financial statements in Item 8 herein for additional information.

Southern Company acquired all of the common stock of Southern Company Gas in July 2016. Southern Company Gas is an energy services holding company whose primary business is the distribution of natural gas in four states - Illinois, Georgia, Virginia, and Tennessee - through the natural gas distribution utilities. Southern Company Gas is also involved in several other businesses that are complementary to the distribution of natural gas. Southern Company Gas was incorporated under the laws of the State of Georgia on November 27, 1995 for the primary purpose of becoming the holding company for Atlanta Gas Light, which was founded in 1856. In July 2018, Southern Company Gas completed sales of three of its natural gas distribution utilities (Elizabethtown Gas, Florida City Gas, and Elkton Gas). In June 2018, Southern Company Gas also completed the sale of Pivotal Home Solutions, which provided home equipment protection products and services. See "The Southern Company System – Southern Company Gas" herein and Note 15 to the financial statements in Item 8 herein for additional information.

Southern Company also owns all of the outstanding common stock or membership interests of SCS, Southern Linc, Southern Holdings, Southern Nuclear, PowerSecure, and other direct and indirect subsidiaries. SCS, the system service company, has contracted with Southern Company, each traditional electric operating company, Southern Power, Southern Company Gas, Southern Nuclear, SEGCO, and other subsidiaries to furnish, at direct or allocated cost and upon request, the following services: general executive and advisory, general and design engineering, operations, purchasing, accounting, finance, treasury, legal, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, cellular tower space, and other services with respect to business and operations, construction management, and power pool transactions. Southern Linc provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber optics services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and energy-related funds and companies, and for other electric and natural gas products and

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services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants and is currently managing construction of and developing Plant Vogtle Units 3 and 4, which are co-owned by Georgia Power. PowerSecure is a provider of energy solutions, including distributed energy infrastructure, energy efficiency products and services, and utility infrastructure services, to customers.

Alabama Power and Georgia Power each own 50% of the outstanding common stock of SEGCO. SEGCO is an operating public utility company that owns electric generating units with an aggregate capacity of 1,020 MWs at Plant Gaston on the Coosa River near Wilsonville, Alabama. Alabama Power and Georgia Power are each entitled to one-half of SEGCO's capacity and energy. Alabama Power acts as SEGCO's agent in the operation of SEGCO's units and furnishes fuel to SEGCO for its units. See Note 7 to the financial statements in Item 8 herein for additional information.

Segment information for Southern Company and Southern Company Gas is included in Note 16 to the financial statements in Item 8 herein.

The registrants' Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to those reports are made available on Southern Company's website, free of charge, as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC. Southern Company's internet address is www.southerncompany.com.

The Southern Company System

Traditional Electric Operating Companies

The traditional electric operating companies are vertically integrated utilities that own generation, transmission, and distribution facilities. See PROPERTIES in Item 2 herein for additional information on the traditional electric operating companies' generating facilities. Each company's transmission facilities are connected to the respective company's own generating plants and other sources of power (including certain generating plants owned by Southern Power) and are interconnected with the transmission facilities of the other traditional electric operating companies and SEGCO. For information on the State of Georgia's integrated transmission system, see "Territory Served by the Southern Company System – Traditional Electric Operating Companies and Southern Power" herein.

Agreements in effect with principal neighboring utility systems provide for capacity and energy transactions that may be entered into from time to time for reasons related to reliability or economics. Additionally, the traditional electric operating companies have entered into various reliability agreements with certain neighboring utilities, each of which provides for the establishment and periodic review of principles and procedures for planning and operation of generation and transmission facilities, maintenance schedules, load retention programs, emergency operations, and other matters affecting the reliability of bulk power supply. The traditional electric operating companies have joined with other utilities in the Southeast to form the SERC to augment further the reliability and adequacy of bulk power supply. Through the SERC, the traditional electric operating companies are represented on the North American Electric Reliability Council.

The utility assets of the traditional electric operating companies and certain utility assets of Southern Power Company are operated as a single integrated electric system, or power pool, pursuant to the IIC. Activities under the IIC are administered by SCS, which acts as agent for the traditional electric operating companies and Southern Power Company. The fundamental purpose of the power pool is to provide for the coordinated operation of the electric facilities in an effort to achieve the maximum possible economies consistent with the highest practicable reliability of service. Subject to service requirements and other operating limitations, system resources are committed and controlled through the application of centralized economic dispatch. Under the IIC, each traditional electric operating company and Southern Power Company retains its lowest cost energy resources for the benefit of its own customers and delivers any excess energy to the power pool for use in serving customers of other traditional electric operating companies or Southern Power Company or for sale by the power pool to third parties. The IIC provides for the recovery of specified costs associated with the affiliated operations thereunder, as well as the proportionate sharing of costs and revenues resulting from power pool transactions with third parties. In connection with the sale of Gulf Power, an appendix was added to the IIC setting forth terms and conditions governing Gulf Power's continued participation in the IIC for a defined transition period that, subject to certain potential adjustments, is scheduled to end on January 1, 2024.

Southern Power and Southern Linc have secured from the traditional electric operating companies certain services which are furnished in compliance with FERC regulations.

Alabama Power and Georgia Power each have agreements with Southern Nuclear to operate the Southern Company system's existing nuclear plants, Plants Farley, Hatch, and Vogtle. In addition, Georgia Power has an agreement with Southern Nuclear to develop, license, construct, and operate Plant Vogtle Units 3 and 4. See "Regulation – Nuclear Regulation" herein for additional information.

Southern Power

Southern Power develops, constructs, acquires, owns, and manages power generation assets, including renewable energy facilities, and sells electricity at market-based rates (under authority from the FERC) in the wholesale market. Southern Power continually seeks opportunities to execute its strategy to create value through various transactions including acquisitions, dispositions, and sales of partnership interests, development and construction of new generating facilities, and entry into PPAs primarily with investor-owned utilities, IPPs, municipalities, electric cooperatives, and other load-serving entities, as well as commercial and industrial customers. Southern Power's business activities are not subject to traditional state regulation like the traditional electric operating companies, but the majority of its business activities are subject to regulation by the FERC. Southern Power has attempted to insulate itself from significant fuel supply, fuel transportation, and electric transmission risks by generally making such risks the responsibility of the counterparties to its PPAs. However, Southern Power's future earnings will depend on the parameters of the wholesale market and the efficient operation of its wholesale generating assets, as well as Southern Power's ability to execute its growth strategy and to develop and construct generating facilities. For additional information on Southern Power's business activities, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Business Activities" of Southern Power in Item 7 herein.

Southern Power Company directly owns and manages generation assets primarily in the Southeast, which are included in the power pool, and has various subsidiaries, which were created to own and operate natural gas and renewable generation facilities either wholly or in partnership with various third parties. At December 31, 2018, Southern Power's generation fleet, which is owned in part with its various partners, totaled 11,888 MWs of nameplate capacity in commercial operation (including 4,508 MWs of nameplate capacity owned by its subsidiaries and including Plant Mankato, which is classified as held for sale in the financial statements). In addition, Southern Power Company has other subsidiaries that are pursuing additional natural gas generation and other renewable generation development opportunities. The generation assets of Southern Power Company's subsidiaries are not included in the power pool.

On May 22, 2018, Southern Power sold a noncontrolling 33% equity interest in SP Solar, a limited partnership indirectly owning substantially all of Southern Power's solar facilities. On December 11, 2018, Southern Power sold a noncontrolling tax equity interest in SP Wind, a holding company which owns a portfolio of eight operating wind farms.

In addition, on December 4, 2018, Southern Power sold all of its equity interests in the Florida Plants and, in November 2018, entered into an agreement to sell Plant Mankato. The completion of the disposition of Plant Mankato is subject to the expansion unit reaching commercial operation as well as various other customary conditions to closing, including FERC and state commission approvals, and is expected to close mid-2019. The ultimate outcome of this matter cannot be determined at this time.

A majority of Southern Power's partnerships in renewable facilities allow for the sharing of cash distributions and tax benefits at differing percentages, with Southern Power being the controlling member and thus consolidating the assets and operations of the partnerships. At December 31, 2018, Southern Power has three tax-equity partnership arrangements where the tax-equity investors receive substantially all of the tax benefits, including ITCs and PTCs. In addition, Southern Power holds controlling interests in eight partnerships in solar facilities through SP Solar. For seven of these solar partnerships, Southern Power and its new 33% partner, Global Atlantic, are entitled to 51% of all cash distributions and the respective partner that holds the Class B membership interests is entitled to 49% of all cash distributions. For the Desert Stateline partnership, Southern Power and Global Atlantic are entitled to 66% of all cash distributions and the Class B member is entitled to 34% of all cash distributions. In addition, Southern Power and Global Atlantic are entitled to substantially all of the federal tax benefits with respect to these eight partnership entities. Finally, for the Roserock partnership, Southern Power is entitled to 51% of all cash distributions and substantially all of the federal tax benefits, with the Class B member entitled to 49% of all cash distributions.

See PROPERTIES in Item 2 herein and Note 15 to the financial statements under "Southern Power" in Item 8 herein for additional information regarding Southern Power's acquisitions, dispositions, construction, and development projects.

Southern Power calculates an investment coverage ratio for its generating assets based on the ratio of investment under contract to total investment using the respective generation facilities' net book value (or expected in-service value for facilities under construction or being acquired) as the investment amount. With the inclusion of investments associated with the wind and natural gas facilities currently under construction, as well as other capacity and energy contracts, Southern Power has an average investment coverage ratio, at December 31, 2018, of 93% through 2023 and 91% through 2028, with an average remaining contract duration of approximately 14 years (including Plant Mankato, which is classified as held for sale in the financial statements).

Southern Power's natural gas and biomass sales are primarily through long-term PPAs that consist of two types of agreements. The first type, referred to as a unit or block sale, is a customer purchase from a dedicated plant unit where all or a portion of the generation from that unit is reserved for that customer. Southern Power typically has the ability to serve the unit or block sale customer from an alternate resource. The second type, referred to as requirements service, provides that Southern Power serves the customer's capacity and energy requirements from a combination of the customer's own generating units and from Southern Power resources not dedicated to serve unit or block sales. Southern Power has rights to purchase power provided by the requirements customers' resources when economically viable. Capacity charges that form part of the PPA payments are designed to recover fixed and variable operations and maintenance costs based on dollars-per-kilowatt year and to provide a return on investment.

Southern Power's electricity sales from solar and wind generating facilities are predominantly through long-term PPAs; however, these solar and wind PPAs do not have a capacity charge and customers either purchase the energy output of a dedicated renewable facility through an energy charge or provide Southern Power a certain fixed price for the electricity sold to the grid. As a result, Southern Power's ability to recover fixed and variable operations and maintenance expenses is dependent upon the level of energy generated from these facilities, which can be impacted by weather conditions, equipment performance, transmission constraints, and other factors.

The following tables set forth Southern Power's PPAs as of December 31, 2018:

Block Sales PPAs

Facility/Source	Counterparty	MWs[1]	Contract Term
Addison Units 1 and 3	Georgia Power	297	through May 2030
Addison Unit 2	MEAG Power	149	through April 2029
Addison Unit 4	Georgia Energy Cooperative	146	through May 2030
Cleveland County Unit 1	North Carolina EMC (NCEMC)	90-180	through Dec. 2036
Cleveland County Unit 2	NCEMC	183	through Dec. 2036
Cleveland County Unit 3	North Carolina Municipal Power Agency 1	183	through Dec. 2031
Dahlberg Units 1, 3, and 5	Cobb EMC	224	through Dec. 2027
Dahlberg Units 2, 6, 8, and 10	Georgia Power	298	through May 2025
Dahlberg Unit 4	Georgia Power	74	through May 2030
Franklin Unit 1	Duke Energy Florida	434	through May 2021
Franklin Unit 2	Morgan Stanley Capital Group	250	through Dec. 2025
Franklin Unit 2	Jackson EMC	60-65	through Dec. 2035
Franklin Unit 2	GreyStone Power Corporation	35	through Dec. 2035
Franklin Unit 2	Cobb EMC	100	through Dec. 2027
Franklin Unit 3	Morgan Stanley Capital Group	200-300	through Dec. 2033
Franklin Unit 3	Dalton	70	through Dec. 2027
Franklin Unit 3	Dalton	16	through Dec. 2019
Harris Unit 1	Georgia Power	640	through May 2030
Harris Unit 2	Georgia Power	657	through May 2019
Harris Unit 2	AMEA[2]	25	through Dec. 2025
Mankato[3]	Northern States Power Company	375	through July 2026
Mankato[3]	Northern States Power Company	345	June 2019 – May 2039[4]
Nacogdoches	City of Austin, Texas	100	through May 2032
NCEMC PPA[5]	EnergyUnited	100	through Dec. 2021
Rowan CT Unit 1	North Carolina Municipal Power Agency 1	150	through Dec. 2030
Rowan CT Units 2 and 3	EnergyUnited	100-175	Jan. 2022 – Dec. 2025
Rowan CT Unit 3	EnergyUnited	113	through Dec. 2023
Rowan CC Unit 4	EnergyUnited	23-328	through Dec. 2025

Block Sales PPAs (continued)

Facility/Source	Counterparty	MWs[1]	Contract Term
Rowan CC Unit 4	Duke Energy Progress, LLC	150	through Dec. 2019
Rowan CC Unit 4	Macquarie	150-250	Jan. 2019 – Nov. 2020
Wansley Unit 6	Century Aluminum	158	Jan. 2019 – Dec. 2020
Wansley Unit 7	JEA[6]	200	through Dec. 2019

(1) The MWs and related facility units may change due to unit rating changes or assignment of units to contracts.
(2) AMEA will also be served by Plant Franklin Unit 1 through December 2019.
(3) On November 5, 2018, Southern Power entered into an agreement with Northern States Power to sell all of its equity interests in Plant Mankato (including the 385-MW expansion currently under construction). The ultimate outcome of this matter cannot be determined at this time. See Note 15 to the financial statements under "Southern Power – Sales of Natural Gas Plants" in Item 8 herein for additional information.
(4) Subject to commercial operation of the 385-MW expansion project.
(5) Represents sale of power purchased from NCEMC under a PPA.
(6) JEA will also be served by Plant Wansley Unit 6 during 2019.

Requirements Services PPAs

Counterparty	MWs[1]	Contract Term
Nine Georgia EMCs	294-376	through Dec. 2024
Sawnee EMC	267-639	through Dec. 2027
Cobb EMC	0-145	through Dec. 2027
Flint EMC	135-194	through Dec. 2024
Dalton	53-92	through Dec. 2027
EnergyUnited	78-159	through Dec. 2025
City of Blountstown, Florida	10	through April 2022

(1) Represents forecasted incremental capacity needs over the contract term.

Solar/Wind PPAs

Facility	Counterparty	MWs[1]	Contract Term
Solar[2]			
Adobe	Southern California Edison Company	20	through June 2034
Apex	Nevada Power Company	20	through Dec. 2037
Boulder 1	Nevada Power Company	100	through Dec. 2036
Butler	Georgia Power	100	through Dec. 2046
Butler Solar Farm	Georgia Power	20	through Feb. 2036
Calipatria	San Diego Gas & Electric Company	20	through Feb. 2036
Campo Verde	San Diego Gas & Electric Company	139	through Oct. 2033
Cimarron	Tri-State Generation and Transmission Association, Inc.	30	through Dec. 2035
Decatur County	Georgia Power	19	through Dec. 2035
Decatur Parkway	Georgia Power	80	through Dec. 2040
Desert Stateline	Southern California Edison Company	300	through Sept. 2036
East Pecos	Austin Energy	119	through April 2032
Garland A	Southern California Edison Company	20	through Sept. 2036
Garland	Southern California Edison Company	180	through Oct. 2031
Gaskell West 1	Southern California Edison Company	20	through March 2038
Granville	Duke Energy Progress, LLC	3	through Oct. 2032
Henrietta	Pacific Gas & Electric Company[3]	100	through Sept. 2036

Imperial Valley	San Diego Gas & Electric Company	150	through Nov. 2039

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Solar/Wind PPAs (continued)

Facility	Counterparty	MWs[(1)]	Contract Term
Lamesa	City of Garland, Texas	102	through April 2032
Lost Hills Blackwell	99% to Pacific Gas & Electric Company[(3)] and 1% to City of Roseville, California	32	through Dec. 2043
Macho Springs	El Paso Electric Company	50	through May 2034
Morelos	Pacific Gas & Electric Company[(3)]	15	through Feb. 2036
North Star	Pacific Gas & Electric Company[(3)]	60	through June 2035
Pawpaw	Georgia Power	30	through March 2046
Roserock	Austin Energy	157	through Nov. 2036
Rutherford	Duke Energy Carolinas, LLC	75	through Dec. 2031
Sandhills	Cobb EMC	111	through Oct. 2041
Sandhills	Flint EMC	15	through Oct. 2041
Sandhills	Sawnee EMC	15	through Oct. 2041
Sandhills	Middle Georgia and Irwin EMC	2	through Oct. 2041
Spectrum	Nevada Power Company	30	through Dec. 2038
Tranquillity	Shell Energy North America (US), LP	204	through Nov. 2019
Tranquillity	Southern California Edison Company	204	Dec. 2019 – Nov. 2034
Wind[(4)]			
Bethel	Google Inc.	225	through Jan. 2029
Cactus Flats	General Mills, Inc.	98	through July 2033
Cactus Flats	General Motors Company	50	through July 2030
Grant Plains	Oklahoma Municipal Power Authority	41	Jan. 2020 – Dec. 2039
Grant Plains	Steelcase Inc.	25	through Dec. 2028
Grant Plains	Allianz Risk Transfer (Bermuda) Ltd.	81-122	through March 2027
Grant Wind	East Texas Electric Cooperative	50	through April 2036
Grant Wind	Northeast Texas Electric Cooperative	50	through April 2036
Grant Wind	Western Farmers Electric Cooperative	50	through April 2036
Kay Wind	Westar Energy Inc.	200	through Dec. 2035
Kay Wind	Grand River Dam Authority	99	through Dec. 2035
Passadumkeag	Western Massachusetts Electric Company	40	through June 2031
Reading[(5)]	Royal Caribbean Cruises Ltd.	200	April 2020 – March 2032
Salt Fork Wind	City of Garland, Texas	150	through Nov. 2030
Salt Fork Wind	Salesforce.com, Inc.	24	through Nov. 2028
Tyler Bluff Wind	The Proctor & Gamble Company	96	through Dec. 2028
Wake Wind	Equinix Enterprises, Inc.	100	through Oct. 2028
Wake Wind	Owens Corning	125	through Oct. 2028
Wildhorse[(5)]	Arkansas Electric Cooperative Corporation	100	Oct. 2019 – Sept. 2039

(1) MWs shown are for 100% of the PPA, which is based on demonstrated capacity of the facility.

(2) In May 2018, Southern Power sold a noncontrolling 33% equity interest in SP Solar (a limited partnership indirectly owning all of Southern Power's solar facilities, except the Roserock and Gaskell West facilities). SP Solar is the 51% majority owner of Boulder 1, Garland, Henrietta, Imperial Valley, Lost Hills Blackwell, North Star, and Tranquillity; the 66% majority owner of Desert Stateline; and the sole owner of the remaining SP Solar facilities. Southern Power is the 51% majority owner of Roserock and also the controlling partner in a tax equity partnership owning Gaskell West. All of these entities are consolidated subsidiaries of Southern Power.

(3) See Note 1 to the financial statements under "Revenues – Concentration of Revenue" in Item 8 herein for additional information on Pacific Gas & Electric Company's bankruptcy filing.

(4) In December 2018, Southern Power sold a noncontrolling tax equity interest in SP Wind (which owns all of Southern Power's wind facilities, except Cactus Flats and the two wind projects under construction, Reading and Wildhorse). SP Wind is the 90.1% majority owner of Wake Wind

and owns 100% of the remaining SP Wind facilities. Southern Power owns 100% of Reading and Wildhorse and is the controlling partner in a tax equity partnership owning Cactus Flats. All of these entities are consolidated subsidiaries of Southern Power.

(5) Subject to commercial operation.

For the year ended December 31, 2018, approximately 9.8% of Southern Power's revenues were derived from Georgia Power. Southern Power actively pursues replacement PPAs prior to the expiration of its current PPAs and anticipates that the revenues attributable to one customer may be replaced by revenues from a new customer; however, the expiration of any of Southern Power's current PPAs without the successful remarketing of a replacement PPA could have a material negative impact on Southern Power's earnings but is not expected to have a material impact on Southern Company's earnings.

Southern Company Gas

Southern Company Gas is an energy services holding company whose primary business is the distribution of natural gas through the natural gas distribution utilities. Southern Company Gas is also involved in several other businesses that are complementary to the distribution of natural gas, including gas pipeline investments, wholesale gas services, and gas marketing services. During the fourth quarter 2018, Southern Company Gas changed its reportable segments to further align with the way its new Chief Operating Decision Maker reviews operating results and has reclassified prior years' data to conform to the new reportable segment presentation. This change resulted in a new reportable segment, gas pipeline investments, which was formerly included in gas midstream operations. Gas pipeline investments consists primarily of joint ventures in natural gas pipeline investments including a 50% interest in SNG, two significant pipeline construction projects, and a 50% joint ownership interest in the Dalton Pipeline. Gas distribution operations, wholesale gas services, and gas marketing services continue to remain as separate reportable segments and reflect the impact of the Southern Company Gas Dispositions. The all other non-reportable segment includes segments below the quantitative threshold for separate disclosure, including the storage and fuels operations that were formerly included in gas midstream operations, and other subsidiaries that fall below the quantitative threshold for separate disclosure.

Gas distribution operations, the largest segment of Southern Company Gas' business, operates, constructs, and maintains approximately 75,200 miles of natural gas pipelines and 14 storage facilities, with total capacity of 158 Bcf, to provide natural gas to residential, commercial, and industrial customers. Gas distribution operations serves approximately 4.2 million customers across four states.

On July 1, 2018, a Southern Company Gas subsidiary, Pivotal Utility Holdings, completed the sales of the assets of two of its natural gas distribution utilities, Elizabethtown Gas and Elkton Gas, to South Jersey Industries, Inc. On July 29, 2018, Southern Company Gas and its wholly-owned direct subsidiary, NUI Corporation, completed the stock sale of Pivotal Utility Holdings, which then primarily consisted of Florida City Gas, to NextEra Energy. The transactions raised approximately $2.3 billion in proceeds. See Note 15 to the financial statements under "Southern Company Gas" in Item 8 herein for additional information.

Gas pipeline investments includes joint ventures in natural gas pipeline investments that enable the provision of diverse sources of natural gas supplies to the customers of Southern Company Gas. SNG, the largest natural gas pipeline investment, is the owner of a 7,000-mile pipeline connecting natural gas supply basins in Texas, Louisiana, Mississippi, and Alabama to markets in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina, and Tennessee.

Wholesale gas services consists of Sequent and engages in natural gas storage and gas pipeline arbitrage and provides natural gas asset management and related logistical services to most of the natural gas distribution utilities as well as non-affiliate companies.

Gas marketing services is comprised of SouthStar and provides natural gas commodity and related services to customers in competitive markets or markets that provide for customer choice. SouthStar, serving approximately 697,000 natural gas commodity customers, markets gas to residential, commercial, and industrial customers and offers energy-related products that provide natural gas price stability and utility bill management.

On June 4, 2018, Southern Company Gas completed the stock sale of Pivotal Home Solutions to American Water Enterprises LLC for $365 million. See Note 15 to the financial statements under "Southern Company Gas" in Item 8 herein for additional information.

Other Businesses

PowerSecure, which was acquired by Southern Company in 2016, provides energy solutions, including distributed energy infrastructure, energy efficiency products and services, and utility infrastructure services, to customers.

Southern Holdings is an intermediate holding subsidiary, primarily for Southern Company's investments in leveraged leases and energy-related funds and companies, and also for other electric and natural gas products and services.

Southern Linc provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public. Southern Linc delivers multiple wireless communication options including push to talk, cellular service, text messaging, wireless internet access, and wireless data. Its system covers approximately 127,000 square miles in the Southeast. Southern Linc also provides fiber optics services within the Southeast through its subsidiary, Southern Telecom, Inc.

These efforts to invest in and develop new business opportunities may offer potential returns exceeding those of rate-regulated operations. However, these activities often involve a higher degree of risk.

Construction Programs

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. For estimated construction and environmental expenditures for the periods 2019 through 2023, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of each registrant in Item 7 herein. The Southern Company system's construction program consists of capital investment and capital expenditures to comply with environmental laws and regulations. In 2019, the construction program is expected to be apportioned approximately as follows:

	Southern Company system[(a)(b)]	Alabama Power[(a)]	Georgia Power[(a)]	Mississippi Power
		(in billions)		
New generation	$ 1.6	$ —	$ 1.6	$ —
Environmental compliance[(c)]	0.5	0.2	0.2	—
Generation maintenance	0.9	0.4	0.4	0.1
Transmission	1.0	0.3	0.6	—
Distribution	1.1	0.5	0.5	0.1
Nuclear fuel	0.2	0.1	0.1	—
General plant	0.5	0.2	0.2	—
	5.8	1.8	3.7	0.2
Southern Power[(d)]	0.3			
Southern Company Gas[(e)]	1.6			
Other subsidiaries	0.3			
Total[(a)]	$ 8.0	$ 1.8	$ 3.7	$ 0.2

(a) Totals may not add due to rounding.

(b) Includes the Subsidiary Registrants, as well as the other subsidiaries. See "Other Businesses" herein for additional information.

(c) Reflects cost estimates for environmental regulations. These estimated expenditures do not include any potential compliance costs associated with pending regulation of CO_2 emissions from fossil-fuel-fired electric generating units or costs associated with ash pond closure and groundwater monitoring under the CCR Rule and the related state rules. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations" and FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company and each traditional electric operating company in Item 7 herein for additional information.

(d) Excludes up to approximately $0.5 billion for planned expenditures for plant acquisitions and placeholder growth, which may vary materially due to market opportunities and Southern Power's ability to execute its growth strategy.

(e) Includes costs for ongoing capital projects associated with infrastructure improvement programs for certain natural gas distribution utilities that have been previously approved by their applicable state regulatory agencies. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Infrastructure Replacement Programs and Capital Projects" of Southern Company Gas in Item 7 herein for additional information.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental laws and regulations; the outcome of any legal challenges to environmental rules; changes in electric generating plants, including unit retirements and replacements and adding or changing fuel sources at existing electric generating units, to meet regulatory requirements; changes in FERC rules and regulations; state regulatory agency approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can

be no assurance that costs related to capital expenditures will be fully recovered. Additionally, planned expenditures for plant acquisitions may vary due to market opportunities and Southern Power's ability to execute its growth strategy.

The construction program also includes Plant Vogtle Units 3 and 4, which includes components based on new technology that only recently began initial operation in the global nuclear industry at this scale and which may be subject to additional revised cost estimates during construction. The ability to control costs and avoid cost and schedule overruns during the development, construction, and operation of new facilities is subject to a number of factors, including, but not limited to, changes in labor costs, availability, and productivity; challenges with management of contractors, subcontractors, or vendors; adverse weather conditions; shortages, increased costs, or inconsistent quality of equipment, materials, and labor; contractor or supplier delay; non-performance under construction, operating, or other agreements; operational readiness, including specialized operator training and required site safety programs; engineering or design problems; design and other licensing-based compliance matters, including the timely resolution of ITAAC and the related approvals by the NRC; challenges with start-up activities, including major equipment failure and system integration; and/or operational performance. See Note 2 to the financial statements under "Georgia Power – Nuclear Construction" in Item 8 herein for additional information regarding Georgia Power's construction of Plant Vogtle Units 3 and 4.

Also see "Regulation – Environmental Laws and Regulations" herein for additional information with respect to certain existing and proposed environmental requirements and PROPERTIES – "Electric – Jointly-Owned Facilities" and – "Natural Gas – Jointly-Owned Facilities" in Item 2 herein and Note 5 to the financial statements under "Joint Ownership Agreements" in Item 8 herein for additional information concerning Alabama Power's, Georgia Power's, and Southern Power's joint ownership of certain generating units and related facilities with certain non-affiliated utilities and Southern Company Gas' joint ownership of a pipeline facility.

Financing Programs

See each of the registrant's MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY in Item 7 herein and Note 8 to the financial statements in Item 8 herein for information concerning financing programs.

Fuel Supply

Electric

The traditional electric operating companies' and SEGCO's supply of electricity is primarily fueled by natural gas and coal. Southern Power's supply of electricity is primarily fueled by natural gas. See MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Electricity Business – Fuel and Purchased Power Expenses" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Fuel and Purchased Power Expenses" of each traditional electric operating company in Item 7 herein for information regarding the electricity generated and the average cost of fuel in cents per net KWH generated for the years 2016 through 2018.

The traditional electric operating companies have agreements in place from which they expect to receive substantially all of their 2019 coal burn requirements. These agreements have terms ranging between one and four years. In 2018, the weighted average sulfur content of all coal burned by the traditional electric operating companies was 1.06%. This sulfur level, along with banked SO_2 allowances, allowed the traditional electric operating companies to remain within limits set by Phase I of the Cross-State Air Pollution Rule (CSAPR) under the Clean Air Act. In 2018, the Southern Company system did not purchase any SO_2 allowances, annual NOx emission allowances, or seasonal NOx emission allowances from the market. As any additional environmental regulations are proposed that impact the utilization of coal, the traditional electric operating companies' fuel mix will be monitored to help ensure that the traditional electric operating companies remain in compliance with applicable laws and regulations. Additionally, Southern Company and the traditional electric operating companies will continue to evaluate the need to purchase additional emissions allowances, the timing of capital expenditures for emissions control equipment, and potential unit retirements and replacements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company, each traditional electric operating company, and Southern Power in Item 7 herein for additional information on environmental matters.

SCS, acting on behalf of the traditional electric operating companies and Southern Power Company, has agreements in place for the natural gas burn requirements of the Southern Company system. For 2019, SCS has contracted for 557 Bcf of natural gas supply under agreements with remaining terms up to 15 years. In addition to natural gas supply, SCS has contracts in place for both firm natural gas transportation and storage. Management believes these contracts provide sufficient natural gas supplies, transportation, and storage to ensure normal operations of the Southern Company system's natural gas generating units.

Alabama Power and Georgia Power have multiple contracts covering their nuclear fuel needs for uranium, conversion services, enrichment services, and fuel fabrication. The uranium, conversion services, and fuel fabrication contracts have remaining terms ranging from one to 17 years. The remaining term lengths for the enrichment services contracts range from five to 10 years. Management believes suppliers have sufficient nuclear fuel production capability to permit the normal operation of the Southern Company system's nuclear generating units.

Changes in fuel prices to the traditional electric operating companies are generally reflected in fuel adjustment clauses contained in rate schedules. See "Rate Matters – Rate Structure and Cost Recovery Plans" herein for additional information. Southern Power's natural gas and biomass PPAs generally provide that the counterparty is responsible for substantially all of the cost of fuel.

Alabama Power and Georgia Power have contracts with the United States, acting through the DOE, that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent fuel in 1998, as required by the contracts, and Alabama Power and Georgia Power have pursued and are pursuing legal remedies against the government for breach of contract. See Note 3 to the financial statements under "Nuclear Fuel Disposal Costs" in Item 8 herein for additional information.

Natural Gas

Advances in natural gas drilling in shale producing regions of the United States have resulted in historically high supplies of natural gas and relatively low prices for natural gas. Procurement plans for natural gas supply and transportation to serve regulated utility customers are reviewed and approved by the regulatory agencies in the states where Southern Company Gas operates. Southern Company Gas purchases natural gas supplies in the open market by contracting with producers and marketers and, for the natural gas distribution utilities except Nicor Gas, from its wholly-owned subsidiary, Sequent, under asset management agreements approved by the applicable state regulatory agency. Southern Company Gas also contracts for transportation and storage services from interstate pipelines that are regulated by the FERC. When firm pipeline services are temporarily not needed, Southern Company Gas may release the services in the secondary market under FERC-approved capacity release provisions or utilize asset management arrangements, thereby reducing the net cost of natural gas charged to customers for most of the natural gas distribution utilities. Peak-use requirements are met through utilization of company-owned storage facilities, pipeline transportation capacity, purchased storage services, peaking facilities, and other supply sources, arranged by either transportation customers or Southern Company Gas.

Territory Served by the Southern Company System

Traditional Electric Operating Companies and Southern Power

As of January 1, 2019, the territory in which the traditional electric operating companies provide retail electric service comprises most of the states of Alabama and Georgia, together with southeastern Mississippi. See Note 15 to the financial statements under "Southern Company's Sale of Gulf Power" in Item 8 herein for information on the sale of Gulf Power. In this territory there are non-affiliated electric distribution systems that obtain some or all of their power requirements either directly or indirectly from the traditional electric operating companies. As of January 1, 2019, the territory had an area of approximately 114,000 square miles and an estimated population of approximately 16 million. Southern Power sells electricity at market-based rates in the wholesale market, primarily to investor-owned utilities, IPPs, municipalities, and other load-serving entities, as well as commercial and industrial customers.

Alabama Power is engaged, within the State of Alabama, in the generation, transmission, distribution, and purchase of electricity and the sale of electric service, at retail in approximately 400 cities and towns (including Anniston, Birmingham, Gadsden, Mobile, Montgomery, and Tuscaloosa), as well as in rural areas, and at wholesale to 11 municipally-owned electric distribution systems, all of which are served indirectly through sales to AMEA, and two rural distributing cooperative associations. The sales contract with AMEA is scheduled to expire on December 31, 2025. Alabama Power owns coal reserves near its Plant Gorgas and uses the output of coal from the reserves in its generating plants. Alabama Power also sells, and cooperates with dealers in promoting the sale of, electric appliances and products and markets and sells outdoor lighting services.

Georgia Power is engaged in the generation, transmission, distribution, and purchase of electricity and the sale of electric service within the State of Georgia, at retail in over 600 communities (including Athens, Atlanta, Augusta, Columbus, Macon, Rome, and Savannah), as well as in rural areas, and at wholesale to OPC, MEAG Power, Dalton, various EMCs, and non-affiliated utilities. Georgia Power also markets and sells outdoor lighting services.

Mississippi Power is engaged in the generation, transmission, distribution, and purchase of electricity and the sale of electric service within 23 counties in southeastern Mississippi, at retail in 123 communities (including Biloxi, Gulfport, Hattiesburg, Laurel, Meridian, and Pascagoula), as well as in rural areas, and at wholesale to one municipality, six rural electric distribution cooperative associations, and one generating and transmitting cooperative.

For information relating to KWH sales by customer classification for the traditional electric operating companies, see MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATIONS of Southern Company and each traditional electric operating company in Item 7 herein. For information relating to the number of retail customers served by customer classification for the traditional electric operating companies, see SELECTED FINANCIAL DATA of Southern Company and each traditional electric operating company in Item 6 herein. Also, for information relating to the sources of revenues for Southern Company, each traditional electric operating company, and Southern Power, reference is made to Item 7 herein.

The RUS has authority to make loans to cooperative associations or corporations to enable them to provide electric service to customers in rural sections of the country. As of January 1, 2019, there were approximately 58 electric cooperative distribution systems operating in the territory in which the traditional electric operating companies provide electric service at retail or wholesale.

One of these organizations, PowerSouth, is a generating and transmitting cooperative selling power to several distributing cooperatives, municipal systems, and other customers in south Alabama. As of December 31, 2018, PowerSouth owned generating units with approximately 2,100 MWs of nameplate capacity, including an undivided 8.16% ownership interest in Alabama Power's Plant Miller Units 1 and 2. PowerSouth's facilities were financed with RUS loans secured by long-term contracts requiring distributing cooperatives to take their requirements from PowerSouth to the extent such energy is available. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein and Note 5 to the financial statements under "Joint Ownership Agreements" in Item 8 herein for details of Alabama Power's joint-ownership with PowerSouth of a portion of Plant Miller. Alabama Power has a system supply agreement with PowerSouth to provide 200 MWs of capacity service through December 31, 2030 with an option to extend and renegotiate in the event Alabama Power builds new generation or contracts for new capacity.

Alabama Power has entered into a separate agreement with PowerSouth involving interconnection between their systems. The delivery of capacity and energy from PowerSouth to certain distributing cooperatives in the service territory of Alabama Power is governed by the Southern Company/PowerSouth Network Transmission Service Agreement. The rates for this service to PowerSouth are on file with the FERC.

OPC is an EMC owned by its 38 retail electric distribution cooperatives, which provide retail electric service to customers in Georgia. OPC provides wholesale electric power to its members through its generation assets, some of which are jointly owned with Georgia Power, and power purchased from other suppliers. OPC and the 38 retail electric distribution cooperatives are members of Georgia Transmission Corporation, an EMC (GTC), which provides transmission services to its members and third parties. See PROPERTIES – "Electric – Jointly-Owned Facilities" in Item 2 herein and Note 5 to the financial statements under "Joint Ownership Agreements" in Item 8 herein for additional information regarding Georgia Power's jointly-owned facilities.

Mississippi Power has an interchange agreement with Cooperative Energy, a generating and transmitting cooperative, pursuant to which various services are provided.

As of January 1, 2019, there were approximately 71 municipally-owned electric distribution systems operating in the territory in which the traditional electric operating companies provide electric service at retail or wholesale.

As of December 31, 2018, 48 municipally-owned electric distribution systems and one county-owned system received their requirements through MEAG Power, which was established by a Georgia state statute in 1975. MEAG Power serves these requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and purchases from other resources. MEAG Power also has a pseudo scheduling and services agreement with Georgia Power. Dalton serves its requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and through purchases from Southern Power through a service agreement. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein and Note 5 to the financial statements under "Joint Ownership Agreements" in Item 8 herein for additional information.

Georgia Power has entered into substantially similar agreements with GTC, MEAG Power, and Dalton providing for the establishment of an integrated transmission system to carry the power and energy of all parties. The agreements require an investment by each party in the integrated transmission system in proportion to its respective share of the aggregate system load. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Southern Power assumed or entered into PPAs with Georgia Power, investor-owned utilities, IPPs, municipalities, electric cooperatives, and other load-serving entities, as well as commercial and industrial customers. See "The Southern Company System – Southern Power" above and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" of Southern Power in Item 7 herein for additional information concerning Southern Power's PPAs.

SCS, acting on behalf of the traditional electric operating companies, also has a contract with SEPA providing for the use of the traditional electric operating companies' facilities at government expense to deliver to certain cooperatives and municipalities, entitled by federal statute to preference in the purchase of power from SEPA, quantities of power equivalent to the amounts of power allocated to them by SEPA from certain U.S. government hydroelectric projects.

Southern Company Gas

Southern Company Gas is engaged in the distribution of natural gas in four states through the natural gas distribution utilities. The natural gas distribution utilities construct, manage, and maintain intrastate natural gas pipelines and distribution facilities. Details of the natural gas distribution utilities at December 31, 2018 are as follows:

Utility	State	Number of customers	Approximate miles of pipe
		(in thousands)	
Nicor Gas	Illinois	2,237	34,285
Atlanta Gas Light	Georgia	1,643	33,610
Virginia Natural Gas	Virginia	301	5,650
Chattanooga Gas	Tennessee	67	1,655
Total		4,248	75,200

For information relating to the sources of revenue for Southern Company Gas, see MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATIONS and – FUTURE EARNINGS POTENTIAL of Southern Company Gas in Item 7 herein.

Competition

Electric

The electric utility industry in the U.S. is continuing to evolve as a result of regulatory and competitive factors. Among the early primary agents of change was the Energy Policy Act of 1992, which allowed IPPs to access a utility's transmission network in order to sell electricity to other utilities.

The competition for retail energy sales among competing suppliers of energy is influenced by various factors, including price, availability, technological advancements, service, and reliability. These factors are, in turn, affected by, among other influences, regulatory, political, and environmental considerations, taxation, and supply.

The retail service rights of all electric suppliers in the State of Georgia are regulated by the Territorial Electric Service Act of 1973. Pursuant to the provisions of this Act, all areas within existing municipal limits were assigned to the primary electric supplier therein. Areas outside of such municipal limits were either to be assigned or to be declared open for customer choice of supplier by action of the Georgia PSC pursuant to standards set forth in this Act. Consistent with such standards, the Georgia PSC has assigned substantially all of the land area in the state to a supplier. Notwithstanding such assignments, this Act provides that any new customer locating outside of 1973 municipal limits and having a connected load of at least 900 KWs may exercise a one-time choice for the life of the premises to receive electric service from the supplier of its choice.

Pursuant to the 1956 Utility Act, the Mississippi PSC issued "Grandfather Certificates" of public convenience and necessity to Mississippi Power and to six distribution rural cooperatives operating in southeastern Mississippi, then served in whole or in part by Mississippi Power, authorizing them to distribute electricity in certain specified geographically described areas of the state. The six cooperatives serve approximately 325,000 retail customers in a certificated area of approximately 10,300 square miles. In areas included in a "Grandfather Certificate," the utility holding such certificate may extend or maintain its electric system subject to certain regulatory approvals; extensions of facilities by such utility, or extensions of facilities into that area by other utilities, may not be made except upon a showing of, and a grant of a certificate of, public convenience and necessity. Areas included in a CPCN that are subsequently annexed to municipalities may continue to be served by the holder of the CPCN, irrespective of whether it has a franchise in the annexing municipality. On the other hand, the holder of the municipal franchise may not extend service into such newly annexed area without authorization by the Mississippi PSC.

Generally, the traditional electric operating companies have experienced, and expect to continue to experience, competition in their respective retail service territories in varying degrees from the development and deployment of alternative energy sources such as self-generation (as described below) and distributed generation technologies, as well as other factors.

Southern Power competes with investor-owned utilities, IPPs, and others for wholesale energy sales across various U.S. utility markets. The needs of these markets are driven by the demands of end users and the generation available. Southern Power's success in wholesale energy sales is influenced by various factors including reliability and availability of Southern Power's plants, availability of transmission to serve the demand, price, and Southern Power's ability to contain costs.

As of December 31, 2018, Alabama Power had cogeneration contracts in effect with nine industrial customers. Under the terms of these contracts, Alabama Power purchases excess energy generated by such companies. During 2018, Alabama Power purchased approximately 99 million KWHs from such companies at a cost of $3 million.

As of December 31, 2018, Georgia Power had contracts in effect with 28 small power producers whereby Georgia Power purchases their excess generation. During 2018, Georgia Power purchased 2.1 billion KWHs from such companies at a cost of $140 million. Georgia Power also has PPAs for electricity with four cogeneration facilities. Payments are subject to reductions for failure to meet minimum capacity output. During 2018, Georgia Power purchased 26 million KWHs at a cost of $0.8 million from these facilities.

Also during 2018, Georgia Power purchased energy from three customer-owned generating facilities. These customers provide energy with no capacity commitment and are not dispatched by Georgia Power. During 2018, Georgia Power purchased a total of 341 million KWHs from the three customers at a cost of approximately $28 million.

As of December 31, 2018, Mississippi Power had a cogeneration agreement in effect with one of its industrial customers. Under the terms of this contract, Mississippi Power purchases any excess generation. During 2018, Mississippi Power did not purchase any excess generation from this customer.

Natural Gas

Southern Company Gas' natural gas distribution utilities do not compete with other distributors of natural gas in their exclusive franchise territories but face competition from other energy products. Their principal competitors are electric utilities and fuel oil and propane providers serving the residential, commercial, and industrial markets in their service areas for customers who are considering switching to or from a natural gas appliance.

Competition for heating as well as general household and small commercial energy needs generally occurs at the initial installation phase when the customer or builder makes decisions as to which types of equipment to install. Customers generally use the chosen energy source for the life of the equipment.

Customer demand for natural gas could be affected by numerous factors, including:

- changes in the availability or price of natural gas and other forms of energy;
- general economic conditions;
- energy conservation, including state-supported energy efficiency programs;
- legislation and regulations;
- the cost and capability to convert from natural gas to alternative energy products; and
- technological changes resulting in displacement or replacement of natural gas appliances.

The natural gas-related programs generally emphasize natural gas as the fuel of choice for customers and seek to expand the use of natural gas through a variety of promotional activities. In addition, Southern Company Gas partners with third-party entities to market the benefits of natural gas appliances.

The availability and affordability of natural gas have provided cost advantages and further opportunity for growth of the businesses.

Seasonality

The demand for electric power and natural gas supply is affected by seasonal differences in the weather. While the electric power sales of some of the traditional electric operating companies peak in the summer, others peak in the winter. In the aggregate, electric power sales peak during the summer with a smaller peak during the winter. In most of the areas Southern Company Gas serves, natural gas demand peaks during the winter. As a result, the overall operating results of Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas in the future may fluctuate substantially on a seasonal basis. In addition, the traditional electric operating companies, Southern Power, and Southern Company Gas have historically sold less power and natural gas when weather conditions are milder.

Regulation

States

The traditional electric operating companies and the natural gas distribution utilities are subject to the jurisdiction of their respective state PSCs or applicable state regulatory agencies. These regulatory bodies have broad powers of supervision and regulation over public utilities operating in the respective states, including their rates, service regulations, sales of securities (except for the Mississippi PSC), and, in the cases of the Georgia PSC and the Mississippi PSC, in part, retail service territories. See "Territory Served by the Southern Company System" and "Rate Matters" herein for additional information.

Federal Power Act

The traditional electric operating companies, Southern Power Company and certain of its generation subsidiaries, and SEGCO are all public utilities engaged in wholesale sales of energy in interstate commerce and, therefore, are subject to the rate, financial, and accounting jurisdiction of the FERC under the Federal Power Act. The FERC must approve certain financings and allows an "at cost standard" for services rendered by system service companies such as SCS and Southern Nuclear. The FERC is also authorized to establish regional reliability organizations which enforce reliability standards, address impediments to the construction of transmission, and prohibit manipulative energy trading practices.

Alabama Power and Georgia Power are also subject to the provisions of the Federal Power Act or the earlier Federal Water Power Act applicable to licensees with respect to their hydroelectric developments. As of December 31, 2018, among the hydroelectric projects subject to licensing by the FERC are 14 existing Alabama Power generating stations having an aggregate installed capacity of 1,670,000 KWs and 17 existing Georgia Power generating stations and one generating station partially owned by Georgia Power, with a combined aggregate installed capacity of 1,101,402 KWs.

In 2013, the FERC issued a new 30-year license to Alabama Power for Alabama Power's seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin). Alabama Power filed a petition requesting rehearing of the FERC order granting the relicense seeking revisions to several conditions of the license. Alabama Rivers Alliance, American Rivers, the Georgia Environmental Protection Division, and the Atlanta Regional Commission also filed petitions for rehearing of the FERC order. In 2016, the FERC issued an order granting in part and denying in part Alabama Power's rehearing request. The order also denied all of the other rehearing requests. Also in 2016, Alabama Rivers Alliance and American Rivers filed a second rehearing request and also filed a petition with the U.S. Court of Appeals for the District of Columbia Circuit for review of the license and the rehearing denial order. The FERC issued an order in 2016 denying the second rehearing request, and American Rivers and Alabama Rivers Alliance subsequently filed an appeal of that order at the U.S. Court of Appeals for the District of Columbia Circuit. The U.S. Court of Appeals for the District of Columbia Circuit consolidated the two appeals into one proceeding and, on July 6, 2018, vacated the FERC's 2013 order for the new 30-year license and remanded the proceeding to the FERC. Alabama Power continues to operate the Coosa River developments under annual licenses issued by the FERC. The ultimate outcome of this matter cannot be determined at this time.

In 2018, Alabama Power continued the process of developing an application to relicense the Harris Dam project on the Tallapoosa River, which is expected to be filed with the FERC by November 30, 2021. The current Harris Dam project license will expire on November 30, 2023.

On May 31, 2018, Georgia Power filed an application to relicense the Wallace Dam project on the Oconee River. The current Wallace Dam project license will expire on June 1, 2020. On July 3, 2018, Georgia Power filed a Notice of Intent to relicense the Lloyd Shoals project on the Ocmulgee River. The application to relicense the Lloyd Shoals project is expected to be filed with the FERC by December 31, 2021. The current Lloyd Shoals project license will expire on December 31, 2023. On December 18, 2018, Georgia Power filed applications to surrender the Langdale and Riverview hydroelectric projects on the Chattahoochee River upon their license expirations on December 31, 2023. Both projects together represent 1,520 KWs of Georgia Power's hydro fleet capacity.

Georgia Power and OPC also have a license, expiring in 2027, for the Rocky Mountain project, a pure pumped storage facility of 903,000 KW installed capacity. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Licenses for all projects, excluding those discussed above, expire in the years 2034-2066 in the case of Alabama Power's projects and in the years 2035-2044 in the case of Georgia Power's projects.

Upon or after the expiration of each license, the U.S. Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. In the event of takeover or relicensing to another, the original licensee is to be compensated in accordance with the provisions of the Federal Power Act, such compensation to reflect the net investment of the licensee in the project, not in excess of the fair value of the property, plus reasonable damages to other property of the licensee resulting from the severance therefrom of the property. The FERC may grant relicenses subject to certain requirements that could result in additional costs.

The ultimate outcome of these matters cannot be determined at this time.

Nuclear Regulation

Alabama Power, Georgia Power, and Southern Nuclear are subject to regulation by the NRC. The NRC is responsible for licensing and regulating nuclear facilities and materials and for conducting research in support of the licensing and regulatory process, as mandated by the Atomic Energy Act of 1954, as amended; the Energy Reorganization Act of 1974, as amended; and the Nuclear Nonproliferation Act of 1978, as amended; and in accordance with the National Environmental Policy Act of 1969, as amended, and other applicable statutes. These responsibilities also include protecting public health and safety, protecting the

environment, protecting and safeguarding nuclear materials and nuclear power plants in the interest of national security, and assuring conformity with antitrust laws.

The NRC licenses for Georgia Power's Plant Hatch Units 1 and 2 expire in 2034 and 2038, respectively. The NRC licenses for Alabama Power's Plant Farley Units 1 and 2 expire in 2037 and 2041, respectively. The NRC licenses for Plant Vogtle Units 1 and 2 expire in 2047 and 2049, respectively.

In 2012, the NRC issued combined construction and operating licenses (COLs) for Plant Vogtle Units 3 and 4. Receipt of the COLs allowed full construction to begin. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" of Georgia Power in Item 7 herein and Note 2 to the financial statements under "Georgia Power – Nuclear Construction" in Item 8 herein for additional information.

See Notes 3 and 6 to the financial statements under "Nuclear Insurance" and "Nuclear Decommissioning," respectively, in Item 8 herein for information on nuclear insurance and nuclear decommissioning costs.

Environmental Laws and Regulations

The Southern Company system's operations are regulated by state and federal environmental agencies through a variety of laws and regulations governing air, water, land, and protection of other natural resources. Compliance with these existing environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions or through market-based contracts. There is no assurance, however, that all such costs will be recovered.

For Southern Company Gas, substantially all of these costs are related to former MGP sites, which are generally recovered through existing ratemaking provisions. See Note 3 to the financial statements under "Environmental Matters" in Item 8 herein for additional information.

Compliance with environmental laws and resulting regulations, including, but not limited to, proposed and existing regulations related to air quality, water quality, CCR, and global climate issues, has been, and will continue to be, a significant focus for each of the registrants and SEGCO. Compliance with any new or revised environmental laws and regulations could affect many areas of the traditional electric operating companies', Southern Power's, SEGCO's, and Southern Company Gas' operations. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of each of the registrants in Item 7 herein for additional information about environmental issues.

The Southern Company system's ultimate environmental compliance strategy and future environmental expenditures will depend on various factors, such as state adoption and implementation of requirements, the availability and cost of any deployed control technology, fuel prices, and the outcome of pending and/or future legal challenges. Compliance costs may result from the installation of additional environmental controls, closure and monitoring of CCR facilities, unit retirements, or changing fuel sources for certain existing units, as well as related upgrades to the transmission and distribution (electric and natural gas) systems. Environmental compliance spending over the next several years may differ materially from the amounts estimated. Such expenditures could affect results of operations, cash flows, and/or financial condition if such costs are not recovered on a timely basis through regulated rates for the traditional electric operating companies and the natural gas distribution utilities or through long-term wholesale agreements for the traditional electric operating companies and Southern Power. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for energy, which could negatively affect results of operations, cash flows, and financial condition. Additionally, many commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity and natural gas. See "Construction Program" herein and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of each of the registrants in Item 7 herein for additional information. The ultimate outcome of these matters cannot be determined at this time.

Rate Matters

Rate Structure and Cost Recovery Plans

Electric

The rates and service regulations of the traditional electric operating companies are uniform for each class of service throughout their respective retail service territories. Rates for residential electric service are generally of the block type based upon KWHs used and include minimum charges. Residential and other rates contain separate customer charges. Rates for commercial service are presently of the block type and, for large customers, the billing demand is generally used to determine capacity and minimum bill charges. These large customers' rates are generally based upon usage by the customer and include rates with special features to encourage off-peak usage. Additionally, Alabama Power and Mississippi Power are generally allowed by their respective state PSCs to negotiate the terms and cost of service to large customers. Such terms and cost of service, however, are subject to final state PSC approval.

The traditional electric operating companies recover certain costs through a variety of forward-looking, cost-based rate mechanisms. Fuel and net purchased energy costs are recovered through specific fuel cost recovery provisions. These fuel cost recovery provisions are adjusted to reflect increases or decreases in such costs as needed or on schedules as required by the respective PSCs. Approved compliance, storm damage, and certain other costs are recovered at Alabama Power and Mississippi Power through specific cost recovery mechanisms approved by their respective PSCs. Certain similar costs at Georgia Power are recovered through various base rate tariffs as approved by the Georgia PSC. Costs not recovered through specific cost recovery mechanisms are recovered at Alabama Power and Mississippi Power through annual, formulaic cost recovery proceedings and at Georgia Power through periodic base rate proceedings.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Regulatory Matters" of Southern Company and each of the traditional electric operating companies in Item 7 herein and Note 2 to the financial statements in Item 8 herein for a discussion of rate matters and certain cost recovery mechanisms. Also, see Note 1 to the financial statements in Item 8 herein for a discussion of recovery of fuel costs, storm damage costs, and compliance costs through rate mechanisms.

See "Integrated Resource Planning" herein and Note 2 to the financial statements under "Georgia Power – Integrated Resource Plan" in Item 8 herein for a discussion of Georgia PSC certification of new demand-side or supply-side resources for Georgia Power. In addition, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters -- Nuclear Construction" of Georgia Power in Item 7 herein and Note 2 to the financial statements under "Georgia Power – Nuclear Construction" in Item 8 herein for a discussion of the Georgia Nuclear Energy Financing Act and the Georgia PSC certification of Plant Vogtle Units 3 and 4, which have allowed Georgia Power to recover financing costs for construction of Plant Vogtle Units 3 and 4 since 2011.

See Note 2 to the financial statements under "Kemper County Energy Facility" in Item 8 herein and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Kemper County Energy Facility – Rate Recovery" of Mississippi Power in Item 7 herein for information on cost recovery plans for the Kemper County energy facility.

The traditional electric operating companies and Southern Power Company and certain of its generation subsidiaries are authorized by the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

Mississippi Power serves long-term contracts with rural electric cooperative associations and a municipality located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 17.3% of Mississippi Power's total operating revenues in 2018 and are generally subject to 10-year rolling cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

Natural Gas

Southern Company Gas' natural gas distribution utilities are subject to regulation and oversight by their respective state regulatory agencies. Rates charged to these customers vary according to customer class (residential, commercial, or industrial) and rate jurisdiction. These agencies approve rates designed to provide each natural gas distribution utility the opportunity to generate revenues to recover all prudently-incurred costs, including a return on rate base sufficient to pay interest on debt, and provide a reasonable return.

With the exception of Atlanta Gas Light, which operates in a deregulated environment in which Marketers rather than a traditional utility sell natural gas to end-use customers and earns revenue by charging rates to its customers based primarily on monthly fixed charges that are set by the Georgia PSC, the earnings of the natural gas distribution utilities can be affected by customer consumption patterns that are largely a function of weather conditions and price levels for natural gas.

The natural gas distribution utilities, excluding Atlanta Gas Light, are authorized to use natural gas cost recovery mechanisms that adjust rates to reflect changes in the wholesale cost of natural gas and ensure recovery of all costs prudently incurred in purchasing natural gas for customers. In addition to natural gas cost recovery mechanisms, the natural gas distribution utilities have other cost recovery mechanisms, such as regulatory riders, which vary by utility but allow recovery of certain costs, such as those related to infrastructure replacement programs as well as environmental remediation and energy efficiency plans.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Regulatory Matters – Utility Regulation and Rate Design" of Southern Company Gas in Item 7 herein and Note 2 to the financial statements under "Southern Company Gas" in Item 8 herein for a discussion of rate matters and certain cost recovery mechanisms.

Integrated Resource Planning

Each of the traditional electric operating companies continually evaluates its electric generating resources in order to ensure that it maintains a cost-effective and reliable mix of resources to meet the existing and future demand requirements of its customers. See "Environmental Laws and Regulations" above for a discussion of existing and potential environmental regulations that may impact the future generating resource needs of the traditional electric operating companies.

Alabama Power

Triennially, Alabama Power provides an IRP report to the Alabama PSC. This report overviews Alabama Power's resource planning process and contains information that serves as the foundation for certain decisions affecting Alabama Power's portfolio of supply-side and demand-side resources. The IRP report facilitates Alabama Power's ability to provide reliable and cost-effective electric service to customers, while accounting for the risks and uncertainties inherent in planning for resources sufficient to meet expected customer demand. Under State of Alabama law, a CPCN must be obtained from the Alabama PSC before Alabama Power constructs any new generating facility, unless such construction is deemed an ordinary extension in the usual course of business.

Georgia Power

Triennially, Georgia Power must file an IRP with the Georgia PSC that specifies how it intends to meet the future electric service needs of its customers through a combination of demand-side and supply-side resources. The Georgia PSC, under state law, must certify any new demand-side or supply-side resources for Georgia Power to receive cost recovery. Once certified, the lesser of actual or certified construction costs and purchased power costs is recoverable through rates. Certified costs may be excluded from recovery only on the basis of fraud, concealment, failure to disclose a material fact, imprudence, or criminal misconduct. See Note 2 to the financial statements under "Georgia Power – Rate Plans," " – Integrated Resource Plan," and " – Nuclear Construction" in Item 8 herein for additional information.

Mississippi Power

On February 6, 2018, the Mississippi PSC approved a settlement agreement related to cost recovery for the Kemper County energy facility, pursuant to which Mississippi Power filed a Reserve Margin Plan (RMP) on August 6, 2018. The RMP includes many of the same aspects of a traditional IRP, but the RMP also contains alternatives proposed by Mississippi Power to address its existing reserve capacity, which is greater than the level required to meet Mississippi Power's projected summer peak demand. Mississippi Power developed the alternatives by evaluating the economics of each unit in Mississippi Power's fleet, the opportunities currently available in the wholesale market, and the operational constraints of the Southern Company system. The ultimate outcome of this matter cannot be determined at this time. For additional information, see Note 2 to the financial statements under "Kemper County Energy Facility" in Item 8 herein.

Employee Relations

The Southern Company system had a total of 29,192 employees on its payroll at January 1, 2019.

	Employees at January 1, 2019
Alabama Power	6,650
Georgia Power	6,967
Mississippi Power	1,053
PowerSecure	1,743
SCS	3,799
Southern Company Gas	4,389
Southern Nuclear	3,870
Southern Power	491
Other	230
Total	29,192

The traditional electric operating companies and the natural gas distribution utilities have separate agreements with local unions of the IBEW and the Utilities Workers Union of America generally covering wages, working conditions, and procedures for handling grievances and arbitration. These agreements apply with certain exceptions to operating, maintenance, and construction employees.

Alabama Power has agreements with the IBEW in effect through August 15, 2019. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

Georgia Power has an agreement with the IBEW covering wages and working conditions, which is in effect through June 30, 2021.

Mississippi Power has an agreement with the IBEW covering wages and working conditions, which is in effect through May 1, 2019. In 2015, Mississippi Power signed a separate agreement with the IBEW related solely to the Kemper County energy facility; that current agreement is in effect through March 15, 2021. In August 2017, Mississippi Power signed an agreement with the IBEW that added several job classifications and provided guidelines related to the reorganization at the Kemper County energy facility.

Southern Nuclear has a five-year agreement with the IBEW covering certain employees at Plants Hatch and Plant Vogtle Units 1 and 2, which is in effect through June 30, 2021. A five-year agreement between Southern Nuclear and the IBEW representing certain employees at Plant Farley is in effect through August 15, 2019. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

The agreements also make the terms of the pension plans for the companies discussed above subject to collective bargaining with the unions at either a five-year or a 10-year cycle, depending upon union and company actions.

The natural gas distribution utilities have separate agreements with local unions of the IBEW and Utilities Workers Union of America covering wages, working conditions, and procedures for handling grievances and arbitration. Nicor Gas' agreement with the IBEW is effective through February 29, 2020. Virginia Natural Gas' agreement with the IBEW is effective through May 15, 2020. The agreements also make the terms of the Southern Company Gas pension plan subject to collective bargaining with the unions when significant changes to the benefit accruals are considered by Southern Company Gas.

Item 1A. RISK FACTORS

In addition to the other information in this Form 10-K, including MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL in Item 7 of each registrant, and other documents filed by Southern Company and/or its subsidiaries with the SEC from time to time, the following factors should be carefully considered in evaluating Southern Company and its subsidiaries. Such factors could affect actual results and cause results to differ materially from those expressed in any forward-looking statements made by, or on behalf of, Southern Company and/or its subsidiaries.

UTILITY REGULATORY, LEGISLATIVE, AND LITIGATION RISKS

Southern Company and its subsidiaries are subject to substantial state and federal governmental regulation. Compliance with current and future regulatory requirements and procurement of necessary approvals, permits, and certificates may result in substantial costs to Southern Company and its subsidiaries.

Southern Company and its subsidiaries are subject to substantial regulation from federal, state, and local regulatory agencies and are required to comply with numerous laws and regulations and to obtain numerous permits, approvals, and certificates from governmental agencies. The traditional electric operating companies and the natural gas distribution utilities seek to recover their costs (including a reasonable return on invested capital) through their retail rates, which must be approved by the applicable state PSC or other applicable state regulatory agency. A state PSC or other applicable state regulatory agency, in a future rate proceeding, may alter the timing or amount of certain costs for which recovery is allowed or modify the current authorized rate of return. Rate refunds may also be required. Additionally, the rates charged to wholesale customers by the traditional electric operating companies and by Southern Power and the rates charged to natural gas transportation customers by Southern Company Gas' pipeline investments and for some of its storage assets must be approved by the FERC. These wholesale rates could be affected by changes to Southern Power's and the traditional electric operating companies' ability to conduct business pursuant to FERC market-based rate authority. Retaining this authority from the FERC is important to the traditional electric operating companies' and Southern Power's ability to remain competitive in the wholesale electric markets.

The impact of any future revision or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to Southern Company or any of its subsidiaries is uncertain. Changes in regulation or the imposition of additional regulations could influence the operating environment of Southern Company and its subsidiaries and may result in substantial costs or otherwise negatively affect their results of operations.

The Southern Company system's costs of compliance with environmental laws and satisfying related AROs are significant. The costs of compliance with current and future environmental laws and related AROs and the incurrence of environmental liabilities could negatively impact the net income, cash flows, and financial condition of the registrants.

The Southern Company system's operations are subject to extensive regulation by state and federal environmental agencies through a variety of laws and regulations. Compliance with existing environmental requirements involves significant capital and operating costs including the settlement of AROs, a major portion of which is expected to be recovered through existing ratemaking provisions or through market-based contracts. There is no assurance, however, that all such costs will be recovered. The registrants expect future compliance expenditures will continue to be significant.

The EPA has adopted and is implementing regulations governing air and water quality under the Clean Air Act and regulations governing cooling water intake structures and effluent guidelines for steam electric generating plants under the Clean Water Act. The EPA has also adopted regulations governing the disposal of CCR, including coal ash and gypsum, in landfills and surface impoundments at active generating power plants. The cost estimates for AROs related to the disposal of CCR are based on information using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule. The traditional electric operating companies will continue to periodically update their ARO cost estimates.

Additionally, environmental laws and regulations covering the handling and disposal of waste and release of hazardous substances could require the Southern Company system to incur substantial costs to clean up affected sites, including certain current and former operating sites, and locations affected by historical operations or subject to contractual obligations.

Existing environmental laws and regulations may be revised or new environmental laws and regulations may be adopted or become applicable to the Southern Company system. In addition, existing environmental laws and regulations may be impacted by related legal challenges.

Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, releases of regulated substances, and alleged exposure to regulated substances, and/or requests for injunctive relief in connection with such matters.

Compliance with any new or revised environmental laws or regulations could affect many areas of the Southern Company system's operations. The Southern Company system's ultimate environmental compliance strategy and future environmental expenditures will depend on various factors, such as state adoption and implementation of requirements, the availability and cost of any deployed control technology, and the outcome of pending and/or future legal challenges. Compliance costs may result from the installation of additional environmental controls, closure and monitoring of CCR facilities, unit retirements, or changing fuel sources for certain existing units, as well as related upgrades to the Southern Company system's transmission and distribution (electric and natural gas) systems. Environmental compliance spending over the next several years may differ materially from the amounts estimated. Such expenditures could affect results of operations, cash flows, and/or financial condition if such costs are not recovered on a timely basis through regulated rates for the traditional electric operating companies and the natural gas distribution utilities or through long-term wholesale agreements for the traditional electric operating companies and Southern Power. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for energy, which could negatively affect results of operations, cash flows, and financial condition. Additionally, many commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity or natural gas.

The Southern Company system may be exposed to regulatory and financial risks related to the impact of GHG legislation, regulation, and emission reduction goals.

The EPA has published rules limiting CO_2 emissions from new, modified, and reconstructed fossil fuel-fired electric generating units and guidelines for states to develop plans to meet EPA-mandated CO_2 emission performance standards for existing units (known as the Clean Power Plan or CPP). On August 31, 2018, the EPA published a proposed rule known as the Affordable Clean Energy (ACE) Rule, which is intended to replace a regulation enacted in 2015 known as the Clean Power Plan (CPP), that would limit CO_2 emissions from existing fossil fuel-fired electric generating units. The CPP has been stayed by the U.S. Supreme Court since 2016. The ACE Rule would require states to develop GHG unit-specific emission rate standards based on heat-rate efficiency improvements for existing fossil fuel-fired steam units. As proposed, combustion turbines, including natural gas combined cycles, are not affected sources. As of January 1, 2019, the Southern Company system has ownership interests in 40 fossil fuel-fired steam units to which the proposed ACE Rule is applicable. The ultimate impact of this rule to the Southern Company system is currently unknown and will depend on changes between the proposal and the final rule, subsequent state plan developments and requirements, and any associated legal challenges.

The EPA also has proposed a review of final rules adopted in 2015 to establish performance standards for new, modified, and reconstructed electric utility generating units. The impact of any changes will depend on the content of any final rule adopted by the EPA and the outcome of any related legal challenges.

In April 2018, Southern Company established an intermediate goal of a 50% reduction in carbon emissions from 2007 levels by 2030 and a long-term goal of low- to no-carbon operations by 2050. To achieve these goals, the Southern Company system expects to continue growing its renewable energy portfolio, optimize technology advancements to modernize its transmission and distribution systems, increase the use of natural gas for generation, complete ongoing construction projects, including Georgia Power's interest in Plant Vogtle Units 3 and 4, invest in energy efficiency, and continue research and development efforts focused on technologies to lower GHG emissions. The Southern Company system's ability to achieve these goals also will be dependent on many external factors, including supportive national energy policies, low natural gas prices, and the development, deployment, and advancement of relevant energy technologies.

Costs associated with GHG legislation, regulation, and emission reduction goals could be significant. However, the ultimate impact will depend on various factors, such as state adoption and implementation of requirements, low natural gas prices, the development, deployment, and advancement of relevant energy technologies, the ability to recover costs through existing ratemaking provisions, and the outcome of pending and/or future legal challenges.

Because natural gas is a fossil fuel with lower carbon content relative to other fossil fuels, future GHG constraints, including, but not limited to, the imposition of a carbon tax, may create additional demand for natural gas, both for production of electricity and direct use in homes and businesses. Future GHG constraints designed to minimize emissions from natural gas could likewise result in increased costs to the Southern Company system and affect the demand for natural gas as well as the prices charged to customers and the competitive position of natural gas.

The net income of Southern Company, the traditional electric operating companies, and Southern Power could be negatively impacted by changes in regulations related to transmission planning processes and competition in the wholesale electric markets.

The traditional electric operating companies currently own and operate transmission facilities as part of a vertically integrated utility. A small percentage of transmission revenues are collected through the wholesale electric tariff but the majority are collected through retail rates. FERC rules pertaining to regional transmission planning and cost allocation present challenges to transmission planning and the wholesale market structure. The key impacts of these rules include:

- possible disruption of the integrated resource planning processes within the states in the Southern Company system's service territory;
- delays and additional processes for developing transmission plans; and
- possible impacts on state jurisdiction of approving, certifying, and pricing new transmission facilities.

The FERC rules related to transmission are intended to spur the development of new transmission infrastructure to promote and encourage the integration of renewable sources of supply as well as facilitate competition in the wholesale market by providing more choices to wholesale power customers. Technology changes in the power and fuel industries continue to create significant impacts to wholesale transaction cost structures. The impact of these and other such developments and the effect of changes in levels of wholesale supply and demand are uncertain. The financial condition, net income, and cash flows of Southern Company, the traditional electric operating companies, and Southern Power could be adversely affected by these and other changes.

The traditional electric operating companies and Southern Power could be subject to higher costs as a result of implementing and maintaining compliance with the North American Electric Reliability Corporation mandatory reliability standards along with possible associated penalties for non-compliance.

Owners and operators of bulk power systems, including the traditional electric operating companies, are subject to mandatory reliability standards enacted by the North American Electric Reliability Corporation and enforced by the FERC. Compliance with or changes in the mandatory reliability standards may subject the traditional electric operating companies and Southern Power to higher operating costs and/or increased capital expenditures. If any traditional electric operating company or Southern Power is found to be in noncompliance with these standards, such traditional electric operating company or Southern Power could be subject to sanctions, including substantial monetary penalties.

OPERATIONAL RISKS

The financial performance of Southern Company and its subsidiaries may be adversely affected if the subsidiaries are unable to successfully operate their facilities or perform certain corporate functions.

The financial performance of Southern Company and its subsidiaries depends on the successful operation of the electric generation, transmission, and distribution facilities and natural gas distribution and storage facilities and the successful performance of necessary corporate functions. There are many risks that could affect these operations and performance of corporate functions, including:

- operator error or failure of equipment or processes;
- accidents;
- operating limitations that may be imposed by environmental or other regulatory requirements or in connection with joint owner arrangements;
- labor disputes;
- physical attacks;
- fuel or material supply interruptions and/or shortages;
- transmission disruption or capacity constraints, including with respect to the Southern Company system's and third parties' transmission, storage, and transportation facilities;
- compliance with mandatory reliability standards, including mandatory cyber security standards;
- implementation of new technologies;
- information technology system failures;
- cyber intrusions;
- environmental events, such as spills or releases; and
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events, or other similar occurrences.

A decrease or elimination of revenues from the electric generation, transmission, or distribution facilities or natural gas distribution or storage facilities or an increase in the cost of operating the facilities would reduce the net income and cash flows and could adversely impact the financial condition of the affected registrant.

Operation of nuclear facilities involves inherent risks, including environmental, safety, health, regulatory, natural disasters, cyber intrusions or physical attacks, and financial risks, that could result in fines or the closure of the nuclear units owned by Alabama Power or Georgia Power and which may present potential exposures in excess of insurance coverage.

Alabama Power owns, and contracts for the operation of, two nuclear units and Georgia Power holds undivided interests in, and contracts for the operation of, four existing nuclear units. The six existing units are operated by Southern Nuclear and represent approximately 3,680 MWs, or 8% of the Southern Company system's electric generation capacity at January 1, 2019. In addition, these units generated approximately 25% of the total KWHs generated by each of Alabama Power and Georgia Power in the year ended December 31, 2018. In addition, Southern Nuclear, on behalf of Georgia Power and the other Vogtle Owners, is managing the construction of Plant Vogtle Units 3 and 4. Due solely to the increase in nuclear generating capacity, the below risks are expected to increase incrementally once Plant Vogtle Units 3 and 4 are operational. Nuclear facilities are subject to environmental, safety, health, operational, and financial risks such as:

- the potential harmful effects on the environment and human health and safety resulting from a release of radioactive materials in connection with the operation of nuclear facilities and the storage, handling, and disposal of radioactive material, including spent nuclear fuel;
- uncertainties with respect to the ability to dispose of spent nuclear fuel and the need for longer term on-site storage;
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of licensed lives and the ability to maintain and anticipate adequate capital reserves for decommissioning;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with the nuclear operations of Alabama Power and Georgia Power or those of other commercial nuclear facility owners in the U.S.;
- potential liabilities arising out of the operation of these facilities;
- significant capital expenditures relating to maintenance, operation, security, and repair of these facilities, including repairs and upgrades required by the NRC;
- actual or threatened cyber intrusions or physical attacks; and
- the potential impact of an accident or natural disaster.

It is possible that damages, decommissioning, or other costs could exceed the amount of decommissioning trusts or external insurance coverage, including statutorily required nuclear incident insurance.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines and/or shut down any unit, depending upon its assessment of the severity of the situation, until compliance is achieved. NRC orders or regulations related to increased security measures and any future safety requirements promulgated by the NRC could require Alabama Power and Georgia Power to make substantial operating and capital expenditures at their nuclear plants. In addition, if a serious nuclear incident were to occur, it could result in substantial costs to Alabama Power or Georgia Power and Southern Company. A major incident at a nuclear facility anywhere in the world could cause the NRC to delay or prohibit construction of new nuclear units or require additional safety measures at new and existing units. Moreover, a major incident at any nuclear facility in the U.S., including facilities owned and operated by third parties, could require Alabama Power and Georgia Power to make material contributory payments.

In addition, actual or potential threats of cyber intrusions or physical attacks could result in increased nuclear licensing or compliance costs that are difficult to predict.

Transporting and storing natural gas involves risks that may result in accidents and other operating risks and costs.

Southern Company Gas' natural gas distribution and storage activities involve a variety of inherent hazards and operating risks, such as leaks, accidents, explosions, and mechanical problems, which could result in serious injury to employees and non-employees, loss of life, significant damage to property, environmental pollution, and impairment of its operations. The location of pipelines and storage facilities near populated areas could increase the level of damage resulting from these risks. Additionally, these pipeline and storage facilities are subject to various state and other regulatory requirements. Failure to comply with these regulatory requirements could result in substantial monetary penalties or potential early retirement of storage facilities, which could trigger an associated impairment. The occurrence of any of these events not fully covered by insurance or otherwise could adversely affect Southern Company Gas' and Southern Company's financial condition and results of operations.

Physical attacks, both threatened and actual, could impact the ability of the Subsidiary Registrants to operate and could adversely affect financial results and liquidity.

The Subsidiary Registrants face the risk of physical attacks, both threatened and actual, against their respective generation and storage facilities and the transmission and distribution infrastructure used to transport energy, which could negatively impact their ability to generate, transport, and deliver power, or otherwise operate their respective facilities, or, with respect to Southern Company Gas, its ability to distribute or store natural gas, or otherwise operate its facilities, in the most efficient manner or at all. In addition, physical attacks against third-party providers could have a similar effect on Southern Company and its subsidiaries.

Despite the implementation of robust security measures, all assets are potentially vulnerable to disability, failures, or unauthorized access due to human error, natural disasters, technological failure, or internal or external physical attacks. If assets were to fail, be physically damaged, or be breached and were not restored in a timely manner, the affected Subsidiary Registrant may be unable to fulfill critical business functions. Moreover, the amount and scope of insurance maintained against losses resulting from any such events or physical security breaches may not be sufficient to cover losses or otherwise adequately compensate for any disruptions to business that could result.

These events could harm the reputation of and negatively affect the financial results of the registrants through lost revenues and costs to repair damage, if such costs cannot be recovered.

An information security incident, including a cybersecurity breach, or the failure of one or more key information technology systems, networks, or processes could impact the ability of the registrants to operate and could adversely affect financial results and liquidity.

Information security risks have generally increased in recent years as a result of the proliferation of new technology and increased sophistication and frequency of cyber attacks and data security breaches. The Subsidiary Registrants operate in highly regulated industries that require the continued operation of sophisticated information technology systems and network infrastructure, which are part of interconnected distribution systems. Because of the critical nature of the infrastructure, increased connectivity to the internet, and technology systems' inherent vulnerability to disability or failures due to hacking, viruses, acts of war or terrorism, or other types of data security breaches, Southern Company and its subsidiaries face a heightened risk of cyberattack. Parties that wish to disrupt the U.S. bulk power system or Southern Company system operations could view these computer systems, software, or networks as targets. The registrants and their third-party vendors have been subject, and will likely continue to be subject, to attempts to gain unauthorized access to their information technology systems and confidential data or to attempts to disrupt utility operations. As a result, Southern Company and its subsidiaries face on-going threats to their assets, including assets deemed critical infrastructure, where databases and systems have been, and will likely continue to be, subject to advanced computer viruses or other malicious codes, unauthorized access attempts, phishing, and other cyber attacks. While there have been immaterial incidents of phishing and attempted financial fraud across the Southern Company system, there has been no material impact on business or operations from these attacks. However, the registrants cannot guarantee that security efforts will prevent breaches, operational incidents, or other breakdowns of information technology systems and network infrastructure and cannot provide any assurance that such incidents will not have a material adverse effect in the future.

In addition, in the ordinary course of business, Southern Company and its subsidiaries collect and retain sensitive information, including personally identifiable information about customers, employees, and stockholders, and other confidential information. In some cases, administration of certain functions may be outsourced to third-party service providers that could also be targets of cyber attacks. Generally, Southern Company and its subsidiaries enter certain contractual security guarantees and assurances with these third parties to help ensure the security and safety of this information.

Despite the implementation of robust security measures, all assets are potentially vulnerable to disability, failures, or unauthorized access due to human error, natural disasters, technological failure, or internal or external cyber attacks. If assets were to fail or be breached and were not restored in a timely manner, the affected registrant may be unable to fulfill critical business functions, and sensitive and other data could be compromised. Any cyber breach or theft, damage, or improper disclosure of sensitive electronic data may also subject the affected registrant to penalties and claims from regulators or other third parties. Moreover, the amount and scope of insurance maintained against losses resulting from any such events or security breaches may not be sufficient to cover losses or otherwise adequately compensate for any disruptions to business that could result. In addition, as cybercriminals become more sophisticated, the cost of proactive defensive measures may increase.

These events could negatively affect the financial results of the registrants through lost revenues, costs to recover and repair damage, costs associated with governmental actions in response to such attacks, and litigation costs if such costs cannot be recovered through insurance or otherwise.

The Southern Company system may not be able to obtain adequate natural gas, fuel supplies, and other resources required to operate the traditional electric operating companies' and Southern Power's electric generating plants or serve Southern Company Gas' natural gas customers.

The traditional electric operating companies and Southern Power purchase fuel, including coal, natural gas, uranium, fuel oil, and biomass, as applicable, from a number of suppliers. Additionally, the traditional electric operating companies and Southern

Power need adequate access to water, which is drawn from nearby sources to aid in the production of electricity and, once it is used, returned to its source. Disruption in the delivery of fuel, including disruptions as a result of, among other things, transportation delays, weather, labor relations, force majeure events, or environmental regulations affecting any of these fuel suppliers, or the availability of water, could limit the ability of the traditional electric operating companies and Southern Power to operate certain facilities, which could result in higher fuel and operating costs and potentially reduce the net income of the affected traditional electric operating company or Southern Power and Southern Company.

Southern Company Gas' primary business is the distribution and sale of natural gas through its regulated and unregulated subsidiaries. Natural gas supplies can be subject to disruption in the event production or distribution is curtailed, such as in the event of a hurricane or a pipeline failure. Southern Company Gas also relies on natural gas pipelines and other storage and transportation facilities owned and operated by third parties to deliver natural gas to wholesale markets and to Southern Company Gas' distribution systems. The availability of shale gas and potential regulations affecting its accessibility may have a material impact on the supply and cost of natural gas. Disruption in natural gas supplies could limit the ability to fulfill these contractual obligations.

The traditional electric operating companies and Southern Power have become more dependent on natural gas for a portion of their electric generating capacity and expect to continue to increase such dependence. In many instances, the cost of purchased power for the traditional electric operating companies and Southern Power is influenced by natural gas prices. Historically, natural gas prices have been more volatile than prices of other fuels. In recent years, domestic natural gas prices have been depressed by robust supplies, including production from shale gas. These market conditions, together with additional regulation of coal-fired generating units, have increased the traditional electric operating companies' reliance on natural gas-fired generating units.

The traditional electric operating companies are also dependent on coal for a portion of their electric generating capacity. The traditional electric operating companies depend on coal supply contracts, and the counterparties to these agreements may not fulfill their obligations to supply coal to the traditional electric operating companies. The suppliers may experience financial or technical problems that inhibit their ability to fulfill their obligations. In addition, the suppliers may not be required to supply coal under certain circumstances, such as in the event of a natural disaster. If the traditional electric operating companies are unable to obtain their coal requirements under these contracts, they may be required to purchase their coal requirements at higher prices, which may not be recoverable through rates.

The revenues of Southern Company, the traditional electric operating companies, and Southern Power depend in part on sales under PPAs. The failure of a counterparty to one of these PPAs to perform its obligations, the failure of the traditional electric operating companies or Southern Power to satisfy minimum requirements under the PPAs, or the failure to renew the PPAs or successfully remarket the related generating capacity could have a negative impact on the net income and cash flows of the affected traditional electric operating company or Southern Power and of Southern Company.

Most of Southern Power's generating capacity has been sold to purchasers under PPAs. Southern Power's top three customers, Georgia Power, Duke Energy Corporation, and Southern California Edison accounted for 9.8%, 6.8%, and 6.2%, respectively, of Southern Power's total revenues for the year ended December 31, 2018. In addition, the traditional electric operating companies enter into PPAs with non-affiliated parties. Revenues are dependent on the continued performance by the purchasers of their obligations under these PPAs. The failure of one of the purchasers to perform its obligations, including as a result of a general default or bankruptcy, could have a negative impact on the net income and cash flows of the affected traditional electric operating company or Southern Power and of Southern Company. Although the credit evaluations undertaken and contractual protections implemented by Southern Power and the traditional electric operating companies take into account the possibility of default by a purchaser, actual exposure to a default by a purchaser may be greater than predicted or specified in the applicable contract. See Note 1 to the financial statements under "Revenues – Concentration of Revenue" in Item 8 herein for additional information on Pacific Gas & Electric Company's bankruptcy filing.

Additionally, neither Southern Power nor any traditional electric operating company can predict whether the PPAs will be renewed at the end of their respective terms or on what terms any renewals may be made. The failure of the traditional electric operating companies or Southern Power to satisfy minimum operational or availability requirements under these PPAs could result in payment of damages or termination of the PPAs.

The asset management arrangements between Southern Company Gas' wholesale gas services and its customers, including the natural gas distribution utilities, may not be renewed or may be renewed at lower levels, which could have a significant impact on Southern Company Gas' financial results.

Southern Company Gas' wholesale gas services currently manages the storage and transportation assets of the natural gas distribution utilities (except Nicor Gas) as well as certain non-affiliated customers. Southern Company Gas' wholesale gas services has a concentration of credit risk for services it provides to its counterparties, which is generally concentrated in 20 of its counterparties.

The profits earned from the management of affiliate assets are shared with the respective affiliate's customers (and for Atlanta Gas Light with the Georgia PSC's Universal Service Fund), except for Chattanooga Gas where wholesale gas services are provided under annual fixed-fee agreements. These asset management agreements are subject to regulatory approval and such agreements may not be renewed or may be renewed with less favorable terms.

The financial results of Southern Company Gas' wholesale gas services could be significantly impacted if any of its agreements with its affiliated or non-affiliated customers are not renewed or are amended or renewed with less favorable terms. Sustained low natural gas prices could reduce the demand for these types of asset management arrangements.

Increased competition could negatively impact Southern Company's and its subsidiaries' revenues, results of operations, and financial condition.

The Southern Company system faces increasing competition from other companies that supply energy or generation and storage technologies. Changes in technology may make the Southern Company system's electric generating facilities owned by the traditional electric operating companies and Southern Power less competitive. Southern Company Gas' business is dependent on natural gas prices remaining competitive as compared to other forms of energy. Southern Company Gas also faces competition in its unregulated markets.

A key element of the business models of the traditional electric operating companies and Southern Power is that generating power at central station power plants achieves economies of scale and produces power at a competitive cost. There are distributed generation and storage technologies that produce and store power, including fuel cells, microturbines, wind turbines, solar cells, and batteries. Advances in technology or changes in laws or regulations could reduce the cost of these or other alternative methods of producing power to a level that is competitive with that of most central station power electric production or result in smaller-scale, more fuel efficient, and/or more cost effective distributed generation that allows for increased self-generation by customers. Broader use of distributed generation by retail energy customers may also result from customers' changing perceptions of the merits of utilizing existing generation technology or tax or other economic incentives. Additionally, a state PSC or legislature may modify certain aspects of the traditional electric operating companies' business as a result of these advances in technology.

It is also possible that rapid advances in central station power generation technology could reduce the value of the current electric generating facilities owned by the traditional electric operating companies and Southern Power. Changes in technology could also alter the channels through which electric customers buy or utilize power, which could reduce the revenues or increase the expenses of Southern Company, the traditional electric operating companies, or Southern Power.

Southern Company Gas' gas marketing services is affected by competition from other energy marketers providing similar services in Southern Company Gas' service territories, most notably in Illinois and Georgia. Southern Company Gas' wholesale gas services competes for sales with national and regional full-service energy providers, energy merchants and producers, and pipelines based on the ability to aggregate competitively-priced commodities with transportation and storage capacity. Southern Company Gas competes with natural gas facilities in the Gulf Coast region of the U.S., as the majority of the existing and proposed high deliverability salt-dome natural gas storage facilities in North America are located in the Gulf Coast region.

If new technologies become cost competitive and achieve sufficient scale, the market share of the Subsidiary Registrants could be eroded, and the value of their respective electric generating facilities or natural gas distribution and storage facilities could be reduced. Additionally, Southern Company Gas' market share could be reduced if Southern Company Gas cannot remain price competitive in its unregulated markets. If state PSCs or other applicable state regulatory agencies fail to adjust rates to reflect the impact of any changes in loads, increasing self-generation, and the growth of distributed generation, the financial condition, results of operations, and cash flows of Southern Company and the affected traditional electric operating company or Southern Company Gas could be materially adversely affected.

Failure to attract and retain an appropriately qualified workforce could negatively impact Southern Company's and its subsidiaries' results of operations.

Events such as an aging workforce without appropriate replacements, mismatch of skill sets to future needs, or unavailability of contract resources may lead to operating challenges such as lack of resources, loss of knowledge, and a lengthy time period associated with skill development, including with the workforce needs associated with major construction projects and ongoing operations. The Southern Company system's costs, including costs for contractors to replace employees, productivity costs, and safety costs, may rise. Failure to hire and adequately obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect Southern Company and its subsidiaries' ability to manage and operate their businesses. If Southern Company and its subsidiaries are unable to successfully attract and retain an appropriately qualified workforce, results of operations could be negatively impacted.

CONSTRUCTION RISKS

The registrants may incur additional costs or delays in the construction of new plants or other facilities and may not be able to recover their investments. Also, existing facilities of the Subsidiary Registrants require ongoing expenditures, including those to meet AROs and other environmental standards and goals.

General

The businesses of the registrants require substantial expenditures for investments in new facilities and, for the traditional electric operating companies, capital improvements to transmission, distribution, and generation facilities, for Southern Power, capital improvements to generation facilities, and, for Southern Company Gas, capital improvements to natural gas distribution and storage facilities. These expenditures also include those to meet AROs and environmental standards and goals. Certain of the traditional electric operating companies and Southern Power are in the process of constructing new generating facilities and adding environmental controls equipment at existing generating facilities. Southern Company Gas is replacing certain pipelines in its natural gas distribution system and is involved in two new gas pipeline construction projects. The Southern Company system intends to continue its strategy of developing and constructing other new facilities, expanding or updating existing facilities, and adding environmental control equipment. These types of projects are long term in nature and in some cases may include the development and construction of facilities with designs that have not been finalized or previously constructed. The completion of these types of projects without delays or significant cost overruns is subject to substantial risks, including:

- shortages, increased costs, or inconsistent quality of equipment, materials, and labor;
- changes in labor costs, availability, and productivity;
- challenges related to management of contractors, subcontractors, or vendors;
- work stoppages;
- contractor or supplier delay;
- non-performance under construction, operating, or other agreements;
- delays in or failure to receive necessary permits, approvals, tax credits, and other regulatory authorizations;
- delays in start-up activities (including major equipment failure and system integration) and/or operational performance;
- operational readiness, including specialized operator training and required site safety programs;
- impacts of new and existing laws and regulations, including environmental laws and regulations;
- the outcome of any legal challenges to projects, including legal challenges to regulatory approvals;
- failure to construct in accordance with permitting and licensing requirements (including satisfaction of NRC requirements);
- failure to satisfy any environmental performance standards and the requirements of tax credits and other incentives;
- continued public and policymaker support for projects;
- adverse weather conditions or natural disasters;
- engineering or design problems;
- changes in project design or scope;
- environmental and geological conditions;
- delays or increased costs to interconnect facilities to transmission grids; and
- increased financing costs as a result of changes in market interest rates or as a result of project delays.

If a Subsidiary Registrant is unable to complete the development or construction of a project or decides to delay or cancel construction of a project, it may not be able to recover its investment in that project and may incur substantial cancellation payments under equipment purchase orders or construction contracts, as well as other costs associated with the closure and/or abandonment of the construction project. See Note 2 to the financial statements under "Kemper County Energy Facility" for information related to the abandonment of and related closure activities and costs for the mine and gasifier-related assets at the Kemper County energy facility.

Additionally, each Southern Company Gas pipeline construction project involves separate joint venture participants, Southern Power participates in partnership agreements with respect to renewable energy projects, and Georgia Power jointly owns Plant Vogtle Units 3 and 4 with other co-owners. Any failure by a partner or co-owner to perform its obligations under the applicable agreements could have a material negative impact on the applicable project under construction. In addition, partnership and joint ownership agreements may provide partners or co-owners with certain decision-making authority in connection with projects under construction, including rights to cause the cancellation of a construction project under certain circumstances.

Even if a construction project (including a joint venture construction project) is completed, the total costs may be higher than estimated and may not be recoverable through regulated rates, if applicable. In addition, construction delays and contractor performance shortfalls can result in the loss of revenues and may, in turn, adversely affect the net income and financial position of the affected registrant. See Note 2 to the financial statements under "FERC Matters – Southern Company Gas" for information regarding the Atlantic Coast Pipeline construction delays and the associated cost increase.

Construction delays could result in the loss of otherwise available tax credits and incentives. Furthermore, if construction projects are not completed according to specification, a registrant may incur liabilities and suffer reduced plant efficiency, higher operating costs, and reduced net income.

Once facilities become operational, ongoing capital expenditures are required to maintain reliable levels of operation. Significant portions of the traditional electric operating companies' existing facilities were constructed many years ago. Older equipment, even if maintained in accordance with good engineering practices, may require significant expenditures to maintain efficiency, to comply with changing environmental requirements, to provide safe and reliable operations, and/or to meet related retirement obligations.

The largest construction project currently underway in the Southern Company system is Plant Vogtle Units 3 and 4.

Plant Vogtle Units 3 and 4 construction and rate recovery

Background

In 2009, the Georgia PSC certified construction of Plant Vogtle Units 3 and 4. Georgia Power holds a 45.7% ownership interest in Plant Vogtle Units 3 and 4. In 2012, the NRC issued the related combined construction and operating licenses, which allowed full construction of the two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities to begin. Until March 2017, construction on Plant Vogtle Units 3 and 4 continued under the Vogtle 3 and 4 Agreement, which was a substantially fixed price agreement. In March 2017, the EPC Contractor filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code.

In connection with the EPC Contractor's bankruptcy filing, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into the Interim Assessment Agreement with the EPC Contractor to allow construction to continue. The Interim Assessment Agreement expired in July 2017 when Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the EPC Contractor entered into the Vogtle Services Agreement. Under the Vogtle Services Agreement, Westinghouse provides facility design and engineering services, procurement and technical support, and staff augmentation on a time and materials cost basis.

In October 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, executed the Bechtel Agreement, a cost reimbursable plus fee arrangement, whereby Bechtel is reimbursed for actual costs plus a base fee and an at-risk fee, which is subject to adjustment based on Bechtel's performance against cost and schedule targets.

Cost and Schedule

Georgia Power's approximate proportionate share of the remaining estimated capital cost to complete Plant Vogtle Units 3 and 4 by the expected in-service dates of November 2021 and November 2022, respectively, is as follows:

		(in billions)
Base project capital cost forecast(a)(b)	$	8.0
Construction contingency estimate		0.4
Total project capital cost forecast(a)(b)		8.4
Net investment as of December 31, 2018(b)		(4.6)
Remaining estimate to complete(a)	**$**	**3.8**

(a) Excludes financing costs expected to be capitalized through AFUDC of approximately $315 million.

(b) Net of $1.7 billion received from Toshiba under the Guarantee Settlement Agreement and approximately $188 million in related Customer Refunds.

Georgia Power estimates that its financing costs for construction of Plant Vogtle Units 3 and 4 will total approximately $3.1 billion, of which $1.9 billion had been incurred through December 31, 2018.

As construction continues, challenges with management of contractors, subcontractors, and vendors; labor productivity, availability, and/or cost escalation; procurement, fabrication, delivery, assembly, and/or installation and testing, including any required engineering changes, of plant systems, structures, and components (some of which are based on new technology that only recently began initial operation in the global nuclear industry at this scale); or other issues could arise and change the projected schedule and estimated cost. Monthly construction production targets required to maintain the current project schedule will continue to increase significantly throughout 2019. To meet these increasing monthly targets, existing craft construction productivity must improve and additional craft laborers must be retained and deployed.

Georgia Power and Southern Nuclear believe it is a leading practice in connection with a construction project of this size and complexity to periodically validate recent construction progress in comparison to the projected schedule and to verify and update quantities of commodities remaining to install, labor productivity, and forecasted staffing needs. This verification process, led by Southern Nuclear, was underway as of December 31, 2018 and is expected to be completed during the second quarter 2019. Georgia Power currently does not anticipate any material changes to the total estimated project capital cost forecast for Plant Vogtle Units 3 and 4 or the expected in-service dates of November 2021 and November 2022, respectively, resulting from this verification process. However, the ultimate impact on cost and schedule, if any, will not be known until the verification process is completed. Georgia Power is required to report the results and any project impacts to the Georgia PSC by May 15, 2019.

There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4 at the federal and state level and additional challenges may arise. Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance matters, including the timely resolution of ITAAC and the related approvals by the NRC, may arise, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs.

The ultimate outcome of these matters cannot be determined at this time. However, any extension of the project schedule is currently estimated to result in additional base capital costs of approximately $50 million per month, based on Georgia Power's ownership interests, and AFUDC of approximately $12 million per month. While Georgia Power is not precluded from seeking recovery of any future capital cost forecast increase, management will ultimately determine whether or not to seek recovery. Any further changes to the capital cost forecast that are not expected to be recoverable through regulated rates will be required to be charged to income and such charges could be material.

Joint Owner Contracts

In November 2017, the Vogtle Owners entered into an amendment to their joint ownership agreements for Plant Vogtle Units 3 and 4 to provide for, among other conditions, additional Vogtle Owner approval requirements. Effective August 31, 2018, the Vogtle Owners further amended the joint ownership agreements to clarify and provide procedures for certain provisions of the joint ownership agreements related to adverse events that require the vote of the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 to continue construction (as amended, and together with the November 2017 amendment, the Vogtle Joint Ownership Agreements).

As a result of the increase in the total project capital cost forecast and Georgia Power's decision not to seek rate recovery of the increase in the base capital costs as described below, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 were required to vote to continue construction. On September 26, 2018, the Vogtle Owners unanimously voted to continue construction of Plant Vogtle Units 3 and 4.

Amendments to the Vogtle Joint Ownership Agreements

In connection with the vote to continue construction, Georgia Power entered into (i) a binding term sheet (Vogtle Owner Term Sheet) with the other Vogtle Owners and MEAG's wholly-owned subsidiaries MEAG Power SPVJ, LLC (MEAG SPVJ), MEAG Power SPVM, LLC (MEAG SPVM), and MEAG Power SPVP, LLC (MEAG SPVP) to take certain actions which partially mitigate potential financial exposure for the other Vogtle Owners, including additional amendments to the Vogtle Joint Ownership Agreements and the purchase of PTCs from the other Vogtle Owners, and (ii) a term sheet (MEAG Term Sheet) with MEAG and MEAG SPVJ to provide funding with respect to MEAG SPVJ's ownership interest in Plant Vogtle Units 3 and 4 (Project J) under certain circumstances. On January 14, 2019, Georgia Power, MEAG, and MEAG SPVJ entered into an agreement to implement the provisions of the MEAG Term Sheet (MEAG Funding Agreement). On February 18, 2019, Georgia Power, the other Vogtle Owners, and MEAG's wholly-owned subsidiaries MEAG SPVJ, MEAG SPVM, and MEAG SPVP entered into certain amendments to the Vogtle Joint Ownership Agreements to implement the provisions of the Vogtle Owner Term Sheet (Global Amendments).

Pursuant to the Global Amendments, and consistent with the Vogtle Owner Term Sheet, the Vogtle Joint Ownership Agreements were modified as follows: (i) each Vogtle Owner must pay its proportionate share of qualifying construction costs for Plant Vogtle Units 3 and 4 based on its ownership percentage up to the estimated cost at completion (EAC) for Plant Vogtle Units 3 and 4 which formed the basis of Georgia Power's forecast of $8.4 billion in the nineteenth VCM plus $800 million; (ii) Georgia Power will be responsible for 55.7% of actual qualifying construction costs between $800 million and $1.6 billion over the EAC in the nineteenth VCM (resulting in $80 million of potential additional costs to Georgia Power), with the remaining Vogtle Owners responsible for 44.3% of such costs pro rata in accordance with their respective ownership interests; and (iii) Georgia

Power will be responsible for 65.7% of qualifying construction costs between $1.6 billion and $2.1 billion over the EAC in the nineteenth VCM (resulting in a further $100 million of potential additional costs to Georgia Power), with the remaining Vogtle Owners responsible for 34.3% of such costs pro rata in accordance with their respective ownership interests.

If the EAC is revised and exceeds the EAC in the nineteenth VCM by more than $2.1 billion, each of the other Vogtle Owners will have a one-time option at the time the project budget forecast is so revised to tender a portion of its ownership interest to Georgia Power in exchange for Georgia Power's agreement to pay 100% of such Vogtle Owner's remaining share of total construction costs in excess of the EAC in the nineteenth VCM plus $2.1 billion. In this event, Georgia Power will have the option of cancelling the project in lieu of purchasing a portion of the ownership interest of any other Vogtle Owner. If Georgia Power accepts the offer to purchase a portion of another Vogtle Owner's ownership interest in Plant Vogtle Units 3 and 4, the ownership interest(s) to be conveyed from the tendering Vogtle Owner(s) to Georgia Power will be calculated based on the proportion of the cumulative amount of construction costs paid by each such tendering Vogtle Owner(s) and by Georgia Power as of the COD of Plant Vogtle Unit 4. For purposes of this calculation, payments made by Georgia Power on behalf of another Vogtle Owner in accordance with the second and third items described in the paragraph above will be treated as payments made by the applicable Vogtle Owner.

In the event the actual costs of construction at completion of a Unit are less than the EAC reflected in the nineteenth VCM report and such Unit is placed in service in accordance with the schedule projected in the nineteenth VCM report (i.e., Plant Vogtle Unit 3 is placed in service by November 2021 or Plant Vogtle Unit 4 is placed in service by November 2022), Georgia Power will be entitled to 60.7% of the cost savings with respect to the relevant Unit and the remaining Vogtle Owners will be entitled to 39.3% of such savings on a pro rata basis in accordance with their respective ownership interests.

For purposes of the foregoing provisions, qualifying construction costs will not include costs (i) resulting from force majeure events, including governmental actions or inactions (or significant delays associated with issuance of such actions) that affect the licensing, completion, start-up, operations, or financing of Plant Vogtle Units 3 and 4, administrative proceedings or litigation regarding ITAAC or other regulatory challenges to commencement of operation of Plant Vogtle Units 3 and 4, and changes in laws or regulations governing Plant Vogtle Units 3 and 4, (ii) legal fees and legal expenses incurred due to litigation with contractors or subcontractors that are not subsidiaries or affiliates of Southern Company, and (iii) additional costs caused by requests from the Vogtle Owners other than Georgia Power, except for the exercise of a right to vote granted under the Vogtle Joint Ownership Agreements, that increase costs by $100,000 or more.

Pursuant to the Global Amendments, and consistent with the Vogtle Owner Term Sheet, the provisions of the Vogtle Joint Ownership Agreements requiring that Vogtle Owners holding 90% of the ownership interests in Plant Vogtle Units 3 and 4 vote to continue construction following certain adverse events (Project Adverse Events) were modified. Pursuant to the Global Amendments, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 must vote to continue construction if certain Project Adverse Events occur, including: (i) the bankruptcy of Toshiba; (ii) the termination or rejection in bankruptcy of certain agreements, including the Vogtle Services Agreement, the Bechtel Agreement, or the agency agreement with Southern Nuclear; (iii) Georgia Power publicly announces its intention not to submit for rate recovery any portion of its investment in Plant Vogtle Units 3 and 4 or the Georgia PSC determines that any of Georgia Power's costs relating to the construction of Plant Vogtle Units 3 and 4 will not be recovered in retail rates, excluding any additional amounts paid by Georgia Power on behalf of the other Vogtle Owners pursuant to the Global Amendments described above and the first 6% of costs during any six-month VCM reporting period that are disallowed by the Georgia PSC for recovery, or for which Georgia Power elects not to seek cost recovery, through retail rates; and (iv) an incremental extension of one year or more over the most recently approved schedule. Under the Global Amendments, Georgia Power may cancel the project at any time in its sole discretion.

In addition, pursuant to the Vogtle Joint Ownership Agreements, the required approval of holders of ownership interests in Plant Vogtle Units 3 and 4 is at least (i) 90% for a change of the primary construction contractor and (ii) 67% for material amendments to the Vogtle Services Agreement or agreements with Southern Nuclear or the primary construction contractor, including the Bechtel Agreement.

The Global Amendments provide that if the holders of at least 90% of the ownership interests fail to vote in favor of continuing the project following any future Project Adverse Event, work on Plant Vogtle Units 3 and 4 will continue for a period of 30 days if the holders of more than 50% of the ownership interests vote in favor of continuing construction (Majority Voting Owners). In such a case, the Vogtle Owners (i) have agreed to negotiate in good faith towards the resumption of the project, (ii) if no agreement is reached during such 30-day period, the project will be cancelled, and (iii) in the event of such a cancellation, the Majority Voting Owners will be obligated to reimburse any other Vogtle Owner for the incremental costs it incurred during such 30-day negotiation period.

Purchase of PTCs During Commercial Operation

Pursuant to the Global Amendments, and consistent with the Vogtle Owner Term Sheet, Georgia Power has agreed to purchase additional PTCs from OPC, Dalton, MEAG SPVM, MEAG SPVP, and MEAG SPVJ (to the extent any MEAG SPVJ PTC rights remain after any purchases required under the MEAG Funding Agreement as described below) at varying purchase prices dependent upon the actual cost to complete construction of Plant Vogtle Units 3 and 4 as compared to the EAC reflected in the nineteenth VCM report. The purchases are at the option of the applicable Vogtle Owner.

Potential Funding to MEAG Project J

Pursuant to the MEAG Funding Agreement, and consistent with the MEAG Term Sheet, if MEAG SPVJ is unable to make its payments due under the Vogtle Joint Ownership Agreements solely as a result of the occurrence of one of the following situations that materially impedes access to capital markets for MEAG for Project J: (i) the conduct of JEA or the City of Jacksonville, such as JEA's legal challenges of its obligations under a PPA with MEAG (PPA-J), or (ii) PPA-J is declared void by a court of competent jurisdiction or rejected by JEA under the applicable provisions of the U.S. Bankruptcy Code (each of (i) and (ii), a JEA Default), at MEAG's request, Georgia Power will purchase from MEAG SPVJ the rights to PTCs attributable to MEAG SPVJ's share of Plant Vogtle Units 3 and 4 (approximately 206 MWs) within 30 days of such request at varying prices dependent upon the stage of construction of Plant Vogtle Units 3 and 4. The aggregate purchase price of the PTCs, together with any advances made as described in the next paragraph, shall not exceed $300 million.

At the option of MEAG, as an alternative or supplement to Georgia Power's purchase of PTCs as described above, Georgia Power has agreed to provide up to $250 million in funding to MEAG for Project J in the form of advances (either advances under the Vogtle Joint Ownership Agreements or the purchase of MEAG Project J bonds, at the discretion of Georgia Power), subject to any required approvals of the Georgia PSC and the DOE.

In the event MEAG SPVJ certifies to Georgia Power that it is unable to fund its obligations under the Vogtle Joint Ownership Agreements as a result of a JEA Default and Georgia Power becomes obligated to provide funding as described above, MEAG is required to (i) assign to Georgia Power its right to vote on any future Project Adverse Event and (ii) diligently pursue JEA for its breach of PPA-J. In addition, Georgia Power agreed that it will not sue MEAG for any amounts due from MEAG SPVJ under MEAG's guarantee of MEAG SPVJ's obligations so long as MEAG SPVJ complies with the terms of the MEAG Funding Agreement as to its payment obligations and the other non-payment provisions of the Vogtle Joint Ownership Agreements.

Under the terms of the MEAG Funding Agreement, Georgia Power may cancel the project in lieu of providing funding in the form of advances or PTC purchases.

Regulatory Matters

In December 2017, the Georgia PSC voted to approve (and issued its related order on January 11, 2018) Georgia Power's recommendation to continue construction and resolved the following regulatory matters related to Plant Vogtle Units 3 and 4: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report should be disallowed from rate base on the basis of imprudence; (ii) the Contractor Settlement Agreement was reasonable and prudent and none of the amounts paid pursuant to the Contractor Settlement Agreement should be disallowed from rate base on the basis of imprudence; (iii) (a) capital costs incurred up to $5.68 billion would be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, (b) Georgia Power would have the burden to show that any capital costs above $5.68 billion were prudent, and (c) a revised capital cost forecast of $7.3 billion (after reflecting the impact of payments received under the Guarantee Settlement Agreement and related Customer Refunds) was found reasonable; (iv) construction of Plant Vogtle Units 3 and 4 should be completed, with Southern Nuclear serving as project manager and Bechtel as primary contractor; (v) approved and deemed reasonable Georgia Power's revised schedule placing Plant Vogtle Units 3 and 4 in service in November 2021 and November 2022, respectively; (vi) confirmed that the revised cost forecast does not represent a cost cap and that prudence decisions on cost recovery will be made at a later date, consistent with applicable Georgia law; (vii) reduced the ROE used to calculate the NCCR tariff (a) from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 ARP) to 10.00% effective January 1, 2016, (b) from 10.00% to 8.30%, effective January 1, 2020, and (c) from 8.30% to 5.30%, effective January 1, 2021 (provided that the ROE in no case will be less than Georgia Power's average cost of long-term debt); (viii) reduced the ROE used for AFUDC equity for Plant Vogtle Units 3 and 4 from 10.00% to Georgia Power's average cost of long-term debt, effective January 1, 2018; and (ix) agreed that upon Unit 3 reaching commercial operation, retail base rates would be adjusted to include carrying costs on those capital costs deemed prudent in the Vogtle Cost Settlement Agreement. The January 11, 2018 order also stated that if Plant Vogtle Units 3 and 4 are not commercially operational by June 1, 2021 and June 1, 2022, respectively, the ROE used to calculate the NCCR tariff will be further reduced by 10 basis points each month (but not lower than Georgia Power's average cost of long-term debt) until the respective Unit is commercially operational. The ROE reductions negatively impacted earnings by approximately $100 million, $25 million, and $20 million in 2018, 2017, and 2016, respectively, and are estimated to have negative earnings impacts of approximately $75 million in 2019 and an aggregate of approximately $615 million from 2020 to 2022.

In its January 11, 2018 order, the Georgia PSC also stated if other conditions change and assumptions upon which Georgia Power's seventeenth VCM report are based do not materialize, the Georgia PSC reserved the right to reconsider the decision to continue construction.

On February 12, 2018, Georgia Interfaith Power & Light, Inc. (GIPL) and Partnership for Southern Equity, Inc. (PSE) filed a petition appealing the Georgia PSC's January 11, 2018 order with the Fulton County Superior Court. On March 8, 2018, Georgia Watch filed a similar appeal to the Fulton County Superior Court for judicial review of the Georgia PSC's decision and denial of Georgia Watch's motion for reconsideration. On December 21, 2018, the Fulton County Superior Court granted Georgia Power's motion to dismiss the two appeals. On January 9, 2019, GIPL, PSE, and Georgia Watch filed an appeal of this decision with the Georgia Court of Appeals. Georgia Power believes the appeal has no merit; however, an adverse outcome in the appeal combined with subsequent adverse action by the Georgia PSC could have a material impact on Southern Company's and Georgia Power's results of operations, financial condition, and liquidity.

In preparation for its nineteenth VCM filing, Georgia Power requested Southern Nuclear to perform a full cost reforecast for the project. This reforecast, performed prior to the nineteenth VCM filing, resulted in a $0.7 billion increase to the base capital cost forecast reported in the second quarter 2018. This base cost increase primarily resulted from changed assumptions related to the finalization of contract scopes and management responsibilities for Bechtel and over 60 subcontractors, labor productivity rates, and craft labor incentives, as well as the related levels of project management, oversight, and support, including field supervision and engineering support.

Although Georgia Power believes these incremental costs are reasonable and necessary to complete the project and the Georgia PSC's order in the seventeenth VCM proceeding specifically states that the construction of Plant Vogtle Units 3 and 4 is not subject to a cost cap, Georgia Power did not seek rate recovery for these cost increases included in the current base capital cost forecast (or any related financing costs) in the nineteenth VCM report. In connection with future VCM filings, Georgia Power may request the Georgia PSC to evaluate costs currently included in the construction contingency estimate for rate recovery as and when they are appropriately included in the base capital cost forecast. After considering the significant level of uncertainty that exists regarding the future recoverability of costs included in the construction contingency estimate since the ultimate outcome of these matters is subject to the outcome of future assessments by management, as well as Georgia PSC decisions in these future regulatory proceedings, Georgia Power recorded a total pre-tax charge to income of $1.1 billion ($0.8 billion after tax) in the second quarter 2018, which includes the total increase in the base capital cost forecast and construction contingency estimate.

The ultimate outcome of these matters cannot be determined at this time.

See Note 2 to the financial statements under "Georgia Power – Nuclear Construction" in Item 8 herein for additional information regarding Plant Vogtle Units 3 and 4.

Southern Company Gas' significant investments in pipelines and pipeline development projects involve financial and execution risks.

Southern Company Gas has made significant investments in existing pipelines and pipeline development projects. Many of the existing pipelines are, and when completed many of the pipeline development projects will be, operated by third parties. If one of these agents fails to perform in a proper manner, the value of the investment could decline and Southern Company Gas could lose part or all of its investment. In addition, from time to time, Southern Company Gas may be required to contribute additional capital to a pipeline joint venture or guarantee the obligations of such joint venture.

With respect to certain pipeline development projects, Southern Company Gas will rely on its joint venture partners for construction management and will not exercise direct control over the process. All of the pipeline development projects are dependent on contractors for the successful and timely completion of the projects. Further, the development of pipeline projects involves numerous regulatory, environmental, construction, safety, political, and legal uncertainties and may require the expenditure of significant amounts of capital. These projects may not be completed on schedule, at the budgeted cost, or at all. There may be cost overruns and construction difficulties that cause Southern Company Gas' capital expenditures to exceed its initial expectations. Moreover, Southern Company Gas' income will not increase immediately upon the expenditure of funds on a pipeline project. Pipeline construction occurs over an extended period of time and Southern Company Gas will not receive material increases in income until the project is placed in service.

Work continues with state and federal agencies to obtain the required permits to begin construction on the PennEast Pipeline. Any material delays may impact forecasted capital expenditures and the expected in-service date.

The Atlantic Coast Pipeline has experienced challenges to its permits since construction began in 2018. During the third and fourth quarters 2018, a FERC stop work order, together with delays in obtaining permits necessary for construction and construction delays due to judicial actions, impacted the cost and schedule for the project. As a result, total project cost estimates have increased and the operator of the joint venture currently expects to achieve a late 2020 in-service date for at least

key segments of the Atlantic Coast Pipeline, while the remainder may extend into early 2021. Abnormal weather, work delays (including due to judicial or regulatory action), and other conditions may result in additional cost or schedule modifications, which could result in an impairment of Southern Company Gas' investment and could have a material impact on Southern Company's and Southern Company Gas' financial statements.

The ultimate outcome of these matters cannot be determined at this time and the occurrence of these or any other of the foregoing events could adversely affect the results of operations, cash flows, and financial condition of Southern Company Gas and Southern Company.

FINANCIAL, ECONOMIC, AND MARKET RISKS

The electric generation and energy marketing operations of the traditional electric operating companies and Southern Power and the natural gas operations of Southern Company Gas are subject to risks, many of which are beyond their control, including changes in energy prices and fuel costs, which may reduce revenues and increase costs.

The generation, energy marketing, and natural gas operations of the Southern Company system are subject to changes in energy prices and fuel costs, which could increase the cost of producing power, decrease the amount received from the sale of energy, and/or make electric generating facilities less competitive. The market prices for these commodities may fluctuate significantly over relatively short periods of time. Among the factors that could influence energy prices and fuel costs are:

- prevailing market prices for coal, natural gas, uranium, fuel oil, biomass, and other fuels, as applicable, used in the generation facilities of the traditional electric operating companies and Southern Power and, in the case of natural gas, distributed by Southern Company Gas, including associated transportation costs, and supplies of such commodities;
- demand for energy and the extent of additional supplies of energy available from current or new competitors;
- liquidity in the general wholesale electricity and natural gas markets;
- weather conditions impacting demand for electricity and natural gas;
- seasonality;
- transmission or transportation constraints, disruptions, or inefficiencies;
- availability of competitively priced alternative energy sources;
- forced or unscheduled plant outages for the Southern Company system, its competitors, or third party providers;
- the financial condition of market participants;
- the economy in the Southern Company system's service territory, the nation, and worldwide, including the impact of economic conditions on demand for electricity and the demand for fuels, including natural gas;
- natural disasters, wars, embargos, physical or cyber attacks, and other catastrophic events; and
- federal, state, and foreign energy and environmental regulation and legislation.

These factors could increase the expenses and/or reduce the revenues of the registrants. For the traditional electric operating companies and Southern Company Gas' regulated gas distribution operations, such impacts may not be fully recoverable through rates.

Historically, the traditional electric operating companies and Southern Company Gas from time to time have experienced underrecovered fuel and/or purchased gas cost balances and may experience such balances in the future. While the traditional electric operating companies and Southern Company Gas are generally authorized to recover fuel and/or purchased gas costs through cost recovery clauses, recovery may be denied if costs are deemed to be imprudently incurred, and delays in the authorization of such recovery, both of which could negatively impact the cash flows of the affected traditional electric operating company or Southern Company Gas and of Southern Company.

The registrants are subject to risks associated with a changing economic environment, customer behaviors, including increased energy conservation, and adoption patterns of technologies by the customers of the Subsidiary Registrants.

The consumption and use of energy are fundamentally linked to economic activity. This relationship is affected over time by changes in the economy, customer behaviors, and technologies. Any economic downturn could negatively impact customer growth and usage per customer, thus reducing the sales of energy and revenues. Additionally, any economic downturn or disruption of financial markets, both nationally and internationally, could negatively affect the financial stability of customers and counterparties of the Subsidiary Registrants.

Outside of economic disruptions, changes in customer behaviors in response to energy efficiency programs, changing conditions and preferences, or changes in the adoption of technologies could affect the relationship of economic activity to the consumption of energy.

Both federal and state programs exist to influence how customers use energy, and several of the traditional electric operating companies and Southern Company Gas have PSC or other applicable state regulatory agency mandates to promote energy efficiency. Conservation programs could impact the financial results of the registrants in different ways. For example, if any traditional electric operating company or Southern Company Gas is required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact on such traditional electric operating company or Southern Company Gas and Southern Company. Customers could also voluntarily reduce their consumption of energy in response to decreases in their disposable income, increases in energy prices, or individual conservation efforts.

In addition, the adoption of technology by customers can have both positive and negative impacts on sales. Many new technologies utilize less energy than in the past. However, electric and natural gas technologies such as electric and natural gas vehicles can create additional demand. The Southern Company system uses best available methods and experience to incorporate the effects of changes in customer behavior, state and federal programs, PSC or other applicable state regulatory agency mandates, and technology, but the Southern Company system's planning processes may not appropriately estimate and incorporate these effects.

All of the factors discussed above could adversely affect a registrant's results of operations, financial condition, and liquidity.

The operating results of the registrants are affected by weather conditions and may fluctuate on a seasonal and quarterly basis. In addition, catastrophic events, such as fires, earthquakes, hurricanes, tornadoes, floods, droughts, and storms, could result in substantial damage to or limit the operation of the properties of a Subsidiary Registrant and could negatively impact results of operation, financial condition, and liquidity.

Electric power and natural gas supply are generally seasonal businesses. In many parts of the country, demand for power peaks during the summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter months. While the electric power sales of some of the traditional electric operating companies peak in the summer, others peak in the winter. In the aggregate, electric power sales peak during the summer with a smaller peak during the winter. Additionally, Southern Power has variability in its revenues from renewable generation facilities due to seasonal weather patterns primarily from wind and sun. In most of the areas Southern Company Gas serves, natural gas demand peaks during the winter. As a result, the overall operating results of the registrants may fluctuate substantially on a seasonal basis. In addition, the Subsidiary Registrants have historically sold less power and natural gas when weather conditions are milder. Unusually mild weather in the future could reduce the revenues, net income, and available cash of the affected registrant.

Further, volatile or significant weather events could result in substantial damage to the transmission and distribution lines of the traditional electric operating companies, the generating facilities of the traditional electric operating companies and Southern Power, and the natural gas distribution and storage facilities of Southern Company Gas. The Subsidiary Registrants have significant investments in the Atlantic and Gulf Coast regions and Southern Power and Southern Company Gas have investments in various states which could be subject to severe weather and natural disasters, including wildfires. Further, severe drought conditions can reduce the availability of water and restrict or prevent the operation of certain generating facilities. There have been multiple significant hurricanes in the Southern Company system service territory in recent years.

In the event a traditional electric operating company or Southern Company Gas experiences any of these weather events or any natural disaster or other catastrophic event, recovery of costs in excess of reserves and insurance coverage is subject to the approval of its state PSC or other applicable state regulatory agency. Historically, the traditional electric operating companies from time to time have experienced deficits in their storm cost recovery reserve balances and may experience such deficits in the future. For example, at December 31, 2018, Georgia Power had a substantial underrecovered balance in its storm cost recovery balance as a result of multiple recent significant hurricanes in its service territory. Any denial by the applicable state PSC or other applicable state regulatory agency or delay in recovery of any portion of such costs could have a material negative impact on a traditional electric operating company's or Southern Company Gas' and on Southern Company's results of operations, financial condition, and liquidity.

In addition, damages resulting from significant weather events within the service territory of any traditional electric operating company or Southern Company Gas or affecting Southern Power's customers may result in the loss of customers and reduced demand for energy for extended periods and may impact customers' ability to perform under existing PPAs. See Note 1 to the financial statements under "Revenues – Concentration of Revenue" in Item 8 herein for additional information on Pacific Gas & Electric Company's bankruptcy filing. Any significant loss of customers or reduction in demand for energy could have a material negative impact on a registrant's results of operations, financial condition, and liquidity.

Acquisitions, dispositions, or other strategic ventures or investments may not result in anticipated benefits and may present risks not originally contemplated, which may have a material adverse effect on the liquidity, results of operations, and financial condition of Southern Company and its subsidiaries.

Southern Company and its subsidiaries have made significant acquisitions and investments in the past, as well as recent dispositions, and may in the future make additional acquisitions, dispositions, or other strategic ventures or investments, including the pending disposition by Southern Power of Plant Mankato, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries. Southern Company and its subsidiaries continually seek opportunities to create value through various transactions, including acquisitions or sales of assets. Specifically, Southern Power continually seeks opportunities to execute its strategy to create value through various transactions, including acquisitions, dispositions, and sales of partnership interests, development and construction of new generating facilities, and entry into PPAs primarily with investor-owned utilities, IPPs, municipalities, and other load-serving entities, as well as commercial and industrial customers.

Southern Company and its subsidiaries may face significant competition for transactional opportunities and anticipated transactions may not be completed on acceptable terms or at all. In addition, these transactions are intended to, but may not, result in the generation of cash or income, the realization of savings, the creation of efficiencies, or the reduction of risk. These transactions may also affect the liquidity, results of operations, and financial condition of Southern Company and its subsidiaries.

These transactions also involve risks, including:

- they may not result in an increase in income or provide adequate or expected funds or return on capital or other anticipated benefits;
- they may result in Southern Company or its subsidiaries entering into new or additional lines of business, which may have new or different business or operational risks;
- they may not be successfully integrated into the acquiring company's operations and/or internal control processes;
- the due diligence conducted prior to a transaction may not uncover situations that could result in financial or legal exposure or may not appropriately evaluate the likelihood or quantify the exposure from identified risks;
- they may result in decreased earnings, revenues, or cash flow;
- Southern Company, Southern Company Gas, and certain of their subsidiaries have retained obligations in connection with transitional agreements related to dispositions that subject these companies to additional risk;
- Southern Company or the applicable subsidiary may not be able to achieve the expected financial benefits from the use of funds generated by any dispositions;
- expected benefits of a transaction may be dependent on the cooperation or performance of a counterparty; or
- for the traditional electric operating companies and Southern Company Gas, costs associated with such investments that were expected to be recovered through regulated rates may not be recoverable.

Southern Company and Southern Company Gas are holding companies and Southern Power owns many of its assets indirectly through subsidiaries. Each of these companies is dependent on cash flows from their respective subsidiaries to meet their ongoing and future financial obligations, including making interest and principal payments on outstanding indebtedness and, for Southern Company, to pay dividends on its common stock.

Southern Company and Southern Company Gas are holding companies and, as such, they have no operations of their own. Substantially all of Southern Company's and Southern Company Gas' and many of Southern Power's respective consolidated assets are held by subsidiaries. A significant portion of Southern Company Gas' debt is issued by its 100%-owned subsidiary, Southern Company Gas Capital, and is fully and unconditionally guaranteed by Southern Company Gas. Southern Company's, Southern Company Gas' and, to a certain extent, Southern Power's ability to meet their respective financial obligations, including making interest and principal payments on outstanding indebtedness, and, for Southern Company, to pay dividends on its common stock, is dependent on the net income and cash flows of their respective subsidiaries and the ability of those subsidiaries to pay upstream dividends or to repay borrowed funds. Prior to funding Southern Company, Southern Company Gas, or Southern Power, the respective subsidiaries have financial obligations and, with respect to Southern Company and Southern Company Gas, regulatory restrictions that must be satisfied, including among others, debt service and preferred stock dividends. These subsidiaries are separate legal entities and, except as described below, have no obligation to provide Southern Company, Southern Company Gas, or Southern Power with funds. Certain of Southern Power's assets are held through controlling interests in subsidiaries. In certain cases, distributions without partner consent are limited to available cash, and the subsidiaries are obligated to distribute all available cash to their owners each quarter. In addition, Southern Company, Southern Company Gas, and Southern Power may provide capital contributions or debt financing to subsidiaries under certain circumstances, which would reduce the funds available to meet their respective financial obligations, including making interest and principal payments on outstanding indebtedness, and to pay dividends on Southern Company's common stock.

A downgrade in the credit ratings of any of the registrants, Southern Company Gas Capital, or Nicor Gas could negatively affect their ability to access capital at reasonable costs and/or could require posting of collateral or replacing certain indebtedness.

There are a number of factors that rating agencies evaluate to arrive at credit ratings for the registrants, Southern Company Gas Capital, and Nicor Gas, including capital structure, regulatory environment, the ability to cover liquidity requirements, and other commitments for capital. The registrants, Southern Company Gas Capital, and Nicor Gas could experience a downgrade in their ratings if any rating agency concludes that the level of business or financial risk of the industry or the applicable company has deteriorated. Changes in ratings methodologies by the agencies could also have a negative impact on credit ratings. If one or more rating agencies downgrade any registrant, Southern Company Gas Capital, or Nicor Gas, borrowing costs likely would increase, including automatic increases in interest rates under applicable term loans and credit facilities, the pool of investors and funding sources would likely decrease, and, particularly for any downgrade to below investment grade, significant collateral requirements may be triggered in a number of contracts. Any credit rating downgrades could require altering the mix of debt financing currently used, and could require the issuance of secured indebtedness and/or indebtedness with additional restrictive covenants binding the applicable company.

Uncertainty in demand for energy can result in lower earnings or higher costs. If demand for energy falls short of expectations, it could result in potentially stranded assets. If demand for energy exceeds expectations, it could result in increased costs for purchasing capacity in the open market or building additional electric generation and transmission facilities or natural gas distribution and storage facilities.

Southern Company, the traditional electric operating companies, and Southern Power each engage in a long-term planning process to estimate the optimal mix and timing of new generation assets required to serve future load obligations. Southern Company Gas engages in a long-term planning process to estimate the optimal mix and timing of building new pipelines and storage facilities, replacing existing pipelines, rewatering storage facilities, and entering new markets and/or expanding in existing markets. These planning processes must look many years into the future in order to accommodate the long lead times associated with the permitting and construction of new generation and associated transmission facilities and natural gas distribution and storage facilities. Inherent risk exists in predicting demand as future loads are dependent on many uncertain factors, including economic conditions, customer usage patterns, efficiency programs, and customer technology adoption. Because regulators may not permit the traditional electric operating companies or Southern Company Gas' regulated operating companies to adjust rates to recover the costs of new generation and associated transmission assets and/or new pipelines and related infrastructure in a timely manner or at all, Southern Company and its subsidiaries may not be able to fully recover these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs and the recovery in customers' rates. In addition, under Southern Power's model of selling capacity and energy at negotiated market-based rates under long-term PPAs, Southern Power might not be able to fully execute its business plan if market prices drop below original forecasts. Southern Power and/or the traditional electric operating companies may not be able to extend existing PPAs or find new buyers for existing generation assets as existing PPAs expire, or they may be forced to market these assets at prices lower than originally intended. These situations could have negative impacts on net income and cash flows for the affected registrant.

The traditional electric operating companies are currently obligated to supply power to retail customers and wholesale customers under long-term PPAs. Southern Power is currently obligated to supply power to wholesale customers under long-term PPAs. At peak times, the demand for power required to meet this obligation could exceed the Southern Company system's available generation capacity. Market or competitive forces may require that the traditional electric operating companies purchase capacity on the open market or build additional generation and transmission facilities and that Southern Power purchase energy or capacity on the open market. Because regulators may not permit the traditional electric operating companies to pass all of these purchase or construction costs on to their customers, the traditional electric operating companies may not be able to recover some or all of these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs of purchased or constructed capacity and the traditional electric operating companies' recovery in customers' rates. Under Southern Power's long-term fixed price PPAs, Southern Power may not be able to recover all of these costs. These situations could have negative impacts on net income and cash flows for the affected registrant.

The businesses of the registrants, SEGCO, and Nicor Gas are dependent on their ability to successfully access funds through capital markets and financial institutions. The inability of any of the registrants, SEGCO, or Nicor Gas to access funds may limit its ability to execute its business plan by impacting its ability to fund capital investments or acquisitions that it may otherwise rely on to achieve future earnings and cash flows.

The registrants, SEGCO, and Nicor Gas rely on access to both short-term money markets and longer-term capital markets as a significant source of liquidity for capital requirements not satisfied by the cash flow from their respective operations. If any of the registrants, SEGCO, or Nicor Gas is not able to access capital at competitive rates or on favorable terms, its ability to implement its business plan will be limited by impacting its ability to fund capital investments or acquisitions that it may otherwise rely on to achieve future earnings and cash flows. In addition, the registrants, SEGCO, and Nicor Gas rely on committed bank lending agreements as back-up liquidity which allows them to access low cost money markets. Each of the registrants, SEGCO, and Nicor Gas believes that it will maintain sufficient access to these financial markets based upon current credit ratings. However, certain events or market disruptions may increase the cost of borrowing or adversely affect the ability to raise capital through the issuance of securities or other borrowing arrangements or the ability to secure committed bank lending agreements used as back-up sources of capital. Such disruptions could include:

- an economic downturn or uncertainty;
- bankruptcy or financial distress at an unrelated energy company, financial institution, or sovereign entity;
- capital markets volatility and disruption, either nationally or internationally;
- changes in tax policy, including further interpretation and guidance on tax reform;

- volatility in market prices for electricity and natural gas;
- actual or threatened cyber or physical attacks on the Southern Company system's facilities or unrelated energy companies' facilities;
- war or threat of war; or
- the overall health of the utility and financial institution industries.

Georgia Power's ability to make future borrowings through its term loan credit facility with the FFB is subject to the satisfaction of customary conditions, as well as certification of compliance with the requirements of the loan guarantee program under Title XVII of the Energy Policy Act of 2005, including accuracy of project-related representations and warranties, delivery of updated project-related information and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Title XVII Loan Guarantee Program. Prior to obtaining any further advances under Georgia Power's loan guarantee agreement with the DOE, Georgia Power is required to obtain the DOE's approval of the Bechtel Agreement.

Failure to comply with debt covenants or conditions could adversely affect the ability of the registrants, SEGCO, Southern Company Gas Capital, or Nicor Gas to execute future borrowings.

The debt and credit agreements of the registrants, SEGCO, Southern Company Gas Capital, and Nicor Gas contain various financial and other covenants. Georgia Power's loan guarantee agreement with the DOE contains additional covenants, events of default, and mandatory prepayment events relating to the construction of Plant Vogtle Units 3 and 4. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements, which would negatively affect the applicable company's financial condition and liquidity.

Volatility in the securities markets, interest rates, and other factors could substantially increase defined benefit pension and other postretirement plan costs and the funding available for nuclear decommissioning.

The costs of providing pension and other postretirement benefit plans are dependent on a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plan, changes in actuarial assumptions, government regulations, and/or life expectancy, and the frequency and amount of the Southern Company system's required or voluntary contributions made to the plans. Changes in actuarial assumptions and differences between the assumptions and actual values, as well as a significant decline in the value of investments that fund the pension and other postretirement plans, if not offset or mitigated by a decline in plan liabilities, could increase pension and other postretirement expense, and the Southern Company system could be required from time to time to fund the pension plans with significant amounts of cash. Such cash funding obligations could have a material impact on liquidity by reducing cash flows and could negatively affect results of operations. Additionally, Alabama Power and Georgia Power each hold significant assets in their nuclear decommissioning trusts to satisfy obligations to decommission Alabama Power's and Georgia Power's nuclear plants. The rate of return on assets held in those trusts can significantly impact both the funding available for decommissioning and the funding requirements for the trusts.

The registrants are subject to risks associated with their ability to obtain adequate insurance at acceptable costs.

The financial condition of some insurance companies, actual or threatened physical or cyber attacks, and natural disasters, among other things, could have disruptive effects on insurance markets. The availability of insurance covering risks that the registrants and their respective competitors typically insure against may decrease, and the insurance that the registrants are able to obtain may have higher deductibles, higher premiums, and more restrictive policy terms. Further, the insurance policies may not cover all of the potential exposures or the actual amount of loss incurred.

Any losses not covered by insurance, or any increases in the cost of applicable insurance, could adversely affect the results of operations, cash flows, or financial condition of the affected registrant.

The use of derivative contracts by Southern Company and its subsidiaries in the normal course of business could result in financial losses that negatively impact the net income of the registrants or in reported net income volatility.

Southern Company and its subsidiaries use derivative instruments, such as swaps, options, futures, and forwards, to manage their commodity and interest rate exposures and, to a lesser extent, manage foreign currency exchange rate exposure and engage in limited trading activities. The registrants could recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform. These risks are managed through risk management policies, limits, and procedures, which might not work as planned and cannot entirely eliminate the risks associated with these activities. In addition, derivative contracts entered into for hedging purposes might not offset the underlying exposure being hedged as expected, resulting in financial losses. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. The factors used in the valuation of these instruments become more difficult to predict and the calculations become less reliable further into the

ALABAMA POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

ALABAMA POWER COMPANY

By: Mark A. Crosswhite
Chairman, President, and Chief Executive Officer

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 19, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Mark A. Crosswhite
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Anita Allcorn-Walker
Vice President and Comptroller
(Principal Accounting Officer)

Directors:

Whit Armstrong	*Robert D. Powers*
Angus R. Cooper, III	*Catherine J. Randall*
O. B. Grayson Hall, Jr.	*C. Dowd Ritter*
Anthony A. Joseph	*R. Mitchell Shackleford, III*
James K. Lowder	*Phillip M. Webb*

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 19, 2019

A.P.S.C. DOCKET NO 32953
Ala. Solar Ind. Assn. EX NO 3
Bush Cross

Company is proposing to acquire, and Barry Unit 8, correct?

A. That's correct.

Q. So you have no written analysis to offer concerning this opinion that those units are unlikely to become stranded assets during their remaining lives, correct?

A. I don't have written analysis specifically, but given the efficiencies, for example, for Barry 8, would be the most efficient combined cycle unit on the system, and the rest of the system would be impacted significantly more than Barry 8. I don't expect it to be a stranded asset.

Q. Is the efficiency of the unit the only thing that determines whether or not it will become a stranded asset?

A. No.

Q. And you haven't analyzed those other factors besides your general --

A. I don't have any analysis relative to that.

Q. And you're not assuming, sir, any legal responsibility for the accuracy, completeness, or

Georgia Power

BIN 10230
241 Ralph McGill Blvd NE
Atlanta, GA 30308-3374

A.P.S.C. DOCKET NO 32953
Ala Solar Ind Assn.'s EX. NO. 4
WITNESS Looney Cross

EXHIBIT
4
ALA SOLAR INDUSTRY ASSN
PENGAD 800-631-6989

March 22, 2017

Mr. Reece McAlister
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, GA 30334-5701

Re: Georgia Power Company's 2016 Integrated Resource Plan and Application for Decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT; Docket No. 40161

Dear Mr. McAlister:

Enclosed for filing pursuant to the Georgia Public Service Commission's December 22, 2016, Order Approving Joint Recommendation Regarding the Renewable Cost Benefit Framework, are the original and 15 copies of Georgia Power Company's "A Framework for Determining the Costs and Benefits of Renewable Resources in Georgia" ("Framework") This document, filed originally in Technical Appendix Volume 1 to Georgia Power's 2016 Integrated Resource Plan, has been modified to reflect the changes agreed upon by Staff and the Company.

Please note that the Framework is being filed Public Disclosure. Georgia Power is also filing Trade Secret and Public Disclosure versions of the updated Table 1 from the solar and wind analysis documents filed in Technical Appendix Volume 1 (entitled "The Costs and Benefits of Distributed Solar Generation in Georgia" and "The Costs and Benefits of Fixed and Variable Wind Delivered to Georgia," respectively).

Should you have any questions, please call me at 404-506-3050.

Sincerely,

Kyle C. Leach
Vice President, Regulatory Affairs

Encl.

Table 1: Levelized Costs and Benefits of Distributed Solar Generation ($/MWH)

Tranche Size	1000
Avoided Energy Costs	REDACTED
Deferred Generation Capacity Costs	REDACTED
Deferred Transmission Investment	REDACTED
Reduced Distribution Losses	REDACTED
Distribution Operations Costs	
Ancillary Services - Reactive Supply and Voltage Control	
Generation Remix Costs	REDACTED
Support Capacity (Flexible Reserves)	REDACTED
Bottom Out Costs	
Long Term Service Agreement (LTSA) Maintenance Costs	
Target Reserve Margin Costs	
Program and Administration Costs	
Total Net Avoided Cost	REDACTED

** The results shown in Table 1 are levelized across 30 years beginning in 2019. Positive values represent benefits. Negative (red) values represent costs.*

Table 1: Levelized Costs and Benefits of Wind ($/MWH)

Tranche Size	Variable Wind 1000MW	Fixed Wind 1000MW
Avoided Energy	REDACTED	REDACTED
Deferred Generation Capacity Costs	REDACTED	REDACTED
Deferred Transmission Investment	N/A	N/A
Reduced Distribution Losses	N/A	N/A
Distribution Operations Cost		
Ancillary Services – Reactive Supply and Voltage Control		
Generation Remix Costs	REDACTED	REDACTED
Support Capacity (Flexible Reserves)	REDACTED	N/A
Bottom Out Costs		
Long Term Service Agreement Maintenance Costs		
Target Reserve Margin Costs		
Program and Administration Costs		
Total Net Avoided Cost	REDACTED	REDACTED

** The results shown in Table 1 are levelized across 30 years beginning in 2019. Positive values represent benefits. Negative (red) values represent costs.*

A Framework for Determining The Costs and Benefits of Renewable Resources in Georgia

Revised: 3/22/17

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SECTION 1 – EXECUTIVE SUMMARY

Introduction

When considering any generation technology, including renewable resources, it is crucial that all of the appropriate benefits and costs of such technology be determined and allocated in a way that ensures equitable treatment and continued reliability of the system. Such analysis is particularly important in light of the dramatic increase of renewable resources being deployed to serve customers. Additionally, there have been numerous "Value of Solar" (VOS) studies performed in the industry in recent years suggesting various benefits associated with solar generation. Over the same period, there has been increased activity by the solar industry at the various state regulatory agencies of the Southern Companies, some of which have suggested the need for a "Value of Solar" determination within those jurisdictions. As a result, the Southern Companies have established a Framework for Determining the Costs and Benefits of Renewable Resources on the Southern Company electric system ("Framework" or "RCB Framework"). The purpose of this document is to describe that Framework and how it will be used in determining the costs and benefits of renewable resources on the Southern Company electric system, specifically related to Georgia Power Company.

Limitations on the Scope of Analysis

When considering the costs and benefits of renewable resources (or any other technology), there are many possible views. Given the vertically integrated, state-regulated nature of Georgia Power, however, there are certain limitations regarding what can (and cannot) properly be considered in such analyses. This Framework is based on existing legal and regulatory requirements applicable to Georgia Power as well as industry standards. The overall value of solar generation to Georgia Power is sensitive to changes in such rules, regulations, and standards, but until any such changes are known with certainty, an analysis cannot be predicated upon them. Similarly, this Framework considers technology and supporting infrastructure, as they exist presently. Future technological developments may well have an impact on the costs and benefits of solar generation, but until such developments transpire, a practical analysis can only account for the current state of technology and infrastructure.

Components Included In Cost-Benefit Analysis

Upon reviewing various industry studies and reports related to the Value of Solar and comparing them to the Southern Companies' current generation evaluation methodologies, and based on our experience with actual renewable resources installed on the Southern Company system, the Southern Companies identified components that should be considered in calculating the costs and benefits of renewable resources on the Southern Company electric system. Among the studies reviewed are the following: "Minnesota Value of Solar: Methodology" (April 2014); "2014 Value of Solar at Austin Energy"

(October 2013); "The Benefits and Cost of Solar Distributed Generation for Arizona Public Service" (May 2013); "A Review of Solar PV Benefits & Cost Studies" (April 2013); "The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania" (November 2012); "The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources" (February 2014); and "Maine Distributed Solar Valuation Study" (March 2015).

Due to the non-dispatchable, intermittent nature, the two primary types of renewable resources impacted by this Framework are wind and solar. For purposes of illustration, solar is utilized throughout this document. However, wind will yield similar impacts and results. Where needed for clarity, references may be made regarding the specific circumstances related to wind generation. For solar resources, the Southern Companies recognize five different categories of solar to differentiate the type of solar generation being evaluated. Those categories are as follows:

1. **Utility Scale-Transmission (US-T):** Central station solar generation facilities that are interconnected at the transmission level.
2. **Utility Scale-Distribution (US-D):** Central station solar generation facilities that are interconnected at the distribution level on a dedicated distribution feeder.
3. **Distributed-Greenfield (DG-G):** Central station solar generation facilities that are interconnected at the distribution level on an existing (non-dedicated) distribution feeder.
4. **Distributed-Metered (DG-M):** Solar generation at a customer's site where the solar generation is metered separately from the load.
5. **Distributed-Behind the Meter (DG-BM):** Solar generation at a customer's site where only a single bi-directional meter exists, with any generation in excess of load sold to the host utility in accordance with applicable laws and tariff requirements.

Appendix E contains representative single line diagrams for each of the above categories.

Table 1 shows the list of cost-benefit components included in this Framework and whether each component is a cost or a benefit. Each of these components is discussed further in Section 3.

Table 1: In Scope Renewable Cost Benefit Components

Component	Utility Scale	Distributed Generation
Avoided Fuel and Purchased Power Costs	Benefit	Benefit
Avoided Generation VO&M Costs	Benefit	Benefit
Avoided Environmental Compliance Costs	Benefit	Benefit
Deferred Generation Capacity Costs	Benefit	Benefit
Deferred Generation FO&M Costs	Benefit	Benefit
Reduced Transmission Losses (Energy Related)	Benefit	Benefit
Reduced Transmission Losses (Capacity Related)	(1)	Benefit
Deferred Transmission Investment	(1)	Benefit
Reduced Distribution Losses (Energy Related)	N/A	(2)
Distribution Operations Costs	N/A	Cost
Generation Remix Costs	Cost or Benefit	Cost or Benefit

Component	Utility Scale	Distributed Generation
Ancillary Services – Reactive Supply and Voltage Control	N/A	Cost
Ancillary Services – Regulation	Cost	Cost
Support Capacity (Flexible Reserves)	Cost	Cost
Bottom Out Costs	Cost	Cost
Long Term Service Agreement Maintenance Cost	Cost	Cost
Target Reserve Margin Cost	Cost or Benefit	Cost or Benefit
Program and Administration Costs	(See note 3)	

Notes:

(1) Determined on a case by case basis.

(2) Should be determined on a case by case basis for DG-G, but will be presumed as a discounted benefit in the aggregate. Represents a benefit for DG-M and DG-BM.

(3) Determined on an Operating Company specific basis.

SECTION 2 – BACKGROUND AND PURPOSE

In recent years, the cost of renewable resources has dropped significantly, and there have been a number of developments related to renewable resources in the electric industry in general and in the Southeast in particular.

A number of states have adopted public policies supporting the development of renewable resources. In some states, such as California, Arizona, North Carolina, and Minnesota, regulatory policies have been established specifically favoring solar generation and other renewables relative to other resources. These policies have resulted in subsidies to the renewable industry through mechanisms such as tax incentives, special financing, VOS payments, and even net metering requirements. These state subsidies augment the existing federal subsidies. These policies have resulted in significant penetrations of renewable resources in those regions, which have stimulated increased interest for renewable resources in other areas.

In the Southeast, a number of initiatives have increased the interest in renewables, particularly solar energy. For example, in the state of Florida, interveners in the Florida Energy Efficiency and Conservation Act Goal Setting Docket have filed testimony arguing that a VOS study be initiated, with the potential end result being payments made to solar generators in that state. In Mississippi, the Mississippi Public Service Commission is holding proceedings relating to the promulgation and implementation of net metering and interconnection standards. Prior to commencing these proceedings, the Commission hired an external consultant from the solar industry to establish the estimated value of solar.

The most interest in solar in the Southern Company electric system, however, has occurred in the state of Georgia. In 2002, the Georgia Public Service Commission (GPSC) authorized the Renewable and Non Renewable (RNR) tariff for generators to sell their renewable energy to the Company. In 2003, the GPSC approved the Green Energy Program, which utilized solar generation from RNR participants with single-directional metering as a program resource. In 2011, the Large Scale Solar program sought to purchase up to 50MW of energy from utility scale projects at a fixed price not to exceed projected long-term avoided energy and capacity costs. In 2012, Georgia Power implemented the Advanced Solar Initiative and is currently purchasing energy from 206MW of solar resources (90MW distributed and 116MW utility scale) at a price not to exceed the projected 2010 IRP avoided energy and capacity costs. As part of the 2013 IRP Final Order, Georgia Power is implementing a second phase of the Advanced

Solar Initiative to add to its generation mix 539MW of solar resources (100MW distributed and 439MW utility scale) at prices not to exceed projected avoided costs. In 2014, the Georgia Solar Energy Industry Association (GSEIA) filed a petition asking for workshops to establish a statewide VOS methodology for the distributed generation (DG) portion of the second round of the Advanced Solar Initiative. Georgia Power responded with an alternative proposal to implement a competitive bidding process (Market Based Pricing). As a result, the GPSC agreed to have 50MW of the required 100MW of ASI distributed solar generation implemented through a competitive bid process.

Considering these developments, the Southern Companies have worked to establish a methodology to appropriately reflect the costs and benefits of renewable resources across the Southern Company electric system. This methodology is consistent with how other resource additions are evaluated and, among other things, quantifies the non-dispatchable, intermittent nature of renewable resources and their effect on system reliability. This methodology also recognizes that each of the retail operating companies has different service obligations and varying regulatory requirements and policies governing such service. Given such, a uniform application of the methodology by each of the operating companies should not be expected, as case-specific circumstances may warrant the inclusion or exclusion of certain components in order to appropriately quantify the costs and benefits of a particular renewable resource being added to a particular operating company's system. This Framework document is specific to Georgia Power Company.

This Framework does not and is not intended to represent an endorsement of any particular form of incentives or compensation for distributed solar generation or any renewable resource in particular. Nor does it represent any presumption regarding pricing structures or compensation arrangements that may be appropriate for any future programs or individual generator agreements undertaken in the various regulatory jurisdictions. Furthermore, this Framework by design cannot reflect full consideration of the various laws, regulations, and policies prevailing in the different jurisdictions served by the Southern Companies. Rather, the Framework establishes a means for determining an objective assessment of the costs and benefits of renewable resources within jurisdictions served by the Southern Companies. How the Framework may be used in various jurisdictions for the development of future programs, incentives, or pricing structures will be the prerogative of those jurisdictions.

SECTION 3 – RENEWABLE COST-BENEFIT COMPONENTS CONSIDERED

This section describes the components that were considered for potential inclusion in the RCB Framework.

Definitions

Avoided Energy Cost: The energy-related costs that are avoided on the Southern Company electric system in any given hour (including components associated with marginal replacement fuel costs, Variable Operations and Maintenance, Fuel Handling, compliance related environmental costs, intra-day commitment costs, and transmission losses) because the load was served by the renewable generation.

Capacity Worth Factor Table: Sometimes referred to as a Loss of Load Probability (LOLP) Table, the Capacity Worth Factor Table (CWFT) is the relative allocation of capacity worth across the year and represents the relative reliability risk (i.e., risk of unserved energy) in one hour relative to another.

Distributed-Behind the Meter (DG-BM): Renewable generation at a customer's site where only a single bi-directional meter exists, with generation in excess of load pushed to the grid in accordance with applicable laws and tariff requirements. This type of solar facility is typically less than 125% of the connected load.

Distributed-Greenfield (DG-G): Central station solar generation facilities that are interconnected at the distribution level on an existing (non-dedicated) distribution feeder.

Distributed-Metered (DG-M): Solar generation at a customer's site where the solar generation is metered separately from the load. This type of solar facility is typically less than 125% of the connected load.

Economic Carrying Cost (ECC): The capital and Fixed Operations & Maintenance (FOM) related cost of deferring an investment for one year. ECC represents the avoided cost of an investment for a given year.

Flexible Resource: Any resource that can be committed (i.e., brought online such that it is providing energy to the grid) in 30 minutes and fully dispatched (i.e., brought to its desired level) within 60 minutes.

Incremental Capacity Equivalent (ICE): The equivalent capacity value of a potential resource that is based on the resource's contribution to reducing expected unserved energy as compared to that of a dispatchable combustion turbine (CT) resource.

Long Term Service Agreement (LTSA): The long-term warranty and maintenance agreements on combustion turbine and combined cycle facilities that define certain maintenance requirements as a function of certain unit operations.

Renewable Energy Credit (REC): A certificate, document, or record representing the environmental attributes of 1 megawatt-hour (MWH) of energy produced by a qualified renewable resource.

Utility Scale-Distribution (US-D): Central station solar generation facilities that are interconnected at the distribution level on a dedicated distribution feeder.

Utility Scale-Transmission (US-T): Central station solar generation facilities that are interconnected at the transmission level.

Variable Energy Resource (VER): A device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.[1]

The following section provides detailed discussion on each component considered for inclusion in the RCB Framework.

<u>**Avoided Fuel and Purchased Power Costs**</u>

Recommendation: Include as part of Avoided Energy Cost. As such, this item is a project-specific component.

[1] This definition was established by FERC: FERC Stats. & Regs. ¶ 32,664 at 64.

Description and Discussion: This item represents fuel costs as well as expenses associated with purchased power that are actually avoided because a portion of the load is being served by a renewable resource.

Avoided Fuel and Purchased Power should be included as a ***benefit*** in the Framework, and should be calculated as part of the renewable-weighted Avoided Energy Cost.[2] As discussed in Section 4, the renewable-weighted Avoided Energy Cost used in the Framework reflects the projected fuel and technology expected to represent the marginal unit for dispatch in any given hour in which the renewable resource is expected to be producing electricity. It does not reflect any specific single fuel or any specific single technology. This approach is superior to limiting the analysis to a specific fuel or technology in the avoided cost calculation. The renewable-weighted Avoided Energy Cost approach determines the cost of the actual energy expected to be avoided on an hourly basis during the hours that the renewable resource is expected to be generating rather than a less robust approach of making an assumption regarding the technology and fuel that will be avoided.

Avoided Generation Variable Operations and Maintenance (VOM) Costs

Recommendation: Include as part of Avoided Energy Cost. As such, this item is a project-specific component.

Description and Discussion: This item represents operational costs and maintenance costs that vary in direct proportion to the generation that is avoided because a portion of the load is being served by a renewable resource.

Avoided VOM should be included as a ***benefit*** in the Framework, and should be calculated as part of the Avoided Energy Cost.

Avoided Water Consumption Costs

Recommendation: Direct water consumption and treatment costs are included in VOM calculations. As such, this item is a project-specific component.

[2] The method for calculating Avoided Energy Costs can be found in Appendix C, while the method for using the Avoided Energy Costs to calculate a renewable-weighted Avoided Energy Cost is specified in Section 4 below.

Description and Discussion: This item represents costs associated with water consumption by generating facilities that are avoided because a portion of the load is being served by a renewable resource. Currently, the Southern Companies already include the withdrawal and treatment costs of the water in VOM costs, and thus the costs are reflected in Avoided Energy Costs. The merits of including a proxy for presumed "societal" costs and benefits, such as might be associated with avoided water use, are addressed separately in the Externalities component. These costs are speculative and very difficult to value with any degree of accuracy. Moreover, these costs represent an externality for which benefits do not accrue to the electric utility and therefore cannot be passed on to utility customers.

Water consumption costs included in VOM are already a part of the Southern Companies' Avoided Energy Costs and thus ***are included*** in the Framework calculations. It is recommended that the societal costs of avoided water consumption ***should not be included*** in the Framework.

Avoided Environmental Compliance Costs

Recommendation: Include avoided costs of compliance with environmental regulations that are already accounted for in Avoided Energy Costs; as such, this item is a project-specific component. Do not include societal costs.

Description and Discussion: This item represents the actual avoided costs of complying with existing environmental regulations because a portion of the load is being served by a renewable resource. Note that these costs do not specifically refer to fixed and sunk costs already incurred to bring the system into compliance – such as the cost of switching fuels, or building baghouses, scrubbers, or similar environmental controls. Such costs cannot be avoided once they have been incurred. Rather, this component represents the incrementally avoided environmental costs, which are primarily associated with avoided environmental allowance costs or consumables necessary for environmental compliance. Such costs are already included in Southern Companies' Avoided Energy Cost calculations. This specific component does not include any proxy for presumed societal environmental costs or benefits or anticipated environmental legislation or regulation. The merits of including a proxy for societal costs and benefits are addressed separately in the Externalities component, and the avoided costs and benefits of anticipated legislation or regulation cannot be properly known until a law is enacted or a final rule is established.

Avoided compliance costs associated with meeting existing environmental regulations, which are already included in Avoided Energy Costs, should be included as a ***benefit*** in the Framework. However, societal avoided costs ***should not be included*** because the benefits do not accrue to the electric utility and therefore cannot be passed on to utility customers. It is acknowledged that as environmental laws and regulations change, the specific environmental compliance costs included in the costs and benefits of renewables will change.

Fuel Hedging

Recommendation: Do not include.

Description and Discussion: Certain industry studies presume that renewable resources can provide fuel hedging benefits in the form of decreased fuel cost volatility risk associated with the portion of load being served by a fixed price resource. The Southern Companies do not believe renewable resources provide such benefits, because such benefits derive primarily from the contractual obligation of the supplier to deliver under the contract at the specified price or suffer a contractual penalty for non-delivery. When a supplier has no firm obligation to provide output to the utility and may withdraw production at its convenience, there are no benefits. To the extent there may be a contractual obligation to deliver a set amount of energy, the calculation of a potential hedge benefit nonetheless requires a degree of speculation that would significantly diminish confidence in the results and would therefore be inappropriate in the regulated environment. In addition, there are risks associated with fixed price contracts that could offset any potential fuel hedging benefits.[3] Any incorporation of analysis to consider fuel hedging benefits would also need to take such risks into account.

Furthermore, the Southern Companies have specific fuel hedging programs already in place that are regulated and overseen by their respective regulatory authorities. Considering additional fuel hedging benefits resulting from renewable contracts may require incorporating those contracts into the fuel hedging program. Rather than specifically incorporating those projects into the fuel hedging program, the Southern Companies maintain a diversified fleet of generating resources – including renewable resources – to provide a portfolio-based hedge against fuel price volatility. There is no

[3] Such risks would include, for example, the risk that there would be significant technological advances that lower costs, the risk that loads may not materialize as expected, and the risk that fuel prices will drop during the course of the PPA.

precedent within the Southern Companies to ascribe any particular fuel hedging value to the economic evaluation of any fixed price contract. To ascribe such value for one resource while not ascribing similar value to other resources would represent an inconsistent approach in resource evaluations, resulting in the biasing of one resource type in favor of another resource type. In the event that, at some point in the future, evaluation procedures for all such resources were to include these theoretical fuel hedging benefits, they would be included in the RCB Framework as well.

Fuel hedging associated with renewables ***should not be included*** in the Framework.

Deferred Generation Capacity Costs

Recommendation: Include deferred generation capacity costs. This item is a project-specific component.

Description and Discussion: This item represents capacity costs that are deferred because a portion of the load is being served by a renewable resource. In determining such costs, the intermittent and non-dispatchable nature of renewables must be factored into the analysis. The Southern Companies use a method called the Incremental Capacity Equivalent factor, which establishes a capacity value based on a resource's capacity worth across the entire year, not just a few summer hours. This method approximates the reliability of a renewable resource relative to the reliability of a dispatchable CT resource as opposed to just determining the peak load carrying capability.

In Georgia, renewable resources receive capacity value credit in the year when the next capacity need is forecast. The Southern Companies already employ a well-established coordinated planning process to determine the next capacity need. Through that process, generation capacity needs are identified and expansion plans are established to meet load serving requirements. Generating resources that are added to the system through that process have a capacity value that results from the fact that such capacity was added to meet a specific need. When considering changes to the existing resource fleet (such as generation retirements), it is appropriate to consider that value in all years. However, when resources are added to the system outside of the coordinated planning process or for reasons other than a specifically stated capacity need, the assignment of capacity value to that resource may be influenced by other considerations, such as when the resource expansion plan indicates a capacity need. Renewable resources added outside the coordinated planning process would fall into this category of capacity addition. When performing evaluations, Georgia Power Company will give capacity credit based on the first year of capacity need as indicated in the Company's resource expansion plan.

Further, there may be a limit to the amount of capacity that can be deferred as a result of renewable resources, particularly with respect to solar resources. For example, as more solar generation is added to the system, the effective summer peak demand for planning purposes (i.e., the effective load served after taking into account the output of the intermittent resources – modeled in Appendix B as a reduction in load) will begin to shift from the mid-to-late afternoon hours into the evening hours. At significantly high penetrations of solar generation, the effective system peak demand will occur after sunset and no further amount of solar will offset that peak demand. This result will ultimately be reflected through significantly reduced, if not eliminated, capacity values. As indicated by the reductions in effective peak demand in Appendix B, capacity deferral benefits associated with higher penetrations of solar generation will be greatly reduced such that they are likely to be eliminated with penetrations at levels significant enough to shift the effective peak demand to dusk. Southern Company's ICE Factor determination is designed to capture this potential reduction in capacity through use of the CWFT. As renewable penetrations increase, the CWFT changes, reflecting the change in capacity value for the renewable resources. (See Section 4 for a description of how the CWFT is applied.) Although the potential for emerging storage technologies may mitigate this impact and restore some of this lost capacity value, it is premature to take such technologies into account at this time. If a specific project proposal contains storage technology, the potential for including capacity credit as a result of the storage will be evaluated on a case-by-case basis.

Finally, it should be noted that since the evaluation of deferred generation capacity costs implicitly presumes that the renewable generation resource will be available long term, the application of deferred generation capacity costs should only be included in the Framework when there is a reasonable expectation that the renewable resource will be available well into the future. In those cases for which no such reasonable expectation exists, deferred generation capacity costs should not be included in the Framework calculations.

Deferred generation capacity costs, properly adjusted by an ICE factor, should be included as a ***benefit*** in the Framework when there is reasonable assurance that the renewable resource will be present well into the future. The prevailing regulatory environments also must be considered in calculating deferred generation capacity costs.

Deferred Reserve Capacity Costs

Recommendation: This item is included as part of Deferred Generation Capacity Costs. As such, this item is a project-specific component.

Description and Discussion: This item represents reserve capacity costs that are deferred because a portion of the load is being served by a renewable resource. The basis for including these costs is premised in part on the recognition of renewable resources as a net load reduction. That presumed net reduction in load caused by renewable resources is then presumed to not only defer direct capacity, but also the planning reserve capacity needed to serve that load. The Southern Companies do not consider a renewable resource to be a reduction in load,[4] but rather a non-dispatchable generation resource. As such, the Southern Companies view those resources, along with all other resources, as generating capacity available to serve load. The planning process identifies an amount of capacity, including reserves, necessary to reliably serve that load. For renewable resources, the Southern Companies use the ICE factor to calculate a capacity equivalent on a basis that has equivalent reliability to CT capacity. In so doing, the renewable resource becomes another equivalent resource for meeting the planning reserve requirement. The calculation of capacity deferred by renewable resources is, therefore, not solely a calculation of deferral based on the load-serving capacity requirement, but of deferral based on total capacity requirements including reserve requirements. Avoided Capacity Cost calculations, therefore, already account for Reserve Capacity benefits.

Deferred reserve capacity costs should be included as a ***benefit*** in the Framework as an integrated part of the Deferred Generation Capacity Cost component.

Deferred Fixed Operation and Maintenance (FOM) Costs

Recommendation: Include only to the extent it relates to deferred generation capacity. As such, this item is a project-specific component.

[4] Although renewable resources are not to be considered a reduction in load, modeling limitations sometimes require such generation to be evaluated as if it were a reduction in load. See, for example, Appendix B.

Description and Discussion: This item represents FOM costs that are deferred because a portion of the load is being served by a renewable resource. To the extent capacity costs are deferred, it is also appropriate to take into account the associated FOM costs. For the Southern Companies, the FOM costs are already included in the Economic Carrying Cost associated with the avoided capacity.

Deferred FOM Costs should be included in the Framework as a ***benefit*** as an integrated part of the Deferred Generation Capacity Cost component.

Deferred Transmission Investment

Recommendation: Include as either a cost or a benefit as appropriate for the specific location and type of renewable facility. This item is a technology-specific component for distribution level implementations (transmission level implementations are evaluated on a case by case basis).

Description and Discussion: This item represents the potential cost or benefit of deferred transmission investment associated with a renewable resource. In the Southern Companies' view, the benefit of deferred transmission investment is highly dependent upon the type and location of the renewable facility. In addition – as with deferred generation capacity – there is a limit to the amount of transmission that can be deferred due to solar generation in the summer because of the shift of the peak demand from the daylight hours to the night-time hours. During the winter, the system peaks generally occur just before or at dawn and after dusk. For these reasons, solar generation will not have an appreciable impact on deferring future transmission capacity investments.

For larger, utility scale facilities, there may actually be a transmission cost rather than a transmission benefit, depending upon the location and size of the facilities. For these implementations, there are well established, existing processes in place for determining the appropriate transmission impacts. For wind generation outside of the Southern Company Balancing Authority Area (SBAA), this requires either the purchase of transmission service and/or construction of new transmission facilities to import wind energy into the region. Therefore, deferred transmission investment for utility scale implementations should be included in the Framework, but whether such is deemed a ***cost*** or a ***benefit*** should be determined on a case-by-case basis.

For facilities interconnected at the distribution level, there may be some deferred transmission cost, but the amount still depends highly on the location and quantity of the resource. Therefore, geographic penetration assumptions will influence the deferred transmission investment calculation. Also, as with deferred generation capacity, the deferred transmission benefit should only be included in the Framework if there is a reasonable expectation that the resource will be available well into the future. For distribution level implementations, the deferred transmission should be included as a ***benefit*** in the Framework when there is reasonable assurance that the resource will be present well into the future.

<u>Reduced Transmission Losses</u>

Recommendation: Include as a cost or benefit depending upon the specific location. This item is a project-specific component.

Description and Discussion: This item represents the benefit of reduced transmission losses associated with a renewable resource. This benefit comes in two forms – reduced energy losses and reduced capacity losses.

The reduced energy losses on the transmission system represent the reduced generation (in MWH) resulting from a reduction in transmission system losses due to the renewable resource. Most studies take these transmission losses into account. With respect to energy losses on the transmission system, the Southern Companies already include the impacts of transmission losses necessary to deliver generation to load in its projected Avoided Energy Costs. In the existing filing requirements under Dockets 4822 and 16573, including the filings made December 2016 under those dockets, transmission losses are not included in the calculation of PURPA avoided energy costs.

The reduced capacity losses on the transmission system represent the reduction in demand (MW) on the transmission system resulting from a reduction in transmission system losses due to the renewable resource. With respect to these capacity losses, none of the avoided energy cost calculations include the transmission capacity loss impacts. However, they are included as part of the Deferred Transmission Investment calculation used by the Southern Companies. Therefore, the two loss components (energy and demand) are both considered, but are considered separately as part of the determination of other components.

The impact of transmission capacity losses is dependent upon where and how a renewable resource is connected to the grid. Distributed resources will typically provide transmission capacity loss benefits. However, the larger scale projects – even those connected to the distribution system – may be either a transmission capacity loss benefit or cost depending upon the location. This is because the larger scale projects are typically designed specifically to back feed into the transmission system rather than serve local load. Depending upon the location of these larger scale systems, this may actually increase losses rather than offset them.

Transmission losses – both capacity and energy – should be included in the Framework. Transmission energy losses should be included as a ***benefit*** and should be included through use of the projected Avoided Energy Costs. Transmission capacity losses should be included as a ***benefit*** for distributed resources and calculated as part of the Deferred Transmission Investment calculation, but for larger scale projects connected to the distribution or transmission system, transmission capacity losses should be evaluated on a case-by-case basis to determine whether there is a ***benefit*** or a ***cost***.

Deferred Distribution Investment

Recommendation: Do not include.

Description and Discussion: Certain industry studies presume there is a benefit of deferred distribution investment associated with distributed renewable resources. The Southern Companies do not believe distributed renewable generation provides such benefits.

Per IEEE 1547, the IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems, Southern Company requires all distributed resources (including solar generation facilities) to cease energizing the distribution system upon occurrence of a fault on the distribution system. These resources are required to stay off-line for up to five minutes after the distribution system voltage and frequency are restored to ranges specified in ANSI C84.1 Standard. Therefore, the distribution system must be capable of serving 100 percent of the load during this timeframe. As a result, while the impacts of renewable resources on the distribution system (particularly solar) must be properly taken into account, planning of the distribution system must assume that the feeders containing such generation are still required to carry the full load connected to these circuits, thereby negating any potential deferment of distribution investment.

Another concern with solar in particular is the relationship of intermittent cloud cover to solar generation output and load on the distribution system in a specific geographic location. Cloud cover reduces the amount of solar generation from a solar facility in minutes, if not seconds. However, residential and commercial load on the circuit, including thermal load, will not diminish in the same timeframe. Thermal inertia present in physical objects such as brick walls will delay any change in load at businesses or residences, potentially for hours, during periods of intermittent cloud cover. Since the load changes very little, if at all, during a period in which the amount of solar generation is decaying, the net effect is that the distribution system will be required to serve the load that had been served by the solar facility before the cloud cover. Similar concerns would exist for a distributed wind resource as it relates to the intermittency of prevailing winds.

An additional concern is the fact that it is estimated that approximately 30 percent of distribution circuits across the Southern Company electric system are winter peaking circuits. Because the winter peaks generally occur just before or at dawn and after dusk, solar generation on these circuits will have no positive impact on deferring future distribution capacity investments. This concern is compounded by the fact that the Southern Companies are trending towards becoming dual-season peaking utilities. As such, the trend will be that larger numbers of distribution feeders will peak in the winter rather than in the summer.

In summary, the Southern Companies believe that distribution circuits will still need to be sized to handle the full burden of the load so that the load can continue to be served when the intermittent resource is unavailable.

Deferred distribution investment ***should not*** be included in the Framework. It is acknowledged that future changes in laws, standards, and regulatory structures could result in the need to re-examine whether this component should be included in the Framework.

<u>Reduced Distribution Losses</u>

Recommendation: Include as a cost or benefit depending upon the specific location. This item is a project-specific component.

Description and Discussion: This item represents potential impact on distribution losses associated with distributed renewable resources and is not applicable to utility scale resources. This impact, increase or decrease, comes in two forms – capacity losses and energy losses. The change in capacity losses would be represented by the change in demand (MW) on the distribution system associated with a change in losses on the distribution system due to the distributed generation. The change in energy losses represents the change in generation (in MWH) associated with a change in losses on the distribution system due to the distributed generation. Unlike transmission losses, the Southern Companies do not include the impact of distribution losses in its projected Avoided Energy Costs.

As stated previously in the Deferred Distribution Investment section, there is no deferred distribution capacity investment. Because there is no deferred distribution capacity investment, it would therefore follow that there would be no deferred distribution investment associated with a reduction in the capacity component of distribution losses.

A determination of distribution losses is a challenging proposition, and one dependent on factors such as the amount and location of load on a circuit at any given time, and the amount and location of renewable generation on the circuit at the corresponding time. For a renewable facility located closer to a given load, losses should be reduced (as the load would be expected to consume the energy before any losses occurred). For renewable generation located farther from the load, losses would increase.

It is reasonable to assume that small, customer-sited renewable generation would be consumed by load that is located close to the facility. Therefore, losses are reduced in such instances. However, larger, or greenfield, sites up to and even greater than 1 MW may not be sited close to corresponding load. Therefore, losses on the distribution system may be reduced or increased, depending on the location and amount of load and solar generation. Therefore, the determination of distribution losses may be different for the different categories of distributed generation.

Reduced distribution losses should be included in the Framework as a ***benefit*** for Distributed-Behind the Meter (DG-BM), Distributed-Metered (DG-M), and small (up to 100kW) Distributed-Greenfield (DG-G) facilities – although DG-G facilities may have locational implications that require a different methodology for determining the benefit. It is recommended that larger projects (i.e., Distributed-Greenfield (DG-G) projects over 100kW and all Utility Scale (i.e., US-D) projects) be evaluated on a case-by-case basis to determine whether they should be included as either a ***benefit*** or a ***cost*** depending upon the project specific evaluation and circumstances.

Distribution Operations Costs

Recommendation: Include as a cost.

Description and Discussion: This component reflects the operation and maintenance costs that the Southern Companies would not have otherwise incurred except for the addition of distributed generation on the system. These costs include expenses that are related to ensuring safety, system reliability, and power quality. There are three primary areas of cost impacts that fall into this category.

- First, there may be impacts associated with the Southern Companies' conservation voltage reduction programs. These load reduction programs are based upon the premise of reducing demand at system peak by reducing distribution voltage. Distributed solar generation will have the effect of raising distribution voltage, potentially making these programs less effective.
- Second, there are impacts to the operation and maintenance costs of voltage regulators and other related distribution equipment. The voltage swings on the distribution system caused by the intermittent nature of the renewable generation will create additional duty on this equipment, thereby increasing required maintenance or shortening the equipment life.
- Third, distributed renewable resources will have an impact on automatic fault isolation and restoration schemes. Renewable generation will mask actual load. This may result in limiting the system's ability to restore service or in overloading adjacent circuits upon a restoration attempt.

These Distribution Operations Costs should be included as a ***cost*** in the Framework.

Generation Remix Costs

Recommendation: Include as a cost or benefit as appropriate. This item is a technology-specific component.

Description and Discussion: This item represents the impact that a large penetration of renewable resources will have on both system commitment and dispatch, as well as the expected future generation expansion plan build-out of the system associated with the addition of a renewable resource. When evaluating a large resource addition, it is appropriate to consider both the total production cost impacts as well as the capital cost impacts of "re-mixing" the system after the addition of the resource. This is necessary because the addition of a large resource will change both the commitment and dispatch of the system as well as the future system mix (i.e., the mix of future generation added to the system). Such an evaluation requires a comparative analysis with and without the resource being evaluated (i.e., a "delta" case analysis). However, when only a few, small increments of renewable resources are being evaluated, their addition is not expected to have a significant impact on either system commitment or future system mix. Therefore, due to the small size of the resource, the full impact on avoided energy and deferred capacity costs may not materialize in a traditional "marginal" analysis. Thus, the impacts of these small, incremental additions become incorporated into the next budget cycle such that they are embedded in the avoided energy and deferred capacity costs by the time the next incremental resources are being evaluated. However, when large blocks of renewable resources are being evaluated over a short period of time, the assumption that the addition of the resource will not significantly impact either commitment or future system mix can no longer be presumed accurate. As such, a traditional "marginal" analysis would be insufficient as it will either over or under state the avoided cost benefit of smaller renewables. Generation Remix performs a "delta" analysis on a tranche of renewable resources to generically capture that additional cost or benefit not otherwise captured in the marginal analysis. This allows each small, incremental addition to be individually evaluated using the marginal analysis approach and yet have the additional costs (or benefits) associated with the aggregate impact of all the anticipated projects properly considered. This is necessary due to the fact that a large number of incrementally small renewable resources cannot be practically evaluated using the delta analysis approach on an individual basis and yet, in aggregate, they have costs not captured by the marginal approach.

Generation Remix Costs should be included as a ***cost or benefit as appropriate*** in the Framework.

Ancillary Services

Recommendation: See specific recommendations for each ancillary service below.

Description and Discussion: This item represents the impacts to ancillary services associated with renewable resources. While some studies claim there are ancillary services benefits associated with renewable resources, the Southern Companies believe that the intermittent nature of renewable resources actually increases the utility's cost to supply such services. The following outlines each of the Open Access Transmission Tariff (OATT) ancillary services categories and how the Southern Companies view the impacts of renewable resources on their cost to provide such services.

Scheduling, System Control, and Dispatch: The Scheduling, System Control, and Dispatch Ancillary Service components represent the service to transmission customers for scheduling the movement of power through, out of, within, or into a Balancing Authority. There are no benefits to this ancillary service associated with renewable resources. In fact, there are likely to be increased system costs associated with the scheduling, system control, and dispatch of such generation. Any such increase in cost would likely be captured as part of the "Support Capacity" calculation (see Support Capacity section below). As such, this item is a technology-specific component.

Reactive Supply and Voltage Control: The Reactive Supply and Voltage Control Ancillary Service components represent the service associated with the maintenance of transmission voltages on the Transmission Provider's facilities within acceptable limits. Generators interconnected at the transmission level, including renewable facilities interconnected at the transmission level, are required by interconnection procedures to have the ability to maintain system voltage schedule. This does not avoid any other reactive power supply, but rather provides the reactive power necessary to deliver the real power produced by that facility. For renewable resources interconnected at the distribution level, there may be some benefits associated with reactive supply and voltage control if the resource is implemented with smart inverters. However, there is no guarantee (without a specific requirement to do so) that distributed resources will install these smart inverters. Nor – even if such smart inverters are installed – is there any guarantee that there will be sufficient capability installed (e.g., for solar, a combination of DC panel capacity, inverter capability, and appropriate control technology) to take advantage of that capability while also providing the expected real power benefits. Finally, even if all of these are present, without some requirement for interconnected facilities to meet voltage control requirements, the utility will not have access to the use of such capability. Currently, there are no such requirements for renewable resources connected at the distribution level, and resources at the sub-transmission level (i.e., 46kV and/or 69kV) are required to maintain a fixed power factor rather than control voltage.[5] Absent these guarantees, the intermittent nature of renewable resources will create significant voltage fluctuations on the distribution system and sub-transmission system that will need to be controlled. Therefore, the utility will be required to implement measures to mitigate these voltage fluctuations. The implementation of these mitigating measures will mean increased costs that need to be considered in the costs and benefits of renewable resources. Even when the prerequisites described above are present and such capability exists, there is still no guarantee that the positive impacts will outweigh the negative impacts. The existence and scope of such impacts would require further study before any benefits could be attributed. Therefore, Reactive Supply and Voltage control should be included as a ***cost*** in the Framework.

Regulation: The Regulation Ancillary Service represents the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). The intermittent nature of renewable resources creates an increased need for regulating reserves on the system. Regulation should be included as a ***cost*** in the Framework. Note: This cost is being included as part of Support Capacity below. As such, this item is a technology-specific component.

Energy Imbalance: The Energy Imbalance Ancillary Service represents the difference between the energy scheduled and the actual energy delivered to a ***load*** located within a Balancing Authority over a single hour. Renewable resources are not dispatchable and therefore provide no energy imbalance ancillary service benefit. However, because they are ***resources*** and not ***load***, it likewise does not cause any specific increase in energy imbalance costs. Therefore, Energy Imbalance ***should not be included*** in the Framework.

Operating Reserve-Spinning and Operating Reserve-Supplemental: The Operating Reserve Ancillary Service represents the maintenance of adequate generation capacity necessary to satisfy applicable NERC requirements for Spinning and Supplemental Operating Reserves. Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Supplemental

[5] For transmission interconnections, voltage guidelines are established through OATT Large Generator Interconnection Agreement and Small Generator Interconnection Agreement documents available on OASIS. For distribution interconnections, voltage regulation guidelines are specified in both the Southern Company Distribution Interconnection Policy and Interconnection Agreement documents and are based on ANSI C84.1, Table 1, Range A and IEEE 1547 - 2003.

Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Currently, renewable resources do not have a direct impact on the amount of Spinning and Supplemental Reserves required by NERC standards, but they do have an indirect impact because Spinning and Supplemental Reserves may be dispatched to mitigate the impacts associated with renewable resource uncertainty. In addition to the uncertainty caused by its intermittency, renewable resources are also uncertain because their output is difficult to forecast with any significant degree of accuracy. Regulating Reserves are sufficient to meet the intra-hour intermittency and renewable forecast error volatility only to the extent such volatility can be corrected within 10 minutes (the timeframe in which Regulating Reserves are deployed). Outside of that 10 minute window – which is primarily where forecasting errors are manifested – other available resources (primarily Spinning and Supplemental Reserves) are deployed to correct these volatilities. Spinning and Supplemental Reserves have a very specific purpose under NERC criteria,[6] which is to respond to contingencies on the system. The intermittent nature of renewables, including forecasting errors, are not currently considered a "contingency" *per se*, but in order to keep from violating NERC disturbance control standards, Spinning and Supplemental Reserves (in addition to Regulating Reserves) will likely have to be deployed to mitigate these volatilities. If Spinning and Supplemental Reserves are deployed for any reason (including the need to handle the intermittent and forecast error aspects of solar generation), NERC standards require that they be replaced within a specific timeframe. Therefore, significant penetrations of renewables will impose the need for a certain amount of flexible (i.e., responsive in the 30-60 minute time frame) resources to be available to replace the Spinning and Supplemental Reserves deployed to mitigate forecast errors associated with solar generation. Southern Companies refer to these flexible resources as Support Capacity. Therefore, while it is noted that Operating Reserve-Spinning and Operating Reserve-Supplemental are impacted by renewable resources, they ***should not be included directly*** in the Framework; but ***rather the impacts should be included as part of Support Capacity***, which is described below. As such, this item is a technology-specific component.

Support Capacity

Recommendation: Include as a cost. This item is a technology-specific component.

[6] See NERC Reliability Standard BAL-002-0 Disturbance Control Performance.

Description and Discussion: Support Capacity represents the impact that renewable resources have on the reliability of the System. In can be viewed as additional resources needed to "back up" the renewable resource because of its non-dispatchable, intermittent nature; or, alternately, it can be viewed as a reduction in the overall capacity value of the resource resulting from that intermittency. Support Capacity is needed for several reasons, including (a) replacement of additional Regulating Reserves needed to handle the volatility of the output of the intermittent resources, (b) accounting for the impact of the forecast error associated with predicting the output of the intermittent resources, and (c) managing increased generation ramping and load following requirements associated with heavy penetrations of non-dispatchable renewable resources.[7] There may be some ability in the existing system to handle these flexible dispatching requirements, and the methodology for determining Support Capacity will take this into account. However, even for lower levels of solar penetration, there will still be ***production costs*** that will need to be considered even in the early years of the analysis. Both production and capital costs must be considered.

Support Capacity should be included as a ***cost*** in the Framework. See Appendix A for a more detailed write up on the need for Support Capacity.

Bottom Out Costs

Recommendation: Include as a cost.

Description and Discussion: This item represents the costs associated with increased risk and occurrences of bottom out conditions caused by renewable resources. Bottom out conditions occur when the demand on the system reaches a point that is so low that online generating resources can no longer reduce their output without de-committing, i.e., turning off. Many lower cost, high load factor generating resources have long minimum downtimes, meaning that once they de-commit, they must remain offline for an extended period of time before coming back online. When the system reaches a bottom out condition, decisions to bring these lower cost resources offline may result in those resources

[7] Some commentators have suggested that demand-side resources can meet these flexibility requirements. However, due to the immediate and specific response required to handle the intermittent nature of renewable resources, no such demand response programs currently exist in the Southern Companies' service territories that would be able to provide a response that is timely (in the 30-60 minute time frame), absolutely dependable in quantity, and allowable to be used for this specific purpose. The intent of this process is to establish a cost benchmark for Support Capacity, not to explore all possible alternatives to meet Support Capacity needs.

not being able to serve the upcoming high demand period. The subsequent high demand period must therefore be served with higher cost, more flexible resources. This effect is especially prominent in the winter when the load pattern is characterized by a sharp morning peak and a sharp evening peak with a low load period in between. Renewable resources increase this risk in the winter as well as in the lower load spring and fall periods because it adds non-dispatchable generation when the system is at its lowest demand. Appendix B demonstrates an example of how solar generation can increase the risk of bottom out and shows the phenomenon that has been referred to in the industry as the "duck curve." To the extent modeling capabilities can capture such costs in the recommitment of the system, these costs have already been included as part of the Generator Remix calculation. However, to the extent there is excessive DUMP energy in the models (i.e., energy that the model must "dump" because it cannot recommit the system around those conditions), those costs must also be considered.

Bottom out costs, which for purposes of this Framework refer to the costs associated with this DUMP energy, should be included as a ***cost*** in the Framework. Recommitment costs are already included in Generator Remix.

Improved Grid Security/System Protection

Recommendation: Do not include.

Description and Discussion: This item represents the value of increased reliability and security of the grid caused by distributed renewable resources, and so is only applicable to distributed renewable generation.

Proponents of deriving a value from these purported reliability benefits attribute them in part to localized islanding of the system during times of system outages. However, existing IEEE 1547 guidelines and the Southern Companies' policies prohibit islanding at the distribution level, a condition in which part of the utility's system is served by distributed generation while that part is electrically separated from the rest of the system. Therefore, any such "benefits" could only be realized as a result of operating the distribution grid in a manner directly conflicting with existing standards and policies. Georgia Power believes that this is not in the best interests of customers.

Moreover, while it may be theoretically possible to analyze the existence and extent of such benefits, including the consideration of benefits associated with islanded operation, this is a level of analysis that would not be appropriate at this time given the requirements and prohibitions associated with current, prevailing standards and policies.

Grid Security/System Protection ***should not*** be included in the Framework. Future changes in laws, standards, and regulatory structures, however, could result in the need to re-examine whether this component should be included as a cost or benefit of renewable resources.

Avoided Renewable Energy Credit Costs

Recommendation: Do not include.

Description and Discussion: This item represents the avoided costs associated with acquiring RECs to meet a specified Renewable Portfolio Standard (RPS). At present, none of the jurisdictions in which the Southern Companies provide retail service has an RPS. As such, there are no REC costs to be avoided. For this reason, there is no basis to consider the avoided value of RECs, if any.

REC costs ***should not be included*** in the Framework.

Long Term Service Agreement Maintenance Cost

Recommendation: Include as a cost.

Description and Discussion: This item represents the increased LTSA costs associated with increased generation ramping and startups of CTs and combined cycles (CCs) that may result from the intermittent nature of renewable resources. Anticipated starts-based maintenance is included in existing O&M values. However, those O&M values are based upon a presumption of future anticipated starts. As indicated in the section on Support Capacity above, increased penetration of intermittent resources will create the need for increased use of flexible resources such as CTs. It will also create increased cycling of resources such as CCs during low load periods. This will increase the use of these resources for load following (generation ramping) and will also increase the number of starts incurred by these resources. As such, it will affect the LTSA maintenance costs for those resources and ultimately is projected to result in increased operation and maintenance costs not currently accounted for in the avoided energy costs.

Increased starts-based maintenance costs should be included as a ***cost*** in the Framework.

Target Reserve Margin Cost

Recommendation: Include as ***cost*** or ***benefit*** if deemed applicable.

Description and Discussion: This item represents the increased costs associated with an increased target reserve margin associated with intermittent renewable resources. These increased costs are additional reliability impacts not otherwise included in the Support Capacity component but identifiable as being attributable to renewable resources. As renewable penetration increases, the effective load profile (i.e., that served by the remaining, non-intermittent resources) of the Southern Companies will also change. As these changes to the effective load profile occur, the Southern Companies' Capacity Worth Factor Table may experience significant changes that could affect the target planning reserve margin. In the event that the target planning reserve margin does change in a manner that is definitively attributable to renewable resources, there would be very real impacts (costs or benefits, depending upon whether the target reserve margin increases or decreases) to Southern Companies' customers.

The cost or benefit impacts on the long term planning target reserve margin, ***whether it is a cost or a benefit,*** should be included in the Framework.

Program and Administrative Costs

Recommendation: See individual categories below.

Description and Discussion: This item represents the various program and administrative costs associated with implementing a distributed renewable resource program and is not applicable to utility scale projects. Distributed renewable resources, however, could be added to the electric system in the absence of a formal program. The intent of this category is to capture program and administrative costs that may be associated with a formal program and inclusion of these items in a cost-benefit analysis. The discussion and recommendations below generally address the items themselves and whether they ought to be included as either a cost or a benefit if such is allowed or proscribed by Georgia jurisdictional requirements.

Interconnection Costs: These are the directly assignable generation interconnection costs that are typically assigned to the distributed generator at the time of implementation.[8] Because they are charged to the specific generator, these costs ***should not be included*** in the Framework.

Program Costs: These are the directly assignable costs that the Southern Companies may experience to promote and administer any particular renewable program. These would include any directly assignable costs that are not charged to the renewable resource at the time of implementation. To the extent such costs exist, can be identified, and may be allocated to the specific project per governing regulatory rules, it is recommended these costs should be included as a ***cost*** in the Framework.

Administrative Costs: These are the indirect administrative and general costs incurred by Southern Companies that would not have otherwise occurred except for the renewable program. These costs include expenses related to forecasting and accounting for the intermittent and unpredictable nature of the renewable resource. Additional costs are borne due to the administration requirements of the PPA's, including compliance and reporting activities. To the extent such costs can be identified, isolated, and may be allocated to the specific project per governing regulatory rules, it is recommended that these costs should be included as a ***cost*** in the Framework.

Accounting Costs: These are the imputed financing costs that the Southern Companies may experience depending upon how the renewable programs are structured, including such costs as imputed capital associated with certain types of leases and impacts associated with Variable Interest Entities. Whether such costs exist depends entirely upon how the programs are structured. To the extent such costs exist and are allocated to the specific project per governing regulatory rules, these costs should be included as a ***cost*** in the Framework.

Market Price Mitigation

Recommendation: Do not include.

Description and Discussion: This item represents the potential reduction in market prices that results from the penetration of renewable resources into the market. Some studies suggest that the

[8] Transmission interconnection costs are determined in accordance with FERC Large and Small Generation Interconnection procedures.

reduction in market prices is significant and should be considered. However, most studies making such recommendation do so based on the fact that market price mitigation is necessary in those markets (e.g., in Locational Marginal Pricing markets) to fully capture the avoided cost benefit. This is especially true given the fact that many of those studies presumed natural gas to be on the margin and some even determined avoided fuel costs using an assumed, guaranteed natural gas price. Therefore, the market price reduction calculation is an attempt to capture the total avoided costs experienced by customers in that market. By comparison, the Southern Companies do not have a market structure in which costs for all customers are determined by the cost of the marginal generating unit. As such, there are no such corresponding benefits to the Southern Companies. Therefore, the avoided cost calculations anticipated to be used by the Southern Companies is sufficient for capturing the benefits to the customers in this market.

Market price mitigation ***should not be included*** in the Framework.

Externalities

Recommendation: Do not include.

Description and Discussion: This item represents the many potential externalities that are often recommended to be included in the determination of the value of renewable resources. Such externalities include presumed benefits such as ***non-compliance related environmental benefits, anticipated future (as yet undefined) environmental compliance costs, health benefits, economic development benefits, the value of civic engagement and awareness of renewable energy, the long term societal value of renewables, and the like.*** As explained in Appendix D, these purported benefits do not accrue to the Southern Companies and thus cannot be passed along to customers. Accordingly, these are not appropriately considered in a cost-benefit determination.

Externalities ***should not be included*** in the Framework.

SECTION 4 – RENEWABLE COST-BENEFIT COMPONENT METHODOLOGY

Avoided Energy Costs

As indicated in Section 3, a number of the components recommended to be included in the RCB Framework are included in the determination of the Avoided Energy Cost, including Fuel and Purchased Power, Variable O&M, Environmental Compliance, and Transmission Energy Losses.

For purposes of the RCB Framework, it is recommended that the "base case" scenario Avoided Energy Costs[9] be used for determining the appropriate renewable resource Avoided Energy Costs. The details for how the Avoided Energy Costs are calculated and how Fuel and Purchased Power, Variable O&M, Environmental Compliance, and Transmission Energy Loss costs are all incorporated into the Avoided Energy Costs can be found in Appendix C.

The specific renewable resource Avoided Energy Costs used in the Framework should be calculated by multiplying – on an hourly basis – the hourly renewable generation profile (in MW) by the appropriate System Avoided Cost (in $/MWH) for that same hour. The sum of this product across all 8760 hours for the year (8784 hours during leap years) represents the avoided energy cost for that year (in dollars). This annual sum is divided by the annual renewable generation (in MWH) to give a single avoided energy cost (in $/MWH) for the year. This calculation is then performed for each year of the study period. The equation for this calculation is as follows:

$$AEC_j = \left[\sum_{i=1}^{8760} RGP(i,j)\ x\ SAC(i,j)\right] / \sum_{i=1}^{8760} RGP(i,j)$$

Where

AEC_j = the avoided energy cost in year *j (measured in $/MWH)*

RGP(i,j) = the renewable hourly generation profile for hour *i* in year *j (measured in MWH)*, and

SAC(i,j) = the System Avoided Cost for hour *i* in year *j (measured in $/MWH).*

[9] These avoided costs are available as a result of the Southern Companies' annual Integrated Resource Planning and Energy Budgeting processes. The current expected case scenario is the Moderate Gas $0 Carbon scenario.

Deferred Generation Capacity Costs

The deferred capacity cost methodology incorporates two of the identified components from Section 3, deferred capacity costs and deferred Fixed O&M costs.

The aggregate amount of capacity credit to be included should be based upon the impact that the renewable profile would have on system reliability as determined by the CWFT. This process results in the determination of the ICE factor for the renewable project. The incremental capacity equivalent itself (in MW) is calculated by multiplying the hourly CWFT by the renewable hourly generation profile. This product is then summed by hour across the year. The sum for the 8760 hours in the year (8784 hours during leap year) represents the total capacity value (in MW) in that year for the renewable project. The ICE factor is this MW value divided by the nominal capacity installed. The capacity equivalent (in MW) is then multiplied by the value of generation capacity to be deferred, which includes Fixed O&M impacts, to calculate the total deferred generation capacity cost benefit for the year. The formulas for the above calculations are as follows:

$$\textit{Deferred Capacity Cost}_j = \textit{Capacity Value}_j \; x \; \textit{Capacity Equivalence}_j$$

Where

Deferred Capacity Cost$_j$ = Deferred Capacity Costs in year *j (measured in \$),*

Capacity Value$_j$ = value of deferred generation capacity in year *j* (measured in \$/kW), and

Capacity Equivalence$_j$ = capacity equivalence in year j as defined by the equation below (measured in kW).

$$\textit{Capacity Equivalence}_j = \sum_{i=1}^{8760} CWFT(i) \; x \; RGP(i,j)$$

Where

CWFT (i) = the capacity worth factor for hour *i* in any given year (measured in %) and

RGP(i,j) = the renewable generation profile in hour *i* of year *j (measured in kW).*

And finally,

$$\textit{ICE Factor}_j = \textit{Capacity Equivalence}_j \,/\, \textit{Nominal Value of Resource}$$

Where

ICE Factor$_j$ = Ice Factor in year *j, and*

Nominal Value of Resource = maximum delivered MW to the AC system.

Deferred Transmission Investment

As discussed in Section 3, the transmission impacts associated with utility scale renewable generation may be either a cost or a benefit depending upon the circumstances, and so the impacts of utility scale renewable generation should be evaluated on a case-by-case basis according to established generator interconnection procedures. Impacts of widely distributed generation should be determined as described below.

The smaller size and varied location of distributed generation (DG) should be evaluated in a system-wide study based on the assumed future DG penetration. The deferred transmission investment costs and benefits associated with the addition of DG would be determined by evaluating two alternative future system scenarios, one with and one without additional DG, to determine the transmission investments and in-service timing of projects necessary over the study horizon for each scenario. The DG analysis is performed in a similar manner to traditional 10 year transmission expansion planning, except for considering a longer term planning horizon (≈20 years in the current study), and the analysis focuses on how the required in-service date of any identified projects are impacted by DG.

The starting point year chosen for the study is based on the last known year of firm, state commission-approved, resource decisions for load-serving purposes. Since future generation to serve future load growth over the longer term study period has not yet been determined, the ultimate location and magnitude of any future generation is speculative and uncertain. Therefore, to avoid locational impacts to the transmission system driven solely by the assumed placement of the new generation, new generation to serve load growth will be modeled as proxy generator injections into the 500 kV network. However, the metropolitan areas of Atlanta and Birmingham will be excluded from the new proxy generation additions to simulate delivery of power into these major load centers over the bulk transmission network.

For purposes of performing the analysis to determine the increase in power flows on transmission facilities from load growth, the power flow model will be utilized to scale the system load in the transmission planning cases by 500 MW for each year of projected load growth. This load scale is performed on a pro-rata basis for the load located at each existing system load bus.

$$\Delta load_n = \frac{load_n}{load_{total}} \times 500\ MW$$

This process will be repeated for each year in the 20-year study timeframe until the system load has been scaled by a total of 10,000 MW. The load at each bus will be scaled using an assumption that the power factor (pf) of the load does not change as it is scaled.

In order to determine the transmission projects necessary to support 20 years of load growth, the Managing and Utilizing System Transmission (MUST) power flow transfer analysis tool is utilized on the created cases. MUST simultaneously scales up the proxy generation and forecast load, simulating serving load growth from the proxy generation. The single transmission line (i.e., N-1) contingency analysis performed by MUST is utilized to determine the MW transfer level at which a given transmission facility becomes overloaded. A series of approximately 60 more cases are created with individual existing units modeled offline in order to create generation contingency (i.e., N-G) system models. A similar MUST analysis is run resulting in a single transmission line plus generator contingency (i.e., N-G-1) analysis matching the typical transmission planning expansion criteria. The most limiting system loading from the N-1 and N-G-1 cases are reviewed to determine the need for transmission expansion projects. Each thermal constraint identified through the MUST analysis process will then be evaluated on a case-by-case basis to determine the transmission project necessary to alleviate the constraint. The cost of each identified project is determined using planning level cost estimates. The timing of those projects is determined based on the MW transfer level identified for the constraint. The identified MW transfer level is divided by 500 MW load growth per year to determine the expected year of construction for identified projects.

This process is performed with and without the DG to determine the impact that the DG has on the expected timing of the projects. This resulting difference in transmission project timing to serve load over the 20-year study period is evaluated in an economic analysis that results in a cost or benefit that can be attributed to DG.

Reduced Transmission Losses

As discussed in the Avoided Energy Cost section above and in Appendix C, the energy component of transmission losses is incorporated into the process for calculating avoided energy costs.

The demand component of transmission losses represents the reduction in demand (MW) on the transmission system resulting from a reduction in transmission system losses due to the renewable generation. DG will typically provide transmission capacity loss benefits. However, the utility scale projects connected to the distribution system may be either a transmission capacity loss benefit or cost depending upon the location. This is because the larger scale projects typically feed back into the transmission system and look more like a utility scale generator than distributed generation. Depending upon the location of the larger scale system, this may actually increase losses rather than offset them.

The impact of the demand component of transmission losses is incorporated into the transmission planning studies for Deferred Transmission Investment. The transmission planning models have load represented in the system model at the actual substation location with an amount based on load forecast. The load is distributed among system buses based on historical field measurements of load at each modeled location. DG is studied in the transmission planning models as a reduction in load at specific buses based on the proposed distribution of DG. That reduction in load is then simulated to determine if there is an impact to the transmission expansion plan. As the load is reduced, or displaced in the model by DG, the impact of the load reduction and related transmission system losses is inherently included in the analysis of any change in timing of transmission investment. Therefore, the demand component is recognized as a benefit that is already included in the Deferred Transmission Investment.

Reduced Distribution Energy Losses

The reduced distribution energy loss due to the addition of DG is calculated by applying an 8760-hour (8784 for leap year) distribution loss profile to the system avoided energy costs. The distribution loss profile is developed by multiplying the distribution profile by system-weighted distribution loss factors that include components for transmission substation losses, sub-transmission losses, and distribution system losses. Alternatively, the DG profile can be grossed up by the amount of distribution losses. In this case, the benefit of the reduced distribution energy losses is incorporated into the avoided energy cost calculation.

Generation Remix Costs

Generation Remix costs will include both a capital cost component and a production cost component.

The capital cost component of the Generation Remix costs is determined by modeling the renewable resource in the "System Mix" model[10] and determining the impact on the future build-out of the generation expansion plan.[11] Comparing the capital cost of the future build-out of the case with the renewable resource to the base case should indicate the extent to which the addition of the renewable resource has altered the future mix of the system beyond the simple Deferred Generation determined by the marginal cost analysis. The "delta" analysis of the two cases – that is, the difference in total capital costs between these cases – reflects the total capital cost impact of adding the renewable, including both the Deferred Generation Capacity Costs associated with the renewable resource and the capital cost impacts associated with Generation Remix. Therefore, to isolate just the Generation Remix Capital cost, subtract the previously determined Deferred Generation Capacity Costs associated with the renewable resource as follows:

$$GRC = (SMC_{remix} - SMC_{base}) - DGCC.$$

Where:

GRC = Generation Remix Capital Cost,

SMC_{base} = Capital cost of the future build-out of the System Mix base case,

SMC_{remix} = Capital cost of the future build-out of the System Mix case with the renewable resource, and

$DGCC$ = Deferred Generation Capacity Costs associated with the renewable resource.

The production cost component of the Generation Remix costs is determined by modeling the renewable resource, along with the new generation expansion plan from the System Mix Generator

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[10] Currently this model is Strategist, although that may change in the future. Strategist is a production cost model that uses dynamic programming techniques to calculate the total capital and operating costs of hundreds of combinations of generating units to determine the proper mix of capacity resources to serve designated loads. The model determines a least cost plan (based on total NPV) of generic expansion resources to add to an existing fleet for the purposes of meeting a Company's load requirements (energy and capacity).

[11] In order to incorporate the renewable profile into both the system mix and production cost models, adjustments to the profile may be necessary to account for losses.

Remix case, in the "Production Cost" model.[12] Comparing the production cost of the renewable case to the base case should indicate the extent to which the addition of the renewable resource has altered system production costs beyond the simple Avoided Energy Costs determined by the marginal cost analysis. The "delta" analysis of the two cases – that is, the difference in total production costs between these cases – reflects the total production cost impact of adding the renewable, including both the Avoided Energy Cost associated with the renewable resource and the production cost impacts associated with Generation Remix. To isolate just the Generation Remix costs, subtract the previously calculated Avoided Energy Cost savings associated with the renewable resource as follows:

$$GRP = (SPC_{remix} - SPC_{base}) - AEC.$$

Where:
GRP = Generation Remix Production Cost,
SPC_{base} = System production cost of the base case,
SPC_{remix} = System production cost of the case with the renewable resource and modified expansion plan, and
AEC = Avoided Energy Cost associated with the renewable resource.

Total Generation Remix Costs is then the sum of the Generation Remix capital costs and the Generation Remix production costs. Generation Remix costs can either be a cost or a benefit depending upon the outcome of the above calculations.

Ancillary Services – Reactive Supply and Voltage Control

At this time, the Southern Companies have not developed a methodology to calculate the cost impacts that solar generation has on Reactive Supply and Voltage Control.

[12] The Production Cost case is developed using the official production cost model used by the Southern Companies for development of their official Energy Budget. The Production Cost model performs a detailed 8760-hour unit commitment and dispatch simulation to calculate these production costs and avoided energy costs.

Ancillary Services – Regulation

In order to maintain Area Control Error (ACE) within NERC required limits, the intermittent nature of VERs must be managed through the use of Regulating Reserves. NERC Standard BAL-001 specifies these Regulating Reserve requirements, which include regulating the system to within specified tolerances for at least 90% of the 10-minute windows in a given month. The determination of the impacts of renewable resources on Regulating Reserve requirements will be based upon the requirements in NERC BAL-001.

The intermittency of renewable generation within the 10-minute Regulating Reserve window has the potential to increase the amount of Regulating Reserves. This is due to the operating characteristics of generating resources on Automatic Generation Control (AGC) which are required to respond in order to balance the system's supply and demand while managing renewable intermittency. Therefore, generation resources on AGC dispatched because of the renewable intermittency would not be available to respond to load variability as they traditionally would, thereby increasing the need for additional Regulating Reserves. There are immediate production cost impacts associated with maintaining these additionally required Regulating Reserves, and to the extent the need for these additional Regulating Reserves may impact system reliability, it could eventually result in a capacity need (as determined below in the Support Capacity section). The amount of additional Regulating Reserves needed can be determined by evaluating the 10-minute "ramp down" volatility of the renewable resources.[13] Since NERC Standard BAL-001 requires ***at least*** a 90% compliance rate, an amount equal to the 95th percentile of these 10-minute ramps provides a reasonable estimate of the additional Regulating Reserves that will ultimately be required as a result of the renewable resource. The cost impacts associated with these additional reserves should be determined according to the Support Capacity calculations specified below.

Support Capacity

Appendix A contains a detailed explanation of the need for and causes of Support Capacity along with an overview for how to determine the amount of Support Capacity that is to be evaluated. This

[13] Only the "ramp down" occurrences are considered because only these occurrences contributed to the "Reg Up" Regulating Reserve requirement.

amount (as specified in Appendix A) is determined by calculating the sum of the aggregate incremental needs of:

(a) The incremental Regulating Reserve requirement and its impact on expected unserved energy;
(b) The incremental renewable forecast error on expected unserved energy; and
(c) Any incremental generation ramp requirement.[14]

The addition of these Support Capacity requirements results in both a capital cost and an associated production cost for each of the three types of capacity additions.

To determine the Support Capacity capital costs, these additions, in aggregate, should be modeled in the System Mix model as a reduction in the modeled ICE Factor of the renewable resources and a "delta" case comparison of the capital costs of the resulting future build should be made against the Generation Remix case. The resulting difference in capital costs of the two cases is the Support Capacity capital cost, calculated as follows:

$$SCC = (SMC_{support} - SMC_{remix}).$$

Where:
SCC = Support Capacity Capital Cost,
$SMC_{support}$ = Capital cost of the future build-out of the System Mix base case with the additional support capacity requirements, and
SMC_{remix} = Capital cost of the future build-out of the Generation Remix System Mix case.

To determine the Support Capacity production costs, a Production Cost model case is developed using the Generation Remix Production Cost case as a base. That case is modified to include the expansion plan from the Support Capacity System Mix case, but also includes the modeling of the additional Regulating Reserve requirements to capture the production costs associated with those requirements. Regarding the production cost associated with forecast errors, given the expectation of

[14] At this time, the Southern Companies have not developed an agreed-upon methodology for determining the ramping requirements of a significant penetration of renewable resources.

the mean-reverting nature of the renewable forecasting process, the forecast error production costs have been assumed to be zero (0) for purposes of this Framework.[15] The production cost of this case is then compared against the production cost of the Generation Remix case to determine the Support Capacity Production Costs as follows:

$$SCP = (SPC_{support} - SPC_{remix})\ .$$

Where:

SCP = Support Capacity Production Cost,

$SPC_{support}$ = System production cost of the Support Capacity case, and

SPC_{remix} = System production cost of the Generation Remix case.

Total Support Capacity Costs is then the sum of the Support Capacity Capital Costs and the Support Capacity Production Costs.

Bottom Out Costs

At this time, the Southern Companies have not developed an agreed-upon methodology to calculate the expected bottom out costs associated with significant penetrations of renewable resources.

Starts-Based Maintenance Costs

At this time, the Southern Companies have not developed a methodology to calculate the expected starts-based maintenance costs associated with significant penetrations of renewable resources.

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[15] This assumption is based on the premise that a perfectly unbiased mean-reverting forecasting methodology would, over time, always converge back such that the net production cost impact of the forecast error is zero or negligible. In reality, forecasting biases as well as temporal differences in production cost would result in a relatively small but non-zero net production cost impact associated with the forecast errors. The Framework provides for the fact that if such can be determined, then these costs can be properly included.

Planning Reserve Margin Costs

At this time, the Southern Companies have not completed studies to calculate the expected planning reserve margin costs associated with significant penetrations of renewable resources.

Distribution Operating Costs

At this time, the Southern Companies have not developed a methodology to calculate the expected distribution operation and maintenance costs associated with significant penetrations of renewable resources.

Program and Administrative Costs

At this time, the Southern Companies have not developed a methodology to calculate the expected program and administrative costs associated with significant penetrations of renewable resources.

APPENDIX A – SUPPORT CAPACITY

The Need for Support Capacity

The purpose of this appendix is to provide a description of the need for and method of determining Support Capacity associated with the implementation of Variable Energy Resources on the electric grid. The Company has identified a number of costs associated with significant penetrations of VERs. These costs are real costs that are a direct result of VERs and not attributable to traditional, dispatchable resources.

It has been widely acknowledged that VERs may require some form of "backup" capacity to firm those resources during periods of time when they are not operating. The hourly integrated expected output from these resources varies from hour to hour and from year to year depending upon the weather. In its planning processes, the Southern Companies view this "backup" capacity not in terms of a cost adder but rather in terms of de-rating a VER's nominal capacity to its Incremental Capacity Equivalent. However, in addition to this capacity equivalency, there is still the need for additional adjustments to this ICE Factor that are necessary to account for the other aspects of the intermittent nature of the VERs. This intermittent nature has a negative impact on system reliability (as described below) that can be mitigated through the addition of resources. For planning purposes, these intermittency impacts are reflected in a reduction in the ICE Factor of the renewable resource. This adjusted ICE Factor ultimately results in the need for more capacity than would otherwise be assumed using the unadjusted ICE Factor. Additionally, the intermittent nature of VERs creates a need for additional flexible resources in the operational horizon (as described below) to account for ramping requirements. It is possible that at significant enough penetrations of VERs, it may become necessary to add generation resources solely to meet this flexible resource requirement. These flexible resources would be those resources (such as CTs, hydro, etc.) that are capable of being committed and fully dispatched within a 30-60 minute timeframe. The Support Capacity concept is also used to capture all of these requirements.

Based on the above, Support Capacity needs are caused by (a) the reliability impacts associated with the additional Regulating Reserve requirements necessary to handle moment to moment swings in VER output, (b) the reliability impacts associated with VER forecasting errors, and (c) increased generation ramping/load following requirements caused by VERs.

Regulating Reserves: Although VER output is not considered "load" *per se*, because VERs are not dispatchable, the output of VERs has an "effective" result on the economic dispatch ramping requirements of the remaining generation fleet. As the output of VERs fluctuate (e.g., as clouds pass over solar resources or as wind starts/stops blowing), other dispatchable resources must adjust to account for these fluctuations. This affects the generation fleet as if it were a fluctuation in load. Because many of these fluctuations occur over a short period of time (i.e., seconds to minutes), these moment to moment swings in the generation ramping requirements must be managed by Regulating

Reserves in order to maintain compliance with NERC balancing requirements. To ensure those NERC requirements are met, this need must be met by a resource that is on Automatic Generation Control and capable of ramping in 10 minutes. When a VER resource experiences a reduction in output over a 10-minute period (i.e., a "ramp down" condition), it results in the need for Regulating Reserves to ramp up. Assuming no definitive correlation between load volatility and VER volatility, it must be assumed that these fluctuations are additive in nature, resulting in a need for additional Regulating Reserves than would otherwise be required. This additional requirement would be necessary in all hours that the VER is expected to operate. However, when determining the impact of this additional requirement on system reliability, only those hours in which there is a reliability risk should be considered. This ensures that the existing capabilities of the system are being considered when determining the Support Capacity requirement.

VER Forecast Errors: Because VERs are not dispatchable, there is a need to forecast the expected output of the VERs to be able to properly plan for and operate the system. To the extent the actual output of the VERs differs from the forecasted output of the VERs, other resources will have to make up the difference. The timeframe in which these forecast error effects are manifested is typically in the 30-60 minute window, which also creates a need for generation response from existing online and available resources, furthering the need for flexible resources. In the case where this error is the result of an over forecast (i.e., more output was forecasted than was actually generated), this can create a reliability concern, particularly if it occurs in an hour where there is already a reliability risk.

Generation Ramping/Load Following: Finally, in many cases (such as when solar resources stop generating at sunset), these fluctuations in VER output can result in significant increased generation ramping (i.e., load following) requirements for the remaining dispatchable resources on the system. These changes in the generation ramping requirements can occur in multiple timeframes from minutes to hours. Initially, these fluctuations will be managed and served by online and available resources (i.e., Contingency Reserves). However, to maintain compliance with NERC Contingency Reserve requirements, these Contingency Reserves must be replaced within a short period of time, thus creating a need for flexible resources.

The Determination of Support Capacity Requirements

Generally speaking and assuming the system has enough flexible resources to handle the total Support Capacity requirements, Support Capacity can be used to serve double duty – that is, provide both load-serving capability as well as meeting flexibility requirements. However, there are three exceptions.

First, Support Capacity that is required to provide incremental Regulating Reserves at any given time cannot also serve load at the same time. Otherwise, it would not be available for providing regulation to the system. Therefore, any incremental Regulating Reserve requirement associated with the VER must be properly accounted for as a capacity reserve obligation in the planning process. However, to the extent the addition of the renewable resource may have offset other generating capacity, that capacity may be used to meet the Regulating Reserve requirement. Therefore, to determine the reliability impact of the incremental Regulating Reserve requirement, an hourly Regulating Reserve requirement profile can be developed and multiplied each hour by the CWFT. The CWFT identifies the relative reliability risk in each hour and so would discount or eliminate the impacts of those hours in which the reliability risk is reduced or non-existent.

To develop this Regulating Reserve requirement, a sufficient amount of historical or simulated 10 minute ramp information for the renewable resource is necessary. This information is first reduced so that only the "ramp down" instances are considered. From the remaining data, the 95th percentile of all ramp down instances determines the total Regulating Reserve Requirement (for production cost purposes). However, to determine the reliability impact (for capital cost purposes), the 95th percentile of the ramp down instances are determined ***for each hour*** of the year. This produces an hourly Regulating Reserve requirement profile that can then be multiplied by the CWFT as follows:

$$VER_{RR} = [\ \sum_{i=1}^{8760} CWFT(i)\ x\ VRR(i)\ ]$$

Where

VER_{RR} = the VER Regulating Reserve reliability impact (in % of nominal VER capacity),
CWFT (i) = the Capacity Worth Factor for hour *i* in any given year (measured in %), and
VRR(i) = the expected VER Regulating Reserve requirement in hour *i* (measured in % of nominal VER capacity).

If necessary, a MW impact can be determined by multiplying this requirement by the nominal capacity of the VER resource.

Second, as with Regulating Reserves, Support Capacity needed to account for VER forecast error likewise cannot serve planned load. Otherwise, it would not be available to make up any differences associated with VER forecast error. However, there are many hours in which there is sufficient existing capability on the system to handle this forecast error. As with Regulating Reserves, only the impact of forecast error in those hours in which there is a reliability risk should be considered. To determine the reliability impact associated with VER Forecast Error, therefore, sufficient historical or simulated forecast error data is necessary so that an hourly VER Forecast Error profile can be developed. Because only those instances in which the forecast error reflects an over forecast create a potential reliability risk, the dataset is first reduced by eliminating the under forecasted instances. From the remaining dataset, an hourly VER Forecast Error profile is developed that appropriately reflects the Company's risk tolerance related to VER Forecast Error.[16] This VER Forecast Error profile can then be multiplied by the CWFT to determine the impact that VER Forecast Error has on system reliability as follows:

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[16] Currently this profile is developed based upon a risk tolerance that reflects the 68th percentile (i.e., one standard of deviation) of the over forecasted instances in each hour.

$$VER_{FE} = [\ \sum_{i=1}^{8760} CWFT(i)\ x\ VFE(i)\ ]$$

Where

VER_{FE} = the VER Forecast Error reliability impact (in % of nominal VER capacity),
CWFT (i) = the Capacity Worth Factor for hour *i* in any given year (measured in %), and
VFE(i) = the expected VER Forecast Error in hour *i* (measured in % of nominal VER capacity).

If necessary, a MW impact can be determined by multiplying this requirement by the nominal capacity of the VER resource.

At this time, the Southern Companies do not have an agreed-upon methodology for determining the Support Capacity impacts associated with ramping.

Therefore, the total reliability impact of the Support Capacity requirement is equal to the sum of the incremental Regulating Requirement reliability impact plus the VER Forecast Error reliability impact. In other words:

$$SC_{Inc} = VER_{RR} + VER_{FE}$$

This amount (in % of nominal VER capacity), represents the total adjustment necessary to the VER ICE Factor to account for the intermittent reliability risk.

The capital and production costs associated with this Support Capacity requirement is determined as specified in Section 3 of this Framework.

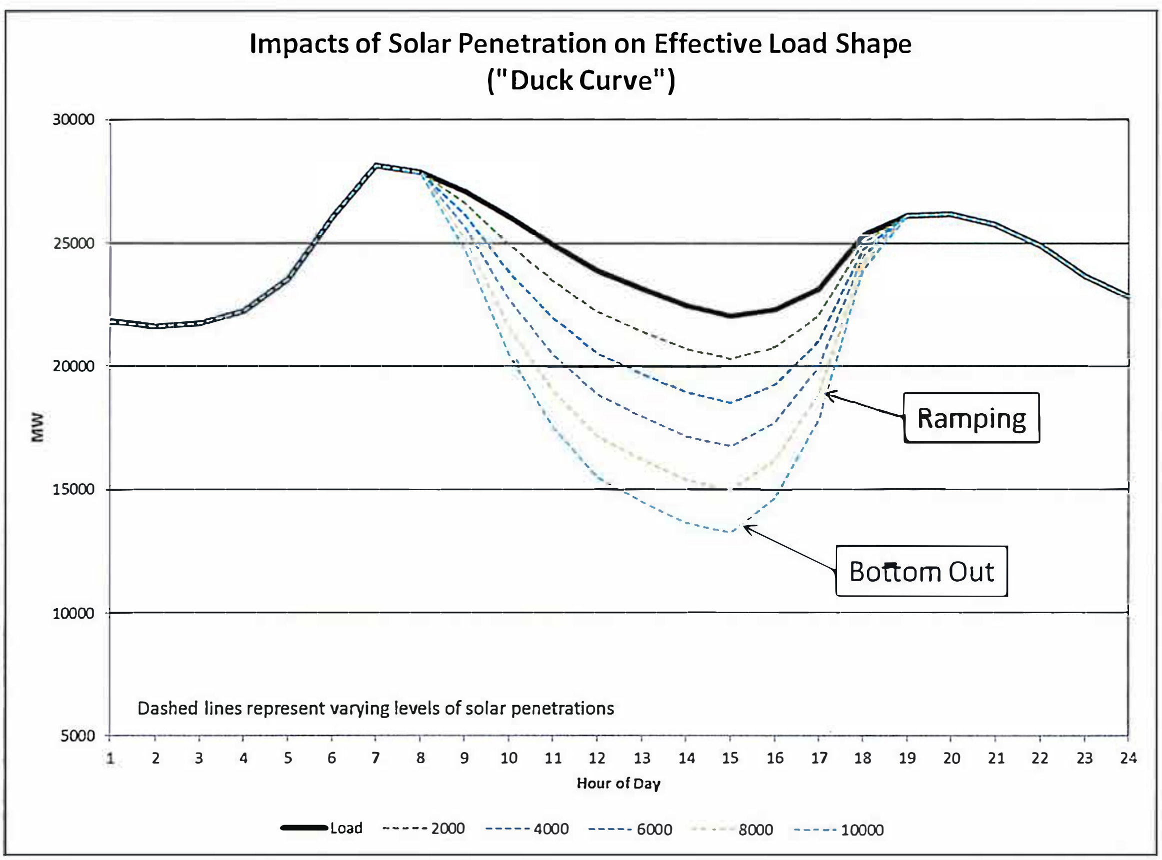
APPENDIX B – IMPACTS OF RENEWABLE GENERATION ON EFFECTIVE SYSTEM DEMAND

It has been widely publicized in the electric industry that significant penetrations of renewable resources can have detrimental impacts on the generation ramping requirements of the system. For example, while solar is a resource and not a "negative" demand, solar generation is non-dispatchable and therefore has an impact on the residual load to be served by the remaining, dispatchable resources. There are two significant impacts that large penetrations of solar can have on this effective system demand. The first is the "duck curve" phenomenon and the second is a shift of summer peak demand (i.e., "peak shift") from afternoon into post-dusk evening.

The Duck Curve Impact

Solar facilities produce electricity only during daylight hours. Large penetrations of solar will result in significant ramping up of solar generation at dawn. Likewise, there will also be a ramping down of solar generation at dusk. In the winter time, load is typically reaching its daily peak just prior to or shortly after dawn, ramps down during the midday hours, and then ramps up again in the evening, creating a double-peak effect to the load shape. This means that solar generation is ramping up as load is ramping down on winter mornings and solar generation is ramping down as load is ramping up on winter evenings. The net effect is an exaggerated midday low in the effective system demand, which can exacerbate that which is often already a difficult generation ramping condition. This effect, demonstrated in Figure B-1 below, has been referred to as the "duck curve" in the industry due to the shape of the resulting effective generation ramp resembling a duck.

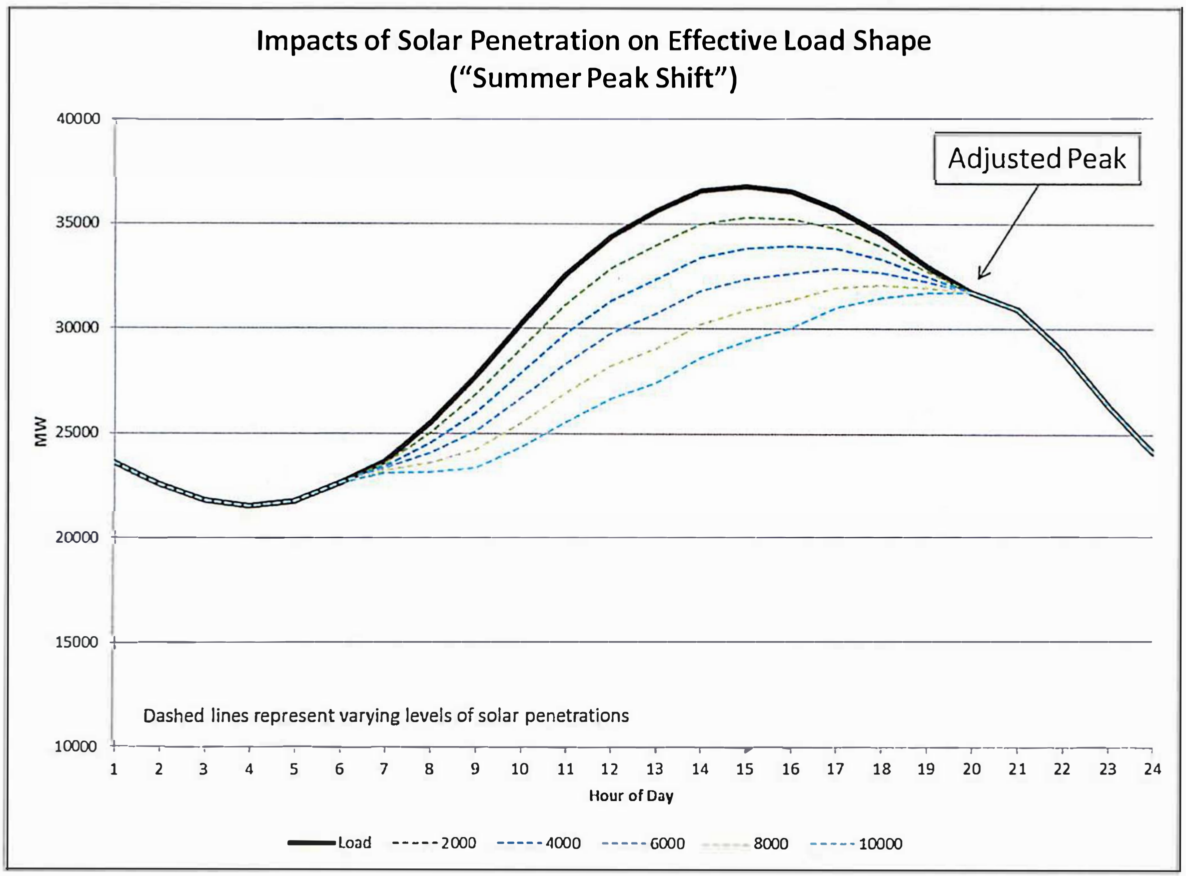
Figure B-1. Impacts of Solar Generation on Winter Effective System Demand



The Peak Shift Impact

In the summer, load is ramping up in the morning and ramping down in the evening. As such, solar has the effect of shaving the peak of the effective system demand. As more solar generation is added to the system, the effective system demand is lowered. However, because solar begins ramping down at dusk, solar can never lower the effective summer peak demand below the demand point immediately after sunset. With sufficient penetrations of solar, the effective summer peak demand will therefore shift from late afternoon to immediately after sunset as demonstrated in Figure B-2 below.

Figure B-2. Impacts of Solar on Effective Summer Peak Demand



APPENDIX C – SYSTEM AVOIDED COSTS

The Southern Companies make avoided energy cost projections based on a scenario planning process. In this process, the Southern Companies work with external consultants to develop a set of scenarios that reflect uncertainties relevant to the continuous need to serve customers reliably and in a cost-effective manner, and the numerous decisions associated with that service. The scenarios analyzed consider variations to modeling inputs, such as changes in assumptions associated with forecasted fuel and carbon allowance prices, along with overall energy demand developed using a macro-economic model. Products of these scenarios also reflect expansion, retirement, and retrofit plans for the Southern Companies' generating fleet. These plans are used in conjunction with the modeling inputs to produce avoided energy costs for every scenario.

Avoided energy cost projections are developed using the Production Cost model. The Production Cost model is a complete electric utility/regional pool analysis and accounting system that is designed for performing planning and operational studies. It is an hourly production cost model that has the fundamental goal of minimizing total production cost while providing detailed projections of fuel cost and pool accounting, including individual unit information. Inputs into the Production Cost model include scenario-specific information such as load forecasts, fuel price forecasts, fleet expansion plans, and emissions allowance prices. Other inputs that do not necessarily change across scenarios are transmission constraints, economic energy purchases and sales, nuclear and hydro budgets, and unit characteristics (heat rates, emission rates, variable O&M, max/min capacities, outage schedules, etc.).

The avoided energy cost, or marginal cost, is the dispatch cost of serving the next kWh. Avoided energy costs are determined every hour and represent the cost to produce the next increment of electrical power to meet the Southern Companies' total load. As the first derivative of the production cost equation, the dispatch cost equation includes these components: incremental heat rate; marginal replacement fuel; emissions; variable O&M; fuel handling; and transmission penalty factor (transmission energy losses). These components are described in detail below.

Incremental heat rate: This is the heat input required to increase energy output by 1kW. Heat rate coefficients required to calculate a unit's incremental heat rate are provided by the Southern Companies' generating plants from historical testing, and coal units are monitored monthly based on 12-month rolling average actuals.

Marginal replacement fuel: This is the cost of supplying additional fuel to the plant. Marginal delivered fuel forecasts are based on short term and long term forecasts developed in the scenario planning process.

Emissions: This is the replacement cost of allowances to emit SO_2 and/or NOx when burning the next Btu of fuel. Allowance price forecasts are based on market data regarding the allowances collected during the scenario planning process.

Variable operations & maintenance: This is the variable cost of maintenance required to obtain an additional MW over one hour for a specific generating unit. VOM forecasts are developed using budgeted VOM dollars from FERC specified accounts provided by the operating companies.

Fuel handling: This is the variable cost of in-plant fuel handling required to obtain an additional MW over one hour for a specific generating unit. Fuel handling forecasts are developed using the same methodology as VOM except that fuel handling is received as a separate line item in budgeted dollars from the operating companies. These accounts are also FERC-defined.

Transmission penalty factor (TPF): This is a location dependent multiplication factor that is applied to the marginal cost to account for the loss of energy during transmission from the generator to bulk transmission levels. TPFs are unit specific multipliers based on average historical data that represent the change in generating cost that occurs when going from the generator to the load center.

APPENDIX D – EXTERNALITIES

The Southern Companies agree that known and quantifiable costs and benefits that directly impact the Southern Companies' cost to serve its customers should be a part of the evaluation of the benefit of solar on the Southern Company electric system.

There are a number of components that stakeholders in the solar industry have proposed to be included in cost-benefit analyses for solar related to purported benefits that are unknown, speculative, or not readily quantifiable. For example, some have suggested that solar cost-benefit analyses should include benefits for improved health. Similarly, some have suggested that the analyses should include benefits associated with potential downstream economic development opportunities. Such benefits are very difficult to quantify with any degree of confidence, and any estimation of them is speculative, subjective, and open to considerable debate. Moreover, inclusion of such benefits in a cost-benefit analysis would ultimately lead to additional costs predicated on them (i.e., the Southern Companies would build or purchase solar at inflated prices assuming these benefits would offset the higher costs). Those costs in turn would be passed on to customers. In the Southern Companies' view, it is inappropriate to require customers to bear such costs.

Similarly, there are a number of components that stakeholders in the solar industry have proposed to be included in the cost-benefit analyses for solar that do not have a direct impact on the Southern Companies' cost to serve its customers. For example, some have suggested that a value should be derived for purported societal benefits associated with avoided water consumption costs. The Southern Companies, however, do not incur such costs directly as part of providing service to customers. Thus, costs arising from an assignment of value to such benefits cannot be properly recovered from customers under prevailing regulatory requirements. Indeed, inclusion of such components in a cost-benefit analysis would result in an inequitable burden on other customers in subsidizing the solar participants. For this reason, the Southern Companies have not included societal components in the cost-benefit analysis for solar generation.

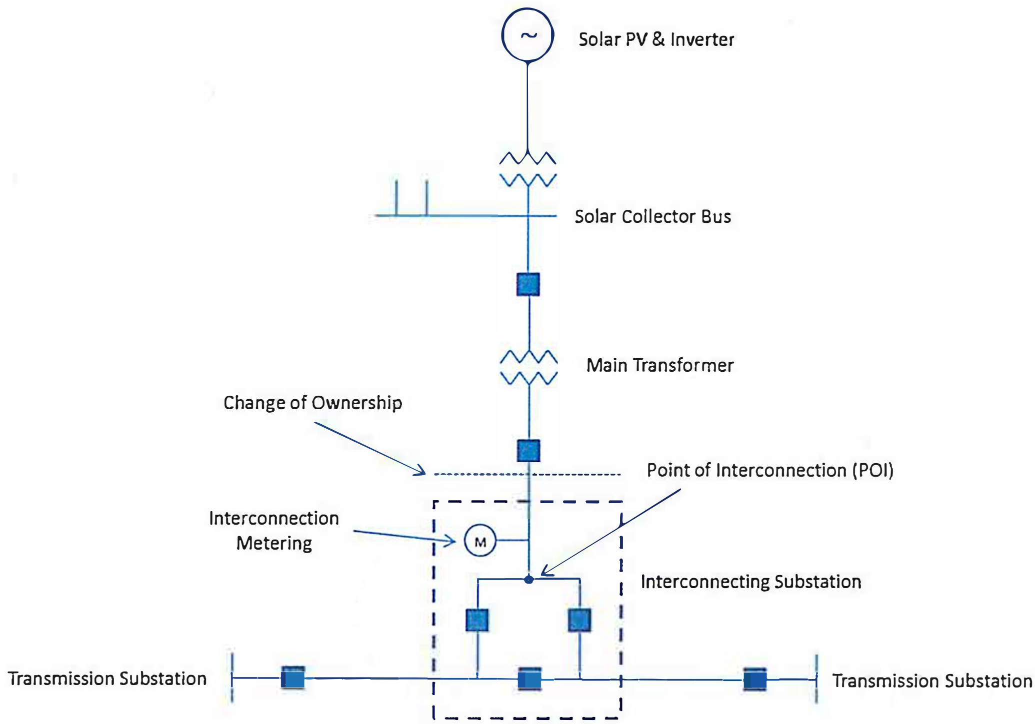
Finally, some stakeholders in the solar industry suggest that cost-benefit analyses for solar should include benefits that are based upon the expectation of future environmental legislation or changes in law, regulatory structure, or industry standards. For example, claims of benefits associated with grid resiliency and enhanced reliability, which are based upon the development of a micro-grid structure not in use in the Southern Companies' service territories today, would require significant changes to a number of industry standards. The Southern Companies do not find it appropriate to incur costs for such purported benefits. Most notably, such benefits may never materialize as the law, rule or standard may not change. But even with change, the benefits may not materialize in a manner consistent with what was presumed in the analysis, resulting in an inaccurate valuation of those benefits. Therefore, the Southern Companies have not factored such benefits into its cost-benefit analyses.

In conclusion, the Southern Companies believe that the methodology put forth in this Framework document properly accounts for the known and quantifiable benefits and costs of those components that have been identified as having a direct impact on the Southern Companies' cost to serve their customers.

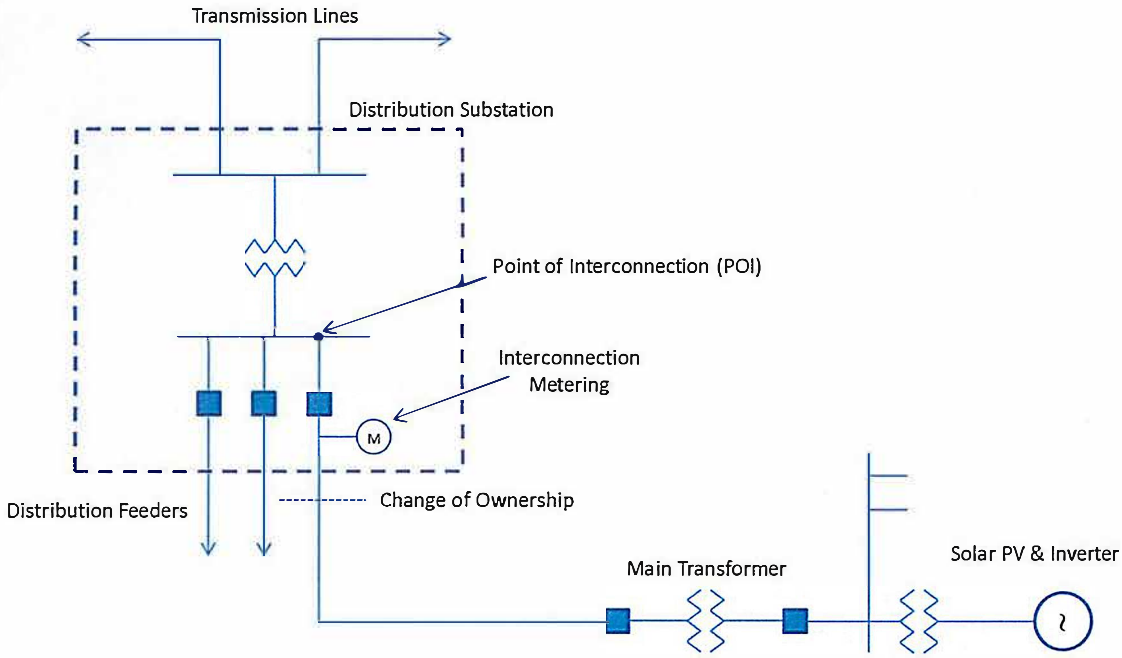
APPENDIX E – REFERENCE CONNECTIONS

The various connection types shown are for illustrative purposes only. For Utility Scale – Transmission (US-T), Utility Scale – Distribution (US-D), and Distributed – Greenfield (DG-G), the exact interconnection configuration will be determined by the respective operating company.

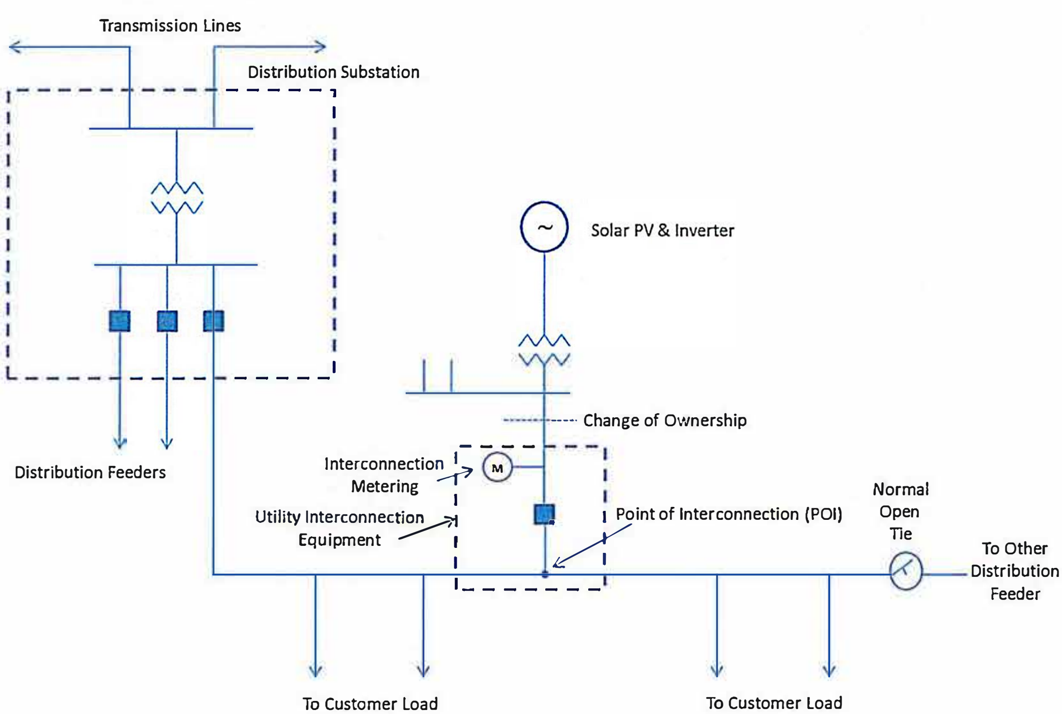
Utility Scale – Transmission (US-T)



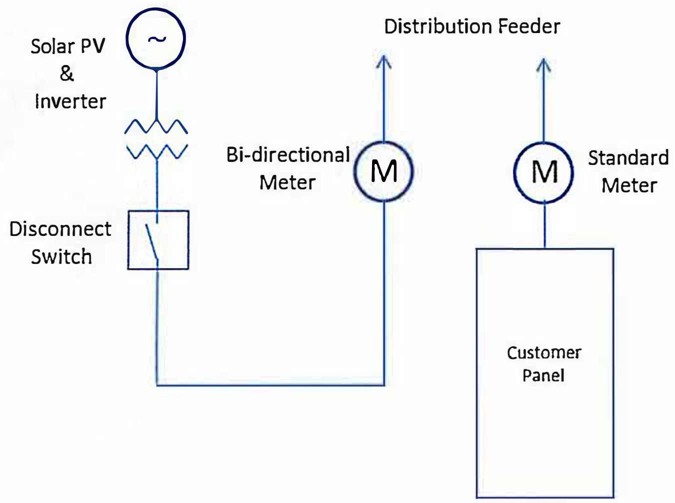
Utility Scale – Distribution (US-D)



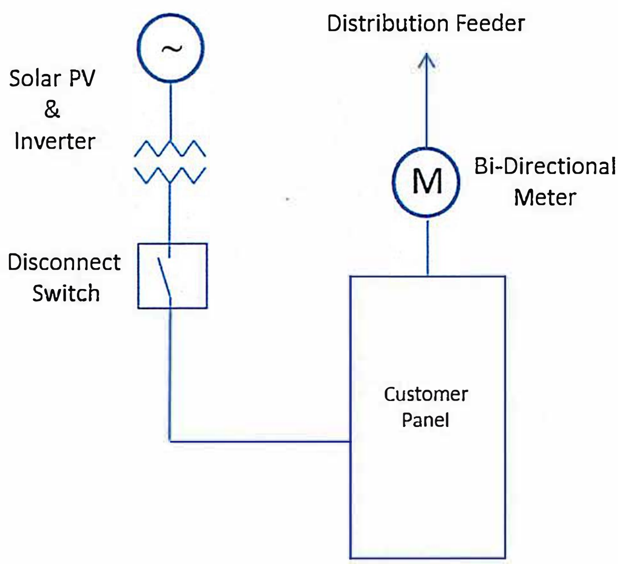
Distributed – Greenfield (DG-G)



Distributed – Metered (DG-M)



Distributed – Behind the Meter (DG-BM)



BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 40161

AFFIDAVIT AND BASIS FOR THE ASSERTION THAT PORTIONS OF THE INFORMATION SUBMITTED ARE PROTECTED TRADE SECRETS

Compliant with the Georgia Public Service Commission's December 22, 2016 Order Approving Joint Recommendation Regarding the Renewable Cost Benefit Framework in Docket No. 40161, Georgia Power Company ("Georgia Power" or the "Company") submits to the Commission an updated Table 1 from the Costs and Benefits of Distributed Solar Generation in Georgia and the Costs and Benefits of Fixed and Variable Wind Delivered to Georgia documents originally filed in Technical Appendix - Volume 1 to Georgia Power's 2016 Integrated Resource Plan. Table 1 in each of these documents contains specific resource, technology, and avoided cost information (the "Information") of the Company. Certain portions of the Information are trade secrets of Georgia Power and the Southern Company and their affiliates.

The trade secret portions of the Information derive economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from their disclosure or use. Specifically, the trade secret portions of the Information contain competitively sensitive cost information related to process and data used by Georgia Power in analyzing long-term technology specific resource additions to the System. Public dissemination of the trade secret portions of the Information would allow Georgia Power's competitors and suppliers to have access to such processes and thereby gain an unfair competitive advantage in the marketplace. Competitors would obtain an unfair advantage because they are not required to reveal similar information and can utilize such trade secret portions of the Information to manipulate pricing and timing of supply to the disadvantage of Georgia Power. Competitors would also unfairly benefit by having access and insight into the Company's planning processes and methodologies. This competitive advantage for the Company's suppliers and competitors would mean that Georgia Power will potentially pay higher prices to suppliers, ultimately harming Georgia Power and its customers.

The trade secret portions of the Information are subject to substantial procedures to maintain their secrecy. Only select Georgia Power and Southern Company personnel are granted access to the trade secret portions of the Information. Those personnel receive access only on a "need to know" basis. Parties outside Georgia Power and Southern Company who have been granted access to the trade secret portions of the Information, if any, have been required to sign confidentiality agreements.

Alison Chiock, first being duly sworn, deposes and states that she has reviewed Table 1 to the Costs and Benefits of Distributed Solar Generation in Georgia and the Costs and Benefits of Fixed and Variable Wind Delivered to Georgia documents originally filed in Technical Appendix - Volume 1 to Georgia Power's 2016 Integrated Resource Plan and that to the best of her knowledge the specific information designated as trade secret constitute trade secrets in accordance with O.C.G.A. Article 27 of Chapter 1 of Title 10.

____
Alison Chiock
Director, Resource Policy & Planning
Georgia Power Company

Subscribed and sworn to before me this _____ day of _______, 2017.

____
Notary Public

My Commission expires: