LEFT IN THE DARK:

How the Alabama Public Service Commission Makes Customers Pay Billions of Dollars for Alabama Power Investments without Any Meaningful Public Review or Involvement

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Executive Summary

Utility companies across the U.S. conduct Integrated Resource Plan (IRP) analyses to determine the optimal mix of supply-side (generation) and demand-side (energy efficiency and conservation) investments in energy production and consumption. These analyses are used to plan energy decisions decades into the future and are typically reviewed every few years. As part of an IRP analysis, utilities regularly evaluate economic decisions affecting customers. These include switching fuels at existing plants, spending money on energy efficiency and renewable resources, purchasing power from and selling power to other providers and the cost effectiveness and risks of retiring older power plants versus keeping them in operation.

In many states, including a majority of those in the South, these IRP analyses are typically reviewed in regulatory processes that offer affected ratepayers access to critical information, as well as an opportunity to participate in evidentiary hearings or to submit detailed comments before the utilities' resource plans are approved.

The Alabama Public Service Commission (PSC) is the exception.

The Alabama PSC regulates Alabama Power Company's IRP and its related resource-planning decisions in an opaque process that has allowed the Company to invest over $3 billion in environmental upgrades at its existing power plants in just the past 10 years. Alabama Power has been allowed to make these investments without having to offer any public evidence that these expenditures represent the most cost-effective and least economically risky alternatives for its customers. In fact, the only opportunity that affected ratepayers have to question the Company's resource plans is in an annual informal off-the-record meeting that lasts less than one day. Even though there is no opportunity for meaningful public participation in the decision-making process, Alabama Power's customers will pay for the Company's billions of dollars of investments for decades to come.

In contrast to Alabama, the regulatory processes in other Southern states require investor-owned utilities to publicly demonstrate that expenditures for upgrades are more cost-effective and lower economic and financial risk alternatives.

This report details:

- The significance of Alabama Power's Integrated Resource Plans and why the public's involvement in Alabama Power's resource planning process is important.
- How the Alabama PSC's cursory and opaque regulation of Alabama Power's investments differs from the public reviews made by state regulatory commissions in other southern states and by the Tennessee Valley Authority's extensive public IRP process.
- The more than $3 billion of expenditures in power plant upgrades made by Alabama Power since 2005 without offering any public evidence showing that these investments represent the most cost-effective and less economically risky alternatives for the Company's ratepayers, and the $722 million of similar plant upgrades that the Company intends to include in rates by 2019.
- The Alabama PSC's failure to provide any evidence to support its claims that it closely monitors and oversees Alabama Power's power plant investments.

This report also recommends that the Alabama Public Service Commission adopt new regulatory processes that allow for true transparency and full public participation in Alabama Power's resource planning processes. These changes are needed to ensure that Alabama Power is properly considering all viable supply-side and demand-side options in its resource planning analyses and to build public confidence that the Company is managing its system in the public interest.

Why Integrated Resource Plans (IRPs) are Important

IRPs ensure that utilities are adequately considering a wide range of feasible supply-side (generation) and demand-side (energy efficiency and conservation) options in order to determine the most cost-effective and the lowest risk resource plan for meeting their customers' future energy and capacity needs. As performed by utilities throughout the U.S., IRPs look at a utility's projected sales over a long-term timeframe, typically 10 to 40 years, and evaluate the alternative options for meeting that demand for power while assuring that there will be an adequate level of reserves to meet unexpected increases in electric loads, spiking in extreme weather conditions or unanticipated power plant or transmission line outages.

Using computers to model various future scenarios (fuel prices, regulatory policies, etc.), utilities typically consider a wide range of options in IRPs for meeting future loads, including the continued operation and upgrading of existing power plants, building new plants, or buying power from non-utility merchant generators. IRPs also examine a range of possible fuels and generating technologies – such as coal, gas, utility-scale wind and solar, distributed solar photovoltaics (solar PV), etc. - to include as part of their long-term resource plans. In addition, IRPs also evaluate non-generation, also known as demand-side, alternatives that reduce demand for electricity instead of producing more of it. These demand reduction strategies include energy efficiency investments, reducing transmission and distribution system line losses, and any other available, reliable, and cost-effective means of meeting customer needs.

As explained by the North Carolina Utilities Commission in a recent report to the Governor and the legislature of that state:

> Integrated resource planning is an overall planning strategy which examines conservation, energy efficiency, load management, and other demand-side measures in addition to utility-owned generating plants, non-utility generation, renewable energy, and other supply-side resources in order to determine the least cost way of providing electric service. The primary purpose of integrated resource planning is to integrate both demand-side and supply-side resource planning into one comprehensive procedure that weighs the costs and benefits of all reasonably available options in

order to identify those options which are the most cost-effective for ratepayers consistent with the obligation to provide adequate, reliable service.[1]

As the future cannot be forecast with absolute certainty, IRPs typically examine multiple alternatives or energy resource plan scenarios, and examines the costs, reliability and environmental impacts of each scenario under a range of different assumptions concerning such important inputs as future energy demands, costs and regulatory policies. As explained by the Regulatory Assistance Project (RAP),[2]

> The goal of an IRP is to identify the least-cost resource mix for the utility and its customers. *Least-cost* in this case means lowest total cost over the planning horizon, given the risks faced. The best resource mix is typically the one that remains cost-effective across a wide range of futures and sensitivity cases – the most *robust* alternative – and that also minimizes the adverse environmental consequences associated with its implementation.[3]

The PSC does not require Alabama Power to make public any economic analyses justifying the billions of dollars that the Company has spent in just the past ten years to upgrade its existing, mostly coal, power plants.

The utility will then use the results of the IRP to decide which types of resources to invest in, whether it is better to own power plants or buy power from third parties, and how much energy efficiency and/or renewable resources like solar and wind to add.[4]

A total of 39 states require investor owned utilities (IOU) like Alabama Power to conduct long-term resource planning or procurement.[5] Many states also require IOUs to submit IRP-like analyses to justify expensive investments in upgrading existing power plants.

1 N.C. Utils. Comm'n, *Annual Report Regarding Long Range Needs for Expansion of Electric Generation for Service in North Carolina Required Pursuant to G.S. 62-110.1(a)*, at 7–8 (Dec. 11, 2013), *available at* http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=def9271d-7ead-4bbd-81ea-f273d2c0c57e.

2 The Regulatory Assistance Project an internationally recognized organization of former state regulatory commissioners and senior regulatory commission staff personnel who provide analysis and assistance to any entities working with utility commissions. *See* Regulatory Assistance Project, http://www.raponline.org/.

3 Regulatory Assistance Project, *Electricity Regulation in the US: A Guide*, at 73–74 (2011), *available at* http://www.raponline.org/.

4 *Id,* at 74.

5 Municipal, federal or state-owned utilities may not be under the jurisdiction of a state regulatory authority and thus may not be subject to state requirements. However, as will be discussed later in this report, the Tennessee Valley Authority (TVA) does conduct a public IRP process.

The Alabama PSC Regulates Alabama Power's Resource Decisions in an Opaque Process that Provides only Limited Opportunities for Public Involvement

Alabama Power prepares an IRP every three years.[6] Although a very brief summary of the IRP is sometimes made available, neither Alabama Power nor the PSC makes public the details of that IRP or the underlying economic analyses that form the basis for the Company's decisions on which resources to add and which investments to make. In particular, the PSC does not require Alabama Power to make public any economic analyses justifying the billions of dollars that the Company has spent in just the past ten years to upgrade its existing, mostly coal, power plants.

An IRP is meant to provide an advance perspective as to what a utility believes its future needs are likely to be, which gives outside parties a chance to identify more cost-effective alternatives that the company may not have considered. The cursory information that is sometimes made public for Alabama Power's IRP and the Alabama PSC's cursory and opaque review process do not allow for this.

The PSC has made a number of claims concerning how well Alabama Power evaluates cost-effective energy efficiency and demand-side management in its IRP. For example, in its October 28, 2010 Order in Docket 31045, the PSC said that "under the existing IRP process, "cost-effective energy efficiency" is viewed as a "priority resource" in the long-term planning efforts of Alabama Power."[7]

Moreover, in 2009 comments to the U.S. Department of Energy concerning transmission planning, the Commission touted the successes of Alabama Power's IRP process and noted the following:

> [T]he major reason for this lack of long-term congestion is that Alabama remains a state in which both generation and transmission, along with distribution and demand side management, are all jointly studied through the integrated resource planning process to provide service to consumers on a least-cost basis. In this process, reliability and long-term economic dispatch are the primary drivers for transmission system improvements and expansion plans. This integrated process reduces congestion by ensuring that new and existing

6 Alabama Power Company, *2013 Integrated Resource Plan, Public Summary Report*, at page 5.
7 *Id.*

> generation resources committed to serving the citizens of this region on a long-term basis can be delivered without congestion….[8]

However, neither the PSC nor Alabama Power has made any documentation available to the public to support these claims.

Each fall, Alabama Power submits an application to the PSC for approval to recover new environmental investments and associated operating costs through what is called the Rate Certificated New Plant – Environmental (Rate CNP-Environmental) formula. Instead of reviewing this application, or the IRP on which it is based, in on-the-record public evidentiary hearings, the PSC conducts a very short, informal public meeting each December that, at most, lasts a single day.[9]

Although the public is allowed to ask some questions at this informal meeting and the company does file a summary environmental compliance plan in November and summary Rate CNP-Environmental calculations a week before the meeting,[10] there is no public evidentiary hearing. Consequently, there is:

- No pre-filed testimony from the Company offering any economic justification for the investments that it is seeking to recover through rates;
- No PSC mandated requirement that the Company provide any additional information or documents in response to discovery questions from the public;[11]
- No requirement that witnesses testify under oath.

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8 Alabama Public Service Commission Comments, Transmission Planning Processes Under Order No. 890, FERC Docket No. AD09-8, Request for Comments, at 3–4 (Dec. 18, 2009).

9 The Alabama PSC's informal day-long public meeting addresses the Company's application to recover environmental investments through Rate CNP-Environmental and its Rate RSE requested return on investments for the upcoming year. Thus, the Rate CNP-Environmental portion of the meeting may last only for one-half day. *See, e.g.*, Notice, Alabama Power Company Rate CNP Environmental Compliance, Ala. Pub. Serv. Comm'n Docket Nos. 18117 & 18416 (Nov. 4, 2014) (scheduling the annual informal meeting for Rate CNP at 9:30 AM on December 9, 2014); Notice, Alabama Power Company Rate RSE & Rate CNP, Ala. Pub. Serv. Comm'n Docket Nos. 18117 & 18416 (Nov. 4, 2014) (scheduling the annual informal meeting for Rate RSE at 2:00 PM on December 9, 2014).

10 *See, e.g.*, Alabama Power Company, Preliminary Version of Environmental Compliance Plan Associated with Rate CNP, Ala. Pub. Serv. Comm'n Docket Nos. 18117 & 18416 (Nov. 3, 2014); Alabama Power Company, Final Version of Environmental Compliance Plan Associated with Rate CNP, Ala. Pub. Serv. Comm'n Docket Nos. 18117 & 18416 (Dec. 9, 2014).

11 Each of Alabama Power's annual Rate CNP–Environmental publicly available filings essentially present the same description of the various federal environmental regulations required by the Company for Clean Air Act compliance. Although the Company presents summary data on the costs of these upgrades, and how they affect the rates paid by Alabama Power's customers, it does not include any information showing this analysis or that completing the upgrades and continuing to operate older power plants is the most cost-effective alternative for ratepayers. *See id.*

As a result, the Alabama Public Service Commission has allowed Alabama Power to collect from its customers through Rate CNP-Environmental approximately $2.6 billion in higher rates since the beginning of 2005 associated with some $3.2 billion of expensive power plant environmental upgrades, in an opaque, mostly secret process, without meaningful public participation.

Only a Short Summary of Alabama Power's IRP is Made Public

Upon request from the media and members of the public, the Alabama PSC has made public a very cursory summary of Alabama Power's IRP. For example, in early 2014, the PSC released a 15-page document that included only summary descriptive language about the Company's 2013 Integrated Resource Plan.[12] The very limited narrative included in this summary did not include any detailed data information on such important issues as what Company expects its future needs will be or any economic analyses showing that the resource plan adopted by Alabama Power is more cost-effective and less economically risky for ratepayers than other alternative scenarios. By way of contrast, Alabama Power's sister company, Georgia Power Company, submitted an IRP in January 2013 that was approximately 190 pages long, including appendices, and contained significant detail on the supply-side and demand-side resource alternatives that had been considered by the Company in developing its proposed resource plan.[13] The data that Georgia Power considered confidential or proprietary was redacted from the public version of the IRP. However, interested parties could sign a non-disclosure agreement (NDA) to obtain the redacted data and could petition the Georgia PSC to have some of the confidential information made public.

As will be discussed below, the other major electric utility in the state of Alabama, the Tennessee Valley Authority (TVA), conducts a public IRP process in which ratepayers are invited to participate.[14] TVA releases a detailed public version of its IRP as part of this process. For example, TVA's 216-page 2011 IRP is available on its website.[15] TVA also makes a large number of related analyses and presentations, including a quarterly update of the 2015 IRP development process, available on its website.[16]

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12 *See* Attachment 1.

13 Georgia Power Company's 2013 Integrated Resource Plan and Application for Decertification, Ga. Pub. Serv. Comm'n Docket No. 36498 (Jan. 31, 2013), *available at* http://www.psc.state.ga.us/factsv2/Docket.aspx?docketNumber=36498.

14 This process is not mandated by any federal or state statute but reflects its Board's policy.

15 *See* Tenn. Valley Auth., *Integrated Resource Plan: TVA's Environmental and Energy Future* (2011), http://www.tva.com/environment/reports/irp/archive/pdf/Final_IRP_complete.pdf.

16 *See Integrated Resource Plan*, Tenn. Valley Auth., *available at* http://www.tva.com/environment/reports/irp/index.htm.

The 2013 IRP submitted by Duke Energy to the North Carolina Utilities Commission and the South Carolina Public Service Commission in September 2013 was 151 pages long, including tables and various appendices.[17] This IRP also contained very detailed information about the company's projected future loads and resource requirements and the various supply-side and demand-side alternatives it had considered in developing its proposed resource plan.[18] As in Georgia, information that Duke Energy considered confidential or proprietary was redacted from the public version of the IRP. However, interested parties can intervene to participate in the North and South Carolina commission dockets reviewing the IRP and sign NDAs to see redacted information.

The Public is only allowed a Cursory Opportunity to Question Alabama Power at the Annual PSC Informal Rate CNP Meetings

The Alabama PSC conducts an informal meeting each December, approximately one month after the Company files its draft Environmental Compliance Plan and one week after Alabama Power files its application for Rate CNP-Environmental rates for the next calendar year. This short timeframe does not allow ratepayers any meaningful opportunity to submit written discovery questions to the Company seeking additional information or documents. It is also simply impossible to fully understand and comment on the Company's resource plans that form the basis for its annual Rate CNP expenditures without the underlying information and a reasonable amount of time for analysis.

The public was only allowed to ask questions for approximately 25 minutes, with several parties unable to finish their questioning before they were cut off.

Moreover, ratepayers are extremely limited in their opportunities to ask the Company questions at the informal meeting. For example, at the December 9, 2014 Rate CNP meeting, Alabama Power's opening presentation lasted more than two hours, and the public was only allowed to ask questions for approximately 25 minutes, with several parties unable to finish their questioning before they were cut off.

The experience at this informal meeting was not unique. At the December 10, 2013 Rate CNP meeting, Alabama Power spent more than half of the meeting on its

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17 This IRP is available on the South Carolina Energy Office's website. *See* Duke Energy Carolinas, *Integrated Resource Plan (Annual Report)* (Oct. 15, 2013), *available at* http://www.energy.sc.gov/files/view/DUKE_2013_IRP_10.23.2013.pdf.

18 The table of contents from Duke Energy Carolinas 2013 IRP is included as Attachment 2 to this Report.

presentations, leaving little time for public questioning. As indicated earlier, none of the Company's presentations or answers to parties' questions were under oath or on the record, common requirements found in most commissions when important expenditures are discussed.

The State Regulatory Commissions in Florida, Georgia, and Mississippi, Conduct Public Hearings on Important Resource Decisions with Participation by Affected Ratepayers

Unlike the Alabama PSC that does not allow the citizens to participate in the energy planning decisions that affect the rates they pay, the regulatory commissions in Georgia, Mississippi, and Florida, states in which Alabama Power's retail affiliates operate, conduct public reviews of important utility resource decisions.

Georgia

The Georgia Public Service Commission conducts extensive public reviews of the resource plans and decisions of the Georgia Power Company that afford significant opportunities for participation by the ratemaking public.

Every three years, Georgia Power files an IRP with the Commission. This IRP is reviewed in an open evidentiary hearing process in which interested parties are permitted to intervene and present expert testimony on alternatives to the Company's proposed resource plans. For example, as a result of issues raised in IRP hearings, Georgia Power is currently on track to add nearly 1,000 MW of solar by 2016, because it was cost efficient and in the best interests of utility customers. More than 525 MW of this new solar capacity is a direct result of the Georgia Commission's July 2013 IRP order.

In addition, Georgia Power filed applications with the state's Public Service Commission in 2011 and 2013 seeking permission to decertify (that is, retire) 19 of its existing fossil-fired generating units.[19] These requests were based on Georgia Power's computer modeling that showed that the costs of

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[19] Georgia Power Company's Application for Decertification, Ga. Pub. Serv. Comm'n Docket No. 34218 (Aug. 4, 2011), *available at* http://www.psc.state.ga.us/factsv2/Docket.aspx?docketNumber=34218; Georgia Power Company's 2013 Integrated Resource Plan and Application for Decertification, Ga. Pub. Serv. Comm'n Docket No. 36498 (Jan. 31, 2013), *available at* http://www.psc.state.ga.us/factsv2/Docket.aspx?docketNumber=36498.

upgrading and/or repairing the existing units were too high to justify keeping them operational. The Company's applications were public and pre-filed in advance of the hearings so that all parties could review, as were redacted versions of the Company's Unit Retirement Studies and its updated 2011 IRP and 2013 IRP that were submitted in support of the applications. Affected parties were permitted to participate as official "intervenors" in the Public Service Commission's cases and obtain non-redacted versions of these documents if they signed a non-disclosure-agreement. Intervenors also were permitted to examine the workpapers for the Company's analyses, to question the Company's witnesses under oath, to present their own expert testimony and to submit briefs at the end of the public hearing process.

Mississippi

Although the Mississippi Public Service Commission does not hold public evidentiary hearings on Mississippi Power Company's IRP, it did conduct full public evidentiary hearings on the Company's application to undertake an expensive scrubber project at its Victor J. Daniel Electric Generating Facility in 2012.[20] During these hearings intervenor parties were permitted to submit discovery questions to Mississippi Power to obtain additional information and the studies and analyses underlying the Company's request. Through this process, parties were able to review significant information from Mississippi Power's most recent IRP. Intervenor parties also were allowed to question the Company's witnesses under oath in an on-the-record evidentiary hearing, to present their own expert testimony, and to submit briefs at the end of the public hearing process.

Florida

Alabama Power's affiliate in Florida, Gulf Power Company, is also owned by Southern Company. Gulf Power files a public Ten Year Site Plan with the Florida Public Service Commission (Florida PSC) every April.[21] Although this is not an Integrated Resource Plan and there are no formal hearings on the Site Plan, it does contain significant and substantial information about the

20 In re: Petition of Mississippi Power Company for a Certificate of Public Convenience and Necessity, Miss. Pub. Serv. Comm'n Docket No. 2010-UA-279 (July 26, 2010), *available at* http://www.psc.state.ms.us/InsiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=256885.

21 Gulf Power Company, Ten Year Site Plan 2014-2023, Fla. Pub. Serv. Comm'n Document No. 01433-14, at 1–2 (Apr. 1, 2014), *available at* http://www.psc.state.fl.us/library/FILINGS/14/01433-14/01433-14.pdf.

company's expected future loads and resources. Witnesses in other Florida PSC evidentiary hearings are able to use the information from the Site Plan when discussing long-term resource alternatives, including energy efficiency and increased investments in renewable resources. Florida utilities also have submitted their IRPs in Florida PSC dockets as part of need certifications for new power plants.

The Florida Public Service Commission also conducts annual public evidentiary Environmental Cost Recovery Clause hearings for the state's utilities including Gulf Power Company. Intervenor parties are allowed to participate in these dockets by submitting discovery seeking additional information from the utility, questioning utility witnesses under oath, presenting expert witness testimony and submitting briefs to the Commission.

The economic costs and benefits of proposed power plant upgrades are among the issues that can be addressed in a Florida PSC Environmental Cost Recovery Clause docket. For example, in March 2011, Gulf Power Company submitted "a retirement and replacement evaluation" in support of its request to make expensive upgrades at its existing fossil units, including the addition of a scrubber at the Plant Daniel coal-fired unit that Gulf Power jointly owns with Mississippi Power. Gulf Power explained that this "retirement and replacement evaluation" was used:

> to compare retrofit compliance options to premature retirement and replacement of specific generating units in order to determine the most reasonable, cost-effective compliance option. The retirement option is typically more applicable to smaller, older, less efficient coal plants that cannot financially support the addition of environmental controls.[22]

Thus, Alabama is the only state in the Southern Company operating area that prevents ratepayers from any meaningful public participation in the PSC process.

The Alabama PSC's refusal to allow meaningful public review of Alabama Power's IRP is even more remarkable given that the resource plans of each of the Southern Company's retail operating companies are coordinated and developed within the Southern Electric System Integrated Resource Planning (SES IRP) process and the planning is performed in conjunction with the entire Southern Company system. As Gulf Power's *2014 Ten Year Site Plan* explains:

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22 Gulf Power Company, Environmental Compliance Program Update for the Clean Air Interstate Rule and the Clean Air Visibility Rule, Fla. Pub. Serv. Comm'n Docket No. 110007-EI, Document No. 02191-11, at 11 (Apr. 1, 2011), *available at* http://www.psc.state.fl.us/library/FILINGS/11/02191-11/02191-11.pdf.

> The resource planning process utilized by Gulf to determine its future capacity needs is coordinated within the Southern electric system Integrated Resource Planning (SES IRP) process. Gulf participates in the IRP process along with other Southern electric system retail operating companies, Alabama Power Company, Georgia Power Company, and Mississippi Power Company, (collectively, the "Southern electric system" or SES), and it shares in a number of benefits gained from planning in conjunction with a large system such as the SES. These benefits include the economic sharing of SES generating reserves, the ability to install large, efficient generating units, and reduced requirements for operating reserves.[23]

Consequently, it appears that Alabama Power's resource decisions may well be driven by Southern Company-wide needs. Without a full and transparent regulatory process in Alabama, there is absolutely no proof that the most cost-effective plan for the entire Southern Company system that results from the SES IRP process is necessarily the most cost-effective resource plan for Alabama Power's ratepayers.

Other State Regulatory Commissions and the Tennessee Valley Authority Also Allow for Significant Public Involvement in Reviews of Utility Resource Planning Decisions

In addition to Florida, Georgia and Mississippi, the regulatory commissions in other southern states, beyond those served by retail affiliates of the Southern Company, also require utilities to submit IRPs or other long-term resource procurement plans and/or demonstrate the reasonableness of proposed spending on power plant retrofits and upgrades. The Tennessee Valley Authority (TVA), which sells power to customers in northern Alabama, Tennessee, and Kentucky, also has a multi-step public IRP process in which representatives of its customers can participate.

[23] Gulf Power Company, Ten Year Site Plan 2014-2023, Fla. Pub. Serv. Comm'n Document No. 01433-14, at 1–2 (Apr. 1, 2014), *available at* http://www.psc.state.fl.us/library/FILINGS/14/01433-14/01433-14.pdf.

Tennessee Valley Authority

TVA periodically updates its Integrated Resource Plan to identify the resource “portfolio most likely to help [it] lead the region and the nation toward a cleaner and more secure energy future.”[24] TVA last completed an IRP in 2011. It had planned to prepare another in 2016 but that schedule has been advanced due to what it termed a rapid industry shift in such important factors as load growth, natural gas prices and pending environmental regulations. These are the types of inputs generally considered in adequate IRP planning analyses.

TVA seeks out and obtains substantial public input and involvement in this IRP process. For example, TVA seeks input from the general public, its customers, its partners and regulators about a number of factors including: (a) the sources they use to generate power (fossil fuels, renewables, nuclear, etc.), (b) how it can reduce demand (energy efficiency programs, time-of-use pricing, environmental impact, etc.) and (c) how it delivers power (transmission, environmental impact, pricing, etc.).[25] Based on the information gathered through this scoping process, TVA then develops resource scenarios that are evaluated for viability and environmental impact. With this information, TVA develops a draft Integrated Resource Plan and a draft Supplemental Environmental Impact Statement that are made available to the public for comment.

TVA works throughout the IRP update process with an IRP Working Group that includes representatives from a broad range of perspectives including customers, businesses, activists, elected officials and economic development experts.[26] As TVA explains, it meets frequently with this Working Group to get feedback, insights and challenges as it develops scenarios, strategies and plan measurements along the way.

TVA also posts its IRP presentations, updates, and IRP Working Group meeting materials on its website.

North Carolina

The North Carolina Utilities Commission (NCUC) requires each investor owned utility subject to its jurisdiction to submit an IRP biannually, with IRP updates in the years in which a new IRP is not

24 *See Integrated Resource Plan*, Tenn. Valley Auth., http://www.tva.com/environment/reports/irp/index.htm.
25 *See id.*
26 *Id.*

submitted. The NCUC has ordered each IOU to conduct very detailed analyses considering both supply-side and demand-side resource options and to include very detailed information in each IRP submission.[27] As noted above, Duke Energy Carolina's 2013 IRP was 151 pages in length and included detailed tables, appendices and economic analyses.

Interested parties are permitted to intervene in the ongoing NCUC dockets in which each company's annual IRP and IRP Update filings are reviewed. Parties also are permitted to submit their own comments on a utility's filing. Although there is no formal requirement for discovery, there is typically an informal exchange of information among the parties to each NCUC IRP docket. The NCUC may set on-the-record evidentiary hearings depending on the issues raised in the IRP or in the comments submitted by intervening parties.

South Carolina

The IOUs subject to the jurisdiction of the South Carolina Public Service Commission (SCPSC) are required to submit IRPs every three years and to file IRP Updates in each of the intervening years. Each IRP must contain the following information:

1. The company's demand and energy forecast for at least a 15-year period.
2. The company's program for meeting the requirements shown in its forecast in an economic and reliable manner, including both demand-side and supply-side options.
3. A brief description and summary of the cost-benefit analysis, if available, of each option considered, including those not selected.
4. The company's assumptions and conclusions with respect to the effect of the resource plan on the cost and reliability of energy service, and a description of the external, environmental and economic consequences of the plan to the extent practicable.[28]

As in North Carolina, interested parties are permitted to intervene in the ongoing SCPSC docket in which each company's annual IRP or IRP Update filings are reviewed. Parties also are permitted to

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27 The NCUC's July 11, 2007 Order in Docket No. E-100, Sub 111, setting forth the analyses that a utility must undertake as part of its IRP and the information that must be submitted as part of an IRP filing, is included as Attachment 3 to this Report.

28 Order Modifying Reporting Requirements, In re: Least-Cost Planning Procedures for Electric Utilities Under the Jurisdiction of the Public Service Commission, S.C. Pub. Serv. Comm'n Docket No. 87-223-E, Order No. 1998-502 (July 2, 1998), *available at* http://dms.psc.sc.gov/pdf/orders/33D9F286-EE86-2206-C8442BE057BC1430.pdf.

submit their own comments on a utility's filing. Although there is no formal requirement for discovery, there is typically an informal exchange of information among the parties to each SCPSC IRP docket. The SCPSC may require the utility to submit further information and/or set on-the-record evidentiary hearings depending on the issues raised in the IRP or in the comments submitted by intervening parties.

Louisiana

In 2012, the Louisiana Public Service Commission adopted a Rule for Integrated Resource Planning for Electric Utilities. This rule requires that a utility submit an IRP about every four years and outlines in some detail the information that the utility must submit and the types of analyses that the utility must include in its long-term planning. These analyses, which include both demand-side and supply-side resource evaluations and an optimized analysis, are used to develop an initial reference resource plan. This plan is then subjected to a series of sensitivity and scenarios analyses to evaluate how viable it would be under changed circumstances.[29]

All of these state commissions have far more robust public processes for ratepayer participation than the Alabama PSC.

As significant as the range of information and analyses that the Louisiana Commission requires to be included in an IRP, the Commission's rule also requires public involvement in the development of the IRP through a series of stakeholder meetings to discuss on the utility's draft assumptions and later its draft IRP report. Interested stakeholders also are given the opportunity to file written comments with the utility about the draft IRP report.[30] Finally, stakeholders are given the opportunity to submit a list of disputed issues and alternative recommendations to the Commission after the final

29 Order, In re: Development and Implementation of Rule for Integrated Resource Planning for Electric Utilities, La. Pub. Serv. Comm'n Docket No. R-30021, at Attach. A, 1–14 (Apr. 18, 2012), *available at http://www.entergy-louisiana.com/content/irp/LPSC_General_Order_R30021.pdf*.

30 For example, the 194-page draft 2015 IRP released by the Southwestern Electric Power Company and an outline of the public stakeholder process that will be followed in developing its final IRP are available on the company's website. *See* Southwestern Electric Power Company, *Integrated Resource Planning Report to the Louisiana Public Service Commission* (Feb. 6, 2015), *available at* https://www.swepco.com/global/utilities/lib/docs/info/projects/SWEPCOIntegratedResourcePlan/2015_DRAFT_SWEPCO_LA_IRP_Filed_Feb_6.pdf; Southwestern Electric Power Company, *IRP Process Schedule of Events, First Full IRP Cycle* (Jan. 30, 2014), *available at* https://www.swepco.com/global/utilities/lib/docs/info/projects/SWEPCOIntegratedResourcePlan/SWEPCO_IRP_PROCESS_SCHEDULE_REV_1_Final_1-30-14.pdf.

IRP Report is filed. If the Commission decides that there are disputed issues it needs to decide, it will establish a procedural hearing schedule to address those issues.[31]

Clearly, all of these state commissions have far more robust public processes for ratepayer participation than the Alabama PSC.

Alabama Power has Invested Billions of Dollars Since 2005 in Upgrades at its Generating Facilities Without Demonstrating to Ratepayers that these Investments Are Cost-Effective

Alabama Power has a direct financial incentive to make expensive upgrades, even at power plants that are aging and/or that don't generate much electricity, because the Alabama Public Service Commission's regulatory policies allow the Company to add the investments to its rate base on which it earns a return. The larger the Company's total rate base, the higher the Company's profits. Moreover, placing an investment into rate base means that the Company is allowed to earn a return on that investment for decades and can also recover annual operating & maintenance and depreciation expenses attributable to the environmental upgrades.

This is especially true in Alabama where the Commission allows Alabama Power Company to earn an overall 11.6 percent return on the investments it adds to rate base through Rate CNP-Environmental without any formal public evidentiary hearings. The key component of this overall 11.6 percent return is the 13.0 to 14.5 percent return on equity that the Alabama PSC allows Alabama Power to earn. The March 2013 IEEFA Report, *Public Regulation without the Public*, documents how for more than thirty years the Alabama PSC has allowed the Company to earn these extremely high returns on the equity portion of its investments without holding public evidentiary hearings.[32]

From 2005 to 2014, the Alabama PSC allowed Alabama Power to add $3.2 billion in environmental upgrade investments to its rate base through Rate CNP-Environmental, and currently expects to add another $722 million in the coming five years. This can be seen in Figure 1, below:

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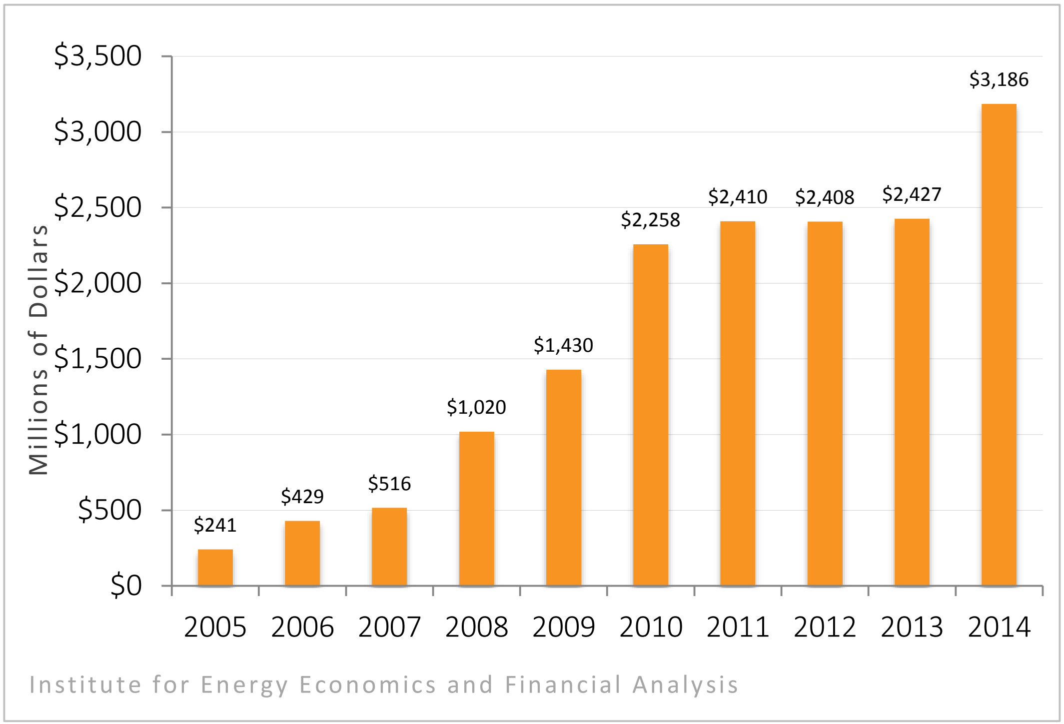
31 Southwestern Electric Power Company, *Integrated Resource Planning Report to the Louisiana Public Service Commission*, at 17–18 (Feb. 6, 2015), *available at* https://www.swepco.com/global/utilities/lib/docs/info/projects/SWEPCOIntegratedResourcePlan/2015_DRAFT_SWEPCO_LA_IRP_Filed_Feb_6.pdf.

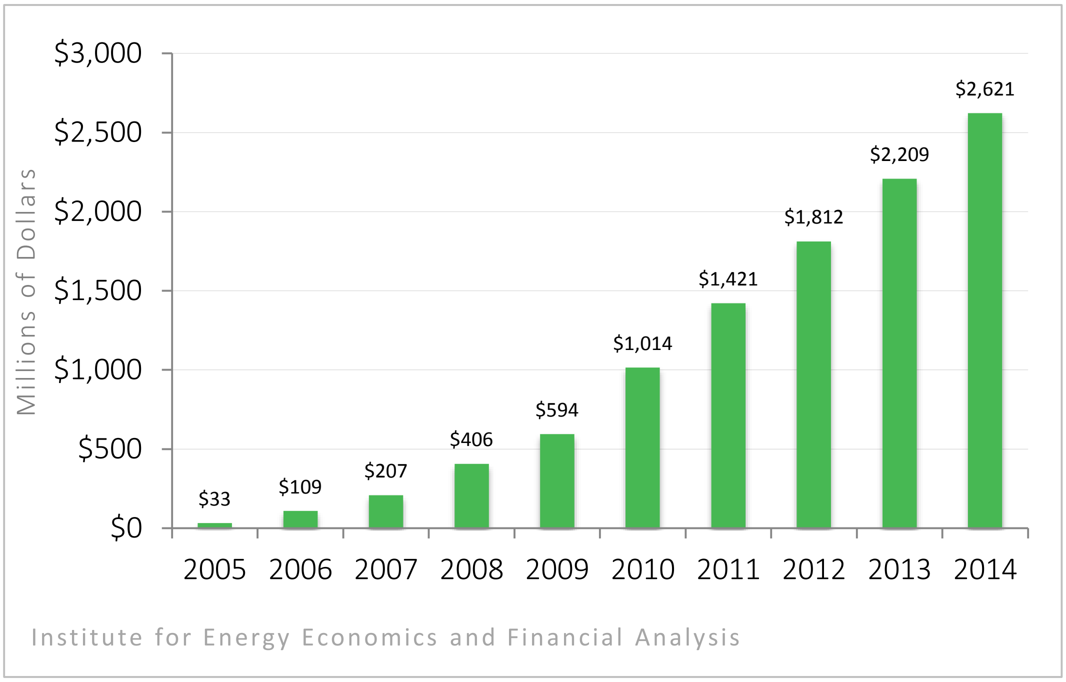
32 *See* David Schlissel & Anna Sommer, Inst. For Energy Econ. & Fin. Analysis, *Public Regulation with the Public* (Mar. 1, 2013), *available at* http://ieefa.org/report-weak-psc-oversight-benefits-alabama-power-at-customers-expense/.

Figure 1: Cumulative Upgrade Investments Placed into Alabama Power's Retail Rate Base through Rate CNP-Environmental.[33]



Consequently, through the end of 2014, Alabama Power's retail customers have paid over $2.6 billion just for the return on the more than $3 billion of upgrades added to rate base through Rate CNP-Environmental and associated Operating & Maintenance (O&M) and depreciation expenses, as shown in Figure 2, below.

Figure 2: Cumulative Rates Paid by Alabama Power's Retail Alabama Ratepayers through Rate CNP-Environmental, 2005-2014.[34]



But this is not the end of the road. Ratepayers will continue to pay billions of dollars in future years for these same investments. And all of these costs are being passed through to ratepayers without any on-the-record evidentiary hearings in which the public can participate and without any requirement

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33 The data in this Figure is based on information in the annual filings of Rate CNP Calculations made by Alabama Power each November or December. See Footnotes 7 through 9, above.

34 The data in this Figure is based on information in the annual filings of Rate CNP Calculations made by Alabama Power each November or December.

that Alabama Power demonstrate that its environmental upgrades represent the most cost-effective and least risky option for its ratepayers.

There is good reason to question whether all of the upgrades that Alabama Power has made at its existing power plants really do represent the lowest cost and lowest option for its ratepayers. Some of the plants are old, some have been running at low capacity factors, and many, if not all, have become less economical as a result of competition from cheap natural gas.

Alabama Power's spending on environmental upgrades has included:

- Nearly $1 billion since 2002 on Selective Catalytic Reduction (SCR) nitrous oxide (NO_x) control systems at its seven largest coal-fired units and less expensive Selective Non-Catalytic Reduction (SNCR) NO_x control systems at four other units.
- $1.7 billion of investment to add Sulfur Dioxide (SO_2) scrubbers at nine coal-fired units. Scrubbers are designed to reduce SO_2 emissions.
- $600 to $700 million by 2016 to install baghouses to control mercury emissions from the Gorgas 8-10 and the Gaston 5 coal-fired units.

There is good reason to question whether all of the upgrades that Alabama Power has made at its existing power plants really do represent the lowest cost and lowest option for its ratepayers.

Some of the coal-fired units where Alabama Power has made and is continuing to make these expensive investments are among its oldest power plants. For example:

- Gorgas Unit 8 was nearly 54 years old when a scrubber was installed in 2008. Unit 8 will be 60 years old when a baghouse is added in 2016.
- Gorgas Unit 9 was nearly 50 years old when a scrubber was installed in 2008. Unit 9 will be 58 years old when a baghouse is added in 2016.
- Gorgas Unit 10 was 36 years old when a scrubber was installed in 2008. Unit 10 will be 44 years old when a baghouse is added in 2016.
- Barry Unit 5 was 37 years old when an SCR was added in 2008 and was 39 when a scrubber was added in 2010.

- Gaston Unit 5 was 36 years old when a scrubber was installed in 2010 and will be 42 when a baghouse is installed in 2016.

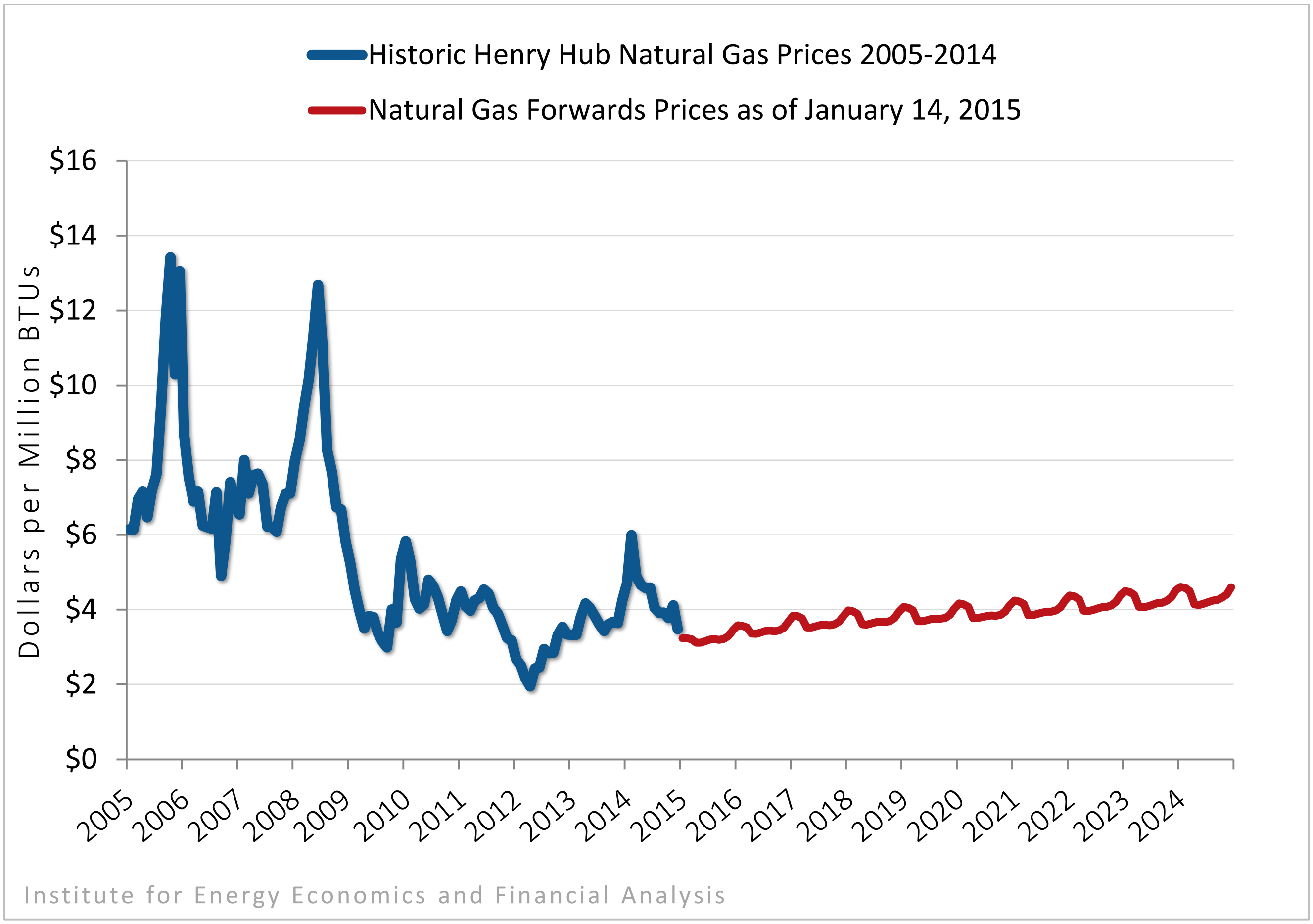
The Company will argue that coal plants can continue to operate effectively for decades beyond the age of 50. That may or may not be true. However, the more important question is how economic it is to make expensive investments and continue to operate those aging power plants in light of expected future circumstances. And Alabama Power has failed to make that demonstration for any of its environmental upgrades over the past decade. Moreover, the average ages of coal plants that have been retired over the past ten years have ranged from 42 to 56 years.[35] This suggests that the Company's older coal units may not continue to be economically viable for many more years, even if they are viable today.

A plant's "capacity factor" is essentially a measure of how often the plant is run, and a plant's capacity factor can be affected by many variables, such as being taken offline for repairs, or simply ceasing to operate when cheaper generation options are available to meet demand. The technical term "capacity factor" measures how much power a generating plant has produced compared to how much it would produce if it operated at 100 percent power for 100 percent of the hours in the period being considered (that is, day, week, month, or year). The higher the capacity factor, the more power that the plant has generated. In general, the lower the capacity factor, the less economic it is for ratepayers when the Company makes expensive investments to continue operating the power plant. This is especially true if the plant is older. Some of these plants cited above have achieved low capacity factors in recent years, calling into question the prudence of making large expenditures and investments to keep them running.

The Alabama PSC and the Company frequently blame coal plant retirements on federal environmental regulations and/or environmentalists. In reality, however, the collapse of natural gas prices, which began in 2008, poses the most significant threat to the economic viability of the Company's existing coal-fired power plants and that threat persists as natural gas prices are expected to remain low for the foreseeable future.

[35] *Regulation, retirements, replacement influence age of US generation fleet*, SNL Financial, Dec. 30, 2014.

Figure 3: Natural Gas Prices Collapsed in Late 2008 and are Expected to Continue to Remain Extremely Low for Years.[36]



This collapse in natural gas prices has led to much lower generation at some of the Company's coal-fired power plants, including some of those at which expensive investments in scrubbers and NO_x control have been made, as coal-fired generation has been displaced by generation from gas-fired units. This can be seen from Figure 4, below, which compares the declining generation from Alabama Power's coal-fired Plant Barry Unit 5 with the increased generation from the Company's natural gas-fired combined cycle plant that is located at the same site.

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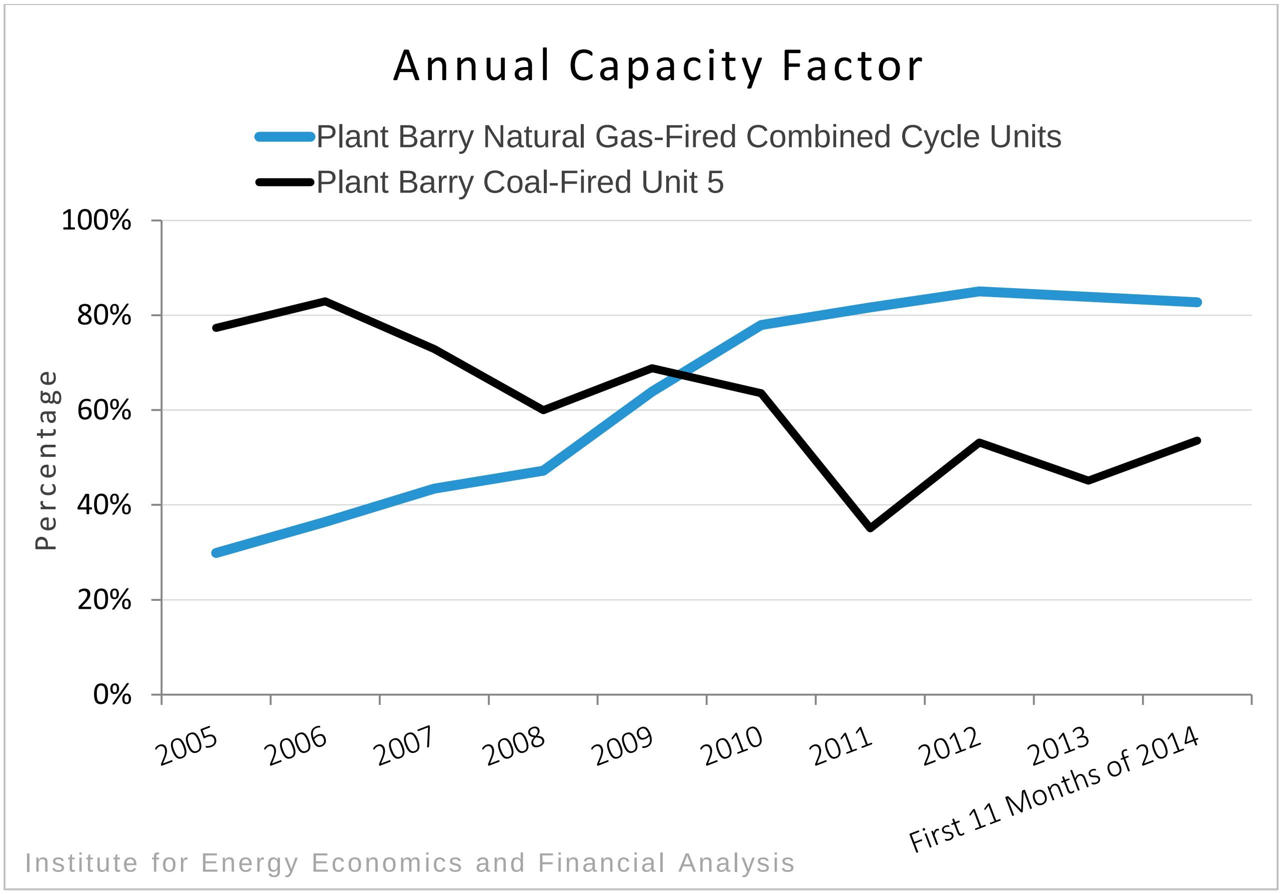
36 The historic natural gas prices shown in Figure 3 are taken from data published by the Energy Information Administration of the U.S. Department of Energy (EIA). The current natural gas forwards prices are from SNL Financial. Henry Hub is a key distribution hub on the natural gas pipeline in Louisiana, Due to its importance, the name Henry Hub is given to spot and forward (i.e., future) natural gas contracts prices.

Figure 4: Plant Barry Generation – Coal-Fired Unit 5 versus Natural Gas-Fired Combined Cycle Units.[37]



In fact, Barry Unit 5 has operated at only a 47 percent capacity factor since the beginning of 2011, after operating at an average 71 percent capacity factor during the preceding six years.

Similarly, Alabama Power's Plant Gorgas Units 8, 9, and 10 (at which a scrubber was added in 2008 and a baghouse will be installed by 2016) have operated at only an average 40 percent capacity factor since January 1, 2011, after operating at an average 67 percent capacity factor in the previous six years.

Given that natural gas prices are generally expected to remain low in coming years, as shown in Figure 3, it also is uncertain how much each of the coal-fired units at which Alabama Power has made expensive environmental upgrades actually will operate in future years. The billions of dollars of environmental upgrades the Commission has allowed into rates through Rate CNP-Environmental will continue to produce significant profits for the Company and its owner, Southern

37 Plant operating data from SNL Financial based on public Alabama Power filings.

Company, for decades, regardless of how little and how poorly any of the upgraded coal units operate in coming years.

While Alabama Power has been spending billions of dollars on extending the lives of its existing coal-fired units, its unregulated merchant affiliate, Southern Power, does not own any coal-fired capacity. Instead, Southern Power has developed a resource mix in the South in the past 15 years that is heavily dependent on natural gas, with increasing investments in gas and solar power in other states around the nation. Consequently, Southern Power has taken advantage of low natural gas prices to produce significant profits while not exposing Southern Company and its shareholders to the multiple short- and long-term risks facing coal-fired power plants that are being borne by Alabama Power's ratepayers.

Now that Alabama Power has completed and placed in rates billions of dollars of investments in upgrades at its existing coal-fired units, and has ensured that its customers will for decades pay higher rates and therefore generate larger profits for Southern Company, the Company has announced that it intends to retire or convert some of its units. It will retire two small coal-fired units at its Plant Gorgas and by 2016 will convert three of the units at its Plant Barry to burn gas. Plant Greene County, jointly owned by Alabama Power and Mississippi Power, also will be converted to burn natural gas instead of coal. Unlike in Georgia, there was no public review or opportunity in Alabama for the public to provide input into whether there were lower cost/lower risk alternatives or to evaluate whether the conversions of the units at Plant Barry and Plant Greene County were more cost-effective than retirement. Nor was there any opportunity for the rate paying public to evaluate whether any other existing fossil-fired units also should be retired and/or converted to burn natural gas.

The Alabama Public Service Commission has failed to Make Public Any Evidence to Show that It Closely Monitors and Oversees the Company's Resource Planning Process

The PSC has claimed that it closely supervises Alabama Power's IRP. For example, its October 28, 2010 Order in Docket 31045 stated that "[u]nder the Commission's supervision, Alabama Power already performs an annual assessment of its supply-side and demand-side options, which includes the consideration of energy efficiency resources."[38] However, the PSC has failed to provide any information to the public to show that, in fact, it closely monitors and oversees Alabama Power resource planning process and decisions.

Indeed, there is no mechanism for the public to know, or even understand, the PSC's "supervision" of the Company's IRP process or have access to any documents related to the PSC staff review or monitoring of Alabama Power's annual assessments of its supply and demand-side options or operation and maintenance costs. These are the unfortunate results of the lack of a formal public IRP review process. As a result, Alabama Power's customers have been left in the dark about the Company's resource plans and planning processes and about the extent to which the PSC and its staff actually monitor Alabama Power's IRP planning processes.

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38 Order, Consideration of Sections 532 and 1307 of the Energy Independence and Security Act of 2007, Ala. Pub. Serv. Comm'n Docket No. 31045, at 2 (Oct. 28, 2010), *available at* https://www.pscpublicaccess.alabama.gov/pscpublicaccess/ViewFile.aspx?Id=848b4c51-2915-492c-9155-d52dd297d4a1.

Recommendations

To allow for the broadest public involvement, the Alabama PSC should adopt a formal IRP review process that includes:

- Involvement by public stakeholders (like TVA);
- On-the-record public evidentiary hearings;
- Pre-filed testimony, with witnesses testifying under oath; and
- An opportunity for interested parties who have intervened in the PSC review process to obtain the Company's IRP workpapers, important input assumptions, and access to the raw data and economic analyses underlying Alabama Power's resource decisions.

Almost every state in the South has some process that includes all or some of these elements.

The public version of Alabama Power's IRP should contain all relevant information that is not confidential or proprietary. Interested parties, however, should be able to obtain any such redacted information after signing an NDA and should also be able to petition the PSC to make such redacted information public.

Although this process would provide meaningful opportunities for participation by Alabama Power's ratepayers and allow interested parties to present alternative resource options, it would not in any way diminish the PSC's power to act as a regulator.

ATTACHMENT 1

STATE OF ALABAMA
ALABAMA PUBLIC SERVICE COMMISSION
P. O. BOX 304260
MONTGOMERY, ALABAMA 36130-4260

LUCY BAXLEY, PRESIDENT
TWINKLE ANDRESS CAVANAUGH, ASSOCIATE COMMISSIONER
TERRY L. DUNN, ASSOCIATE COMMISSIONER

WALTER L. THOMAS, JR.
SECRETARY

January 9, 2014

Mr. Tim Lockette
timlockette@yahoo.com
Capitol and statewide reporter
The Anniston Star

Per your request, attached is a public version of Alabama Power's 2013 Integrated Resource Plan. This document is intended to provide you with a good understanding of the dynamic process used to develop the plan, with due regard for information of a confidential and proprietary nature. As you will see, the fundamental goal of the IRP, as well as Alabama Power's resulting development and procurement activities, is to identify cost-effective resources while maintaining a reliable supply of electric power.

Please feel free to contact me at 334-242-5200 if you have follow-up questions or comments. If you would like to speak directly with Alabama Power regarding this document, please contact Ashley Ramage at (205) 257-0274.

Sincerely,

John A. Garner, Executive Director
Alabama Public Service Commission

ALABAMA POWER COMPANY

2013 INTEGRATED RESOURCE PLAN

PUBLIC SUMMARY REPORT

Executive Summary

As identified in the 2010 IRP and continuing as key elements of the 2013 Integrated Resource Plan, the Company included the return of 1,220 MW of UPS capacity to the system in 2010, the continuing environmental de-rating of coal units between 2010 and 2017 (68 MW), the expiration of the Harris PPA in 2010 (627 MW), the extension of the Calhoun PPA through the end of 2022 (632 MW), and the procurement of renewable resources between 2011 and 2015 (25 MW). Also, the indicated need for new capacity as early as 2022 in the 2010 IRP has moved out to later years due to the impacts of the Great Recession on the load forecast. In the 2013 IRP, the Alabama Power Company fleet will continue to operate throughout the 20 year planning horizon. The additional generation capacity required to maintain an appropriate minimum planning reserve margin to meet customers' projected electrical demand throughout the remainder of the planning horizon will now be added beginning in 2030.

Since the IRP is a dynamic process by which the Company is continuously re-evaluating the optimal mix of supply-side and demand-side resources, subsequent IRPs may reflect changes in the scheduling and technology type for both supply-side and demand-side resource additions beyond 2013.

I. *INTRODUCTION*

Alabama Power Company ("Alabama Power" or "Company") is an investor-owned electric utility, organized and existing under the laws of the State of Alabama. It is primarily engaged in generating, transmitting and distributing electricity to the public in a large section of the State of Alabama, and its retail rates and services are regulated by the Alabama Public Service Commission ("APSC").

The purpose of this document is to present Alabama Power's 2013 Integrated Resource Plan ("IRP") and to describe the process used in its development. The IRP is a schedule that, based on the best information reasonably available to the Company, reflects the optimal mix of supply-side and demand-side resources needed to meet the expected electrical requirements of its customers, consistent with its duties and obligations to the public as a regulated public utility. The process used by Alabama Power to develop the IRP comports with the provisions of the Public Utility Regulatory Policies Act of 1978, as amended, which contemplates the use of appropriate integrated resource planning by electric utilities.

The Company has approximately 1.4 million customers, of which approximately 86% (1.24 million) are residential; 13% (196,000) are commercial; and 0.5% (6000 industrial and 500 other) are industrial and other. Alabama Power has approximately 1.5 million transmission and distribution poles, and approximately 83,000 miles of wire. The Company is committed to providing cost-effective and reliable service to its customers. For the years 2010 – 2012, the Company had a service reliability of 99.97%. Alabama Power has a diverse fleet of generation resources which includes: hydro, natural gas, nuclear, coal, demand-side programs, combined heat and power, purchase power agreements and other resources.

The Company participates in a pooled operation of generating resources along with the other Operating Companies of the Southern electric system (Georgia Power, Gulf Power, Mississippi Power, and Southern Power). There are well-recognized advantages to be gained from operating in such a manner. In order to maximize these benefits, the planning of additional resource facilities is done on a coordinated basis. Although Alabama Power participates in this coordinated planning process, the Company remains the final decision-maker on any resource additions that it may require.

Cogeneration / Combined Heat and Power ("CHP")

Throughout its history, Alabama Power has always focused on listening to and working with its customers in the development of its plans to reliably and cost-effectively meet the load obligations of all its customers under the state's regulatory rules and processes. For the Company's large commercial and industrial customers, these plans include efforts directed toward the management of rates and loads, and in some cases, the consideration of cogeneration/CHP options. For such options to be viable, however, they must offer positive benefits, not only to the individual customer, but all customers in general. Alabama Power, its customers, and the APSC have successfully worked together to meet this objective.

Currently, the Alabama Power system includes approximately 1500 MW of customer-owned generation and more than 500 MW of Company owned CHP generation. The customer-owned generation has allowed Alabama Power to avoid the need and the associated costs of adding approximately 1700 MW of new generation. Cogeneration and CHP have been options for the Company for many years.

During the 1990's, when the Company needed to add new generation to reliably meet the load obligations of its customers, Alabama Power was able to develop new generation resources near certain customer facilities. These new generating facilities provided cost-effective capacity and energy to all of its customers while providing steam to the specific customers at the locations. More recently, the Company has used a program authorized by the APSC to certity two PPAs for rights to capacity and energy from two customer-owned CHP facilities.

The Company's success in identifying CHP projects that are expected to bring benefits to all customers in part is attributable to the recognition by the APSC that resource and capacity additions do not follow a one-size-fits-all approach. This is particularly so with CHPs, where a good working arrangement between all parties is essential for these projects to be developed, and where an adaptive regulatory process is critical to the project's success.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity and impact the Company's forecast of customer loads.

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning and Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2012, the Company had invested approximately $3.0 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $62 million, $34 million, and $130 million for 2012, 2011, and 2010, respectively. The Company expects base level capital expenditures to comply with existing statutes and regulations, including capital expenditures and compliance costs associated with the EPA's final Mercury and Air Toxics Standards (MATS) rule, will total approximately $1.0 billion from 2013 through 2015, with annual totals of approximately $195 million, $424 million, and $411 million for 2013, 2014, and 2015, respectively.

Compliance with any new federal or state legislation or regulations relating to air quality, water, coal combustion byproducts, global climate change, or other environmental and health concerns could significantly affect the Company and its need for resource additions. Additionally, many of the Company's 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.

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company has spent approximately $2.7 billion in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

On February 16, 2012, the EPA published the final MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015, unless a one-year compliance extension is granted by the state or local air permitting agency.

The Company has developed and continuously updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. As part of this strategy, the Company has developed a compliance plan for the MATS rule which includes the construction of baghouses to provide an additional level of control on the emissions of mercury and particulates from certain generating units, the use of additives or other injection technology, and the use of existing or additional natural gas capability. Additionally, certain transmission system upgrades may be required.

In January 2013, the EPA released its revised RICE/NESHAP rules pertaining to customer-owned generation. These new rules impact customers who participate in Alabama Power's Stand-by Generator program. This program, which has been in service for 20 years, has allowed the Company to utilize these stand-by generators in times of critical peak operations. The limited use of these customer-owned generators has allowed the Company to avoid building its own resources, which has helped to avoid higher rates for all customers. Unfortunately, the new EPA rules have put significant restrictions on the customers' use of their generators. In response to these new rules, Alabama Power has worked with the APSC to revise the related Stand-by Generator tariff to give participating customers additional flexibility. The ongoing impact to this program is not known at this time, but the Company expects a reduction in the growth of this demand-side option.

Integrated Resource Plan (IRP)

In order to anticipate future energy requirements and electrical demands of the customers served by Alabama Power, a load forecast is developed which includes a 20-year projection of the expected growth in customer requirements. Alabama Power then develops an IRP that reflects, using the best information reasonably available to the Company, the optimal mix of supply-side and demand-side resources to meet this projected load growth in a cost effective manner that benefits the Company's customers and the state as a whole.

The IRP is updated on a triennial basis, although from time to time circumstances may prompt the development of an interim IRP. The IRP and its underlying details are reviewed with the APSC staff. This review keeps the APSC informed as to the Company's plans and helps to ensure that the process serves its ultimate goals of minimizing rates and providing the desired level of service reliability. These goals are important because they allow the Company to be competitive with other energy providers and promote economic development within the State of Alabama.

This report summarizes information and results on the Integrated Resource Planning process at Alabama Power. It includes a brief overview of the process and an executive summary of the results.

II. INTEGRATED RESOURCE PLAN SUMMARY

II.A. Overview

Alabama Power Company's integrated resource planning process is designed to meet the long-term projection of the expected growth of its customers' energy and demand requirements. The goal of the IRP is to have an effective plan and strategy in place that provide for reliable service that meets or exceeds legal requirements and accounts for risk at the lowest practical cost.

The IRP, which has a 20-year planning horizon, is a tool used by the Company to inform management when a reliability based resource addition appears to be needed and the indicated optimal mix of resources that meets the customers' future load requirements. Using the best information currently available at the time of its development, the IRP provides the basis for estimating potential capital expenditures that may be required for future generating capacity additions. In the IRP, both supply-side and demand-side options are evaluated and integrated on a consistent basis through the use of marginal cost analysis. This approach ensures that both supply-side and demand-side options are included in the IRP when it is economic to do so.

As shown in Figure 1, integrated resource planning is a dynamic process that continuously evaluates existing and potential resources in an effort to identify the best combination, in terms of reliability and expected total cost for serving customers. The principal components in the process are as follows:

Update Marginal Cost Projections Based on Latest IRP

Marginal cost projections are derived using the previous IRP. These projections are then updated to recognize any significant changes in costs such as fuel, technology and regulatory compliance.

Load Forecast

A forecast of future energy and demand requirements for the next 20 years is developed. This forecast incorporates the Company's best estimate of future economic conditions and trends in customer energy usage.

Marginal Cost Demand-Side Evaluations

Demand-side options (DSOs) are evaluated on a marginal cost basis. This procedure establishes a set of cost-effective DSOs for inclusion in the IRP.

Marginal Cost Supply-Side Evaluations

Marginal cost evaluations are performed to determine if modifications to existing resources, new self-build resources and/or power purchases from other suppliers are economically viable.

Resource Mix Analysis and Benchmark Evaluations

This part of the IRP process involves the development of an optimum resource mix. The resource mix is a flexible, iterative analysis that allows for integration of the appropriate combination of resources that meet the projected load at the lowest expected total cost (both fixed and variable), while maintaining a minimum target reliability guideline. This step includes sensitivity analyses to establish boundaries within which the conclusions of a benchmark plan remain valid.

The resource mix analysis incorporates the impacts of existing and projected DSOs, revised load information, and updated cost information (including fuel, capital, operation and maintenance). It also incorporates the most recent information on the characteristics of existing resources, both supply-side and demand-side.

The flexibility of the IRP process allows insertion of marginal cost results from the supply-side or demand-side options in any sequence. The result is a benchmark plan from which the most cost-effective Integrated Resource Plan can be determined in an integration step.

In planning future resource additions, consideration is given to uncertainties associated with unforeseen unit outages, weather and load forecast deviations. In order to minimize the effects of these uncertainties, criteria are established that qualify and quantify an appropriate minimum level of capacity reserves. These reserves are planned to be available so as to account for the potential inability to meet load requirements due to generation shortfalls resulting from uncertainties associated with resource planning. The criteria are called reserve criteria and are specified as margins. The minimum long-term target reserve margin guideline, which is periodically reviewed and re-evaluated, is based on economic analyses, operating experience and system operation input, and seeks to minimize the combined cost of new generating capacity and the customers' cost of outages. The Operating Companies of the Southern electric system currently use a minimum long-term target planning reserve margin guideline of 15% for resource planning. The most recent target reliability reserve margin study was completed in 2012.

By virtue of load diversity across the Southern electric system, the minimum long-term 15% target reserve margin can be met if each Operating Company maintains a minimum long-term reserve margin of at least 13.5%. In other words, Alabama Power's participation in pooled operations enables it to maintain a lower reserve margin than would be required if it operated on a stand-alone basis. Thus, the Company has the same level of reliability to meet its customers' load requirements while avoiding the cost of building or purchasing additional generation resources. Maintaining the appropriate level of generation reserves minimizes the combined cost of new generating capacity, reliability energy purchases and the customers' cost of outages. These capacity savings represent one of the recognized benefits of operating as a pool.

Integration

Demand-side and supply-side options identified as cost-effective choices for resource additions, but not previously reflected in a benchmark plan, are incorporated into the IRP in the integration phase. This phase consists of determining the Company's best alternative for meeting the resource needs identified in the benchmark plan, coordinating resource additions with those of other system companies, and performing a financial assessment of the plan.

The process described above is not necessarily set forth in chronological order. Many evaluations are performed concurrently. Marginal cost evaluations can be performed or updated at several points in the process. Figure 2 describes a typical progression of the IRP process.

II.B. SUMMARY OF RESULTS

This section presents a summary of the results of the 2013 integrated resource planning process, with the output being the 2013 Integrated Resource Plan. Key elements of the plan for the Company include the following:

- A significant change to the 2013 IRP is the delay of the next resource addition from 2022 to 2030. In the 2010 IRP, the Company showed a need for new peaking resources in 2022 and a need for intermediate resources in 2025. In the 2013 IRP, the peaking need is delayed until 2030 and the new intermediate resource need is beyond the planning horizon. There are no resource needs for baseload generating technologies in the scope of this 20 year planning study. These delays were in most part due to (1) the effects of the Great Recession on the economy in lower forecasted loads, (2) the return of the Miller UPS capacity in 2010 (1220 MW), and (3) the extension of the Calhoun purchase power agreement. The latter two items were identified in the 2010 IRP.

- The significant resource additions to the 2013 IRP from the 2010 IRP are (1) the certification of the AbiBow PPA (15 MW), (2) the certification of the Westervelt PPA (7.5 MW), (3) the certification of the Chisholm View PPA (202 MW), and (4) the certification of the Buffalo Dunes PPA (202 MW). The AbiBow PPA started on 6/1/2011 and ends on 6/30/2016. The Westervelt PPA started on 12/7/2011 and ends on 12/31/2021. The Chisholm View PPA started on 12/7/2012 and ends on 12/31/2032. The Buffalo Dunes PPA is scheduled to start on 1/1/2014 and end on 12/31/2033. The AbiBow PPA and Westervelt PPA involve capacity and energy from a biomass resource; the Chisholm View and Buffalo Dunes PPAs entitle the Company to up to 202 MW from each wind project. Under the PPAs, the Company has obtained the environmental attributes, including Renewable Energy Credits (RECs) associated with the energy. For these and other projects that provide Alabama Power with the right to RECs, Alabama Power Company retains the flexibility to retire RECs and serve its customers with renewable energy, or to sell RECs, either bundled with energy or separately, to third parties.

- As seen in the 2010 IRP, the 2013 IRP reflects certain unit de-ratings for environmental measures (scrubbers and SCRs). This causes the Company's coal fleet to be derated a total of 9 MW between 2013 and 2017.

- As seen in the 2010 IRP, the Plan had 25 MW of Renewable Resources identified, which was largely filled by the Westervelt and AbiBow PPAs as part of the Modified Block Process approved by the Commission. The 2013 IRP continues to incorporate a strategy to proactively pursue acquisition of economically viable renewable resources as a cost-effective hedge for environmental concerns, compliance and other customer-driven needs. The 2013 IRP has a total of 25 MW of unidentified renewable resources being added by 2017. Should any of these unidentified renewable resources develop into PPAs, the Company anticipates seeking the appropriate level of Commission approval.

- Other significant changes are the termination of the Harris PPA in 2010 (627 MW), and the Farley 1 and 2 nuclear unit uprates in 2011 (24 MW) and 2012 (24 MW).

- There were no other significant additions / decreases to the Alabama Power Company system expansion since the 2010 IRP.

Based on the Company's current load forecast and target minimum planning reserve margin guideline, additional resources will be needed to meet expected customer requirements beginning in 2030.

The remainder of this section will provide more details on the resource additions shown by the plan and the customer requirements that drive them.

Load Forecast

The Load Forecast is developed using complex models based on near-term and long-term economic indicators and expected electrical usage of the Company's customers. The historical and forecasted peak demands and growth rates are changing very little for the next 20 years. Accordingly, the expected average annual demand growth will continue to be very small.

Reserve Margin

At the present time, the Operating Companies of the Southern electric system have established a collective minimum long-term target planning reserve margin guideline of 15%. As noted above, peak load diversity enables the system to meet the 15% target reserve margin guideline if each Operating Company maintains a reserve margin of at least 13.5%. These planning reserves protect against a shortfall in capacity and a loss of load due to unforeseen future events, such as machine outages, greater than expected load growth or unusual weather. Maintaining an appropriate level of generation reserves also minimizes the combined cost of new generating capacity, reliability energy purchases and the customers' cost of outages.

Based on the current load forecast, the Company has sufficient resources to provide an appropriate level of reserves to meet customers' electrical needs through 2029. Given the projected reserve margin levels, the Company expects to be able to manage any capacity concerns associated with uncertainties surrounding environmental issues. Beginning in 2029, the Company's reserve margin is projected to fall below the diversified minimum target planning reserve margin (13.5%). The projected capacity deficit below target in 2029 is not large enough to result in a resource addition. By 2030, however, Alabama Power is projected to have a need to add new resources to maintain an appropriate minimum level of planning reserves.

In sum, the 2013 IRP indicates that, through 2029, the Company will have generation resources sufficient to maintain the minimum target planning reserve margin required to meet customers' electrical needs in a reliable and cost-effective manner.

IRP Description

The process that led to the development of the 2013 IRP included consideration of demand-side and supply-side options. Detailed analyses were performed on viable options to ensure that cost-effective resource options were chosen to meet projected load growth and satisfy the appropriate reliability criteria.

The resources identified for the 2013 IRP are summarized below:

Demand-Side Options

The 2013 IRP includes approximately 1640 MW of existing demand-side programs that have allowed the deferral of 1323 MW of supply-side resource capacity. The difference between the nominal values shown for the demand-side programs and the associated supply-side resource capacity deferrals is due to the lower availability of a demand-side option, as compared to a supply-side resource. The capacity deferral megawatts are directly controllable, in terms of ability to operate, by the Company (*e.g.*, non-residential interruptible load) and are called "Active DSOs". The DSOs associated with customer energy use patterns (*e.g.*, equipment SEER efficiency increases, insulation/infiltration upgrades) are called "Passive DSOs." The Passive DSOs serve to reduce expected peak load and consequently are embedded in the Company's load forecast. Existing passive DSO programs have resulted in a peak load reduction of 272 MW. Therefore, the total amount of existing DSOs in the IRP is 1640 MW plus 272 MW, for a total of 1912 MW.

Purchased Power

Purchase power contracts are evaluated along with supply-side and demand-side generating resource options to determine the most economic and reliable resource to meet our customers' energy needs. Short-term power purchases are used when appropriate to meet short-term capacity needs.

Renewable Resources

In the 2013 IRP, a small amount (25 MW) of additional Renewable Resources has been included as a resource expansion option. These resources have been placed in the plan as placeholders to address potential environmental concerns, compliance, and contingencies rather than reliability margins. As these resource options materialize, either through a Company RFP or by other means, a determination is made to their economic viability as compared to other options for Alabama ratepayers. The opportunity for 25 MW of Renewable Resources has been represented between years 2013 and 2017 in the 2013 IRP.

Future Generation

Long term purchase power contracts are evaluated and compared to other generation options so that the most cost-effective and reliable generation resources are selected to meet our customers' electrical needs. This process, for example, resulted in the selection of the Harris PPA and the Calhoun PPA for certification by the APSC. Alabama Power will continue to evaluate purchase power options as a part of its IRP process, with the goal being to provide customers with reliable energy at the lowest practical cost.

Based on the current load forecast, increases in customer electrical demand through 2029 can be met with the Company's existing generation and demand-side resources. Beginning in 2030, the 2013 IRP indicates that additional generation capacity will be required to meet forecast increases in customer electrical demand throughout the remainder of the planning horizon.

Since the IRP is a dynamic process by which the Company is continually re-evaluating the optimal mix of supply-side and demand-side resources, subsequent IRPs may reflect changes in the scheduling and technology type for both supply-side and demand-side resource additions beyond 2013.

Uncommitted Resource Options

Assumptions for cost, performance, design maturity, regulatory approval, and other parameters for uncommitted resource options continue to change. The following list represents, but is not all-inclusive of, resource technology options that may be selected in the future.

Peaking
- -Demand-Side Options
- -Power Purchases
- -Combustion Turbine
- -Diesel Generator
- -Photovoltaic
- -Wind Turbine
- -Advanced Battery
- -Cogeneration / CHP
- -Superconducting Magnetic Energy Storage

Intermediate
- -Demand-Side Options
- -Power Purchases
- -Combined Cycle
- -Cycling Coal
- -Pumped Storage Hydro
- -Cogeneration / CHP
- -Repowering
- -Compressed Air Energy Storage

Base
- -Demand-Side Options
- -Power Purchases
- -Nuclear
- -Conventional Pulverized Coal – Super Critical and Ultra Super Critical
- -Conventional Pulverized Coal – Super Critical and Ultra Super Critical w/CCS
- -Integrated Gasification Combined Cycle
- -Fuel Cells
- -Landfill Gas
- -Wood
- -Cogeneration / CHP
- -Repowering

Conclusion

Based on the load forecast used for this IRP, customers' electrical requirements through 2029 can be met reliably with the Company's existing generation and demand-side resources. With the exception of a small amount of renewable resources discussed above, no new generating resources are planned through 2029. The Company will have some existing coal capacity derated for environmental measures through 2017, but those derates should not trigger any near-term resource additions. Beginning in 2030, the IRP indicates that additional resources will be needed to meet projected customer electrical requirements for the remainder of the planning horizon.

FIGURE 1
ALABAMA POWER COMPANY
INTEGRATED RESOURCE PLANNING PROCESS

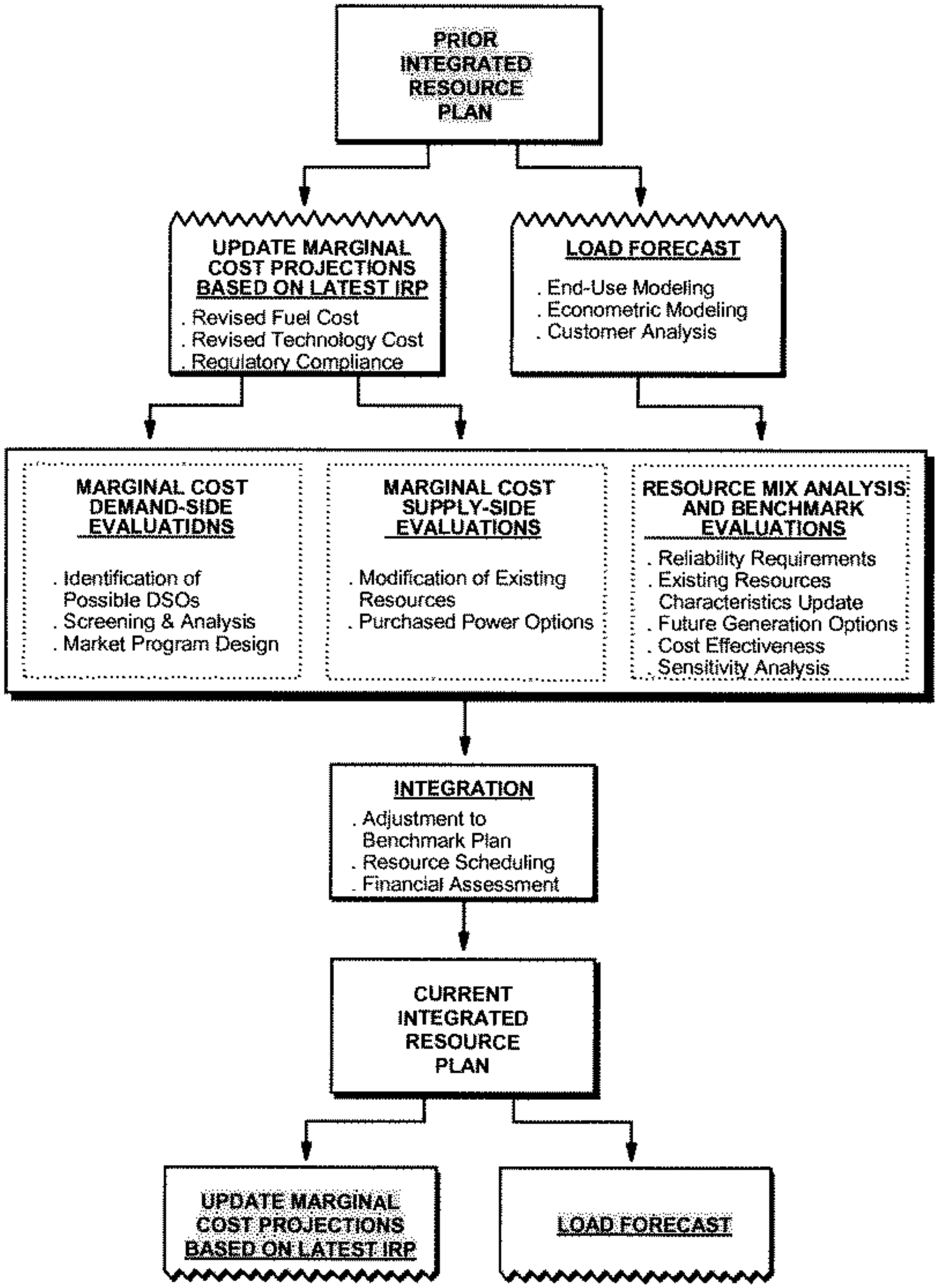

FIGURE 2

TYPICAL PROGRESSION OF KEY ACTIVITIES
RELATED TO THE DEVELOPMENT OF THE
INTEGRATED RESOURCE PLAN

Marginal Cost Projection Update

Preliminary System-Wide Fuel Price Workshop

Supply-Side Technology Issues Reviewed

Demand-Side Option Screening and Analysis

Planning Issues Identified

Preliminary Planning Assumptions Established

Preliminary System-Wide Fuel Forecasts

Technology Panel Review

Candidate Unit Assumptions Established

Load Forecast Finalized

Demand-Side Option Forecast Finalized

Planning Assumptions Reviewed and Finalized

Resource Mix Analysis Process

Preliminary IRP Review

Benchmark Plan Completed

Financial Assessment

IRP Approval

ATTACHMENT 2

DUKE ENERGY® CAROLINAS

Duke Energy Carolinas

Integrated Resource Plan (Annual Report)

October 15, 2013

Public

DEC 2013 IRP TABLE OF CONTENTS

ATTACHMENT 3

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 111

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking Proceeding to Consider	)	ORDER REVISING INTEGRATED
Revisions to Commission Rule R8-60	)	RESOURCE PLANNING RULES
on Integrated Resource Planning	)	

BY THE COMMISSION: G.S. 62-2(3a) and 62-110.1(c) set forth certain policies and requirements for integrated resource planning (IRP) in North Carolina. The Commission implements G.S. 62-2(3a) and 62-110.1(c) through the provisions of Commission Rule R8-60. By order issued on October 19, 2006, in Docket No. E-100, Subs 103, 110, and 111, the Commission opened the present rulemaking proceeding "to consider revisions in the IRP process as currently provided in Commission Rule R8-60."[1] On November 27, 2006, the Commission issued an order requesting comments and reply comments on proposed revisions to the Rule. That order designated the members of the Sub 103 workgroup as parties to the present docket without the need to intervene.

As part of its comments filed on February 26, 2007, the Public Staff submitted a proposed revision to Commission Rule R8-60, reflecting input from both Duke Energy Carolinas, LLC (Duke) and Progress Energy Carolinas, LLC (Progress). Comments were filed by Duke; Virginia Electric and Power Company d/b/a Dominion North Carolina Power (Dominion); the North Carolina Sustainable Energy Association (NCSEA); Carolina Industrial Groups for Fair Utility Rates (CIGFUR); and Wells Eddleman. Reply comments were filed by Duke and Progress jointly; Dominion; NCSEA; the Attorney General; the North Carolina Waste Awareness and Reduction Network, Inc. (NC WARN); and the Public Staff.

In its reply comments, the Public Staff requested that the Commission allow three weeks for the parties to attempt to reach consensus on some, if not all, of the issues raised in the parties' filings and stated that it would report to the Commission on the progress of the discussions. The Commission allowed the Public Staff's request by an order issued on April 2, 2007. The Public Staff subsequently requested, and was granted, an extension of time for the discussions and the filing of a report.

The Public Staff filed its Report on the Status of the Integrated Resource Planning Rulemaking on May 14, 2007. The Report states that, on May 7, 2007, representatives of the following parties, in person or by conference call, discussed the

[1] The October 19, 2006 order was prompted by recommendations made by a workgroup that was created by the Commission in connection with the 2005 IRP proceedings in Docket No. E-100, Sub 103.

Public Staff's proposed rule and the issues raised in the comments: Duke, Progress, Dominion, the Attorney General, the North Carolina Electric Membership Corporation (NCEMC), NCSEA, NC WARN, CIGFUR, the Southern Alliance for Clean Energy (SACE), and the Public Staff. With the exception of SACE, which expressed neither opposition nor support, the parties came to a consensus regarding both the content and the language of a proposed revision to Rule R8-60.

On May 24, 2007, the Public Staff filed a Motion for Adoption of Proposed Revised Integrated Resource Planning Rules, setting forth a proposed Rule R8-60 as agreed to by the parties (with the exception of SACE) listed above. The Public Staff asserted that the proposed rule addresses many of the concerns about the IRP process that were raised in the 2005 IRP proceeding in Docket No. E-100, Sub 103, while balancing the interests of the utilities, the environmental intervenors, the industrial intervenors, and the ratepayers. Without detailing all of the changes, the Public Staff noted that the proposed rule expressly requires the utilities to assess on an on-going basis both the potential benefits of reasonably available supply-side energy resource options, as well as programs to promote demand-side management. Proposed Rule R8-60(e) and (f). The proposed rule also substantially increases both the detail and the amount of information required from the utilities regarding those assessments. Proposed R8-60(i)(6) and (7). Additionally, the proposed rule extends the planning horizon from 10 to 15 years, so the need for additional generation is identified sooner. The proposed rule specifically requires "[a] tabulation of the utility's forecast for at least a 15-year period . . . with and without projected supply- or demand-side resource additions." Proposed Rule R8-60(i)(1)(B). This tabulation shall also indicate the projected effects of demand response and energy efficiency programs and activities on forecasted annual energy and peak loads on an annual basis for a 15-year period. The Public Staff also noted that the proposed rule provides for a biennial, as opposed to annual or triennial, filing of IRP reports with annual updates of forecasts, revisions, and amendments to the biennial report.

The Public Staff requested that the Commission issue an order promulgating the proposed Rule R8-60 to supplant the current Commission Rule R8-60, effective immediately. The Public Staff further renewed its earlier request that the requirement of the Commission's February 20, 2003 Order Approving Integrated Resource Plans in Docket No. E-100, Sub 97, directing that all IRP filings by Duke, Progress, and Dominion include information on levelized busbar costs for various generation technologies, remain in effect.

The Public Staff further noted that adoption of the proposed Rule R8-60 would necessitate revisions to Rule R8-61(b) to reflect the change in the frequency of the filing of the IRP reports. Therefore, the Public Staff, acting on its own behalf, suggested the following underlined revisions to Commission Rule R8-61(b):

> (b) In filing an application for a certificate of public convenience and necessity pursuant to G.S. 62-110.1(a) in order to construct a generating facility, a utility shall include the following:

(1) The most recent biennial report and the most recent annual report (as defined in Rule R8-60) of the utility plus any proposals by the utility to update said report;

(2) Testimony specifically indicating the extent to which the proposed construction conforms to the utility's most recent biennial report and the most recent annual report (as defined in Rule R8-60); and

(3) Testimony supporting any utility proposals to update its most recent biennial report and the most recent annual report (as defined in Rule R8-60).

In summary, the Public Staff requested that the Commission adopt the proposed Rule R8-60, amend Rule R8-61(b) as provided above, and provide that the requirement of the February 20, 2003 Order Approving Integrated Resource Plans in Docket No. E-100, Sub 97, directing that all IRP filings by Duke, Progress, and Dominion include information on levelized busbar costs for various generation technologies, remain in effect.

Based upon the consensus reached among the various parties and the reasonableness of the proposed revisions, the Commission finds good cause to adopt proposed Rule R8-60 and to amend Rule R8-61(b). The Commission also finds good cause to incorporate into Rule R8-60 the requirement that all future IRP filings by Duke, Progress, and Dominion include information on levelized busbar costs for various generation technologies. This requirement was stated in the February 20, 2003 Order Approving Integrated Resource Plans in Docket No. E-100, Sub 97, and was restated in the recent Order Approving Integrated Resource Plans in Docket No. E-100, Sub 109. The Commission has included this requirement as Rule R8-60(i)(9) in order to collect all filing requirements in one place. In addition, the Commission, on its own motion, finds good cause to order certain additional provisions and understandings. First, G.S. 62-110.1(c) requires the Commission, after conferring with public utilities, to develop an analysis of, and make a plan for, the long-range needs for expansion of electric generation in the State. G.S. 62-110.1(b) provides that, for purposes of this section, the term "public utility" shall include any electric membership corporation (EMC) operating within the State. In the past, the Commission has relied upon the report of NCEMC to cover all EMC activities; however, with certain individual EMCs now making their own provisions for power supply, the Commission finds good cause to extend the applicability of Rule R8-60 to any individual EMC that is responsible for procurement of any, or all, of its own power supply resources, and Rule R8-60(b) has been so revised. Second, the Commission has revised Rule R8-60(i)(1)(B) to include load duration curves as part of the information to be included in each utility's biennial report. Third, in order to assure a full explication of the utility's reasoning, the provisions of Rule R8-60(i)(2)(B) and Rule R8-60(i)(6)(B) have been expanded to require a statement of the utility's rationale for the particular generation addition or demand-side management program being discussed. Finally, with respect to the purchased power provisions of

Rule R8-60(d), the Commission finds good cause to state its understanding and interpretation that this requirement obligates each utility to analyze its purchase options on an ongoing basis in order to test, confirm, and justify any build option that it has chosen.

The Commission concludes that revised Rules R8-60 and R8-61(b), attached hereto as Appendix A, shall become effective as of the date of this Order; however, since utilities may not be able to comply with the new requirements of Rule R8-60 in their 2007 IRP filings due on or before September 1, 2007, the revised Rule R8-60 shall apply for the first time to the 2008 IRP proceedings. The 2007 IRP filings due on or before September 1, 2007, shall be filed and considered in accordance with the provisions of Rule R8-60, and applicable Commission orders, in existence prior to the date of this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That revised Rules R8-60 and R8-61(b), attached hereto as Appendix A, are hereby adopted and shall become effective as of the date of this Order; and

2. That revised Rule R8-60 shall apply for the first time to the 2008 IRP proceedings, and the 2007 IRP filings due on or before September 1, 2007, shall be filed and considered in accordance with the provisions of Rule R8-60, and applicable Commission orders, in existence prior to the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.

This the 11th day of July, 2007.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount

Gail L. Mount, Deputy Clerk

Ah071107.01

ARTICLE 11

R8-60 INTEGRATED RESOURCE PLANNING AND FILINGS

(a) *Purpose.* The purpose of this rule is to implement the provisions of G.S. 62-2(3a) and G.S. 62-110.1 with respect to least cost integrated resource planning by the utilities in North Carolina.

(b) *Applicability.* This rule is applicable to Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.; Duke Energy Carolinas, LLC; Virginia Electric and Power Company, d/b/a Dominion North Carolina Power; the North Carolina Electric Membership Corporation; and any individual electric membership corporation to the extent that it is responsible for procurement of any or all of its individual power supply resources.

(c) *Integrated Resource Plan*. Each utility shall develop and keep current an integrated resource plan, which incorporates, at a minimum, the following:

(1) a 15-year forecast of native load requirements (including any off-system obligations approved for native load treatment by the Commission) and other system capacity or firm energy obligations extending through at least one summer or winter peak (other system obligations), and supply-side (including owned/leased generation capacity and firm purchased power arrangements) and demand-side resources expected to satisfy those loads, and the reserve margin thus produced; and

(2) a comprehensive analysis of all resource options (supply- and demand-side) considered by the utility for satisfaction of native load requirements and other system obligations over the planning period, including those resources chosen by the utility to provide reliable electric utility service at least cost over the planning period.

(d) *Purchased Power*. As part of its integrated resource planning process, each utility shall assess on an on-going basis the potential benefits of soliciting proposals from wholesale power suppliers and power marketers to supply it with needed capacity.

(e) *Alternative Supply-Side Energy Resources.* As part of its integrated resource planning process, each utility shall assess on an on-going basis the potential benefits of reasonably available alternative supply-side energy resource options. Alternative supply-side energy resources include but are not limited to renewable energy resources such as hydro, wind, geothermal, solar thermal, solar photovoltaic, municipal solid waste, fuel cells, and biomass.

(f) *Demand-Side Management.* As part of its integrated resource planning process, each utility shall assess on an on-going basis programs to promote demand-side management, including costs, benefits, risks, uncertainties, reliability, and customer acceptance where appropriate. For purposes of this rule, demand-side management consists of demand response programs and energy efficiency and conservation programs.

(g) *Evaluation of Resource Options*. As part of its integrated resource planning process, each utility shall consider and compare a comprehensive set of potential resource options, including both demand-side and supply-side options, to determine an integrated resource plan that offers the least cost combination (on a long-term basis) of reliable resource options for meeting the anticipated needs of its system. The utility shall analyze potential resource options and combinations of resource options to serve its system needs, taking into account the sensitivity of its analysis to variations in future estimates of peak load, energy requirements, and other significant assumptions, including, but not limited to, the risks associated with wholesale markets, fuel costs, construction/implementation costs, transmission and distribution costs, and costs of complying with environmental regulation. Additionally, the utility's analysis should take into account, as applicable, system operations, environmental impacts, and other qualitative factors.

(h) *Filings.*

(1) By September 1, 2008, and every two years thereafter, each utility subject to this rule shall file with the Commission its then current integrated resource plan, together with all information required by subsection (i) of this rule. This biennial report shall cover the next succeeding two-year period.

(2) By September 1 of each year in which a biennial report is *not* required to be filed, an annual report shall be filed with the Commission containing an updated 15-year forecast of the items described in subparagraph (c)(1), as well as significant amendments or revisions to the most recently filed biennial report, including amendments or revisions to the type and size of resources identified, as applicable.

(3) Each biennial and annual report filed shall be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports.

(4) If a utility considers certain information in its biennial or annual report to be proprietary, confidential, and within the scope of G.S. 132-1.2, the utility may designate the information as “confidential” and file it under seal.

(i) *Contents of Reports*. Each utility shall include in each biennial report, revised as applicable in each annual report, the following:

(1) *Forecasts of Load, Supply-side Resources, and Demand-side Resources.* The forecasts filed by each utility as part of its biennial report shall include descriptions of the methods, models, and assumptions used by the utility to prepare its peak load (MW) and energy sales (MWH) forecasts and the variables used in the models. In both the biennial and annual reports, the forecasts filed by each utility shall include, at a minimum, the following:

(A) The most recent ten-year history and a forecast of customers by each customer class, the most recent ten-year history and a forecast of energy sales (kWh) by each customer class; and

(B) A tabulation of the utility's forecast for at least a 15-year period, including peak loads for summer and winter seasons of each year, annual energy forecasts, reserve margins, and load duration curves, with and without projected supply- or demand-side resource additions. The tabulation shall also indicate the projected effects of demand response and energy efficiency programs and activities on the forecasted annual energy and peak loads on an annual basis for a 15-year period, and these effects also may be reported as an equivalent generation capacity impact; and

(C) Where future supply-side resources are required, a description of the type of capacity/resource (base, intermediate, or peaking) that the utility proposes to use to address the forecasted need.

(2) *Generating Facilities*. Each utility shall provide the following data for its existing and planned electric generating facilities (including planned additions and retirements, but excluding cogeneration and small power production):

(A) Existing Generation. The utility shall provide a list of existing units in service, with the information specified below for each listed unit. The information shall be provided for a 15-year period beginning with the year of filing:

i. Type of fuel(s) used;

ii. Type of unit (e.g., base, intermediate, or peaking);

iii. Location of each existing unit;

iv. A list of units to be retired from service with location, capacity and expected date of retirement from the system;

v. A list of units for which there are specific plans for life extension, refurbishment or upgrading. The reporting utility shall also provide the expected (or actual) date removed from service, general location, capacity rating upon return to service, expected return to service date, and a general description of work to be performed; and

vi. Other changes to existing generating units that are expected to increase or decrease generation capability of the unit in question by an amount that is plus or minus 10%, or 10 MW, whichever is greater.

(B) Planned Generation Additions. Each utility shall provide a list of planned generation additions, the rationale as to why each listed generation addition was selected, and a 15-year projection of the following for each listed addition:

i. Type of fuel(s) used;

ii. Type of unit (e.g. baseload, intermediate, peaking);

iii. Location of each planned unit to the extent such location has been determined; and

iv. Summaries of the analyses supporting any new generation additions included in its 15-year forecast, including its designation as base, intermediate, or peaking capacity.

(C) Non-Utility Generation. Each utility shall provide a separate and updated list of all non-utility electric generating facilities in its service areas, including customer-owned and stand-by generating facilities. This list shall include the facility name, location, primary fuel type, and capacity (including its designation as base, intermediate, or peaking capacity). The utility shall also indicate which facilities are included in their total supply of resources. If any of this information is readily accessible in documents already filed with the Commission, the utility may incorporate by reference the document or documents in its report, so long as the utility provides the docket number and the date of filing.

(3) *Reserve Margins*. The utility shall provide a calculation and analysis of its winter and summer peak reserve margins over the projected 15-year period. To the extent the margins produced in a given year differ from target reserve margins by plus or minus 3%, the utility shall explain the reasons for the difference.

(4) *Wholesale Contracts for the Purchase and Sale of Power.*

(A) The utility shall provide a list of firm wholesale purchased power contracts reflected in the biennial report, including the primary fuel type, capacity (including its designation as base, intermediate, or peaking capacity), location, expiration date, and volume of purchases actually made since the last biennial report for each contract.

(B) The utility shall discuss the results of any Request for Proposals (RFP) for purchased power it has issued since its last biennial report. This discussion shall include a description of each RFP, the number of entities responding to the RFP, the number of proposals received, the terms of the proposals, and an explanation of why the proposals were accepted or rejected.

(C) The utility shall include a list of the wholesale power sales contracts for the sale of capacity or firm energy for which the utility has committed to sell power during the planning horizon, the identity of each wholesale entity to which the utility has committed itself to sell power during the planning horizon, the number of megawatts (MW) on an annual basis for each contract, the length of each contract, and the type of each contract (e.g., native load priority, firm, etc.).

(5) *Transmission Facilities.* Each utility shall include a list of transmission lines and other associated facilities (161 kV or over) which are under construction or for which there are specific plans to be constructed during the planning horizon, including the capacity and voltage levels, location, and schedules for completion and operation. The utility shall also include a discussion of the adequacy of its transmission system (161kV and above).

(6) *Demand-side Management.* Each utility shall provide the results of its overall assessment of existing and potential demand-side management

programs, including a descriptive summary of each analysis performed or used by the utility in the assessment. The utility also shall provide general information on any changes to the methods and assumptions used in the assessment since its last biennial report.

(A) For demand-side programs available at the time of the report, the utility shall provide the following information for each resource: the type of resource (demand response or energy efficiency); the capacity and energy available in the program; number of customers enrolled in each program; the number of times the utility has called upon the resource; and, where applicable, the capacity reduction realized each time since the previous biennial report. The utility shall also list any demand-side resource it has discontinued since its previous biennial report and the reasons for that discontinuance.

(B) For demand-side management programs it proposes to implement within the biennium for which the report is filed, the utility shall provide the following information for each resource: the type of resource (demand response or energy efficiency); a description of the new program and the target customer segment; the capacity and energy expected to be available from the program; projected customer acceptance; the date the program will be launched; and the rationale as to why the program was selected.

(C) For programs evaluated but rejected the utility shall provide the following information for each resource considered: the type of resource (demand response or energy efficiency); a description of the program and the target customer segment; the capacity and energy available from the program; projected customer acceptance; and reasons for the program's rejection.

(D) For consumer education programs the utility shall provide a comprehensive list of all such programs the utility currently provides to its customers, or proposes to implement within the biennium for which the report is filed, including a description of the program, the target customer segment, and the utility's promotion of the education program. The utility shall also provide a list of any educational program it has discontinued since its last biennial report and the reasons for discontinuance.

(7) *Assessment of Alternative Supply-Side Energy Resources.* The utility shall include its current overall assessment of existing and potential alternative supply-side energy resources, including a descriptive summary

of each analysis performed or used by the utility in the assessment. The utility shall also provide general information on any changes to the methods and assumptions used in the assessment since its most recent biennial or annual report.

(A) For the currently operational or potential future alternative supply-side energy resources included in each utility's plan, the utility shall provide information on the capacity and energy actually available or projected to be available, as applicable, from the resource. The utility shall also provide this information for any actual or potential alternative supply-side energy resources that have been discontinued from its plan since its last biennial report and the reasons for that discontinuance.

(B) For alternative supply-side energy resources evaluated but rejected, the utility shall provide the following information for each resource considered: a description of the resource; the potential capacity and energy associated with the resource; and the reasons for the rejection of the resource.

(8) *Evaluation of Resource Options.* Each utility shall provide a description and a summary of the results of its analyses of potential resource options and combinations of resource options performed by it pursuant to subsection (g) of this rule to determine its integrated resource plan.

(9) *Levelized Busbar Costs.* Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.; Duke Energy Carolinas, LLC; and Virginia Electric and Power Company, d/b/a Dominion North Carolina Power shall provide information on levelized busbar costs for various generation technologies.

(j) *Review.* Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report of amendments or revisions, the Public Staff or any other intervenor may file an integrated resource plan or report of its own as to any utility or may file an evaluation of or comments on the reports filed by the utilities, or both. The Public Staff or any intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. Within 14 days after the filing of initial comments, the parties may file reply comments addressing any substantive or procedural issue raised by any other party. A hearing to address issues raised by the Public Staff or other intervenors may be scheduled at the discretion of the Commission. The scope of any such hearing shall be limited to such issues as identified by the Commission. One or more hearings to receive testimony from the public, as required by law, shall be set at a time and place designated by the Commission.

R8-61 PRELIMINARY PLANS AND CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY FOR CONSTRUCTION OF ELECTRIC GENERATION AND RELATED TRANSMISSION FACILITIES IN NORTH CAROLINA

* * *

(b) In filing an application for a certificate of public convenience and necessity pursuant to G.S. 62-110.1(a) in order to construct a generating facility, a utility shall include the following:

(1) The most recent biennial report and the most recent annual report (as defined in Rule R8-60) of the utility plus any proposals by the utility to update said report;

(2) Testimony specifically indicating the extent to which the proposed construction conforms to the utility's most recent biennial report and the most recent annual report (as defined in Rule R8-60); and

(3) Testimony supporting any utility proposals to update its most recent biennial report and the most recent annual report (as defined in Rule R8-60).