I. Meeting Packet

State of Florida
Public Service Commission
INTERNAL AFFAIRS AGENDA
Wednesday, November 28, 2012
9:30 a.m.
Betty Easley Conference Center, Room 140

1. Approve October 16, 2012, Internal Affairs Meeting Minutes. (Attachment 1)
2. Staff's Review of the 2012 Ten-Year Site Plan. Approval is sought. (Attachment 2)
3. Draft Report on Electric Vehicle Charging Station Study. Approval is sought. (Attachment 3)
4. Draft 2012 Lifeline Report. Approval is sought. (Attachment 4)
5. Legislative Update. (No Attachment)
6. Executive Director's Report. (No Attachment)
7. Other Matters.

BB/css

OUTSIDE PERSONS WISHING TO ADDRESS THE COMMISSION ON ANY OF THE AGENDAED ITEMS SHOULD CONTACT THE OFFICE OF THE EXECUTIVE DIRECTOR AT (850) 413-6463.

Attachment 1

State of Florida

Public Service Commission

INTERNAL AFFAIRS MINUTES

Tuesday, October 16, 2012
10:03 AM – 10:31 AM
Betty Easley Conference Center, Room 148

COMMISSIONERS PRESENT: Chairman Brisé
Commissioner Edgar
Commissioner Graham
Commissioner Balbis
Commissioner Brown

STAFF PARTICIPATING: Baez, Ellis, Maurey

1. Approve October 2, 2012, Internal Affairs Meeting Minutes.

   The minutes were approved.

   Commissioners participating: Brisé, Edgar, Graham, Balbis, Brown

2. Staff's Review of the 2012 Ten-Year Site Plan. Approval is sought.

   After some discussion, it was decided to bring this matter back to the November 28, 2012, Internal Affairs Meeting.

   Commissioners participating: Brisé, Edgar, Graham, Balbis, Brown

3. Draft Report on the Status of Staff Assisted Rate Cases, as Required by Section 367.0814(10), F.S. Approval is sought.

   Draft Report on the Status of Staff Assisted Rate Cases was approved.

   Commissioners participating: Brisé, Edgar, Graham, Balbis, Brown

4. Administrative Disposition of Certain Matters.

   Mr. Baez updated the Commissioners on the status of administrative disposition of certain matters. Modification to APM 2.07 Administrative Disposition of Certain Matters was approved.

   Commissioners participating: Brisé, Edgar, Graham, Balbis, Brown

5. Executive Director's Report.

Mr. Baez had no further matters to report.

Commissioners participating: Brisé, Edgar, Graham, Balbis, Brown

6. Other Matters.

a) Chairman Brisé and Commissioner Balbis shared information regarding compressed natural gas. Staff was directed to establish a timeline for a potential workshop, and to reach out to the Energy Office, the House Energy Committee, and other persons who may have an interest in compressed natural gas.

b) Commissioner Brown updated the Commissioners on Water and Wastewater Study Committee matters, and announced an upcoming committee meeting scheduled for October 18, 2012.

Commissioners participating: Brisé, Edgar, Graham, Balbis, Brown

Attachment 2

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: October 26, 2012

TO: Braulio L. Baez, Executive Director

FROM: Phillip O. Ellis, Engineering Specialist III, Division of Engineering POE PV JJ

RE: Draft Review of the 2012 Ten-Year Site Plans

CRITICAL INFORMATION: Please place on the November 28, 2012, Internal Affairs Agenda. Approval by the Commission is required by December 31, 2012.

Staff submits the attached draft as a replacement to the original draft provided on October 8, 2012. The attached draft incorporates the changes described in the previous request for oral modification on October 12, 2012.

Pursuant to Section 186.88(1), F.S., the Commission is required to classify each generating electric utility's Ten-Year Site Plan as either "suitable" or "unsuitable" by December 31 each year. The attached draft satisfies this requirement and its approval by the Commission is sought.

Please let me know if you have any questions or need additional information in reference to the attached document.

Thank you.

POE/jc
Attachment
cc: Paul Vickery
Tom Ballinger
Bob Trapp
Chuck Hill

DRAFT

REVIEW OF THE

2012 TEN-YEAR SITE PLANS

FOR FLORIDA'S ELECTRIC UTILITIES

FLORIDA PUBLIC SERVICE COMMISSION

TALLAHASSEE, FL
DECEMBER 2012

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Statewide Perspective

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LIST OF TEN-YEAR SITE PLAN UTILITIES

Investor-Owned Electric Utilities

FPL	Florida Power & Light
PEF	Progress Energy Florida
TECO	Tampa Electric Company
GULF	Gulf Power Company

Municipal Electric Utilities & Rural Electric Cooperatives

FMPA	Florida Municipal Power Agency
GRU	Gainesville Regional Utilities
JEA	JEA (formerly Jacksonville Electric Authority)
LAK	Lakeland Electric
OUC	Orlando Utilities Commission
SEC	Seminole Electric Cooperative
TAL	City of Tallahassee

LIST OF ACRONYMS

AB	Agricultural Byproducts (Biomass)
CC	Combined Cycle
CR3	Crystal River 3 Nuclear Unit
CT	Combustion Turbine
DACS	Department of Agriculture and Consumer Services
DEP	Department of Environmental Protection
DOE	Department of Energy
EIA	Energy Information Agency
EPA	Environmental Protection Agency
F.A.C.	Florida Administrative Code
F.S.	Florida Statutes
FEECA	Florida Energy Efficiency & Conservation Act
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
INT	Interruptible Load
IOU	Investor-Owned Utility
IPP	Independent Power Producer
LFG	Landfill Gas
LM	Load Management
MMBtu	Million British Thermal Units
MSW	Municipal Solid Waste
MW	Megawatts
MWh	Megawatt-hours
NEL	Net Energy for Load
NUG	Non-Utility Generators
NUG	Non-Utility Generator
OBG	Other Biogas (Biomass)
PPSA	Power Plant Siting Act
QF	Qualifying Facilities
REC	Renewable Energy Credits
RFP	Request for Proposals
RPS	Renewable Portfolio Standard
SUN	Solar
TLSA	Transmission Line Siting Act
TYSP	Ten-Year Site Plan
WAT	Hydro / Water
WDS	Wood Waste Solids (Biomass)
WH	Waste Heat

EXECUTIVE SUMMARY

Pursuant to Section 186.801(1), Florida Statutes (F.S.), each generating electric utility must submit to the Florida Public Service Commission (Commission) a Ten-Year Site Plan (TYSP or Plan) which estimates the utility's power generating needs and the general locations of its proposed power plant sites over a ten-year planning horizon. The Commission is required to perform a preliminary study of each plan and classify each one as either "suitable" or "unsuitable." This document represents the study of the 2012 Ten-Year Site Plans for Florida's electric utilities. All findings of the Commission are made available to the Florida Department of Environmental Protection (DEP) for its consideration at any subsequent electrical power plant site certification proceedings pursuant to the Power Plant Siting Act (PPSA)[1]. In addition, this document is forwarded to the Department of Agriculture and Consumer Services (DACS) pursuant to Section 377.703(2)(e), F.S., which requires the Commission to provide a report on electricity and natural gas forecasts. A copy of this report is also posted on the Commission's website and is available to the public.

The Commission has reviewed the Ten-Year Site Plans filed by the eleven reporting utilities, as well as supplemental data provided through data requests, and finds that the projections of load growth appear reasonable.[2] The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity at a reasonable cost. Therefore, the Commission finds the 2012 Ten-Year Site Plans filed by the reporting utilities, augmented with supplemental data provided, to be suitable for planning purposes.

Since the TYSP is not a binding plan of action for electric utilities, the Commission's classification of these Plans as suitable or unsuitable does not constitute a finding or determination in docketed matters before the Commission. The Commission may address any concerns raised by a utility's TYSP at a public hearing.

Growth in Demand and Capacity

Customer growth remained positive in the last year, and is anticipated to continue at a somewhat slower pace than projected last year, but still below historic levels. Between 2012 and 2021, the annual average growth rate for residential customers is projected at 1.26 percent, slightly below last year's projection of 1.37 percent for 2011 through 2020, and down significantly from the 2.36 percent rate seen for the period 2002 through 2007. In contrast, commercial and industrial customers show a slightly increased rate of growth, but also remain below historic levels.

Generating capacity within the State of Florida is anticipated to grow to meet the increase in customer demand, with approximately 7,200 megawatts (MW) of new generation added over the planning horizon. This figure represents a decrease from last year's TYSPs, which estimated

[1] The Power Plant Siting Act is Sections 403.501 through 403.518, Florida Statutes

[2] Investor-owned utilities (IOUs) filing 2012 Ten-Year Site Plans include Florida Power & Light Company (FPL) Progress Energy Florida, Inc. (PEF), Tampa Electric Company (TECO), and Gulf Power Company (Gulf). Municipal utilities filing 2012 Ten-Year Site Plans include Florida Municipal Power Agency (FMPA), Orlando Utilities Commission (OUC), City of Lakeland (LAK), City of Tallahassee (TAL), JEA (formerly Jacksonville Electric Authority), and Gainesville Regional Utilities (GRU). Seminole Electric Cooperative (SEC) also filed a 2012 Ten-Year Site Plan.

the need for about 10,300 MW new generation. This reduction in the estimated need for new capacity is primarily due to several units being constructed in 2012, and others being delayed beyond the ten year period due to slightly lower load forecasts. The 2012 Plans include retirements and uprates of existing units, along with new generating units to be added during the ten-year period. As in previous planning cycles, natural gas-fired generating units make up a majority of the generation additions and now represent a majority of energy produced within the state.

All TYSPs are subject to modification due to factors such as changes to fuel price forecast, energy demand forecasts, shifts in energy policy, or other factors. A notable change to the 2012 TYSPs is PEF's delay of the Levy 1 nuclear unit, which was originally planned to start commercial service in June 2021, but has been delayed until June 2024. PEF is anticipated to update their 2013 TYSP to reflect this change in projected installed capacity. While the delay is a significant impact on PEF's reserve margin in 2021, the statewide reserve margin is projected to be adequate to provide reliable service with the planned delay of the Levy nuclear units.

Demand-Side Management

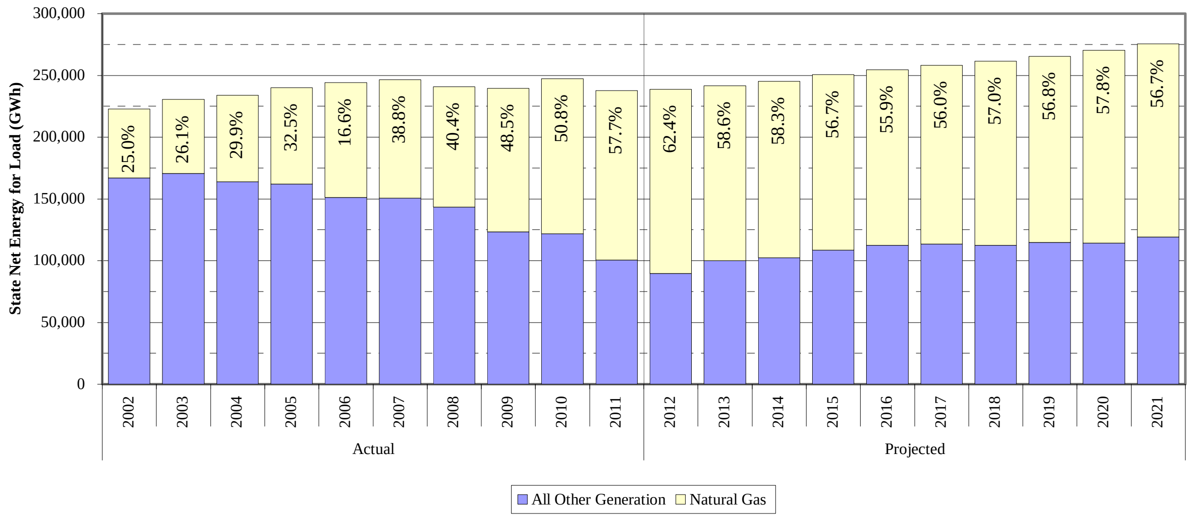
The first step in any resource planning process is to focus on the efficient use of electricity by consumers. Government mandates, such as building codes and appliance efficiency standards, provide the starting point for increasing energy efficiency. Customer choice is the next step in reducing the state's dependence upon expensive fuels and lowering greenhouse gas emissions. Consequently, educating consumers to make smart energy choices is particularly important. Finally, Florida's utilities can efficiently serve their customers by offering demand-side management (DSM) and conservation programs designed to use fewer resources at lower cost.

Florida's utilities project considerable demand and energy savings over the planning period, with conservation and load management programs by 2021 reducing the system's total seasonal peak demand by over 9,000 MW, or 15 percent for summer and winter, and reducing annual energy consumption by over 15,000 GWh or 5 percent.

Fuel Diversity

Natural gas is anticipated to remain the dominant fuel over the planning horizon, with usage in 2011 increasing to 57.7 percent of the state's net energy for load (NEL), up from 50.8 percent of NEL in 2010. Figure 1 below illustrates the increase in the role of natural gas in the state's electricity production during the last ten years, and the projected use during the next decade. Based on the Florida Reliability Coordinating Council (FRCC) 2012 Load and Resource Plan, state-wide natural gas usage is expected to peak in 2012, and then slowly decline throughout the planning period, to 56.7 percent in 2021.

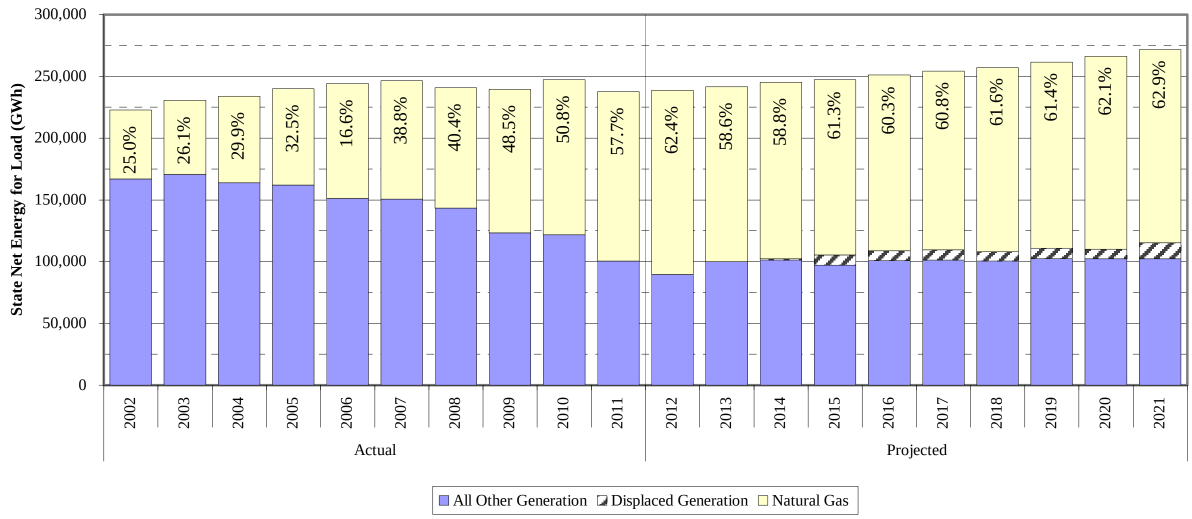
Figure 1. State of Florida: Natural Gas Usage (Total & Percent NEL)



Source: FRCC 2004 - 2012 Load and Resource Plans

While natural gas usage is projected to remain relatively level over the planning period, this situation is due to projected increases in nuclear generation, and a limited impact of new environmental compliance requirements. The FRCC 2012 Load and Resource Plan includes the addition of the Levy 1 nuclear unit in 2021, which has since been delayed until 2024. Also, this projection assumes the return to service in November 2014 of PEF's Crystal River 3 nuclear unit (CR3). However, no decision has been made regarding the repair or retirement of CR3. Furthermore, as discussed at the 2012 TYSP Workshop, PEF's Crystal River 1 & 2 coal units, along with GULF's Lansing Smith 1 & 2 coal units, may face challenges in economically meeting new environmental compliance requirements. If the facilities are unable to install sufficient emissions controls, they would face retirement as early as 2015. If the projected generation associated with these nuclear and coal units is displaced by natural gas, it would have the net effect of increasing natural gas' share of state electric generation to 62.9 percent by 2021, as shown in Figure 2 below.

Figure 2. State of Florida: Natural Gas Usage With Displaced Generation (Total & Percent NEL)



Source: FRCC 2004 - 2012 Load and Resource Plans, PEF 2012 TYSP, Responses to Staff Data Requests.

In an attempt to reduce natural gas consumption, Florida's utilities have encouraged other energy resources, including renewable energy and nuclear generation. Approximately 1,421 MW of renewable generation is currently operating in Florida, an increase of about 138 MW from the previous year. Presently, municipal solid waste (MSW) and biomass each represent roughly a third of renewable generation in Florida. Other major types of renewable generation operating in the state include waste heat, hydroelectric, landfill gas, and solar.

Over the planning horizon, approximately 957 MW of additional renewable generation is planned in Florida, an increase of 51 MW from last year. The majority of these additions are solar and biomass. While these new projects represent a significant increase from the existing total, renewable generation continues to provide a relatively small contribution towards the reduction of our state's reliance on fossil fuels.

While no new nuclear units are projected until 2022, uprates for all five existing nuclear units have been approved by the Commission, representing an increase of approximately 600 MW. Extended outages associated with unit uprates and other major maintenance work has reduced nuclear generation, and is projected to reduce nuclear's contribution to annual energy in the near future. One of the nuclear units, CR3, has been offline since 2009 due to a delamination of the concrete containment structure discovered during a steam generator replacement project. The unit, including the 154 MW of uprated capacity, is currently scheduled to return to service in the end of 2014. Currently four new nuclear units, Turkey Point 6 & 7, and Levy 1 & 2, totaling over 4,000 MW generation are planned outside of the ten-year horizon.

New and Proposed EPA Rules

Florida's electric utilities must also consider environmental concerns regarding existing and planned generation to meet Florida's electric needs. The Environmental Protection Agency

(EPA) has finalized or proposed several new rules in the last year that will have an impact on Florida's existing generation fleet, as well as on its proposed new facilities.

The new or proposed EPA rules limit emissions from existing power plants on a variety of pollutants, including mercury, other heavy metals, organic toxics, particulates, sulfur oxides, and nitrogen oxides. While many facilities within the state already have sufficient emissions control technologies to address these rules, some will require installation of new equipment to bring emissions into compliance. Other rules address concerns relating to cooling water's impact on aquatic life, and the disposal of coal ash. All of these activities will require investment and potential for extended outages of the relevant generating units, which will require careful planning to allow for a minimum impact on system reliability.

At this time, a final estimate of costs and units affected is not available, as some of the proposed rules are not yet final. Several of the TYSP utilities have provided preliminary estimates based upon known and proposed rule language, and are shown in Table 1 below.

Table 1. TYSP Utilities: Preliminary Estimates of EPA Rule Compliance Cost

Utility	Preliminary Total Cost Estimates* ($ Millions)
Florida Power & Light	$348 - $1,741
Progress Energy Florida	$165 - $1,330
Tampa Electric Company	$763
Gulf Power Company	$1,270 - $2,737
Florida Municipal Power Agency	$39
Gainesville Regional Utilities	Not Available
JEA	Not Available
Lakeland Electric	Not Available
Orlando Utilities Commission	$157
Seminole Electric Cooperative	Not Available
City of Tallahassee	$5
Total of All Utilities	**$2,747 - $6,772**

* These estimates are not final, and may not include all rules.
Source: Responses to Staff's Data Requests.

New Generation Facilities

The State of Florida has a total summer generating capacity of 56,973 MW installed as of January 1, 2012. A total of 7,200 MW of new generation units are planned in the ten-year period, all of which will be natural gas-fired units. Other impacts noted in the report reflect changes to existing units and/or purchased power agreements.

As noted previously, the primary purpose of this review of the utilities' TYSPs is to provide information regarding new electric power plants to the DEP for its use in the certification process. Table 2 displays those generation facilities included in the 2012 TYSPs that have not yet received a certification under the PPSA by the Commission. Certification is generally anticipated at four years in advance of the in-service date for a natural gas-fired combined cycle unit. TECO has recently filed a Request for Proposals (RFP) for their conversion to combined cycle configuration of their existing Polk Power Station units 2 through 5, and filed a petition for a determination of need on September 12, 2012.

Table 2. State of Florida: Proposed Generating Units Without PPSA Certification

Utility	Generating Unit Name	Unit Type	Fuel Type	Summer Capacity (MW)	In-Service Date
TECO	Polk 2-5 CC	CC	NG	1,063	Jan 2017
PEF	Unknown	CC	NG	767	Jun 2019
SEC	Unnamed CC1	CC	NG	196	Dec 2020
SEC	Unnamed CC2	CC	NG	196	Dec 2020
SEC	Unnamed CC3	CC	NG	196	Dec 2021

Source: Utilities 2012 TYSP

In addition to generating units, transmission lines that will require the Commission's certification under the Transmission Line Siting Act (TLSA) are projected during the planning period. Table 3 below details the only TLSA project included in the utility's plans, which is associated with TECO's combined cycle conversion at the Polk Power Station.

Table 3. State of Florida: Proposed Transmission Without TLSA Certification

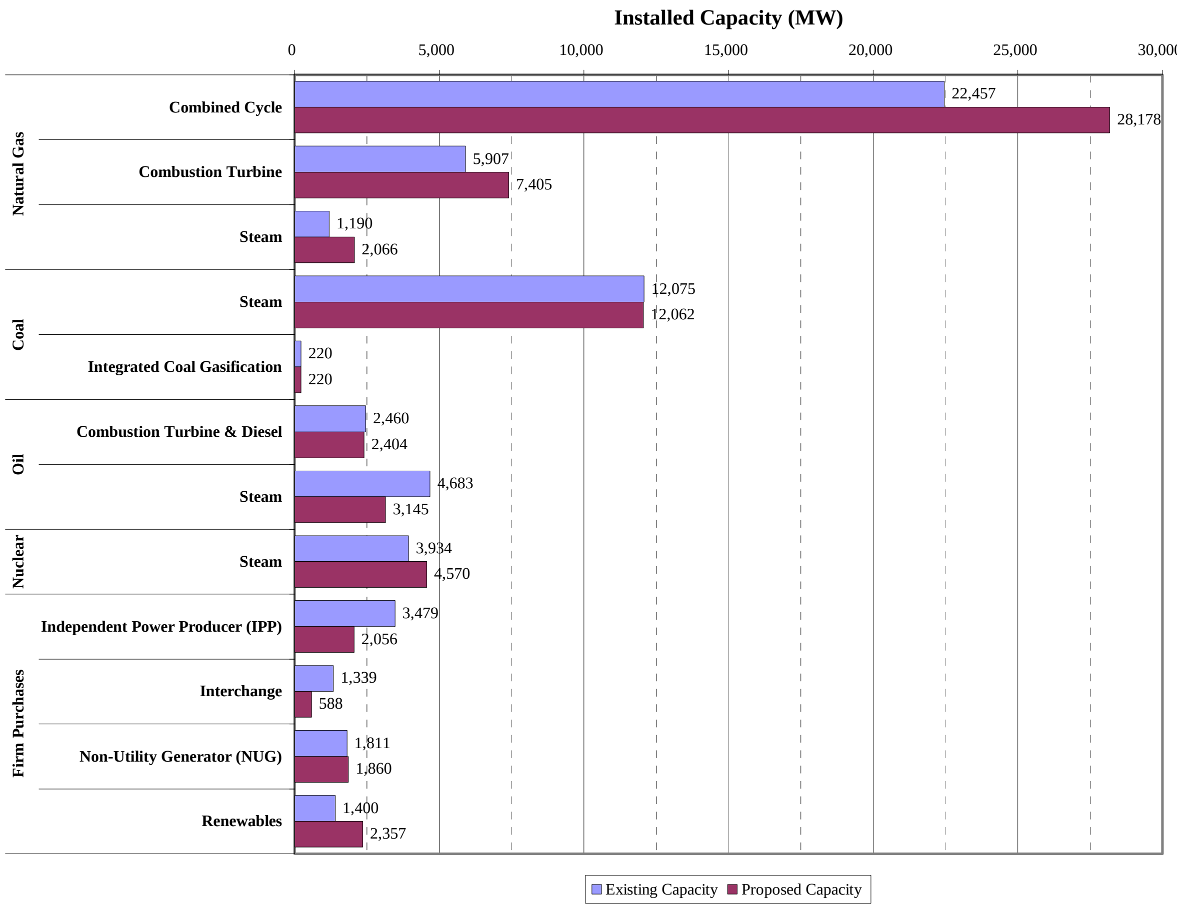
Utility	Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Commercial In-Service Date
TECO	Polk-Aspen-FishHawk	62.5	230	2017

Source: Utilities 2012 TYSP

Summary of the State of Florida

Figure 3 below illustrates the present and future aggregate capacity mix. The capacity values in Figure 3 incorporate all proposed additions, changes, and retirements contained in the reporting utilities' 2012 Ten-Year Site Plans.

Figure 3. State of Florida: Existing and Projected Capacity



Source: FRCC 2012 Load and Resource Plan, Responses to Staff Data Requests

INTRODUCTION

The Ten-Year Site Plans of Florida's electric utilities are designed to give state, regional, and local agencies advance notice of proposed power plants and transmission facilities. The Commission receives comments from these agencies regarding any issues with which they may have concerns. Because the TYSPs are considered to be planning documents and can contain tentative data, they may not necessarily contain sufficient information to allow regional planning councils, water management districts, and other reviewing agencies to evaluate site-specific issues within their respective jurisdictions. Each utility is responsible for providing detailed information based on individual assessments during certification proceedings under the Power Plant Siting Act (PPSA), Sections 403.501-403.518, F.S., or the Transmission Line Siting Act (TLSA), Sections 403.52-403.5365, F.S. In addition, other regulatory processes may require utilities to provide additional information as needed.

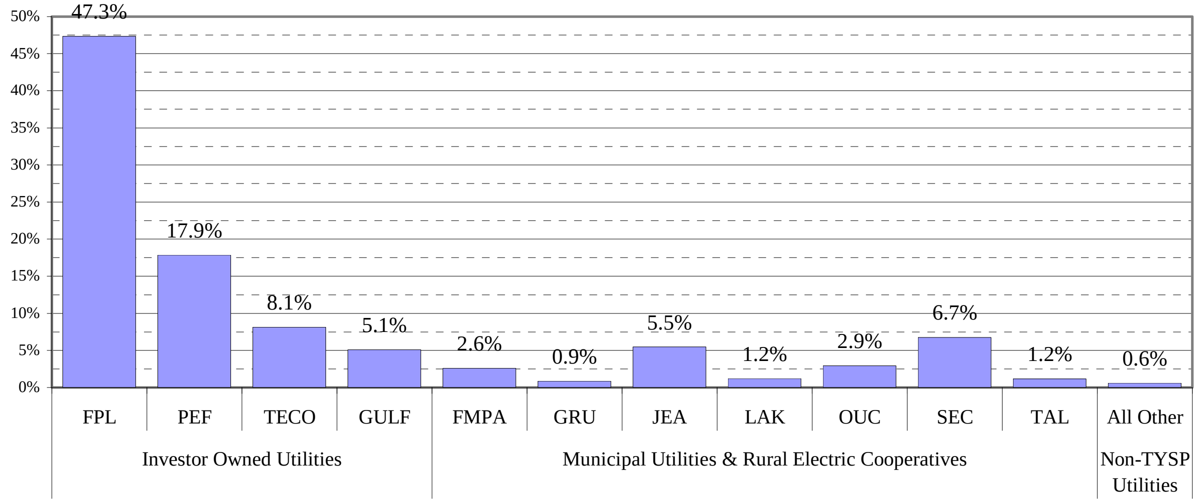
Statutory Authority

Section 186.801, F.S., requires that all major generating electric utilities submit a TYSP to the Commission for annual review. Section 377.703(2)(e), F.S., requires the Commission to analyze these plans and provide natural gas and electricity forecasts to the Department of Agriculture and Consumer Services (DACS). The Commission has adopted Rules 25-22.070 through 25-22.072, Florida Administrative Code (F.A.C.) in order to fulfill these statutory requirements.

Florida is served by 58 electric utilities, including 5 investor-owned utilities (IOUs), 35 municipal utilities, and 18 rural electric cooperatives. Only generating electric utilities with an existing capacity above 250 megawatts or a planned unit with a capacity of 75 MW or greater are required to file with the Commission a TYSP, at least once every two years. In 2012, eleven utilities filed TYSPs, including 4 IOUs, 6 municipal utilities, and 1 rural electric cooperative.

Figure 4 below illustrates each TYSP utility's representative share of the state's net energy for load for 2011. In total, the investor-owned TYSP utilities represent 78 percent of net energy for load, with the remaining TYSP utilities contributing 21 percent. Those utilities which are not required to file a TYSP make up the remaining 1 percent.

Figure 4. State of Florida: Percent State Net Energy for Load by Electric Utility (2011 Actual)



Source: FRCC 2012 Load & Resource Plan, Utilities 2012 TYSPs

As outlined in the Commission's rules, each utility's TYSP contains projections of the utility's electric power needs, fuel requirements, and general location of proposed power plant sites and major transmission facilities. The utilities provide historic and projected information on existing generating capacity, customer base and energy usage, impact of demand-side management, fuel consumption, fuel diversity, anticipated reserve margin, and proposed new generating units and transmission.

In accordance with Section 186.801, F.S., the Commission performs a preliminary study of each TYSP and makes a determination as to whether it is suitable or unsuitable. This determination is non-binding, and is made in recognition that the information provided is tentative, and is subject to change by the utility upon written notice. The results of the Commission's study are contained in this report, Review of the 2012 Ten-Year Site Plans, and are forwarded to the DEP for use in subsequent power plant siting proceedings.

Information Sources for the Report

Contained in each utility's TYSP is a series of required tables which provide detailed information on a number of items. This information, supplemented by additional data requests, provides the basis of the Commission's review.

The Florida Reliability Coordinating Council (FRCC) is also an important source of information for the Commission's review. Each year, the FRCC publishes its Regional Load and Resource Plan which contains aggregate data on demand and energy, capacity and reserves, and proposed new generating units and transmission line additions, both for Peninsular Florida and for the state as a whole. In addition to its *2012 Regional Load and Resource Plan*, the Commission used the FRCC's *2012 Reliability Assessment* as a resource in the production of this review. The Commission held a public workshop on August 13, 2012, to facilitate discussion of the annual planning process and the Regional Load & Resource Plan and to allow for public comments on the TYSPs that were filed with the Commission.

Structure of the Report

This report is divided into multiple sections. The Statewide perspective provides a look at the impact of all planned unit additions to the State as a whole, and is intended as a resource for those seeking understanding of Florida's energy systems. Individual utility reports focus on the issues facing each electric utility and its unique situation. Lastly, Appendix A contains comments received from various review agencies, local governments, and others that have been collected and included in this report.

Conclusions

As discussed in each of the individual utility's reviews, the Commission's review of the eleven reporting utilities' 2012 TYSPs finds them all suitable for planning purposes. Through the review process, the Commission has determined that the projections of load growth appear reasonable, and that reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity at a reasonable cost.

Since the TYSP is not a binding plan of action for electric utilities, the Commission's classification of these Plans as suitable or unsuitable does not constitute a finding or determination in any docketed matters before the Commission. The Commission may address any concerns raised by a utility's TYSP at a public hearing.

Statewide Perspective

Forecasting load growth is the first component of system planning for Florida's electric utilities. In order to maintain a reliable system, utilities must stay abreast of changes in customer base as well as trends in demand and energy consumption. Utilities perform load and energy forecasts to estimate the amount and timing of future capacity needs.

Historical data forms the foundation for utility load and energy forecasts. These sets of data include energy usage patterns, trends in population growth, economic variables, and weather data for each utility's service territory. Econometric forecast models are then used to quantify the historical impact of population growth, economic conditions, and weather on energy usage patterns.

Finally, sets of forecast assumptions on future population growth, economic conditions, and weather are assembled and together with the forecast models, yield the final demand and energy forecasts. Each utility's peak demand and energy forecasts serve as a starting point for determining if and when new capacity additions are needed to reliably and efficiently serve the anticipated load.

Customer Growth Projections

The most basic starting point in the utility's forecast modeling is the projected number and type of electric customers. Florida is dominated by the residential class, which makes up a majority in both number of customers and energy sales, as shown in Table 4 below. As a result, Florida's electrical demands and energy requirements heavily focus on residential use patterns. While commercial and industrial customers may be lower in number, they typically consume far more per customer, and combined represent the other half of energy consumed in Florida. Compared to last year, Florida experienced a slight growth in the number of customers, but an overall decline in energy consumption.

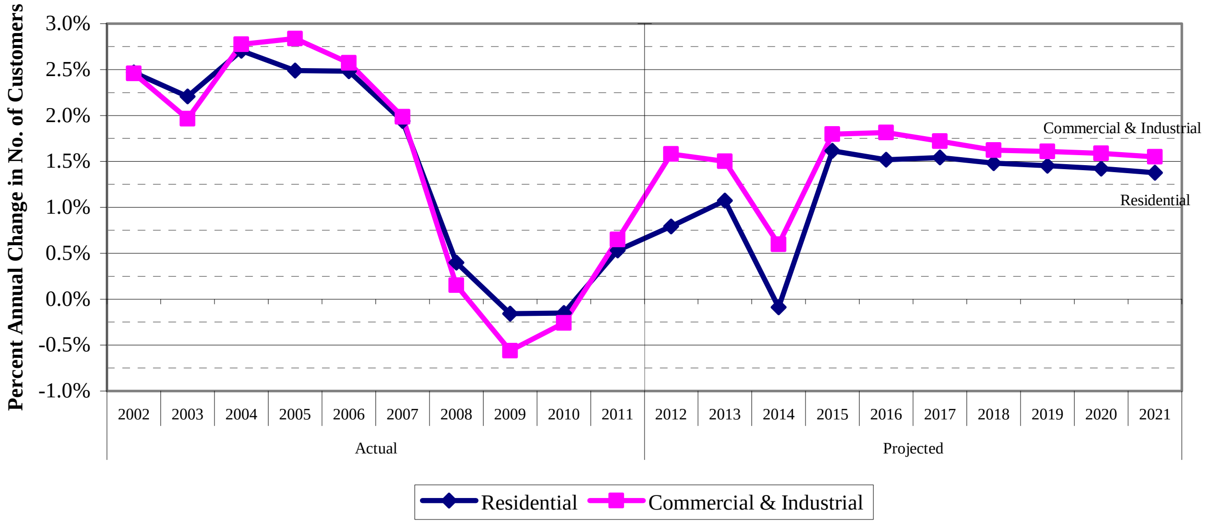
Table 4. State of Florida: Customer Numbers and Energy Usage (2011 Actual)

Customer Class	Number of Customers	% of Customers	Energy Sales (GWh)	% of Sales
Residential	8,369,607	88.71%	113,554	52.97%
Commercial	1,037,584	11.00%	80,284	37.45%
Industrial	27,202	0.29%	20,556	9.59%
Total	**9,434,393**		**214,394**	

Source: FRCC 2012 Load & Resource Plan

Florida's annual customer growth rate in 2011 was positive but significantly below historic norms for all customer classes, and is not anticipated to return to its previous rate during the planning period. Figure 5 shows the actual annual growth rate between 2002 and 2011, and the projected customer growth between 2012 and 2021. The historic data clearly shows the decline from high annual customer growth, resulting in significantly lower or even negative customer growth.

Figure 5. State of Florida: Annual Customer Growth Rate by Customer Class

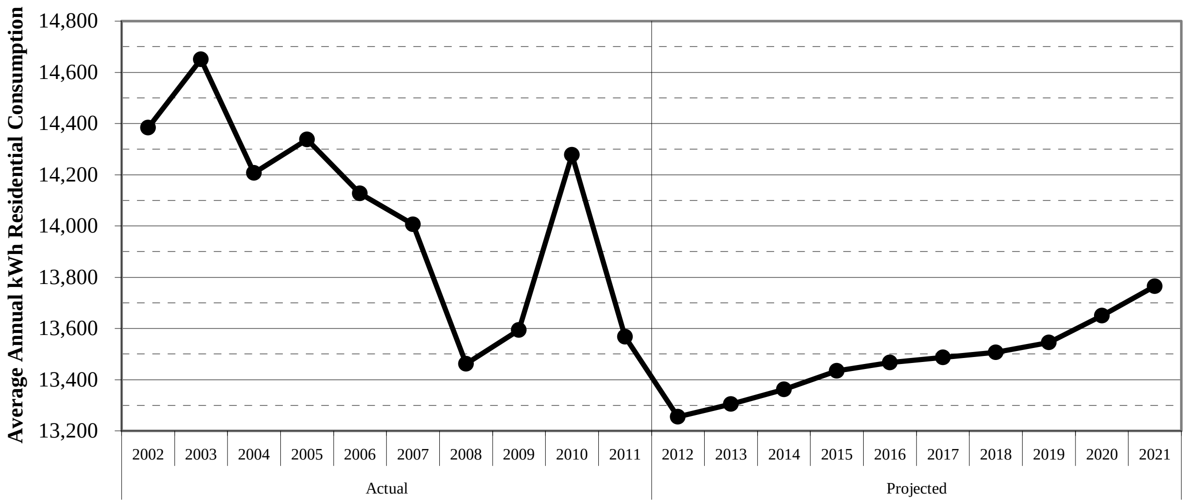


Source: FRCC 2012 Load & Resource Plan

Customer growth is projected to increase and remain higher throughout the planning period, with the exception of 2014. In 2014, both FMPA and SEC note that several member utilities are anticipated to change their service agreements, including the City of Lake Worth (which would leave FMPA's All Requirements Power Supply Project) and Lee County Electric Cooperative (which would no longer be served by SEC), resulting in the declining customer growth seen above in Figure 5.

Florida's energy requirements are heavily dependent on the energy consumption behaviors of residential customers. This relationship is a result of the fact that close to 90 percent of electric customers in Florida are residential accounts, with these customers purchasing more than half the energy sold in the state in 2011. Figure 6 shows the actual per-customer consumption from 2002 through 2011, as well as the projection for the period 2012 through 2021. Actual usage has generally decreased, excluding a spike in 2010 that is attributed to extreme winter weather. Per-customer residential sales are expected to decline in 2012, but then slowly rebound throughout the planning period.

Figure 6. State of Florida: Average Annual Residential Customer Energy Consumption



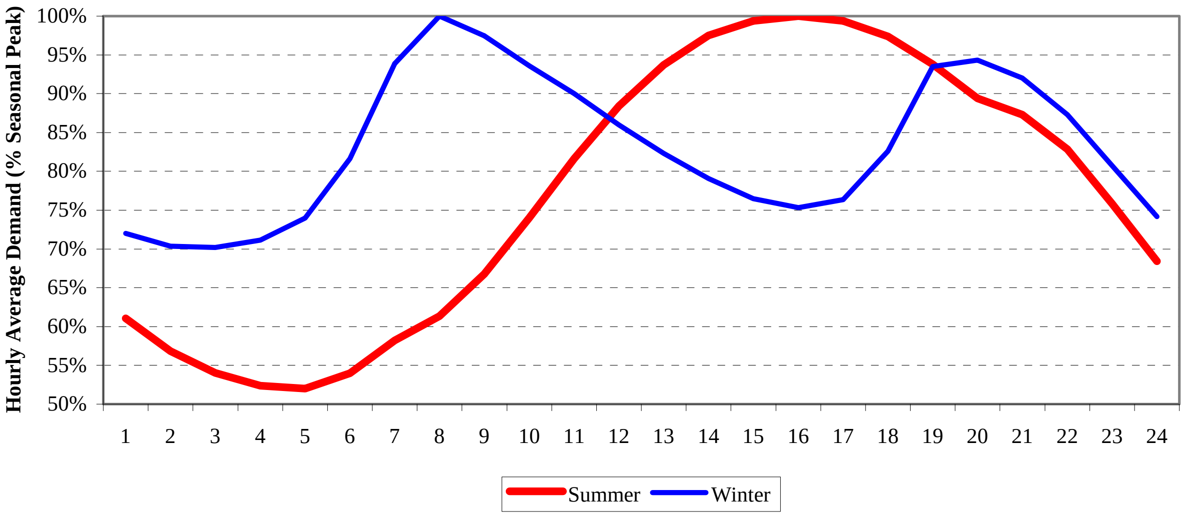
Source: FRCC 2012 Load & Resource Plan

Seasonal Peak Demand Forecast

Since there exists no economically feasible means to store electricity at the grid-scale, electric utilities must supply electricity near instantaneously to the time of its consumption. For a majority of the time, system demand is significantly less than the daily peak. However, system peak demand determines the timing of new generation needs, and is driven by seasonal weather patterns. With a growing customer base dominated by residential customers, both the rate of growth and usage patterns are important considerations in planning sufficient future generation to meet the state's projected customer load.

Figure 7 illustrates typical daily load curves for each season, which shows evidence of the influence of residential customers. In summer, air-conditioning demand causes a steady climb in the morning and a peak in early evening, before declining into the evening. In contrast, winter's demand curve is dominated by electric heating and water heating, causing a rapid peak in mid-morning and a second peak in the late evening.

Figure 7. TYSP Utilities: Example Daily Load Curve



Source: Responses to Staff Data Request (2011)

Florida is typically a summer-peaking state, meaning that the summer peak demand generally controls the amount of generation required. While winter peak demands tend to be greater than summer, the higher peak is offset by the increased winter rating of power plants, which can take advantage of lower ambient air and water temperatures to produce more electricity from the same generating unit. During summer peak demand, higher temperatures instead can decrease generation, as high water temperatures may reduce not only the quality, but quantity of cooling water available based on environmental permits.

As with daily load, there is a great variation in seasonal peak load. Generally speaking, Florida's summer season is significantly longer than its winter. The periods between the seasonal peaks are referred to as "shoulder months," and utilities take advantage of these periods of relatively low demand to perform maintenance without impacting their ability to meet the daily peak demand.

In general, a major controlling factor to seasonal peak demand is short-term weather conditions. While utilities forecast annual peak demand based upon historic factors, customer counts, and normalized weather patterns, utilities also continuously monitor weather conditions in their service territory and prepare for any increases (or decreases) in customer demand. By close monitoring of the weather situation, utilities can fine tune maintenance schedules to ensure the highest unit availability during time of the utility's peak demand.

Demand Side Management

The first step in any resource planning process is to focus on the efficient use of electricity by consumers. Government mandates, such as building codes and appliance efficiency standards, provide the starting point for increasing energy efficiency. Customer choice is the next step in reducing the state's dependence upon expensive fuels and lowering greenhouse gas emissions. Consequently, educating consumers to make smart energy choices is particularly important. Finally, Florida's utilities can efficiently serve their customers by offering DSM and conservation programs designed to use fewer resources at lower cost.

The Florida Legislature directed the Commission to encourage utilities to decrease the growth in seasonal peak demand and energy consumption in Sections 366.80 through 366.85 and Section 403.519, F.S., known as the Florida Energy Efficiency and Conservation Act (FEECA). Under FEECA, the Commission is required to set goals for demand and energy reduction for 7 electric utilities, namely the 5 investor-owned electric utilities (4 of which file TYSPs, the exception being Florida Public Utility Company, which is a non-generating utility) and 2 municipal electric utilities (JEA and OUC). These utilities represent 87 percent of sales in Florida.

DSM Programs generally fall into three categories: interruptible/curtailable load (INT), load management (LM), and conservation. The first two are generally considered dispatchable, meaning that the utility can call upon them during a period of peak demand, but otherwise they are not in active use. In contrast, conservation measures are considered passive and are always working to reduce customer demand.

Interruptible or curtailable load is achieved through the use of agreements with large customers to allow the utility to interrupt selected portions of the customer's load during periods of peak demand. Interrupted or curtailed customers could make up for this generation by reducing their own industrial processes or by activating back-up generation. In exchange for the ability to reduce their electrical load, the utility usually offers such customers a discounted rate for energy or other credits which are paid for by all customers.

Load management programs involve the installation of a device that can interrupt a customer's appliance(s) for a short duration during a period of peak demand. These interruptions tend to have less notice than those provided to interruptible customers, and generally do not fully disconnect customers, but interrupt an individual appliance. Normally, interruptions are kept to short periods and are cycled between groups of customers. Due to the nature of the program, certain devices would be more appropriate to handle different seasonal demands. For example, air conditioning units would be interrupted to reduce a summer peak, while water heaters being interrupted may contribute more towards reducing a winter peak. As of 2012, over 7,165 MW of interruptible load and load management is available for summer peak, and is anticipated to expand to 9,219 MW by 2021.

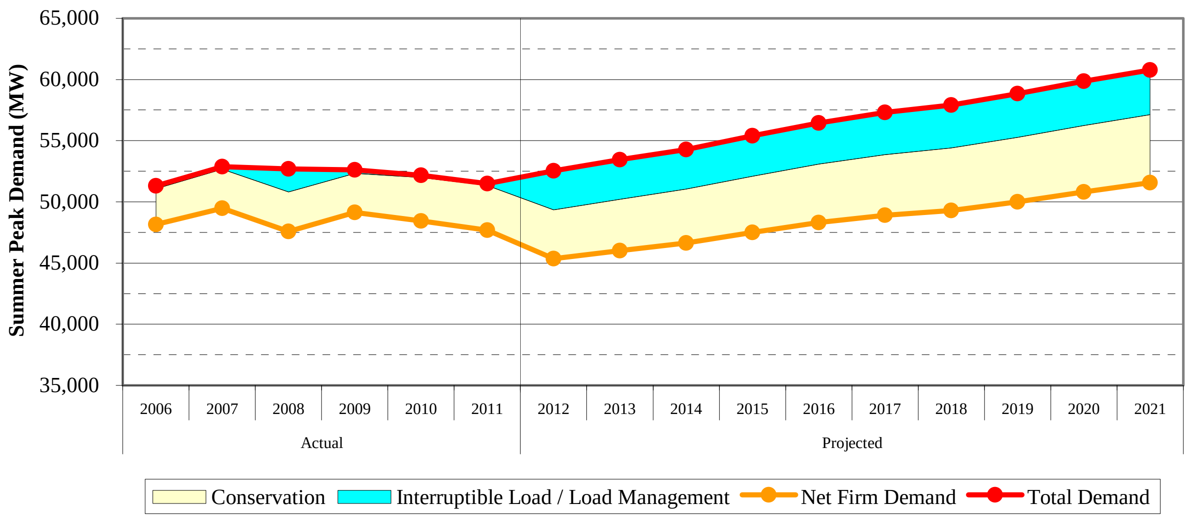
In addition to active measures, customer-based conservation measures can have an impact on peak demand without requiring activation by the utility. These passive conservation measures typically involve improving a home or business' building envelope, such as greater insulation and energy-efficient windows, or installing more efficient appliances. These energy efficiency improvements decrease the customer's load at all times without requiring an interruption or reduction in service, and also have an impact on annual energy consumption.

The seven FEECA utilities currently offer DSM programs to residential, commercial, and industrial programs. Energy audit programs provide a first step for utilities and customers to evaluate conservation opportunities and serve as the foundation for other programs.

Projected Peak Demands

Figure 8 below shows the historic and projected total summer peak demand, as well as demand side management impacts and the resulting net firm demand experienced by the utilities. While summer peak demand has been relatively steady in the past few years, demand is anticipated to increase steadily throughout the planning period. Interruptible load and load management programs have not been fully implemented in past years, with the primary impact shown below in 2008. When planning for future load, the electric utilities use net firm seasonal demand.

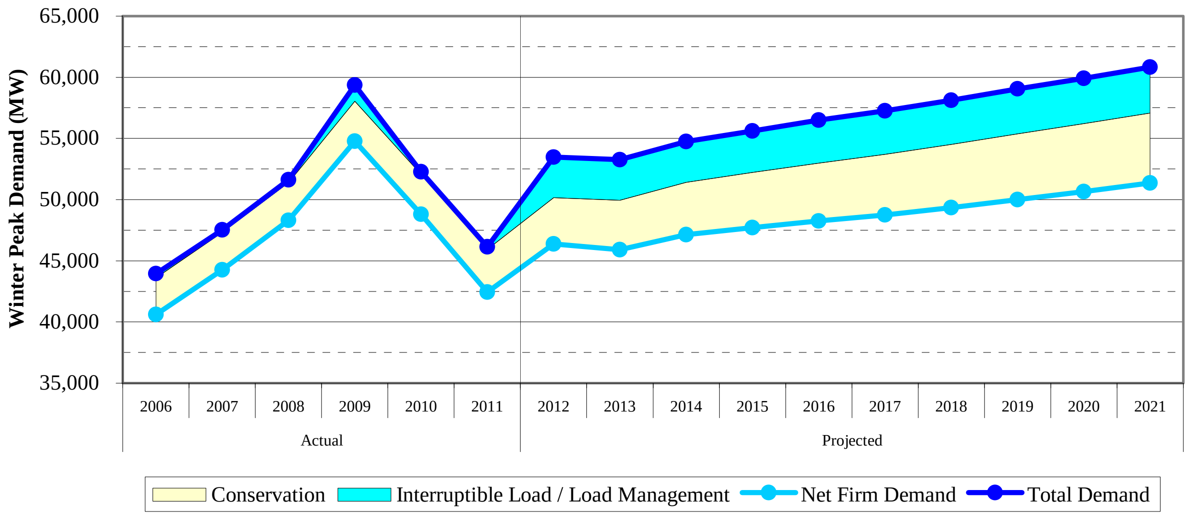
Figure 8. State of Florida: Historic & Projected Summer Peak Demand (With DSM Impacts)



Source: FRCC 2008 - 2012 Load and Resource Plans

Figure 9 below shows the historic and projected total winter peak demand, as well as DSM impacts and the resulting net firm demand experienced by the utilities. As with summer peak demand, demand response resources have not historically been fully utilized, as shown by the small reduction in the actual firm demand.

Figure 9. State of Florida: Historic & Projected Winter Peak Demand (With DSM Impacts)

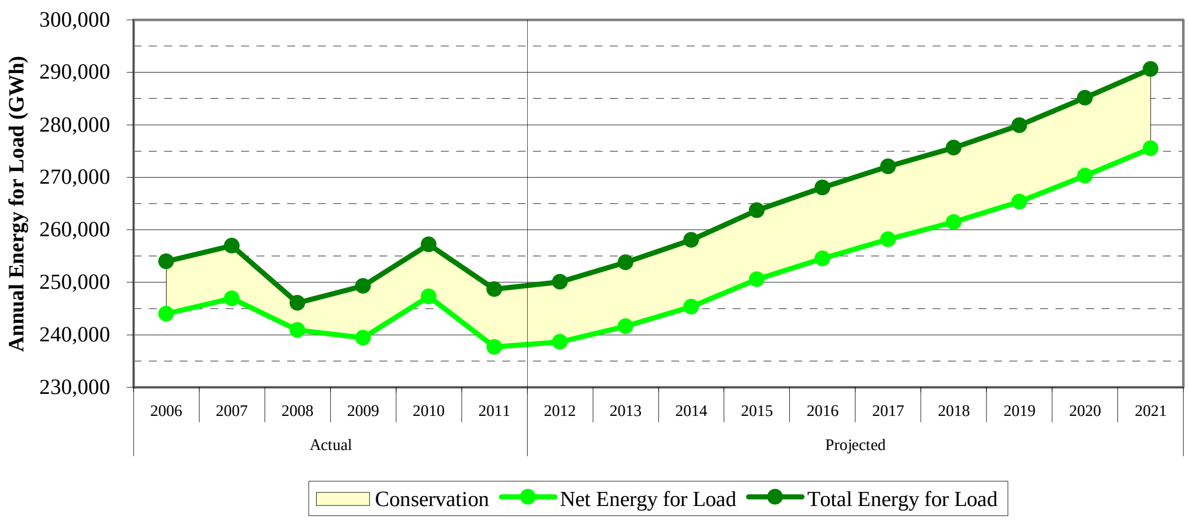


Source: FRCC 2008 - 2012 Load and Resource Plans

Annual Energy Consumption Forecasts

While peak demand is the instantaneous usage of a customer on the system, annual energy consumption addresses the total cumulative demand on the system over time, which determines the type of units required and the resulting amount of fuel consumed. Figure 10 below shows the historic and projected annual energy for load for the state of Florida. While energy consumption has been relatively steady for the past few years, it is anticipated to increase steadily through the end of the planning period.

Figure 10. State of Florida: Historic & Projected Annual Energy for Load (With DSM Impacts)



Source: FRCC 2008 - 2012 Load and Resource Plans

Historical Accuracy of Energy Forecasts

For each utility filing a TYSP, the Commission reviewed the historical forecast accuracy of total retail energy sales for the five-year period 2007 to 2011. The review compared actual energy sales for each year to energy sales forecasts made three, four, and five years prior. For example, the actual 2007 energy sales were compared to the projected 2007 forecasts made in 2002, 2003, and 2004. These differences, expressed as a percentage error rate, were used to calculate the utility's historical forecast accuracy.

Table 5 below illustrates the historical forecast error for 2012 and 2011, on an average error and average absolute error basis. The calculated average error is positive for all TYSP utilities, this shows a tendency to over-forecast, with the resulting average forecast error for all TYSP utilities combined at 11.38 percent in 2012, an increase from 8.45 percent in 2011.

Table 5. TYSP Utilities: Historical Accuracy of Net Energy for Load Forecasts

TYSP Utility	Forecast Error (%)			
	2012 (Years 2011 – 2007)		2011 (Years 2010 – 2006)	
	Average	Average Absolute	Average	Average Absolute
FPL	12.12%	12.12%	10.92%	10.97%
PEF	11.36%	11.90%	6.17%	7.05%
TECO	13.07%	13.07%	8.95%	8.95%
GULF	5.44%	7.37%	1.97%	5.62%
FMPA	11.81%	13.99%	6.09%	12.83%
GRU	11.40%	11.40%	8.32%	8.32%
JEA	12.72%	12.72%	9.78%	9.78%
LAK	7.89%	7.89%	5.69%	5.69%
OUC	5.83%	5.83%	5.87%	6.61%
SEC	11.41%	12.63%	4.41%	8.38%
TAL	8.77%	8.85%	7.04%	7.28%
Weighted Average	**11.38%**	**11.38%**	**8.45%**	**8.63%**

Source: Staff Calculation based on Utilities 2001 – 2012 TYSPs

The high error rate, increased from last year's, represents the impact of the recession on energy usage in Florida. This analysis primarily uses forecasts developed from between 2002 and 2008, a majority of which occurred before the recession. Due to the unexpected nature of the recent recession, it could not have been included in forecasts as far as 5 years preceding the event. As this analysis moves forward and begins to use forecasts developed after the beginning of the recession, the error rate should fall back to typical levels.

As indicated by this high error rate, utilities projected increased need for energy that has not materialized due to the recession. As discussed below, Florida currently has an excess of generation, in part due to these projections. The TYSP utilities have responded to changing circumstances by delaying or cancelling new generation, as discussed in previous annual reviews of the TYSPs.

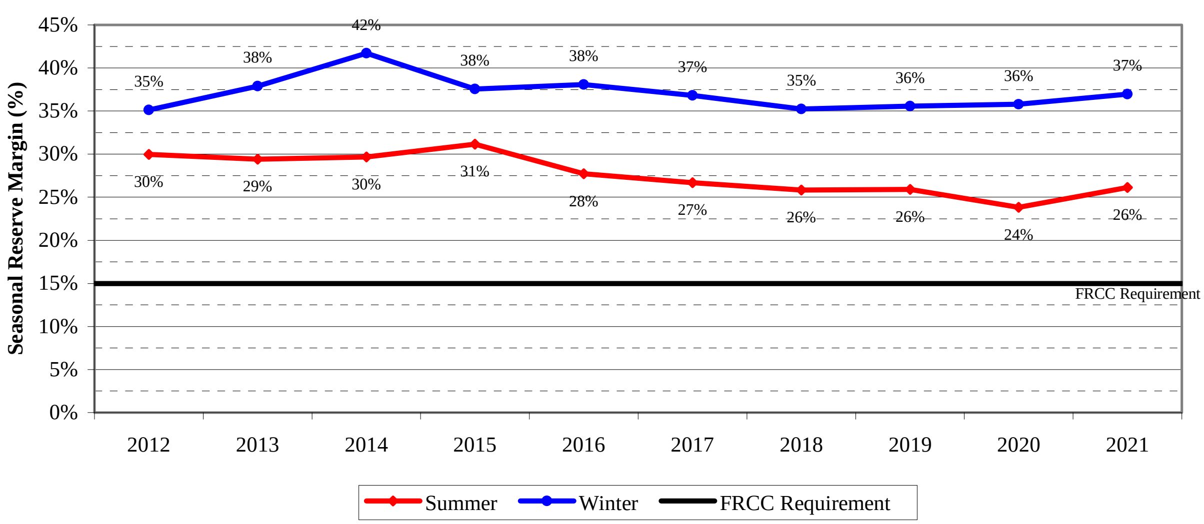
Reserve Margin Requirements

In order to maintain stability in the electric system, utilities must constantly adjust system output to match demand from moment to moment. As demand fluctuates, utilities must generate the precise amount of electrical power that will keep the system in balance while also performing periodic maintenance on its generating units. In addition, utilities must be prepared at any moment to meet unforeseen circumstances, such as extreme weather events or unit outages. Therefore, each utility must maintain a certain amount of "extra" or reserve capacity in the event that demand rises above or supply drops below forecasted levels. This additional amount of generating capacity is expressed as a percentage of firm demand and is referred to as the reserve margin.

Reserve margins in Florida typically remain well above the FRCC minimum of 15 percent for most of the year, and usually will only approach minimum levels in the summer peak season when air conditioning loads are at their highest levels. The higher margins during winter peak seasons are also due to the fact that generating units can operate at a higher capacity in colder temperatures. The three largest IOUs, FPL, PEF, and TECO, were party to a stipulation approved by the Commission setting a 20 percent reserve margin planning criterion.

The values in Figure 11 below include both supply-side and demand-side contributions, and shows that planning is mostly controlled by summer peak demand. It should be noted that the figure below is for the State of Florida, and therefore contains generating capacity outside of the FRCC region.

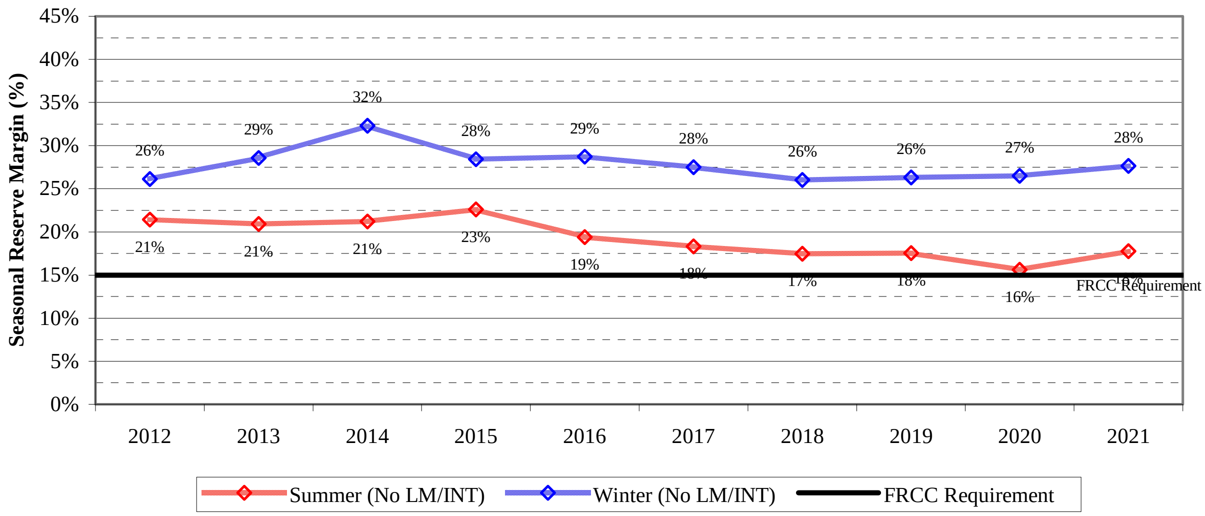
Figure 11. State of Florida: Seasonal Reserve Margin (With LM/INT)



Source: FRCC 2012 Load and Resource Plan

It should be noted that the reserve margin figures above are calculated using the net firm system demand, which assumes full use of interruptible load and load management devices to reduce peak demand. Participation in interruptible rates and load management programs are voluntary, for which incentives are provided in the form of lower rates or credits paid to the participant. As shown in Figure 12 below, the state as a whole has sufficient generation capacity planned throughout the period to meet the minimum reserve margin of 15 percent without relying on interruptible and load management customers.

Figure 12. State of Florida: Seasonal Reserve Margin (Without LM/INT)

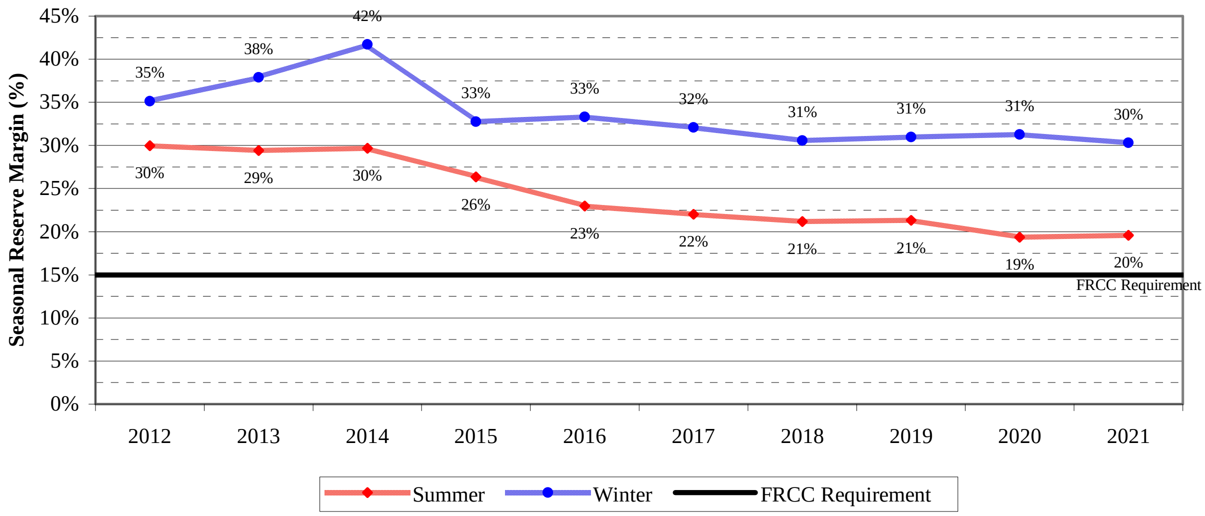


Source: FRCC 2012 Load and Resource Plan

The previous two figures have assumed that the expansion plans filed in the utilities TYSPs will continue as planned. Since the filing of the 2012 TYSPs, PEF has delayed the in-service date of the Levy 1 nuclear unit outside of the planning period. Staff is also aware of the long-term outage at PEF's CR3 nuclear unit, which is currently offline and scheduled to return to service in November 2014 if repaired. Retirement remains an open option for this unit in the event it is determined to be uneconomic to repair, which would have an impact on the statewide reserve margin. In addition, several coal-fired plants were identified at the Commission's Workshop on the 2012 Ten-Year Site Plans, which if retired would further decrease the state's reserve margin.[3] Figure 13 shows the total impact of the delay or potential retirement of all the units discussed above and that the state should still retain sufficient generating capacity. The potential impacts to PEF and GULF are discussed in the individual utility section of the report.

[3] Specifically, PEF's Crystal River 1 and 2 and GULF's Lansing Smith 1 and 2.

Figure 13. State of Florida: Seasonal Reserve Margin After Potential Unit Retirements (With LM/INT)



Source: FRCC 2012 Load and Resource Plan, Staff Calculation

Federal Legislation

In 1978, the U.S. Congress enacted the Public Utility Regulatory Policies Act (PURPA)[4]. PURPA endorsed three broad national purposes: (1) conservation of electric energy, (2) increased efficiency in the use of facilities and resources by electric utilities, and (3) equitable rates for electricity consumers. Section 210 of Title II, entitled "Cogeneration and Small Power Production," required electric utilities to interconnect and sell electric energy to qualifying cogeneration and small power production facilities, referred to as Qualifying Facilities, or QFs, and to purchase electric energy from these facilities at the utility's full avoided cost. The Federal Energy Regulatory Commission (FERC) subsequently adopted rules to implement PURPA. In addition, states were delegated authority to implement the FERC rules for electric utilities over which they have rate making authority.[5] In 1980, the FERC issued its rules establishing the criteria for determining the qualifying status of a facility and setting out regulations for electric utility interconnection with QFs, along with sales to and purchases from QFs.[6]

State Legislation

In 1981, the Florida Legislature authorized the Commission to establish guidelines for the purchase and sale of capacity and energy from cogenerators and small power producers, which includes renewable generators. In 1989, the statutes were broadened with the enactment of Section 366.051, F.S., which provides, in part, the following:

> Electricity produced by cogeneration and small power production is of benefit to the public when included as part of the total energy supply of the entire electric grid of the state or consumed by a cogenerator or small power producer. The electric utility in whose service area a cogenerator or small power producer is located shall purchase, in accordance with applicable law, all electricity offered for sale by such cogenerator or small power producer; or the cogenerator or small power producer may sell such electricity to any other electric utility in the state. The Commission shall establish guidelines relating to the purchase of power or energy by public utilities from cogenerators or small power producers and may set rates at which a public utility must purchase power or energy from a cogenerator or small power producer. In fixing rates for power purchased by public utilities from cogenerators or small power producers, the Commission shall authorize a rate equal to the purchasing utility's full avoided costs. A utility's "full avoided costs" are the incremental costs to the utility of the electric energy or capacity, or both, which, but for the purchase from cogenerators or small power producers, such utility would generate itself or purchase from another source.

[4] Public Law 95-617 (HR 4018) November 9, 1978.
[5] PURPA at Title II, section 210(f); In Florida, the Florida Public Service Commission has ratemaking jurisdiction over five investor-owned electric utilities: Florida Power & Light Company (FPL), Progress Energy Florida (PEF), Gulf Power Company (Gulf), Tampa Electric Company (TECO), and Florida Public Utilities Company (FPUC).
[6] 18 C.F.R. 292.101 through 18 CFR 292.602.

In 2005, the Legislature enacted Section 366.91, F.S., which requires IOUs to continuously offer purchase contracts to producers of renewable energy, and adopts the avoided cost standard as defined in Section 366.051, F.S. Section 366.91, F.S., also defines the term "renewable energy" as follows:

> "Renewable energy" means electrical energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen produced from sources other than fossil fuels, biomass, solar energy, geothermal energy, wind energy, ocean energy, and hydroelectric power. The term includes the alternative energy resource, waste heat, from sulfuric acid manufacturing operations and electrical energy produced using pipeline-quality synthetic gas produced from waste petroleum coke with carbon capture and sequestration.

Commission Rules

Renewable facilities are permitted to enter into two types of contractual agreements for selling power: standard offer and negotiated contracts. Under these contracts, the energy can be sold as either "firm" or "as-available," depending on the characteristics of the output of the facility. When the output is continuous, except for occasional shutdowns for maintenance and repair, the utility also makes payments for the dependable capacity. These contract and payment options are outlined in Rules 25-17.0825 and 25-17.0832, F.A.C.

Standard Offer Contracts

Standard offer contracts are pre-approved contracts for the purchase of firm capacity and energy from any renewable generating facility or small QF. Rule 25-17.230, F.A.C., requires each investor-owned electric utility to establish a standard offer contract for each fossil-fueled generating unit type identified in the utility's TYSP. The renewable energy generator is allowed to select from a number of payment options that best fits its financing requirements as long as the total cumulative present value of such payments does not exceed full avoided cost, and adequate security for front-end loaded payments is provided. For example, the Commission rules allow for levelized payments over the life of the contract which may include both capacity and energy costs.

Negotiated Contracts

Renewable generating facilities are encouraged to negotiate purchased power contracts with IOUs pursuant to Rule 25-17.240, F.A.C. Payments made to a qualified renewable generator under a negotiated contract may be recovered from ratepayers by the purchasing utility as long as the cumulative present value of the payments does not exceed the utility's full avoided cost and adequate security for front-end loaded payments is provided.

Renewable Payment Types

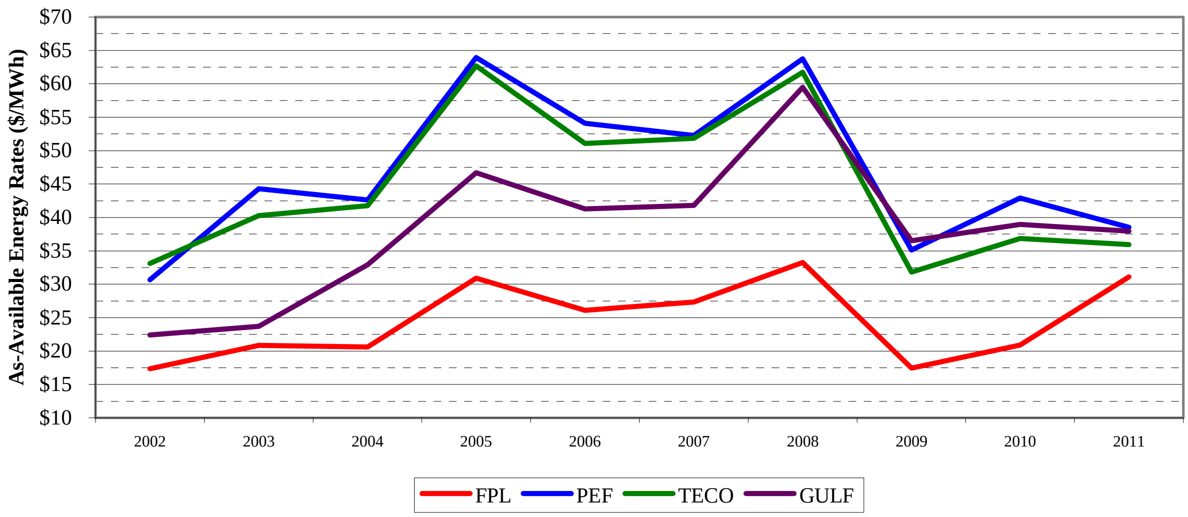
Pursuant to current state and federal law, payments made by utilities to generation facilities using renewable energy sources are capped at the utility's avoided cost for capacity and energy.

Firm capacity payments: Firm capacity is capacity (MW) produced and sold by a renewable energy generator pursuant to a standard offer contract or a negotiated contract subject to contractual commitments as to the quantity, time, and reliability of delivery. Firm capacity is purchased at a rate specified in a contract which is equal to the utility's avoided capacity cost or at a negotiated rate which may not exceed the utility's avoided capacity cost. Full avoided cost is calculated by determining the cumulative present value of a year-by-year value of deferring each avoided unit over the term of the contract.

Firm energy payments: Firm energy is energy (kWh) produced and sold by a renewable energy generator pursuant to a negotiated contract or a standard offer contract subject to contractual commitments as to the quantity, time, and reliability of delivery. Generally, the rate of payment for firm energy, in cents per kWh, is the lesser of the fuel cost associated with the avoided unit or the utility system's incremental fuel cost.

As-available energy payments: As-available energy is energy (kWh) produced and sold by a renewable energy generator on an hour-by-hour basis for which contractual commitments as to the quantity, time, or reliability of delivery are not required. As-available energy is purchased at a rate in cents per kilowatt hour (kWh) equal to the utility's hourly incremental system fuel cost, which reflects the highest fuel cost of generation dispatched each hour. No capacity payments are made for as-available energy because no reliability benefits are received. Figure 14 below illustrates historic as-available energy payments from the investor-owned TYSP utilities for the period 2002 through 2011. When natural gas prices spiked in 2008, averaging $10/MMBtu, as-available energy rates rose as well. As natural gas prices have declined since 2008, as-available energy rates have also decreased.

Figure 14. Investor Owned Utilities: Average Annual As-Available Energy Rates



Source: Responses to Staff Data Requests

Renewable Resource Outlook

In 2003, the Commission, in consultation with the DEP, completed the 2003 Renewable Energy Assessment Report to identify renewable energy viability in Florida. According to the report, the most feasible sources of renewable energy in Florida are from biomass materials, such as agricultural waste products or wood residues, and industrial waste heat. The 2003 report also stressed that technical feasibility does not ensure economic cost-effectiveness when determining energy resource production.

The Commission, in conjunction with the U.S. Department of Energy and the Lawrence Berkeley National Laboratory, retained Navigant Consulting, Inc. to prepare a detailed assessment of Florida's renewable potential. The 2008 Navigant Consulting Renewable Energy Potential Assessment (the 2008 Navigant Consulting Report) reported on the existing renewable conditions and the projected potential for renewable development in Florida through 2020, compared cost-effective differences, and considered the potential levels of economic impact future renewables may have. The 2008 Navigant Consulting Report substantiated the Commission's 2003 assessment by observing that the majority of Florida's existing renewables consist of solid biomass plants and municipal solid waste facilities. Although the 2008 Navigant Consulting Report considered solar technologies to have the largest technical potential of any renewable resource in Florida, only a portion of this potential can actually be economically achieved at this time.

The 2008 Navigant Consulting Report described the comparison of the technical or physical potential versus the achievable potential for renewable energy development in Florida. For example, although the technical potential for solar power in Florida may be relatively high according to Navigant Consulting, cost-effectiveness and siting issues significantly reduce the achievable potential to commercially develop solar energy technology. The driving forces to the expansion and sustainability of the renewable market depend on the overall value of renewable energy, a basis that is determined by the financial environment as well as government regulation and support. As noted in the 2008 Navigant Consulting Report, a favorable scenario for the renewable market which has meaningful growth in Florida assumed the following:

1. High fossil fuel costs
2. Access to low cost capital and debt rates
3. Continual government rebate programs and tax incentives
4. Established pricing of CO_2 emissions
5. Formation of a Renewable Energy Certificate (REC) market

Since the 2008 Navigant Consulting Report was completed, economic and policy conditions have not been favorable for future renewable development. Specifically, Navigant Consulting assumed in their 2008 natural gas costs to be $11-$14/MMBtu in the favorable scenario. Natural gas is currently trading at approximately $2.95/MMBtu. Most forecasts project natural gas prices to gradually increase over the long term.

In the favorable scenario, Navigant assumed the estimated cost of debt to be approximately 6.5 percent, the cost of equity approximately 10 percent, and ready access to debt would make up 70 percent of renewable project financing. Currently credit markets are still tight for small businesses, and obtaining financing for renewable energy projects will be much more difficult for a smaller company than for a large utility.

In the favorable scenario, Navigant Consulting estimated that Florida's solar rebate program would expire in 2020, with a $10 million annual funding level. The Florida Energy and Climate Commission was authorized to provide $25.4 million in rebates for solar energy equipment between 2006 and 2009. Currently the authorized budget has been depleted. Also, the favorable scenario for carbon pricing assumes $2/ton initially, then scaling to $50/ton by 2020. Currently, there is no federal or state policy establishing carbon pricing. The favorable scenario also envisioned the creation of a Renewable Energy Credit (REC) market, with REC prices of approximately $18/MWh initially, decreasing to $11/MWh by 2020. At this time, no Renewable Energy Credit market has been established in Florida.

Table 6 below compares selected assumptions included in Navigant's favorable scenario and current market conditions. As detailed in the table, most current market conditions are not aligned with Navigant's favorable scenario for renewable generation development.

Table 6. State of Florida: Market Outlook for Renewable Energy

Market Area	2008 Navigant Consulting Report Favorable Scenario	Current Market Conditions
Natural Gas Prices ($/MMBTU)	$11 - $14	$3 - $4
Access to Capital & Debt	Available at Low Cost	Credit Markets Tight
Florida Solar Rebate Program	Expires in 2020, $10M/year	No Funds Allocated
CO2 Emissions Pricing ($/ton)	$2 (2009) to $50 (2020)	No pricing established
Renewable Energy Certificates ($/MWh)	$18 (2009) to $11 (2020)	No REC Market established

Source: 2008 Navigant Consulting Report, Responses to Staff Data Requests

Existing Renewable Resources

Currently, renewable energy facilities provide approximately 1,400 MW of gross electric generation capacity as reported by the FRCC. Compared to figures in the 2011 Ten-Year Site Plan Review, existing renewable generation facilities have increased by approximately 120 MW, or 9 percent. Table 7 summarizes Florida's existing renewable resources.

Table 7. State of Florida: Existing Renewable Generation Capacity

Renewable Type	Capacity (MW)
Solar	143.3
Wind	0.0
Biomass	401.5
Municipal Solid Waste	453.7
Waste Heat	297.1
Landfill Gas	58.4
Hydro	55.7
Total	**1,400**

Sources: FRCC 2012 Load and Resource Plan, Responses to Staff Data Requests

Firm Capacity Contracts

Roughly 28 percent of all renewable capacity in Florida is from renewable generators with firm capacity contracts, which are required to provide a particular amount of capacity for a specified period of time pursuant to contractual obligations. Approximately 78 percent of this renewable capacity consists of municipal solid waste (MSW) facilities. Although the majority of firm capacity is purchased by investor-owned utilities, a significant portion (137.8 MW) is purchased by Seminole Electric Company (SEC).

Table 8 lists the existing renewable generators that provide firm capacity. Significant changes in the firm contracts since 2011 include rerates from FPL's Palm Beach County Facility, SEC's Lee County Resource Recovery Facility, and a new contract agreement for firm energy between McKay Bay Waste to Energy Facility with SEC.

Table 8. State of Florida: Firm Renewable Resources

Purchasing Utility	Facility Name	Fuel Type	Gross Capacity* (MW)	Commercial In-Service Date
Investor-Owned Utilities				
FPL	(Wheelabrator) Broward-South	MSW	68	1987
FPL	(Wheelabrator) Broward-North	MSW	62	1992
FPL	Solid Waste Authority of Palm Beach	MSW	40	2005
PEF	Pinellas County Resource Recovery	MSW	61.7	1983
PEF	Lake County Resource Recovery	MSW	14.8	1990
PEF	Dade County Resource Recovery	MSW	43	1991
PEF	Pasco County Resource Recovery	MSW	26	1991
PEF	Ridge Generating Station	WDS	39.6	1994
	Subtotal of IOUs		**227.7**	
Municipal Utilities				
GRU	G2 Energy	LFG	4	2008
GRU	Solar FIT Program/Net Meter	SUN	26.8	2009
JEA	Trailridge	LFG	9	2008
	Subtotal of Municipals		**22.3**	
Cooperative Utilities				
SEC	Lee County Resource Recovery	MSW	50	1999
SEC	Telogia Power, LLC	WDS	13	2004
SEC	Seminole Landfill	LFG	6.2	2007
SEC	Brevard Energy	LFG	9	2008
SEC	Timberline Energy	LFG	1.6	2008
SEC	Hillsborough Waste to Energy	MSW	42.6	2010
SEC	McKay Bay Waste to Energy	MSW	22	2011
	Subtotal of Cooperatives		**137.8**	
	Total		**387.8**	

*The capacity listed here represents the gross capacity of the unit, which may be in excess of the contracted firm capacity of the generating unit.
Sources: FRCC 2012 Load and Resource Plan, Responses to Staff Data Requests

Non-Firm Renewable Energy Generators

In addition to the 387.8 MW of firm capacity described in Table 8 above, renewable energy facilities with a total capacity of 680.7 MW produce energy for sale to utilities on an as-available basis. Energy purchased on an as-available basis is considered non-firm capacity, and therefore cannot be counted on by Florida's utilities for reliability purposes. The energy produced by these providers, however, does contribute to the avoidance of burning fossil fuels in existing generators. Table 9 details the various non-firm energy contracts.

Table 9. State of Florida: Non-Firm Renewable Resources

Purchasing Utility	Facility Name	Fuel Type	Gross Capacity (MW)	Commercial In-Service Date
Investor-Owned Utilities				
FPL	New Hope / Okeelanta	AB	130	1991
FPL	Georgia Pacific	WDS	56.8	1995
FPL	Tomoka Farms	LFG	3.8	1998
FPL	MMA FLA LP	SUN	0.3	2007
FPL	WM Renewable Energy	LFG	8	2010
PEF	Potash Of Saskatchewan	WH	44.2	1986
PEF	Buckeye	WDS	52.3	1993
PEF	G2	LFG	3.5	2008
TECO	Mosaic: South Pierce	WH	30	1969
TECO	Mosaic: New Wales	WH	79	1984
TECO	CF Industries	WH	34.9	1988
TECO	City Of Tampa Sewage	OBG	1.5	1989
TECO	Mosaic: Ridgewood	WH	62	1992
TECO	Mosaic: Millpoint	WH	47	1995
GULF	Stone Container	AB	25	1960
GULF	International Paper Company	WDS	56	1983
GULF	Bay County Solid Waste	MSW	13.6	2008
	Subtotal of IOUs		**647.9**	
Municipal Utilities				
FMPA	US Sugar Corporation	AB	26.5	1984
LAK	Lakeland Center (Solar)	SUN	0.3	2010
OUC	Regenesis Stanton Energy Center	SUN	6	2011
	Subtotal of Municipals		**32.8**	
	Total		**680.7**	

Sources: FRCC 2012 Load and Resource Plan, Responses to Staff Data Requests

Utility-Owned Renewable Facilities

Several utilities also own renewable facilities, primarily solar generation, landfill gas, and hydroelectric technologies. Table 10 lists some of the larger utility-owned resources, which consist mostly of non-firm or intermittent resources.

Table 10. State of Florida: Utility Owned Renewable Generation

Purchasing Utility	Facility Name	Fuel Type	Gross Capacity (MW)	Commercial In-Service Date
Investor-Owned Utilities				
FPL	DeSoto	SUN	25	2009
FPL	Martin	SUN	75	2010
FPL	Space Coast Next Generation	SUN	10	2010
GULF	Perdido 1	LFG	1.8	2010
GULF	Perdido 2	LFG	1.8	2010
	Subtotal of IOUs		**113.6**	
Municipal Utilities				
JEA	North Landfill	LFG	1.5	1997
JEA	Girvin Landfill	LFG	1.2	1999
JEA	Buckman	OBG	0.8	2003
OUC	Co-Fired Stanton Energy Center	LFG	7	1998
TAL	Corn Hydro	WAT	12.2	1985
	Subtotal of Municipals		**22.7**	
Other Utilities				
UCEM	Jim Woodruff	WAT	43.5	1957
	Subtotal of Other		**43.5**	
	Total		**179.8**	

Sources: FRCC 2012 Load and Resource Plan, Responses to Staff Data Requests

Because most of the energy produced is non-firm, the majority of these renewable facilities serve more to reduce fossil fuel consumption than to provide system capacity. Among some of the recent notable additions to utility-owned renewables are the construction and operation of three solar generators by FPL in 2009 and 2010. The DeSoto, Martin, and Space Coast facilities are currently the largest solar facilities in Florida.[7] Also in 2010, GULF commissioned two landfill gas generation facilities, Perdido 1 and 2, to provide that utility with a total renewable gross capacity of 3.6 MW.

Existing Net Metering

Net metering is an arrangement between a utility and a customer with renewable generation capability whereby the customer's energy usage is offset, or credited, by the amount of energy generated. The customer will be billed for any net energy consumed that exceeds the energy generated.

In April 2008, the Commission amended Rule 25-6.065, F.A.C., on interconnection and net metering for customer-owned renewable generation. The rule requires the IOUs to offer net metering for all types of renewable generation up to 2 MW in capacity and a standard interconnection agreement with an expedited interconnection process. Customers benefit from

[7] The DeSoto and Space Coast facilities are direct energy-producing photovoltaic facilities, whereas the Martin facility uses thermal heat to create replacement steam for a pre-existing steam turbine usually supplied through fossil fuel generation.

such renewable systems by reducing their energy purchases from the utility and potentially selling excess energy to the utility.

The Commission's rule requires all electric utilities to annually report data associated with interconnection and net metering programs. Data submitted in April 2010 show that the number of customers owning renewable generation systems in Florida continues to grow. Statewide, a total of 29.3 MW of solar photovoltaic (PV) capacity from 3,994 systems have been installed, up from 2.8 MW produced by 537 systems in 2008. Table 11 displays the information on customer-owned renewable generation for 2011 reported by Florida's utilities.

Table 11. State of Florida: Customer Owned Renewable Generation

Utility Type	Connections	Non-Firm Capacity (MW)
Investor-Owned	2,826	20.4
Municipal	615	5.0
Rural Electric Cooperatives	553	3.9
Total	**3,994**	**29.3**

Sources: 2012 Interconnection and Net Metering of Customer-Owned Generation Report

Planned Renewables Additions

Florida's utilities plan to construct or purchase an additional 957 MW of renewable generation over the ten-year planning period. The expected major contributors to actual energy generation are planned biomass resources. Table 12 summarizes the overall proposed planned increases by generation type of all utilities. The largest source of planned renewable generation comes in the form of non-firm solar capacity built by a single vendor, National Solar. The company has as-available energy contracts with PEF, and as they have no capacity portion, are not considered for reliability purposes.

Table 12. State of Florida: Planned Renewable Resource Net Additions

Fuel Type	Capacity (MW)
Solar	**553.4**
Wind	**0**
Biomass	**321**
Municipal Solid Waste	**70**
Waste Heat	**0**
Landfill Gas	**13**
Hydro	**0**
Total	**957.4**

Sources: FRCC 2012 Load and Resource Plan, Responses to Staff Data Requests

As of January 2012, firm capacity contracts represent 39 percent of total planned renewable additions. Table 13 and Table 14, provide detailed lists of the renewable resources planned for construction in Florida over the ten-year planning horizon. Table 13 shows that, of the renewable firm capacity planned over the ten-year horizon, the majority is woody biomass that will be purchased by PEF and GRU.

Table 13. State of Florida: Planned Firm Renewable Resources

Purchasing Utility	Facility Name	Fuel Type	Gross Capacity* (MW)	Commercial In-Service Date
Investor-Owned Utilities				
PEF	FB Energy	AB	60	2013
PEF	Trans World Energy	WDS	40	2013
PEF	US EcoGen	WDS	60	2014
FPL	Solid Waste Authority of Palm Beach	MSW	70	2016
	Subtotal of IOUs		**230**	
Municipal Utilities				
JEA	Trailridge	LFG	9	2012
OUC	Port Charlotte	LFG	4	2012
OUC	Harmony	WDS	5	2012
GRU	American Renewables LLC	WDS	116	2013
GRU	Solar FIT Program	SUN	9.3	2021
	Subtotal of Municipals		**143.3**	
	Total		**373.3**	

Sources: FRCC 2012 Load and Resource Plan, Responses to Staff Data Requests

Table 14 shows that most of the non-firm capacity planned in Florida will be purchased by PEF, primarily from National Solar, discussed above.

Table 14. State of Florida: Planned Non-Firm Renewable Resources

Purchasing Utility	Facility Name	Fuel Type	Capacity (MW)	Commercial In-Service Date
Investor-Owned Utilities				
FPL	INEOS Bio	AB	2	2011
PEF	Eliho	WDS	8	2011
PEF	E2E2	WDS	30	2012
PEF	Blue Chip Energy #1	SUN	50	2013
PEF	National Solar #5-10	SUN	450	2021
All IOUs	Solar Installations (Aggregate)	SUN	0.1	2021
	Subtotal of IOUs		**540.1**	
Municipal Utilities				
OUC	CNL/City Hall	SUN	0.4	2012
OUC	GSLD Solar	SUN	0.8	2012
TAL	SDA	SUN	2	2012
TAL	SolarSink	SUN	0.5	2012
TAL	SunnyLand Solar	SUN	1	2012
LAK	Regenesis Power	SUN	15	2016
LAK	SunEdision	SUN	24	2017
All Munis	Solar Installations (Aggregate)	SUN	0.2	2021
	Subtotal of Municipals		**43.9**	
	Total		**584**	

Sources: FRCC 2012 Load and Resource Plan, Responses to Staff Data Requests

Updated Navigant Consulting Report

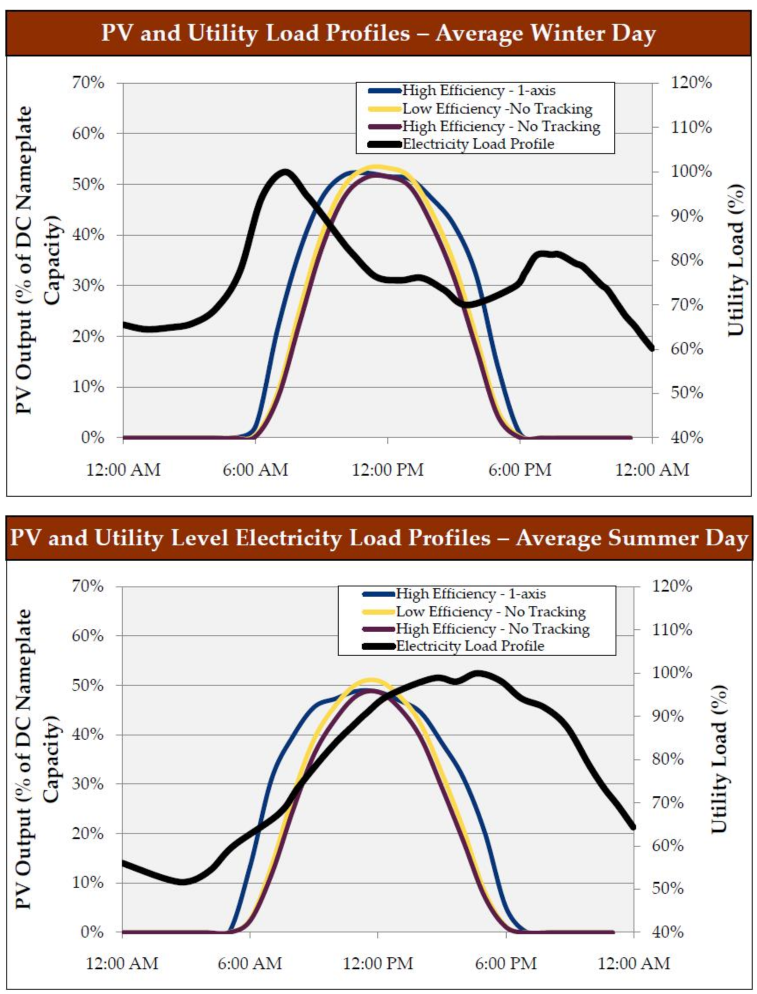
The Commission contracted with Navigant Consulting in early 2010 to update its 2008 analysis with current conditions. In June 2010, Navigant Consulting released new comparisons of cost estimates for different renewable generating facilities. Navigant Consulting also provided additional detail pertaining to Florida's renewable resource which it identified as having the most technical potential for growth, solar PV facilities. Findings from the report are summarized below.

In the 2010 Navigant Consulting Report Update, the most meaningful findings include changes in prices of renewable technologies. PV module prices have fallen and commodity costs for PV units have decreased during the recession, but both are returning to near their pre-recession levels. Wind power prices have also decreased due to the recession, while utility turbine prices have risen as worldwide demand catches up with supply. According to the 2010 Navigant Consulting Report Update, no large performance breakthroughs occurred for any technology. Because Navigant Consulting found solar resources to hold the most potential in Florida, the remainder of the 2010 Navigant Consulting Report Update focuses on solar power.

The 2010 Navigant Consulting Report Update estimates that solar power systems have increased in efficiency while overall prices have decreased up to 40 percent since 2008. In spite of these changes, solar power systems continue to have some of the highest capital costs per kW of any renewable generating system. Varying the methods of using solar energy involving solar tracking technology and alternating solar film receptors produces a slight range of energy output and net capacity factors. In addition, the ability of solar PV systems to provide energy are limited to daytime hours. Supplemental battery storage units may alleviate this issue, but the costs of batteries are not included in Navigant Consulting's estimates.

Even with these advancements, capacity factors of solar panels are projected to remain below 25 percent. Such results indicate that solar PV facilities operate more like a conventional peaking unit and will not replace the need for base-load generating facilities. However, Navigant Consulting also reported that operating characteristics for these systems do not correlate with daily peak load hours. As shown in Figure 15, Navigant Consulting estimates that the peak output from solar PV facilities reaches a maximum of approximately 50 percent of the rated capacity, and occurs after the system's winter peak hour and before the system's summer peak hour. As a result, a solar PV facility's ability to provide reliability benefits appears limited.

Figure 15. Solar PV Output and Utility Seasonal Load Profiles



Sources: 2010 Navigant Consulting Report Update

Current demand and energy forecasts continue to indicate that in spite of increased levels of conservation, energy efficiency, and renewable generation, the need for traditional generating capacity still exists. While reductions in demand have been significant, the total demand for electricity and the per-capita consumption is expected to increase, making the addition of traditional generating units necessary to satisfy reliability requirements and provide sufficient electric energy to Florida's consumers. Because any capacity addition has certain economic impacts based on the capital required for the project, and due to increasing environmental concerns relating to solid fuel-fired generating units, Florida's utilities must carefully weigh the factors involved in selecting a supply-side resource for future traditional generation projects.

In addition to traditional economic analyses, utilities also consider several strategic factors, such as fuel availability, generation mix, and environmental compliance prior to selecting a new supply-side resource. Limited supplies, access to water or rail delivery points, pipeline capacity, water supply and consumption, land area limitations, cost of environmental controls, and fluctuating fuel costs are all important considerations.

Gas fired units have almost exclusively been selected in recent years due to higher thermal efficiencies, lower capital costs, short periods for permitting and construction, and sometimes the smaller land areas required. With the recent decrease in fuel prices due to unconventional natural gas production using hydraulic fracturing, natural gas is the favored fuel for all traditional generating units with the exception of new nuclear units.

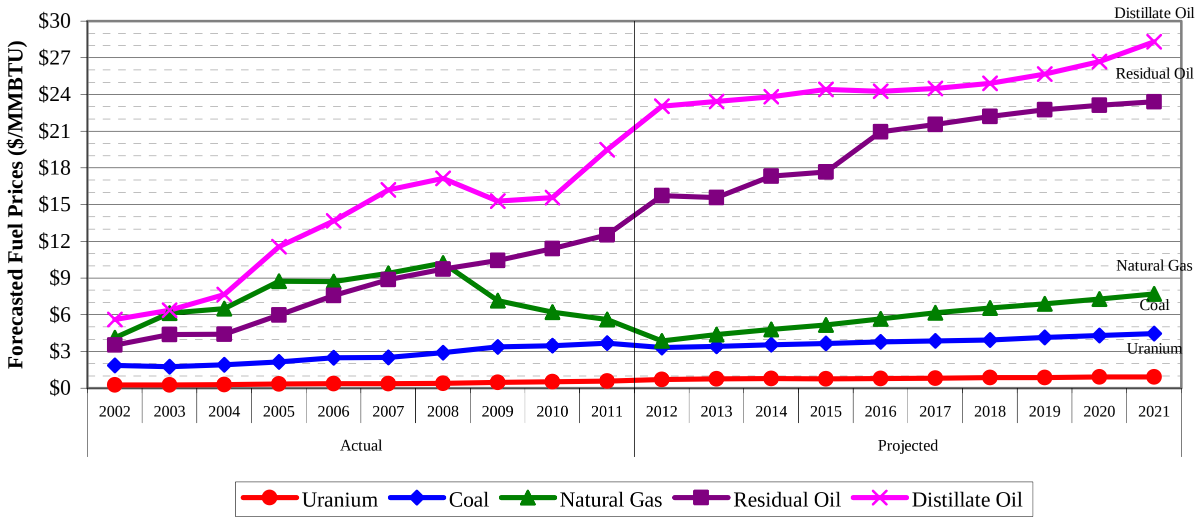
In the last ten years, almost 97 percent of all capacity additions to Florida's electric system use natural gas as the primary fuel. Coal units that were planned have been cancelled, and new nuclear units that have been approved have been delayed beyond the planning horizon. Currently, other than approximately 950 MW of renewable generation and 600 MW in uprates for existing nuclear units, all of the additional generation planned for the next ten years will use natural gas as a fuel source.

Fuel Price Forecasts

Fuel price forecast is the primary factor affecting the type of generating unit added by an electric utility. In general, the capital cost of a generating unit is inversely proportional to the cost of the fuel used to generate electricity from that unit. Historically, when the forecasted price difference between coal or nuclear and natural gas was small, the addition of a natural gas unit became the more attractive option. As the fuel price gap widened, a coal-fired or nuclear unit would normally be the more likely choice.

From 2003 to 2005, the price of natural gas was substantially higher than utilities had forecasted. This disparity led to concern regarding escalating customer bills and an expectation that natural gas prices would continue to be high and extremely volatile. As a result, Florida's utilities began making plans to build coal-fired units rather than continuing to increase the reliance on natural gas. However, as Figure 16 shows, the price of natural gas began to return to more historic levels after peaking in 2008, and has declined in the years since. Forecasts predict that gas prices will increase at a steady level throughout the planning horizon.

Figure 16. TYSP Utilities: Historic & Projected Weighted Average Fuel Prices ($/MMBtu)



Source: Responses to Staff Data Request

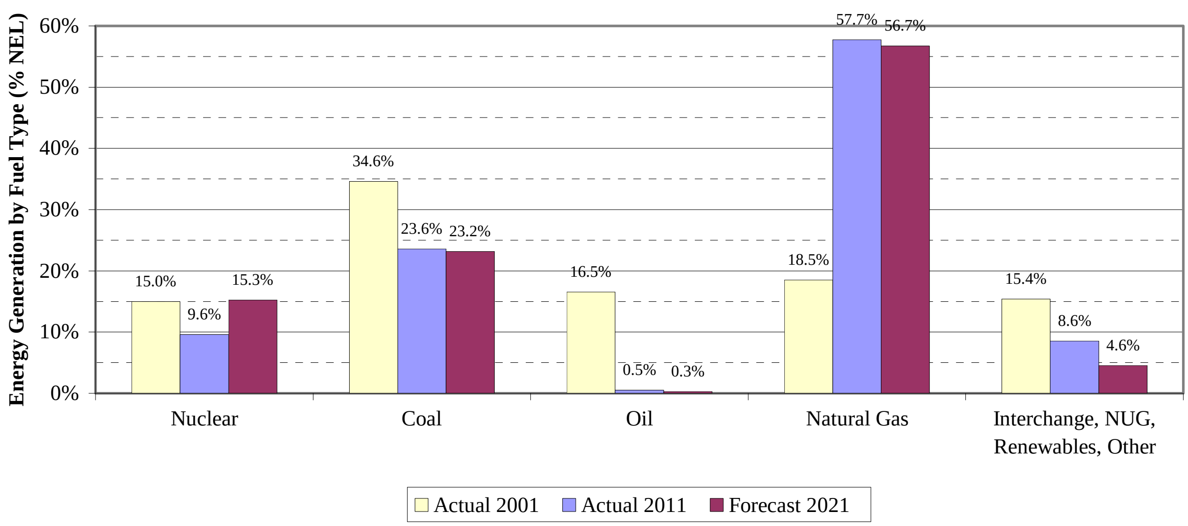
Previous TYSP reviews indicated that increases in gas prices may bring an end to the almost exclusive addition of natural gas-fired generation. As can be seen from Figure 16, the expectation of high prices for natural gas has not materialized and although it is forecasted to increase steadily, the rate of increase is more moderate than was previously contemplated.

Utility plans for a balanced fuel system have historically been highly dependent upon the accuracy of long-term fuel price forecasts, mostly due to the long lead times required for coal and especially nuclear generators. However, in recent years the options available to utilities for the addition of supply-side generation have been limited, and this situation seems unlikely to change at this time. Utilities will be faced with selecting technologies for new generation that will either continue to increase the already very high percentage of natural gas resources, or attempting to obtain approval for solid fuel resources that may have a negative near term rate impact.

Fuel Diversity

Natural gas has risen to become one of the dominant fuels in the state in the last ten years, displacing coal, and in 2011 generated more net energy for load than any two fuels combined in Florida. As Figure 17 shows, natural gas now makes up greater than 57.7 percent of electric energy consumed in Florida. Natural gas usage is anticipated to peak in 2012 at 62.4 percent, and then decline slightly to 56.7 percent by 2021.

Figure 17. State of Florida: Net Energy for Load by Fuel Type



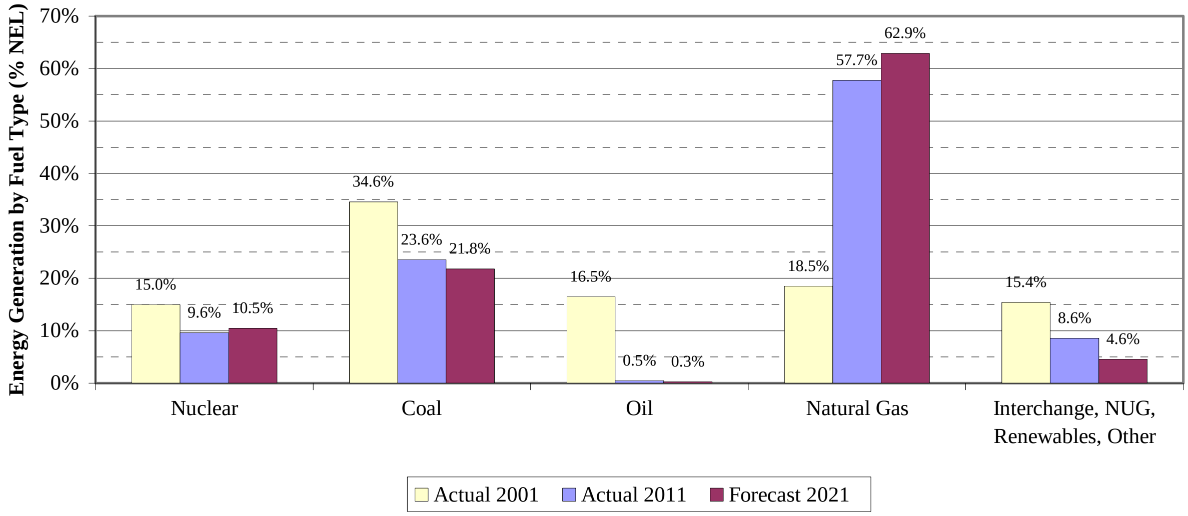
Source: FRCC 2002 and 2012 Load and Resource Plans

The anticipated decline in natural gas consumption by the end of the planning period is the result of increased nuclear generation and relatively stable contribution to NEL from coal-fired generation. Nuclear generation may decline from that projected in the FRCC 2012 Load and Resource Plan, primarily due to the delay of the Levy 1 nuclear unit, discussed below, and if the CR3 nuclear unit is retired instead of repaired. CR3 has been offline since 2009, following a delamination incident during a steam generator replacement project.

Coal generation, beyond the reduction in dispatch due to the cost-competitiveness of natural gas as a baseload fuel, faces challenges relating to new environmental compliance requirements. As discussed below, new EPA regulations will potentially require installation of new environmental controls, which could lead to the retirement of units if it is deemed uneconomic to upgrade its emission control equipment. During the 2012 TYSP Workshop, four coal units, PEF's Crystal River 1 & 2, and GULF's Lansing Smith 1 & 2, were identified by the Sierra Club/Earthjustice as potential units to consider retirement, though at this time all four are scheduled to remain in-service throughout the planning period.

If the projected generation associated with the nuclear and coal units discussed above is displaced by natural gas, it would have the net effect of increasing natural gas' share of state electric generation to 62.9 percent by 2021, as shown in Figure 18 below.

Figure 18. State of Florida: Net Energy for Load by Fuel Type After Generation Displacement



Source: FRCC 2002 and 2012 Load and Resource Plans, Utilities 2012 TYSPs, Responses to Staff Data Requests.

Because a balanced fuel supply can enhance system reliability and mitigate the effects of volatile fuel price fluctuations, it is important that utilities have the greatest possible level of flexibility in their generation fuel source mix. Although the Commission has cited the growing lack of fuel diversity within the State of Florida as a major strategic concern for the past several years, natural gas is anticipated to remain the dominant fuel over the planning horizon. Excluding renewables, all new generation facilities planned within the State of Florida over the ten-year period are natural gas-fired units.

Opportunities for Unit Modernization

Florida's generating fleet consists of incremental new additions to the historic base fleet, with units retiring as they become uneconomical to operate or maintain. Currently Florida's existing capacity ranges greatly in age and fuel type, and legacy investments continue.

While some units must be retired upon reaching the end of their economic life and cannot be refurbished, others have the potential for modernization. The modernization of existing generating units allows for significant improvement in both performance and emissions, typically at a price lower than new construction. Modernization typically involves the conversion of a generating unit from less efficient fossil steam generation to combined cycle operation. For some power plant sites, modernization does not involve using any of the existing generator units themselves, but rather the generation site's existing facilities such as transmission or fuel handling for an entirely new unit. For some steam units, generation output can be improved by installing more advanced equipment, such as the nuclear uprates discussed below. Other modernizations allow for changes in fuel type, or increased ability to use alternate fuels. Due to low natural gas price forecasts, the ability to run a unit on higher quantities of natural gas instead of fuel oil may be an economically viable option, even for an older generating unit.

Since the existing unit must be removed from service for a period of time, a utility's reliability is affected during the conversion process. As a result, scheduling modernizations during periods of temporary excess capacity is more desirable. With the forecasted decline in load, several of Florida's utilities may have sufficient reserve margins to allow some of their smaller units to be converted, and the upcoming ten-year planning horizon appears to be an ideal window for completing these types of projects. Not all sites are candidates for modernization due to site layout and other concerns, and to minimize rate impacts, modernization of existing units should be investigated before considering new construction. Utilities should continue to explore potential conversion projects and report the feasibility and economic viability of each conversion in next year's TYSPs and before any need determination filing.

In response to a staff data request, the TYSP utilities identified the following facilities as potentially capable of conversion. Table 15 below summarizes their responses for conversion from fossil steam generation. Additional units were identified for conversion from simple cycle combustion turbines to combined cycle units.

Table 15. State of Florida: Potential Steam Units for Modernization

Utility	Generating Unit Name	Fuel Type	Summer Capacity (MW)	Original In-Service Date	Modernization Type
FPL	Manatee Units 1 & 2	Oil / NG	1624	1976 - 1977	CC
FPL	Martin Units 1 & 2	Oil / NG	1652	1980 - 1981	CC
FPL	Sanford Unit 3	Oil / NG	138	1959	CC
FPL	Turkey Point Units 1 & 2	Oil / NG	788	1967 - 1968	CC
FPL	Cutler Unit 5 & 6	NG	205	1954 - 1955	CC
PEF	Anclote Units 1 & 2	NG / Oil	1011	1974 - 1978	CC
PEF	Suwannee River Units 1 - 3	NG / Oil	129	1953 - 1956	CC/RF
PEF	Crystal River Units 1 & 2	Coal	873	1966 - 1969	CC/IGCC
PEF	Crystal River Units 4 & 5	Coal	1422	1982 - 1984	CC/IGCC
GULF	Crist Units 4 & 5	Coal	150	1959 - 1961	Natural Gas
GULF	Scholz Units 1 & 2	Coal	92	1953	Biomass
JEA	SJRPP Units 1 & 2	Coal / Petcoke	626	1987 - 1988	CC
JEA	Northside Unit 3	NG / Oil	524	1977	CC

Source: Responses to Staff Data Request

The Commission has previously granted determinations of need for three conversions from fossil steam to combined cycle units. The approved conversions, located at FPL's Cape Canaveral, Riviera, and Port Everglades sites, represent a significant increase in generating capacity while reusing the plant site and reducing fuel usage and emissions. PEF has also recently conducted a conversion of its Bartow plant from fossil steam to a combined cycle unit. This conversion did not require a PPSA determination of need.

Impact of EPA Regulations

In addition to maintaining a fuel efficient and diverse fleet, Florida's utilities must also comply with changing environmental requirements. Within the past several years, the EPA has finalized or proposed several rules which will impact both existing and planned units within the state. Potential environmental requirements and their associated costs must be considered to fully evaluate any new supply-side resources, as well as the maintenance and dispatch of existing generating units.

While at this time no units are anticipated to be retired as a result of any of these regulations, they do represent an increase cost of operations. Each utility should evaluate whether these additional costs or limitations allow the continued economic operation of each impacted unit, and whether installation of emissions control equipment, fuel switching, or retirement is the proper course of action to maintain the lowest cost to customers and meet environmental requirements. Several of the TYSP utilities have provided preliminary estimates based upon known and proposed rule language, and are shown in Table 16 below.

Table 16. TYSP Utilities: Preliminary Estimates of EPA Rule Compliance Cost

Utility	Preliminary Total Cost Estimates* ($ Millions)
Florida Power & Light	$348 - $1,741
Progress Energy Florida	$165 - $1,330
Tampa Electric Company	$763
Gulf Power Company	$1,270 - $2,737
Florida Municipal Power Agency	$39
Gainesville Regional Utilities	Not Available
JEA	Not Available
Lakeland Electric	Not Available
Orlando Utilities Commission	$157
Seminole Electric Cooperative	Not Available
City of Tallahassee	$5
Total of All Utilities	**$2,747 - $6,772**

* These estimates are not final, and may not include all rules.
Source: Responses to Staff Data Request

Table 17 is a partial listing of notable units and their anticipated unit costs for compliance. At this time, several of the proposed EPA Rules are the subject of litigation, or have not yet produced a final rule. More precise data associated with compliance costs for all units is anticipated in future filings by the utilities once rules are finalized and environmental compliance methods are determined.

Table 17. TYSP Utilities: Preliminary Estimates of EPA Rule Compliance Costs by Unit

Primary Owner	Facility Name	Fuel	Net Summer Capacity	EPA Rule Impact ($ Million)				
				MATS[8]	CSPAR[9]	CWIS[10]	CCR[11]	Total
PEF	Anclote 1&2	Oil	1011	80	-	15-130	-	95-210
PEF	Bartow 4	NG	1,133	-	-	10-170	-	10-170
PEF	Crystal River 1&2	Coal	873	TBD	-	45-780	TBD	45-780
PEF	Crystal River 4&5	Coal	1422	5-50	-	2-5	TBD	7-55
PEF	Suwannee 1-3	Oil	129	-	-	5-75	-	5-75
TECO	Big Bend 1-4	Coal	1552	10	-	400	3-6	413-416
TECO	Polk 1	Coal	220	-	-	-	1-2.5	1-2.5
TECO	Bayside 1&2	NG	1,630	-	-	400	-	400
GULF	Daniel 1-2	Coal	510	310-617		1-2	110-210	421-829
GULF	Crist 4-5	Coal	150	40-305		26-47	170-450	236-802
GULF	Crist 6-7	Coal	756					
GULF	Smith 1-2	Coal	357	60-288		1-65	30-260	91-613
GULF	Scholz 1-2	Coal	92	6-97		1-50	160-180	167-327
OUC	Stanton 1&2	Coal	886	2	118	-	13	133
Total Impact			**10,721**	**631-1,557**		**904-2,124**	**487-1,122**	**2,024-4,813**

Source: Responses to Staff Data Request

Power Plant Siting Act

The Florida PSC is given exclusive jurisdiction by the Legislature, through the PPSA, to be the forum for determining the need for new electric power plants. Any proposed steam or solar generating unit of at least 75 MW requires certification under the Power Plant Siting Act.

Approximately 7,200 MW of new generating units are planned to enter service over the next 10-year period, consisting solely of natural gas-fired combustion turbines and combined cycle units. A majority of this capacity has already received a determination of need from the Commission or is exempted from the statutory requirements of the PPSA. Only 2,418 MW still requires certification, as shown in Table 18. TECO has recently issued a Request for Proposals (RFP) for its planned unit, a combined cycle conversion of several existing simple cycle combustion turbines at the Polk Power Station, and filed for a need determination on September 12, 2012.

[8] Mercury and Air Toxics Standards (MATS) Rule.
[9] Cross-State Air Pollution Rule (CSAPR)
[10] Cooling Water Intake Structures (CWIS) Rule
[11] Coal Combustion Residuals (CCR) Rule.

Table 18. State of Florida: Projected Units Requiring Power Plant Siting Act Certification

Utility	Generating Unit Name	Summer Capacity (MW)	Certification Dates		In-Service Date
			Need Approved (Commission)	PPSA Certified	
FPL	St. Lucie Unit 1 Uprate	129	01/2008	09/2008	05/2012
FPL	Turkey Point Unit 3 Uprate	123	01/2008	10/2008	06/2012
FPL	St. Lucie Unit 2 Uprate	84	01/2008	09/2008	10/2012
FPL	Turkey Point Unit 4 Uprate	123	01/2008	10/2008	02/2013
FPL	Cape Canaveral	1,210	09/2008	10/2009	06/2013
FPL	Riviera Beach	1,212	09/2008	11/2009	06/2014
PEF	Crystal River Unit 3 Uprate	154	02/2007	08/2008	11/2014
FPL	Port Everglades	1,277	04/2012	02/2013*	06/2016
TECO	Polk 2-5 CC	1,063	-	-	01/2017
PEF	Unknown	767	-	-	06/2019
SEC	Unnamed CC1	196	-	-	12/2020
SEC	Unnamed CC2	196	-	-	12/2020
SEC	Unnamed CC3	196	-	-	12/2021

*Estimated Date for Siting Board Hearing on Site Certification.
Source: Utilities 2012 TYSPs

Nuclear

Nuclear capacity, while an alternative to natural gas-fired generation, is capital-intensive and requires a long lead time to construct. Florida's utilities project an expansion of nuclear power in the state through uprates at existing nuclear power plants, and the construction of four new nuclear units. FPL's and PEF's TYSPs anticipate approximately 600 MW of capacity to be added by uprates.

While PEF's 2012 TYSP originally projected the in-service date for Levy Unit 1 in 2021, PEF's filing in Docket No. 120009-EI indicates that it will be delayed until 2024. Table 19 below provides a summary of nuclear capacity additions planned in the State.

Table 19. State of Florida: Projected Nuclear Uprates & New Units

Utility	Generating Unit Name	Summer Capacity (MW)	In-Service Date
Existing Nuclear Unit Uprates			
FPL	St. Lucie Unit 1	129	05/2012
FPL	Turkey Point Unit 3	123	06/2012
FPL	St. Lucie Unit 2	84	10/2012
FPL	Turkey Point Unit 4	123	02/2013
PEF	Crystal River Unit 3	154	11/2014
New Nuclear Units			
FPL	Turkey Point 6	1100	06/2022
FPL	Turkey Point 7	1100	06/2023
PEF	Levy 1	1092	06/2024
PEF	Levy 2	1092	06/2025

Source: Utilities 2012 TYSPs, Utilities filings in Docket 120009-EI

Natural Gas

With the exception of the aforementioned renewable and nuclear capacity, all remaining new generation comes in the form of natural gas fired combustion turbines or combined cycle units. The 2012 TYSPs include approximately 7,200 MW of natural gas-fired generation.

A total of 1,571 MW of natural gas-fired combustion turbine capacity is expected to enter service by 2021. Because these units are not steam-fired capacity, they do not require siting under the PPSA. A list of all combustion turbine units entering service is included in Table 20.

Table 20. State of Florida: Projected New Combustion Turbines

Utility	Generating Unit Name	Summer Capacity (MW)	In-Service Date
SEC	Unnamed CT1	158	12/2018
TECO	Future CT 1	149	05/2019
SEC	Unnamed CT2	158	12/2019
SEC	Unnamed CT3	158	12/2020
SEC	Unnamed CT4	158	12/2020
SEC	Unnamed CT5	158	12/2020
SEC	Unnamed CT6	158	05/2021
SEC	Unnamed CT7	158	12/2021
SEC	Unnamed CT8	158	12/2021
SEC	Unnamed CT9	158	12/2021

Source: Utilities 2012 TYSPs

The remainder of the natural gas-fired additions come from combined cycle units, which currently represent the most abundant type of generating capacity in the State of Florida, making up approximately a third of installed capacity in 2012. As combined cycles utilize steam generated from the waste heat of combustion turbines, they fall under the PPSA when they have greater than 75 MW of steam capacity. Table 21 below includes all combined cycle units planned to enter service by 2021. With these new additions (6,117 MW in total), natural gas-fired combined cycles will represent approximately half of all generation within the state.

Table 21. State of Florida: Projected New Combined Cycle Units

Utility	Generating Unit Name	Summer Capacity (MW)	In-Service Date
FPL	Cape Canaveral	1,210	06/2013
FPL	Riviera Beach	1,212	06/2014
FPL	Port Everglades	1,277	06/2016
TECO	Polk 2-5 CC	1,063	01/2017
PEF	Unknown	767	06/2019
SEC	Unnamed CC1	196	12/2020
SEC	Unnamed CC2	196	12/2020
SEC	Unnamed CC3	196	12/2021

Source: Utilities 2012 TYSPs

Transmission Capacity

As generation capacities increase, the transmission system must grow accordingly to maintain the capability of delivering the energy to the end user. The Commission has been given broad authority pursuant to Chapter 366, F.S., to require reliability within Florida's coordinated electric grid and to ensure the planning, development, and maintenance of adequate generation, transmission, and distribution facilities within the state.

The Commission has authority over certain proposed transmission lines under the Transmission Line Siting Act (TLSA). To require certification under Florida's TLSA, a proposed transmission line must meet the following criteria: a nominal voltage rating of at least 230 kV, crossing a county line, and a length of at least 15 miles. Proposed lines in an existing corridor are also exempt from TLSA requirements. The Commission determines the reliability need for and the proposed starting and ending points for lines requiring TLSA certification. The Commission must issue a final order granting or denying a determination of need within 90 days of the petition filing. The proposed corridor route is determined by the DEP during the certification process. Much like the PPSA, the Governor and Cabinet sitting as the Siting Board ultimately must approve or deny the overall certification of the proposed line.

Table 22 below lists all proposed transmission lines in the 2012 TYSPs that require TLSA certification. The Polk-Aspen-FishHawk line is directly associated with the combined cycle conversion at the Polk Power Station, and is anticipated to be reviewed concurrently.

Table 22. State of Florida: Proposed Transmission Requiring Transmission Line Siting Act Certification

Utility	Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Certification Dates		Commercial In-Service Date
				Need Approved (Commission)	TLSA Certified	
PEF	Intercession City - Gifford	13	230	09/2007	01/2009	05/2013
FPL	Manatee – Bobwhite	30	230	08/2006	11/2008	12/2014
FPL	St Johns – Pringle	25	230	05/2005	04/2006	12/2016
TECO	Polk-Aspen-FishHawk	62.5	230	-	-	01/2017
Source: FRCC 2012 Load & Resource Plan, Utilities 2012 TYSPs						

Utility Perspectives

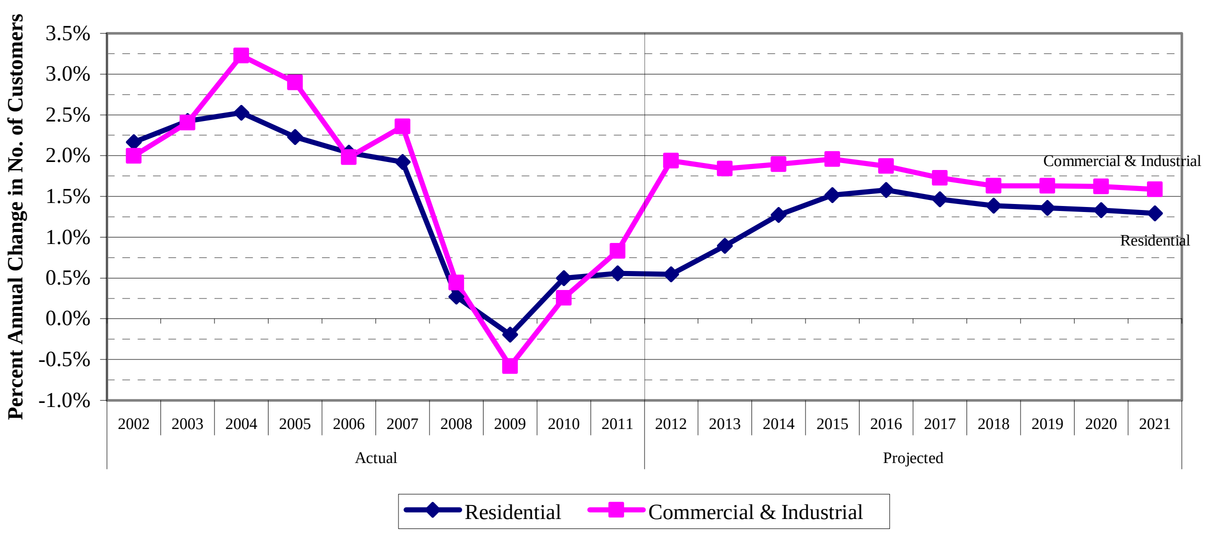
FPL is the state's largest electric utility. The utility's service territory is within the FRCC region, and is primarily in southern Florida and along the east coast. As FPL is an IOU, the Commission has regulatory authority over all aspects of operations, including rates and safety.

In 2011, FPL had an average of 4,547,051 customers, and had a total net energy for load of 103,327 GWh, approximately 47.3 percent of the NEL generated in the entire state last year.

Peak Demand and Energy Forecasts

FPL Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth for 2012 through 2021. Positive growth is anticipated over the entire planning period, with an average annual growth rate (AAGR) of 1.39 percent. This compares to the actual AAGR of 2.27 for the period 2002 through 2007.

FPL Figure 1: Annual Customer Growth Rate by Customer Class



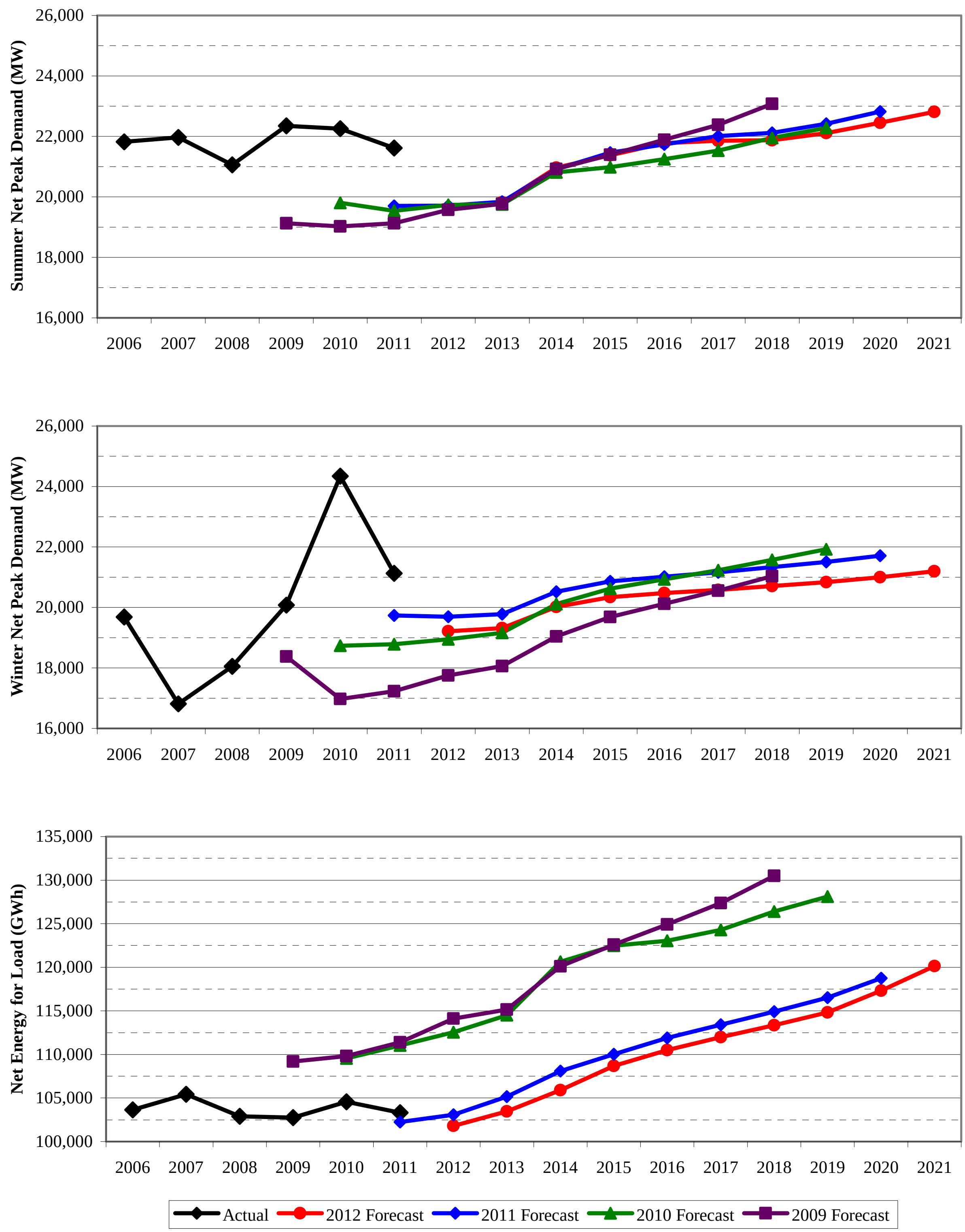
Source: FPL 2012 TYSP

The following three graphs in FPL Figure 2 show FPL's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is similar but slightly lower than the 2011 values for both seasons of peak demand and NEL.

Analysis of FPL's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that FPL's average forecast error is 12.12 percent. This value indicates that the company tends to over-forecast its retail energy sales by 12.12 percent, which is unfavorable when compared to the average forecast error for all eleven of the TYSP utilities, which was

11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

FPL Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

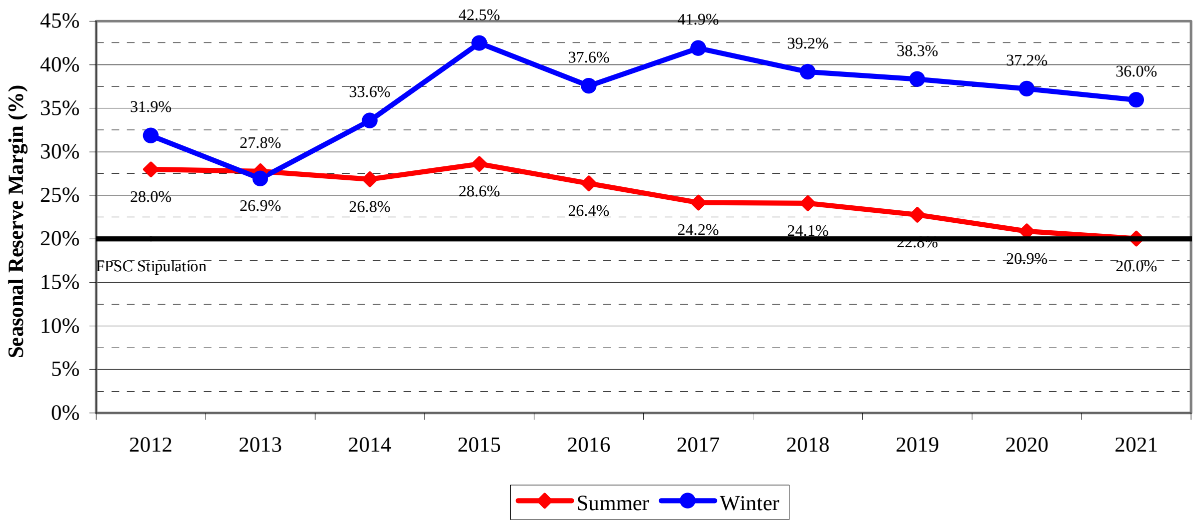


Source: FPL 2009 -2012 TYSPs

Reserve Margin Requirements

As mentioned in the Statewide Perspective, FPL maintains a minimum 20 percent reserve margin for planning purposes based on a stipulation approved by the Commission. FPL Figure 3 displays the projected reserve margin for FPL through the planning period for both seasonal peaks. As shown in the figure, summer peak demand would be the driving force for generation additions. The reserve margin shown below includes the cumulative impact of conservation and demand response on FPL's system demand.

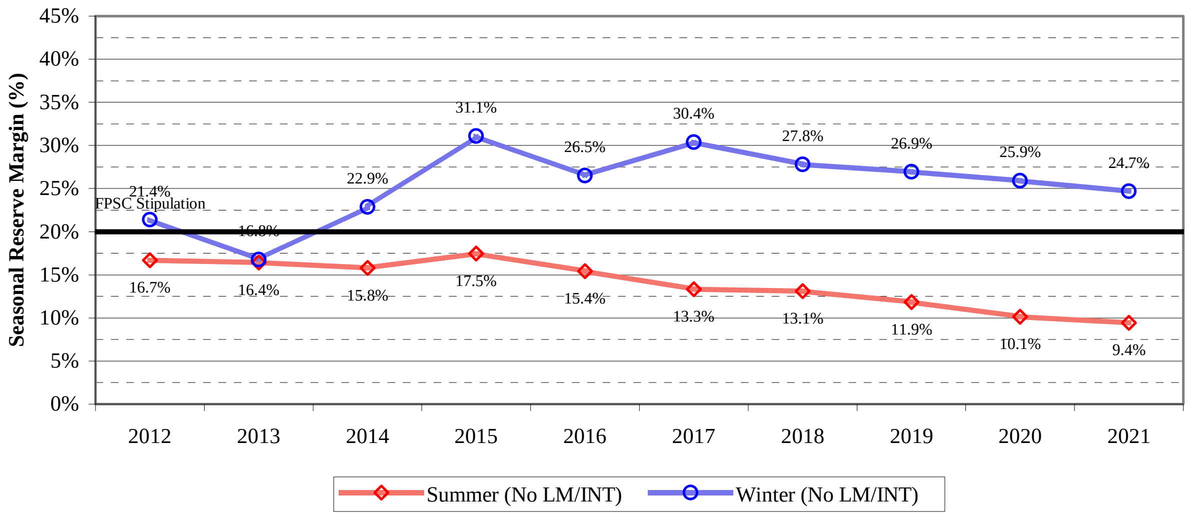
FPL Figure 3. Seasonal Reserve Margin (With LM/INT)



Source: FPL 2012 TYSP

Some concerns have been expressed regarding increased dependence upon demand response to meet customer peak demand. The concern is that interruptible load and load management programs are voluntary, and that customers may elect to opt-out of an existing program if the utility interrupted service too frequently. FPL Figure 4 shows the impact of excluding demand response programs from meeting customer demand, which causes the reserve margin to fall below both the company's stipulated 20 percent reserve margin and the FRCC Region's 15 percent planning margin for the summer only. FPL has indicated that it is continuing to study the possibility of instituting a generation-only minimum reserve.

FPL Figure 4. Seasonal Reserve Margin (Without LM/INT)

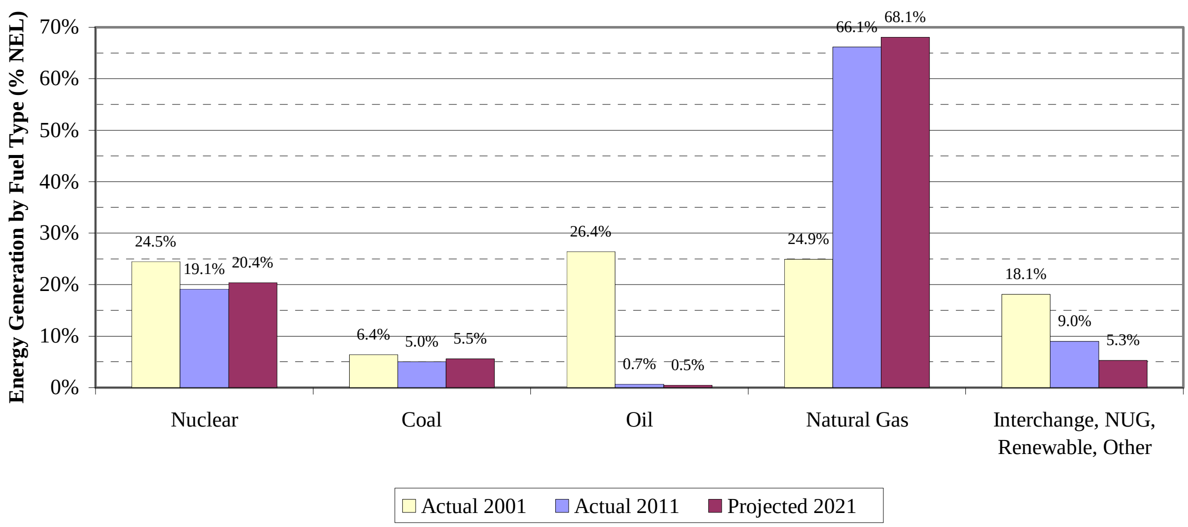


Source: FPL 2012 TYSP

Fuel Diversity

FPL Figure 5 shows FPL's historic fuel mix for 2001 and 2011, and the projected fuel mix for 2021. FPL's primary generation fuel is natural gas, which has increased from about a quarter of system energy in 2001, to approximately two-thirds by 2011. Natural gas is projected to remain the main system fuel, with 68.1 percent of net energy for load generated by natural gas.

FPL Figure 5. Net Energy for Load by Fuel Type



Source: FPL 2002 and 2012 TYSPs

Generation Additions

FPL's 2012 TYSP includes 3 new generating units, all of which are natural gas-fired combined cycles. FPL also anticipates uprates at all its nuclear generation units by 2013, and two new nuclear units, Turkey Point 6 & 7, which are planned beyond the planning horizon. All of the new generation units that FPL is planning to add to its system are shown in FPL Table 1.

FPL Table 1. Planned Generation Additions

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Uprates				
St. Lucie Unit #1 Uprates	129	09/2008	09/2008	5/2012
St. Lucie Unit #2 Uprates *	84	09/2008	09/2008	10/2012
Turkey Point Unit # 3 Uprates	123	09/2008	10/2008	6/2012
Turkey Point Unit # 4 Uprates	123	09/2008	10/2008	2/2013
Combined Cycle Unit Additions				
Cape Canaveral Next Generation Clean Energy Center	1,210	09/2008	10/2009	6/2013
Riviera Beach Next Generation Clean Energy Center	1,212	09/2008	11/2009	6/2014
Port Everglades Next Generation Clean Energy Center	1,277	4/2012	02/2013***	6/2016
Nuclear Unit Additions				
Turkey Point Unit #6**	1,100	3/2008	12/2013***	6/2022
Turkey Point Unit #7**	1,100	3/2008	12/2013***	6/2023

*31 MW of St. Lucie Unit #2 uprates have already been achieved in 2011.
** These units are outside of the 2012-2021 planning period
*** This is the anticipated date of the Siting Board Hearing on Site Certification.
Source: FPL 2012 TYSP

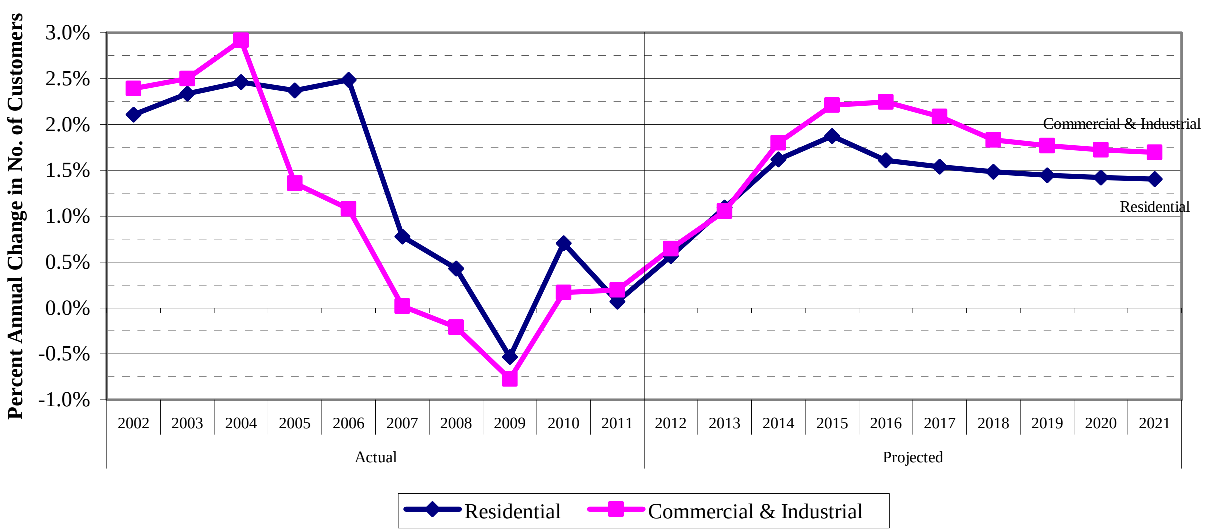
PEF is an investor-owned utility, and Florida's second largest TYSP utility. The utility's service territory is within the FRCC region, and is primarily located in central and west central Florida. As PEF is an IOU, the Commission has regulatory authority over all aspects of operations, including rates and safety.

In 2011, PEF had an average of 1,642,161 customers, and had a total net energy for load of 42,490 GWh, approximately 17.9 percent of the NEL generated in the entire state last year.

Peak Demand and Energy Forecasts

PEF Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth for 2012 through 2021. Customer growth is anticipated to increase from the period of the economic downturn until approximately 2015, and then remain steady or decline somewhat while remaining positive until the end of the period, yielding an average annual growth rate of 1.53 percent. This compares with the actual rate of 2.03 for the period 2002 through 2007.

PEF Figure 1. Annual Customer Growth Rate by Customer Class

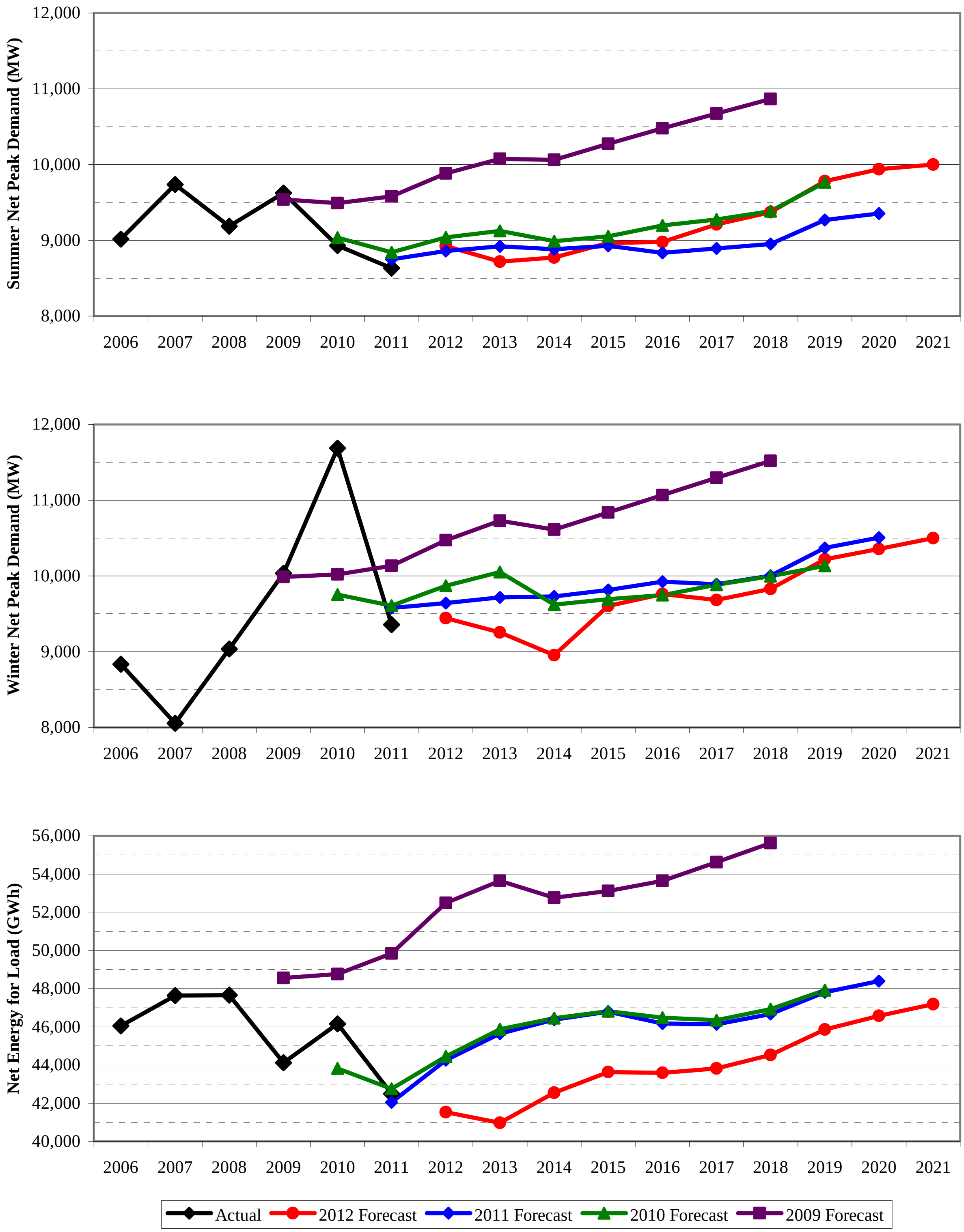


Source: PEF 2012 TYSP

The following three graphs in PEF Figure 2 show PEF's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is significantly above last year's in summer peak demand, but below the 2011 forecast for winter peak demand and NEL.

Analysis of PEF's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that PEF's average forecast error is 11.36 percent. This value indicates that the company tends to over-forecast its retail energy sales by 11.36 percent, which is approximately equivalent to the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

PEF Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

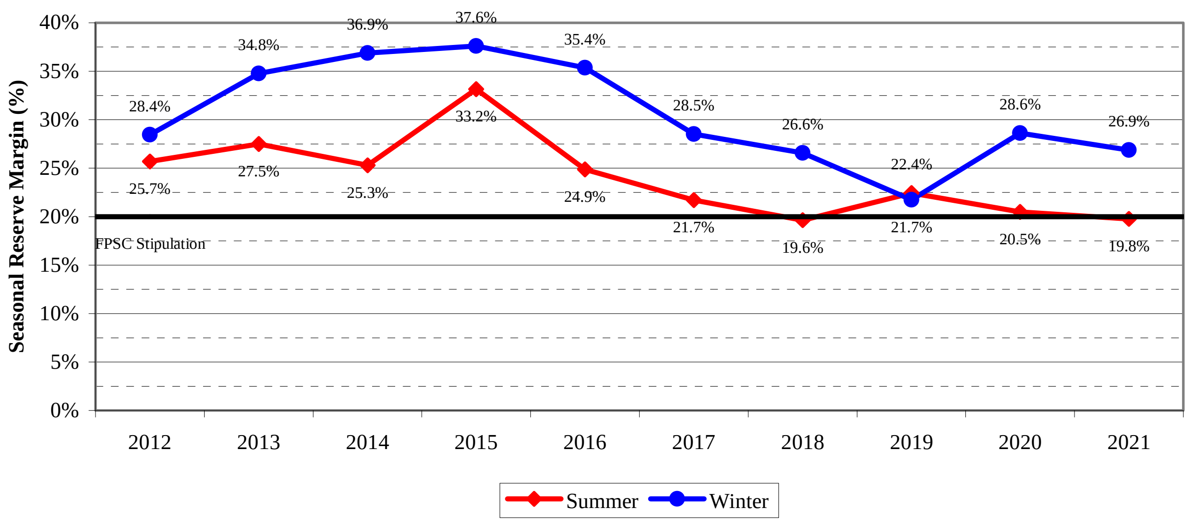


Source: PEF 2009 - 2012 TYSPs

Reserve Margin Requirement

As mentioned in the Statewide Perspective, PEF maintains a minimum 20 percent reserve margin for planning purposes based on a stipulation approved by the Commission. PEF Figure 3 displays the projected reserve margin for PEF through the planning period for both seasonal peaks. As shown in the figure, summer peak demand would be the driving force for generation additions. The reserve margin shown below includes the cumulative impact of conservation and demand response on PEF's system demand. The delay of the Levy 1 nuclear unit and its decrease of the company's reserve margin in 2021 is included in the graph.

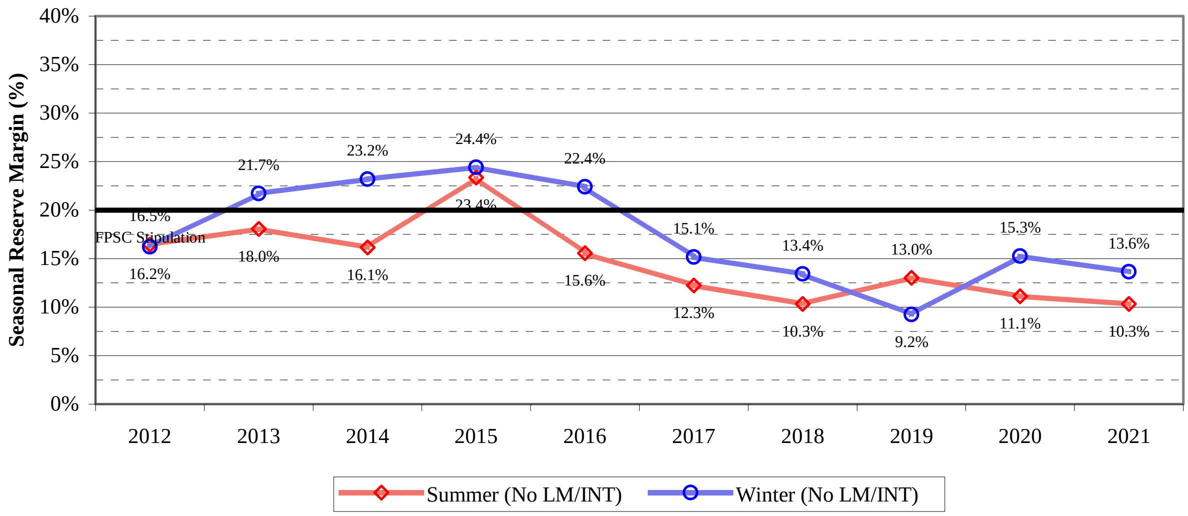
PEF Figure 3. Seasonal Reserve Margin (With LM/INT)



Source: PEF 2012 TYSP

Some concerns have been expressed regarding increased dependence upon demand response to meet customer peak demand. The concern is that interruptible load and load management programs are voluntary, and that customers may elect to opt-out of an existing program if the utility interrupted service too frequently. PEF Figure 4 shows the impact of excluding demand response programs from meeting customer demand, which causes the reserve margin to fall below both the company's stipulated 20 percent reserve margin and the FRCC Region's 15 percent planning margin.

PEF Figure 4. Seasonal Reserve Margin (Without LM/INT)

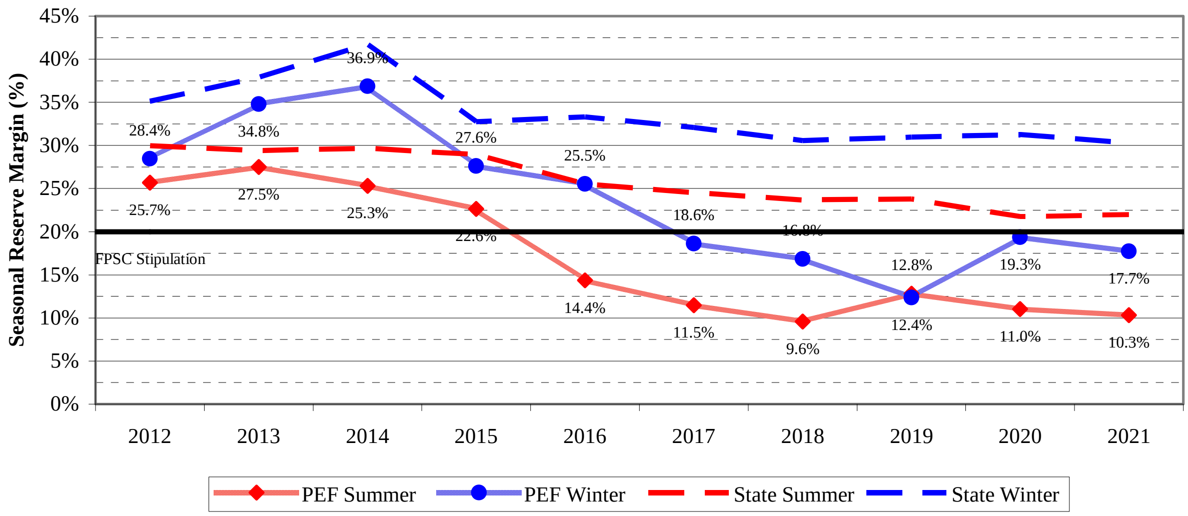


Source: PEF 2012 TYSP

Crystal River 3 Outage

The CR3 nuclear unit has been offline since 2009 due to a concrete delamination experience during a steam generator replacement project. Currently PEF anticipates CR3 returning to service in November 2014, but at this time the decision to repair or retire the unit has not been decided. PEF Figure 5 illustrates the reliability impact of not returning CR3 to service in 2014 and assuming no other changes to PEF's available generation. As shown, PEF would fall below its 20 percent reserve requirement as early as the summer of 2016, and falling to a minimum reserve margin of 9.6 percent for the 2018 summer peak. In the event CR3 is retired or its return to service delayed past 2014, PEF must seek additional firm capacity to meet its reserve requirements, which may be from purchased power contracts, acceleration of currently planned units, and/or new generating units. While the loss of capacity associated with CR3 has a significant impact on PEF's system, the statewide reserve margin appears adequate for possible purchased power agreements.

PEF Figure 5. Seasonal Reserve Margin With Potential Unit Retirements / Delays (With LM/INT)

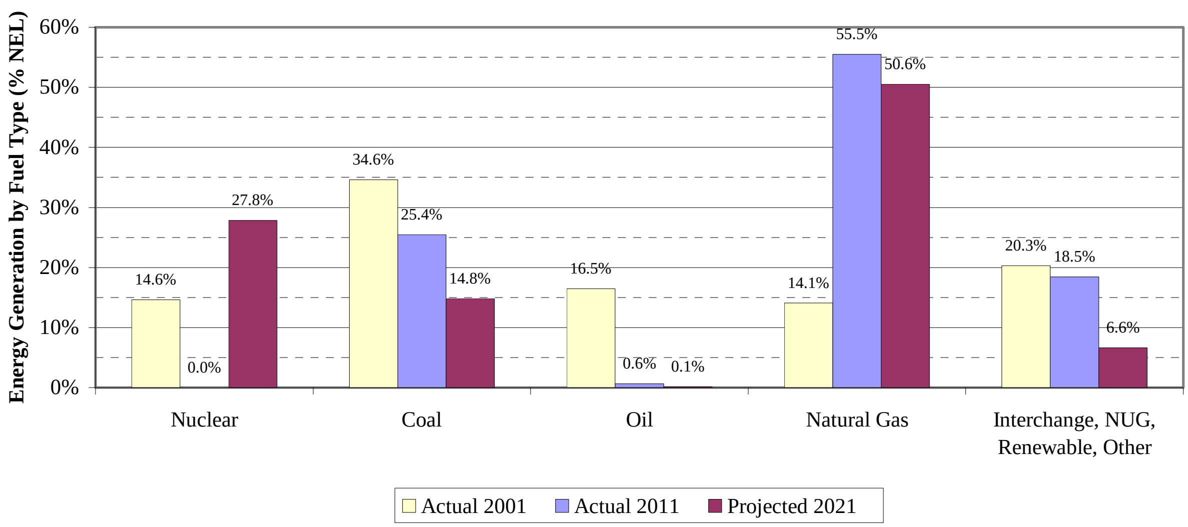


Source: PEF 2012 TYSP, Responses to Staff Data Request

Fuel Diversity

PEF Figure 6 shows PEF's historic fuel mix for 2001 and 2011, and the projected fuel mix for 2021. PEF's primary generation fuel is natural gas, which has increased from approximately 14 percent in 2001, to over 55 percent in 2011. Natural gas is projected to remain the main system fuel, but decline somewhat to 50.6 percent of net energy for load by 2021.

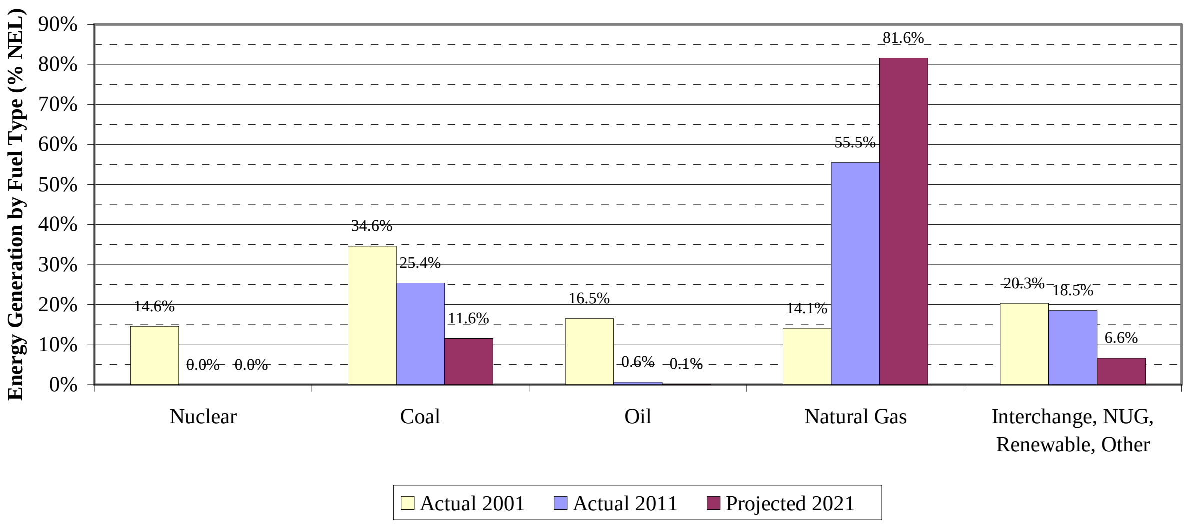
PEF Figure 6. Net Energy for Load by Fuel Type



Source: PEF 2002 and 2012 TYSPs

The decline in natural gas usage is primarily the result of an increase in nuclear generation from the inclusion of the now delayed Levy 1 nuclear unit and the return to service of CR3. While usage of coal for generation is expected to decline, this does not take into account the potential impact of retirements due to new environmental compliance requirements. During the 2012 TYSP workshop, PEF's Crystal River 1 and 2, both coal-fired units, were identified by the Sierra Club/Earthjustice as facing challenges if new emissions control equipment was required. If the projected generation from these nuclear and coal units is displaced by natural gas, it would have the net effect of increasing natural gas' share of PEF's electric generation to 81.6 percent by 2021, as shown in PEF Figure 7 below.

PEF Figure 7. Net Energy for Load by Fuel Type with Displaced Generation



Source: PEF 2002 and 2012 TYSPs, Responses to Staff Data Requests

Generation Additions

PEF's 2012 TYSP includes three generation additions, one of which has been delayed. The first is the uprate of the CR3 nuclear unit, which is subject to the uncertainties discussed above. The second is an unsited 767 MW combined cycle unit, scheduled to begin commercial operation in 2019. The last unit, the Levy 1 nuclear unit, has been delayed outside of the TYSP planning horizon. These are summarized in PEF Table 1.

PEF Table 1. Planned Generation Additions

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Uprates				
Crystal River 3 Uprate	154	2/2007	8/2008	11/2014
Combined Cycle Unit Additions				
Unknown	767	-	-	6/2019
Nuclear Unit Additions				
Levy 1*	1092	5/2008	8/2009	6/2024
Levy 2*	1092	5/2008	8/2009	6/2025

* These units are outside of the 2012-2021 planning period
Source: PEF 2012 TYSP

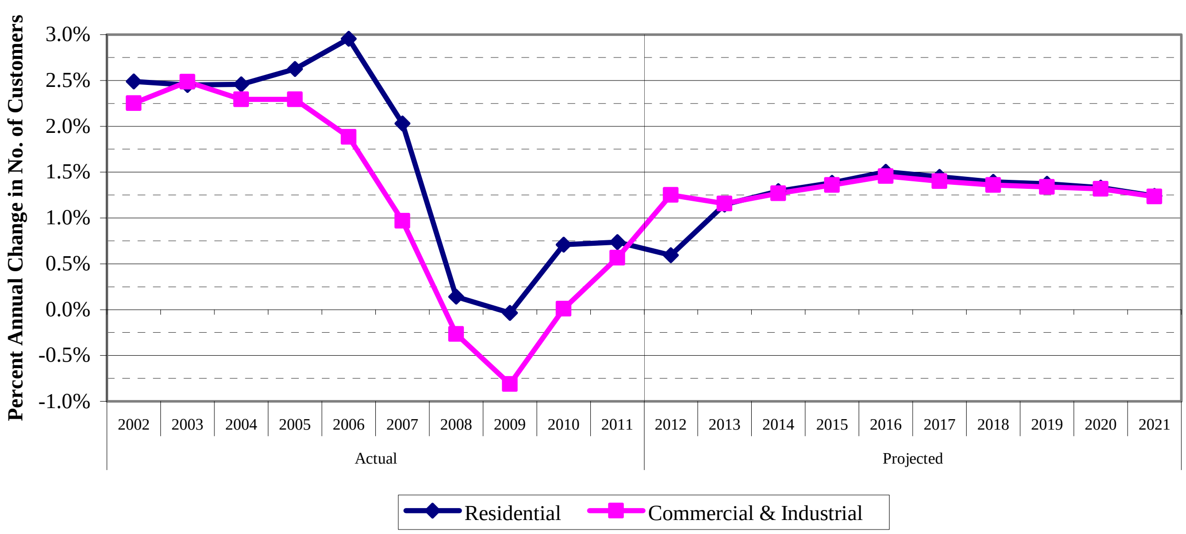
TECO is an investor-owned electric utility, and Florida's third largest TYSP utility. The utility's service territory is within the FRCC region, and consists primarily of the Tampa metropolitan area. As TECO is an IOU, the Commission has regulatory authority over all aspects of operations, including rates and safety.

In 2011, TECO had an average of 675,799 customers, and had a total net energy for load of 19,325 GWh, approximately 8.1 percent of the NEL generated in the state last year.

Peak Demand and Energy Forecasts

TECO Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth for 2012 through 2021. Customer growth is anticipated to stay relatively stable over the planning period, with an average annual growth rate of 1.34 percent. This compares with the actual rate of 2.45 percent for the period 2002 through 2007.

TECO Figure 1. Annual Customer Growth Rate by Customer Class

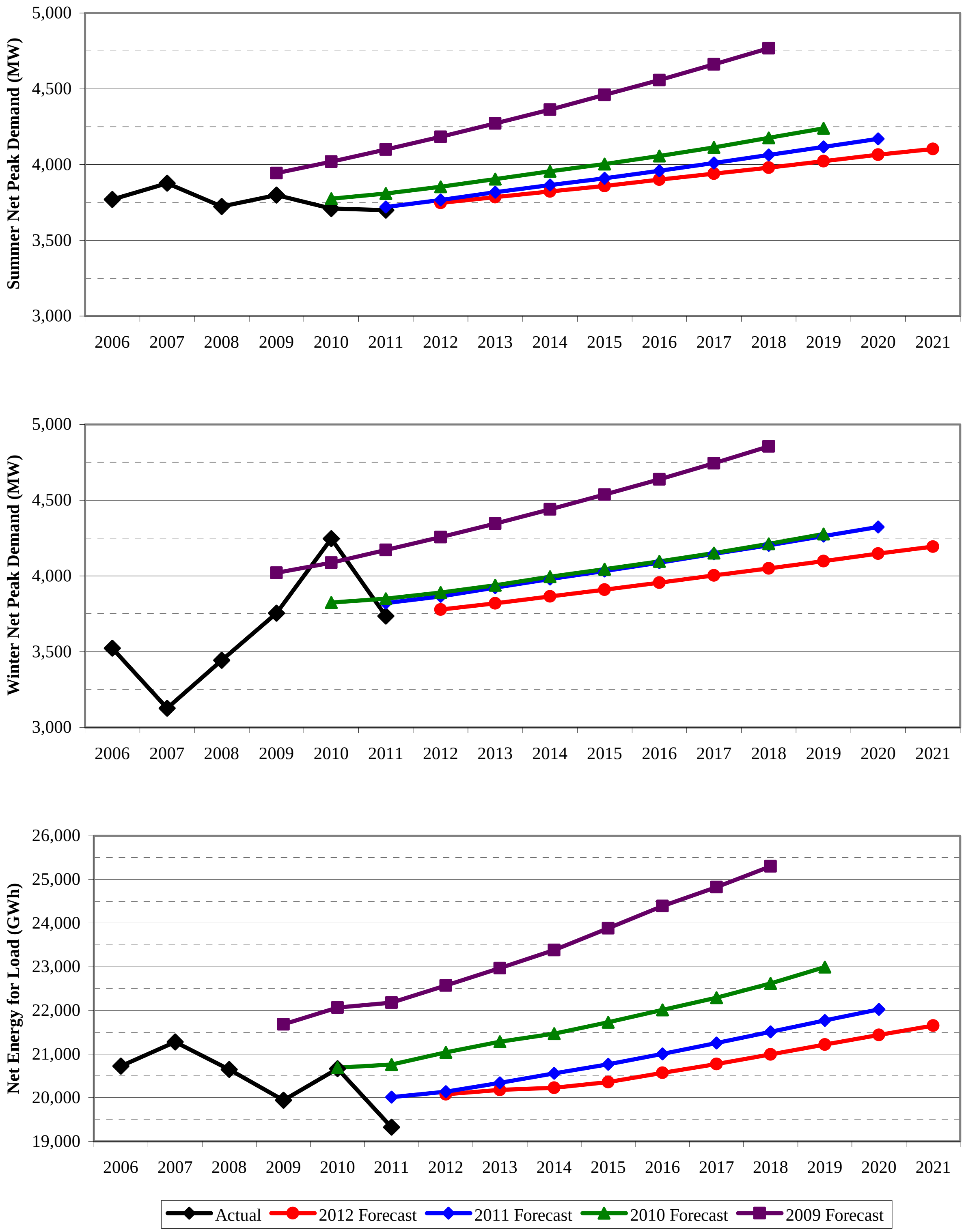


Source: TECO 2012 TYSP

The following three graphs in TECO Figure 2 show TECO's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is lower than the 2011 forecast values for both seasons of peak demand and NEL.

Analysis of TECO's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that TECO's average forecast error is 13.07 percent. This value indicates that the company tends to over-forecast its retail energy sales by 13.07 percent, which is unfavorable when compared to the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

TECO Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

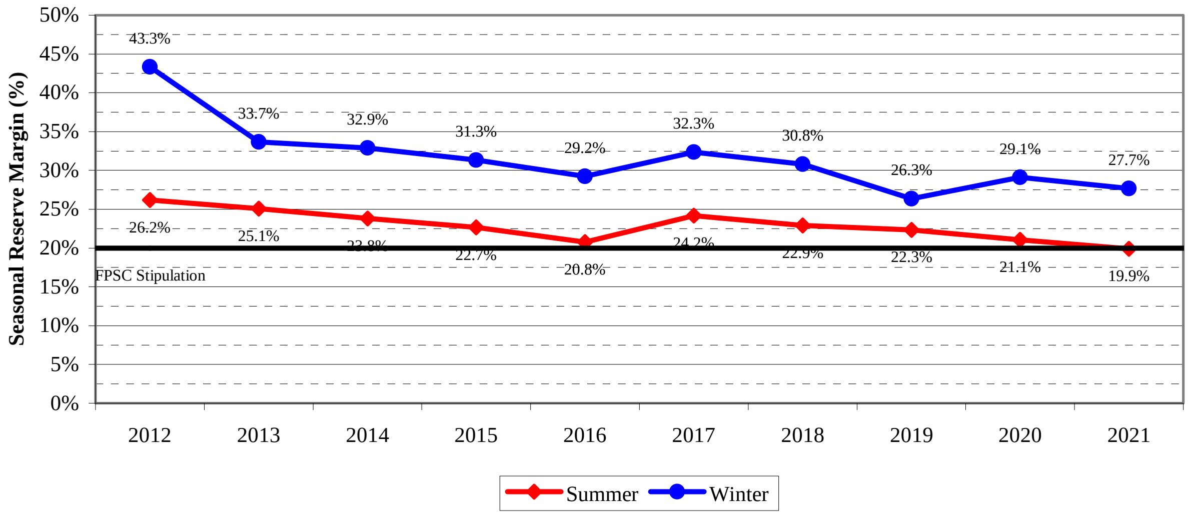


Source: TECO 2009 - 2012 TYSPs

Reserve Margin Requirement

As mentioned in the Statewide Perspective, TECO maintains a minimum 20 percent reserve margin for planning purposes based on a stipulation approved by the Commission. TECO Figure 3 displays the projected reserve margin for TECO through the planning period for both seasonal peaks. As shown in the figure, summer peak demand would be the driving force for generation additions. The reserve margin shown below includes the cumulative impact of conservation and demand response on TECO's system demand.

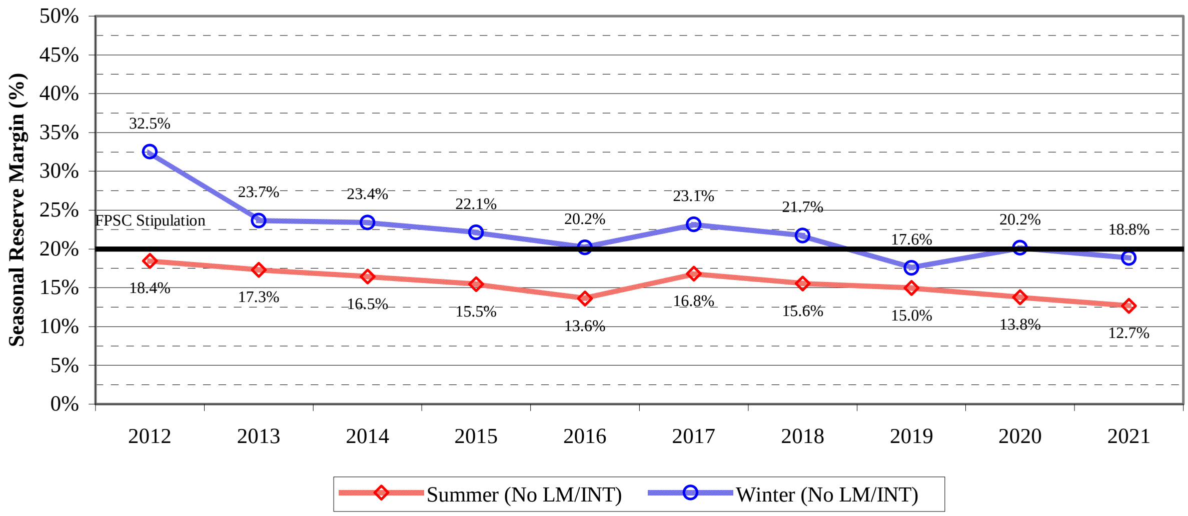
TECO Figure 3. Seasonal Reserve Margin (With LM/INT)



Source: TECO 2012 TYSP

TECO is the only IOU that currently maintains a minimum supply-side contribution to reserve margin, set at 7 percent. As with other utilities, the concern is that interruptible load and load management programs are voluntary, and that customers may elect to opt-out of an existing program if the utility interrupted service too frequently. TECO Figure 4 shows the impact of excluding demand response programs from meeting customer demand, which causes the reserve margin to fall below the company's stipulated 20 percent reserve margin. Even without demand response, TECO exceeds its own supply-side requirements, and generally maintains the FRCC Region's 15 percent planning margin, excluding three summer periods where it falls as low as 12.7 percent in 2021.

TECO Figure 4. Seasonal Reserve Margin (Without LM/INT)

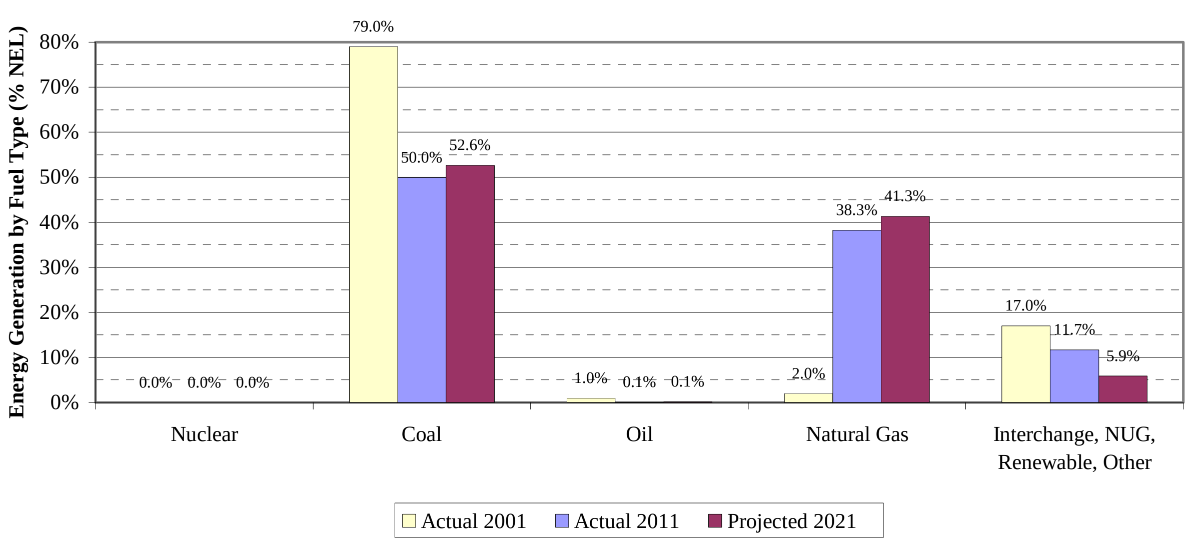


Source: TECO 2012 TYSP

Fuel Diversity

TECO Figure 5 shows TECO's historic fuel mix for 2001 and 2011, and the projected fuel mix for 2021. TECO's primary generation fuel is coal, although this has decreased from nearly 80 percent of system energy in 2001, to only 50 percent in 2011. A slight rebound is anticipated by the end of the planning period, with 52.6 percent of energy from coal-fired generation. Natural gas has increased from a minor fuel on the system, at 2.0 percent in 2001, to the secondary fuel at 38.3 percent in 2011, is also expected to make gains, increasing to 41.3 percent by the end of the planning period.

TECO Figure 5. Net Energy for Load by Fuel Type



Source: TECO 2002 and 2012 TYSPs

Generation Additions

TECO's 2012 TYSP includes two unit additions, including a conversion of its existing Polk facility to combined cycle operation in 2017, and the addition of a single 149 MW combustion turbine in 2019. This represents a reduction from the 2011 TYSP, where TECO included 8 smaller combustion turbines in addition to the Polk CC conversion. TECO's planned additions are summarized in TECO Table 1 below. TECO has recently issued a Request for Proposals (RFP) for its planned combined cycle conversion of several existing simple cycle combustion turbines at the Polk Power Station, and filed for a need determination on September 12, 2012.

TECO Table 1. Planned Generation Additions

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Combined Cycle Unit Additions				
Polk 2-5 CC	1,063	-	-	01/2017
Combustion Turbine Unit Additions				
Future CT 1	149	N/A	N/A	05/2019

Source: TECO 2012 TYSP

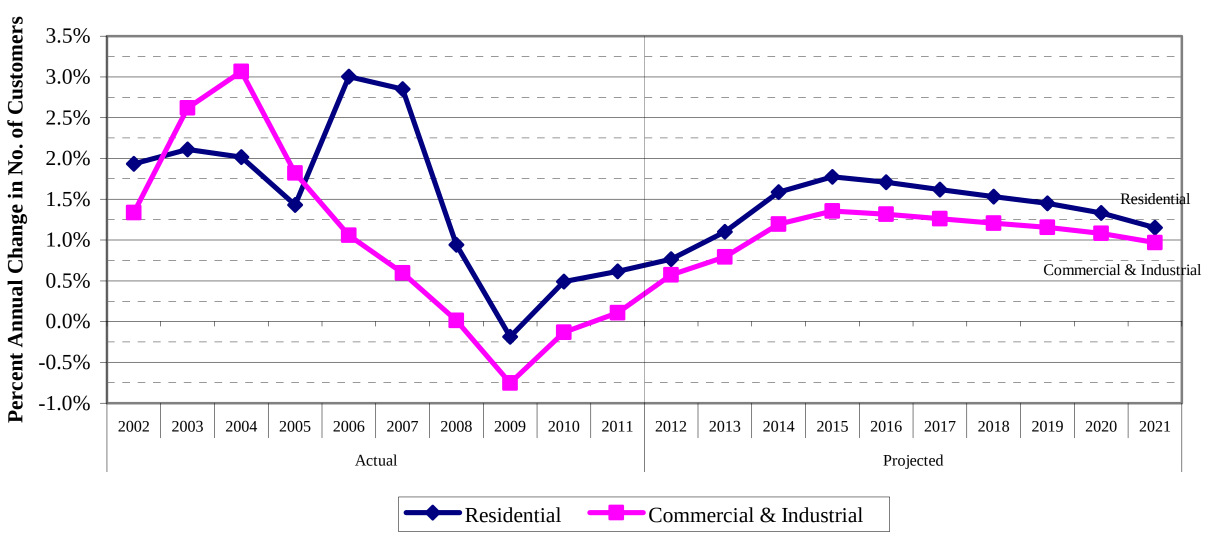
GULF is the smallest investor-owned generating utility, and the sixth largest TYSP utility. The utility's service territory includes western Florida, and is the only TYSP utility outside of the FRCC region. Gulf Power, along with Alabama Power, Georgia Power, and Mississippi Power, are members of the Southern Company electric system. GULF therefore has SERC as its regional reliability entity. Because GULF plans and operates its system in conjunction with the other Southern Company utilities, not all of the energy generated by the GULF units is consumed in Florida. As GULF is an IOU, the Commission has regulatory authority over all aspects of operations, including rates and safety.

In 2011, GULF had an average of 432,403 customers, and had a total net energy for load of 12,086 GWh, approximately 5.1 percent of the NEL generated in the state last year.

Peak Demand and Energy Forecasts

GULF Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth for 2012 through 2021. As shown below, GULF anticipates annual customer growth rates to climb until approximately 2015, and then begin to decline slightly but remain positive till the end of the planning period, with an average annual growth rate of 1.43 percent. This compares to the actual rate of 2.22 percent for the period 2002 through 2007.

GULF Figure 1. Annual Customer Growth Rate by Customer Class

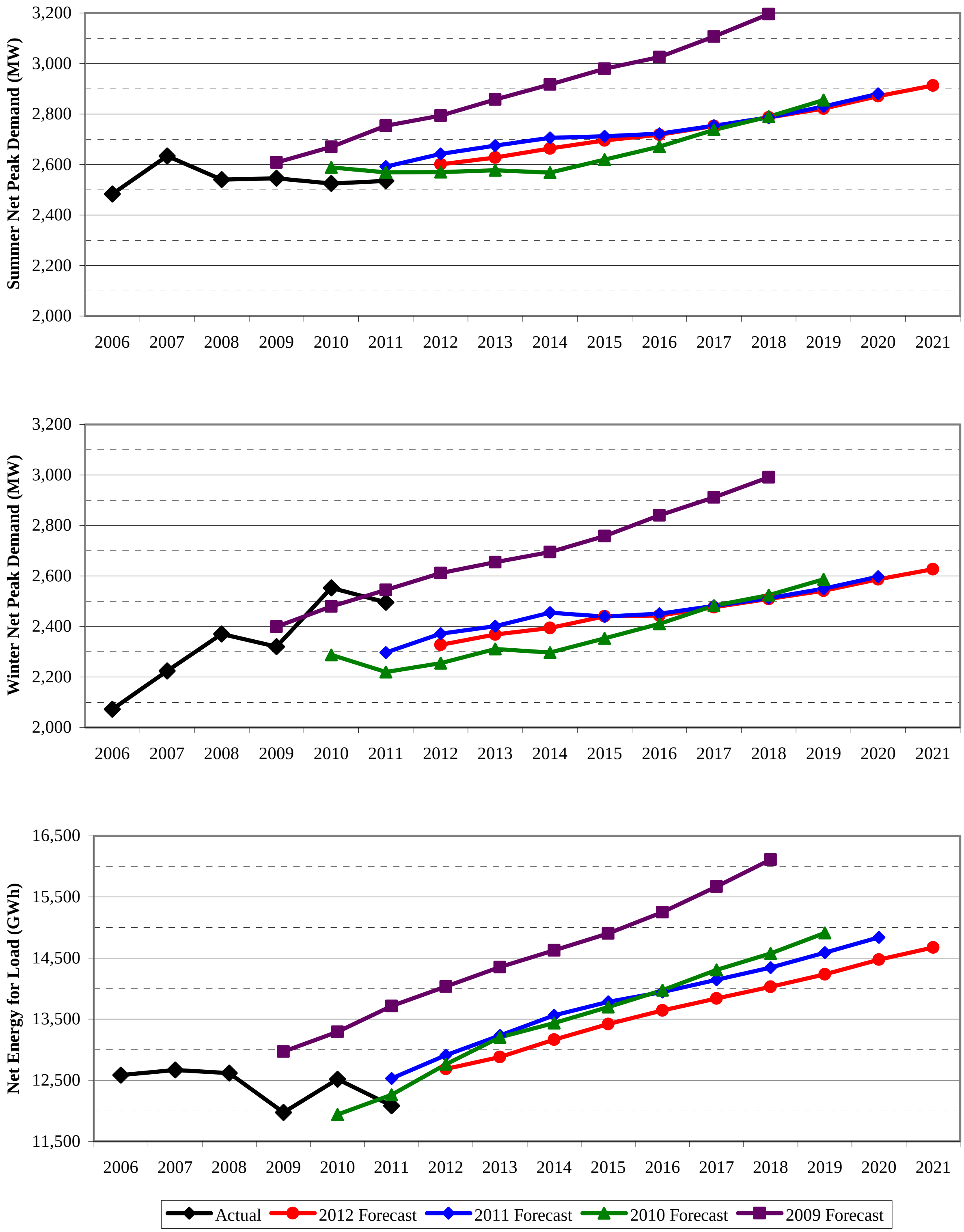


Source: GULF 2012 TYSP

The following three graphs in GULF Figure 2 show GULF's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is similar but slightly below last year's forecast in both seasonal peak demand and NEL.

Analysis of GULF's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that GULF's average forecast error is 5.44 percent. This value indicates that the company tends to over-forecast its retail energy sales by 5.44 percent, the lowest of the TYSP Utilities. GULF's forecast error is favorable when compared to the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

GULF Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

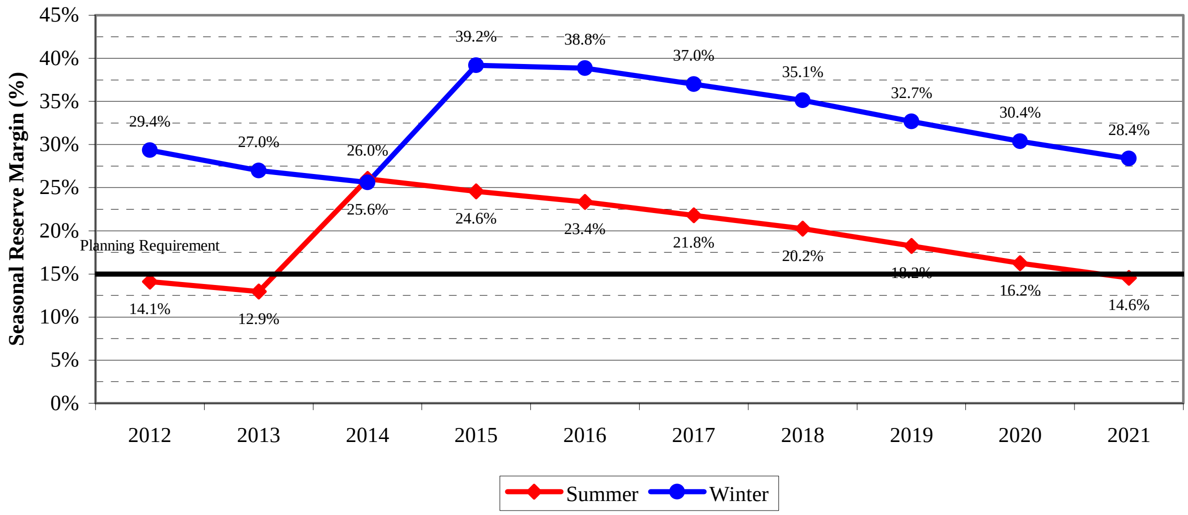


Source: GULF 2009 - 2012 TYSPs

Reserve Margin Requirement

GULF is not within the FRCC region, and therefore not subject to its minimum reserve margin requirements. GULF operates within SERC, and as part of the Southern Power Pool has a planning reserve margin of 15 percent after 2015. The company's projected reserve margin for summer and winter peak demand is shown below in GULF Figure 3. The reserve margin shown below includes the cumulative impact of conservation, but as GULF does not administer any active demand response programs, there are no non-firm load components in its reserve margin.

GULF Figure 3. Seasonal Reserve Margin

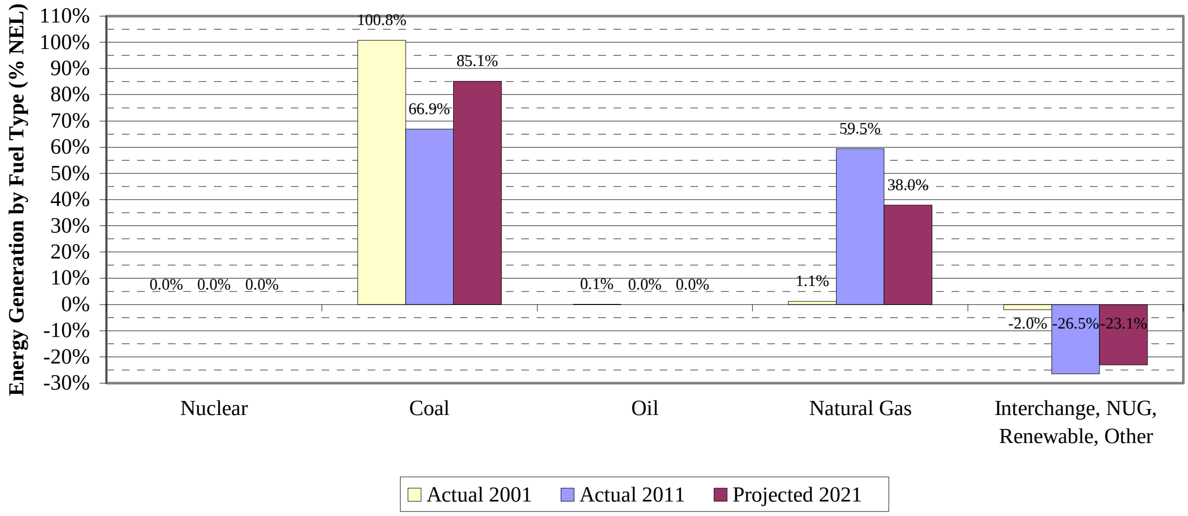


Source: GULF 2012 TYSP

Fuel Diversity

GULF Figure 4 shows GULF's historic fuel mix for 2001 and 2011, and the projected fuel mix for 2021. The negative value for interchange/other category of generation represents power sales, as GULF generates more energy than its native customers consume. GULF's primary generation fuel has been coal, with 66.9 percent of native load served by it in 2011, down from 100.8 percent in 2001. This is anticipated to rebound by the end of the planning period, with a projected 85.1 percent of native NEL from coal in 2021. The main source of reduction in coal generation comes from natural gas, which was used to produce 59.5 of native NEL in 2011, and is projected to decline to 38.0 percent by 2021.

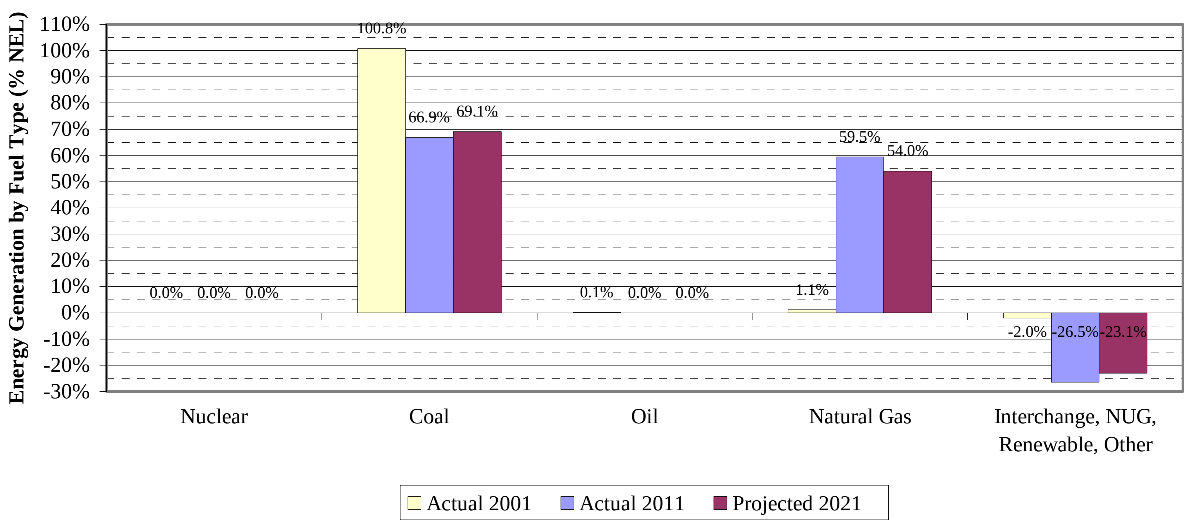
GULF Figure 4. Net Energy for Load by Fuel Type



Source: GULF 2002 and 2012 TYSPs

While usage of coal for generation is expected to increase, this does not take into account the potential impact of retirements due to new environmental compliance requirements. During the 2012 TYSP workshop, GULF's Lansing Smith 1 and 2, both coal-fired units, were identified by the Sierra Club/Earthjustice as facing challenges if new emissions control equipment was required. If the projected generation from these coal units is displaced by natural gas, it would have the net effect of increasing natural gas' share of GULF's electric generation to 54 percent by 2021, while reducing the increase in coal generation to only 69.1 percent, as illustrated in GULF Figure 5 below.

GULF Figure 5. Net Energy for Load by Fuel Type with Displaced Generation



Source: GULF 2002 and 2012 TYSPs, Responses to Staff Data Requests

Generation Additions

GULF has no planned generation additions over the planning horizon. This is consistent with the company's 2011 TYSP, which also included no new generating units through 2020.

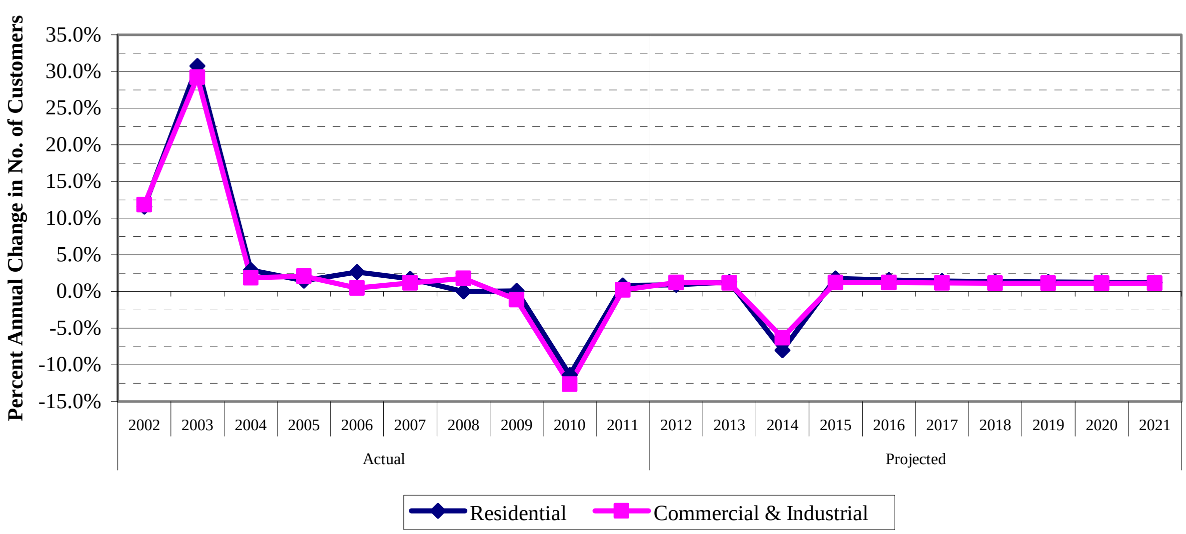
FMPA is a governmental wholesale power company owned by 30 municipal electric utilities located throughout the State of Florida. It is collectively the state's eighth largest TYSP utility. FMPA facilitates opportunities for its members to participate in power supply projects developed by Florida utilities and other producers, and provides economies of scale in power generation and related services. As FMPA is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. FMPA's direct responsibility for power supply is with the All-Requirements Power Supply Project (ARP), where FMPA plans and supplies all of the power requirements for 14 of its participating utilities. The values for capacity in the following figures corresponds to the ARP.

In 2011, FMPA had an average of 262,659 customers, and had a total net energy for load of 6,209 GWh, approximately 2.6 percent of the NEL generated in the state last year.

Peak Demand and Energy Forecasts

FMPA Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth during for 2012 through 2021. The drop in the rate of growth for 2010 is due to the City of Vero Beach leaving the ARP, and the smaller drop in 2014 is the expected result of the departure of the City of Lake Worth from the ARP. These utilities will remain as members of FMPA, but are exercising an option to modify their memberships from a full requirements basis to a partial requirements basis. These changes in membership status means that the ARP will no longer utilize these participants' generating resources, if any exist.

FMPA Figure 1. Annual Customer Growth Rate by Customer Class

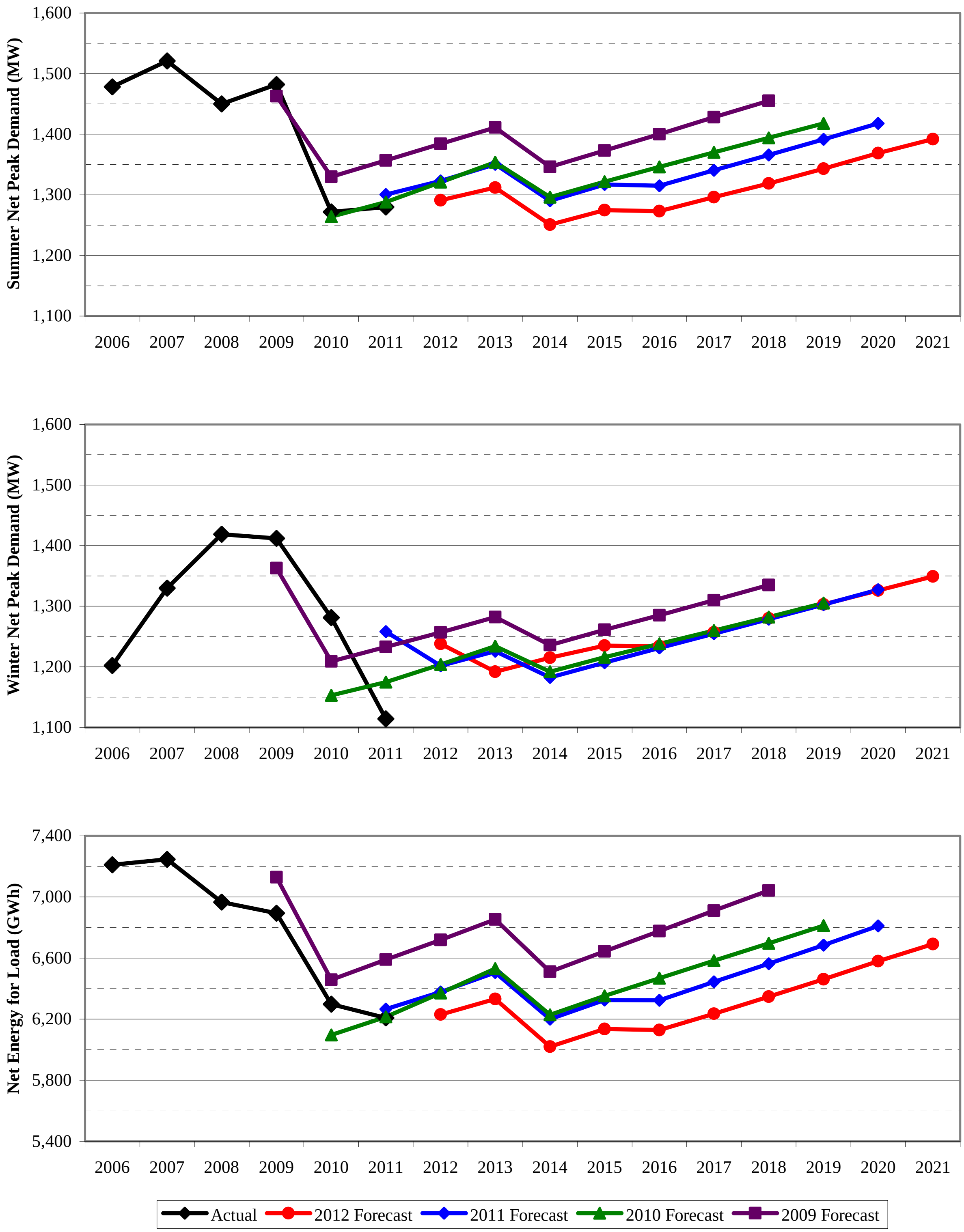


Source: FMPA 2012 TYSP

The following three graphs in FMPA Figure 2 show FMPA's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is below last year's in terms of summer peak demand and NEL, but winter peak demand is similar.

Analysis of FMPA's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that FMPA's average forecast error is 11.81 percent. This value indicates that the company tends to over-forecast its retail energy sales by 11.81 percent, which is somewhat higher than the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

FMPA Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

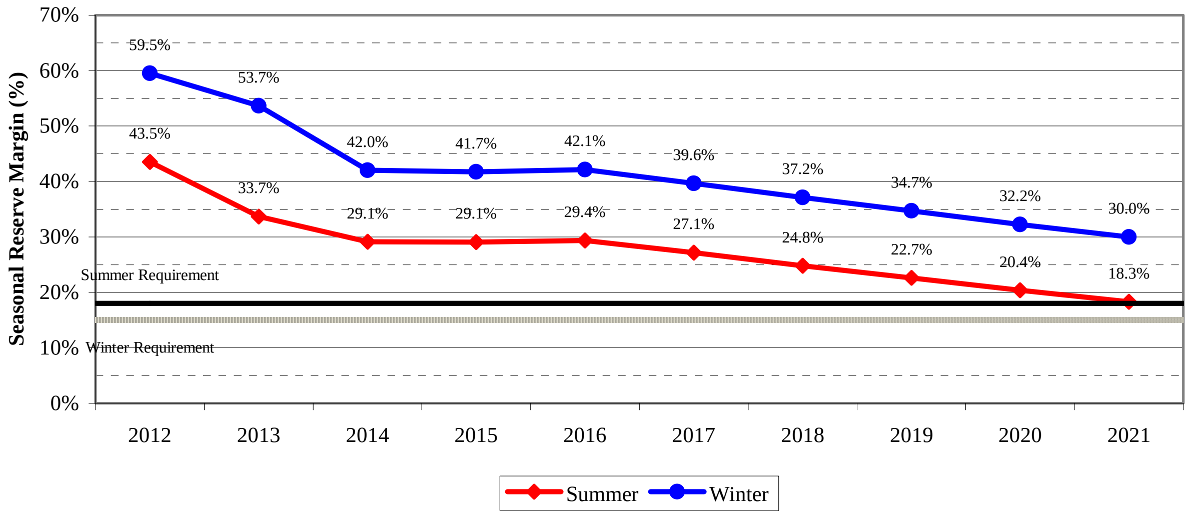


Source: FMPA 2009 - 2012 TYSPs

Reserve Margin Requirement

FMPA is required to maintain a minimum 15 percent reserve margin, pursuant to FRCC requirements. In addition, the utility uses a planning reserve margin of 18 percent for summer peak reserve margin planning. As can be seen in FMPA Figure 3 below, FMPA has ample reserves and its margin only begins to approach the 15 percent minimum in the last few years of the horizon. FMPA does not administer load management or interruptible load programs, and therefore has no non-firm load component in its reserve margin.

FMPA Figure 3. Seasonal Reserve Margin

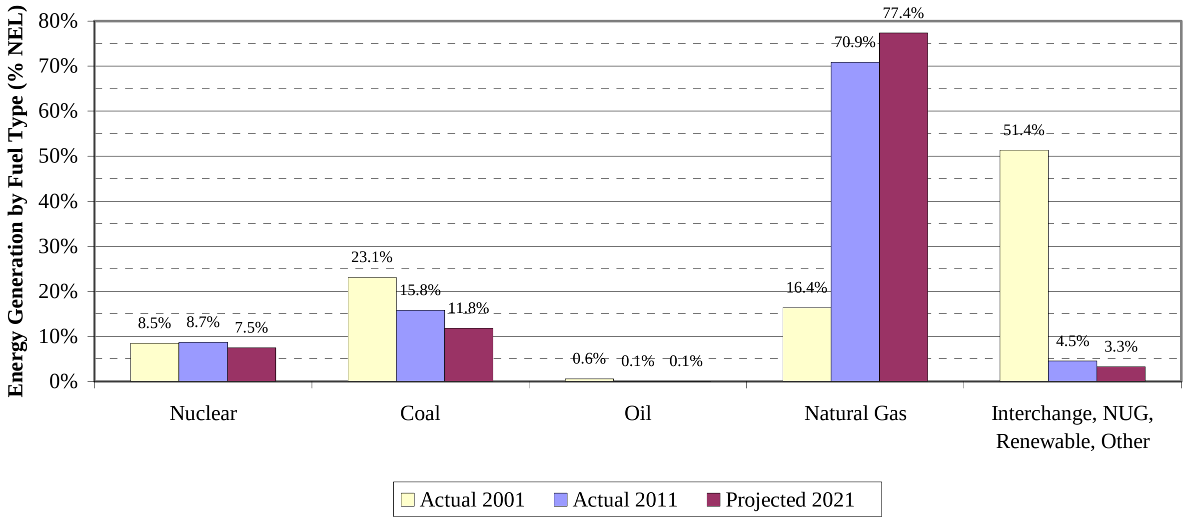


Source: FMPA 2012 TYSP

Fuel Diversity

FMPA Figure 4 displays the composition of FMPA's system in terms of energy generated. Again, natural gas has risen to become the system's primary fuel, increasing over 50 percent, from 16.4 percent in 2001 up to 70.9 percent in 2011. Natural gas is anticipated to increase somewhat to 77.4 percent in 2021, with further decreases in purchased power and coal generation.

FMPA Figure 4. Net Energy for Load by Fuel Type



Source: FMPA 2002 and 2012 TYSPs

Generation Additions

FMPA has no planned generation additions over the planning horizon. This is consistent with the company's 2011 TYSP, which also included no new generating units through 2020.

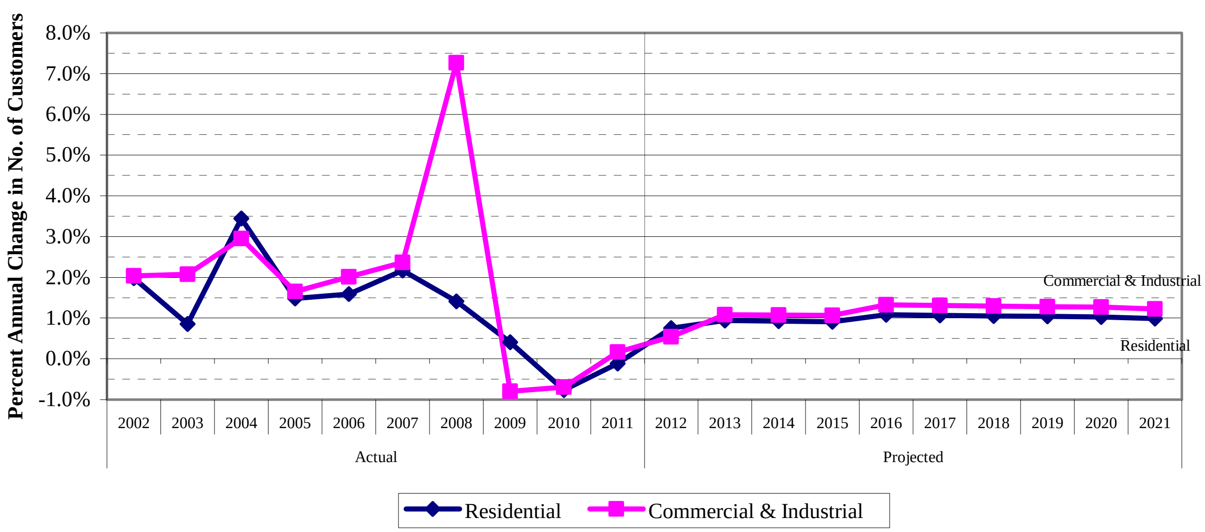
GRU is a municipal utility and the state's smallest TYSP utility. The company's service area is within the FRCC region, and includes the City of Gainesville and its surrounding urban area. GRU also provides wholesale power to the City of Alachua and Clay Electric Cooperative. As GRU is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning

In 2011, GRU had an average of 92,265 customers, and had a total net energy for load of 2,024 GWh, approximately 0.9 percent of the NEL generated in the state last year.

Peak Demand and Energy Forecasts

GRU Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth during for 2012 through 2021. GRU anticipates customer growth to remain steady through the end of the planning period, with an average annual growth rate of 1.03 percent. This compares with the actual rate of 1.94 percent for the period 2002 through 2007.

GRU Figure 1. Annual Customer Growth Rate by Customer Class

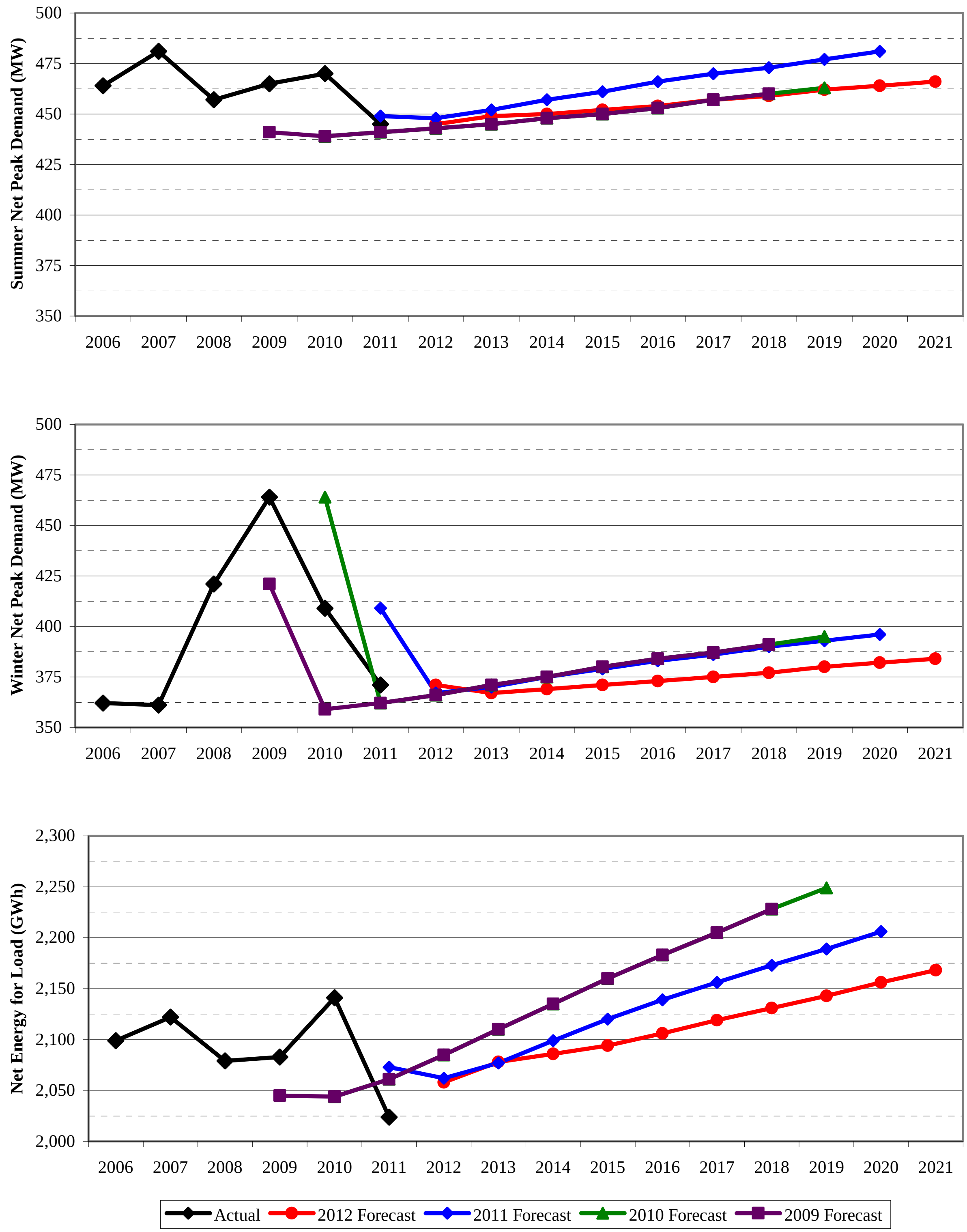


Source: GRU 2012 TYSP

The following three graphs in GRU Figure 2 show GRU's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is below last year's in both seasonal peak demand and NEL.

Analysis of GRU's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that GRU's average forecast error is 11.40 percent. This value indicates that the company tends to over-forecast its retail energy sales by 11.40 percent, which is approximately equivalent to the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

GRU Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

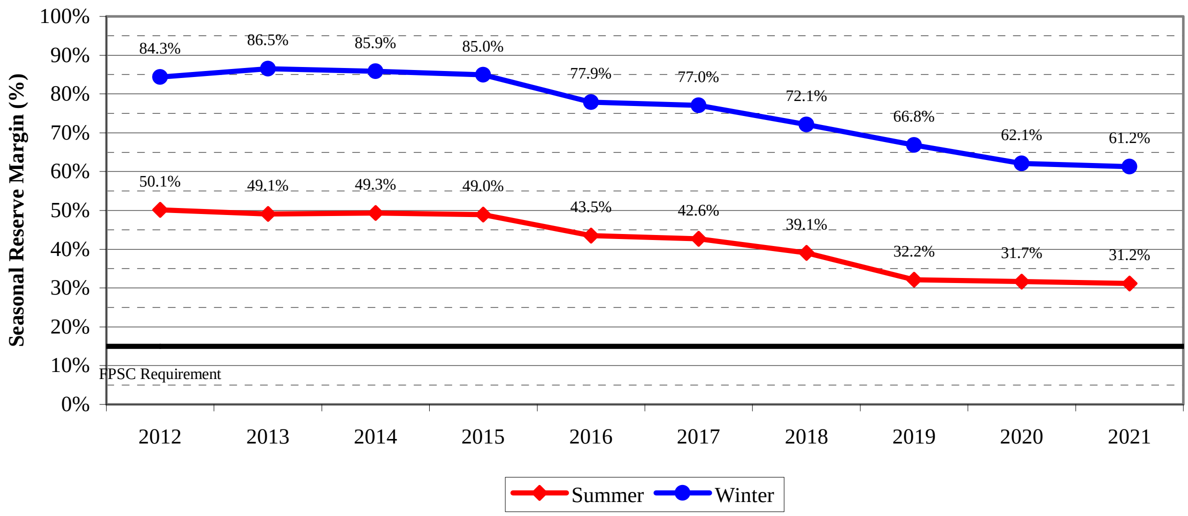


Source: GRU 2009 - 2012 TYSPs

Reserve Margin Requirement

Pursuant to FRCC requirements, GRU maintains a 15 percent reserve margin. As GRU Figure 3 clearly shows, GRU's reserve margin is forecasted to remain well above the minimum level throughout the planning horizon for the summer and winter peak seasons. GRU does not have any active load management or interruptible load programs and therefore has no non-firm load component to its reserve margin.

GRU Figure 3. Seasonal Reserve Margin

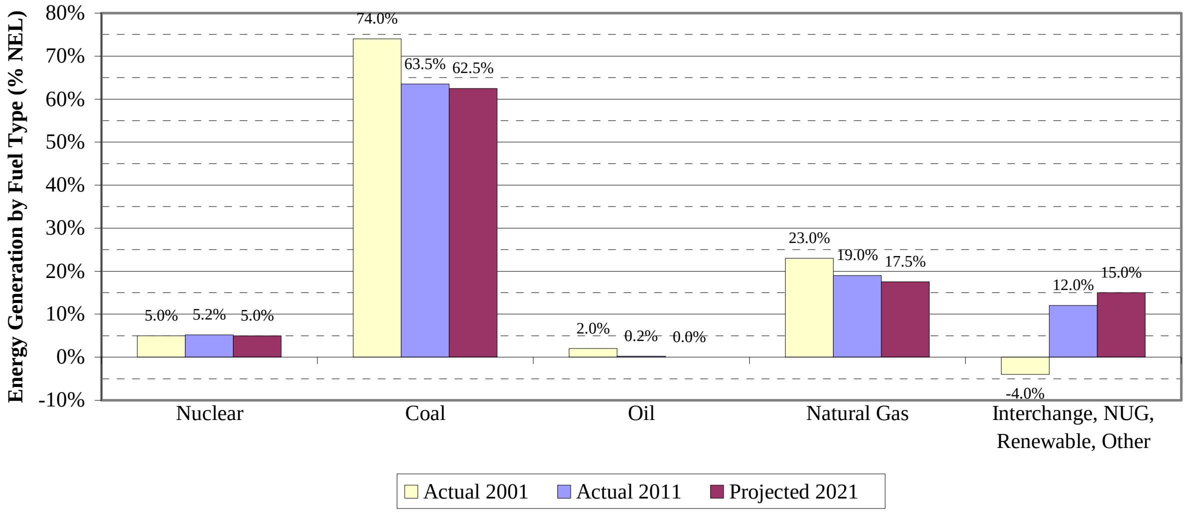


Source: GRU 2012 TYSP

Fuel Diversity

GRU Figure 4 displays the composition of GRU's system in terms of energy generated. The company has historically relied upon coal generation, and it is projected to produce a majority of energy for load through the end of the planning period. Other energy sources include natural gas, nuclear, purchased power, and renewables. GRU anticipates a decline in both coal-fired and natural gas-fired generation, made up for by renewable purchased power contracts, especially a large biomass unit that the Commission authorized recently.

GRU Figure 4. Net Energy for Load by Fuel Type



Source: GRU 2012 TYSP

Generation Additions

GRU has no planned generation additions over the planning horizon. This is consistent with the company's 2011 TYSP, which also included no new generating units through 2020.

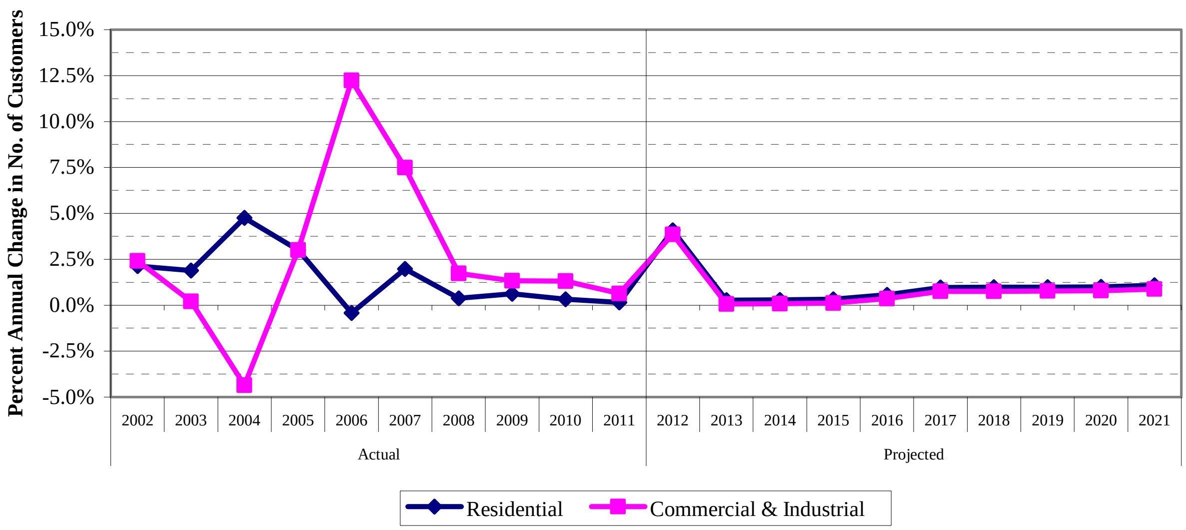
JEA is a municipal electric utility, and the state's fifth largest TYSP utility, and is the largest generating municipal utility. JEA's service territory is within the FRCC region, and includes all of Duval County as well as portions of Clay and St. Johns Counties. As JEA is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning

In 2011, JEA had an average of 416,278 customers, and had a total net energy for load of 12,980 GWh, approximately 5.5 percent of the NEL generated in the state last year.

Peak Demand and Energy Forecasts

JEA Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth for 2012 through 2021. Positive growth is anticipated over the entire planning period, with an average annual growth rate of 0.69 percent. This compares with the actual rate of 2.36 percent for the period 2002 through 2007.

JEA Figure 1. Annual Customer Growth Rate by Customer Class

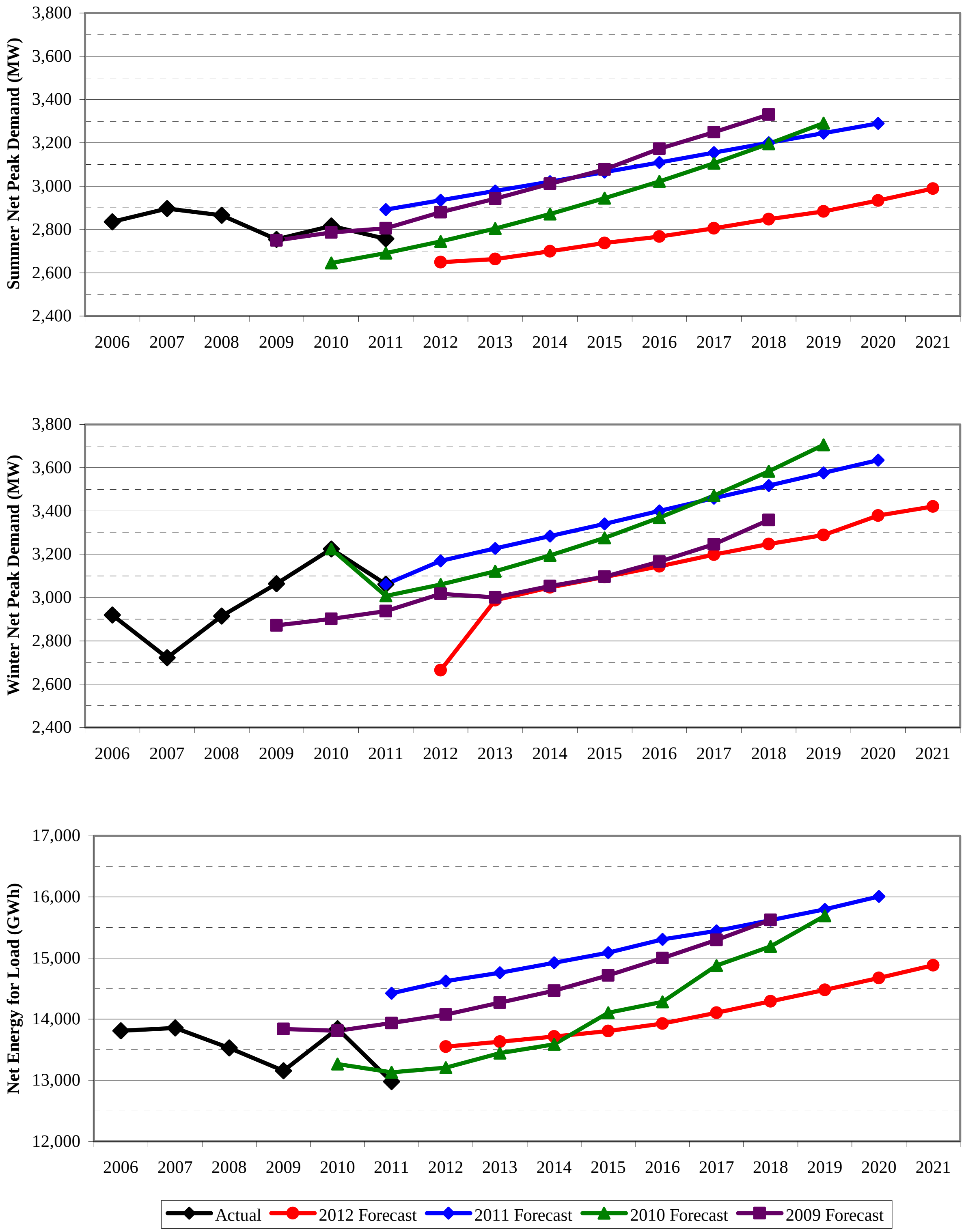


Source: JEA 2012 TYSP

The following three graphs in JEA Figure 2 show JEA's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is below last year's in both seasonal peak demand and NEL.

Analysis of JEA's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that JEA's average forecast error is 12.72 percent. This value indicates that the company tends to over-forecast its retail energy sales by 12.72 percent, which is unfavorable when compared to the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

JEA Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

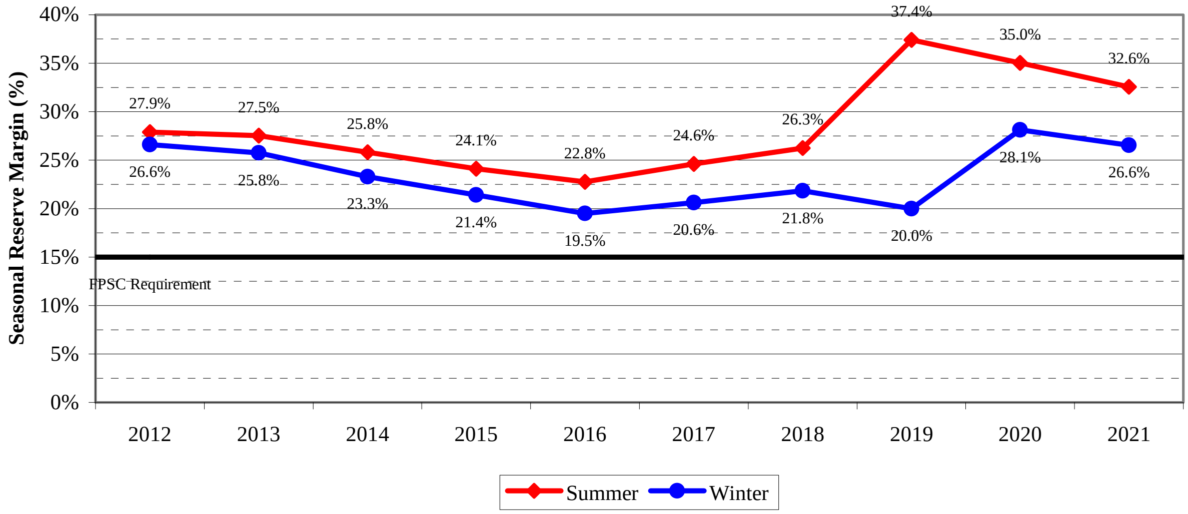


Source: JEA 2009 - 2012 TYSPs

Reserve Margin Requirement

JEA maintains a 15 percent reserve margin pursuant to FRCC requirements. JEA Figure 3 shows their projected reserve margin, which is sufficient for both summer and winter seasonal peaks.

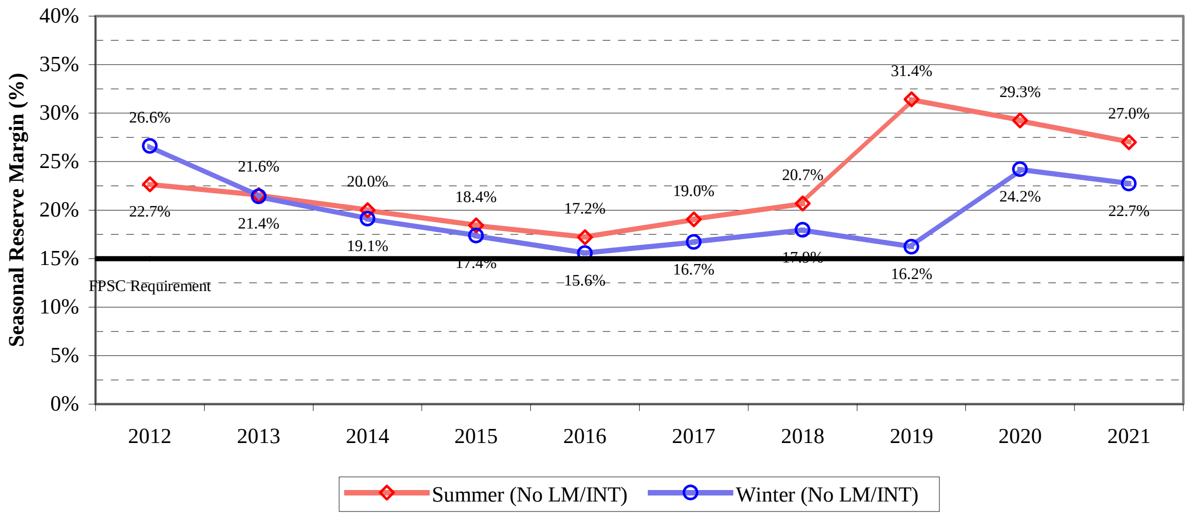
JEA Figure 3. Seasonal Reserve Margin (With LM/INT)



Source: JEA 2012 TYSP

Because JEA does have active load management and interruptible load programs in place, a portion of its reserve margin can be attributed to non-firm load. The measure of reserve margin without any contribution from demand-side programs is shown in JEA Figure 4. JEA's reserve margin exceeds its planning requirement for both summer and winter peak demand throughout the ten year horizon without activating demand response programs.

JEA Figure 4. Seasonal Reserve Margin (Without LM/INT)

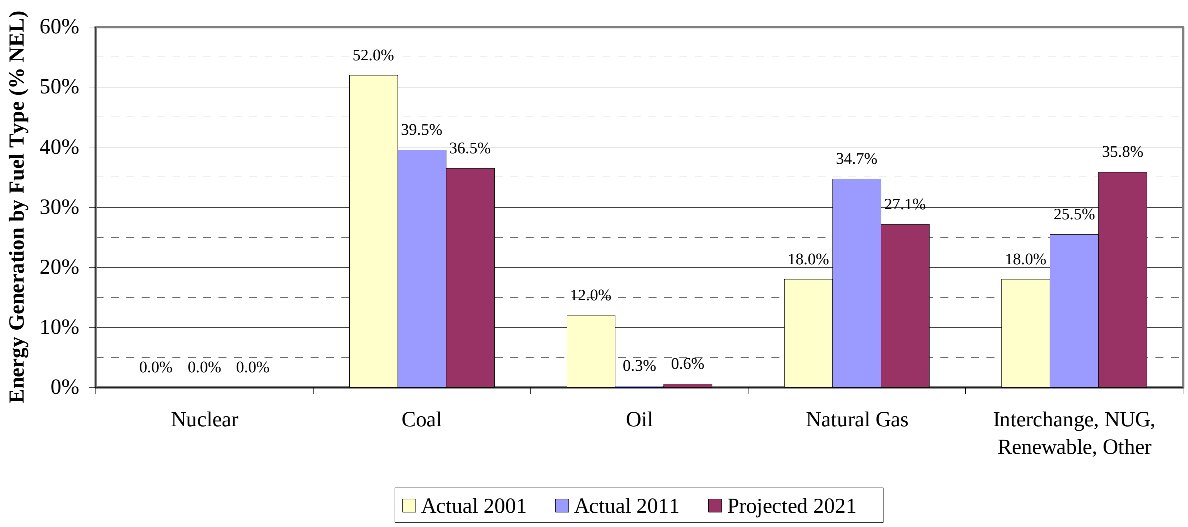


Source: JEA 2012 TYSP

Fuel Diversity

JEA Figure 5 displays the composition of JEA's system in terms of energy generated. Coal, natural gas, and purchased power are the primary sources, with coal overall declining since 2001 while natural gas and purchased power have increased by 2011. Coal is expected to further decline, along with natural gas, in favor of purchased power by 2021.

JEA Figure 5. Net Energy for Load by Fuel Type



Source: JEA 2002 and 2012 TYSPs

Generation Additions

JEA has no planned generation additions over the planning horizon. This is consistent with the company's 2011 TYSP, which also included no new generating units through 2020.

LAKELAND ELECTRIC (LAK)

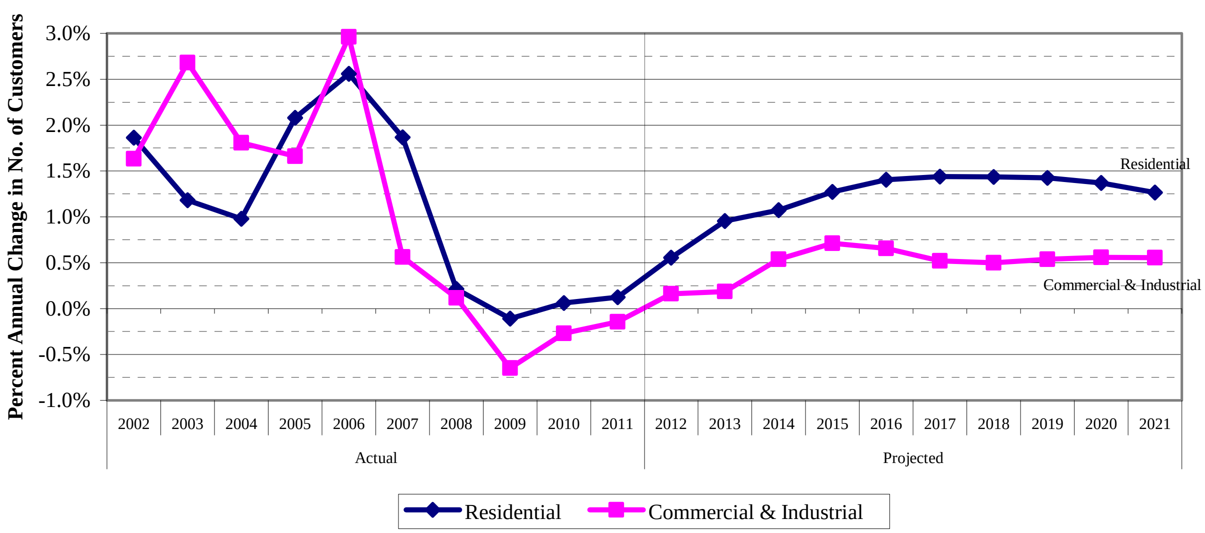
LAK is the municipal utility, and is the state's ninth largest TYSP utility. LAK is owned and operated by the City of Lakeland. LAK is a member of the Florida Municipal Power Pool (FMPP), along with OUC and FMPA's All-Requirements Project (ARP). The FMPP operates as an hourly energy pool with all FMPP capacity from its members committed and dispatched together. Each member of the FMPP retains the responsibility of adequately planning it own system to meet native load and FRCC reserve requirements. As LAK is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning

In 2011, LAK had an average of 121,763 customers, and had a total net energy for load of 2,893 GWh, approximately 1.2 percent of the NEL generated in the state last year.

Peak Demand and Energy Forecasts

LAK Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth during for 2012 through 2021. Customer growth is anticipated to increase slowly throughout the planning period, with an average annual growth rate of 1.21 percent. This compares with the actual rate of 1.75 percent for the period 2002 through 2007.

LAK Figure 1. Annual Customer Growth Rate by Customer Class

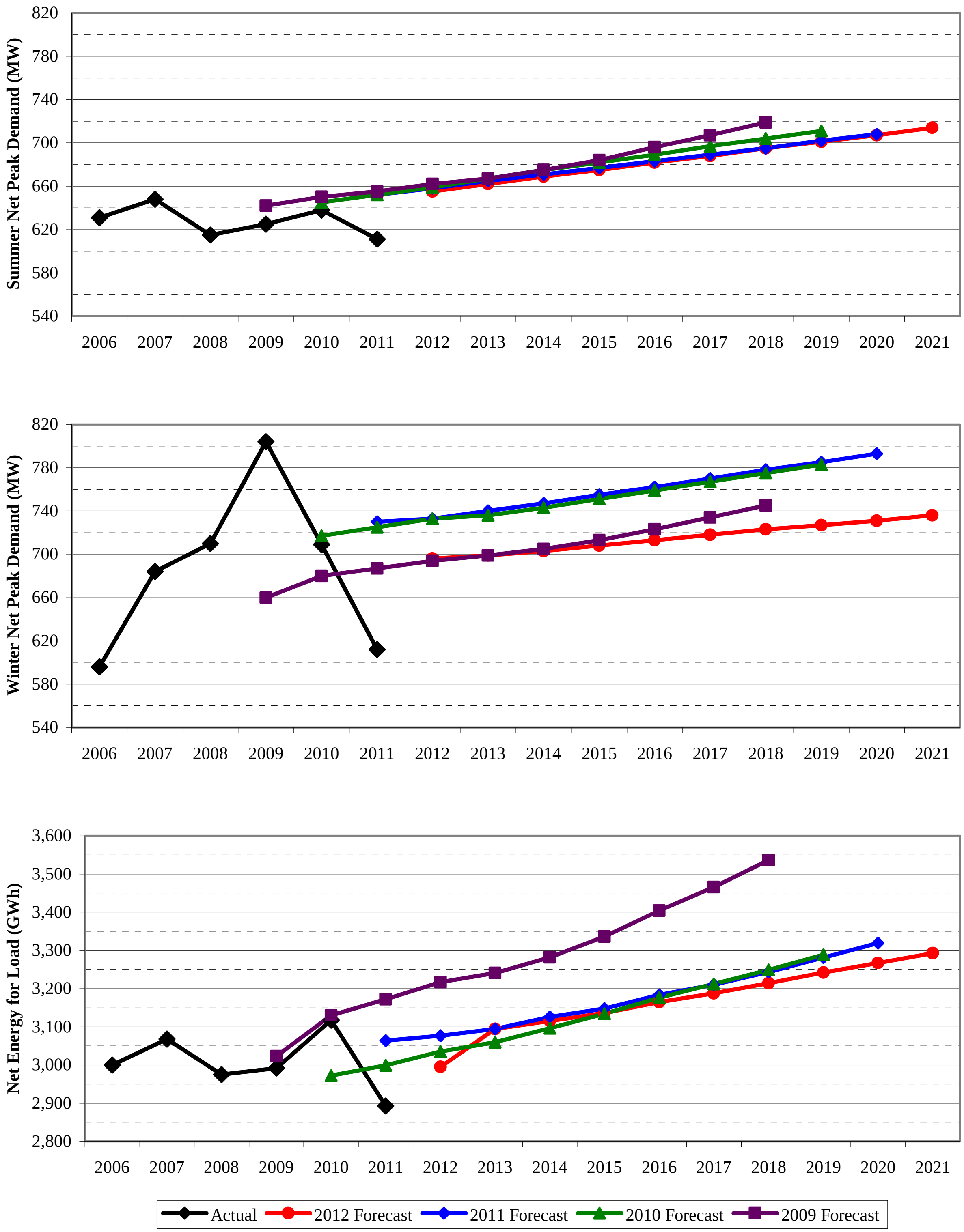


Source: LAK 2012 TYSP

The following three graphs in LAK Figure 2 show LAK's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is equivalent to last year's for summer peak demand and NEL, but notably below for winter peak demand.

Analysis of LAK's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that LAK's average forecast error is 7.89 percent. This value indicates that the company tends to over-forecast its retail energy sales by 7.89 percent, which is favorable when compared to the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

LAK Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

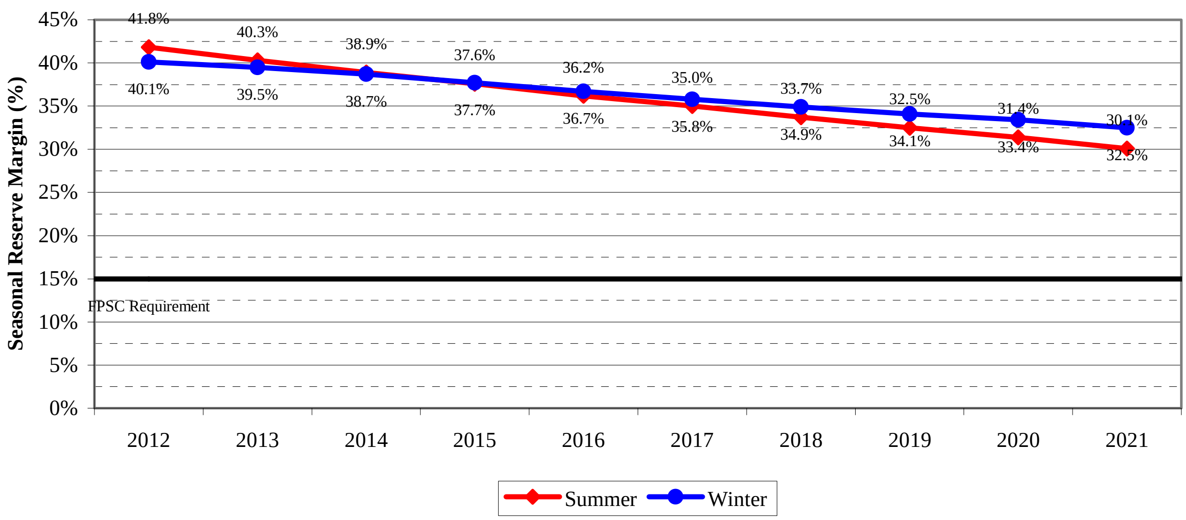


Source: LAK 2009 - 2012 TYSPs

Reserve Margin Requirement

As an FRCC utility, LAK maintains a 15 percent minimum reserve margin. As LAK Figure 3 shows, although LAK's reserve margin decreases steadily over the planning horizon, it remains well above the minimum level of 15 percent.

LAK Figure 3. Seasonal Reserve Margin

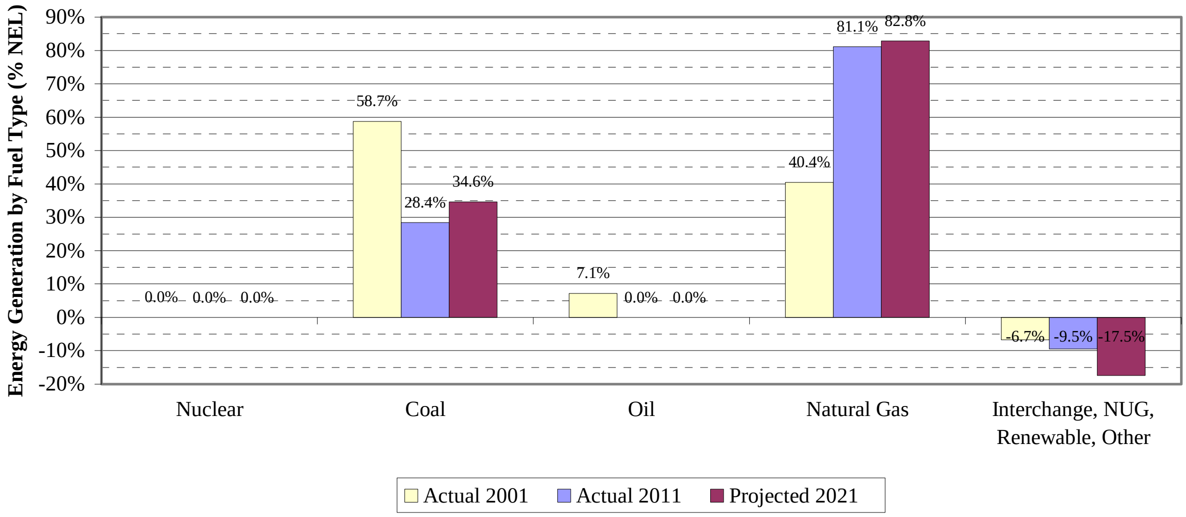


Source: LAK 2012 TYSP

Fuel Diversity

LAK Figure 4 displays the composition of LAK's system in terms of energy generated. Natural gas has increased its share of the company's energy from 40.4 percent in 2001 to 81.1 percent in 2011. While coal and oil made a significant portion of generation historically, oil usage has been drastically reduced, and coal's portion of generation has declined to approximately a third of system energy. LAK also makes significant energy sales, which cause its total energy produced to exceed 100 percent of its native load.

LAK Figure 4. Net Energy for Load by Fuel Type



Source: LAK 2012 TYSP

Generation Additions

LAK has no planned generation additions over the planning horizon. This is consistent with the company's 2011 TYSP, which also included no new generating units through 2020.

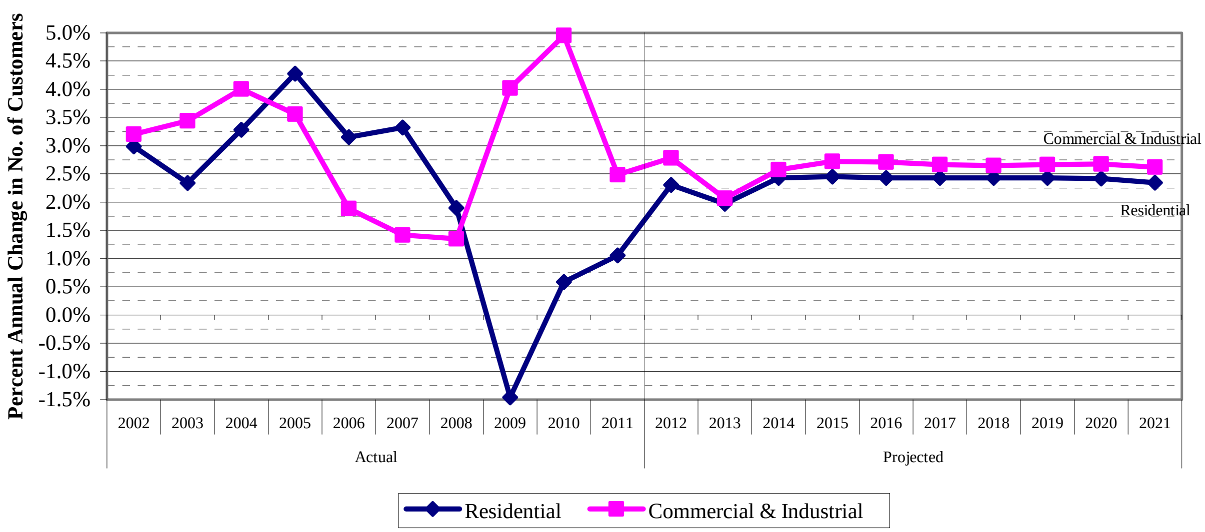
OUC is a municipal utility, and the state's seventh largest TYSP utility. The utility's service territory is within the FRCC region, and serves the Orlando metropolitan area. OUC is a member of the FMPP, along with LAK and FMPA's All-Requirements Project (ARP). As OUC is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning.

In 2011, OUC had an average 209,638 customers, and had a total net energy for load of 6,977 GWh, approximately 2.9 percent of the NEL generated in the state last year.

Peak Demand and Energy Forecasts

OUC Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth for 2012 through 2021. Overall, OUC projected a steady growth throughout the planning period, with an average annual growth rate of 2.40 percent through 2021. This compares with the actual rate of 3.22 percent for the period 2002 through 2007.

OUC Figure 1. Annual Customer Growth Rate by Customer Class

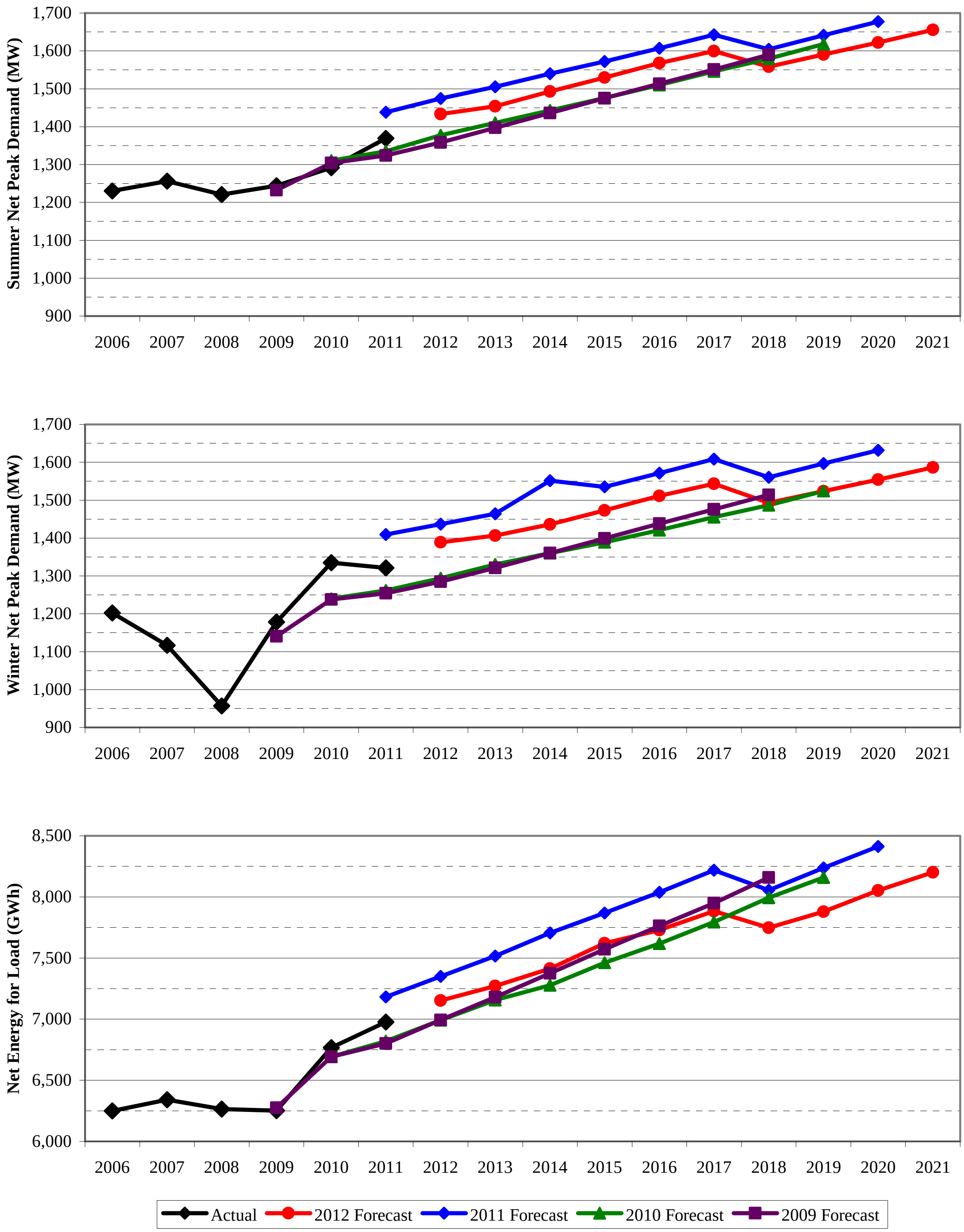


Source: OUC 2012 TYSP

The following three graphs in OUC Figure 2 show OUC's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is below last year's for both seasonal peaks and NEL.

Analysis of OUC's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that OUC's average forecast error is 5.83 percent, the second lowest error rate in 2012. This value indicates that the company tends to over-forecast its retail energy sales by 5.83 percent, which is favorable when compared to the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

OUC Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

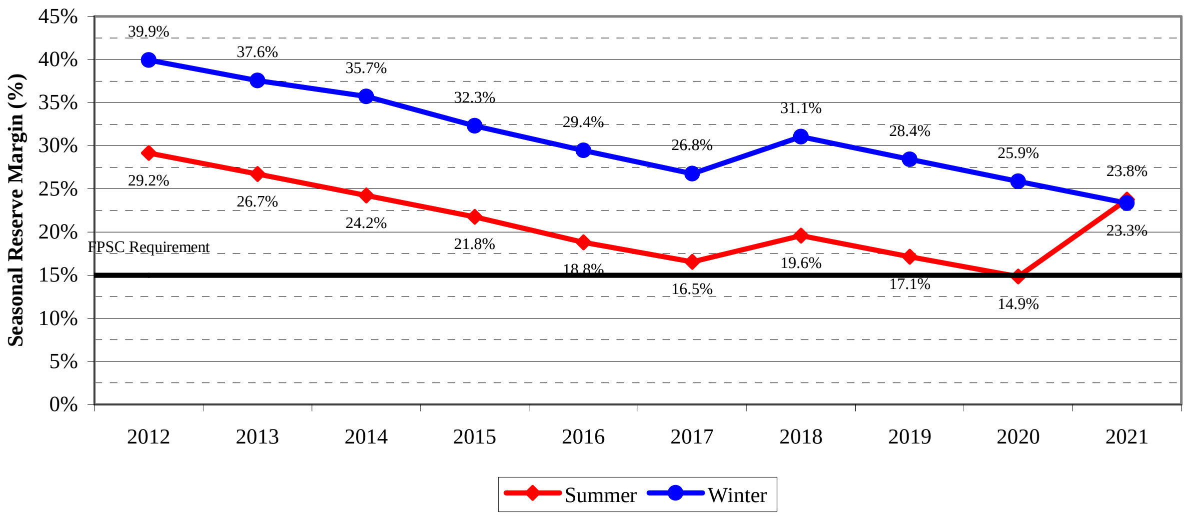


Source: OUC 2009 - 2012 TYSPs

Reserve Margin Requirement

OUC maintains a 15 percent reserve margin pursuant to FRCC requirements. OUC Figure 3 shows their projected reserve margin, which is sufficient for both summer and winter seasonal peaks. OUC does not have active load management and interruptible load programs as part of its DSM program, and therefore has no energy efficiency component included in its reserve margin.

OUC Figure 3. Seasonal Reserve Margin

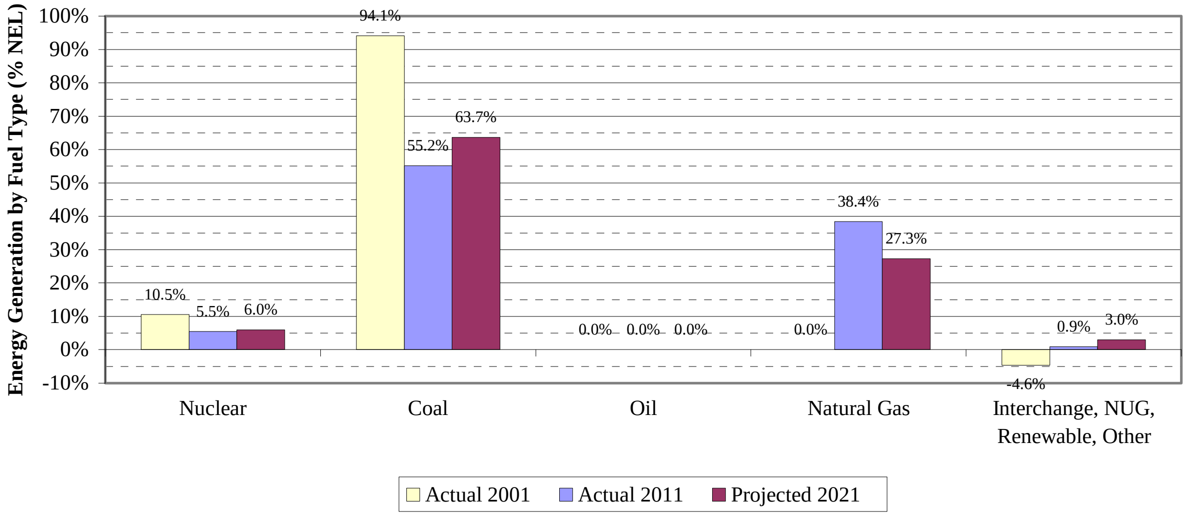


Source: OUC 2012 TYSP

Fuel Diversity

OUC Figure 4 displays the composition of OUC's system in terms of energy generated. As seen in the figure, OUC is historically a coal dependent utility, and as of 2001 did not use natural gas for generation, and was a net exporter of energy. However, by 2011, natural gas had assumed a significant role in OUC's system, with 38.4 percent of generation, as compared to 55.2 percent for coal. The utility's projected fuel mix shows an increase in coal over the planning period, which would result in a reduction of natural gas from its current level.

OUC Figure 4. Net Energy for Load by Fuel Type



Source: OUC 2002 and 2012 TYSPs

Generation Additions

OUC's 2012 TYSP includes a single new generating unit, an sited 185 MW natural gas-fired combustion turbine with an in-service date in 2021, as detailed in OUC Table 1 below.

OUC Table 1. Planned Generation Additions

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Combustion Turbine Unit Additions				
Unknown CT1	185	N/A	N/A	05/2021

Source: OUC 2012 TYSP

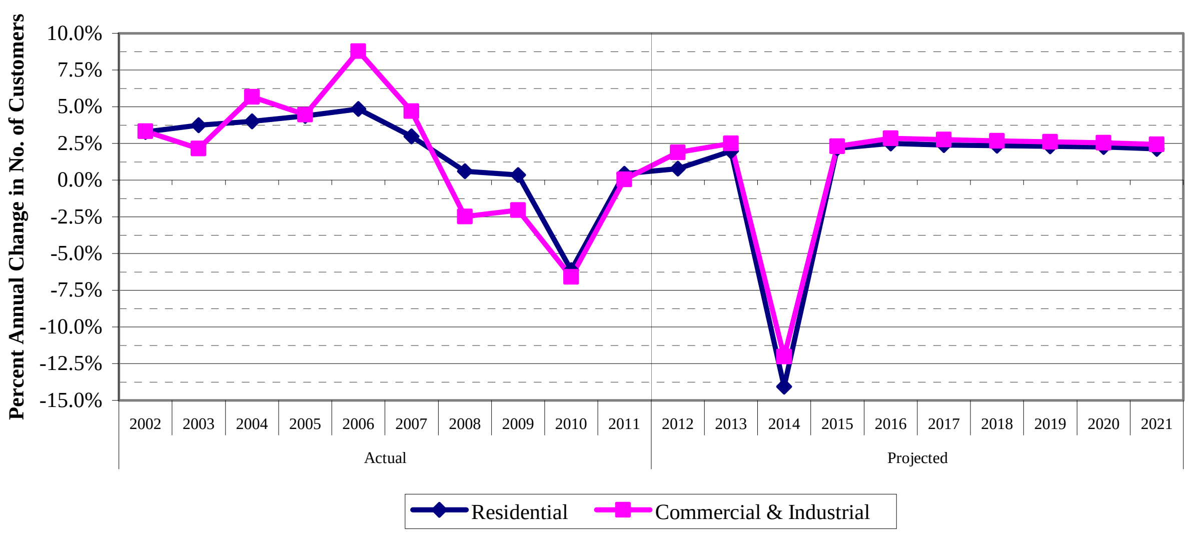
SEC is a corporation that provides electric power to its distribution members' systems, and is collectively the state's fourth largest TYSP utility. SEC is a generation and transmission rural electric cooperative that serves only wholesale customers that purchase power from SEC under long-term wholesale power contracts. SEC is within the FRCC Region, with load serviced throughout the State of Florida. Its generation assets are primarily within the central region. As SEC is a rural electric cooperative, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning

In 2011, SEC had an average 849,059 customers, and had a total net energy for load of 16,037 GWh, approximately 6.7 percent of the NEL generated in the state last year.

Peak Demand and Energy Forecasts

SEC Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth for 2012 through 2021. Generally the utility expects level growth throughout the planning period, with the exception of 2014. As SEC is composed of multiple members, the overall growth of the utility is heavily impacted by their departure. The projected drop in customers in 2014 is due to the Lee County Electric Cooperative load no longer being served by SEC beginning January 1, 2014.

SEC Figure 1. Annual Customer Growth Rate by Customer Class

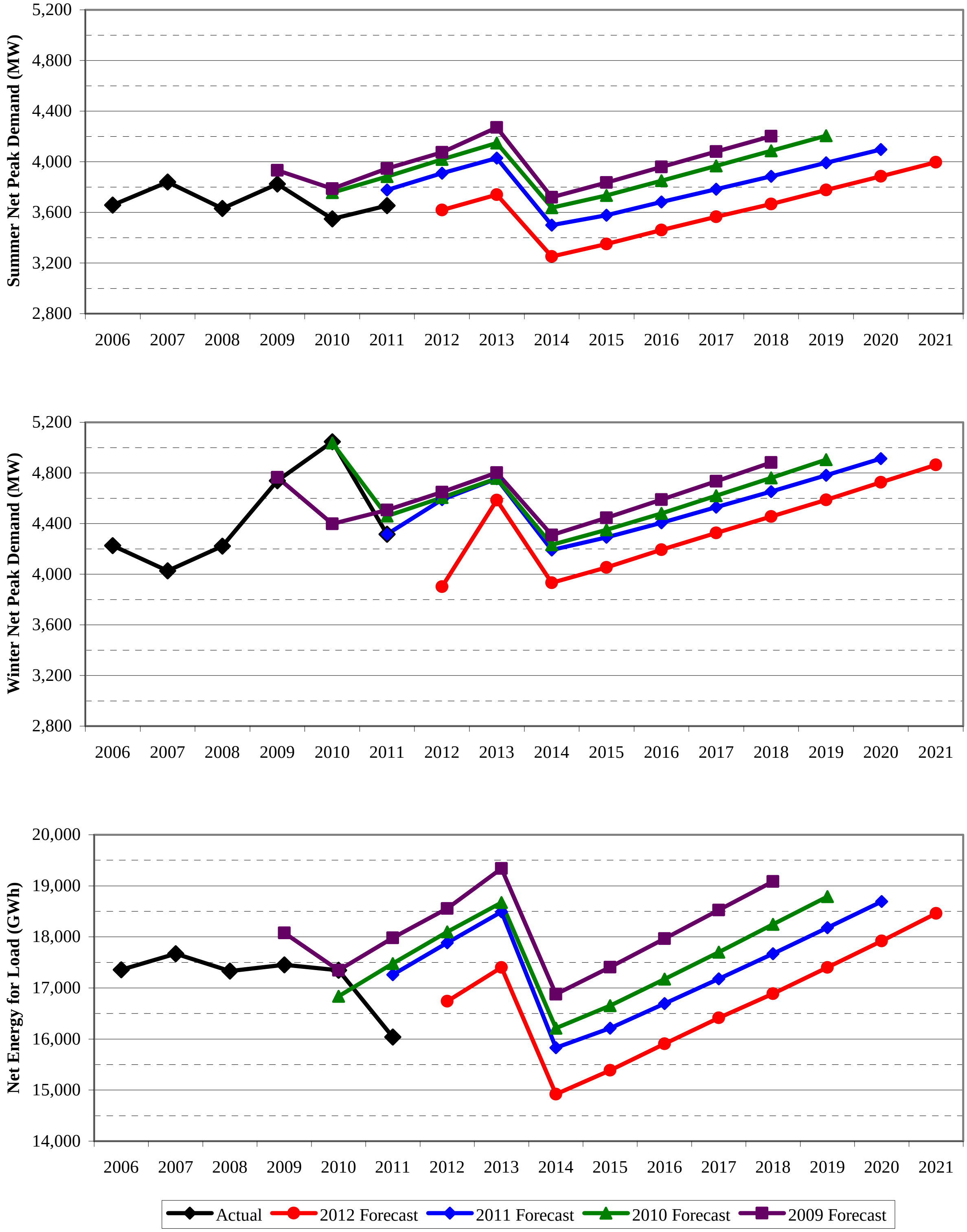


Source: SEC 2012 TYSP

The following three graphs in SEC Figure 2 show SEC's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is below last year's for both seasonal peaks and NEL. The forecasts show a significant drop in 2014, associated with the reduction in customers discussed above.

Analysis of SEC's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that SEC's average forecast error is 11.41 percent. This value indicates that the company tends to over-forecast its retail energy sales by 11.41 percent, which is approximately equivalent to the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

SEC Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

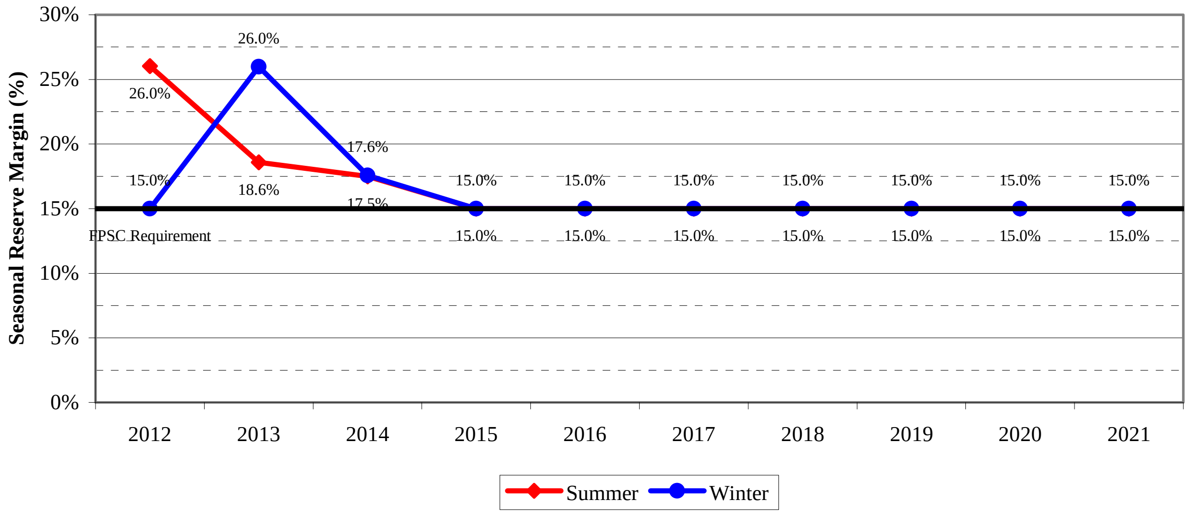


Source: SEC 2009 - 2012 TYSPs

Reserve Margin Requirement

As SEC is within the FRCC region, it is required to meet a 15 percent reserve margin requirement. SEC projects its reserve margin to remain at or above this requirement for both summer and winter seasonal peaks, as shown in SEC Figure 3.

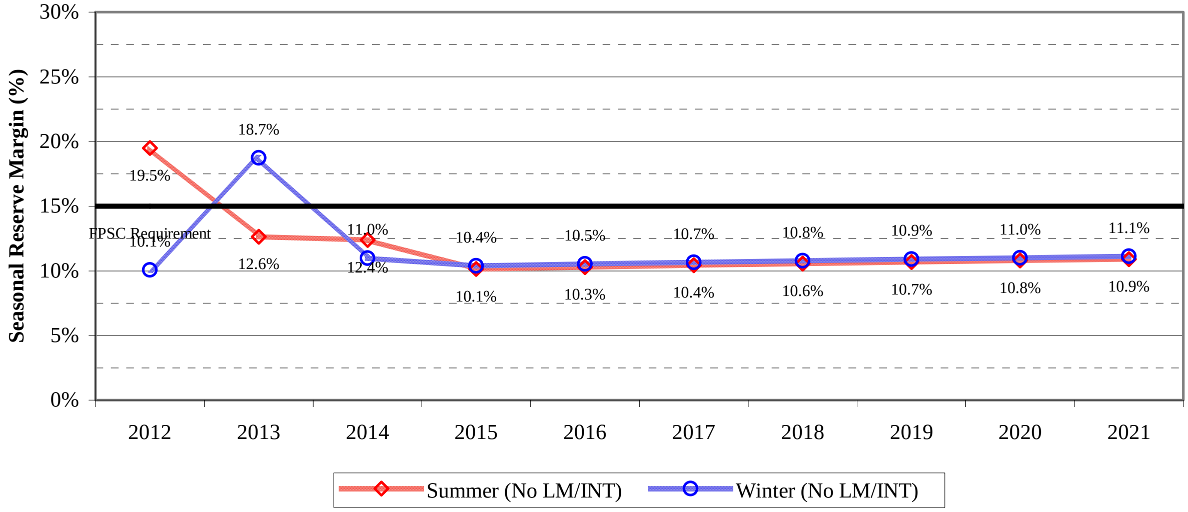
SEC Figure 3. Seasonal Reserve Margin (With LM/INT)



Source: SEC 2012 TYSP

Because SEC does offer load management programs, a portion of its reserve margin can be attributed to non-firm load. The measure of reserve margin without any contribution from demand-side programs is shown in SEC Figure 4. As the figure shows, SEC's reserve margin is projected to remain at approximately 10 percent without activating demand response programs.

SEC Figure 4. Seasonal Reserve Margin (Without LM/INT)

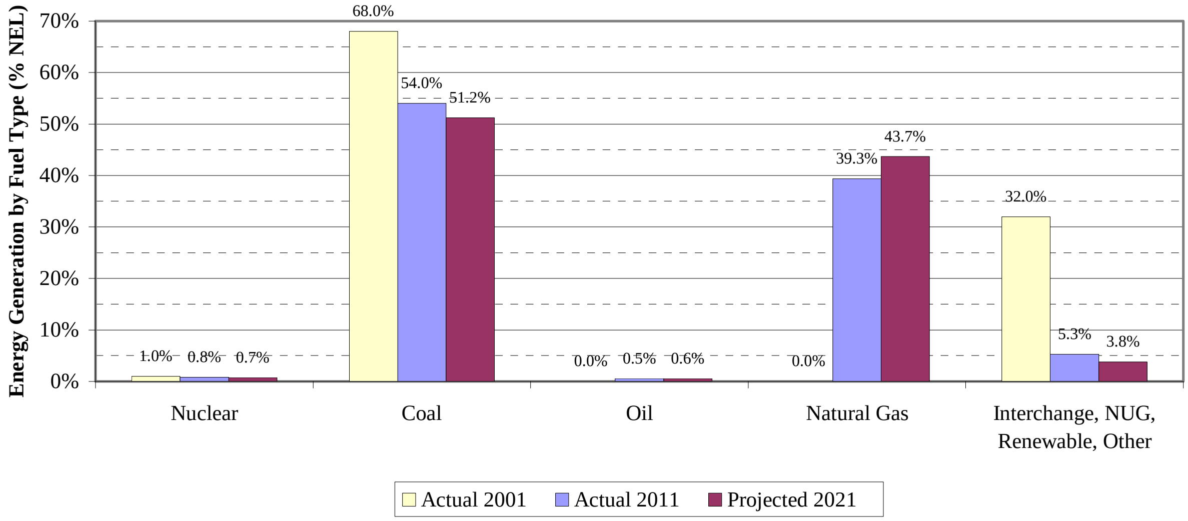


Source: SEC 2012 TYSP

Fuel Diversity

SEC Figure 5 displays the composition of SEC's system in terms of energy generated. As the figure shows, SEC is historically a coal dependent utility, though this portion has decreased from 68 percent in 2001 to 54 percent in 2011. SEC did not have any generation from natural gas in 2001, but now a significant portion of its generation comes from natural gas units. While purchased power made up a significant portion of system reserves, this has decreased dramatically, from 32 percent to 5.3 percent last year. Generally, SEC's projected fuel mix is unchanged, except for a slight shift from coal and purchased power towards natural gas generation.

SEC Figure 5. Net Energy for Load by Fuel Type



Source: SEC 2002 and 2012 TYSPs

Generation Additions

SEC's 2012 TYSP includes the addition of nine natural gas combustion turbine units, and three combined cycle units by the end of the planning period. SEC Table 1 details the generation additions below.

SEC Table 1. Planned Generation Additions

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Combustion Turbine Unit Additions				
Unnamed CT1	158	N/A	N/A	12/2018
Unnamed CT2	158	N/A	N/A	12/2019
Unnamed CT3	158	N/A	N/A	12/2020
Unnamed CT4	158	N/A	N/A	12/2020
Unnamed CT5	158	N/A	N/A	12/2020
Unnamed CT6	158	N/A	N/A	05/2021
Unnamed CT7	158	N/A	N/A	12/2021
Unnamed CT8	158	N/A	N/A	12/2021
Unnamed CT9	158	N/A	N/A	12/2021
Combined Cycle Unit Additions				
Unnamed CC1	196	-	-	Dec-20
Unnamed CC2	196	-	-	Dec-20
Unnamed CC3	196	-	-	Dec-21

Source: SEC 2012 TYSP

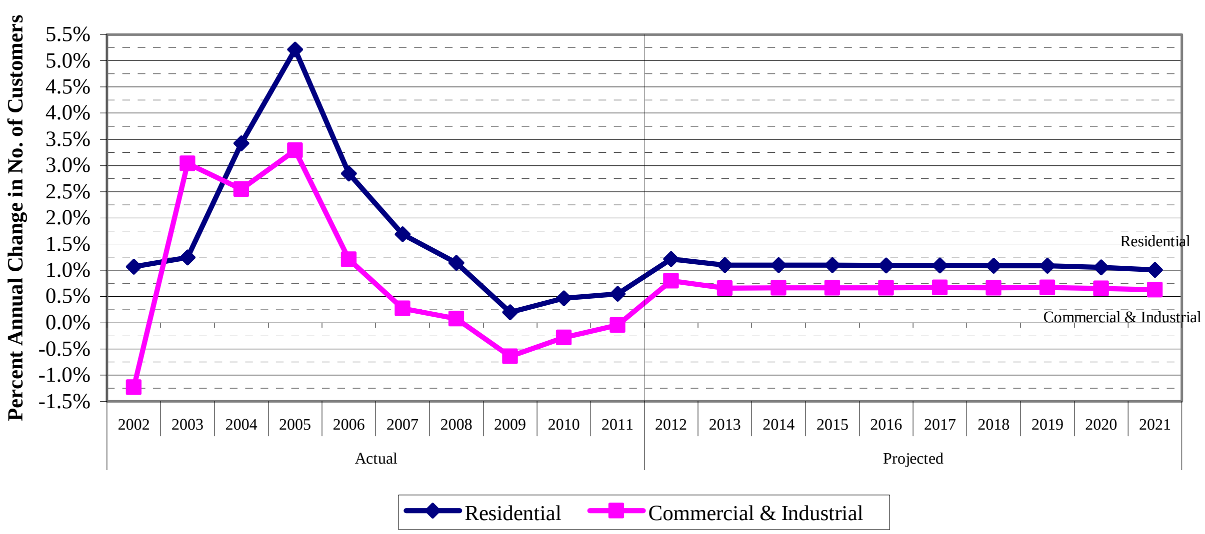
TAL is a municipal utility, and the state's second smallest TYSP utility. The utility's service territory is within the FRCC region, in Leon County, and primarily serves the City of Tallahassee. As TAL is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning.

In 2011, TAL had an average 114,212 customers, and had a total net energy for load of 2,799 GWh, approximately 1.2 percent of the NEL generated in the state last year.

Peak Demand and Energy Forecasts

TAL Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth for 2012 through 2021. A level, but positive growth is anticipated over the entire planning period, with an average annual growth rate of 1.01 percent. This compares to the actual average growth rate of 2.74 percent for the period 2002 through 2007, before the economic downturn.

TAL Figure 1. Annual Customer Growth Rate by Customer Class

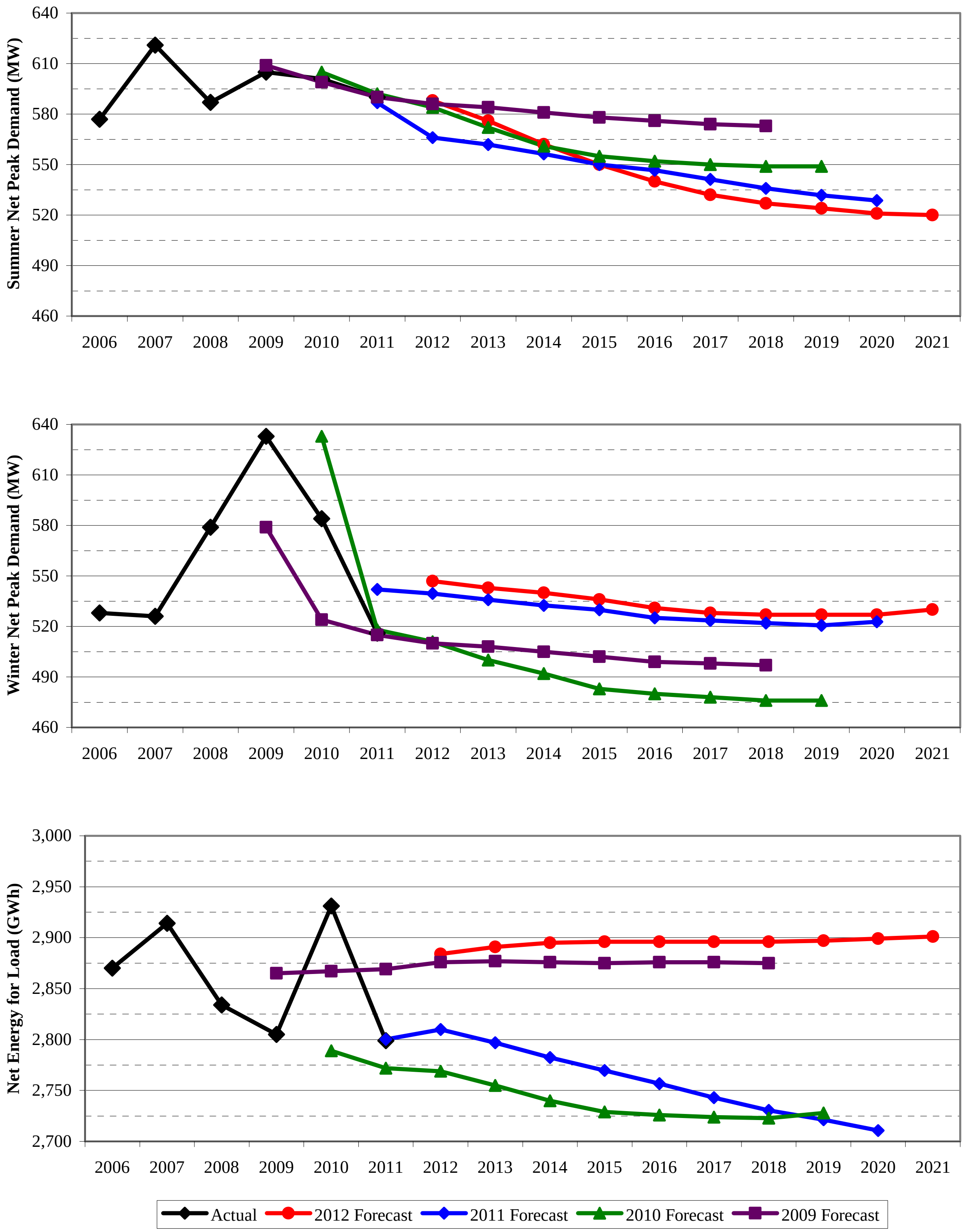


Source: TAL 2012 TYSP

The following three graphs in TAL Figure 2 show TAL's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is similar for seasonal peak demand, but higher for NEL.

Analysis of TAL's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that TAL's average forecast error is 8.77 percent. This value indicates that the company tends to over-forecast its retail energy sales by 8.77 percent, which is favorable when compared to the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

TAL Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

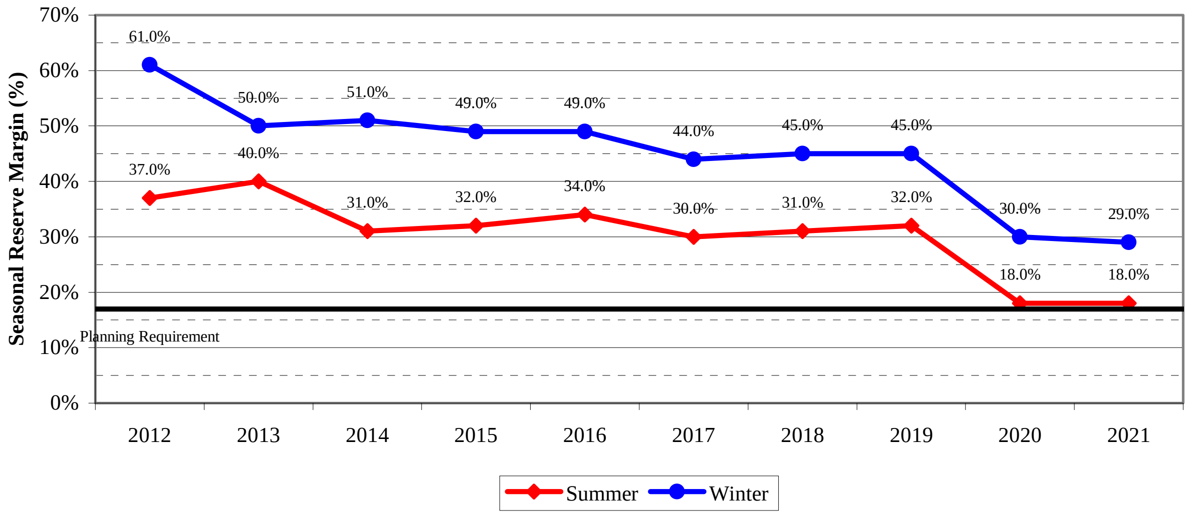


Source: TAL 2009 - 2012 TYSPs

Reserve Margin Requirement

As TAL is within the FRCC region, it is required to meet a 15 percent reserve margin requirement. However, TAL has adopted an 18 percent planning reserve margin requirement, as reflected in TAL Figure 3 below. TAL has sufficient reserve margin including the impact of demand response.

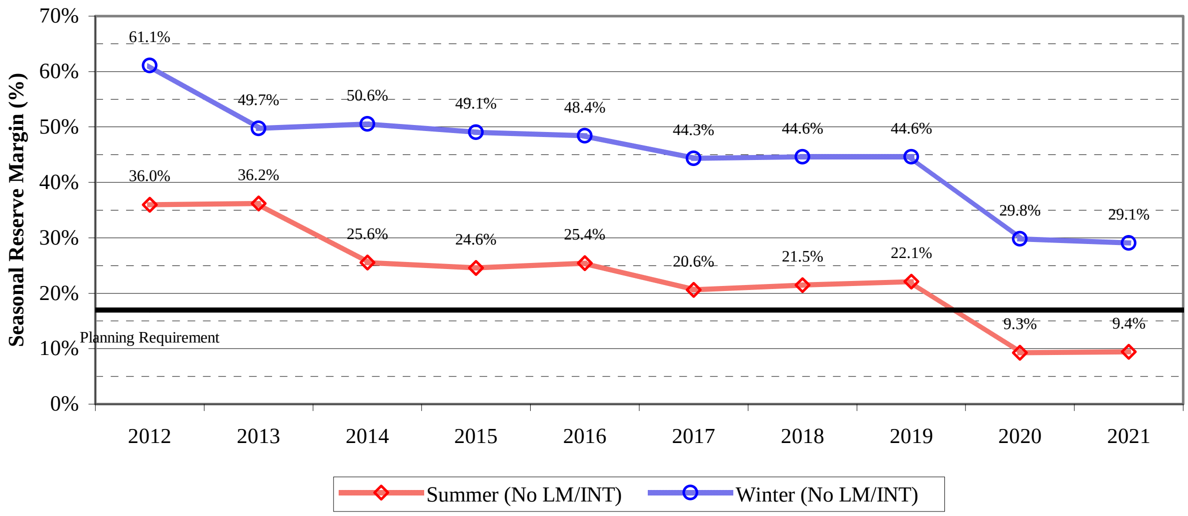
TAL Figure 3. Seasonal Reserve Margin (With LM/INT)



Source: TAL 2012 TYSP

In addition to supply-side resources, TAL has interruptible load and load management programs, which assist the utility in meeting reserve margin requirements. TAL Figure 4 below illustrates the impact on reserve margin of excluding demand response programs. As seen below, the summer peak demand period would fall below the planning reserve margin without the use of demand response programs to reduce peak demand in the outer years.

TAL Figure 4. Seasonal Reserve Margin (Without LM/INT)

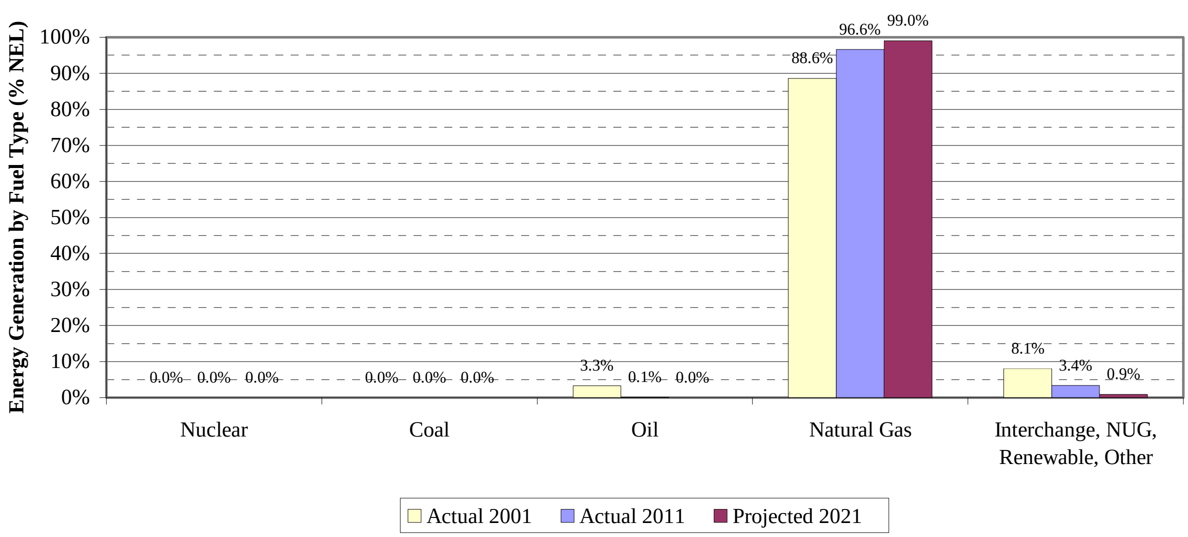


Source: TAL 2012 TYSP

Fuel Diversity

TAL Figure 5 displays the composition of Tallahassee's system in terms of energy generated. As seen below, TAL has an almost exclusive dependence on natural gas, and by the end of the planning period almost 100 percent of energy for load will be from natural gas. The only other sources of energy on TAL's system are oil, purchased power, and renewable energy.

TAL Figure 5. Net Energy for Load by Fuel Type



Source: TAL 2002 and 2012 TYSPs

Generation Additions

TAL has no planned generation additions over the planning horizon. This represents a decline from the company’s 2011 TYSP, which anticipated the addition of a 46 MW combustion turbine unit in 2020.

Appendix A to the
Review of the
2012 Ten-Year Site Plans
For Florida's Electric Utilities

Comments From
State, Regional, and Local Agencies,
& Other Organizations

Florida Public Service Commission

Tallahassee, FL
December 2012

Ten-Year Site Plan Comments

State Agencies
- Florida Department of Economic Opportunity
- Florida Department of Transportation
- Fish & Wildlife Conservation Commission

Regional Planning Councils (RPCs)
- Central Florida RPC
- East Central Florida RPC
- North Central Florida RPC
- Treasure Coast RPC

Water Management Districts (WMDs)
- Southwest Florida WMD
- St. Johns River WMD

Other Organizations
- Seminole Tribe of Florida
- South Florida Wildlands Association
- Sierra Club
- Sierra Club & Earthjustice

State Agencies

Florida Department of Economic Opportunity

Rick Scott
GOVERNOR

12 JUN 27 AM 9:53

DIVISION OF
REGULATORY COMPLIANCE

FLORIDA DEPARTMENT of ECONOMIC OPPORTUNITY

Hunting F. Deutsch
EXECUTIVE DIRECTOR

June 29, 2012

Mr. Michael S. Haff
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Mr. Haff:

At your request we have reviewed the 2012 Ten-Year Site Plans of the electric utilities. The Department of Economic Opportunity's review focused on potential sites for future power generation, and the compatibility of those sites with the applicable local comprehensive plan, including the adopted future land use map, adjacent land uses, and natural resources on or adjacent to the potential sites.

Our review of the 2012 Ten-Year Site Plans addressed sixteen potential power plant sites identified in the Ten-Year Site Plans of the following utilities: Florida Power & Light Company, Gulf Power Company, and Seminole Electric Cooperative. None of the potential sites were found to be incompatible with the applicable local comprehensive plan.

Should you have any questions regarding these comments, please call Julie Evans, Planning Analyst, at (850) 717-8485.

Sincerely,

J. Thomas Beck

J. Thomas Beck, AICP
Director, Division of Community Development

JTB/je
Enclosure

Florida Department of Economic Opportunity | The Caldwell Building | 107 E. Madison Street | Tallahassee, FL | 32399-4120
866.FLA.2345 | 850.245.7105 | 850.921.3223 Fax | www.FloridaJobs.org | www.twitter.com/FLDEO | www.facebook.com/FLDEO

2012 Ten-Year Site Plan Review

Three utilities, Gulf Power, Florida Power and Light, and Seminole Electric, have identified a total of sixteen potential sites for future power generation. Potential sites are defined in Rule 25-22.070, F.A.C. as "sites within the state that an electric utility is considering for possible location of a power plant, a power plant alteration, or an addition resulting in an increase in generating capacity." These sites are discussed below.

1. Gulf Power

In its Ten-Year Site Plan, Gulf Power stated it will consider five properties as potential sites for future generating facilities. Three potential sites contain existing power plants: Plant Crist in Escambia County, Plant Smith in Bay County, and Plant Scholtz in Jackson County. Two sites, Shoal River in Walton County, and Caryville in Holmes and Washington Counties, are undeveloped.

A. Crist Site. This site, located adjacent to the Escambia River, is designated Industrial and Agriculture on the adopted Future Land Use Map (FLUM). Electric power generation facilities are an allowed use in the Industrial category, and may be allowed as a conditional use in Agriculture. The northern and eastern parts of the site are located in the coastal high hazard area, and contain wetlands and 100-year floodplain. Adjacent land uses are Industrial, Conservation, Agriculture and Mixed-Use Suburban.

For information regarding the location of the coastal high hazard area relative to the site, contact Julie Dennis with the Department of Economic Opportunity, Bureau of Comprehensive Planning, at (850) 717-8478. For wetland compatibility issues, contact the Department of Environmental Protection (DEP) Office of Submerged Lands and Environmental Resources at (850) 2456-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960

B. Smith Site. Located in Bay County, the Smith site is adjacent to the North Bay area of St. Andrews Bay. The site is located in the Category 1, 2, 3 and 4 storm surge zones. It is designated Industrial and Conservation on the adopted FLUM. Public utilities are allowed uses in both Industrial and Conservation. Adjacent land uses are Agriculture-Timber and Conservation. Wetlands and 100-year floodplains are also located onsite.

For further information regarding the location of storm surge zones relative to the site, Gulf Power should contact Julie Dennis with the Department of Economic Opportunity, Bureau of Comprehensive Planning, at (850) 717-8478. For assistance with wetland compatibility issues, contact the DEP Office of Submerged Lands and Environmental Resources at (850) 245-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960

C. Scholtz Site. This site, located in Jackson County, is adjacent to the Apalachicola River, an Outstanding Florida Water. The site is designated Agricultural-1 and Conservation. An electrical generating facility may be allowed as a conditional use in Agricultural-1; however, this use is not allowed in Conservation. Parts of the eastern and southeastern areas of the site are located in the 100-year floodplain. Wetlands are also present onsite. Gulf Power should contact the following DEP offices for further information: 1) for compatibility with OFWs, contact the Standards and Assessment section at (850) 245-8064; 2) for wetland compatibility issues, contact the Office of Submerged Lands and Environmental Resources at (850) 245-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960.

D. Shoal River Site. This is a greenfield site located in Walton County. It is adjacent to the Shoal River, an Outstanding Florida Water. The site is designated Rural-Residential to the south and Agricultural to the north. Wetlands and 100-year floodplain areas are primarily located along the southern part of the site, adjacent to the Shoal River. Walton County is currently working with Eglin Air Force Base to identify Military Influence Planning Areas. While these areas have not been finalized, it is possible that the Shoal River site may be located within a future Military Influence Planning Area.

Gulf Power should contact the following DEP offices for further information regarding natural resources: 1) for compatibility with OFWs, contact the Standards and Assessment section at (850) 245-8064; 2) for wetland compatibility issues, contact the Office of Submerged Lands and Environmental Resources at (850) 245-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960. For further information regarding compatibility issues with Eglin Air Force Base, contact Jeffrey Fanto, Community Planner, Eglin Air Force Base, at (850) 882-8036.

E. Caryville Site. Located in Holmes County, Washington County, and the City of Caryville, this site is adjacent to the Choctawhatchee River. It is designated Agriculture in Holmes County, Agriculture/Silviculture in Washington County, and Agriculture and Conservation in Caryville. In all three jurisdictions, public utilities are allowed in areas designated Agriculture. The site is surrounded by agricultural land uses. Floodplain and wetland areas exist throughout the site.

Gulf Power should contact the following DEP offices for further information: 1) for compatibility with OFWs, contact the Standards and Assessment section at (850) 245-8064; 2) for wetland compatibility issues, contact the Office of Submerged Lands and Environmental Resources at (850) 245-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960.

2. Florida Power and Light. FPL has identified ten potential sites, described below.

A. Babcock Ranch, Charlotte County. This site is designated Babcock Ranch Overlay District (BROD) on the FLUM. The Development Order for the Babcock Ranch Development of Regional Impact (DRI) identifies this site as a Primary Active Greenway approved for the placement of solar generating facilities. Adjacent land uses to the east, west and south are also BROD. Land north of the site is designated Resource Conservation. The BROD is being developed under a cohesive set of policies, guided by the comprehensive plan, through the Master Incremental DRI process. No environmental or other compatibility issues have been identified for this site.

B. DeSoto Solar Expansion, DeSoto County. This site is designated Electrical Generating Facility on the adopted Future Land Use Map. The surrounding FLUM designations are Electrical Generating Facility and Rural/Agriculture. The site has been disturbed as a result of agricultural activities on the property. It is adjacent to an existing transportation corridor with roadway capacity. Demands on water facilities have already been considered in the growth projections of the Comprehensive Plan. No environmental or other compatibility issues have been identified for this site.

C. Florida Heartland Solar site, Glades County. This site is designated Agriculture/Open. An electrical generating facility is required to meet locational and siting criteria; therefore, such facility would likely have to be approved as a conditional or special use. The site is primarily surrounded by Agriculture/Open Space. There is also an adjacent area designated Transition which allows residential, non-residential and agricultural uses. No environmental or other compatibility issues have been identified for this site.

D. Hendry County site. The Hendry site, designated Agricultural on the FLUM, consists of over 3,000 acres in the southern part of the County. Utilities, including electrical generating facilities, are an allowed use in Agricultural. The site has been disturbed as a result of its use for crops and pastureland. There are scattered wetlands onsite. Significant areas in Hendry County are Florida panther habitat. FPL has offered to provide panther habitat corridors onsite and/or provide habitat mitigation if needed.

For assistance with wetland compatibility issues, FPL should contact the Office of Submerged Lands and Environmental Resources at (850) 245-8474.

E. Manatee Plant site, Manatee County. This site is designated Public/Semipublic-2 on the adopted FLUM. Power generating facilities are an allowed use in this FLUM category. Adjacent uses are Public/Semipublic-2 and Agricultural-Rural. The site is also adjacent to Lake Parrish, which provides water to the existing power facility. Much of the property is disturbed due to agricultural activities onsite. No environmental or other compatibility issues have been identified for this site.

F. Martin County site: FPL is currently evaluating potential sites in Martin County for a future solar facility. No specific locations have been selected. The County's adopted comprehensive plan contains provisions for siting power generating facilities which use renewable energy sources. Future Land Use Policy 4.8C.1 allows alternative energy facilities in appropriate zoning districts. The policy states, "As the technology for wind, solar and other forms of power generation advance, the Land Development Regulations shall be revised to permit different forms of power generation in appropriate zoning districts." Policy 4.13A.12, which addresses the Public Utilities FLUM category, states: "electrical power facilities solely utilizing solar, wind or other renewable energy fuel or energy source may be permitted in any other Future Land Use Designation, consistent with the Land Development Regulations."

G. Northeast Okeechobee County. FP&L is considering a potential site in northeast Okeechobee County. The specific site location was not provided in the TYSP. The predominant land use designation in this area is Agriculture. Public and institutional uses, including power generation, are allowed in Agriculture. Two areas designated Rural Activity Center, and one

Resort Activity Center, also exist in northeast Okeechobee County. Wetlands and 100-year floodplain are located in the northeast County area; however, sufficient upland areas exist to support a power plant site.

For assistance with wetland compatibility issues, FPL should contact the Office of Submerged Lands and Environmental Resources at (850) 245-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960.

H. Palatka Site. Located in unincorporated Putnam County, this site is designated Industrial, Agriculture, and Rural Residential. There is an existing power plant onsite. Electrical generating facilities are allowed as a principal use in the Industrial category. Surrounding land uses are Agriculture to the north and east, Industrial to the south, and the St. Johns River to the west.

I. Putnam County Site. FPL is currently evaluating potential sites in Putnam County for a future solar facility or natural gas-powered facility. No specific locations have been identified. Sites currently under investigation are approximately 2,800 acres in area. The Industrial and Community Facilities and Services land use categories allow electrical generating plants. The County's Comprehensive Plan contains policies that address compatibility and suitability of land uses, as well as directing development away from environmentally sensitive lands.

J. Space Coast Solar Expansion, Brevard County. FPL currently owns a ten-megawatt solar generating facility, known as the Space Coast Next Generation Solar Energy Center, in Brevard County at NASA's Kennedy Space Center (KSC). FPL is considering additional solar generating capacity at this site. NASA's Future Development Concept (FDC) document, which serves as the foundation for the Center Master Plan, supports solar generating facilities at KSC. The FDC states that there are several sites at KSC designated for renewable energy research and production. The sites are intended to help facilitate KSC's goal of achieving increased on-site power generation from renewable energy sources. No environmental or other compatibility issues have been identified for this site.

3. Seminole Electric.

Seminole Electric has identified one site, a 530-acre parcel located northeast of the City of Bell in Gilchrist County, as a potential power plant site. The site is designated Agricultural on the adopted Future Land Use Map. Electric generating facilities may be permitted as a special use in areas designated Agricultural. Issues that would be considered by the County through the special use review process include the amount of water projected to be used by the facility, the impact of water use on agricultural activities, and the impact of the facility on natural resources, including aquifer recharge areas and wetlands. The Gilchrist parcel is located near the Wacasassa Flats, a 50,000-acre high quality wetlands-to-uplands ecosystem located in the middle of the County. Wacasassa Flats is a perched water table system that provides significant water storage, water filtering and wildlife habitat.

For assistance with wetland compatibility issues, Seminole Electric should contact the Office of Submerged Lands and Environmental Resources at (850) 245-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960.

4. Utilities With No Potential Sites Identified in the TYSP: The following utilities identified no potential sites in their TYSPs: Gainesville Regional Utilities, Progress Energy Florida, Lakeland Electric, City of Tallahassee, Florida Municipal Power Agency, Tampa Electric Company, JEA and Orlando Utilities Commission.

MENT of
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UNITY

~~Mr. Michael S. H~~
~~Florida Public S~~
~~2540 Shumard~~
~~Tallahassee, FL~~

3239980850 C001

State Agencies

Florida Department of Transportation

Florida Department of Transportation

RICK SCOTT
GOVERNOR

605 Suwannee Street
Tallahassee, FL 32399-0450

ANANTH PRASAD, P.E.
SECRETARY

June 21, 2012

Phillip Ellis
Division of Regulatory Analysis
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Dear Mr. Ellis:

The Siting Coordination Office has reviewed the ten-year site plans and find these are suitable as planning documents. If you have any questions please feel free to call me at (850)414-4572.

Sincerely,

Connie Mitchell
Siting Coordination Office

www.dot.state.fl.us

State Agencies

Fish & Wildlife Conservation Commission

Florida Fish and Wildlife Conservation Commission

Office of the Executive Director
Nick Wiley
Executive Director

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(850) 921-5786 FAX

Managing fish and wildlife resources for their long-term well-being and the benefit of people.

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MyFWC.com

June 28, 2012

Mr. Phillip Ellis
Division of Regulatory Analysis
Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
pellis@psc.state.fl.us

Re: Progress Energy Florida's Ten-Year Site Plan: 2012 – 2021, Multiple Counties

Dear Mr. Ellis:

The Florida Fish and Wildlife Conservation Commission (FWC) has reviewed the 2012 – 2021 Ten-Year Site Plan (Plan) submitted by Progress Energy Florida (PEF) and provides our comments, pursuant to Rule 25-22.071, Florida Administrative Code.

PEF provides electrical service to 35 counties in central and north-central Florida (Figure 1.1 in the Plan) through the use of 63 power plant units that use steam, combined-cycle, or combustion turbine technology (Table 3.1 in the Plan) for production. Electricity is then transmitted through roughly 5,000 circuit miles of transmission lines and distributed through about 18,000 circuit miles of overhead conductors and 13,000 circuit miles of underground cable (p. 1-1 of the Plan). PEF also has entered into 13 contracts for renewable and cogeneration plants and provides a number of energy conservation programs available to its customers. In addition, there are several research and development programs underway, some of which are pilot studies. The Plan consists of PEF's Base Expansion Plan, which includes resuming operations at Crystal River Unit 3, constructing and operating Levy Unit 1, and constructing a new combined-cycle facility at an as-yet undetermined location.

The FWC participated in the permitting of the Crystal River Unit 3 revisions and the new nuclear power plant in Levy County. Our input was included in the Conditions of Certification associated with each of those plants. Additionally, we encourage PEF to contact us as early as possible in the planning process for the new combined-cycle facility so we can proactively coordinate on fish and wildlife resource issues as they may relate to location, source of cooling water, and associated transmission lines.

We appreciate the opportunity to review the proposed Plan, and find that it is sufficient for planning purposes. If you need further assistance, please do not hesitate to contact Jane Chabre at (850) 410-5367 or at FWCConservationPlanningServices@MyFWC.com. If you have specific technical questions, please contact Mary Ann Poole at (850) 488-8783 or by email at maryann.poole@myfwc.com.

Sincerely,

Bonita Gorham

Bonita Gorham
Land Use Planning Program Administrator
Office of Conservation Planning Services

bg/map
Progress Energy Florida 2012 10-year Site Plan_16168_062812
ENV 1-11-2/3

Florida Fish and Wildlife Conservation Commission

Office of the Executive Director
Nick Wiley
Executive Director

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MyFWC.com

June 7, 2012

Mr. Phillip Ellis
Division of Regulatory Analysis
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
pellis@psc.statea.fl.us

RE: Gulf Power 2012 10-Year Site Plan, Multi-County

Dear Mr. Ellis:

Florida Fish and Wildlife Conservation Commission (FWC) staff has reviewed the Gulf Power 2012 10-Year Site Plan and provides the following comments and recommendations for your consideration.

Project Description

Section 186.801, Florida Statutes requires electric generating facilities to submit a ten-year site plan to the Florida Public Service Commission. Gulf Power owns and operates five plants in Northwest Florida: Plant Crist (Escambia County); Plant Lansing Smith (Bay County); Plant Sholtz (Jackson County); Pea Ridge (Santa Rosa County); and Perdido (Escambia County). Gulf Power has continued to evaluate the construction of generating facilities or the acquisition of equivalent capacity resources in coordination with other Southern Electric System (SES) operating companies. Gulf Power indicates that it has satisfied its need for firm capacity through the May 2023 time period. Any new facility construction is deferred during the 2012-2021 planning cycle. Gulf Power will consider additional capacity at its existing sites at the Plant Crist, Plant Lansing Smith, Plant Scholtz, or at the identified sites on the Shoal River property in Walton County or the Caryville property in Holmes and Washington Counties.

Potentially Affected Resources

Plant Crist (Escambia County) is located adjacent to the Escambia River, which has been designated as Critical Habitat for the Gulf Sturgeon [*Acipenser oxyrinchus desotoi* – Federal Threatened (FT)]. The undeveloped portion of the site includes mixed hardwoods/pines and mixed scrub.

Plant Lansing Smith (Bay County) is located along North Bay of the St. Andrews Bay system. The undeveloped portion of the site is predominantly pine plantation with some wetland areas. The site is adjacent to areas identified for conservation under the Bay County Sector Plan.

Plant Scholtz (Jackson County) is located adjacent to the Apalachicola River. The site consists of a mixture of pine and hardwood forests. Plant Scholtz is adjacent to the Apalachicola River, which has designated critical habitat for the Gulf Sturgeon

[*Acipenser oxyrinchus desotoi* (FT)], and critical habitat for the purple bankclimber [*Elliptoides sloatianus* (FT)] and fat three-ridge [*Amblema neislerii* - Federal Endangered (FE)].

The undeveloped Shoal River Site (Walton County) is located on the Shoal River approximately 3 miles northwest of Mossy Head, Florida. The property is predominantly in pine plantation. The site falls within a federally designated red-cockaded woodpecker consultation area; and contains primary and secondary habitat for the Florida black bear [*Ursus americanus floridanus* – State Threatened (ST)]. This site is also within close proximity to known occurrences of southern sandshell mussel (*Hamiota australis* – Federal, Candidate Endangered), blackmouth shiner [*Notropis melanostomus* – State Endangered (SE)], bluenose shiner [*Pteronotropis welaka* – State Species of Special Concern (SSC)], Eastern indigo snake [*Drymarchon couperi* – (FT)], alligator snapping turtle [*Macrochelys temminckii* (State SSC)], gopher tortoise [*Gopherus polyphemus* – (ST)], and pine barrens treefrog [*Hyla andersonii* (State SSC)].

The undeveloped Caryville Site (Holmes/Washington County) is approximately 1.5 miles northeast of Caryville, Florida. The property is predominantly in agriculture and pine plantation. The site may contain gopher tortoise [*Gopherus polyphemus* (ST)], pine barrens treefrog [*Hyla andersonii* (State SSC)], and the Eastern indigo snake [*Drymarchon couperi* (FT)]. The site is also within close proximity to the Choctawhatchee River, which contains critical habitat for the Gulf Sturgeon [*Acipenser oxyrinchus desotoi* (FT)] and known occurrences of Barbour's Map Turtle [*Graptemys barbouri* (State SSC)], Fuzzy Pigtoe (*Pleurobema strodeanum* – Federal, Candidate Endangered), and bluenose shiner [*Pteronotropis welaka* (State SSC)].

FWC appreciates the opportunity to review Gulf Power's 2012 10-year Site Plan 2012-2021 document and extends an offer to assist Gulf Power in further identifying fish and wildlife resources within their planning area. Based on our review, we have determined that there are no development plans proposed in this Gulf Power Planning document that appear to pose significant fish and wildlife resource issues or potential conflicts for this planning period. If you need further assistance, please do not hesitate to contact Jane Chabre either by phone at (850) 410-5367 or at FWCConservationPlanningServices@MyFWC.com. If you have specific technical questions regarding the content of this letter, please contact Theodore Hoehn at 850-488-8792 or by email at ted.hoehn@myfwc.com.

Sincerely,

Bonita Gorham

for, Scott Sanders, Director
Office of Conservation Planning Services

ss/bg/th
ENV 2-11-4/3
Gulf Power Company 2012 10-year Site Plan_16170_060712
cc: Susan Ritenour, Gulf Power, SDRITENO@southernco.com

Florida Fish and Wildlife Conservation Commission

Office of the Executive Director
Nick Wiley
Executive Director

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Managing fish and wildlife resources for their long-term well-being and the benefit of people.

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(800) 955-8770 (V)

MyFWC.com

July 11, 2012

Mr. Phillip O. Ellis
Strategic Analysis & Government Affairs
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
pellis@psc.state.fl.us

RE: 2012 Orlando Utilities Commission (OUC) 10-year Site Plan 2012-2021, Multi-County

Dear Mr. Ellis:

Florida Fish and Wildlife Conservation Commission (FWC) staff has reviewed OUC's 2012 10-year Site Plan and provides the following comments and recommendations for your consideration.

Project Description

Section 186.801, Florida Statutes, requires electric generating facilities to submit a ten-year site plan to the Florida Public Service Commission. The OUC reviewed its forecast of peak energy demand and existing generating resources and found that it has adequate capacity to satisfy forecast requirements through 2020. OUC forecasts indicate that 23 megawatts of reserve margin capacity will be required by summer 2021. The 10-year Site Plan reports that OUC intends to fulfill its supply requirements by adding a simple cycle combustion turbine at the Stanton Energy Center or Indian River site, both of which are existing facilities.

Potentially Affected Resources

The Stanton Energy Center site is located on S.R. 434 (S. Alafaya Trail) and north of S.R. 528 (Beachline). This facility is situated between the Big and Little Econlockhatchee Rivers and also abutts the Hal Scott Regional Preserve and Park. The electric power facility and associated solid waste disposal area comprise part of the site with the remainder of the property being mostly characterized as longleaf pine flatwoods, cypress wetlands, and dry or wet prairie. Listed species known to occur on the site include the red-cockaded woodpecker (and nest trees), bald eagle, gopher tortoise and Florida Sandhill Crane. A 2005 red-cockaded woodpecker habitat management plan is used to guide land management activities at the Stanton site and is part of the Conditions of Certification for the site.

The Indian River Plant site is located four miles south of Titusville on U.S. Highway 1 near the Indian River. The electric power facility encompasses almost the entire site; north and west of the site is the Space Coast Regional Airport. The predominant and adjacent land uses are urban in nature and contain little habitat for listed species; therefore, impacts to listed species are not anticipated.

FWC staff appreciates the opportunity to review OUC's 10-year Site Plan review the proposed planning document and finds that it is sufficient for planning purposes. We also extend an offer to assist OUC in further identifying fish and wildlife resources within their planning area. If you need further assistance, please do not hesitate to contact Jane Chabre either by phone at (850) 410-5367 or at FWCConservationPlanningServices@MyFWC.com. If you have specific technical questions regarding the content of this letter, please contact Ben Shepherd at (407) 858-6170 or by email at Ben.Shepherd@MyFWC.com.

Sincerely,

Bonita Gorham
Land Use Planning Program Administrator
Office of Conservation Planning Services

bg/jdg/bs
Orlando Utilities Commission 2012 10-year Site Plan_16174_071112
ENV 2-11-4/3

July 16, 2012

Mr. Phillip O. Ellis
Strategic Analysis & Government Affairs
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
pellis@psc.state.fl.us

RE: Multiple Utilities 2012 Ten-year Site Plans

Dear Mr. Ellis:

Florida Fish and Wildlife Conservation Commission (FWC) staff has reviewed the 2012 Ten-year Power Plant Site Plans submitted to the Public Service Commission (PSC).

We will be providing comments on several of the site plans under separate cover; however, we are submitting no comments on the Ten-year Site Plans for the following utilities:

- City of Tallahassee
- Florida Municipal Power Agency
- JEA
- Lakeland Electric
- Seminole Electric Cooperative
- Gainesville Regional Utilities
- Tampa Electric Company

FWC appreciates the opportunity to review the Ten-year Site Plans, as submitted by the PSC. If you need further assistance, please do not hesitate to contact Jane Chabre either by phone at (850) 410-5367 or at FWCConservationPlanningServices@MyFWC.com.

Sincerely,

Bonita Gorham

Bonita Gorham
Land Use Planning Program Administrator
Office of Conservation Planning Services

bg/jdg
ENV 2-11-2
PSC TYSP 2012_071612

Regional Planning Councils

Central Florida RPC

CFRPC
SERVING THE COUNTIES OF • DESOTO • HARDEE • HIGHLANDS • OKEECHOBEE • POLK

July 2, 2012

Phillip Ellis
State of Florida Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Blvd
Tallahassee, FL 32399

Dear Mr. Ellis,

The CFRPC reviewed ten year site plans from Lakeland Electric, Orlando Utilities Commission, Progress Energy Florida, Tampa Electric Company, and Seminole Electric Cooperative as included on the Public Service Commission's website. As requested in the latter dated April 18, 2012, a brief summary and comments related to the suitability of the above mentioned plans as planning documents is below.

Lakeland Electric:

The plan states that there are no planned facilities for the 10-year planning reporting period. There are also no upgrades of existing facilities planned.

This document is suitable for a planning document at a regional level because it provides insight on the development of areas within a portion of the region through current demand and forecast demand. It also is helpful to know what energy conservation and management programs are being utilized as well as the environmental and land impacts that are predicted to occur for the overall planning of the region's growth and development and protection.

This document is also written in a manner that makes it easy for non-utility planners to understand.

Orlando Utilities Commission:

According to the plan, no facilities are planned within the Central Florida Regional Planning Council Region for the 10-year planning reporting period. There are also no upgrades of existing facilities planned in these areas.

This document is suitable for a planning document at a regional level because it provides information as to facilities located within the region. It is somewhat less suitable as a planning document at providing insight on the development through

CENTRAL FLORIDA REGIONAL PLANNING COUNCIL
555 EAST CHURCH STREET, BARTOW, FL 33830-3931; P.O. BOX 2089 BARTOW, FL 33831-2089
(863) 534-7130 • FAX (863) 534-7138 • TOLL FREE (800) 297-8041 • WEBSITE WWW.CFRPC.ORG

current demand and forecast demand because it cannot be extrapolated to a regional or county level because Orlando Utilities Commission services so much of the State of Florida. This document would also be more helpful as a planning document with the inclusion of a service area map.

Progress Energy Florida, Inc:

According to the plan, no facilities are planned within the Central Florida Regional Planning Council Region for the 10-year planning reporting period. There are also no upgrades of existing facilities planned in these areas.

This document is suitable for a planning document at a regional level because it provides information as to the proposed locations of planned new facilities. It is somewhat less suitable as a planning document at providing insight on the development through current demand and forecast demand because it cannot be extrapolated to a regional or county level because Progress Energy's boundaries cover so much of the State of Florida. It is helpful to know what energy conservation and management programs are being utilized as well as the environmental and land impacts are predicted to occur for the overall planning of the region's growth and development and protection.

Tampa Electric Company:

According to the plan, no facilities are planned within the Central Florida Regional Planning Council Region for the 10-year planning reporting period. However, there is a planned expansion at the Polk Power Station in Polk County.

This document is suitable for a planning document at a regional level because it provides information as to the proposed locations of planned new expansions. This document is suitable for a planning document at a regional level because it provides insight on the development of areas within a portion of the region through current demand and forecast demand. It also is helpful to know what energy conservation and management programs are being utilized as well as the environmental and land impacts are predicted to occur for the overall planning of the region's growth and development and protection.

Seminole Electric Cooperative:

According to the plan, no facilities are planned within the Central Florida Regional Planning Council Region for the 10-year planning reporting period. There are also no upgrades of existing facilities planned in these areas.

This document is suitable for a planning document at a regional level because it provides information as to facilities located within the region. It is somewhat less suitable as a planning document at providing insight on the development through current demand and forecast demand because it cannot be extrapolated to a regional or county level because Seminole Electric Cooperative services so much of the State of Florida.

The proposed expansions/potential sitings as indentified in the ten year power plant plans as submitted are consistent with the Central Florida Regional Planning Council Strategic Regional Policy Plan (SRPP). Thank you for the opportunity to review these electric utility ten year site plans.

Sincerely,

Marisa M. Barmby, AICP
Senior Planner

Regional Planning Councils

East Central Florida RPC

East Central Florida Regional Planning Council

309 Cranes Roost Blvd. Suite 2000, Altamonte Springs, FL 32701 • Phone 407.262.7772 • Fax 407.262.7788 • www.ecfrpc.org

Hugh W. Harling, Jr. P.E.
Interim Executive Director

MEMORANDUM

To: Phillip Ellis, Division of Regulatory Analysis, Florida Public Service Commission

From: Hugh W. Harling, Jr., Interim Executive Director
Tara M. McCue, AICP

Date: June 21, 2012

Subject: 2011 Ten-Year Site Plans Review
- Florida Power and Light
- Orlando Utilities Commission
- Progress Energy

The East Central Florida Regional Planning Council staff has completed a review of the 2012 Ten-Year Site Plans for the agencies listed above. Staff comments to each utility are italicized below.

Florida Power and Light (FPL)
In the East Central Florida region, FPL has identified the Space Coast Solar Expansion project in Brevard County as a potential future expansion site. This site already contains of a 10 MW PV facility and has the potential to expand by an additional 10 MW. FPL is also continuing the modernization of the Cape Canaveral Plant. The 10 Year Site Plan did not include any proposed projects or sites which conflict with the ECFRPC Regional Strategic Policy Plan. Staff finds the document to be suitable for planning purposes.

Orlando Utilities Commission (OUC)
The 10 Year Site Plan did not include any proposed projects or sites. Therefore, we find no conflicts with the ECFRPC Regional Strategic Policy Plan. Staff finds the document to be suitable for planning purposes.

Progress Energy Florida (PEF)
The 10 Year Site Plan did not include any proposed projects or sites in the East Central Florida region. Therefore, no conflicts with the ECFRPC Regional Strategic Policy Plan were identified. Staff finds the document to be suitable for planning purposes.

Council staff will provide further comments on environmental and regional impacts when new or modified units, projects or transmission lines are proposed and additional data and information are provided.

If you require any further information or comments, please contact Tara McCue, AICP at tara@ecfrpc.org or by phone at (407) 262-7772.

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12 JUN 28 AM 9:37
DIVISION OF REGULATORY COMPLIANCE

REGIONAL CLEARINGHOUSE
INTERGOVERNMENTAL COORDINATION AND RESPONSE

Date: 6-27-12

PROJECT DESCRIPTION

#68 Seminole Electric Cooperative, Inc., Ten Year Site Plan 2012 -2021

TO: Mr. Phillip Ellis
Division of Regulatory Analysis
Florida Public Service Commission
Capitol Circle Office Center
2540 Shumard Oak Blvd
Tallahassee, FL 32399-0850

_X_ COMMENTS ATTACHED

___ NO COMMENTS REGARDING THIS PROJECT

IF YOU HAVE ANY QUESTIONS REGARDING THESE COMMENTS, PLEASE CONTACT STEVEN DOPP, SENIOR PLANNER, AT THE NORTH CENTRAL FLORIDA REGIONAL PLANNING COUNCIL AT (352) 955-2200 OR SUNCOM 625-2200, EXT 109

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2 JUN 28 AM 9:38
DIVISION OF
REGULATORY COMPLIANCE

June 27, 2012

Mr. Phillip Ellis
Division of Regulatory Analysis
Florida Public Service Commission
Capitol Circle Office Center
2540 Shumard Oak Blvd
Tallahassee, FL 32399-0850

RE: Regional Review of Ten Year Site Plan, 2012 - 2021
Seminole Electric Cooperative, Inc.

Dear Mr. Ellis:

Pursuant to Section 186.801, Florida Statutes, Council staff has reviewed the proposed Ten-Year Site Plan and provides the following comments.

The above-referenced ten-year site plan proposes to construct eight natural gas-powered electrical generation stations by 2021 to be located within Gilchrist County. The combined summer electrical generating capacity of the stations will be 2,010 megawatts, while the combined winter electrical generating capacity of the stations will be 2,301 megawatts. The ten-year site plan notes that 588 megawatts of the summer generating capacity and 681 megawatts of the winter generating capacity will be cooled by water using wet cooling towers with forced air draft fans.

The subject property of the Gilchrist County site is located adjacent to Waccasassa Flats, a Natural Resource of Regional Significance as identified and mapped in the North Central Florida Strategic Regional Policy Plan. Page IV-55 of the North Central Florida Strategic Regional Policy Plan notes the following regarding Waccasassa Flats.

> Occupying approximately 61,653 acres, Waccasassa Flats runs down the center of Gilchrist County. The flats are part of a larger wetland system which runs into Levy County and the Withlacoochee Regional Planning District. During the rainy season, waters in the aquifer build up sufficient pressure to spill out of the many sinkholes and ponds scattered throughout the flats to inundate the area.
>
> The area is predominantly comprised of commercial pine plantation. Pine stands are interspersed among numerous cypress ponds, depression marshes, hydric hammock, and other wetland communities. Several lakes (the largest of which is 150 acres), small areas of upland hardwood forest, sandhill, and other minor natural communities contribute to the diversity of the flats.

Applicable regional plan goals and policies include the following:

> REGIONAL GOAL 4.7. Maintain the quantity and quality of the region's surface water systems in recognition of their importance to the continued growth and development of the region.

Letter to Mr. Phillip Ellis
Page 2
June 27, 2012

> Policy 4.7.5. Use non-structural water management controls as the preferred water management approach for rivers, lakes, springs, and fresh water wetlands identified as natural resources of regional significance.
>
> Policy 4.7.6. Support the coordination of land use and water resources planning for surface water resources designated as natural resources of regional significance among the Council, local governments, and the water management districts through regional review responsibilities, participation in committees and study groups, and ongoing communication.
>
> Policy 4.7.12. Ensure that local government comprehensive plans, DRIs, and requests for federal and state funds for development activities reviewed by the Council include adequate provisions for stormwater management, including retrofit programs for known surface water runoff problem areas, and aquifer recharge protection in order to protect the quality and quantity of water contained in the Floridan Aquifer and surface water systems identified as natural resources of regional significance.
>
> Policy 4.7.13. Work with local governments, state and federal agencies, and the local water management districts in the review of local government comprehensive plans and developments of regional impact as they affect wetlands identified as natural resources of regional significance to ensure that any potential adverse impacts created by the proposed activities on wetlands are minimized to the greatest extent possible.

The proposed electrical power generation site to be located in Gilchrist County will be consistent with the regional plan provided the water consumption of the electrical generating stations does not result in significant and adverse impacts to the wetland functions of Wacassassa Flats. However, the ten-year site plan does not indicate the water source or the amount of water to be used to cool the electrical generating stations. Additionally, the ten-year site plan does not provide an analysis of environmental impacts to Wacassassa Flats of the withdrawal of groundwater used to cool the electrical generating units.

Therefore, it is recommended that the ten-year site plan include information on the water consumption of the electrical generating stations as well as an analysis of environmental impacts to Wacassassa Flats as a result of their water consumption. Finally, it is recommended that an alternative environmental impact analysis be provided whereby 100 percent of the electrical generation capacity of the site is cooled using air.

If you have any questions concerning this matter, please do not hesitate to contact Steven Dopp, Senior Planner of the Planning Council's Regional and Local Government Programs staff, at 352.955.2200, extension 109.

Sincerely,

Scott R. Koons, AICP
Executive Director

v:\chouse\responses\2011-12_68.docx

:e
3-1603

ADDRESS SERVICE
REQUESTED

Mr. Phillip Ellis
Division of Regulatory Analysis
Florida Public Service Commissic
Capitol Circle Office Center
2540 Shumard Oak Blvd
Tallahassee, FL 32399-0850
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REGIONAL CLEARINGHOUSE
INTERGOVERNMENTAL COORDINATION AND RESPONSE

Date: 6-22-12

PROJECT DESCRIPTION

#66 - Progress Energy Florida, Inc. Ten-Year Site Plan, 2012 - 2021

TO: Mr. Phillip Ellis
Division of Regulatory Analysis
Florida Public Service Commission
540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

___ **COMMENTS ATTACHED**

_X_ **NO COMMENTS REGARDING THIS PROJECT**

IF YOU HAVE ANY QUESTIONS REGARDING THESE COMMENTS, PLEASE CONTACT STEVEN DOPP, SENIOR PLANNER, AT THE NORTH CENTRAL FLORIDA REGIONAL PLANNING COUNCIL AT (352) 955-2200 OR SUNCOM 625-2200, EXT 109

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REGIONAL CLEARINGHOUSE
INTERGOVERNMENTAL COORDINATION AND RESPONSE

Date: 6-22-12

PROJECT DESCRIPTION

#67 - Gainesville Regional Utilities - 2012 Ten-Year Site Plan

---

TO: Mr. Phillip Ellis
Division of Regulatory Analysis
Florida Public Service Commission
540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

___ **COMMENTS ATTACHED**

_X_ **NO COMMENTS REGARDING THIS PROJECT**

IF YOU HAVE ANY QUESTIONS REGARDING THESE COMMENTS, PLEASE CONTACT STEVEN DOPP, SENIOR PLANNER, AT THE NORTH CENTRAL FLORIDA REGIONAL PLANNING COUNCIL AT (352) 955-2200 OR SUNCOM 625-2200, EXT 109

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TREASURE COAST REGIONAL PLANNING COUNCIL

INDIAN RIVER – ST. LUCIE – MARTIN – PALM BEACH

June 18, 2012

Mr. Phillip Ellis
Division of Regulatory Analysis
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Subject: 2012 Ten Year Power Plant Site Plans

Dear Mr. Ellis:

Treasure Coast Regional Planning Council has reviewed the ten year power plant site plan prepared by Florida Power and Light Company. Council approved the comments in the attached report at a board meeting on June 15, 2012. The report concludes that the FPL Ten Year Power Plant Site Plan, 2012-2021 is inconsistent with Strategic Regional Policy Plan Goal 9.1, decreased vulnerability of the region to fuel price increases and supply interruptions; and Strategy 9.1.1, reduce the Region's reliance on fossil fuels. Council urges FPL and the State of Florida to continue developing new programs to: 1) reduce the reliance on fossil fuels as future energy sources; 2) increase conservation activities to offset the need to construct new power plants; and 3) increase the reliance on renewable energy sources to produce electricity.

Please contact me if you have any questions.

Sincerely,

Michael J. Busha, AICP
Executive Director

Attachment

cc: Nick Blount, FPL

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TREASURE COAST REGIONAL PLANNING COUNCIL

Report on the

Florida Power & Light Company Ten Year Power Plant Site Plan, 2012-2021

June 15, 2012

Introduction

Each year every electric utility in the State of Florida produces a ten year site plan that includes an estimate of future electric power generating needs, a projection of how those needs will be met, and disclosure of information pertaining to the utility's preferred and potential power plant sites. The Florida Public Service Commission (FPSC) has requested that Council review the most recent ten year site plan prepared by Florida Power & Light Company (FPL). The purpose of this report is to summarize FPL's plans for future power generation and provide comments for transmittal to the FPSC.

Summary of the Plan

The plan indicates that after FPL's demand side management efforts and significant energy efficiency contributions from the federal appliance and lighting efficiency standards are factored in, FPL will still require additional capacity from conventional power plants to meet future electrical demand. FPL is proposing to add a total of 250 megawatts (MW) of summer capacity to its system from 2012 to 2021 (Exhibit 1). FPL plans to obtain additional electricity through: 1) power purchases from qualifying facilities, utilities and other entities; 2) upgrades to existing facilities; 3) returning inactive reserve units to active status; and 4) modernization of existing facilities. Major additions of new generating capacity are as follows:

- 2013 – place in service the Cape Canaveral Next Generation Clean Energy Center (1,210 MW) in Brevard County;
- 2014 – place in service the Riviera Beach Next Generation Clean Energy Center (1,212 MW) in the City of Riviera Beach; and
- 2016 – place in service the Port Everglades Next Generation Clean Energy Center (1,277 MW) in the City of Hollywood.

Based on the projection of future resource needs, FPL has identified the following five preferred sites for future power generating facilities:

1. St. Lucie Plant site in St. Lucie County;
2. Turkey Point Plant site in Miami-Dade County;
3. Cape Canaveral Plant site in Brevard County;
4. Riviera Plant site in Palm Beach County; and
5. Port Everglades Plant site in Broward County.

Also, FPL has identified 10 potential sites for new or expanded power generating facilities. The identification of potential sites does not represent a commitment by FPL to construct new power generating facilities at these sites. The potential sites include:

1. Babcock Ranch site in Charlotte County;
2. DeSoto Solar Expansion site in DeSoto County;
3. Florida Heartland site in Glades County;
4. an undeveloped site in Hendry County;
5. Manatee Plant site in Manatee County;
6. an unidentified location in Martin County for a photovoltaic (PV) facility;
7. an unidentified location in northeast Okeechobee County;
8. Palatka site in Putnam County;
9. an unidentified location in Putnam County; and
10. Space Coast Solar Expansion site in Brevard County.

The plan describes two primary factors that are driving changes in FPL's 2012 ten year site plan compared to the 2011 ten year site plan. The first factor is that it will not be necessary to schedule planned maintenance outages for FPL's fleet of fossil-fueled generating units during all summer and winter peak load months. The second factor is changes in the load forecast, generating unit capabilities, and power purchase capabilities have combined to result in a lowering of FPL's projected resource needs through 2021. The plan also describes the following additional factors influencing FPL's resource planning work:

- Maintaining/enhancing fuel diversity in the FPL system.
- Maintaining a balance between load and generating capacity in southeastern Florida, particularly in Miami-Dade and Broward counties.
- The possibility of establishment of a Florida standard for renewable energy or clean energy.
- The issue of how best to reliably obtain additional natural gas for FPL's system.
- The extent to which FPL's reserves are projected to become increasingly dependent upon demand side management resources as opposed to generation resources.

Evaluation

One of the main purposes of preparing the ten year site plan is to disclose the general location of proposed power plant sites. The FPL ten year site plan identifies two preferred sites and one potential site for future power generating facilities in the Treasure Coast Region (Exhibit 2). The first preferred site is the St. Lucie Plant site, which is located on Hutchinson Island in St. Lucie County. This site has two nuclear-powered generating units, St. Lucie Units 1 and 2, which have been in operation since 1976 and 1983, respectively. The St. Lucie site has been selected as a preferred site for an "uprate" project to increase the capacity of the two existing nuclear generating units. FPL is modifying the two 840 MW nuclear generating units to increase their capacity by about 129 MW for Unit 1 and 115 MW for Unit 2. Council issued a report supporting this project in 2008. This uprate project has been approved by the FPSC and Florida Department of Environmental Protection (FDEP). A portion (31 MW) of the uprate capacity for St. Lucie Unit 2 has already been implemented and the remainder of the uprated capacity is projected to be in-service by the end of 2012. FPL has also been pursuing the addition of six wind turbines at the St. Lucie Plant site for a number of years. However, to date FPL has been unable to obtain the local land use approvals necessary to proceed with the process.

The second preferred site is the Riviera Plant site, which is located in the City of Riviera Beach. The previous generating capacity at this site was made up of two 300 MW oil-fired units, that have been taken out of service and dismantled in 2011. FPL is in the process of modernizing the existing Riviera Plant, which will be renamed the Riviera Beach Next Generation Clean Energy Center. FPL is replacing the existing units with a high-efficiency combined cycle natural gas-fired unit capable of producing 1,212 MW of electricity. Council issued a report supporting this project in 2009. The new facility has been approved by the FPSC and FDEP, and is expected to start commercial operation in 2014.

The only potential site identified in the Treasure Coast Region is in Martin County. The plan indicates FPL is evaluating potential sites in Martin County for a future PV facility. No specific locations have been selected at this time.

The ten year site plan also indicates that FPL is currently evaluating the possibility of serving the electrical loads of several entities (including the Cities of Vero Beach and Lake Worth). However, the load forecast presented in the ten year site plan does not include these potential loads, because these evaluations are still underway.

The ten year site plan indicates that fossil fuels will be the primary source of energy used to generate electricity by FPL during the next 10 years (Exhibit 3). The plan indicates fossil fuels will account for 76.5 percent (4.6 percent from coal, 0.9 percent from oil, and 71.0 percent from natural gas) of FPL's electric generation in 2012. The plan predicts fossil fuels will account for 74.1 percent (5.5 percent from coal, 0.5 percent from oil, and 68.1 percent from natural gas) of FPL's electric generation in 2021. During the same period, nuclear sources are predicted to change from 17.2 percent in 2012 to 20.4 percent in 2021. Solar sources are predicted to remain steady at 0.2 percent in 2012 and 0.2 percent in 2021.

Regarding solar energy, FPL has completed construction of three solar facilities: 1) a 75 MW steam generation solar thermal facility in Martin County (the Martin Next Generation Solar Energy Center); 2) a 25 MW PV electric generation facility in DeSoto County (the DeSoto Next Generation Solar Energy Center); and 3) a 10 MW PV electric generation facility in Brevard County at NASA's Kennedy Space Center (the Space Coast Next Generation Solar Energy Center). These three projects were completed in response to the 2008 Energy Bill, which was enacted to enable the development of clean, zero greenhouse gas emitting renewable generation in the State of Florida. Specifically, the bill authorized cost recovery for the first 110 MW of eligible renewable projects that had the proper land use, zoning, and transmission rights in place. Collectively, these Next Generation Solar Energy Centers are expected to produce a total of approximately 200,000 megawatt-hours of electricity each year, and at peak production provide enough energy to serve the requirements of more than 14,380 homes at current levels of average residential use.

The 2012 ten year site plan indicates that FPL is currently in the process of identifying other potential solar sites in the state in the event that a future Renewable Portfolio Standard, Clean Energy Portfolio Standard, or other legislation is enacted that enables FPL to construct and recover costs for additional renewable energy generation. Council continues to support FPL's existing solar projects and encourages FPL to develop additional projects based on renewable resources.

Conclusion

The elements of the ten year site plan that do not predict a reduction in reliance on fossil fuels and do not predict an increase in reliance on renewable energy are **inconsistent** with Strategic Regional Policy Plan Goal 9.1, decreased vulnerability of the region to fuel price increases and supply interruptions; and Strategy 9.1.1, reduce the Region's reliance on fossil fuels. Over the last ten years, Council's findings of inconsistency with the FPL ten year site plans have remained relatively unchanged, because FPL has made little progress toward addressing Council's concerns. One of the main reasons for this is because the State of Florida does not have a Renewable Portfolio Standard or other policies designed to encourage electric utilities to increase fuel diversity by adding a greater proportion of energy from renewable sources, such as solar and wind energy. Council encourages the Florida Legislature to adopt a Renewable Portfolio Standard in order to provide a mechanism to expand the use of renewable energy in Florida.

The FPL ten year site plan should predict an increase in the use of renewable energy during the next decade. Council recommends that FPL consider new strategies to expand reliance on renewable sources. FPL should develop a program to install, own, and operate PV units on the rooftops of private and public buildings. The shift to rooftop PV systems distributed throughout the area of demand could reduce the reliance on large transmission lines and reduce costs associated with owning property; purchasing fuel; and permitting, constructing, and maintaining a power plant. Another advantage of this strategy is that PV systems do not require water for cooling. The incentive for owners of buildings to participate in this strategy is they could be offered a reduced rate for purchasing electricity. The future development of ocean current technology, which is currently under investigation by the Florida Atlantic University Center for Ocean Energy Technology, may be another opportunity to expand the use of renewable energy.

Council urges FPL and the State of Florida to continue developing new programs to: 1) reduce the reliance on fossil fuels as future energy sources; 2) increase conservation activities to offset the need to construct new power plants; and 3) increase the reliance on renewable energy sources to produce electricity. The complete costs of burning fossil fuels, such as the costs to prevent environmental pollution and costs to the health of the citizens, need to be considered in evaluating these systems. State legislators should amend the regulatory framework to provide financial incentives for the power providers and the customers to increase conservation measures and to rely to a greater extent on renewable energy sources. Also, the State should reconsider the currently used test for energy efficiency and choose a test that will maximize the potential for energy efficiency and renewable energy resources. The phasing in of PV and other locally available energy sources will help Florida to achieve a sustainable future.

Attachments

EXHIBIT 1

Table III.B.1: Projected Capacity Changes for FPL

Projected Capacity Changes			
		Net Capacity Changes (MW)	
Year	Projected Capacity Changes	Winter[1]	Summer[2]
2012	Sanford Unit 5 CT Upgrade	---	19
	St. Lucie Unit 1 Uprate - Outage [5]	(853)	---
	St. Lucie Unit 1 Uprates - Completed	---	129
	Turkey Point Unit 3 Uprates - Completed	---	123
	St. Lucie Unit 2 Uprate - Outage [5]	---	(745)
	Changes to Existing Purchases [3]	375	470
	Scherer Unit 4	---	(30)
	Manatee Unit 2	---	(3)
	Inactive Reserve Units (PE Units 3 & 4) -return to active status [7]	765	761
	Manatee Unit 2 ESP - Outage [6]	(822)	---
2013	Cape Canaveral Next Generation Clean Energy Center [4]	---	1,210
	Changes to Existing Purchases [3]	(555)	(430)
	Manatee Unit 2	(3)	---
	Sanford Unit 5 CT Upgrade	19	9
	Martin Unit 8 CT Upgrade	10	10
	Sanford Unit 4 CT Upgrade	22	31
	Scherer Unit 4	(28)	---
	St. Lucie Unit 1 Uprates - Completed	129	---
	St. Lucie Unit 2 Uprates - Completed	84	84
	Turkey Point Unit 3 Uprates - Completed	123	---
	Turkey Point Unit 4 Uprates - Completed	---	123
	Turkey Point Unit 4 Uprates - Outage [5]	(717)	---
	Inactive Reserve Unit (PE Units 3 & 4) - return to inactive status [7]	(765)	(761)
	Manatee Unit 1 ESP - Outage [6]	(822)	---
	Martin Unit 1 ESP - Outage [6]	--	(826)
2014	Cape Canaveral Next Generation Clean Energy Center [4]	1,355	---
	Sanford Unit 4 CT Upgrade	16	---
	Sanford Unit 5 CT Upgrade	19	10
	Manatee Unit 3 CT Upgrade	---	19
	Turkey Point Unit 5 CT Upgrade	---	33
	Turkey Point Unit 4 Uprates - Completed	123	---
	Martin Unit 1 ESP - Outage [6]	(832)	---
	Martin Unit 2 ESP - Outage [6]	---	(826)
	Riviera Beach Next Generation Clean Energy Center [4]	---	1,212
2015	Manatee Unit 3 CT Upgrade	39	20
	Turkey Point Unit 5 CT Upgrade	33	---
	Ft. Myers Unit 2 CT Upgrade	---	51
	Riviera Beach Next Generation Clean Energy Center [4]	1,344	---
2016	Changes to Existing Purchases [3]	(858)	(858)
	Ft. Myers Unit 2 CT Upgrade	51	---
	Turkey Point Unit 1 operation changed to synchronous condenser	---	(396)
	Port Everglades Next Generation Clean Energy Center [4]	---	1,277
2017	Changes to Existing Purchases [3]	---	(375)
	Turkey Point Unit 1 operation changed to synchronous condenser	(398)	---
	Port Everglades Next Generation Clean Energy Center [4]	1,429	---
2018	Changes to Existing Purchases [3]	(383)	---
2019	---	---	---
2020	---	---	---
2021	Short Term Purchase	---	250

(1) Winter values are forecasted values for January of the year shown.
(2) Summer values are forecasted values for August of the year shown.
(3) These are firm capacity and energy contracts with QF, utilities, and other entities. See Table I.B.1 and Table I.B.2 for more details.
(4) All new unit additions are scheduled to be in-service in June of the year shown. All additions assumed to start in June are included in the Summer reserve margin calculation starting in that year and in the Winter reserve margin calculation starting with the next year.
(5) Outages for uprate work.
(6) Outages for ESP work.
(7) A number of existing FPL power plants have been removed from service and placed on Inactive Reserve status. See Chapter III for a discussion of the units on Inactive Reserves.

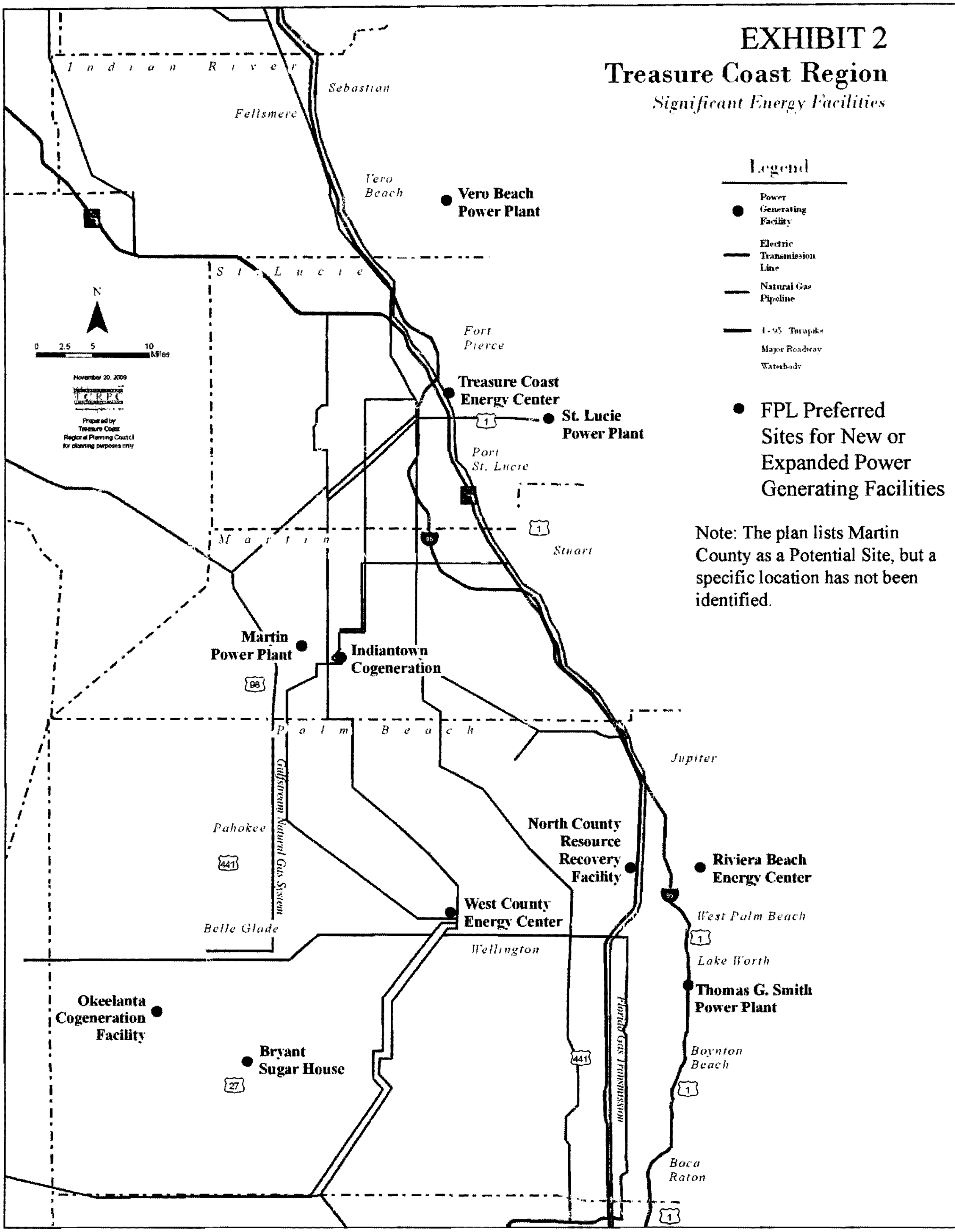
EXHIBIT 2
Treasure Coast Region
Significant Energy Facilities
Legend
Power Generating Facility
Electric Transmission Line
Natural Gas Pipeline
I-95 Turnpike
Major Roadway
Waterbody
FPL Preferred Sites for New or Expanded Power Generating Facilities
Note: The plan lists Martin County as a Potential Site, but a specific location has not been identified.
N
0 2.5 5 10 Miles
November 20, 2009
Prepared by Treasure Coast Regional Planning Council for planning purposes only
Indian River
St. Lucie
Martin
Palm Beach
Sebastian
Fellsmere
Vero Beach
Vero Beach Power Plant
Fort Pierce
Treasure Coast Energy Center
St. Lucie Power Plant
Port St. Lucie
Stuart
Martin Power Plant
Indiantown Cogeneration
Jupiter
Pahokee
Gulfstream Natural Gas System
North County Resource Recovery Facility
Riviera Beach Energy Center
West County Energy Center
Belle Glade
West Palm Beach
Wellington
Lake Worth
Thomas G. Smith Power Plant
Okeelanta Cogeneration Facility
Bryant Sugar House
Florida Gas Transmission
Boynton Beach
Boca Raton
1
95
98
441
27

EXHIBIT 3

Schedule 6.2
Energy Sources % by Fuel Type

Energy Source	Units	Actual [1] 2010	2011	Forecasted 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1) Annual Energy Interchange [2]	%	7.3	5.3	3.8	2.8	2.7	3.4	2.3	0.5	0.0	0.0	0.0	0.0
(2) Nuclear	%	20.0	19.1	17.2	23.6	23.8	21.8	23.1	22.8	21.6	22.2	21.9	20.4
(3) Coal	%	5.0	5.0	4.8	5.4	4.8	5.6	5.5	6.9	6.4	5.8	5.3	5.5
(4) Residual (FO6) -Total	%	3.6	0.6	0.9	0.4	0.3	0.4	0.4	0.4	0.3	0.3	0.4	0.5
(5) Steam	%	3.6	0.6	0.9	0.4	0.3	0.4	0.4	0.4	0.3	0.3	0.4	0.5
(6) Distillate (FO2) -Total	%	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7) Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8) CC	%	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9) CT	%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10) Natural Gas -Total	%	58.3	66.1	71.0	65.0	65.5	64.9	64.6	66.1	68.3	67.1	67.4	68.1
(11) Steam	%	4.4	4.8	2.5	0.9	0.6	0.8	1.0	0.9	0.8	0.8	0.9	1.2
(12) CC	%	53.6	60.8	68.4	64.0	64.8	64.1	63.6	65.1	67.5	66.3	66.5	66.8
(13) CT	%	0.4	0.6	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
(14) Solar [3]	%	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(15) PV	%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(16) Solar Thermal [4]	%	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(17) Other [5]	%	5.6	3.6	2.4	2.7	2.8	3.8	4.0	4.2	4.2	4.4	4.9	5.3
		100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies (UPS contract).
3/ Represents output from FPL's PV and solar thermal facilities.
4/ Estimated projected values.Solar thermal does not produce GWh, but produces steam that displaces fossil fuel-derived steam.
Its 2011 contribution to the Martin 8 CC GWh output is rolled into row (12) for reporting purposes. Its projected contributions for 2012 - 2021 are provided separately on row (16).
5/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.
6/ Net Energy For Load values for the years 2012 - 2021 are also shown in Col. (19) on Schedule 2.3.

Liz Gulick

From: Mike Busha <mbusha@tcrpc.org>
Sent: Monday, June 18, 2012 10:21 AM
To: lgulick@tcrpc.org
Subject: FW: Fw: FPL - Ten Year Power Plant Site Plan 2012-2021

From: RGreene@wpb.org [mailto:RGreene@wpb.org]
Sent: Friday, June 08, 2012 5:16 PM
To: mbusha@tcrpc.org
Cc: MFigueroa@wpb.org; EMitchell@wpb.org; AHansen@wpb.org
Subject: Re: Fw: FPL - Ten Year Power Plant Site Plan 2012-2021

Mike,

I hope all is well with you. Our office conducted a review of the Ten Year Power Plant Site Plan and noted a minor comment on page 142 of the report (page 150 of 248 on the file). The language incorrectly states that the Future Land Use Designation for the area in West Palm Beach immediately south of the proposed Riviera FPL Plant is Residential. The actual FLU designations for that area are Multi Family and Single Family. The same page also inaccurately identifies the Riviera FLU designations to the west as Commercial when in reality they are Utilities and Port.

Please let me know if you have any other questions.

Rick Greene, AICP
Planning Manager
Development Services Department
City of West Palm Beach
401 Clematis Street
West Palm Beach, Florida 33401
(561) 822-1455

From: Ed Mitchell/WESTPALM
To: Millie Figueroa/WESTPALM@WESTPALM
Cc: rgreene@wpb.org
Date: 05/21/2012 02:52 PM
Subject: Fw: FPL - Ten Year Power Plant Site Plan 2012-2021

t file rg
----- Forwarded by Ed Mitchell/WESTPALM on 05/21/2012 02:51 PM -----

From: "Mike Busha" <mbusha@tcrpc.org>
To: <jbaird@ircgov.com>, "Faye Outlaw" <OutlawF@stlucieco.org>, "Taryn Kryzda" <tkryzda@martin.fl.us>, "Bob Weisman" <tmlawren@pbcgov.org>, "Greg Oravec" <goravec@cityofpsl.com>, <jtitcomb@lakeparkflorida.gov>, "Lee Leffingwell" <lleffingwell@townofmangoniapark.com>, "Peter Elwell" <TownManager@townofpalmbeach.com>, "Paul Schofiled" <pschofield@wellingtonfl.gov>, "Ed Mitchell" <emitchell@wpb.org>, "Nick Mimms" <nmimms@fppwd.com>, "Ruth Jones" <rjones@rivierabch.com>
Cc: <pmerritt@tcrpc.org>
Date: 05/21/2012 02:27 PM
Subject: FPL - Ten Year Power Plant Site Plan 2012-2021

Water Management Districts

St. Johns River WMD

St. Johns River
Water Management District
Hans G. Tanzler III, Executive Director • David W. Fisk, Assistant Executive Director

4049 Reid Street • P.O. Box 1429 • Palatka, FL 32178-1429 • (386) 329-4500
On the Internet at floridaswater.com.

June 21, 2012

Mr. Philip Ellis
Division of Regulatory Analysis
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Review of Florida Power and Light Company 2012 Ten-Year Site Plan

Dear Mr. Ellis:

St. Johns River Water Management District (District) staff have reviewed the Ten-Year Site Plan (TYSP) for Florida Power and Light Company (FPL) relative to its suitability as a planning document, as requested by your letter dated April 18, 2012. District staff comments are below.

1. Pursuant to subsection II, A.1.f., of the 2007 operating agreement concerning regulation between the District and the Florida Department of Environmental Protection (DEP), DEP shall review and take final action on all applications for permits for power plants and electrical distribution and transmission lines and other facilities related to the production, transmission, and distribution of electricity.

2. The TYSP for FPL did not contain information relative to projected water demand. In general, the District requires that all consumptive use permit (CUP) applications for new uses and requested increases in CUP allocations demonstrate the use of lowest-quality water source; justify the need for the requested allocation; demonstrate efficient use; and not impact springs, wetlands, water bodies, water quality, or existing legal uses. In addition, all other CUP criteria must be met. When locating or expanding a site for a power facility, FPL should consider the availability of water to meet the proposed demands of the facility and potential impacts due to facility water use, including the cumulative impacts of locating or expanding a facility at a given location.

Please note that the District's contact person for the review of TYSPs has changed and the new contact information is below.

Jeff Cole
Chief of Staff
P.O. Box 1429
Palatka, FL 32178-1429
jcole@sjrwmd.com

If you have any questions, please contact District Intergovernmental Planner Steve Fitzgibbons at (386) 312-2369 or *sfitzgib@sjrwmd.com.*

Sincerely,

Jeff Cole, Chief of Staff

cc: Richard Burklew, St. Johns River Water Management District
Patricia Renish, St. Johns River Water Management District
Jay Lawrence, St. Johns River Water Management District
Chou Fang, St. Johns River Water Management District
Susan Moor, St. Johns River Water Management District
Troy Rice, St. Johns River Water Management District

Water Management Districts

Southwest Florida WMD

Southwest Florida
Water Management District

2379 Broad Street, Brooksville, Florida 34604-6899
(352) 796-7211 or 1-800-423-1476 (FL only)
TDD only: 1-800-231-6103 (FL only)
On the Internet at *WaterMatters.org*

An Equal Opportunity Employer

Bartow Service Office
170 Century Boulevard
Bartow, Florida 33830-7700
(863) 534-1448 or
1-800-492-7862 (FL only)

Sarasota Service Office
6750 Fruitville Road
Sarasota, Florida 34240-9711
(941) 377-3722 or
1-800-320-3503 (FL only)

Tampa Service Office
7601 Highway 301 North
Tampa, Florida 33637-6759
(813) 985-7481 or
1-800-836-0797 (FL only)

June 29, 2012

Mr. Phillip Ellis
Division of Regulatory Analysis
State of Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Subject: Review of the 2012 Ten-Year Site Plans for Florida's Electric Utilities

Dear Mr. Ellis:

On April 18, 2012, the Florida Public Service Commission (FPSC) requested comments from the Southwest Florida water Management District (District) regarding selected ten-year site plans for potential electric generating plants within the District's jurisdictional boundaries. Specifically, the FPSC requested that the District *"... provide comments, along with a brief summary if possible, on their suitability as planning documents."*

It should be noted that under the current Operating Agreement between the Florida Department of Environmental Protection (FDEP) and the District, the FDEP is typically responsible for reviewing Environmental Resource Permit (ERP) applications for Electric Power Plants (reference: Section II.A.1.f of the Operating Agreement).

The following site plan reports were obtained from the FPSC's web site:

http://www.psc.state.fl.us/utilities/electricgas/10yrsiteplans.aspx

- Progress Energy, Inc.
- Tampa Electric Company

Review and Commentary for Progress Energy, Inc. (PEI):

Chapter 4 of PEI's report included a three (3) page general planning summary of their proposed Levy County Nuclear Plant which is estimated to undergo construction by 2021. This summary included two (2) 8.5"x11" figures that provided a general location of the proposed generating facilities.

PEI's report provided good information for general planning purposes in regard to the District's ERP program. The report did not contain information relating to the consumptive use of water.

Mr. Phillip Ellis
Page 2
June 29, 2012

Review and Commentary for Tampa Electric Company (TECO):

Chapter IV (Schedules 8.1 and 9) of TECO's report provides information on potential expansion of their existing (previously permitted) facilities within the next ten years. Chapter VI of the report provides a short location narrative of TECO's existing power plant facilities which includes three (3) supporting 8.5"x11" figures.

TECO's report provided good information for general planning purposes in regard to the District's ERP program. The report did not contain information relating to the consumptive use of water.

I hope that you will find these comments satisfy the request for review. Please do not hesitate to contact me if you have questions or need clarification at Michelle.Maxey@watermatters.org or 813-985-7481.

Sincerely,

Michelle Maxey, E.I.
Chief, Regulatory Support Bureau

cc: Hank Higginbotham, P.E.
Chaz Collins
Ralph Kerr, P.G.
Joe Oros, P.G.

Other Organizations

Seminole Tribe of Florida

Eric Fryson 120000-OT

From: Marilyn Lozada [mlozada@llw-law.com]
Sent: Monday, July 02, 2012 4:20 PM
To: Filings@psc.state.fl.us
Cc: Andrew Baumann; Stephen Walker
Subject: Florida Power & Light's 2012 Ten-Year Power Plant Site Plan
Attachments: Ann Cole Letter re FPL's 2012 Ten-Year Power Platn Site Plan (00109472).PDF

Attached for electronic filing with the Florida Public Service Commission is Seminole Tribe of Florida's letter addressed to Ann Cole re: FPL's 2012 Ten-Year Power Plant Site Plan.

Marilyn Ayala-Lozada
Legal Assistant to:
Kenneth G. Spillias and Andrew J. Baumann
Lewis, Longman & Walker, P.A.
515 North Flagler Drive, Suite 1500
West Palm Beach, Florida 33401
mlozada@llw-law.com
(t) 561.640.0820
(f) 561.640.8202
vCard | Website

LEWIS
LONGMAN &
WALKER | P.A.
ATTORNEYS AT LAW

Reply To: **West Palm Beach**

July 2, 2012

VIA ELECTRONIC MAIL

Ann Cole
Division of the Commission, Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Florida Power & Light Company's 2012 Ten-Year Power Plant Site Plan

This Comment is submitted on behalf of the Seminole Tribe of Florida. Florida Power & Light has submitted its 2012 Ten-Year Power Plant Site Plan listed Potential Site #4 in Hendry County as a future PV and/or Natural Gas facility. Described on pages 153 and 154 of the Plan, the site is located on CR 833 on 3,127 acres of land immediately north of the Seminole Tribe's Big Cypress Reservation.

The Seminole Tribe is currently in litigation with Hendry County and Florida Power & Light concerning zoning approvals already obtained from the County. The Seminole Tribe continues to have serious concerns over the proposed site.

Given the proximity of this proposed plant to residential areas and successful ecotourism operations on the Big Cypress Reservation, the Seminole Tribe has serious concerns about the proposed potential site #4 in Hendry County. Unlike the description in the Site Plan, Florida Power & Light already identified in zoning submittals to Hendry County that it plans to build three natural gas units, with 150-foot-tall cooling towers resulting in a demand for 22.5 million gallons of cooling water per day (7.5 million gallons per unit) to be drawn from the groundwater aquifer adjacent to and beneath this property and the Seminole Big Cypress Reservation. The groundwater aquifer in this area has already been identified as having reached its maximum potential utilization. The Seminole Tribe's rights as protected by both state statute and the Water Compact between the Seminole Tribe and the State of Florida will be adversely impacted by this proposed plant. Additionally locating this plant adjacent to the Big Cypress Reservation will harm the Seminole Tribe's rights to use the Reservation for residential and business uses including agriculture and ecotourism.

See Things Differently

BRADENTON
101 Riverfront Boulevard
Suite 620
Bradenton, Florida 34205
p | 941-708-4040 • f | 941-708-4024

JACKSONVILLE
245 Riverside Avenue
Suite 150
Jacksonville, Florida 32202
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TALLAHASSEE
315 South Calhoun Street
Suite 830
Tallahassee, Florida 32301
p | 850-222-5702 • f | 850-224-9242

WEST PALM BEACH
515 North Flagler Drive
Suite 1500
West Palm Beach, Florida 33401
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00109420-1

www.llw-law.com

Accordingly, the plan should accurately identify the size of the plant, the number of units and accurately state the source and quantity of water demanded for the site, as well as accurately describe the impact to the environment, including the Big Cypress Reservation.

Sincerely,

Andrew J. Baumann

AJB/ml

cc: Jim Shore
Craig Tepper

00109420-1

Eric Fryson

From:	Matthew Schwartz [matthew3222@yahoo.com]
Sent:	Monday, July 02, 2012 6:32 PM
To:	Filings@psc.state.fl.us; Records Clerk
Cc:	Eric Fryson
Subject:	Re: FW: FW: FPL 10 Year Site Plan
Attachments:	SFWA Comments on FPL 10 Year Site Plan.doc

Please see attached.

Sincerely,

Matthew Schwartz
Executive Director
South Florida Wildlands Association
P.O. Box 30211
Ft. Lauderdale, FL 33303
954-634-7173
954-993-5351 (cell)

SOUTH FLORIDA
WILDLANDS ASSOCIATION
P.O. Box 30211
Ft. Lauderdale, FL 33303

July 2, 2012

Dear Florida Public Service Commission:

South Florida Wildlands Association was recently informed that Florida Power and Light (FPL) has included the Hendry County energy center (potential site #4 - Hendry County) in its 2012 Ten Year Power Plant Site Plan submitted to the Florida Public Services Commission. on April 2, 2012.

Our organization has a longstanding objection to the location of this plant which has been brought up on numerous occasions. We objected when the proposal was first brought to the Hendry County Planning and Zoning Board in 2011. When the board transmitted their approval to the full commission, we again objected to the commission prior to their vote approving the re-zoning that would make this project possible. We also attended a meeting organized by Laurie McDonald of the Defenders of Wildlife between FPL and representatives of numerous local and national environmental organizations. We again stressed that this particular site for a 3,750 MW gas fired power plant was completely unacceptable to our organization no matter what steps the utility takes to "mitigate" the damage. We have sent action alerts to our membership on this issue (opposing the project) and our views have been covered by the news media (e.g. The Sun-Sentinel and Fox4 television in southwest Florida).

Our objections fall into the following categories:

1. According the U.S. Fish and Wildlife Service (FWS), all but 6 of the more than 3000 acres purchased by FPL for this project fall in the primary habitat zone of the critically endangered Florida panther. Panthers have been dying in record numbers as the population expands into ever shrinking habitat. Not only will this destroy and degrade a certain amount of habitat on site, but the impacts on panthers and their prey in the surrounding area from an industrial project of this magnitude are unknown (but extremely likely to be negative). FWS has provided us with GIS maps which indicate numerous instances of both roadkill and "intra-specific" aggression (panther on panther fights to the death) both in and around the FPL property (at least 3 panthers have been killed on a section of CR 833 bordering the property. Telemetry shows a great deal of panther occupancy and state FWC maps of collared panthers indicate that the property and the surrounding area is one of the most important - if not the most important - in the entire state for the species.

The former property owner, prior to selling the property to FPL, wrote a letter to the

FWS asking for help putting a conservation easement on the property. In that letter, Mr. Eddie Garcia stressed the property's importance to the panther and numerous other listed and non-listed animals on site (e.g. black bear, crested caracara, eastern indigo snake).

2. The property is currently completely rural and is surrounded by - or in a nexus of - either public lands (e.g. the Big Cypress National Preserve, Dinner Island WMA, OK Slough State Forest, etc.) or lands which have been long sought by Florida Forever for protection. The entire McDaniels Ranch was always expected to have a conservation easement on it - and was in fact included in a Florida Forever project named "Panther Glades". The McDaniels property was considered an "essential" part of that project. The FPL projected energy center will not only degrade the value of nearby public lands, but will introduce development into a still completely rural section of south Florida. Leaving the Seminole Reservation to the south - one encounters virtually no development until one arrives at either Clewiston to the north or Immokalee to the southwest. The area is completely rural. The history of development in south Florida shows that projects like this will not long stand in isolation. Development follows development. In this case - the project alone is enough to cause significant harm to the panther. Further development of the area - including widened roads and increased traffic - would simply be unacceptable.

3. The Hendry County plant would be a virtual twin of the West County Energy Center in Palm Beach County. It is completely unacceptable for a massive utility to be built in such close proximity to a location like the Big Cypress National Preserve Addition Lands (just a few miles to the south). Emissions in the form of CO_2 but also other pollutants are massive and will clearly degrade what the Big Cypress National Preserve resident botanist - Dr. Jim Burch - has referred to as the most biodiverse piece of land in the entire continental United States. Numerous other scientific papers attest to the diversity of flora and fauna nearby to the FPL Hendry County site. It should also be noted that the waters in the preserve are considered "outstanding Florida waters". That is a resource that clearly needs to be preserved in the condition it is now in.

4. In their Ten Year Plan, FPL has said that their plant will utilize up to 7.5 MGD (million gallons per day) per unit. With three units, that would a total of 22.5 MGD from water that currently makes its way not only to the Seminole Reservation, but to the Big Cypress National Preserve. This is about 7 million gallons a day more than is used by a major municipality like Pembroke Pines in Broward Count and is an unacceptably high amount of water to be drawn from this critical location.

5. There are numerous numbers of alternative sites (not far from the chosen site) for this Hendry County plant which would have far fewer ecological consequences. At the meeting with environmentalists, FPL representatives said that the fact that an existing power corridor existed on the north end of the property was a "major

consideration". However, semi-developed and already industrial sites outside the towns of Clewiston, LaBelle, or Immokalee could be easily connected by power corridor and contain available lands that contain far fewer ecological considerations. The "convenience" of a power corridor should not be an excuse for causing irrevocable damage to the one of the most important natural areas left in south Florida.

Time does not allow us to go into numerous other reasons why the FPL plant should not be built at this location. We will send additional information as time allows. Please do not hesitate with any questions or comments regarding this submission.

Thank you for your time and have a very good holiday.

Sincerely,

s/ Matthew R. Schwartz

Matthew Schwartz
Executive Director
South Florida Wildlands Association
P.O. Box 30211
Ft. Lauderdale, FL 33303
954-634-7173
954-993-5351 (cell)

Other Organizations

Sierra Club

To: Filings@psc.state.fl.us, clerk@psc.state.fl.us

Re: FPL 10 Year Power Plant Site Plan Submittal
http://www.psc.state.fl.us/library/filings/12/01983-12/01983-12.pdf

Dear Mr. Ellis and Ms. Matthews

Thank you for accepting this brief comment regarding the above-referenced ten-year plan on behalf of the Sierra Club and its many Florida members. We are writing to resolve an important ambiguity in Florida Power & Light (FP&L)'s plan.

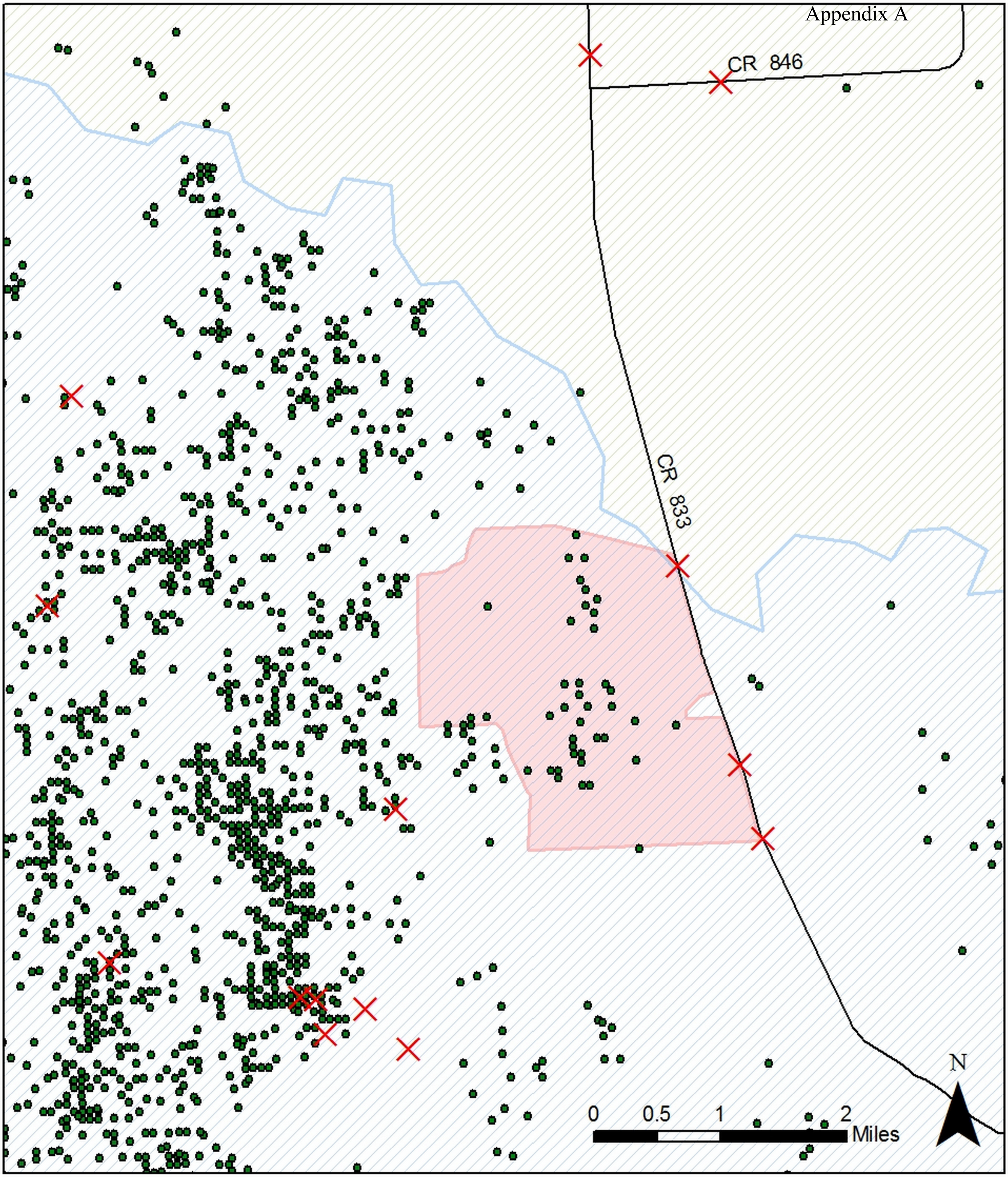
Specifically, the plan submitted by FPL lists a potential future power plant site identified as site #4 in Hendry County. The description of the Hendry County potential site does not explain whether the site would be, could be or must be used for gas, solar PV, or some mix of both, or describe what that mix would be. Further, this potential site is located in Primary Habitat for the federally and state listed endangered Florida panther, making clarifying the use of the site particularly important. See *attached diagram.*

Because ten-year plans must provide sufficient information to judge a site's "environmental impact" and its impact on "fuel diversity within the state," the likely use of this site must be clarified in the Plan, as the impacts of the site will be very different depending on how it is used, and if it is used at all. *See* F.S. 186.801. Accordingly, FP&L should identify its likely use of the site (including the types of generation contemplated for the area, identifying specific megawattage of that generation planned), or, if it cannot, it should explain how that decision will be made. Further, FP&L should specifically discuss the impacts of its plans -- whatever they may be -- upon Florida panthers and their habitat. We respectfully request that the Commission require FP&L to make these clarifications.

Sincerely,

s/ Craig Segall

Craig Segall
Sierra Club Environmental Law Program
50 F St NW, Eighth Floor
Washington, DC, 20001
202-548-4597
Craig.Segall@sierraclub.org



Legend

Panther Habitat Zones

Primary

Secondary

Panther Mortality Points 2010

Panther Telemetry Points 1981 - 2010

Proposed Clean Energy Center Site

CONSERVANCY of Southwest Florida
...OUR WATER, LAND, WILDLIFE, FUTURE.

Other Organizations

Sierra Club & Earthjustice

July 2, 2012

Phillip O. Ellis
Strategic Analysis & Government Affairs
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
pellis@psc.state.fl.us

CC: Traci Matthews
tmatthews@psc.state.fl.us

Re: Comments on Gulf Power's Ten-Year Plan Submittal

Dear Mr. Ellis and Ms Matthews:

Thank you for accepting these comments on behalf of the Sierra Club and its more than 27,000 Florida members, and on behalf of Earthjustice. We look forward to participating in the Public Service Commission (PSC)'s Ten-Year Plan review process. We are writing to help inform the Commission of serious regulatory risks which should be addressed in this Ten-Year Plan.

As you know, Ten-Year Plans are designed to provide a broad overview of a utility's "power-generating needs and the general location of its proposed power plant sites;" accordingly, plans must be "suitable" for planning purposes. F.S. § 186.801; *see also* F.A.C. §§ 25-22.070 & 25-22.071. These plans are among the many tools used by the Commission as it fulfills its statutory responsibilities to maintain "sufficient, adequate, and efficient service" and "fair and reasonable rates" for all Floridians. *See, e.g.*, F.S. § 366.03.

To do so, the Commission will have to address the implications of substantial new environmental compliance obligations at several aging coal-fired units. A recent report for state utility commissioners, primarily authored by former Colorado PSC Chair Ron Binz, puts the problem succinctly, reminding regulators that "[t]he U.S. electric utility industry, which has remained largely stable and predictable during its first century of existence now faces tremendous challenges," including the prospect of substantial retirements of aging coal-fired power plants. *See* Ron Binz & CERES, *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know* (2012) at 5.[1] These "retrofit or retire" decisions will lead to significant changes in the Florida coal fleet, and the PSC will be charged with managing these shifts. As Commissioner Binz writes:

> The question for regulators is whether to approve coal plant closures in the face of new and future EPA regulations, or to approve utility investments in costly pollution controls to keep the plants running. Regulators should treat this much like an IRP proceeding: utilities

[1] Attached as Ex. 1.

> should be required to present multiple scenarios differing in their disposition of the coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. In the end, regulators should enter a decision that addresses all of the relevant risks.

Id. at 9.

These comments highlight some of these important risks. The Commission should use the Ten-Year Plan informational docket to fully investigate them. We have submitted similar comments addressing plans filed by several different utilities; this filing focuses on coal-fired power plants operated by Gulf Power.

I. Gulf Power's Plants Face Substantial Environmental Compliance Costs

Gulf Power's Lansing Smith, Crist, and Scholz plants are aging facilities lacking major pollution controls. These plants are an increasingly bad deal for ratepayers: In addition to posing a serious threat to public health, they are not economic to operate. As utilities and PSCs around the country are increasingly recognizing, rising pollution control and fuel costs make coal power an unattractive proposition, especially as energy efficiency, demand-side resources, and renewable power become ever more available and as natural gas prices continue at record lows. Multi-million dollar life-extension projects for aging coal plants are not prudent in these circumstances. Accordingly, Gulf anticipates that it is likely to retire many of its plants in the near future. Gulf Power Ten Year Plan ("Gulf Plan") at 3.

Because Gulf's plans have important implications for the "need … for electrical power" in its service territory, and for how that need is to be met, as well on "fuel diversity within the state," on the "environmental impact" of any proposed replacement power, and on the state "comprehensive plan," *see* F.S. § 186.801, the Commission should ensure that Gulf discloses its intentions in its Ten-Year Plan as fully as possible. It is particularly important to do so because Gulf will face compliance obligations within the next few years that will lead to retirement decisions. The Commission can best protect Floridians by beginning the planning process for these likely retirements now. The Plan is not suitably detailed to allow for this planning to be successful, so, at the end of these comments, we respectfully urge the PSC to require Gulf to submit critical additional information.

Gulf Power's Lansing Smith and Scholz plants are the most likely retirement targets because both plants lack "scrubbers," the flue-gas desulfurization systems required to remove SO_2, which can cause deadly respiratory damage, and other acid gases from their emissions. Scrubber systems for these plants would cost hundreds of millions of dollars. Such an investment, and the corresponding rate increase, would not be prudent when much cheaper sources of power are available. Accordingly, the Commission should work with Gulf Power to investigate retirement options for these plants.

In the discussion below, we explain the likely sources of scrubber liability for the Lansing Smith and Scholz plants, before briefly highlighting the many other environmental compliance costs which Gulf is likely to face.

A. Likely Scrubber Liability for Gulf Power Facilities

Three separate environmental and public health protection programs are likely to drive scrubber installation requirements, and hence "retire or retrofit" decisions, at the Lansing Smith and Scholz facilities: the SO_2 National Ambient Air Quality Standards ("NAAQS"), 40 C.F.R. § 50.17, the Mercury and Air Toxics Standards ("MATS"), 40 C.F.R. Subpt. UUUUU, and the Regional Haze Rule, 40 C.F.R. § 51.308.

i. The SO_2 NAAQS

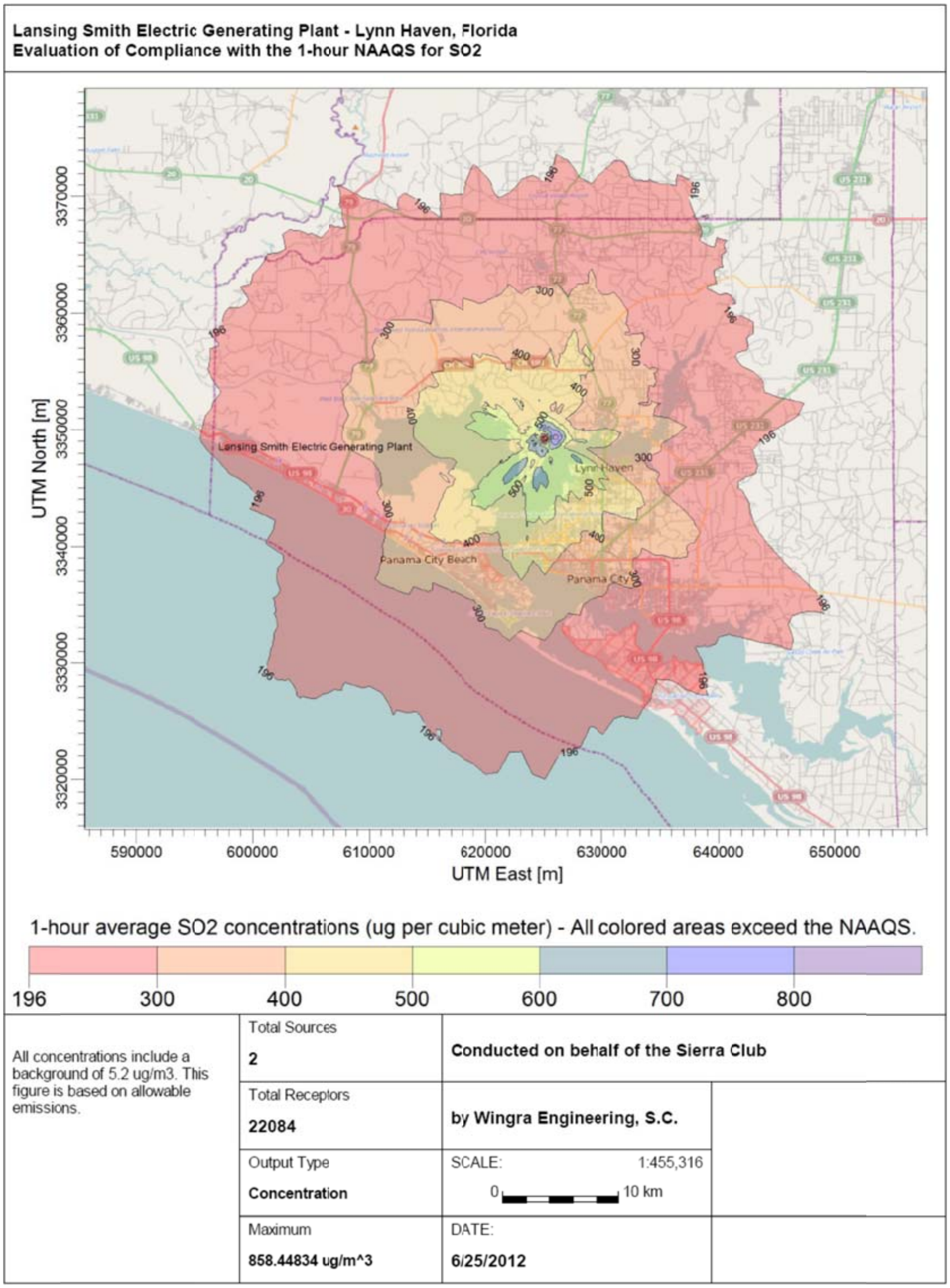
Just five minutes of exposure to SO_2 can make people sick; in fact, the causal link between this pollution and asthma attacks and other respiratory problems is the "strongest" such link which the EPA's scientific advisory board can identify. 75 Fed. Reg. 35,520, 35,525 (June 22, 2010). To protect the public from such pollutants, EPA is required to set NAAQS specifying the safe level of public exposure; states then develop state implementation plans (SIPs) to ensure that those standards are attained. *See* 42 U.S.C. §§ 7409 & 7410. EPA's decision to protect public health by lowering the NAAQS for SO_2 to a maximum allowable exposure of 75 ppb (a concentration equivalent to 196.2 $\mu g/m^3$) over an hour, *see* 75 Fed. Reg. 35,520 (June 22, 2010), thus obliges Florida to update its SIP to ensure that its citizens are protected from this dangerous air pollution.

States are generally required to submit updated SIPs "within 3 years" after EPA updates a NAAQS; because EPA finalized its NAAQS in 2010, Florida's plan is due in 2013. 42 U.S.C. § 7410(a)(1). The plan must "provide[] for implementation, maintenance, and enforcement of" the standard throughout Florida. *Id.* Although EPA's approval and review process may delay plan implementation for a year or two after submission, the Commission can reasonably expect Florida's SIP to be operating by 2015 or before.

This tight timeline is directly relevant to the Commission's review of Gulf Power's plans because the Lansing Smith plant is causing violations of the NAAQS, and so will have to install controls under any legal SIP. Sierra Club engaged an expert air modeler, Steve Klafka of Wingra Engineering, to evaluate the plant's compliance with the NAAQS, using EPA's models and methodology.[2] We modeled both the plant's allowable emissions – those authorized by its Title V Air Operation Permit, No. 0050014-018-AV – and its maximum emissions in 2011, the most recent year with complete data in EPA's Air Pollution Markets Database. Whether measured by its permit or by its most recent maximum emissions, the plant causes the pollution in the air over Panama City to reach unsafe levels, violating the NAAQS several-fold.

[2] The methodology is described in detail in the attached report, Ex. 2.

The figure below shows the SO_2 pollution plume the plant would create when operating at its permit limits. All colored areas violate the NAAQS. While the NAAQS is set at 196.2 µg/m^3, Lansing Smith's permit allows pollution levels to soar to 858.4 µg/m^3, over 400% of the safe value; even a bit further away from the plant, pollution directly over downtown Panama City reaches levels close to double the safe value.



Importantly, Lansing Smith causes NAAQS violations even when operating below its permitted maximums. Last year, Lansing Smith's highest operating hour emissions saw SO_2 concentrations reach 346.5 μg/m^3, which is nearly double the safe value. *See* Ex. 2 at Table 1.

Indeed, Lansing Smith's SO_2 emissions are so extreme that, according to the Florida Department of Environmental Protection ("FL DEP"), they even violate the far more lenient NAAQS that the new standard replaces. *See* FL DEP Permit No. 0050014-018-AV at 5. As such, FL DEP requires Gulf Power to post no trespassing signs to "protect the general public" from crossing the plant's fence line, within which the pollution is the most intense. *See id.* This is not a safe facility.

To reduce this illegal pollution, Lansing Smith would have to cut total facility emissions by 77.6% from its current permit. *Id.* at Table 3. To do so, it is highly likely to have to install a scrubber, thereby confronting hundreds of millions in control costs, which we document more fully below. Importantly, these costs will be far outweighed by public health benefits. EPA determined that the NAAQS will produce on the order of $36 billion in *net* benefits once safe levels of SO_2 have been attained. 75 Fed. Reg. at 35,588. Panama City residents will secure a substantial portion of these benefits – in the form of fewer asthma attacks, emergency room visits, and premature deaths – once Lansing Smith's pollution has been controlled.

We have not yet modeled the Scholz facility, but it is also an unscrubbed coal boiler, burning high-sulfur bituminous coal, and its permitted emissions are far higher than Lansing Smith's. While the Lansing Smith permit allows emissions of up to 4.50 lbs/MMBtu of SO_2, FL DEP Permit No. 0050014-018-AV at 8, the Scholz permit allows the facility to emit up to an astonishingly 6.17 lbs/MMBtu, FL DEP Permit No. 0630014-010-AV at 6. FL DEP candidly acknowledges that this emission rate "indicates exceedances" near the facility of even the more lenient NAAQS which EPA has since replaced, and so requires Gulf Power to take "precautions… to preclude public access." *Id.* Scholz is an even dirtier plant than Lansing Smith, and so is very likely to run afoul of the new NAAQS as well.

In short, the SO_2 NAAQS, a pollution control requirement which Gulf Power does not even acknowledge in its Ten-Year Plan, is highly likely to require the Lansing Smith and Scholz facilities to retrofit or retire. It is not the only requirement to do so, as we next discuss.

ii. MATS Requirements

In the Clean Air Act of 1990, Congress ordered EPA to investigate hazardous air pollutants emitted by power plants, and to promulgate emissions standards for these pollutants if they threatened public health. 42 U.S.C. § 7412(n)(1). Because coal power plants are dominant sources of mercury, acid gases, and other highly toxic pollutants, EPA was obligated to issue such standards, and finally did so in 2012, 22 years later. *See* 77 Fed. Reg. 9,304 (Feb. 16, 2012).

The final MATS rule issued in response to this Congressional mandate requires operators to control mercury and acid gases. A smoke stack scrubber can be required to comply with EPA's control requirements. In EPA's analysis of facility compliance options, it presumed that coal plants emitting more than 2 lbs/MMBtu of SO_2 would have to install scrubbers to comply with the standard. 77 Fed. Reg. at 9,412. As we note above, Lansing Smith emits more than twice this amount, and Scholz emits *three times* this threshold quantity. As such, scrubbers will very likely be required at these plants in order to comply with MATS.

The Clean Air Act requires that existing sources comply with MATS "as expeditiously as practicable, but in no event later than 3 years after the effective date" of the standard. 42 U.S.C. § 7412(i)(3). Because MATS was promulgated and effective on February 16, 2012, plants must comply by that date in 2015. Although limited compliance extension of up to 1-2 additional years may be available in some limited circumstances, *see id.*, these extensions are disfavored.

Accordingly, as Gulf Power recognizes, MATS "may severely restrict Gulf's coal-fired generation or completely eliminate the generation produced by Gulf's coal-fired units at Plants Smith and Scholz by as early as 2015." Gulf Plan at 3.

iii. Regional Haze Requirements

Since 1977, the Clean Air Act has required EPA and the states to make "reasonable progress" towards restoring natural visibility in Class I areas – which are essentially national parks and wildernesses. *See* 42 U.S.C. § 7491. EPA's rules to address regional haze, promulgated in 1999, are now being implemented. Florida is the process of a SIP revision intended to protect Class I areas affected by sources in the state. *See* FL DEP, *Regional Haze Plan for Florida Class I Areas* (Draft as amended May 2012).[3] Gulf Power has already determined that this rule, alone, may lead it to retire the Lansing Smith facility.

The regional haze rule requires that Florida impose controls at all sources of visibility-impairing pollutants to the extent such controls will be needed to make reasonable progress towards restoring natural visibility by 2064. *See* 40 C.F.R. § 51.308(d)(3). The Act and the Rule also require sources which were in existence by August 7, 1977, but which had not been in operation before August 7, 1962, to install "the best available retrofit technology" (BART) to control visibility-impairing pollutants. 42 U.S.C. § 7491(b)(2)(A) & 40 C.F.R. § 51.308(e). FL DEP has determined that the Crist facility is subject to reasonable progress analysis and that Lansing Smith is subject to BART. *See* FL Draft Regional Haze Plan at 98 & 102.

FL DEP had planned to rely upon a separate EPA SO_2 trading program, the Clean Air Interstate Rule ("CAIR") to address these requirements, but CAIR has been replaced with a new program which does not control SO_2 in Florida. *See* 77 Fed. Reg. 31,240, 31,248 (May 25, 2012). As such, FL DEP is reanalyzing control options and will have to consider source-specific control

[3] Available at http://www.dep.state.fl.us/air/rules/regulatory/regional_haze_imp.htm.

requirements for Crist and Lansing Smith. Scholz should also be implicated in this re-analysis because FL DEP had previously excluded relatively small facilities largely because it assumed CAIR would address most SO_2 emissions. Now that CAIR is no longer available, Scholz will have to be analyzed as well. Thus, as a result of these analyses, FL DEP will have to address SO_2 emissions, in some fashion, from all of Gulf Power's coal plants.

These controls are likely to drive scrubber requirements (and other controls or operating restrictions at scrubbed plants like Crist) because, according to FL DEP, SO_2 is the dominant source of visibility-impairing pollution in Florida. *See, e.g.*, FL Draft Regional Haze Plan at 91-92. Thus, these rules, too, are highly likely to drive scrubber requirements at the Lansing Smith facility.

Gulf Power has admitted as much to FL DEP. In a "BART Implementation Plan" submitted to DEP on May 21, 2012[4], it indicated that it will complete a BART analysis for Lansing Smith, and that it will decide, by January 1, 2015, whether to install a scrubber on the plant by 2018 (or later), "commit to retire the operation of Smith Unit 1 by January 1, 2022 and Smith Unit 2 before January 1, 2021," or to seek permit levels by 2015 reducing plant operations below BART emissions limits. Gulf BART Plan at 2. Because BART determinations will be approved within the next year, it is not at all clear how Gulf Power expects to run its plants until the early 2020s. Retirement within the next few years is the more likely option.

iv. Scrubber Costs

We have calculated the approximate cost of installing and running scrubbers (at 90% efficiency, a level which would likely be required, at a minimum, to meet the requirements of all three relevant rules) at Lansing Smith and Scholz, based upon the EPA's Integrated Planning Model and a scrubber-focused appendix developed by Sargent & Lundy.[5] This model predicts that the capital costs for fitting Lansing Smith Units 1 and 2 with scrubbers at $234 million. The incremental costs (including running costs) of these upgrades would be $43.1/MWh annually. Gulf Power would no doubt seek to pass these costs on to rate-payers if it opted to continue to run the plant, rather than to retire it.

Scrubber costs for Scholz are also very high. Using the same government modeling, we calculated that scrubbers for Scholz units 1 & 2 would cost $106 million to install, yielding a $243.5/MWh spike in incremental costs.

These figures do not include the incremental costs of effluent controls for scrubber waste. Any such additional upgrades would, of course, add to these costs, as would any additional measures required at Crist to bring that facility into compliance. The expenditures are extraordinarily high simply in order to extend the lives of these decades-old, expensive, coal-fired power plants. Gulf Power is unlikely to make them and, we submit, it would not be

[4] Attached as Ex. 3.
[5] All modeling parameters can be found at http://www.epa.gov/airmarkt/progsregs/epa-ipm/BaseCasev410.html.

appropriate for the Commission to authorize such costs where less expensive options are available.

B. Other Environmental Liabilities

As Gulf Power acknowledges, Gulf Plan at 3, scrubber costs are not the only liabilities it faces. There are also pending rules requiring upgrades to coal plant cooling water systems, *see* 76 Fed. Reg. 22,174 (Apr. 20, 2011), better handling and disposal practices for coal combustion waste, *see* 75 Fed. Reg. 35,128 (June 21, 2010), and new treatment systems for liquid effluent discharges,[6] all of which are likely to be finalized in the next two years. EPA is also updating the NAAQS for particulate matter and for ozone. Moreover, EPA has recently proposed carbon controls for new electricity generating units. *See* 77 Fed. Reg. 22,39 (Apr. 13, 2012). Once finalized, these rules will obligate EPA to extend carbon controls to existing facilities, including Gulf Power's fleet. *See* 42 U.S.C. § 7411(d). The cumulative impact of these liabilities on Gulf Power will be large. Indeed, according to Gulf, "the additional costs to comply with the final versions of EPA's proposed water quality and coal combustion by-product rules" alone "may result in total combined compliance costs that render controlled coal-fired operations uneconomical in the long term." Gulf Plan at 3.

Coal ash costs will be particularly pressing for Gulf Power. According to the Toxic Release Inventory, its Lansing Smith facility discharged 520,281 pounds of ash to its impoundment in 2006, a typical year, making Lansing Smith the 57th largest source of ash in the country and the second largest sources in Florida.[7] Highly troublingly, carcinogenic hexavalent chromium, which leaches from coal ash, has been found in groundwater wells near Lansing Smith at over 5,000 times safe levels (as determined by California for its drinking water goals), and above federal standards.[8] Clean-up costs for this contamination, including halting wet storage of ash, will be yet another substantial expense for the plants.

C. Likely Retirements

The cumulative compliance costs from all the rules which apply to Gulf Power's fleet are very large. Upon reviewing them, and considering the wide availability of more inexpensive power sources, Gulf Power is highly likely to follow industry trends towards coal retirement.

Coal use is falling quickly, in response both to the cost of pollution controls and to national economic trends, including the growth of inexpensive wind power and the boom in shale gas production. As EPA has recently documented, "all indications suggest that very few new coal-fired power plants will be constructed in the foreseeable future." 77 Fed. Reg. at 22,413, and the Energy Information Administration (EIA) is documenting increasing retirements of existing plants. In particular, the EIA's Annual Energy Outlook for 2012 forecasts no new unplanned

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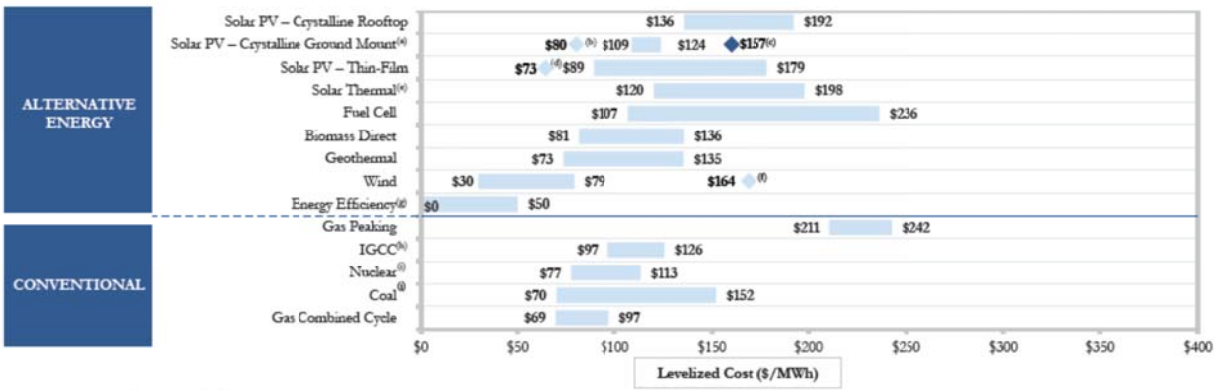
[6] *See* EPA's plans for this rule at http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm
[7] *See* Ex. 4, attached.
[8] Lisa Evans, *EPA's Blind Spot: Hexavalent Chromium in Coal Ash* (2011) at 6, attached as Ex. 5.

coal capacity through 2020. RIA at 5-5. EIA's most recent Electric Power Monthly report confirms that this trend continues. Thus far this year, *none* of the 5,627 MW of new units to come online are coal-fired; instead, new capacity additions are largely in renewable power or natural gas. EIA, *Electric Power Monthly June 2012* at Table ES3.[9] Conversely, retirements to date have been predominantly coal-fired units. *See id.* at Table ES4. Utilities across the country have announced thousands of megawatts worth of coal retirements over the last few years.[10]

Industry-wide levelized cost figures compiled by independent analysts demonstrate why these retirements are occurring. The most recent (2011) edition of Lazard's Levelized Cost of Energy Analysis,[11] a widely-used reference, shows that energy efficiency, wind, and natural gas combined cycle levelized costs are already below those of coal, as the figure below demonstrates.



Under these circumstances, prudent operators are increasingly deciding not to impose additional costs on their ratepayers by running coal-fired units with costly new pollution technology. Instead, they are opting to retire older units and pursue cleaner, cheaper, energy options. Gulf Power could, and should, decide to follow the same course.

D. Recommended Commission Action

Although Gulf Power has acknowledged that some retirements may occur, it nonetheless "assume[s]" that Lansing Smith and Scholz "will be available to operate on coal throughout the 2012-2021 planning cycle." Gulf Plan at 3. As we have demonstrated above, this assumption is

[9] Available at: http://205.254.135.7/electricity/monthly/pdf/epm.pdf.

[10] *See, e.g.*, Progress Energy Press Release, "Progress Energy Carolinas to retire coal power plant ahead of schedule" (Apr. 1, 2011) (recording the retirement of four North Carolina coal plants), available at https://www.progress-energy.com/company/media-room/news-archive/press-release.page?title=Progress+Energy+Carolinas+to+retire+coal+power+plant+ahead+of+schedule&pubdate=04-01-2011; FirstEnergy Press Release, "FirstEnergy, Citing Impact of Environmental Regulations, Will Retire Six Coal-Fired Power Plants" (Jan. 29, 2012) (announcing the retirement of six coal plants in Ohio), available at https://www.firstenergycorp.com/content/fecorp/newsroom/news_releases/firstenergy_citingimpactofenvironmentalregulationswillretiresixc.html; Environment News Service, "Dominion Virginia to Replace Coal Plants with Gas, Nuclear" (Sept. 7, 2011) (documenting retirement of two Virginia coal plants), available at http://www.ens-newswire.com/ens/sep2011/2011-09-07-091.html.

[11] Attached as Ex. 6.

arbitrary and unsupportable: The compliance periods for the scrubber-forcing rules will run within the next two years and retirements will very likely occur within that period, and certainly will occur within the next decade. This error, and Gulf Power's failure fully to address the impacts of retirements upon its system and upon ratepayers, renders the draft plan "unsuitable" as a planning document. *See* F.S. §186.801. The Commission, "may suggest alternatives to the plan," *id.*, however, and may classify a plan as suitable upon the submission of "additional data," *see* F.A.C. § 25-22.071(5). We respectfully request that the PSC exercise its authority to ensure that Gulf Power's plan provides adequate data to allow the PSC and the public to address these plant retirements.

Specifically, we submit that the Commission should seek the following information from Gulf Power and require resubmission of a complete plan addressing these submissions:

1. The utility should provide an analysis of all environmental compliance obligations which it will experience at all of its coal-fired facilities. For each requirement, the utility should cite the relevant rule, explain how it is likely to apply to the plant, the likely costs of compliance to the utility and to ratepayers, and the timeline on which compliance will be required. The utility should also document any steps it has taken to address these compliance obligations, and alternative steps it might take. For instance, if the utility anticipates that it will have to install a scrubber to comply with MATS, it should report to the Commission on scrubber installation and operation costs, whether it has contracted to purchase a scrubber and on what timeline, and what other options it has considered. *See* F.S. § 186.801 (requiring utilities to document "[p]ossible alternatives to the proposed plan").

2. The utility should provide a comparative analysis of compliance costs and the cost costs of replacing the plant's power through energy efficiency, demand response, power purchase agreements, new generation facilities, or other means. *See* F.S. §186.801 (requiring utilities to explain the impact of their plans on fuel diversity and on the need for electric power in their regions). In light of this analysis, the utility should indicate whether it intends to retire any facility, and on what timeline, and the relative costs of retirement versus those of other options. If retirement has not been selected but is being considered, the utility should indicate when the decision will be made.

3. For any facility where retirement is possible, the utility should discuss how it intends to address any reliability issues which may be caused by the retirement. The Commission should play an active role in this regard, as it must maintain reliability of the electric grid. *See* F.S. § 366.05(7)-(8) (authorizing the Commission to "require reports from all electric utilities to assure the development of adequate and reliable energy grids" and to order "installation and repair of necessary facilities" to address reliability issues"). The Commission has determined that "[r]eserve margins in Florida typically remain well above" relevant minimums through 2020, so system-wide resource adequacy problems are unlikely, but the Commission may still need to

address localized reliability issues. If such problems appear to be present, the Commission should work proactively and transparently with the Florida Reliability Coordinating Council to address them well in advance of any planned retirement.

We appreciate this careful consideration of Gulf Power's environmental compliance options, and any resulting plant retirements, and remind the Commission that such thorough analysis is required to ensure that the Ten-Year Plan complies with legal requirements. We request that the Commission share the results of its inquiry with us and with the public, and request formal notice of the Commission's next steps.

Please contact the undersigned with any concerns or questions.

Sincerely,

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July 2, 2012

Mr. Phillip O. Ellis
Strategic Analysis & Government Affairs
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CC: Traci Matthews
tmatthew@psc.state.fl.us

Re**:** Comments on Progress Energy's Ten-Year Plan Submittal

Dear Mr. Ellis and Ms Matthews:

Thank you for accepting these comments on behalf of the Sierra Club and its more than 27,000 Florida members, and on behalf of Earthjustice. We look forward to participating in the Public Service Commission (PSC)'s Ten-Year Plan review process. We are writing to help inform the Commission of serious regulatory risks which should be addressed in this Ten-Year Plan.

As you know, Ten-Year Plans are designed to provide a broad overview of a utility's "power-generating needs and the general location of its proposed power plant sites;" accordingly, plans must be "suitable" for planning purposes. F.S. § 186.801; *see also* F.A.C. §§ 25-22.070 & 25-22.071. These plans are among the many tools used by the Commission as it fulfills its statutory responsibilities to maintain "sufficient, adequate, and efficient service" and "fair and reasonable rates" for all Floridians. *See, e.g.*, F.S. § 366.03.

To do so, the Commission will have to address the implications of substantial new environmental compliance obligations at several aging coal-fired units. A recent report for state utility commissioners, primarily authored by former Colorado PSC Chair Ron Binz, puts the problem succinctly, reminding regulators that "[t]he U.S. electric utility industry, which has remained largely stable and predictable during its first century of existence now faces tremendous challenges," including the prospect of substantial retirements of coal-fired power plants. *See* Ron Binz & CERES, *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know* (2012) at 5.[1] These "retrofit or retire" decisions will lead to significant changes in the Florida coal fleet, and the PSC will be charged with managing these shifts. As Commissioner Binz writes:

> The question for regulators is whether to approve coal plant closures in the face of new and future EPA regulations, or to approve utility investments in costly pollution controls to keep the plants running. Regulators should treat this much like an IRP proceeding: utilities

[1] Attached as Ex. 1.

> should be required to present multiple scenarios differing in their disposition of the coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. In the end, regulators should enter a decision that addresses all of the relevant risks.

Id. at 9.

These comments highlight some of these important risks. The Commission should use the Ten-Year Plan informational docket to fully investigate them. We have submitted similar comments addressing plans filed by several different utilities; this filing focuses on coal-fired power plants operated by Progress Energy.

I. Progress Energy's Crystal River Plant Face Substantial Environmental Compliance Costs

Units 1 and 2 at Progress Energy's Crystal River plant were put into service in the late 1960s, and are operating without major pollution controls, including smokestack scrubbers. *See* FL DEP Air Operation Permit No. 0170004-025-AV (2011) at 6. These units are an increasingly bad deal for ratepayers: In addition to posing a serious threat to public health, they are not economic to operate. As utilities and PSCs around the country are increasingly recognizing, rising pollution control and fuel costs make coal power an unattractive proposition, especially as energy efficiency, demand-side resources, and renewable power become ever more available and as natural gas prices continue at record lows. Multi-million dollar life-extension projects for aging coal plants are not prudent in these circumstances. Progress has already told FL DEP that it will consider retiring units 1 and 2 within the next decade. *See* Progress Energy BART Implementation Plan for Crystal River Units 1 and 2 (June 2012) at 3.[2] Yet, Progress's Ten-Year Plan does not even mention these units, much less address their retirements.

Because of this striking gap, Progress's plan is not "suitable" for planning purposes. *See* F.S. § 186.801. The likely retirement of the Crystal River units has important implications for the "need … for electrical power" in its service territory, and for how that need is to be met, as well on "fuel diversity within the state," the "environmental impact" of any proposed replacement power, and the state "comprehensive plan." *See* F.S. § 186.801. The Commission should therefore ensure that Progress submits a corrected plan which discloses its intentions as fully as possible. It is particularly important to do so because Progress will face compliance obligations within the next few years that will lead to retirement decisions. The Commission can best protect Floridians by beginning the planning process for these likely retirements now.

Crystal River Units 1 and 2 are likely retirement targets because both units lack "scrubbers," the flue-gas desulfurization systems required to remove SO_2, which can cause deadly respiratory damage, from their emissions. Scrubber systems for these plants would cost tens of millions of dollars. Such an investment, and corresponding rate increase, would not be prudent

[2] Attached as Ex. 2.

when much cheaper sources of power are available. Accordingly, the Commission should work with Progress Energy to investigate retirement options for these plants.

In the discussion below, we explain the likely sources of scrubber liability for Crystal River, before briefly highlighting the many other environmental compliance costs which Progress is likely to face.

A. Likely Scrubber Liability for Crystal River Units 1 and 2

Three separate environmental and public health protection programs are likely to drive scrubber installation requirements, and hence "retire or retrofit" decisions, at Crystal River: the SO_2 National Ambient Air Quality Standards ("NAAQS"), 40 C.F.R. § 50.17, the Mercury and Air Toxics Standards ("MATS"), 40 C.F.R. Subpt. UUUUU, and the Regional Haze Rule, 40 C.F.R. § 51.308.

i. The SO_2 NAAQS

Just five minutes of exposure to SO_2 can make people sick; in fact, the causal link between this pollution and asthma attacks and other respiratory problems is the "strongest" such link which the EPA's scientific advisory board can identify. 75 Fed. Reg. 35,520, 35,525 (June 22, 2010). To protect the public from such pollutants, EPA is required to set NAAQS specifying the safe level of public exposure; states then develop state implementation plans (SIPs) to ensure that those standards are attained. *See* 42 U.S.C. §§ 7409 & 7410. EPA's decision to protect public health by lowering the NAAQS for SO_2 to a maximum allowable exposure of 75 ppb (a concentration equivalent to 196.2 $\mu g/m^3$) over an hour, *see* 75 Fed. Reg. 35,520 (June 22, 2010), thus obliges Florida to update its SIP to ensure that its citizens are protected from this dangerous air pollution.

States are generally required to submit updated SIPs "within 3 years" after EPA updates a NAAQS; because EPA finalized its NAAQS in 2010, Florida's plan is due in 2013. 42 U.S.C. § 7410(a)(1). The plan must "provide[] for implementation, maintenance, and enforcement of" the standard throughout Florida. *Id.* Although EPA's approval and review process may delay plan implementation for a year or two after submission, the Commission can reasonably expect Florida's SIP to be operating by 2015 or before.

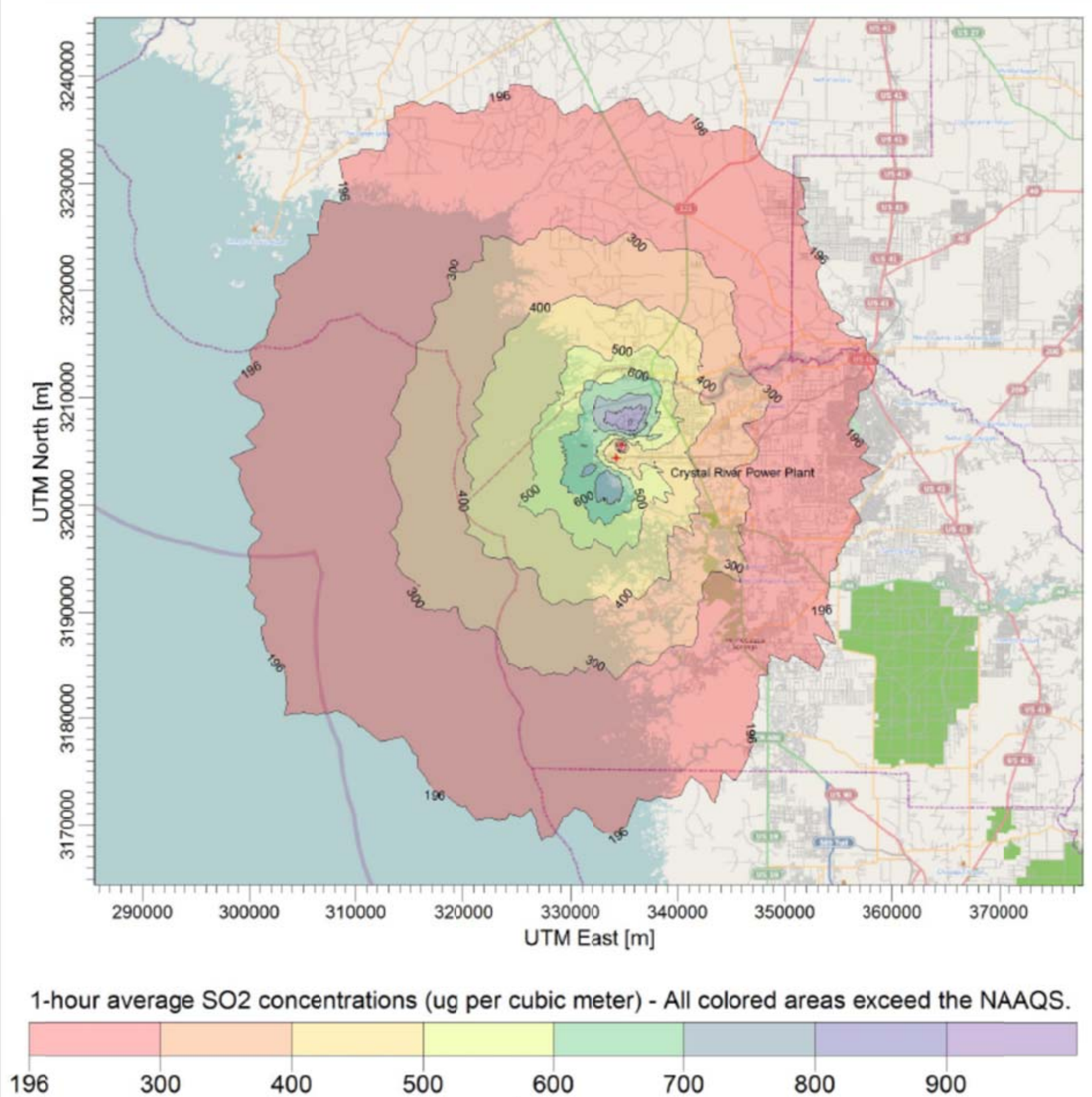
This tight timeline is directly relevant to the Commission's review of Progress Energy's plans because the Crystal River plant is causing violations of the NAAQS, and so will have to install controls under any legal SIP. Sierra Club engaged an expert air modeler, Steve Klafka of Wingra Engineering, to evaluate the plant's compliance with the NAAQS, using EPA's models and methodology.[3] We modeled both the plant's allowable emissions – those authorized by its Title V Air Operation Permit, No. 017000–025-AV, and its maximum emissions in 2011, the most recent year with complete data in EPA's Air Pollution Markets Database. Whether measured by

[3] The methodology is described in detail in the attached report, Ex. 3.

its permit or by its most recent maximum emissions, the plant causes pollutants in the air near Crystal River to reach dangerous levels.

The figure below shows the SO_2 pollution plume the plant would create when operating at its permit limits. All colored areas violate the NAAQS. While the NAAQS is set at 196.2 μg/m^3, Crystal River's permit allows pollution levels to soar to a maximum of 921.0 μg/m^3, over 460% of the safe value; even a bit further away from the plant, the pollution in the air directly over residential areas and over Crystal Bay is well above safe levels.

Crystal River Power Plant - Crystal River, Florida
Evaluation of Compliance with the 1-hour NAAQS for SO2



All concentrations include a background of 5.2 ug/m3. This figure is based on allowable emissions.	Total Sources **6**	**Conducted on behalf of the Sierra Club**
	Total Receptors **22083**	**by Wingra Engineering, S.C.**
	Output Type **Concentration**	SCALE: 1:580,926 0 — 20 km
	Maximum **921.02714 ug/m^3**	DATE: **6/25/2012**

Importantly, Crystal River causes NAAQS violations even when operating below its permitted maximums. Last year, the plant's highest operating hour emissions saw SO_2 concentrations reach 534.6 µg/m^3, which is nearly three times the safe value. *See* Ex. 2 at Table 1.

To reduce this illegal pollution, Crystal River would have to cut total facility emissions by 79.1% from its current permit. *Id.* at Table 3. To do so, it is highly likely to have to install a scrubber, thereby confronting hundreds of millions in control costs, which we document more fully below. Importantly, these costs will be far outweighed by public health benefits. EPA determined that the NAAQS will produce on the order of $36 billion in *net* benefits once safe levels of SO_2 have been attained. 75 Fed. Reg. at 35,588. Crystal River residents will secure a substantial portion of these benefits – in the form of fewer asthma attacks, emergency room visits, and premature deaths – once the plant's pollution has been controlled.

In short, the SO_2 NAAQS, a pollution control requirement which Progress Energy does not even acknowledge in its Ten-Year Plan, is highly likely to require Crystal River Units 1 and 2 to retrofit or retire. It is not the only requirement to do so, as we next discuss.

ii. MATS Requirements

In the Clean Air Act of 1990, Congress ordered EPA to investigate hazardous air pollutants emitted by power plants, and to promulgate emissions standards for these pollutants if they threatened public health. 42 U.S.C. § 7412(n)(1). Because coal power plants are dominant sources of mercury, acid gases, and other highly toxic pollutants, EPA was obligated to issue such standards, and finally did so in 2012, 22 years later. *See* 77 Fed. Reg. 9,304 (Feb. 16, 2012).

The final MATS rule issued in response to this Congressional mandate requires operators to control mercury and acid gases. A smoke stack scrubber can be required to comply with EPA's control requirements. In EPA's analysis of compliance options, it presumed that coal plants emitting more than 2 lbs/MMBtu of SO_2 would have to install scrubbers to comply with the standard. 77 Fed. Reg. at 9,412. Crystal River's air operation permit allows it to emit 2.1 lbs/MMBtu of SO_2, meaning that the MATS rule will likely drive scrubbers installation at the facility. *See* FL DEP Air Operation Permit 0170003-025-AV at 7. Notably, Crystal River is also the single largest source of mercury in Florida, dumping more than 300 kg of mercury a year into the air around the plant.[4] On both counts, MATS compliance will, accordingly, be a major focus for the facility.

[4] *See* Laura S. Sherman *et al.*, *Investigation of Local Mercury Deposition from a Coal-Fired Power Plant Using Mercury Isotopes*, Environment Science & Technology (2012), attached as Ex. 4.

The Clean Air Act requires that existing sources comply with MATS "as expeditiously as practicable, but in no event later than 3 years after the effective date" of the standard. 42 U.S.C. § 7412(i)(3). Because MATS was promulgated and effective on February 16, 2012, plants must comply by that date in 2015. Although limited compliance extension of up to 1-2 additional years may be available in some limited circumstances, *see id.*, these extensions are disfavored. Accordingly, Progress Energy will have to scrub Crystal River by 2015, or shortly thereafter, or retire the facility, yet it entirely fails to acknowledge this major shift in its operations in its Ten-Year Plan.

iii. Regional Haze Requirements

Since 1977, the Clean Air Act has required EPA and the states to make "reasonable progress" towards restoring natural visibility in Class I areas – which are, essentially, national parks and wildernesses. *See* 42 U.S.C. § 7491. EPA has been very slow to implement this mandatory duty, but its rule to address regional haze, promulgated in 1999, are now being implemented, and Florida is the process of a SIP revision intended to protect Class I areas affected by sources in the state. *See* FL DEP, *Regional Haze Plan for Florida Class I Areas* (Draft as amended May 2012).[5]

The regional haze rule requires that Florida impose controls at all sources of visibility-impairing pollutants to the extent such controls will be needed to make reasonable progress towards restoring natural visibility by 2064. *See* 40 C.F.R. § 51.308(d)(3). The Act and the Rule also require sources which were in existence by August 7, 1977, but which had not been in operation before August 7, 1962, to install "the best available retrofit technology" (BART) to control visibility-impairing pollutants. 42 U.S.C. § 7491(b)(2)(A) & 40 C.F.R. § 51.308(e). FL DEP has determined that the Crist facility is subject to BART. *See* FL Draft Regional Haze Plan at 102.

FL DEP had planned to rely upon a separate EPA SO_2 trading program, the Clean Air Interstate Rule ("CAIR") to address these requirements, but CAIR has been replaced with a new program which does not control SO_2 in Florida. *See* 77 Fed. Reg. 31,240, 31,248 (May 25, 2012). As such, FL DEP is reanalyzing control options and will have to propose source-specific control requirements for Crystal River Units 1 and 2.

These controls are likely to drive scrubber requirements because, according to FL DEP, SO_2 is the dominant source of visibility-impairing pollution in Florida. *See, e.g.*, FL Draft Regional Haze Plan at 91-92. Progress Energy has indicated as much to FL DEP. In a 2009 BART permit, Progress Energy agreed to retire the Crystal River units by December 31, 2020, as long as the second unit of its proposed Levy County nuclear facility was operating by that time.[6] Just a few weeks ago, Progress submitted an updated BART implementation plan to FL DEP indicating that, whether or not the Levy County facility comes online, it would either install a

[5] Available at http://www.dep.state.fl.us/air/rules/regulatory/regional_haze_imp.htm.
[6] *See* Air Permit No. 0170004-017-AC (Feb. 26, 2009) at 6, attached as Ex. 5.

scrubber (by 2018 or 5 years after Florida's haze SIP is approved), retire the units by December 31, 2020, or limit operations to keep the plant's operations below BART limits.[7] Because BART determinations will be approved within the next year, it is not at all clear how Progress expects to run its plants until 2020. Retirement within the next few years is the more likely option.

iv. Scrubber Costs

We have calculated the approximate cost of installing and running scrubbers (at 90% efficiency, a level which would likely be required, at a minimum, to meet the requirements of all three relevant rules) at Crystal River Units 1 and 2, based upon the EPA's Integrated Planning Model and a scrubber-focused appendix developed by Sargent & Lundy.[8] This model predicts that the capital costs for fitting these units with scrubbers as $486 million. The result (including operational costs) would be a $36.6/MWh spike in incremental costs. Progress Energy would no doubt seek to pass these costs on to rate-payers if it opted to continue to run the plant, rather than to retire it. These expenditures are extraordinarily high simply in order to extend the lives of these decades-old, expensive, coal-fired power plants.

B. Other Environmental Liabilities

Scrubber costs are not the only liabilities Crystal River faces. There are also pending rules requiring upgrades to coal plant cooling water systems, *see* 76 Fed. Reg. 22,174 (Apr. 20, 2011), better handling and disposal practices for coal combustion waste, *see* 75 Fed. Reg. 35,128 (June 21, 2010), and new treatment systems for liquid effluent discharges,[9] all of which are likely to be finalized in the next two years. EPA is also updating the NAAQS for particulate matter and for ozone. Moreover, EPA has recently proposed carbon controls for new electricity generating units. *See* 77 Fed. Reg. 22,39 (Apr. 13, 2012). Once finalized, these rules will obligate EPA to extend carbon controls to existing facilities, including Crystal River. *See* 42 U.S.C. § 7411(d). The cumulative impact of these liabilities on Progress Energy will be large and are likely to lend further weight to retirement decisions.

C. Likely Retirements

The cumulative compliance costs from all the rules which apply to Progress Energy's Crystal River units are substantial. Upon reviewing them, and considering the wide availability of more inexpensive power sources, Progress is highly likely to follow industry trends towards coal retirement.

Coal use is falling quickly, in response both to the cost of pollution controls and to national economic trends, including the growth of inexpensive wind power and the boom in shale gas production. As EPA has recently documented, "all indications suggest that very few new coal-

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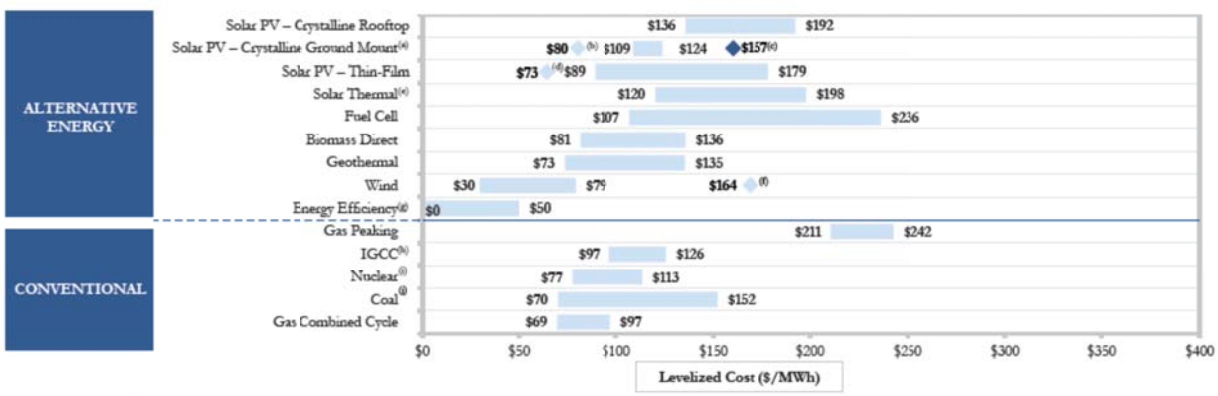
[7] *See* Ex. 2, *supra*.
[8] All modeling parameters can be found at http://www.epa.gov/airmarkt/progsregs/epa-ipm/BaseCasev410.html.
[9] *See* EPA's plans for this rule at http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm

fired power plants will be constructed in the foreseeable future." 77 Fed. Reg. at 22,413, and the Energy Information Administration (EIA) is documenting increasing retirements of existing plants. In particular, the EIA's Annual Energy Outlook for 2012 forecasts no new unplanned coal capacity through 2020. RIA at 5-5. EIA's most recent Electric Power Monthly report confirms that this trend continues. Thus far this year, *none* of the 5,627 MW of new units to come online are coal-fired; instead, new capacity additions are largely in renewable power or natural gas. EIA, *Electric Power Monthly June 2012* at Table ES3.[10] Conversely, retirements to date have been predominantly coal-fired units. *See id.* at Table ES4. Utilities across the country have announced thousands of megawatts worth of coal retirements over the last few years.[11]

Industry-wide levelized cost figures compiled by independent analysts demonstrate why these retirements are occurring. The most recent (2011) edition of Lazard's Levelized Cost of Energy Analysis,[12] a widely-used reference, shows that energy efficiency, wind, and natural gas combined cycle levelized costs are already below those of coal, as the figure below demonstrates.



Under these circumstances, prudent operators are increasingly deciding not to impose additional costs on their ratepayers by running coal-fired units with costly new pollution technology. Instead, they are opting to retire older units and pursue cleaner, cheaper, energy options. Progress Energy could, and should, decide to follow the same course.

D. Recommended Commission Action

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[10] Available at: http://205.254.135.7/electricity/monthly/pdf/epm.pdf.

[11] *See, e.g.*, Progress Energy Press Release, "Progress Energy Carolinas to retire coal power plant ahead of schedule" (Apr. 1, 2011) (recording the retirement of four North Carolina coal plants), available at https://www.progress-energy.com/company/media-room/news-archive/press-release.page?title=Progress+Energy+Carolinas+to+retire+coal+power+plant+ahead+of+schedule&pubdate=04-01-2011; FirstEnergy Press Release, "FirstEnergy, Citing Impact of Environmental Regulations, Will Retire Six Coal-Fired Power Plants" (Jan. 29, 2012) (announcing the retirement of six coal plants in Ohio), available at https://www.firstenergycorp.com/content/fecorp/newsroom/news_releases/firstenergy_citingimpactofenvironmentalregulationswillretiresixc.html; Environment News Service, "Dominion Virginia to Replace Coal Plants with Gas, Nuclear" (Sept. 7, 2011) (documenting retirement of two Virginia coal plants), available at http://www.ens-newswire.com/ens/sep2011/2011-09-07-091.html.

[12] Attached as Ex. 6.

Progress Energy has entirely failed to address these environmental compliance issues, and the impacts of retirements at Crystal River upon its system and upon ratepayers. The failure renders the draft plan "unsuitable" as a planning document. *See* F.S. §186.801. The Commission, "may suggest alternatives to the plan," *id.*, however, and may classify a plan as suitable upon the submission of "additional data," *see* F.A.C. § 25-22.071(5). We respectfully request that the PSC exercise its authority to ensure that Progress's plan provides adequate data to allow the PSC and the public to address these plant retirements.

Specifically, we submit that the Commission should seek the following information from Progress and require resubmission of a complete plan addressing these submissions:

1. The utility should provide an analysis of all environmental compliance obligations which it will experience at the Crystal River plant. For each requirement, the utility should cite the relevant rule, explain how it is likely to apply to the plant, the likely costs of compliance to the utility and to ratepayers, and the timeline on which compliance will be required. The utility should also document any steps it has taken to address these compliance obligations, and alternative steps it might take. For instance, if the utility anticipates that it will have to install a scrubber to comply with MATS, it should report to the Commission on scrubber installation and operation costs, whether it has contracted to purchase a scrubber and on what timeline, and what other options it has considered. *See* F.S. § 186.801 (requiring utilities to document "[p]ossible alternatives to the proposed plan").

2. The utility should provide a comparative analysis of compliance costs and the cost costs of replacing the plant's power through energy efficiency, demand response, power purchase agreements, new generation facilities, or other means. *See* F.S. §186.801 (requiring utilities to explain the impact of their plans on fuel diversity and on the need for electric power in their regions). In light of this analysis, the utility should indicate whether it intends to retire any facility, and on what timeline, and the relative costs of retirement versus those of other options. If retirement has not been selected but is being considered, the utility should indicate when the decision will be made.

3. For any facility where retirement is possible, the utility should discuss how it intends to address any reliability issues which may be caused by the retirement. The Commission should play an active role in this regard, as it must maintain reliability of the electric grid. *See* F.S. § 366.05(7)-(8) (authorizing the Commission to "require reports from all electric utilities to assure the development of adequate and reliable energy grids" and to order "installation and repair of necessary facilities" to address reliability issues"). The Commission has determined that "[r]eserve margins in Florida typically remain well above" relevant minimums through 2020, so system-wide resource adequacy problems are unlikely, but the Commission may still need to address localized reliability issues. If such problems appear to be present, the

Commission should work proactively and transparently with the Florida Reliability Coordinating Council to address them well in advance of any planned retirement.

We appreciate this careful consideration of Progress Energy's environmental compliance options, and any resulting plant retirements, and remind the Commission that such thorough analysis is required to ensure that the Ten-Year Plan complies with legal requirements. We request that the Commission share the results of its inquiry with us and with the public, and request formal notice of the Commission's next steps.

Please contact the undersigned with any concerns or questions.

Sincerely,

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Ceres

PRACTICING RISK-AWARE ELECTRICITY REGULATION:
What Every State Regulator Needs to Know

How State Regulatory Policies Can Recognize and Address the Risk in Electric Utility Resource Selection

A Ceres Report
April 2012

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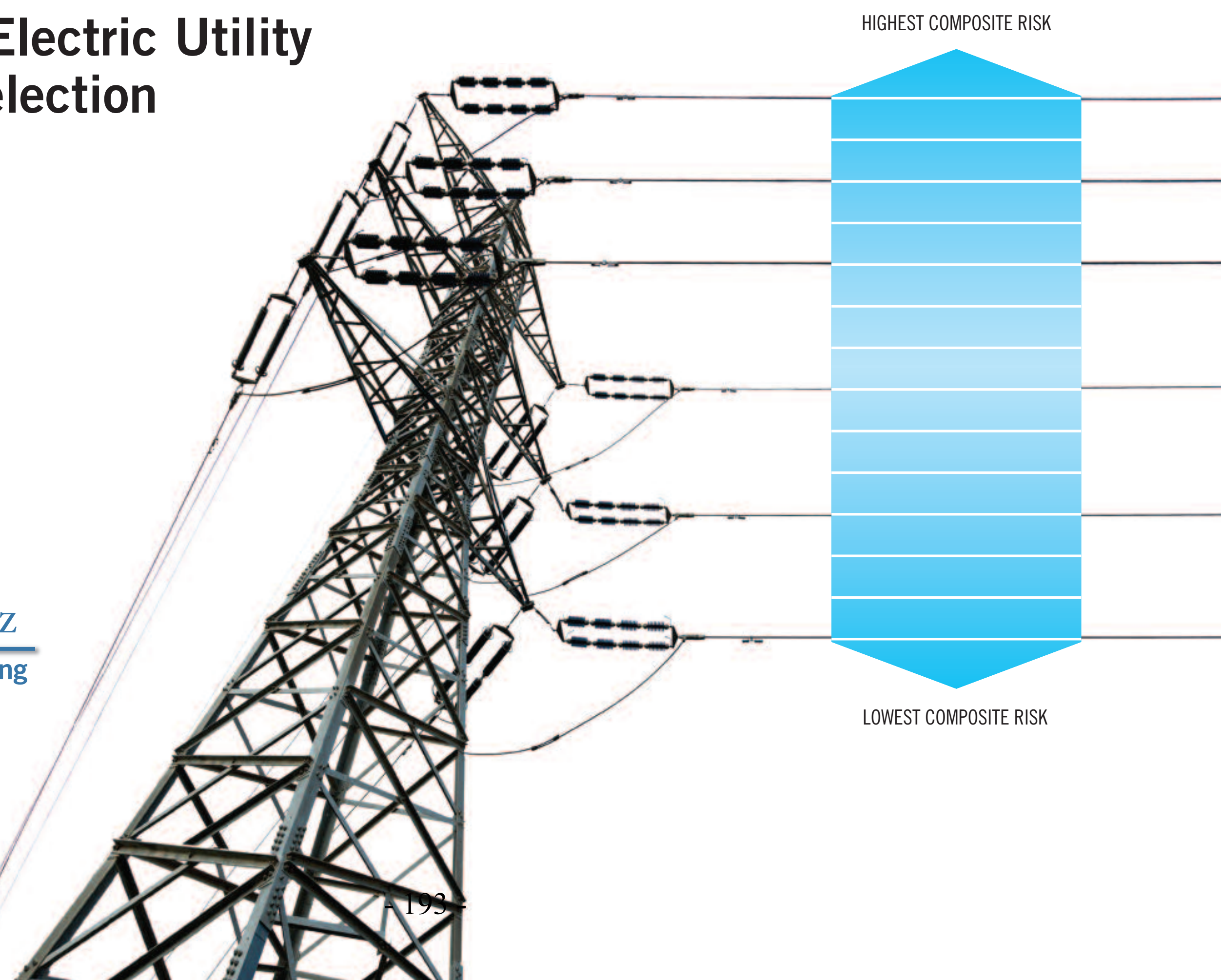

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Ceres is an advocate for sustainability leadership. It leads a national coalition of investors, environmental groups and other public interest organizations working with companies to address sustainability challenges. Ceres also directs the Investor Network on Climate Risk (INCR), a network of 100 institutional investors with collective assets totaling about $10 trillion.

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ABOUT THIS REPORT

AUDIENCE

This report is primarily addressed to **state regulatory utility commissioners**, who will preside over some of the most important investments in the history of the U.S. electric power sector during perhaps its most challenging and tumultuous period. This report seeks to provide regulators with a thorough discussion of risk, and to suggest an approach—“risk-aware regulation”—whereby regulators can explicitly and proactively seek to identify, understand and minimize the risks associated with electric utility resource investment. It is hoped that this approach will result in the efficient deployment of capital, the continued financial health of utilities, and the confidence and satisfaction of the customers on whose behalf utilities invest.

Additionally, this report seeks to present a unique discussion of risk and a perspective on appropriate regulatory approaches for addressing it that will interest numerous **secondary audiences**, including **utility managements, financial analysts, investors, electricity consumers, advocates, state legislatures and energy offices, and other stakeholders** with a particular interest in ensuring that electric system resource investments—which could soon reach unprecedented levels—are made thoughtfully, transparently and in full consideration of all associated risks.

SCOPE

While we believe that the approach described herein is applicable to a broad range of decisions facing state regulators, the report focuses primarily on resource investment decisions by investor-owned electric utilities (IOUs), which constitute roughly 70 percent of the U.S. electric power industry. The findings and recommendations may be of particular interest to regulators in states facing substantial coal generating capacity retirements and evaluating a spectrum of resource investment options.

AUTHORS

Ron Binz, the lead author of this report, is a 30-year veteran of utility and energy policy and principal with Public Policy Consulting. Most recently, he served for four years as the Chairman of the Colorado Public Utilities Commission where he implemented the many policy changes championed by the Governor and the Legislature to bring forward Colorado’s “New Energy Economy.” He is the author of several reports and articles on renewable energy and climate policy has testified as an expert witness in fifteen states.

Richard Sedano is a principal with the Regulatory Assistance Project (RAP), a global, non-profit team of experts focused on the long-term economic and environmental sustainability of the power and natural gas sectors, providing technical and policy assistance to policymakers and regulators on a broad range of energy and environmental issues. RAP is widely viewed as a source of innovative and creative thinking that yields practical solutions. RAP members meet directly with government officials, regulators and their staffs; lead technical workshops and training sessions; conduct in-house research and produce a growing volume of publications designed to better align energy regulation with economic and environmental goals.

Denise Furey has over 25 years of experience with financial institutions, structuring and analyzing transactions for energy and utility companies. In 2011 she founded Regent Square Advisors, a consulting firm specializing in financial and regulatory concerns faced by the sector. She worked with Citigroup covering power and oil & gas companies, and worked with Fitch Rating, Enron Corporation and MBIA Insurance Corporation. Ms. Furey also served with the Securities and Exchange Commission participating in the regulation of investment companies.

Dan Mullen, Senior Manager for Ceres’ Electric Power Programs, works to identify and advance solutions that will transform the U.S. electric utility industry in line with the urgent goal of sustainably meeting society’s 21st century energy needs. In addition to developing Ceres’ intellectual capital and external partnerships, he has engaged with major U.S. electric utilities on issues related to climate change, clean energy and stakeholder engagement, with a particular focus on energy efficiency. A Stanford University graduate, Dan has also raised more than $5 million to support Ceres’ climate change initiatives and organizational development.

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FOREWORD

Today's electric industry faces a stunning investment cycle. Across the country, the infrastructure is aging, with very old parts of the power plant fleet and electric and gas delivery systems needing to be replaced. The regulatory environment is shifting dramatically as rules tighten on air pollution from fossil-burning power plants. Fossil fuel price outlooks have shifted. New options for energy efficiency, renewable energy, distributed generation, and smart grid and consumer technologies are pressing everyone to think differently about energy and the companies that provide it. Customers expect reliable electricity and count on good decisions of others to provide it.

The critical nature of this moment and the choices ahead are the subject of this report. It speaks to key decision-makers, such as: state regulators who have a critical role in determining utility capital investment decisions; utility executives managing their businesses in this era of uncertainty; investors who provide the key capital for utilities; and others involved in regulatory proceedings and with a stake in their outcomes.

The report lays out a suite of game-changing recommendations for handling the tremendous investment challenge facing the industry. As much as $100 billion will be invested each year for the next 20 years, roughly double recent levels. A large portion of those investments will be made by non-utility companies operating in competitive markets. But another large share will be made by utilities—with their (and their key investors') decisions being greatly affected by state regulatory policies and practices.

This is no time for backward-looking decision making. It is vital—for electricity consumers and utilities' own economic viability—that their investment decisions reflect the needs of tomorrow's cleaner and smarter 21st century infrastructure and avoid investing in yesterday's technologies. The authors provide useful advice to state regulators on how they can play a more proactive role in helping frame how electric utilities face these investment challenges.

A key report conclusion in this regard: sensible, safe investment strategies, based on the report's detailed cost and risk analysis of a wide range of generation resources, should include:

- Diversifying energy resource portfolios rather than "betting the farm" on a narrow set of options (e.g., fossil fuel generation technologies and nuclear);
- More emphasis on renewable energy resources such as onshore wind and distributed and utility-scale solar;
- More emphasis on energy efficiency, which the report shows is utilities' lowest-cost, lowest-risk resource.

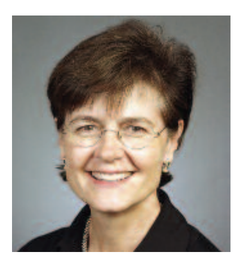
At its heart, this report is a call for "risk-aware regulation." With an estimated $2 trillion of utility capital investment in long-lived infrastructure on the line over the next 20 years, regulators must focus unprecedented attention to risk—not simply keeping costs down today, but minimizing overall costs over the long term, especially in the face of possible surprises. And utilities' use of robust planning tools needs to be sharpened to incorporate risk identification, analysis, and management.

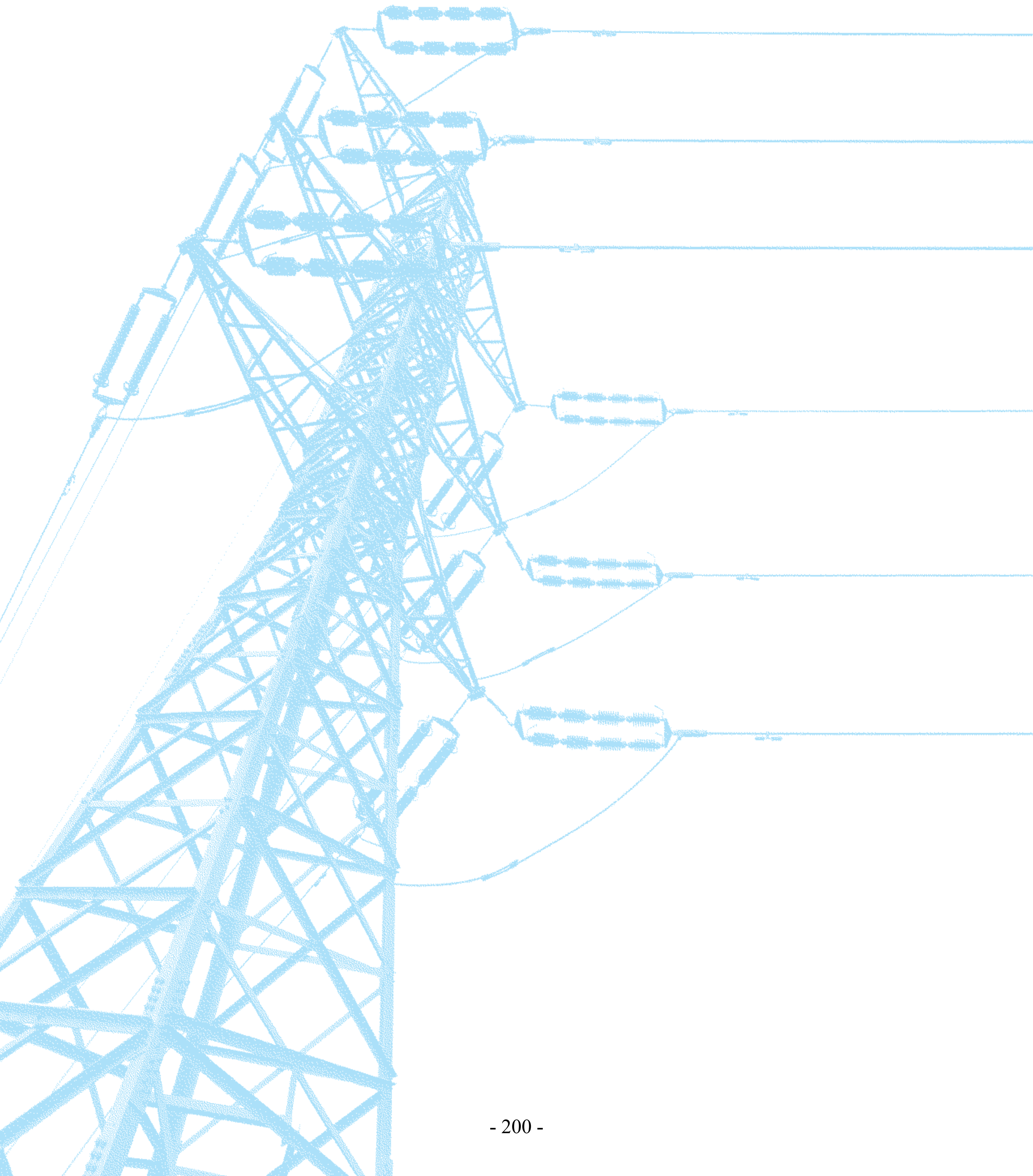
This report offers some good news amid pervasive uncertainty: the authors point out that planning the lowest-cost, lowest risk investment route aligns with a low-carbon future. From a risk management standpoint, diversifying utility portfolios today by expanding investment in clean energy and energy efficiency makes sense regardless of how and when carbon controls come into play. Placing too many bets on the conventional basket of generation technologies is the highest-risk route, in the authors' analysis.

We're in a new world now, with many opportunities as well as risks. More than ever, the true risks and costs of utility investments should be made explicit and carefully considered as decisions on multi-billion-dollar commitments are made.

As the industry evolves, so too must its regulatory frameworks. The authors point out why and offer guidance about how. This is news regulators and the industry can use.

Susan F. Tierney
Managing Principal
Analysis Group





EXECUTIVE SUMMARY

CONTEXT: INCREASING CAPITAL INVESTMENT BY U.S. ELECTRIC UTILITIES AMID HISTORIC UNCERTAINTY AND RISK

The U.S. electric utility industry, which has remained largely stable and predictable during its first century of existence, now faces tremendous challenges. Navigant Consulting recently observed that "the changes underway in the 21st century electric power sector create a level and complexity of risks that is perhaps unprecedented in the industry's history."[1] These challenges include:

- an aging generation fleet and distribution system, and a need to expand transmission;
- increasingly stringent environmental regulation limiting pollutants and greenhouse gases;[2]
- disruptive changes in the economics of coal and natural gas;
- rapidly evolving smart grid technologies enabling greater customer control and choice;
- increased policy maker emphasis on demand-side resources requiring new regulatory approaches and utility business models;
- competition from growth in distributed generation;
- slow demand growth due to protracted economic recovery and high unemployment;
- substantially weakened industry financial metrics and credit ratings, with over three-quarters of companies in the sector rated three notches or less above "junk bond" status.[3]

Many of these same factors are driving historic levels of utility investment. It is estimated that the U.S. electricity industry could invest as much as $100 billion each year for 20 years[4]—roughly twice recent investment levels. This level of investment will double the net invested capital in the U.S. electricity system by 2030. Moreover, these infrastructure investments are long lived: generation, transmission and distribution assets can have expected useful lives of 30 or 40 years or longer. This means that many of these assets will likely still be operating in 2050, when electric power producers may be required to reduce greenhouse gas emissions by 80 percent or more to avoid potentially catastrophic impacts from climate change.

1 Forrest Small and Lisa Frantzis, *The 21st Century Electric Utility: Positioning for a Low-Carbon Future*, Navigant Consulting (Boston, MA: Ceres, 2010), 28, http://www.ceres.org/resources/reports/the-21st-century-electric-utility-positioning-for-a-low-carbon-future-1.

2 Estimates of U.S. coal-fired generating capacity that could be retired in the 2015-2020 timeframe as a result of forthcoming U.S. Environmental Protection Agency (EPA) air quality regulations range from 10 to 70 gigawatts, or between three and 22 percent of U.S. coal-fired generation capacity. Forthcoming EPA water quality regulations could require the installation of costly cooling towers on more than 400 power plants that provide more than a quarter of all U.S. electricity generation. See Susan Tierney, "Electric Reliability under New EPA Power Plant Regulations: A Field Guide," *World Resources Institute*, January 18, 2011, http://www.wri.org/stories/2011/01/electric-reliability-under-new-epa-power-plant-regulations-field-guide.

3 Companies in the sector include investor-owned utilities (IOUs), utility holding companies and non-regulated affiliates.

4 Marc Chupka et al., *Transforming America's Power Industry: The Investment Challenge 2010-2030*, The Brattle Group (Washington DC: The Edison Foundation, 2008), vi, http://www.brattle.com/_documents/UploadLibrary/Upload725.pdf. Brattle's investment estimates apply to the entire U.S. electric utility industry, including IOUs, electric cooperatives and government-owned utilities. From 2000-05, overall annual capital expenditures by U.S. IOUs averaged roughly $48 billion; from 2006-10 that number climbed to $74 billion; see Edison Electric Institute, *2010 Financial Review: Annual Report of the U.S. Shareholder-Owned Electric Utility Industry* (Washington DC: Edison Electric Institute, 2011), 18, http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/finreview/Documents/FR2010_FullReport_web.pdf.

Greatly increased utility investment combined with minimal, zero or even declining electricity demand growth means that retail electricity prices for consumers will rise sharply, claiming a greater share of household disposable income and likely leading to ratepayer resistance.[5] Because the U.S. economy was built on relatively cheap electricity—the only thing many U.S. consumers and businesses have ever known—credit rating agencies are concerned about what this dynamic could mean for utilities in the long term. Rating analysts also point out that the overall credit profile for investor-owned utilities (IOUs) could decline even further since utilities' operating cash flows won't be sufficient to satisfy their ongoing investment needs.[6]

It falls to state electricity regulators to ensure that the large amount of capital invested by utilities over the next two decades is deployed wisely. Poor decisions could harm the U.S. economy and its global competitiveness; cost ratepayers, investors and taxpayers hundreds of billions of dollars; and have costly impacts on the environment and public health.

To navigate these difficult times, it is essential that regulators understand the risks involved in resource selection, correct for biases inherent in utility regulation, and keep in mind the long-term impact that their decisions will have on consumers and society. To do this, regulators must look outside the boundaries established by regulatory tradition.

CHALLENGES TO EFFECTIVE REGULATION

To be effective in the 21st century, regulators will need to be especially attentive to two areas: identifying and addressing risk; and overcoming regulatory biases.

Risk arises when there is potential harm from an adverse event that can occur with some degree of probability. Put another way, risk is "the expected value of a potential loss." *Higher risk* for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Risks for electric system resources have both time-related and cost-related aspects. *Cost risks* reflect the possibility that an investment will not cost what one expects, or that cost recovery for the investment will differ from expectations. *Time risks* reflect the possibility that circumstances will change over the life of the investment and materially affect both the cost of the investment and the degree to which it benefits consumers. **Figure ES-1** summarizes the many varieties of risk for utility resource investment.

Risk is the expected value of a potential loss. Higher risk for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Figure ES-1

VARIETIES OF RISK FOR UTILITY RESOURCE INVESTMENT

Cost-related	*Time-related*
Construction costs higher than anticipated	Construction delays occur
Availability and cost of capital underestimated	Competitive pressures; market changes
Operation costs higher than anticipated	Environmental rules change
Fuel costs exceed original estimates, or alternative fuel costs drop	Load grows less than expected; excess capacity
Investment so large that it threatens a firm	Better supply options materialize
Imprudent management practices occur	Catastrophic loss of plant occurs
Resource constraints (e.g., water)	Auxiliary resources (e.g., transmission) delayed
Rate shock: regulators won't put costs into rates	Other government policy and fiscal changes

5 Moody's Investors Service, *Special Comment: The 21st Century Electric Utility* (New York: Moody's Investors Service, 2010). Importantly, customers who currently enjoy the lowest electricity rates can expect the largest rate increases, in relative terms, as providers of cheap, coal-generated electricity install costly pollution controls or replace old coal-fired units with more expensive new resources. This dynamic could prove especially challenging for regulators, utilities and consumers in the heavily coal-dependent Midwest.

6 Richard Cortright, "Testimony before the Pennsylvania Public Utility Commission," Harrisburg, Pennsylvania, November 19, 2009, http://www.puc.state.pa.us/general/RegulatoryInfo/pdf/ARRA_Testimony-SPRS.pdf.

RISK

Three observations about risk should be stressed:

1. **Risk cannot be eliminated, but it can be managed and minimized.** Since risks are defined as probabilities, it is by definition probable that some risks will be realized—that, sooner or later, risk will translate into dollars for consumers, investors or both. This report concludes with recommendations for how regulators can minimize risk by practicing "risk-aware regulation."
2. **It is unlikely that consumers will bear the full cost of poor utility resource investment decisions.** The very large amount of capital investment that's being contemplated and the resulting upward pressure on electricity rates will make it very unappealing (or simply untenable) for regulators to burden ratepayers with the full cost of utility mistakes. As a result, it is likely that utility investors (specifically shareholders) will be more exposed to losses resulting from poor utility investment decisions than in years past.
3. **Ignoring risk is not a viable strategy.** Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate. Following a practice just because "it's always been done that way," instead of making a fresh assessment of risk and attempting to limit that risk, is asking for trouble.

Traditional utility regulation also contains several built-in biases that effective regulators must overcome.[7] These biases, which result in part from the incentives that traditional regulation provides to utilities, encourage utilities to invest more than is optimal for their customers—which is to say, more than is optimal for the provision of safe, reliable, affordable and environmentally sustainable electricity—and discourage them from investing in the lowest-cost, lowest-risk resources (namely, demand-side resources such as energy efficiency) that provide substantial benefits to ratepayers and local economies. Bias can also lead utilities to seek to exploit regulatory and legislative processes as a means of increasing profits (rather than, for example, improving their own operational efficiencies). Finally, regulators face an inherent information deficit when dealing with utility managements. This can hamper effective collaboration around utility planning, which is arguably the most important function of electricity regulation today.

COSTS AND RISKS OF NEW GENERATION RESOURCES

We closely examine costs and risks of new generation resources for several reasons. First, as the largest share of utility spending in the current build cycle, generation investment is where the largest amount of consumer and investor dollars is at risk. Also, today's decisions about generation investment can trigger substantial future investments in transmission and distribution infrastructure. Proposed power plants can be a lightning rod for controversy, heightening public scrutiny of regulatory and corporate decision-makers. Finally, poor investment decisions about generation resources in IOUs' last major build cycle resulted in tens of billions of dollars of losses for consumers and shareholders.[8] For these and other reasons, it is especially important that regulators address, manage and minimize the risks associated with utility investments in new generation resources.[9]

Ignoring risk is not a viable strategy. Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate.

Acquiring new electric system resources involves dimensions of both cost and risk. Of these two dimensions, the tools for estimating the cost elements of new generation, while imperfect, are more fully developed than the risk-related tools. As a starting point for our examination of the relative cost and risk of new generation resources, we rank a wide range of supply-side resources and one demand-side resource (energy efficiency) according to their levelized cost of electricity, or "LCOE" **(Figure ES-2, p. 8)**.[10] This ranking is based on 2010 data and does not include recent cost increases for nuclear or cost decreases for solar PV and wind. Because carbon controls could add significant costs to certain technologies but the exact timing and extent of these costs is unknown, we include a moderate estimate for carbon cost for fossil-fueled resources. And because incentives such as tax credits and loan guarantees can significantly affect LCOE, we examine the LCOE range for each technology with and without incentives where applicable.

7 These biases, which are discussed further in the report, are *information asymmetry; the Averch-Johnson effect; the throughput incentive; "rent-seeking"*; and *the "bigger-is-better" bias.*

8 Frank Huntowski, Neil Fisher, and Aaron Patterson, *Embrace Electric Competition or It's Déjà Vu All Over Again* (Concord, MA: The NorthBridge Group, 2008), 18, http://www.nbgroup.com/publications/Embrace_Electric_Competition_Or_Its_Deja_Vu_All_Over_Again.pdf. The NorthBridge Group estimates that ratepayers, taxpayers and investors were saddled with $200 billion (in 2007 dollars) in "above-market" costs associated with the build cycle of the 1970s and 80s. Between 1981-91, shareholders lost roughly $19 billion as a result of regulatory disallowances of power plant investments by some regulated utilities; see Thomas P. Lyon and John W. Mayo, "Regulatory opportunism and investment behavior: evidence from the U.S. electric utility industry," *Rand Journal of Economics*, Vol. 36, No. 3 (Autumn 2005): 628–44, http://webuser.bus.umich.edu/tplyon/PDF/Published%20Papers/Lyon%20Mayo%20RAND%202005.pdf. The potential for negative consequences is probably higher today; since the 1980s, electric demand has grown significantly while the environmental risks associated with utility operations, the costs of developing new generation resources, and the pace of technology development have all increased substantially.

9 While our analysis of risks and costs of new generation resources may be of most interest to regulators in "vertically-integrated" states (where utilities own or control their own generation), it also has implications for regulators in restructured states. Regulators in all states can direct electric utilities to invest in cost-effective demand-side resources, which, as this report makes clear, are utilities' lowest-cost and lowest-risk resources.

10 LCOE indicates the cost per megawatt-hour for electricity over the life of the plant, encompassing all expected costs (e.g., capital, operations and maintenance, and fuel). We primarily reference LCOE data compiled by the Union of Concerned Scientists (UCS), which aggregates three common sources of largely consensus LCOE data: the U.S. Energy Information Administration (EIA), the California Energy Commission (CEC) and the investment firm Lazard; see Barbara Freese et al., *A Risky Proposition* (Cambridge, MA: Union of Concerned Scientists, 2011), http://www.ucsusa.org/assets/documents/clean_energy/a-risky-proposition_report.pdf. LCOE costs for technologies not included in UCS's analysis (viz., biomass co-firing, combined cycle natural gas generation with CCS, and distributed solar) were estimated by the authors based on comparable resources referenced by UCS.

Figure ES-2

RELATIVE COST RANKING OF NEW GENERATION RESOURCES

HIGHEST LEVELIZED COST OF ELECTRICITY (2010)

- Solar Thermal
- Solar—Distributed*
- Large Solar PV*
- Coal IGCC-CCS
- Solar Thermal w/ incentives
- Coal IGCC
- Nuclear*
- Coal IGCC-CCS w/ incentives
- Coal IGCC w/ incentives
- Large Solar PV w/ incentives*
- Pulverized Coal
- Nuclear w/ incentives*
- Biomass
- Geothermal
- Biomass w/ incentives
- Natural Gas CC-CCS
- Geothermal w/ incentives
- Onshore Wind*
- Natural Gas CC
- Onshore Wind w/ incentives*
- Biomass Co-firing
- Efficiency

LOWEST LEVELIZED COST OF ELECTRICITY (2010)

Figure ES-3

RELATIVE RISK RANKING OF NEW GENERATION RESOURCES

HIGHEST COMPOSITE RISK

- Nuclear
- Pulverized Coal
- Coal IGCC-CCS
- Nuclear w/ incentives
- Coal IGCC
- Coal IGCC-CCS w/ incentives
- Natural Gas CC-CCS
- Biomass
- Coal IGCC w/ incentives
- Natural Gas CC
- Biomass w/ incentives
- Geothermal
- Biomass Co-firing
- Geothermal w/ incentives
- Solar Thermal
- Solar Thermal w/ incentives
- Large Solar PV
- Large Solar PV w/ incentives
- Onshore Wind
- Solar—Distributed
- Onshore Wind w/ incentives
- Efficiency

LOWEST COMPOSITE RISK

** Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

But the LCOE ranking tells only part of the story. The *price* for any resource in this list does not take into account the relative *risk* of acquiring it. To establish relative risk of new generation resources, we return to the many risks identified in Figure ES-1 and compress those risks into seven main categories:

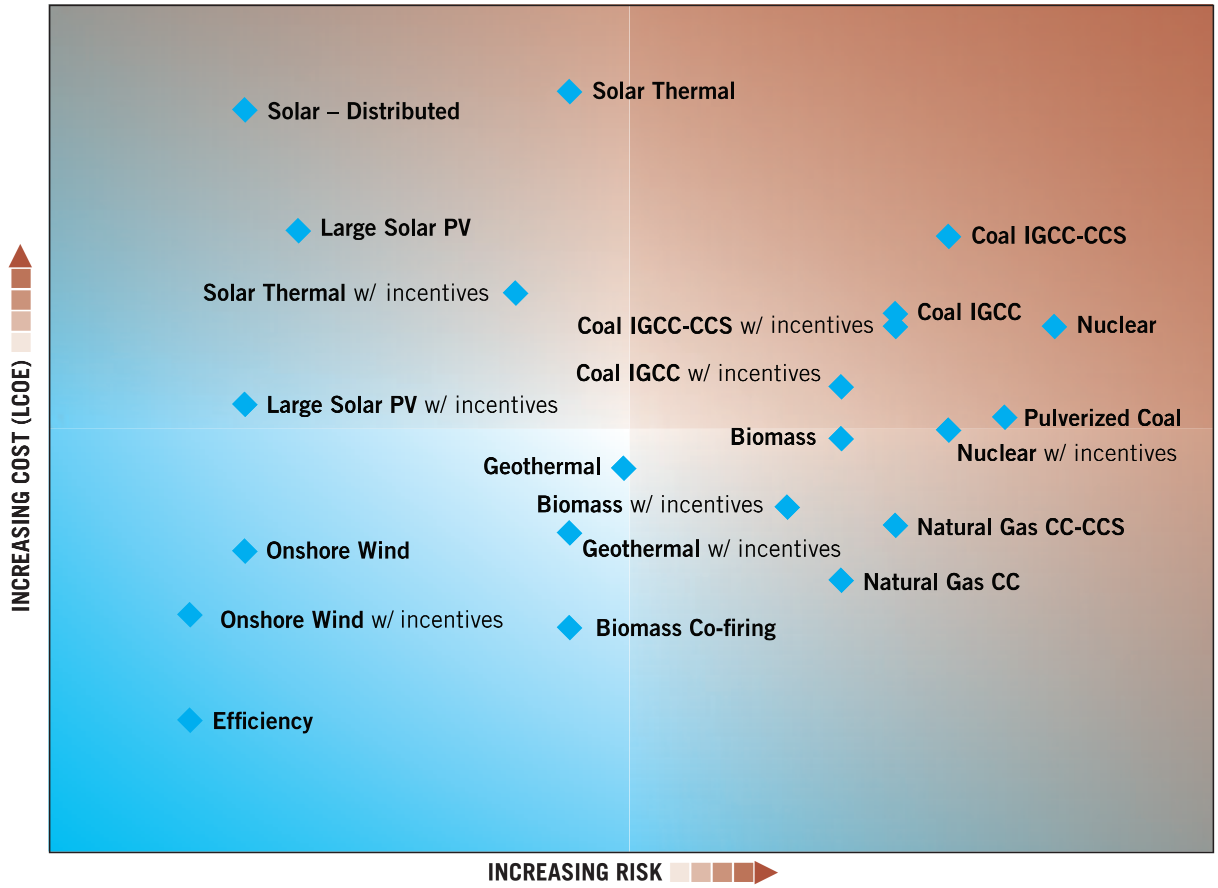
- **Construction Cost Risk:** includes unplanned cost increases, delays and imprudent utility actions
- **Fuel and Operating Cost Risk:** includes fuel cost and availability, as well as O&M cost risks
- **New Regulation Risk:** includes air and water quality rules, waste disposal, land use, and zoning
- **Carbon Price Risk:** includes state or federal limits on greenhouse gas emissions
- **Water Constraint Risk:** includes the availability and cost of cooling and process water
- **Capital Shock Risk:** includes availability and cost of capital, and risk to firm due to project size
- **Planning Risk:** includes risk of inaccurate load forecasts, competitive pressure

We then evaluate each resource profiled in the LCOE ranking and apply our informed judgment to quantify each resource's relative exposure to each type of risk.[11] This allows us to establish a composite risk score for each resource (with the highest score indicating the highest risk) and rank them according to their relative composite risk profile **(Figure ES-3)**.

11 Risk exposure in each risk category ranges from "None" to "Very High." We assigned scores (None = 0, Very High = 4) to each risk category for each resource and then summed them to establish an indicative quantitative ranking of composite risk. We also tested the robustness of the risk ranking by calculating two additional rankings of the risk scores: one that overweighted the cost-related risk categories and one that overweighted the environmental-related risk categories.

Figure ES-4

PROJECTED UTILITY GENERATION RESOURCES IN 2015
Relative Cost and Relative Risk



The risk ranking differs from the cost ranking in several important ways. First, the risk ranking shows a clear division between renewable resources and non-renewable resources. Second, nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

With largely consensus quantitative LCOE data, and having developed indicative composite risk scores for each resource, we can summarize relative risks and costs of utility generation resources in a single graph **(Figure ES-4)**.[12]

While this report focuses on new generation resources, the approach to "risk-aware regulation" described herein works equally well for the "retire or retrofit" decisions concerning existing coal plants facing regulators and utilities in many states.

While this report focuses on new generation resources, the approach to "risk-aware regulation" described herein works equally well for the "retire or retrofit" decisions concerning existing coal plants facing regulators and utilities in many states. The question for regulators is whether to approve coal plant closures in the face of new and future EPA regulations, or to approve utility investments in costly pollution controls to keep the plants running. Regulators should treat this much like an IRP proceeding: utilities should be required to present multiple scenarios differing in their disposition of the coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. In the end, regulators should enter a decision that addresses all of the relevant risks.

12 Resources are assumed to come online in 2015.

PRACTICING RISK-AWARE REGULATION: SEVEN ESSENTIAL STRATEGIES FOR STATE REGULATORS

MANAGING RISK INTELLIGENTLY IS ARGUABLY THE MAIN DUTY OF REGULATORS WHO OVERSEE UTILITY INVESTMENT. EFFECTIVELY MANAGING RISK IS NOT SIMPLY ACHIEVING THE LEAST COST *TODAY*, BUT RATHER IS PART OF A STRATEGY TO *MINIMIZE OVERALL COSTS OVER THE LONG TERM*. WE IDENTIFY SEVEN ESSENTIAL STRATEGIES THAT REGULATORS SHOULD EMPLOY TO MANAGE AND MINIMIZE RISK:

1. **DIVERSIFYING UTILITY SUPPLY PORTFOLIOS** with an emphasis on low-carbon resources and energy efficiency. Diversification—investing in different asset classes with different risk profiles—is what allows investors to reduce risk (or "volatility") in their investment portfolios. Similarly, diversifying a utility portfolio by including various supply and demand-side resources that behave independently from each other in different future scenarios reduces the portfolio's overall risk.

2. **UTILIZING ROBUST PLANNING PROCESSES** for all utility investment. In many vertically integrated markets and in some organized markets, regulators use "integrated resource planning" (IRP) to oversee utilities' capital investments. IRP is an important tool to ensure that the utilities, regulators and other stakeholders have a common understanding of a full spectrum of utility resource options; that the options are examined in a structured, disciplined way; that demand-side resources get equal consideration alongside supply-side resources; and that the final resource plan is understood by all.

3. **EMPLOYING TRANSPARENT RATEMAKING PRACTICES** that reveal risk. For example, allowing a current return on construction work in progress (CWIP) to enable utilities to finance large projects doesn't actually reduce risk but rather transfers it from the utility to consumers.[13] While analysts and some regulators favor this approach, its use can obscure a project's risk and create a "moral hazard" for utilities to undertake more risky investments. Utility investment in the lowest-cost and lowest-risk resource, energy efficiency, requires regulatory adjustments that may include decoupling utility revenues from sales and performance-based financial incentives.

4. **USING FINANCIAL AND PHYSICAL HEDGES**, including long-term contracts. These allow utilities to lock in a price (e.g., for fuel), thereby avoiding the risk of higher market prices later. But these options must be used carefully since using them can foreclose an opportunity to enjoy lower market prices.

5. **HOLDING UTILITIES ACCOUNTABLE** for their obligations and commitments. This helps to create a consistent, stable regulatory environment, which is highly valued in the marketplace and ensures that agreed-upon resource plans become reality.

6. **OPERATING IN ACTIVE, "LEGISLATIVE" MODE**, continually seeking out and addressing risk. In "judicial mode," a regulator takes in evidence in formal settings and resolves disputes; in contrast, a regulator operating in "legislative mode" proactively seeks to gather all relevant information and to find solutions to future challenges.

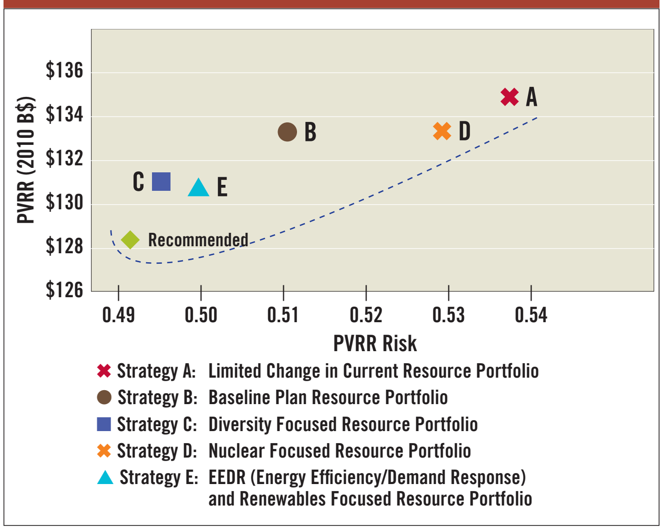
7. **REFORMING AND RE-INVENTING RATEMAKING POLICIES** as appropriate. Today's energy industry faces disruptions similar to those experienced by the telecommunications industry over the past two decades, which led regulators to modernize their tools and experiment with various types of incentive regulation. One area where electricity regulators might profitably question existing practices is rate design; existing pricing structures should be reviewed for the incentives they provide for customers and the outcomes they create for utilities.

13 For example, the use of CWIP financing in Florida could result in Progress Energy customers paying the utility more than $1 billion for a new nuclear plant (the Levy County Nuclear Power Plant) that may never be built. Florida state law prohibits ratepayers from recouping their investment in Levy or other CWIP-financed projects.

Careful planning is the regulator's primary risk management tool. A recently completed IRP by the Tennessee Valley Authority (TVA) illustrates how robust planning enables risk-aware resource choices and avoids higher-cost, higher-risk supply portfolios. TVA considered five resource strategies and subjected each to extensive scenario analysis. **Figure ES-5** shows how these strategies mapped out along an "efficient frontier" according to TVA's analysis of cost and risk.[14] The highest-cost, highest-risk strategies were those that maintained TVA's current resource portfolio[15] or emphasized new nuclear plant construction. The lowest-cost, lowest-risk strategies were the ones that diversified TVA's resource portfolio by increasing TVA's investment in energy efficiency and renewable energy. The TVA analysis is careful and deliberate; analyses by other utilities that reach significantly different thematic conclusions must be scrutinized carefully to examine whether the costs and risks of all resources have been properly evaluated.

Figure ES-5

TVA ANALYSIS OF RESOURCE PLAN COSTS & FINANCIAL RISK



Updating traditional practices will require effort and commitment from regulators and regulatory staff. Is it worth it? This report identifies numerous benefits from practicing "risk-aware regulation":

- **Consumer benefits** from improved regulatory decision-making and risk management, leading to greater utility investment in lower-cost, lower-risk resources;
- **Utility benefits** in the form of a more stable, predictable business environment that enhances long-term planning capabilities;
- **Investor benefits** resulting from lowered threats to utility cost recovery, which simultaneously preserves utility credit quality and capital markets access and keeps financing costs low, benefitting all stakeholders;
- **Systemic regulatory benefits** resulting from expanded transparency, inclusion and sophistication in the regulatory process, thereby strengthening stakeholder relationships, building trust and improving policy maker understanding of energy options—all of which enhances regulators' ability to do their jobs;
- **Broad societal benefits** flowing from a cleaner, smarter, more resilient electricity system.

With two trillion dollars on the line, both the stakes and the potential benefits are high. If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Practicing risk-aware regulation will enable them to avoid expensive mistakes and identify the most important utility investments for realizing the promise of an advanced 21st century electricity system.

Effectively managing risk is not simply achieving the least cost today, but rather is part of a strategy to minimize overall costs over the long term.

14 Tennessee Valley Authority (TVA), *TVA's Environmental and Energy Future* (Knoxville, TN: Tennessee Valley Authority, 2011), 161, http://www.tva.com/environment/reports/irp/pdf/Final_IRP_complete.pdf.

15 As of spring 2010, TVA's generation mix consisted mainly of coal (40 percent), natural gas (25 percent) and nuclear (18 percent) (TVA, 73).

CONCLUSIONS & RECOMMENDATIONS

- **The U.S. electric utility industry has entered what may be the most uncertain, complex and risky period in its history.** Several forces will conspire to make the next two decades especially challenging for electric utilities: large investment requirements, stricter environmental controls, decarbonization, changing energy economics, rapidly evolving technologies and reduced load growth. Succeeding with this investment challenge—building a smarter, cleaner, more resilient electric system for the 21st century at the lowest overall risk and cost—will require commitment, collaboration, shared understanding, transparency and accountability among regulators, policy makers, utilities and a wide range of stakeholders.

- **These challenges call for new utility business models and new regulatory paradigms.** Both regulators and utilities need to evolve beyond historical practice. Today's electricity industry presents challenges that traditional electricity regulation did not anticipate and cannot fully address. Similarly, the constraints and opportunities for electric utilities going forward are very different than they were a century ago, when the traditional (and still predominant) utility business model emerged.

  Regulators must recognize the incentives and biases that attend traditional regulation, and should review and reform their approaches to resource planning, ratemaking and utility cost recovery accordingly. Utilities must endorse regulatory efforts to minimize investment risks on behalf of consumers and utility shareholders. This means promoting an inclusive and transparent planning process, diversifying resource portfolios, supporting forward-looking regulatory policies, continually reevaluating their strategies and shaking off "we've always done it that way" thinking.

- **Avoiding expensive utility investment mistakes will require improved approaches to risk management in the regulatory process.** One of the most important duties of a 21st century electricity regulator is to understand, examine and manage the risk inherent in utility resource selection. Existing regulatory tools often lack the sophistication to do this effectively.

  Higher risk for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both. Our analysis across seven major risk categories reveals that, almost without exception, the riskiest resources—the ones that could cause the most financial harm—are large base load fossil and nuclear plants. It is therefore especially important that regulators and utilities explicitly address and manage risk when considering the development of these resources.

  Regulators practicing "risk-aware regulation" must exhaust lower-risk investment options like energy efficiency before allowing utilities to commit huge sums to higher-risk projects. Regulators should immediately notify regulated utilities of their intention to address risks more directly, and then begin explicitly to include risk assessment in all decisions about utility resource acquisition.

- **More than ever, ratepayer funding is a precious resource.** Large investment requirements coupled with flat or decreasing load growth will mean higher utility rates for consumers. Increased consumer and political resistance to rising electricity bills, and especially to paying for expensive mistakes, leaves much less room for error in resource investment decisions and could pose a threat to utility earnings.

- **Risk shifting is not risk minimization.** Some regulatory practices that are commonly perceived to reduce risk (e.g., construction work in progress financing, or "CWIP") merely transfer risk from the utility to consumers. This risk shifting can inhibit the deployment of attractive lower-cost, lower-risk resources. Regulatory practices that shift risk must be closely scrutinized to see if they actually increase risk—for consumers in the short term, and for utilities and shareholders in the longer term.
- **Investors are more vulnerable than in the past.** During the 1980s, power plant construction cost overruns and findings of utility mismanagement led regulators to disallow more than six percent of utilities' overall capital investment, costing shareholders roughly $19 billion. There will be even less tolerance for errors in the upcoming build cycle and more pressure on regulators to protect consumers. Investors should closely monitor utilities' large capex decisions and consider how the regulatory practice addresses the risk of these investments. Investors should also observe how the business models and resource portfolios of specific utilities are changing, and consider engaging with utility managements on their business strategies going forward.
- **Cost recovery mechanisms currently viewed positively by the investment community including the rating agencies could pose longer-term threats to utilities and investors.** Mechanisms like CWIP provide utilities with the assurance of cost recovery before the outlay is made. This could incentivize utilities to take on higher-risk projects, possibly threatening ultimate cost recovery and deteriorating the utility's regulatory and business environment in the long run.
- **Some successful strategies for managing risk are already evident.** Regulators and utilities should pursue diversification of utility portfolios, adding energy efficiency, demand response, and renewable energy resources to the portfolio mix. Including a mix of supply and demand-side resources, distributed and centralized resources, and fossil and non-fossil generation provides important risk management benefits to resource portfolios because each type of resource behaves independently from the others in different future scenarios. In the other direction, failing to diversify resources, "betting the farm" on a narrow set of large resources, and ignoring potentially disruptive future scenarios is asking for trouble.

Including a mix of supply and demand-side resources, distributed and centralized resources, and fossil and non-fossil generation provides important risk management benefits to resource portfolios because each type of resource behaves independently from the others in different future scenarios.

- **Regulators have important tools at their disposal.** Careful planning is the regulator's primary tool for risk mitigation. This is true for regulators in both vertically-integrated and restructured electricity markets. Effective resource planning considers a wide variety of resources, examines possible future scenarios and considers the risk of various portfolios. Regulators should employ transparent ratemaking practices that reveal and do not obscure the level of risk inherent in a resource choice; they should selectively apply financial and physical hedges, including long-term contracts. Importantly, they must hold utilities accountable for their obligations and commitments.

1. CONTEXT:

INCREASING CAPITAL INVESTMENT BY U.S. ELECTRIC UTILITIES AMID HISTORIC UNCERTAINTY & RISK

U.S. ELECTRIC UTILITIES ARE FACING A SET OF CHALLENGES UNPARALLELED IN THE INDUSTRY'S HISTORY, PROVIDING MANY REASONS TO CONCLUDE THAT THE TRADITIONAL PRACTICES OF UTILITIES AND THEIR REGULATORS MUST BE UPDATED TO ADD A SHARPER FOCUS ON RISK MANAGEMENT IN THE REGULATORY PROCESS.

Consider the forces acting on the electricity sector in 2012:

- an aging generation fleet;
- infrastructure upgrades to the distribution system;
- increasingly stringent environmental regulation limiting pollutants and greenhouse gases;[16]
- disruptive changes in the economics of coal and natural gas;
- new transmission investments;
- rapidly evolving smart grid technologies enabling greater customer control and choice;
- increased policy maker emphasis on demand-side resources requiring new regulatory approaches and utility business models;
- competition from growth in distributed generation;
- slow demand growth due to protracted economic recovery and high unemployment;
- tight credit in a difficult economy and substantially weakened industry financial metrics and credit ratings.

In a recent book, Peter Fox-Penner, principal and chairman emeritus of the Brattle Group, concluded that the sum of these forces is leading to a "second revolution" in the electric power industry.[17] Navigant Consulting has observed that "the changes underway in the 21st century electric power sector create a level and complexity of risks that is perhaps unprecedented in the industry's history."[18]

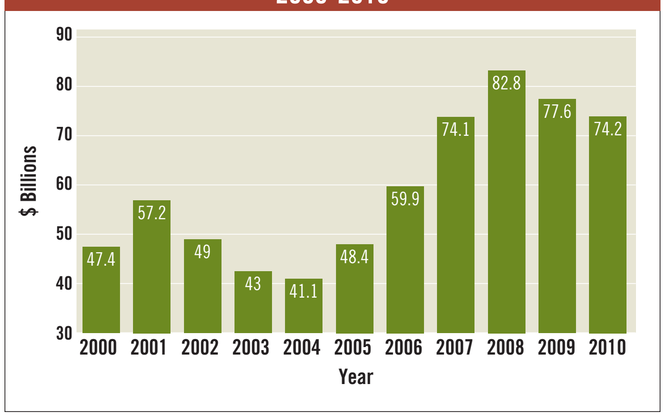
THE INVESTMENT CHALLENGE

The United States electric utility industry is a network of approximately 3,300 investor-owned utilities (IOUs), cooperative associations and government entities. In addition, about 1,100 independent power producers sell power to utilities, either under contract or through auction markets. The net asset value of the plant in service for all U.S. electric utilities in 2010 was about $1.1 trillion, broken down as $765 billion for IOUs, about $200 billion for municipal (publicly-owned) utilities (or "munis"), and $112 billion for rural electric cooperatives (or "co-ops").[19]

IOUs therefore constitute the largest segment of the U.S. electric power industry, serving roughly 70 percent of the U.S. population. **Figure 1** illustrates IOUs' capital expenditures from 2000-2010 and captures the start of the current "build cycle," beginning in 2006.[20] Between 2006 and 2010, capital spending by IOUs—for generation, transmission and distribution systems—was about 10 percent of the firms' net plant in service.

Figure 1

CAPITAL EXPENDITURES BY U.S. INVESTOR-OWNED UTILITIES, 2000-2010



16 See footnote 2.

17 Peter Fox-Penner, *Smart Power* (Washington DC: Island Press, 2010). The "first revolution" was triggered by George Westinghouse, Thomas Edison, Nicola Tesla, Samuel Insull and others more than a century ago.

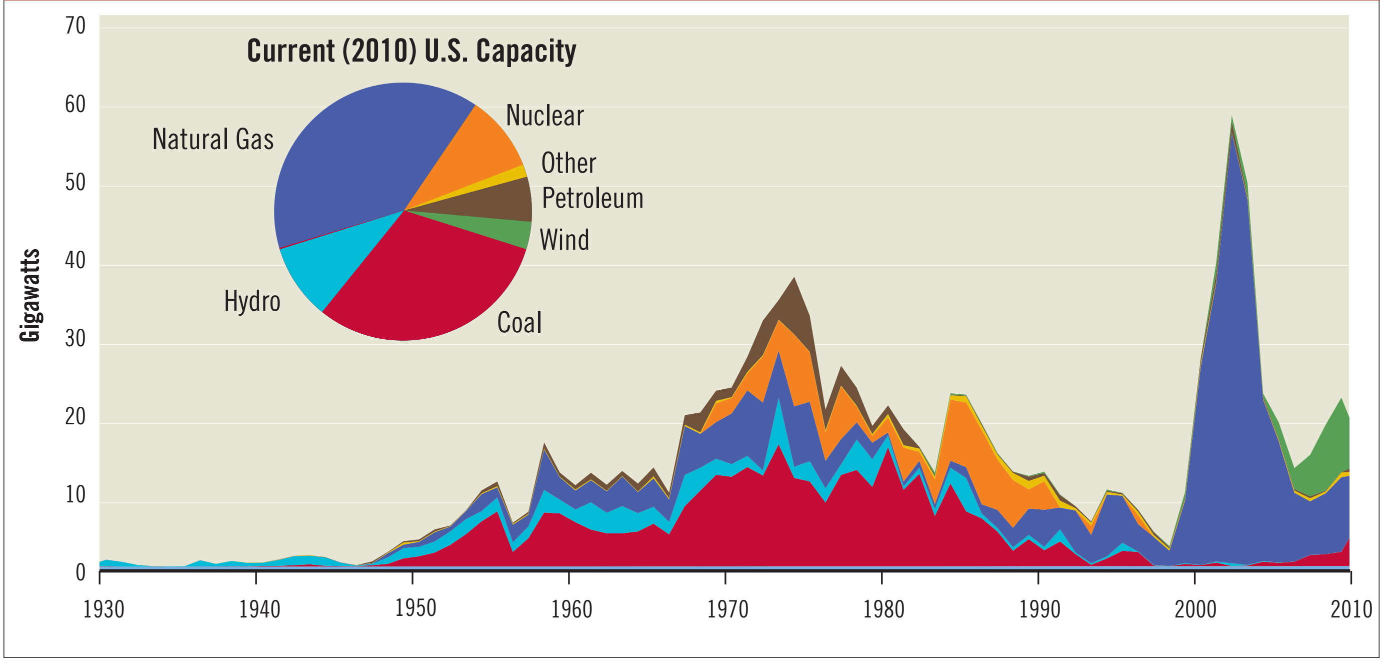
18 Small and Frantzis, *The 21st Century Electric Utility*, 28.

19 See U.S. Energy Information Administration, "Electric Power Industry Overview 2007," http://www.eia.gov/cneaf/electricity/page/prim2/toc2.html; National Rural Electric Cooperative Association, "Co-op Facts and Figures," http://www.nreca.coop/members/Co-opFacts/Pages/default.aspx; Edison Electric Institute, "Industry Data," http://www.eei.org/whatwedo/DataAnalysis/IndustryData/Pages/default.aspx. Note that these numbers do not include investment by non-utility generators.

20 Edison Electric Institute, *2010 Financial Review*, 18.

Figure 2

U.S. ELECTRIC GENERATING CAPACITY BY IN-SERVICE YEAR AND FUEL TYPE



In 2008, the Brattle Group projected that the collected U.S. electric utility industry—IOUs, munis, and co-ops—would need to invest capital at historic levels between 2010 and 2030 to replace aging infrastructure, deploy new technologies, and meet future consumer needs and government policy requirements. In all, Brattle predicted that total industry-wide capital expenditures from 2010 to 2030 would amount to between $1.5 trillion and $2.0 trillion.[21] Assuming that the U.S. implements a policy limiting greenhouse gas emissions, the collected utility industry may be expected to invest at roughly the same elevated annual rate as in the 2006-2010 period *each year for 20 years.*

If the U.S. utility industry adds $100 billion each year between 2010 and 2030, the net value of utility plant in service will grow from today's $1.1 trillion to more than $2.0 trillion—a doubling of net invested capital.

If the U.S. utility industry adds $100 billion each year between 2010 and 2030, the net value of utility plant in service will grow from today's $1.1 trillion to more than $2.0 trillion—a doubling of net invested capital. This growth is considerably faster than the country has seen in many decades.

To understand the seriousness of the investment challenge facing the industry, consider the age of the existing generation fleet. About 70 percent of U.S. electric generating capacity is at least 30 years old (**Figure 2**).[22] Much of this older capacity is coal-based generation subject to significant pressure from the Clean Air Act (CAA) because of its emissions of traditional pollutants such as nitrous oxides, sulfur dioxides, mercury and particulates. Moreover, following a landmark Supreme Court ruling, the U.S. Environmental Protection Agency (EPA) is beginning to regulate as pollutants carbon dioxide and other greenhouse gas emissions from power plants.[23] These regulations will put even more pressure on coal plants, which produce the most greenhouse gas emissions of any electric generating technology. The nuclear capacity of the U.S., approximately 100,000 megawatts, was built mainly in the 1970s and 80s, with original licenses of 40 years. While the lives of many nuclear plants are being extended with additional investment, some of these plants will face retirement within the next two decades.

21 Chupka et al., *Transforming America's Power Industry*, vi. Brattle's investment estimates apply to the entire U.S. electric utility industry, including IOUs, electric cooperatives and government-owned utilities. The range in Brattle's investment estimate is due to its varying assumptions about U.S. climate policy enactment.

22 U.S. Energy Information Administration, "Today in Energy: Age of electric power generators varies widely," June 16, 2011, http://www.eia.gov/todayinenergy/detail.cfm?id=1830.

23 U.S. Supreme Court, *Massachusetts v. Environmental Protection Agency,* 549 U.S. 497 (2007), http://www.supremecourt.gov/opinions/06pdf/05-1120.pdf.

Figure 3

PROJECTED GENERATION CAPEX BY REGION

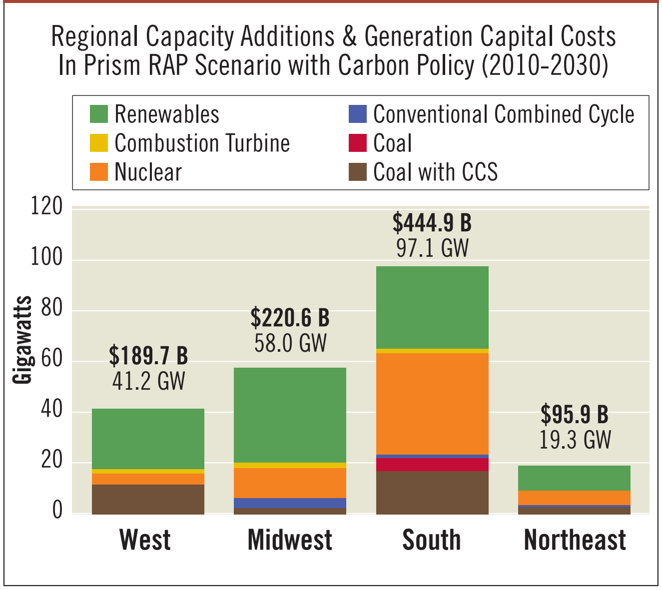


Figure 4

PROJECTED CAPACITY ADDITIONS BY STATE & AS A PERCENTAGE OF 2010 GENERATING CAPACITY

State	Predicted Capacity Additions (MW), 2010-2030[25]	Predicted Additions as a Percentage of 2010 Generating Capacity[26]
Texas	23,400	22%
Florida	12,200	21%
Illinois	11,000	25%
Ohio	8,500	26%
Pennsylvania	6,300	14%
New York	5,400	14%
Colorado	2,500	18%

Figure 3 shows the Brattle Group's investment projections for new generating capacity for different U.S. regions,[24] while **Figure 4** predicts capacity additions for selected U.S. states. Importantly, the Brattle Group noted that some of this investment in new power plants could be avoided if regulators and utilities pursued maximum levels of energy efficiency.

DRIVERS OF UTILITY INVESTMENT

Technological change, market pressures and policy imperatives are driving these historic levels of utility investment. As we will see, these same forces are interacting to create unprecedented uncertainty, risk and complexity for utilities and regulators.

Here are eight factors driving the large investment requirements:

1. **THE NEED TO REPLACE AGING GENERATING UNITS.** As mentioned earlier, the average U.S. generating plant is more than 30 years old. Many plants, including base load coal and nuclear plants, are reaching the end of their lives, necessitating either life-extending investments or replacement.

2. **ENVIRONMENTAL REQUIREMENTS.** Today's Clean Air Act (CAA) traces its lineage to a series of federal laws dating back to 1955. Until recent years, the CAA has enjoyed broad bipartisan support as it steadily tightened controls on emissions from U.S. electric power plants. These actions were taken to achieve science-based health improvements for people and the human habitat. While the current set of EPA rules enforcing the CAA has elicited political resistance, it is unlikely that the five-decade long movement in the United States to reduce acid rain, smog, ground ozone, particulates and mercury, among other toxic pollutants, will be derailed. Owners of many fossil-fueled plants will be forced to decide whether to make significant capital investments to clean up emissions and manage available water, or shutter the plants. Since the capacity is needed to serve consumers' demand for power (or "load"), these clean air and clean water policies will stimulate the need for new construction.

24 Chupka et al., *Transforming America's Power Industry*, x. Brattle's Prism RAP Scenario "assumes there is a new federal policy to constrain carbon emissions, and captures the cost of EPRI's [Electric Power Research Institute] Prism Analysis projections for generation investments (nuclear, advanced coal, renewables, etc.) that will reduce the growth in carbon emissions. This scenario further assumes the implementation of RAP [realistically achievable potential] EE/DR programs" (ibid., vi). Brattle used EPRI's original Prism analysis, published in September 2007; that document and subsequent updates are available online at http://my.epri.com/portal/server.pt?open=512&objID=216&&PageID=229721&mode=2.

25 State capacity addition predictions are based on Brattle's regional projections and assume that new capital expenditures will be made in proportion to existing investment levels.

26 State generating capacity data: U.S. Energy Information Administration, "State Electricity Profiles," January 30, 2012, http://www.eia.gov/electricity/state/. Percentage is rounded to the nearest whole number.

3 **NEW TRANSMISSION LINES AND UPGRADES.** Utility investment in transmission facilities slowed significantly from 1975 to 1998.[27] In recent years, especially after the creation of deregulated generation markets in about half of the U.S., it has become clear that the transmission deficit will have to be filled. Adding to the need for more transmission investment is the construction of wind, solar and geothermal generation resources, far from customers in areas with little or no existing generation or transmission. Regional transmission planning groups have formed across the country to coordinate the expected push for new transmission capacity.

4 **NETWORK MODERNIZATION/SMART GRID.** The internet is coming to the electric power industry. From synchrophasors on the transmission system (which enable system-wide data measurement in real time), to automated substations; from smart meters, smart appliances, to new customer web-based energy management, investments to "smarten" the grid are fundamentally changing the way electricity is delivered and used. While much of today's activity results from "push" by utilities and regulators, many observers think a "pull" will evolve as consumers engage more fully in managing their own energy use. Additionally, "hardening" the grid against disasters and to enhance national security will drive further investment in distribution infrastructure.

5 **HIGHER PRICES FOR CONSTRUCTION MATERIALS.** Concrete and steel are now priced in a world market. The demand from developing nations is pushing up the cost of materials needed to build power plants and transmission and distribution facilities.

6 **DEMAND GROWTH.** Overall U.S. demand for electric power has slowed with the recent economic recession and is projected to grow minimally in the intermediate term (though some areas, like the U.S. Southwest and Southeast, still project moderate growth). Further, the expected shift toward electric vehicles has the potential to reshape utility load curves, expanding the amount of energy needed in off-peak hours.

7 **DEPLOYING NEW TECHNOLOGIES AND SUPPORTING R&D.** To meet future environmental requirements, especially steep reductions of greenhouse gas emissions by 2050, utilities will need to develop and deploy new technologies at many points in the grid. Either directly or indirectly, utilities will be involved in funding for R&D on carbon capture and storage, new renewable and efficiency technologies, and electric storage.

8 **NATURAL GAS PRICE OUTLOOK.** Natural gas prices have fallen sharply as estimates of U.S. natural gas reserves jumped with the development of drilling technologies that can economically recover gas from shale formations. Longer-term price estimates have also dropped, inducing many utilities to consider replacing aging coal units with new gas-fired units. But in January 2012, the U.S. Energy Information Administration (EIA) sharply revised downward its estimates of U.S. shale gas reserves by more than 40 percent and its estimates of shale gas from the Marcellus region by two-thirds.[28] Reduced long-term supplies and a significant commitment to natural gas for new electric generation could obviously lead to upward pressure on natural gas prices.

FINANCIAL IMPLICATIONS

The credit quality and financial flexibility of U.S. investor-owned electric utilities has declined over the past 40 years, and especially over the last decade (**Figure 5, p. 18**).[29] The industry's financial position today is materially weaker than it was during the last major "build cycle" that was led by vertically-integrated utilities, in the 1970s and 80s. Then the vast majority of IOUs had credit ratings of "A" or higher; today the average credit rating has fallen to "BBB."

While it is rare for utilities to experience multiple notch downgrades in a short period of time, the heightened event risk inherent in the approaching sizable capital spending cycle could cause the rating agencies to pursue more aggressive rating actions.

This erosion of credit quality is mainly the result of intentional decisions by regulators and utility managements, who determined that maintaining an "A" or "AA" balance sheet wasn't worth the additional cost.[30] And while there isn't reason to believe that most utilities' capital markets access will become significantly constrained in the near future, the fact remains that more than a quarter of companies in the sector are now one notch above non-investment grade status (also called "Non-IG," "high yield" or "junk"), and nearly half of the companies in the sector are rated only two or three notches above this threshold.[31] While it is rare for utilities to experience multiple notch downgrades in a short period of time, the heightened event risk inherent in the approaching sizable capital spending cycle could cause the rating agencies to pursue more aggressive rating actions. Dropping below

27 Edison Electric Institute, *EEI Survey of Transmission Investment* (Washington DC: Edison Electric Institute, 2005), 3, http://www.eei.org/ourissues/ElectricityTransmission/Documents/Trans_Survey_Web.pdf.

28 U.S. Energy Information Administration, *AEO2012 Early Release Overview* (Washington DC: U.S. Energy Information Administration, 2012), 9, http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2012).pdf.

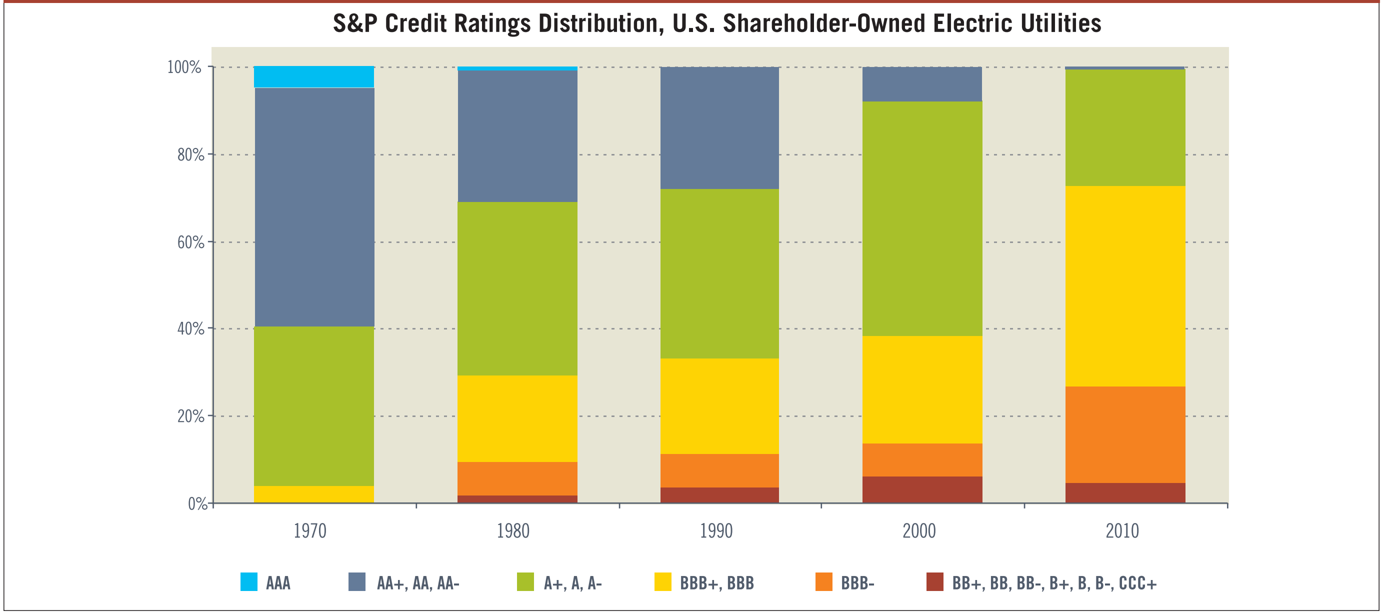
29 Source: Standard & Poor's Ratings Service.

30 The difference in the interest rate on an "A" rated utility and BBB is on average over time rarely more than 100 basis points. By contrast, equity financing typically costs a utility at least 200 basis points more than debt financing.

31 Companies in the sector include IOUs, utility holding companies and non-regulated affiliates.

Figure 5

U.S. ELECTRIC IOUs CREDIT RATINGS HISTORY, 1970 – 2010



investment grade (or "IG") triggers a marked rise in interest rates for debt issuers and a marked drop in demand from institutional investors, who are largely prohibited from investing in junk bonds under the investment criteria set by their boards.

According to a Standard & Poor's analyst, utilities' capital expenditure programs will invariably cause them to become increasingly cash flow negative, pressuring company balance sheets, financial metrics and credit ratings: "In other words, utilities will be entering the capital markets for substantial amounts of both debt and equity to support their infrastructure investments as operating cash flows will not come close to satisfying these infrastructure needs."[32] Specific utilities that S&P has identified as particularly challenged are companies—such as Ameren, Dominion, FirstEnergy, and PPL—that have both regulated and merchant generation businesses and must rely on market pricing to recover environmental capital expenditures for their merchant fleets.[33]

Appendix 1 of this report presents an overview of utility finance.

While the growth of rate base presents an earnings opportunity for regulated utilities and their investors, the corresponding increase in customer bills could greatly exacerbate the political and regulatory risks that threaten utilities' cost recovery.

CUSTOMER IMPACTS

The surge in IOU capital investment will translate directly into higher electric rates paid by consumers. Increased capital investment means higher annual depreciation expenses as firms seek to recover their investment. Greater levels of investment mean higher revenue requirements calculated to yield a return on the investment. And since electric sales may not grow much or at all during the coming two decades, it is likely that unit prices for electricity will rise sharply.

While the growth of rate base presents an earnings opportunity for regulated utilities and their investors, the corresponding increase in customer bills could greatly exacerbate the political and regulatory risks that threaten utilities' cost recovery. The rating agency Moody's Investors Service has noted that "consumer tolerance to rising rates is a primary concern"[34] and has identified political and regulatory risks as key longer-term challenges facing the sector.[35]

Further, Moody's anticipates an "inflection point" where consumers revolt as electricity bills consume a greater share of disposable income (**Figure 6, p. 19**),[36] pressuring legislators and regulators to withhold from utilities the recovery of even prudently incurred expenses.

32 Cortright, "Testimony."

33 Standard & Poor's, *The Top 10 Investor Questions for U.S. Regulated Electric Utilities in 2012* (New York: Standard & Poor's, 2012).

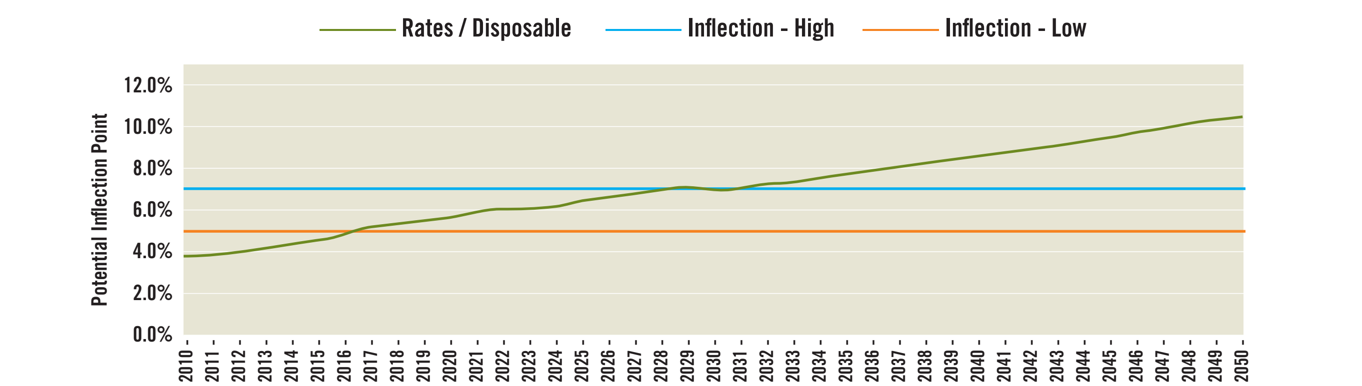
34 Moody's Investors Service, *Industry Outlook: Annual Outlook* (New York: Moody's Investors Service, 2011).

35 Moody's Investors Service, *Industry Outlook: Annual Outlook* (New York: Moody's Investors Service, 2010).

36 Moody's, *Special Comment: The 21st Century Electric Utility*, 12.

Figure 6

MOODY'S PROJECTED "INFLECTION POINT" OF CONSUMER INTOLERANCE FOR RISING ELECTRICITY BILLS



Source: Moody's

THE IMPORTANCE OF REGULATORS

With this background, the challenge becomes clear: how to ensure that the large level of capital invested by utilities over the next two decades is deployed wisely? How to give U.S. ratepayers, taxpayers and investors the assurance that $2 trillion will be spent in the best manner possible? There are two parts to the answer: *effective regulators* and the *right incentives for utilities*.

If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Each regulator will, on average, vote to approve more than $6.5 billion of utility capital investment during his or her term.[37] It is essential that regulators understand the risks involved in resource selection, correct for the biases facing utility regulation and keep in mind the impact their decisions will have on consumers and society.

Are U.S. regulatory institutions prepared? Consumers, lawmakers and the financial markets are counting on it. The authors are confident that well-informed, focused state regulators are up to the task. But energy regulation in the coming decades will be quite different from much of its history. The 21st century regulator must be willing to look outside the boundaries established by regulatory tradition. Effective regulators must be informed, active, consistent, curious and often courageous.

This report focuses on techniques to address the risk associated with utility resource selection. It provides regulators with some tools needed to understand, identify and minimize the risks inherent in the industry's investment challenge. In short, we hope to help regulators become more "risk-aware."

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37 In 2012, the median number of years served by a state regulator was 3.7 years; see Janice A. Beecher, Ph.D., *IPU Research Note: Commissioner Demographics 2012* (East Lansing, MI: Michigan State University, 2012), http://ipu.msu.edu/research/pdfs/IPU-Commissioner-Demographics-2012.pdf.

2. CHALLENGES

TO EFFECTIVE REGULATION

THE CHALLENGE FOR U.S. ELECTRIC UTILITIES IS TO RAISE, SPEND AND RECOVER A HISTORIC AMOUNT OF CAPITAL DURING A PERIOD OF UNPRECEDENTED UNCERTAINTY. THE CHALLENGE FOR STATE REGULATORS IS TO DO EVERYTHING POSSIBLE TO ENSURE THAT UTILITIES' INVESTMENTS ARE MADE WISELY. TO DO THIS EFFECTIVELY, REGULATORS WILL NEED TO BE ESPECIALLY ATTENTIVE TO TWO AREAS: IDENTIFYING AND ADDRESSING RISK, AND OVERCOMING REGULATORY BIASES. THIS SECTION DISCUSSES RISK AND BIAS IN MORE DETAIL.

RISK INHERENT IN UTILITY RESOURCE SELECTION

Risk arises when there is potential harm from an adverse event that can occur with some degree of probability. Risk accumulates from multiple sources. In mathematical terms:

Risk = $\sum_i \textit{Event}_i \times (\textit{Probability of Event}_i)$

for a situation in which a set of independent events will cause a loss with some probability. In English, this means that risk is the sum of each possible loss times the probability of that loss, assuming the events are independent of each other. If a financial instrument valued at $100 million would be worth $60 million in bankruptcy, and the probability of bankruptcy is 2 percent, then the bankruptcy risk associated with that instrument is said to be ($100 million - $60 million) x 2%, or $800,000. Thus, risk is the *expected value of a potential loss*. There is an obvious tie to insurance premiums; leaving aside transaction costs and the time value of money, an investor would be willing to pay up to $800,000 to insure against the potential bankruptcy loss just described.

Higher risk for a resource or portfolio means a larger expected value of a potential loss. In other words, higher risk means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Uncertainty is similar to risk in that it describes a situation where a deviation from the expected can occur, but it differs in two respects. First, the probability of the unexpected event cannot feasibly be determined with any precision. Consider the potential of much higher costs for natural gas used as a generation resource for an electric utility. Such an outcome is certainly possible (and perhaps even likely, given the potential for an increased rate of construction of new natural gas generation). But the likelihood and scope of such a change would be difficult to assess in terms of mathematical probabilities. Second, unlike risk, uncertainty can result in

The Historical Basis for Utility Regulation

Utilities aren't like other private sector businesses. Their services are essential in today's world, and society expects utilities to set up costly infrastructure networks supported by revenue from electric rates and to serve everyone without discrimination. Because of their special attributes, we say that investor-owned utilities are private companies that are "affected with the public interest." Indeed, this is often the statutory definition of utilities in state law.

Utility infrastructure networks include very long-lived assets. Power plants and transmission lines are designed to last decades; some U.S. transmission facilities are approaching 100 years old. The high cost of market entry makes competition impractical, uneconomic or impossible in many sectors of these markets. And because society requires universal service, it made economic sense to grant monopoly status to the owners of these essential facilities and then to regulate them.

State regulatory utility commissioners began administering a system of oversight for utilities at about the turn of the 20th century, filling a role that had previously been accorded to state legislatures. Regulatory commissions were tasked with creating a stable business environment for investment while assuring that customers would be treated "justly and reasonably" by monopoly utilities. Then as now, consumers wanted good utility services and didn't want to pay too much for them. Rules for accounting were supplemented by regulatory expectations, which were then followed by a body of precedents associated with cost recovery.

Because the sector's complexity and risks have evolved considerably since many regulatory precedents were established, today's regulators are well-advised to "think outside the box" and consider reforming past precedent where appropriate. The last section of this report, "Practicing Risk-Aware Regulation," contains specific ideas and recommendations in this regard.

Figure 7

VARIETIES OF RISK FOR UTILITY RESOURCE INVESTMENT	
Cost-related	*Time-related*
Construction costs higher than anticipated	Construction delays occur
Availability and cost of capital underestimated	Competitive pressures; market changes
Operation costs higher than anticipated	Environmental rules change
Fuel costs exceed original estimates, or alternative fuel costs drop	Load grows less than expected; excess capacity
Investment so large that it threatens a firm	Better supply options materialize
Imprudent management practices occur	Catastrophic loss of plant occurs
Resource constraints (e.g., water)	Auxiliary resources (e.g., transmission) delayed
Rate shock: regulators won't put costs into rates	Other government policy and fiscal changes

either upside or downside changes. As we will see later, uncertainty should be identified, modeled and treated much like risk when considering utility resource selection. In this report we will focus on risk and the negative aspect of uncertainty, and we will simplify by using the term "risk" to apply to both concepts.

The risks associated with utility resource selection are many and varied and arise from many possible events, as shown in **Figure 7**. There are several ways to classify these risks. One helpful distinction is made between cost-related risks and time-related risks.

Cost risks reflect the possibility that an investment will not cost what one expects, or that cost recovery for the investment will differ from expectations. Construction costs for a project can increase between regulatory approval and project completion. Transmission projects are notorious for this phenomenon due to unexpected obstacles in siting, or to unexpected changes in raw material costs.

Costs can change unexpectedly at any time. For example, a catastrophic equipment failure or the adoption of a new standard for pollution control could present unforeseen costs that a utility may not be willing to pay to keep an asset operating. Planned-for cost recovery can be disrupted by changes in costs for which regulators are unwilling to burden customers, or for other reasons. If an asset becomes obsolete, useless or uneconomic before the end of its predicted economic life, a regulator could find that it is no longer "used and useful" to consumers and remove it from the utility rate base. In these ways, decisions made by utilities and their regulators may turn out to be much more costly than initially expected. For this reason, it is especially important that regulators and utilities consider a full range of options and resources at the time a major investment decision is made.

Time risks reflect the possibility that circumstances will change over the life of the investment and materially affect both the cost of the investment and the degree to which it benefits consumers. Sometimes this risk can manifest itself even between the time a utility makes a decision and the time approval is sought. For example, anticipated load growth may not materialize, so that a planned generation resource is not needed, at least not now.

Time risks also reflect the fact that, for some investments, some essential condition may not occur on a schedule necessary for the investment to be approved and constructed. Consider the dilemma of the developer who wishes to build a low cost wind farm in an area with weak electric transmission. The wind project might require three to four years to build, but the transmission capacity needed to move the power to market may take five to seven years to build—*if* the development goes relatively smoothly. Investors may forego the wind farm due to uncertainty that the transmission will be built, while at the same time the transmission might not be built because, without the wind farm, it is simply too speculative.

Decisions made by utilities and their regulators may turn out to be much more costly than initially expected. For this reason, it is especially important that regulators and utilities consider a full range of options and resources at the time a major investment decision is made.

In the power sector, investments are so long-lived that time can be measured in generations. Generally speaking, regulators consider it most fair if the generation of consumers that uses an asset is the same one that pays for the asset. Burdening customers before or after an asset is useful is often seen as violating the "just and reasonable" standard. The challenge to the utility, therefore, is to fit cost recovery for an asset into the timeframe in which it is used. Otherwise, the utility may bear the risk that regulators or consumers push back on assuming responsibility for the cost.

Perspectives on Risk

Risk means different things to different stakeholders. For example:

- For **utility management**, risks are a threat to the company's financial health, its growth, even its existence; a threat to the firm's competitiveness, to the firm's image, and to its legacy.
- For **customers**, risk threatens household disposable income, the profitability of businesses, the quality of energy service, and even comfort and entertainment.
- **Investors** focus on the safety of the income, value of the investment (stock or bond holders), or performance of the contract (counterparties). In addition, investors value utility investments based on their expectations of performance.
- **Employees** are uniquely connected to the utility. Their employment, safety and welfare is directly related to their company's ability to succeed and to avoid financial catastrophes.
- **Society generally** has expectations for utilities ranging from providing reliable, universal service, to aiding in economic development, to achieving satisfactory environmental and safety performance. Risk threatens these goals.

ELECTRICITY MARKET STRUCTURE AND RISK

Much has changed since non-utility power producers led the most recent industry build cycle in the 1990s and early 2000s. To begin with, financial reforms from Sarbanes-Oxley legislation, other "Enron fixes," and now the Dodd-Frank Act have substantially changed some accounting and corporate disclosure rules. Investors now receive more detailed and transparent information about asset value (which is "marked to market") and possible risks in contracts with counter-parties.

These changes, which protect investors, may have the associated effect of discouraging investments if cumulative risks are judged to be outsized for the circumstances. This is especially relevant for markets served by the competitive generation system that now supplies power to about half of U.S. consumers. It is unclear whether independent generators have the tolerance to take on large, risky investments; experience indicates that there is a frontier beyond which these companies and their backers may not go.

This dynamic could raise important questions for regulators in restructured markets, who need to be aware of the degree to which investment options might be limited by these concerns. In vertically-integrated markets, regulators' concern should be not to expose utilities, customers and investors to undue risk by approving large projects that informed market players would not pursue in the absence of regulatory approval.

One potentially risky but necessary area of investment is in low carbon generation technologies. The U.S. power sector, which has embraced generation competition, is required to develop these technologies. Some promising technologies—including coal-fired generation with carbon capture and storage or sequestration (CCS), advanced nuclear power technologies and offshore wind—have not reached a commercial stage or become available at a commercial price.

Risks requiring special attention are those associated with investments that "bet the company" on their success. Gigawatt-sized investments in any generation technology may trigger this concern, as can a thousand-mile extra high voltage transmission line. Any investment measured in billions of dollars can be proportionately out of scale with what a utility can endure if things go awry. Regulators should avoid a situation where the only choices left are a utility bankruptcy or a waiving of regulatory principles on prudence and cost recovery in order to save the utility, placing a necessary but unreasonable cost burden on consumers.

REGULATORS, RATING AGENCIES AND RISK

Investor-owned utilities sometimes attempt to get out in front of the event risk inherent in large investment projects by seeking pre-approval or automatic rate increase mechanisms. As discussed later, these approaches don't actually reduce risk, but instead shift it to consumers. This may give companies and investors a false sense of security and induce them to take on excessive risk. In the long run this could prove problematic for investors; large projects can trigger correspondingly large rate increases years later, when regulators may not be as invested in the initial deal or as willing to burden consumers with the full rate increase.

Given the influence of regulators on the operations and finances of IOUs, ratings agencies and investors closely monitor the interactions between utility executives and regulators. Constructive relationships between management and regulators are viewed as credit positive; less-than-constructive relationships, which can result from regulators' concerns about the competence or integrity of utility management, are seen as a credit negative and harmful to a utility's business prospects.

Analysts define a constructive regulatory climate as one that is likely to produce stable, predictable regulatory outcomes over time. "Constructive," then, refers as much to the quality of regulatory decision-making as it does to the financial reward for the utility. Regulatory decisions that seem overly generous to utilities could raise red flags for analysts, since these decisions could draw fire and destabilize the regulatory climate. Analysts may also become concerned about the credit quality of a company if the state regulatory process appears to become unduly politicized.

While they intend only to observe and report, ratings agencies can exert a discipline on utility managements not unlike that imposed more formally by regulators. For example, ratings agencies can reveal to utility managements the range of factors they should consider when formulating an investment strategy, thereby influencing utility decision-making. Both regulators and ratings agencies set long-term standards and expectations that utilities are wise to mind; both can provide utilities with feedback that would discourage one investment strategy or another.

Since ratings reflect the issuer's perceived ability to repay investors over time, the ratings agencies look negatively on anything that increases event risk. The larger an undertaking (e.g., large conventional generation investments), the larger the fallout if an unforeseen event undermines the project. The pressure to maintain healthy financial metrics may, in practice, serve to limit utilities' capital expenditure programs and thus the size of rate increase requests to regulators.

TAKEAWAYS ABOUT RISK

Here are three observations about risk that should be stressed:

1. RISK CANNOT BE ELIMINATED—BUT IT CAN BE MANAGED AND MINIMIZED. Because risks are defined in terms of probabilities, it is (by definition) probable that some risk materializes. In utility resource selection, this means that risk will eventually find its way into costs and then into prices for electricity. Thus, taking on risk is inevitable, and risk will translate into consumer or investor costs—into dollars—sooner or later. Later in this report, we present recommendations to enable regulators to practice their trade in a "risk-aware" manner—incorporating the notion of risk into every decision.

2. IT IS UNLIKELY THAT CONSUMERS WILL BEAR THE FULL COST OF POOR UTILITY RESOURCE INVESTMENT DECISIONS. Put another way, it is likely that utility investors (specifically shareholders) will be more exposed to losses resulting from poor utility investments than in years past. In utility regulation, risk is shared between investors and customers in a complex manner. To begin, the existence of regulation and a group of customers who depend on utility service is what makes investors willing to lend utilities massive amounts of money (since most customers have few if any choices and must pay for utility service). But the actualization of a risk, a loss, may be apportioned by regulators to utility investors, utility consumers, or a combination of both. The very large amount of capital investment that's being contemplated and the resulting upward pressure on electricity rates will make it very unappealing (or simply untenable) for regulators to make ratepayers pay for the full cost of utility mistakes.

3. IGNORING RISK IS NOT A VIABLE STRATEGY. Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate. In utility regulation, perhaps more so than anywhere else, making no choice is itself making a choice. Following a practice just because "it's always been done that way," instead of making a fresh assessment of risk and attempting to limit that risk, is asking for trouble.

NATURAL BIASES AFFECTING UTILITY REGULATION

Notwithstanding economic theory, we must admit that utilities are not perfectly rational actors and that their regulation is not textbook-perfect, either. Utility regulation faces several built-in biases, which one can think of as headwinds against which regulation must sail. For example, under traditional cost-of-service regulation, a considerable portion of fixed costs (i.e., investment in rate base) is often recovered through variable charges to consumers. In this circumstance, one would expect utilities to have a bias toward promoting sales of the product once rates are established—even if increasing sales might result in increased financial, reliability, or environmental risks and mean the inefficient use of consumer dollars.

Here are five natural biases that effective utility regulation must acknowledge and correct for:

- **Information asymmetry.** Regulators are typically handicapped by not having the same information that is available to the regulated companies. This becomes especially significant for the utility planning process, where regulators need to know the full range of potential options for meeting electric demand in future periods. In the same vein, regulators do not normally have adequate information to assess market risks. These are the considerations of CFOs and boardrooms, and not routinely available to regulators. Finally, operating utilities often exist in a holding company with affiliated interests. The regulator does not have insight into the interplay of the parent and subsidiary company—the role played by the utility in the context of the holding company.
- **The Averch-Johnson effect.** A second bias is recognized in the economic literature as the tendency of utilities to over-invest in capital compared to labor. This effect is known by the name of the economists who first identified the bias: the Averch-Johnson effect (or simply the "A-J effect"). The short form of the A-J effect is that permitting

a rate of return on investment will have the predictable effect of encouraging more investment than is optimal. This can manifest itself in the "build versus buy" decisions of integrated utilities and is often cited as a reason utilities might "gold plate" their assets. This effect can also be observed in the "invest versus conserve" decisions that utilities face. Under traditional regulatory rules, most utilities do not naturally turn toward energy efficiency investment, even though such investments are usually least cost for customers.

- **The throughput incentive.** A third bias that can be observed with utilities is the bias for throughput—selling more electricity. This is undoubtedly grounded in the vision that most utilities have traditionally had for themselves: providers of electricity. Importantly, the regulatory apparatus in most states reinforces the motivation to sell more electricity: a utility's short-run profitability and its ability to cover fixed costs is directly related to the utility's level of sales. The price of the marginal unit of electricity often recovers more than marginal costs, so utilities make more if they sell more. Only in recent years has the concept of an energy services provider developed in which the utility provides or enables energy efficiency, in addition to providing energy.
- **Rent-seeking.** A fourth bias often cited in the literature is "rent seeking," where the regulated company attempts to use the regulatory or legislative processes as a means of increasing profitability (rather than improving its own operational efficiency or competitive position). This can occur when firms use law or regulation to protect markets that should be open to competition, or to impose costs on competitors.
- **"Bigger-is-better"** syndrome. Another bias, related to the Averch-Johnson effect, might be called the "bigger is better" syndrome. Utilities tend to be conservative organizations that rely on past strategies and practices. Making large investments in relatively few resources had been the rule through the 1980s and into the 1990s. Because of this history, utilities may not naturally support smaller scale resources, distributed resources or programmatic solutions to energy efficiency.[38]

Regulation can compensate for these biases by conducting clear-headed analysis, using processes that bring forth a maximum of relevant information and, very importantly, identifying the risk that these biases might introduce into utility resource acquisition. In the next section, we will take a close look at the many risks facing generation resource investments, which involve some of the most important and complex decisions that regulators and utilities make.

38 To be fair, smaller scale resources can add transaction and labor expenses for which the utility would not earn a return under traditional cost of service regulation, which helps to explain limited utility interest in these options.

3. COSTS AND RISKS

OF NEW GENERATION RESOURCES

THE CAPITAL INVESTED BY U.S. ELECTRIC UTILITIES TO BUILD A SMARTER, CLEANER, MORE RESILIENT ELECTRICITY SYSTEM OVER THE NEXT TWO DECADES WILL GO TOWARDS UTILITIES' GENERATION, TRANSMISSION AND DISTRIBUTION SYSTEMS.

In this section we'll take an in-depth look at costs and risks of new generation resources, for several reasons:

- Generation investment will be the largest share of utility spending in the current build cycle; this is where the largest amount of consumer and investor dollars will be at stake.
- Today's decisions about generation investment can shape tomorrow's decisions about transmission and distribution investment (by reducing or increasing the need for such investment).
- Technology breakthroughs—in energy storage, grid management, solar PV, and elsewhere—could radically transform our need for base load power within the useful lives of power plants being built today.
- Generation resources are among utilities' most visible and controversial investments and can be a lightning rod for protest and media attention, intensifying scrutiny on regulatory and corporate decision-makers.
- The industry's familiarity with traditional generating resources (e.g., large centralized fossil and nuclear plants) and relative lack of familiarity with newer alternatives (e.g., demand-side resources such as energy efficiency and demand response, or smaller, modular generating resources like combined heat and power) could lead regulators and utilities to underestimate risks associated with traditional resources and overestimate risks of newer resources.
- Finally, investment decisions about generation resources (especially nuclear power) during the last major build cycle that was led by vertically-integrated utilities, in the 1970s and 80s, destroyed tens of billions of dollars of consumer and shareholder wealth.

For these and other reasons, a comprehensive look at risks and costs of today's generation resources is in order.

While this discussion is most directly applicable to regulators (and other parties) in vertically-integrated states where electric utilities build and own generation, it also has implications for regulators (and other parties) in restructured states. For example, regulators in some restructured states (e.g., Massachusetts) are beginning to allow transmission and distribution (T&D) utilities to own generation again, specifically small-scale renewable generation to comprise a certain percentage of a larger renewable portfolio standard. Further, enhanced appreciation of the risks embedded in T&D utilities' supply portfolios could induce regulators to require utilities to employ best practices with regard to portfolio management, thereby reducing the risks and costs of providing electricity service.[39] Finally, regulators in all states can direct electric utilities to invest in cost-effective demand-side resources, which, as the following discussion makes clear, are utilities' lowest-cost and lowest-risk resources.

PAST AS PROLOGUE: FINANCIAL DISASTERS FROM THE 1980s

The last time regulated U.S. utilities played a central role in building significant new generating capacity additions as part of a major industry-wide build cycle was during the 1970s and 80s.[40] At the time the industry's overwhelming focus was on nuclear power, with the Nuclear Regulatory Commission (NRC) licensing construction of more than 200 nuclear power plants.

The difficulties the industry experienced were numerous and well-known: more than 100 nuclear plants abandoned in various stages of development;[41] cost overruns so high that the average plant cost three times initial estimates;[42] and total "above-market" costs to society—ratepayers, taxpayers and shareholders—estimated at more than $200 billion.[43]

39 For a discussion of energy portfolio management, see William Steinhurst et al., *Energy Portfolio Management: Tools & Resources for State Public Utility Commissions* (Cambridge, MA: Synapse Energy Economics, 2006), http://www.naruc.org/Grants/Documents/NARUC%20PM%20FULL%20DOC%20FINAL1.pdf.

40 The natural gas build-out of the 1990s and early 2000s was led by independent power producers, not regulated utilities.

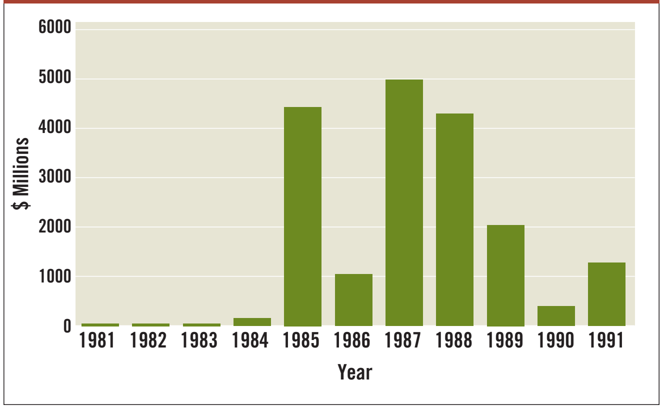
41 Peter Bradford, *Subsidy Without Borders: The Case of Nuclear Power* (Cambridge, MA: Harvard Electricity Policy Group, 2008).

42 U.S. Energy Information Administration, *An Analysis of Nuclear Power Plant Construction Costs* (Washington, DC: U.S. Energy Information Administration, 1986).

43 Huntowski, Fisher and Patterson, *Embrace Electric Competition*, 18. Estimate is expressed in 2007 dollars.

Figure 8

U.S. UTILITY GENERATION INVESTMENT DISALLOWED BY REGULATORS, 1981-1991



While the vast majority of these losses were borne by ratepayers and taxpayers, utility shareholders were not immune. Between 1981 and 1991, U.S. regulators disallowed about $19 billion of investment in power plants by regulated utilities (**Figure 8**).[44] During this time, the industry invested approximately $288 billion, so that the disallowances equated to about 6.6 percent of total investment. The majority of the disallowances were related to nuclear plant construction, and most could be traced to a finding by regulators that utility management was to blame.

To put this in perspective for the current build cycle, consider **Figure 9**. For illustrative purposes, it shows what disallowances of 6.6 percent of IOU investment would look like for shareholders in the current build cycle, using Brattle's investment projections for the 2010-2030 timeframe referenced earlier. The table also shows what shareholder losses would be if regulators were to disallow investment a) at half the rate of disallowances of the 1981-91 period; and b) at twice the rate of that period.[45]

Figure 9

ILLUSTRATIVE PROSPECTIVE SHAREHOLDER LOSSES DUE TO REGULATORY DISALLOWANCES, 2010-2030

Disallowance Ratio	Investment	
	$1.5 T	$2.0 T
3.3%	$34.6 B	$46.2 B
6.6%	$69.3 B	$92.4 B
13.2%	$138.6 B	$184.8 B

Obviously, the *average* disallowance ratio from the 1980s doesn't tell the full story. A few companies bore the brunt of the regulatory action. One of the largest disallowances was for New York's Nine Mile Point 2 nuclear plant, where the $2 billion-plus disallowance was estimated to be 34 percent of the project's original capital cost.[46] When Niagara Mohawk, the lead utility partner in the project, wrote down its investment in the project by $890 million, Standard & Poor's lowered the company's credit rating by two notches, from A- to BBB. Thus the risk inherent in building the Nine Mile Point 2 plant was visited on investors, who experienced a loss of value of at least $890 million, and consumers, who faced potentially higher interest rates going forward. A major theme of this paper is how consumer and investor interests are intertwined, and how both are served by strategies that limit risk.

Another large disallowance was levied on Pacific Gas and Electric for the Diablo Canyon nuclear station in California. The disallowance took the form of a "performance plan" that set consumers' price for power at a level that was independent of the plant's actual cost. In its 1988 decision, the California Public Utilities Commission approved a settlement whereby PG&E would collect $2 billion less, calculated on a net present value basis, than it had spent to build the plant. The CPUC's decision to approve the disallowance was controversial, and some felt it didn't go far enough. The California Division of Ratepayer Advocate (DRA) calculated PG&E's actual "imprudence" to be $4.4 billion (about 75 percent of the plant's final cost), and concluded that customers ultimately paid $2.4 billion more than was prudent for the plant—even after the $2 billion disallowance.[47]

A major theme of this paper is how consumer and investor interests are intertwined, and how both are served by strategies that limit risk.

These two large disallowances could be joined by many other examples where unrecognized risk "came home to roost." Consider the destruction of shareholder equity that occurred when Public Service of New Hampshire (PSNH) declared bankruptcy in 1988 because of the burden of its investment in the Seabrook Nuclear Unit, or the enormous debt burden placed on ratepayers by the failure of New York's largest utility, Long Island Lighting Company (LILCO), or the 1983 multi-billion dollar municipal bond default by the Washington Public Power Supply System (WPPSS) when it abandoned attempts to construct five nuclear units in southeast Washington.

44 Lyon and Mayo, *Regulatory opportunism*, 632.

45 Assumes 70 percent of investment is by regulated entities. Illustrative estimates do not include potential losses for utility customers or taxpayers.

46 Fred I. Denny and David E. Dismukes, *Power System Operations and Electricity Markets* (Boca Raton, FL: CRC Press, 2002), 17.

47 The California Public Utilities Commission Decision is available on the Lexis database at: 1988 Cal. PUC LEXIS 886; 30 CPUC2d 189; 99 P.U.R.4th 141, December 19, 1988; As Amended June 16, 1989.

All of these financial disasters share four important traits:

- a weak planning process;
- the attempted development of large, capital-intensive central generation resources;
- utility management's rigid commitment to a preferred investment course; and
- regulators' unwillingness to burden consumers with costs judged retrospectively to be imprudent.

We do not propose to assess blame twenty-five years later, but we do question whether the regulatory process correctly interpreted the risk involved in the construction of these plants—whether, with all risks accounted for, these plants should actually have been part of a "least cost" portfolio for these utilities. The lesson is clear: both investors and customers would have been much better served if the regulators had practiced "risk-aware" regulation.

Finally, while the financial calamities mentioned here rank among the industry's worst, the potential for negative consequences is probably higher today. Since the 1980s, electric demand has grown significantly while the environmental risks associated with utility operations, the costs of developing new generation resources, and the pace of technology development have all increased substantially. And, as noted earlier, electric utilities have entered the current build cycle with lower financial ratings than they had in the 1980s.

CHARACTERISTICS OF GENERATION RESOURCES

A utility's generation portfolio typically consists of a variety of resources that vary in their costs and operating characteristics. Some plants have high capital costs but lower fuel costs (e.g., coal and nuclear) or no fuel costs (e.g., hydro, wind, solar PV). Other plants have lower capital costs but relatively high fuel and operating costs (e.g., natural gas combined cycle). Some plants are designed to operate continuously in "base load" mode, while others are designed to run relatively few hours each year, ramping up and down quickly.

Some resources (including demand response) offer firm capacity in the sense that they are able to be called upon, or "dispatchable," in real time, while other resources are not dispatchable or under the control of the utility or system operator (e.g., some hydro, wind, solar PV).

Generation resources also vary widely in their design lives and exposure to climate regulations, among other differences.

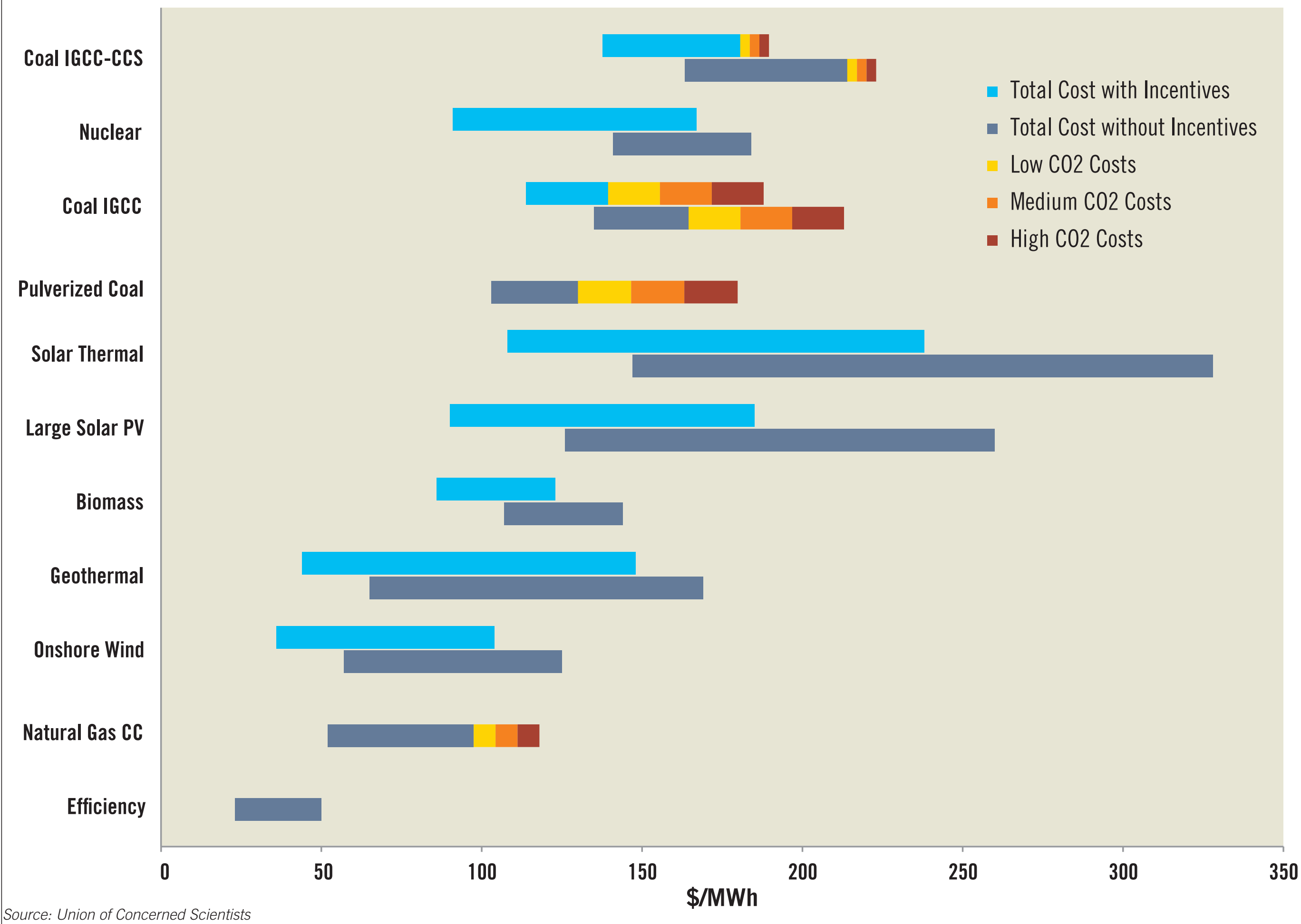
None of these characteristics *per se* makes a resource more or less useful in a utility's resource "stack." Some utility systems operate with a large percentage of generation provided by base load plants. Other systems employ a large amount of non-dispatchable generation like wind energy, combined with flexible gas or hydro generation to supply capacity. What's important is how the resources combine in a portfolio.

For example, in 2008 the Colorado Public Utilities Commission determined that an optimum portfolio for Xcel Energy would include a large amount of wind production, mixed in with natural gas generation and older base load coal plants. Xcel has learned how to manage its system to accommodate large amounts of wind production even though wind is not a "firm" resource. In October 2011, Xcel Energy set a world record for wind energy deployment by an integrated utility: in a one-hour period, wind power provided 55.6 percent of the energy delivered on the Xcel Colorado system.[48]

48 Mark Jaffe, "Xcel Sets World Record for Wind Power Generation," *The Denver Post*, November 15, 2011, http://www.denverpost.com/breakingnews/ci_19342896.

Figure 10

LEVELIZED COST OF ELECTRICITY FOR VARIOUS GENERATION TECHNOLOGIES IN 2015 (2010$)



Source: Union of Concerned Scientists

DECIPHERING THE LEVELIZED COST OF ELECTRICITY

Despite the differences between generation resources, it's possible to summarize and compare their respective costs in a single numerical measure. This quantity, called the "levelized cost of electricity," or "LCOE," indicates the cost per megawatt-hour for electricity over the life of the plant. LCOE encompasses all expected costs over the life of the plant, including costs for capital, operations and maintenance (O&M) and fuel.

Three of the most commonly cited sources of LCOE data for new U.S. generation resources are the Energy Information Administration (EIA); the California Energy Commission (CEC); and the international advisory and asset management firm Lazard. In a recent publication, the Union of Concerned Scientists (UCS) combined the largely consensus LCOE estimates from these three sources to produce a graphic illustrating LCOE for a range of resources (**Figure 10**).[49] The data is expressed in dollars per megawatt-hour, in 2010 dollars, for resources assumed to be online in 2015.

The UCS chart allows a visual comparison of the relative LCOEs among the selected group of resources. The width of the bars in the chart reflects the uncertainty in the cost of each resource, including the variation in LCOE that can result in different regions of the U.S. The UCS report also shows the resources' relative exposure to future carbon costs—not surprisingly, coal-based generation would be most heavily affected—as well as their dependence on federal investment incentives.[50]

49 Freese et al., *A Risky Proposition*, 41.

50 The UCS report estimated incentives by including tax credits for a wide range of technologies and both tax credits and loan guarantees for new nuclear plants. Tax credits currently available for wind and biomass were assumed to be extended to 2015 for illustrative purposes.

We'll use these LCOE estimates to illustrate the combined attributes of cost and risk for new generation resources. To do this, we'll take the midpoint of the cost ranges (including a medium estimate for costs associated with carbon controls) for each technology and create an indicative ranking of these resources by highest to lowest LCOE (**Figure 11**).

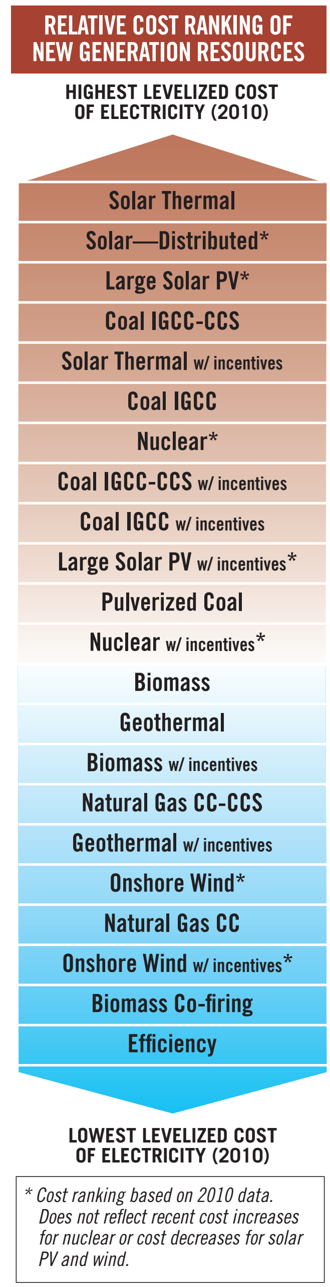
For consistency, we use UCS's data compilation, which is based on 2010 cost estimates, without modification. But the actual cost of nuclear power in 2015 is likely to be sharply higher than this estimate following the Fukushima nuclear accident and recent experience with new nuclear projects. For wind and photovoltaic power, the actual costs in 2015 are likely to be lower than the estimate due to recent sharp cost declines and the 2011 market prices for these resources.[51]

Several observations are in order about this ranking. First, some of the technologies show a very wide range of costs, notably geothermal, large solar PV and solar thermal. The breadth of the range represents, in part, the variation in performance of the technology in various regions of the country. In other words, the underlying cost estimates incorporate geographically varying geothermal and solar energy levels.

Second, the estimates used in this ranking are sensitive to many assumptions; the use of the midpoint to represent a technology in this ranking may suggest greater precision than is warranted. For this reason, the ranking shown in Figure 11 should be considered an indicative ranking. Two resources that are adjacent in the ranking might switch places under modest changes in the assumptions. That said, the ranking is useful for visualizing the relative magnitude of costs associated with various technologies and how those are projected to compare in the next few years.

Finally, the LCOE ranking tells only part of the story. The main point of this paper is that the *price* for any resource does not take into account the relative *risk* of acquiring it. In the next section we will examine these same technologies and estimate the composite risk to consumers, the utility and its investors for each technology.

Figure 11



The main point of this paper is that the *price* for any resource does not take into account the relative *risk* of acquiring it.

51 For example, in November 2011, the Colorado Public Utilities Commission approved a 25-year power purchase agreement between Xcel Energy and NextEra for wind generation in Colorado. The contract price is $27.50 per MWh in the first year and escalates at 2 percent per year. The levelized cost of the contract over 25 years is $34.75, less than the assumed lowest price for onshore wind with incentives in 2015 in Figure 10. For details, see Colorado PUC Decision No. C11-1291, available at http://www.colorado.gov/dora/cse-google-static/?q=C11-1291&cof=FORIDA10&ie=UTF-8&sa=Search. For more on wind power cost reductions, see Ryan Wiser et al., "Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects" (presentation materials funded by the Wind and Water Power Program of the U.S. Department of Energy, February 2012), http://eetd.lbl.gov/ea/ems/reports/wind-energy-costs-2-2012.pdf. For information on recent PV cost reductions, see Solar Energy Industries Association (SEIA), *U.S. Solar Market Insight Report: 2011 Year in Review: Executive Summary* (Washington, DC: Solar Energy Industries Association, 2012), 10-11, http://www.seia.org/cs/research/solarinsight.

RELATIVE RISK OF NEW GENERATION RESOURCES

In Figure 7 on p. 21, we identified many of the time-related and cost-related risks that attach to a decision to choose a utility resource. We will now examine various generation resource choices in light of these risks, grouping those examples of risk into seven categories:

- **Construction Cost Risk:** includes unplanned cost increases, delays and imprudent utility actions
- **Fuel and Operating Cost Risk:** includes fuel cost and availability, as well as O&M cost risks
- **New Regulation Risk:** includes air and water quality rules, waste disposal, land use, and zoning
- **Carbon Price Risk:** includes state or federal limits on greenhouse gas emissions
- **Water Constraint Risk:** includes the availability and cost of cooling and process water
- **Capital Shock Risk:** includes availability and cost of capital, and risk to firm due to project size
- **Planning Risk:** includes risk of inaccurate load forecasts, competitive pressure

These risks are discussed in detail below.

Intermittency vs. Risk

Certain resources, like wind, solar, and some hydropower facilities, are termed "intermittent" or "variable" resources. This means that while the power produced by them can be well characterized over the long run and successfully predicted in the short run, it cannot be precisely scheduled or dispatched. For that reason, variable resources are assigned a relatively low "capacity value" compared to base load power plants. The operating characteristics of any resource affect how it is integrated into a generation portfolio, and how its output is balanced by other resources.

This characteristic, intermittency, should not be confused with the concept of risk. Recall that risk is the expected value of a loss. In this case, the "loss" would be that the plant does not perform as expected—that it does not fulfill its role in a generation portfolio. For wind or solar resources, intermittency is expected and is accommodated in the portfolio design. Thus, while individual wind towers might be highly intermittent, and a collection of towers in a wind farm less so, a wind farm can also be termed highly reliable and present low risk because it will likely operate as predicted.

CONSTRUCTION COST RISK

Construction cost risk is the risk that the cost to develop, finance and construct a generation resource will exceed initial estimates. This risk depends on several factors, including the size of the project, the complexity of the technology, and the experience with developing and building such projects. The riskiest generation resources in this regard are technologies still in development, such as advanced nuclear and fossil-fired plants with carbon capture and storage. Construction cost risk is especially relevant for nuclear plants due to their very large size and long lead times. (Recall that a large percentage of the disallowed investment during the 1980s was for nuclear plants.) Transmission line projects are also subject to cost overruns, as are other large generation facilities. For example, Duke Energy's Edwardsport coal gasification power plant in Indiana has experienced billion-dollar cost overruns that have raised the installed cost to $5,593 per kilowatt, up from an original estimate of $3,364 per kilowatt.[52]

The lowest construction cost risk attaches to energy efficiency and to renewable technologies with known cost histories. In the middle will be technologies that are variations on known technologies (e.g., biomass) and resources with familiar construction regimes (e.g., gas and coal thermal plants).

FUEL AND OPERATING COST RISK

Fossil-fueled and nuclear generation is assigned "medium risk" for the potential upward trend of costs and the volatility familiar to natural gas supply.[53] Efficiency and renewable generation have no "fuel" risk. Biomass is assigned "medium" in this risk category because of a degree of uncertainty about the cost and environmental assessment of that fuel. Plants with higher labor components (e.g., nuclear, coal) have higher exposure to inflationary impacts on labor costs.

Analysts are split on the question of the future price of natural gas. The large reserves in shale formations and the ability to tap those resources economically through new applications of technology suggest that the price of natural gas may remain relatively low for the future and that the traditional volatility of natural gas prices will dampen. On the other hand, there remains substantial uncertainty about the quantity of economically recoverable shale gas reserves and controversy about the industrial processes used to develop these unconventional resources.

52 John Russell, "Duke CEO about plant: 'Yes, it's expensive,'" *The Indianapolis Star,* October 27, 2011, http://www.indystar.com/article/20111027/NEWS14/110270360/star-watch-duke-energy-Edwardsport-iurc.

53 Research conducted by the late economist Shimon Awerbuch demonstrated that adding renewable resources to traditional fossil portfolios lowers portfolio risk by hedging fuel cost variability; see Awerbuch, "How Wind and Other Renewables Really Affect Generating Costs: A Portfolio Risk Approach" (presentation at the European Forum for Renewable Energy Resources, Edinburgh, UK, October 7, 2005), http://www.eufores.org/uploads/media/Awerbuch-edinburgh_risk-portoflios-security-distver-Oct-20051.pdf. For a discussion of using renewable energy to reduce fuel price risk and environmental compliance in utility portfolios, see Mark Bolinger and Ryan Wiser, *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans* (Berkeley, CA: Lawrence Berkeley National Laboratory, 2005), http://eetd.lbl.gov/ea/ems/reports/58450.pdf.

There is also significant debate at the moment about the future price of coal. Some sources of low-sulfur coal are being depleted, raising the specter of higher production costs. Further, U.S. exports to China and other countries suggest upward pressure on this traditionally stable-priced fuel.

In this report we have steered a middle course on natural gas and coal prices, assuming that the risk of future surprises in natural gas and coal availability and price to be "medium." This is consistent with the price projection for these two generation fuels used by the Energy Information Administration in its current long-term energy forecast. In its most recent estimate, EIA assumes a real annual price escalation between 2010 and 2035 of about 1.3 percent for coal at the mine mouth and 1.8 percent for natural gas at the wellhead.[54]

Finally, operating cost risk includes the potential for catastrophic failure of a resource. This is especially significant for systems that could be taken down by a single point of failure. Contrast the impact of the failure of a turbine at a large steam plant as compared to the failure of a single turbine at a 100-turbine wind farm. The first failure causes the unavailability of 100 percent of capacity; the second failure causes a 1 percent reduction in capacity availability. Even if the probabilities of the failures are widely different, the size of the loss (risk) has cost implications for the reserve capacity (insurance) that must be carried on the large plant. Small outages are much easier to accommodate than large ones.[55]

Intermittency should not be confused with the concept of risk… For wind or solar resources, intermittency is expected and is accommodated in the portfolio design.

Modularity and unit size are also relevant to demand-side resources that are, by their nature, diverse. Designing good energy efficiency programs involves scrutinizing individual measures for the potential that they may not deliver the expected level of energy savings over time. This estimate can be factored into expectations for overall program performance so that the resource performs as expected. Since it would be extremely unlikely for individual measure failures to produce a catastrophic loss of the resource, diverse demand-side resources are, on this measure, less risky than large generation-side resources.

NEW REGULATION RISK

Nuclear generation is famously affected by accidents and the resulting changes in regulations. The recent accident at Fukushima in Japan illustrates how even a seemingly settled technology—in this case, GE boiling water reactors—can receive increased regulatory scrutiny. Further, the future of nuclear waste disposal remains unclear, even though the current fleet of reactors is buffered by reserves that are designed to cover this contingency. For these reasons, we consider nuclear power to face a high risk of future regulations.

Carbon sequestration and storage (CCS) appears to be subject to similar elevated risks regarding liability. The ownership and responsibility for long-term maintenance and monitoring for carbon storage sites will remain an unknown risk factor in coal and gas generation proposed with CCS.

Other thermal generation (e.g., biomass and geothermal) are also given a "medium" probability due to potential air regulations and land use regulations. Finally, as noted above, the price of natural gas, especially shale gas produced using "fracking" techniques, is at risk of future environmental regulation.

CARBON PRICE RISK

Fossil generation without CCS has a high risk of being affected by future carbon emission limits. Although there is no political agreement on the policy mechanism to place a cost on carbon (i.e., tax or cap), the authors expect that the scientific evidence of climate change will eventually compel concerted federal action and that greenhouse gas emissions will be costly for fossil-fueled generation. Energy efficiency, renewable and nuclear resources have no exposure to carbon risk, at least with respect to emissions at the plant.[56]

A more complex story appears when we consider the emissions related to the full life-cycle of generation technologies and their fuel cycles. For example, nuclear fuel production is an energy-intensive and carbon-intensive process on its own. As the cost of emitting carbon rises, we should expect the cost of nuclear fuel to rise.

Similar comments could apply to renewable facilities that require raw materials and fabrication that will, at least in the near-term, involve carbon-emitting production processes. However, these effects are second-order and much smaller than the carbon impact of primary generation fuels or motive power (e.g., coal, gas, wind, sun, nuclear reactions). The exposure of biomass to carbon constraints will depend on the eventual interpretation of carbon offsets and life-cycle analyses. For that reason, biomass and co-firing with biomass is assigned a non-zero risk of "low."

54 U.S. Energy Information Administration, *AEO2012 Early Release Overview*, 12-13.

55 This discussion refers to the *availability factor* of a resource; the *capacity factor* of a resource is a different issue, with implications for generation system design and operation.

56 For a discussion of how larger amounts of energy efficiency in a utility portfolio can reduce risk associated with carbon regulation, see Ryan Wiser, Amol Phadke and Charles Goldman, *Pursuing Energy Efficiency as a Hedge against Carbon Regulatory Risks: Current Resource Planning Practices in the West*, Paper 20 (Washington DC: U.S. Department of Energy Publications, 2008), http://digitalcommons.unl.edu/usdoepub/20.

"Retire or Retrofit" Decisions for Coal-Fired Plants

In this report, we've stressed how risk-aware regulation can improve the outcomes of utility selection of new resources. But many regulators will be focusing on existing power plants during the next few years. A key question facing the industry is whether to close coal plants in the face of new and future EPA regulations, or spend money on control systems to clean up some of the plant emissions and keep them running.

States and utilities are just coming to grips with these sorts of decisions. In 2010, Colorado implemented the new Clean Air Clean Jobs Act, under which the Colorado PUC examined Xcel Energy's entire coal fleet. The Colorado Commission entered a single decision addressing the fate of ten coal units. Some were closed, some were retrofitted with pollution controls, and others were converted to burn natural gas. Elsewhere, Progress Energy Carolinas moved decisively to address the same issue with eleven coal units in North Carolina.

We expect that three types of coal plants will emerge in these analyses: plants that should obviously be closed; newer coal plants that should be retrofitted and continue to run; and "plants in the middle." Decisions about these plants in the middle will require regulators to assess the risk of future fuel prices, customer growth, environmental regulations, capital and variable costs for replacement capacity, etc. In short, state commissions will be asked to assess the risks of various paths forward for the plants for which the economics are subject to debate.

The tools we describe in this report for new resources apply equally well to these situations. Regulators should treat this much like an IRP proceeding (see "Utilizing Robust Planning Processes" on p. 40). Utilities should be required to present multiple different scenarios for their disposition of coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. At the end, regulators should enter a decision that addresses all of the relevant risks.

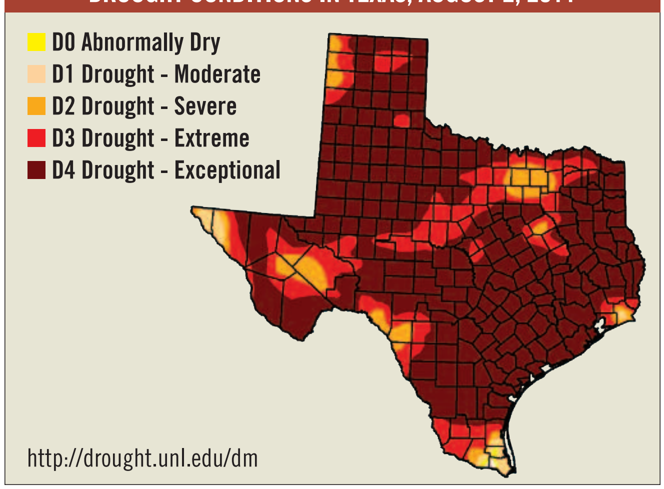
WATER CONSTRAINT RISK

Electric power generation—specifically the cooling of power plants—consumes about 40 percent of all U.S. freshwater withdrawals.[57] The availability and cost of water required for electricity generation will vary with geography but attaches to all of the thermal resources.[58] The recent promulgation by the EPA of the "once-through" cooling rule illustrates the impact that federal regulation can have on thermal facilities; one estimate predicts that more than 400 generating plants providing 27 percent of the nation's generating capacity may need to install costly cooling towers to minimize impacts on water resources.[59] One potential approach, especially for solar thermal, is the use of air-cooling, which significantly lowers water use at a moderate cost to efficiency. Non-thermal generation and energy efficiency have no exposure to this category of risk.

Water emerged as a significant issue for the U.S. electric power sector in 2011. A survey of more than 700 U.S. utility leaders by Black & Veatch indicated "water management was rated as the business issue that could have the greatest impact on the utility industry."[60] Texas suffered from record drought in 2011 at the same time that it experienced all-time highs in electricity demand. **Figure 12** depicts widespread "exceptional drought" conditions in Texas on August 2, 2011,[61] the day before the Electric Reliability Council of Texas (ERCOT) experienced record-breaking peak demand. ERCOT managed to avoid rolling blackouts but warned that continued drought and lack of sufficient cooling water could lead to generation outages totaling "several thousand megawatts."[62]

Figure 12

DROUGHT CONDITIONS IN TEXAS, AUGUST 2, 2011



57 J.F. Kenny et al., "Estimated use of water in the United States in 2005," *U.S. Geological Survey Circular 1344* (Reston, VA: U.S. Geological Survey, 2009), http://pubs.usgs.gov/circ/1344/pdf/c1344.pdf.

58 For a discussion of freshwater use by U.S. power plants, see Kristen Averyt et al., *Freshwater Use by U.S. Power Plants* (Cambridge, MA: Union of Concerned Scientists, 2011), http://www.ucsusa.org/assets/documents/clean_energy/ew3/ew3-freshwater-use-by-us-power-plants.pdf.

59 Bernstein Research, *U.S. Utilities: Coal-Fired Generation is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* (New York: Bernstein Research, 2010), 69.

60 "U.S. Utility Survey Respondents Believe Energy Prices Will Rise Significantly, Place Emphasis on Growing Nexus of Water and Energy Challenge," Black & Veatch press release, June 13, 2011, http://www.bv.com/wcm/press_release/06132011_9417.aspx.

61 National Drought Mitigation Center, "U.S. Drought Monitor: Texas," August 2, 2011, http://droughtmonitor.unl.edu/archive/20110802/pdfs/TX_dm_110802.pdf.

62 Samantha Bryant, "ERCOT examines grid management during high heat, drought conditions," *Community Impact Newspaper*, October 14, 2011, http://impactnews.com/articles/ercot-examines-grid-management-during-high-heat,-drought-conditions.

In addition to drought, water rights could be an issue for electricity generators in Texas (and elsewhere).[63] The North American Electric Reliability Corporation (NERC) points out that in an extreme scenario, up to 9,000 MW of Texas' generation capacity—over 10 percent of ERCOT's total installed capacity—could be at risk of curtailment if generators' water rights were recalled.[64]

CAPITAL SHOCK RISK

This risk is generally proportional to the size of the capital outlay and the time required for construction of a generating unit. Simply put, the larger the capital outlay and the longer that cost recovery is uncertain, the higher the risk to investors. In this regard, nuclear installations and large new coal facilities with CCS face the highest risk. Smaller, more modular additions to capacity and especially resources that are typically acquired through purchase power agreements record less risk. Finally, distributed solar generation, modifications to enable biomass co-firing and efficiency are accorded low exposure to the risk of capital shock.

PLANNING RISK

This risk relates to the possibility that the underlying assumptions justifying the choice of a resource may change, sometimes even before the resource is deployed. This can occur, for example, when electric demand growth is weaker than forecast, which can result in a portion of the capacity of the new resource being excess. In January 2012, lower-than-anticipated electricity demand, combined with unexpectedly low natural gas prices, led Minnesota-based wholesale cooperative Great River Energy to mothball its brand-new, $437 million Spiritwood coal-fired power plant immediately upon the plant's completion. The utility will pay an estimated $30 million next year in maintenance and debt service for the idled plant.[65]

Generation projects with a high ratio of fixed costs and long construction lead times are most susceptible to planning risk. This means that the exposure of base load plants is higher than peaking units, and larger capacity units have more exposure than smaller plants.

In addition to macroeconomic factors like recessions, the electric industry of the early 21st century poses four important unknown factors affecting energy planning. These are 1) the rate of adoption of electric vehicles; 2) the pace of energy efficiency and demand response deployment; 3) the rate of growth of customer-owned distributed generation; and 4) progress toward energy storage. These four unknowns affect various resources in different ways.

Electric vehicles could increase peak demand if customers routinely charge their cars after work, during the remaining hours of the afternoon electrical peak. On the other hand, if electric vehicle use is coupled with time-of-use pricing, this new load has the opportunity to provide relatively desirable nighttime energy loads, making wind generation and nuclear generation and underutilized fossil generation more valuable in many parts of the country.

Energy efficiency (EE) and demand response (DR) affect both electricity (kilowatt-hours) and demand (kilowatts). EE and DR programs differ in relatively how much electricity or demand they conserve. Depending on portfolio design, EE and DR may improve or worsen utility load factors, shifting toward more peaking resources and away from base load plants. Changing customer habits and new "behavioral" EE efforts add to the difficulty in forecasting demand over time.

Distributed generation, especially small solar installation, is expanding rapidly, spurred by new financing models that have lowered the capital outlay from consumers. In addition, we may expect commercial and industrial customers to continue to pursue combined heat and power applications, especially if retail electricity rates continue to rise. Both of these trends will have hard-to-predict impacts on aggregate utility demand and the relative value of different generation resources, but also impacts on primary and secondary distribution investment.

Finally, electric storage at reasonable prices would be a proverbial game-changer, increasing the relative value of intermittent resources such as wind and solar. Microgrids with local generation would also be boosted by low-cost battery storage.

63 For a discussion of how water scarcity could impact municipal water and electric utilities and their bondholders, see Sharlene Leurig, *The Ripple Effect: Water Risk in the Municipal Bond Market* (Boston, MA: Ceres, 2010), http://www.ceres.org/resources/reports/water-bonds/at_download/file. For a framework for managing corporate water risk, see Brooke Barton et al., *The Ceres Aqua Gauge: A Framework for 21st Century Water Risk Management* (Boston, MA: Ceres, 2011), http://www.ceres.org/resources/reports/aqua-gauge/at_download/file.

64 North American Electric Reliability Corporation, *Winter Reliability Assessment 2011/2012* (Atlanta, GA: North American Electric Reliability Corporation, 2011), 29, http://www.nerc.com/files/2011WA_Report_FINAL.pdf.

65 David Shaffer, "Brand new power plant is idled by economy," *Minneapolis StarTribune*, January 9, 2012, http://www.startribune.com/business/134647533.html.

Figure 13

RELATIVE RISK EXPOSURE OF NEW GENERATION RESOURCES							
Resource	Initial Cost Risk	Fuel, O&M Cost Risk	New Regulation Risk	Carbon Price Risk	Water Constraint Risk	Capital Shock Risk	Planning Risk
Biomass	Medium	Medium	Medium	Medium	High	Medium	Medium
Biomass w/ incentives	Medium	Medium	Medium	Medium	High	Low	Medium
Biomass Co-firing	Low	Low	Medium	Low	High	Low	Low
Coal IGCC	High	Medium	Medium	Medium	High	Medium	Medium
Coal IGCC w/ incentives	High	Medium	Medium	Medium	High	Low	Medium
Coal IGCC-CCS	High	Medium	Medium	Low	High	High	High
Coal IGCC-CCS w/ incentives	High	Medium	Medium	Low	High	Medium	High
Efficiency	Low	None	Low	None	None	Low	None
Geothermal	Medium	None	Medium	None	High	Medium	Medium
Geothermal w/ incentives	Medium	None	Medium	None	High	Low	Medium
Large Solar PV	Low	None	Low	None	None	Medium	Low
Large Solar PV w/ incentives	Low	None	Low	None	None	Low	Low
Natural Gas CC	Medium	High	Medium	Medium	Medium	Medium	Medium
Natural Gas CC-CCS	High	Medium	Medium	Low	High	High	Medium
Nuclear	Very High	Medium	High	None	High	Very High	High
Nuclear w/ incentives	Very High	Medium	High	None	High	High	Medium
Onshore Wind	Low	None	Low	None	None	Low	Low
Onshore Wind w/ incentives	Low	None	Low	None	None	None	Low
Pulverized Coal	Medium	Medium	High	Very High	High	Medium	Medium
Solar - Distributed	Low	None	Low	None	None	Low	Low
Solar Thermal	Medium	None	Low	None	High	Medium	Medium
Solar Thermal w/ incentives	Medium	None	Low	None	High	Low	Medium

ESTABLISHING COMPOSITE RISK

In line with the foregoing discussion, the table in **Figure 13** summarizes the degree of exposure of various generation technologies to these seven categories of risk. The technologies listed are taken from UCS's LCOE ranking in Figure 10 on p. 28, plus three more: natural gas combined cycle with CCS, biomass co-firing and distributed solar PV generation. The chart estimates the degree of risk for each resource across seven major categories of risk, with estimates ranging from "None" to "Very High."

Three comments are in order. First, these assignments of relative risk were made by the authors, and while they are informed they are also subjective. As we discuss later, regulators should conduct their own robust examination of the relative costs and risks including those that are unique to their jurisdiction. Second, the assessment of risk for each resource is intended to be relative to each other, and not absolute in a quantitative sense. Third, while there are likely some correlations between these risk categories—resources with low fuel risk will have low carbon price exposure, for example—other variables exhibit substantial independence.

Figure 14

RELATIVE COST RANKING AND RELATIVE RISK RANKING OF NEW GENERATION RESOURCES

HIGHEST LEVELIZED COST OF ELECTRICITY (2010)	HIGHEST COMPOSITE RISK
Solar Thermal	Nuclear
Solar—Distributed*	Pulverized Coal
Large Solar PV*	Coal IGCC-CCS
Coal IGCC-CCS	Nuclear w/ incentives
Solar Thermal w/ incentives	Coal IGCC
Coal IGCC	Coal IGCC-CCS w/ incentives
Nuclear*	Natural Gas CC-CCS
Coal IGCC-CCS w/ incentives	Biomass
Coal IGCC w/ incentives	Coal IGCC w/ incentives
Large Solar PV w/ incentives*	Natural Gas CC
Pulverized Coal	Biomass w/ incentives
Nuclear w/ incentives*	Geothermal
Biomass	Biomass Co-firing
Geothermal	Geothermal w/ incentives
Biomass w/ incentives	Solar Thermal
Natural Gas CC-CCS	Solar Thermal w/ incentives
Geothermal w/ incentives	Large Solar PV
Onshore Wind*	Large Solar PV w/ incentives
Natural Gas CC	Onshore Wind
Onshore Wind w/ incentives*	Solar—Distributed
Biomass Co-firing	Onshore Wind w/ incentives
Efficiency	Efficiency
LOWEST LEVELIZED COST OF ELECTRICITY (2010)	LOWEST COMPOSITE RISK

** Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

The risk ranking shows a clear difference between renewable resources and non-renewable resources. Nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

Figure 15

RELATIVE COST AND RISK RANKINGS OF NEW GENERATION RESOURCES WITHOUT INCENTIVES

HIGHEST LEVELIZED COST OF ELECTRICITY (2010)	HIGHEST COMPOSITE RISK
Solar Thermal	Nuclear
Solar–Distributed*	Pulverized Coal
Large Solar PV*	Coal IGCC-CCS
Coal IGCC-CCS	Coal IGCC
Coal IGCC	Natural Gas CC-CCS
Nuclear*	Biomass
Pulverized Coal	Natural Gas CC
Biomass	Geothermal
Geothermal	Biomass Co-firing
Natural Gas CC-CCS	Solar Thermal
Onshore Wind*	Large Solar PV
Natural Gas CC	Onshore Wind
Biomass Co-firing	Solar–Distributed
Efficiency	Efficiency
LOWEST LEVELIZED COST OF ELECTRICITY (2010)	LOWEST COMPOSITE RISK

** Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

To derive a ranking of these resources with respect to risk, we assigned numeric values to the estimated degrees of risk (None=0, Very High=4) and totaled the rating for each resource. The scores were then renormalized so that the score of the highest-risk resource is 100 and the others are adjusted accordingly. The composite relative risk ranking that emerges is shown in **Figure 14**, which, for ease of comparison, we present alongside the relative cost ranking from Figure 11.

The risk ranking differs from the cost ranking in several important ways. First, the risk ranking shows a clear difference between renewable resources and non-renewable resources. Second, nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

To illustrate how resources stack up against each other in more general terms, and for simplicity of viewing, **Figure 15** presents those same rankings without information about incentives.

To test the robustness of the composite risk ranking, we also examined two rankings where the scores were weighted. In one case, the environmental factors were given double weight; in the other, the cost factors were given double weight. As before, the scores were renormalized so that the highest-scoring resource is set to 100. The results of the unweighted ranking, together with the two weighted rankings, are shown in **Figure 16**. By inspection, one can see that the rank order changes very little across the three methods, so that the risk ranking in Figure 14 appears to be relatively robust. Once again, we emphasize that these figures are intended to show the relative risk among the resources, not to be absolute measures of risk.[66]

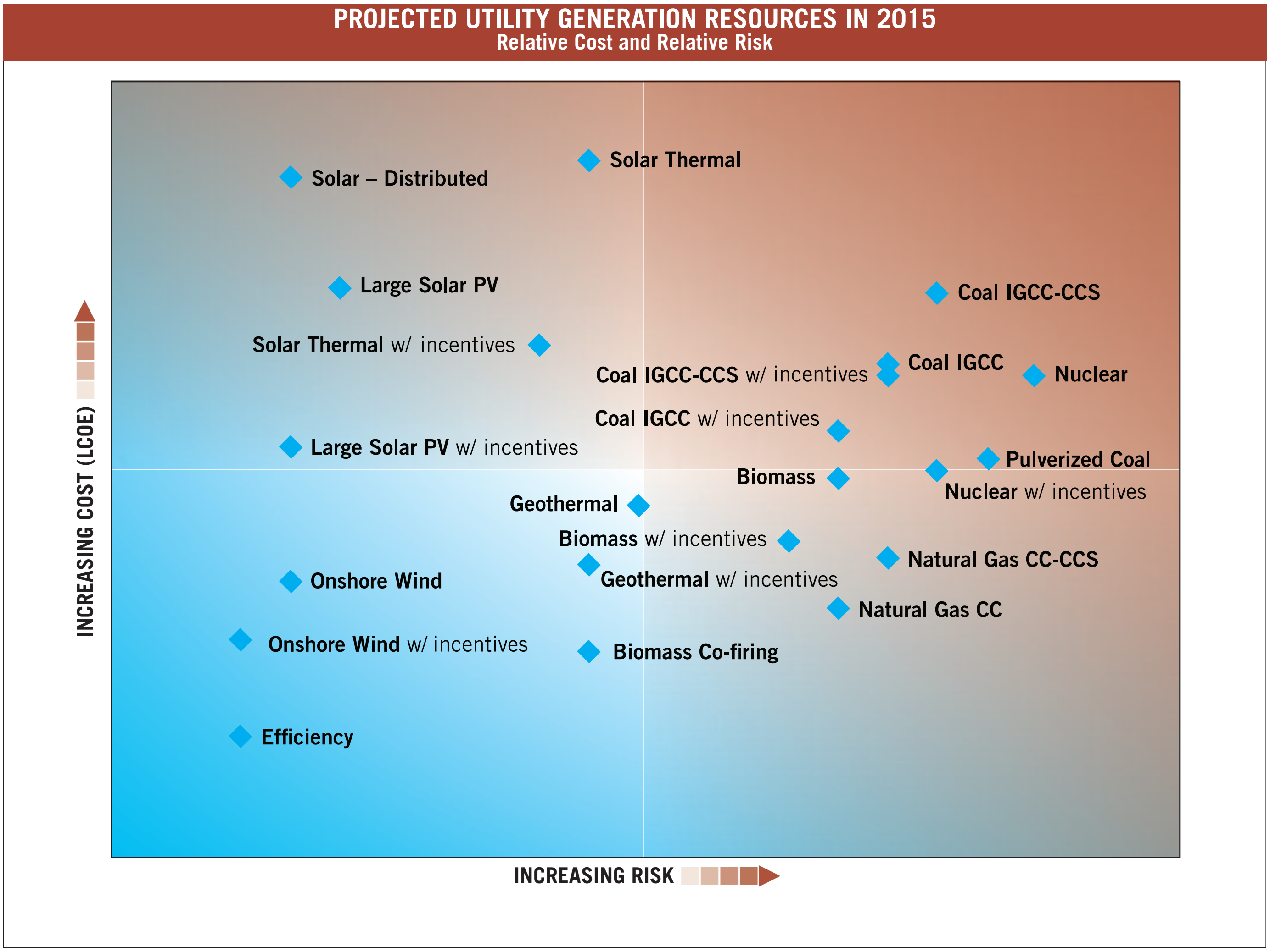
Figure 16

SUMMARY OF RISK SCORES FOR NEW GENERATION RESOURCES

Resource	Composite Score	Environmental Weighted Score	Cost Weighted Score
Biomass	79	79	72
Biomass w/ incentives	74	76	66
Biomass Co-firing	53	57	44
Coal IGCC	84	83	79
Coal IGCC w/ incentives	79	79	72
Coal IGCC-CCS	89	84	87
Coal IGCC-CCS w/ incentives	84	81	80
Efficiency	16	14	16
Geothermal	58	59	52
Geothermal w/ incentives	53	55	46
Large Solar PV	26	22	28
Large Solar PV w/ incentives	21	19	21
Natural Gas CC	79	76	75
Natural Gas CC-CCS	84	79	82
Nuclear	100	91	100
Nuclear w/ incentives	89	83	89
Onshore Wind	21	19	21
Onshore Wind w/ incentives	16	16	15
Pulverized Coal	95	100	82
Solar - Distributed	21	19	21
Solar Thermal	53	52	49
Solar Thermal w/ incentives	47	48	43

66 Dr. Mark Cooper, a longtime utility sector analyst and supporter of consumer interests, recently arrived at similar conclusions about composite risk; see Cooper, *Least-Cost Planning For 21st Century Electricity Supply* (So. Royalton, VT: Vermont Law School, 2011), http://www.vermontlaw.edu/Documents/21st%20Century%20Least%20Cost%20Planning.pdf. Cooper's analysis incorporated not only variations in "risk" and "uncertainty," but also the degrees of "ignorance" and "ambiguity" associated with various resources and the universe of possible future energy scenarios.

Figure 17



Finally, we can combine the information in the cost ranking and the risk ranking into a single chart. **Figure 17** shows how resources compare with each other in the two dimensions of cost and risk. The position of a resource along the horizontal axis denotes the relative risk of each resource, while the position on the vertical axis shows the relative cost of the resource.

4. PRACTICING RISK-AWARE REGULATION:

SEVEN ESSENTIAL STRATEGIES FOR STATE REGULATORS

UTILITY REGULATORS ARE FAMILIAR WITH A SCENE THAT PLAYS OUT IN THE HEARING ROOM: DIFFERENT INTERESTS—UTILITIES, INVESTORS, CUSTOMER GROUPS, ENVIRONMENTAL ADVOCATES AND OTHERS—COMPETE TO REDUCE COST AND RISK FOR THEIR SECTOR AT THE EXPENSE OF THE OTHERS. WHILE THE ADVERSARIAL PROCESS MAY MAKE THIS COMPETITION SEEM INEVITABLE, AN OVERLOOKED STRATEGY (THAT USUALLY LACKS AN ADVOCATE) IS TO REDUCE OVERALL RISK TO EVERYONE. MINIMIZING RISK IN THE WAYS DISCUSSED IN THIS SECTION WILL HELP ENSURE THAT ONLY THE UNAVOIDABLE BATTLES COME BEFORE REGULATORS AND THAT THE PUBLIC INTEREST IS SERVED FIRST.

Managing risk intelligently is arguably the main duty of regulators who oversee utility investment. But minimizing risk isn't simply achieving the least cost today. It is part of a strategy to *minimize overall long term costs*. And, as noted earlier, while minimizing risk is a worthy goal, eliminating risk is not an achievable goal. The regulatory process must provide balance for the interests of utilities, consumers and investors in the presence of risk.

One of the goals of "risk-aware" regulation is avoiding the kind of big, costly mistakes in utility resource acquisition that we've seen in the past. But there is another, more affirmative goal: ensuring that society's limited resources (and consumers' limited dollars) are spent wisely. By routinely examining and addressing risk in every major decision, regulators will produce lower cost outcomes in the long run, serving consumers and the public interest in a very fundamental way.

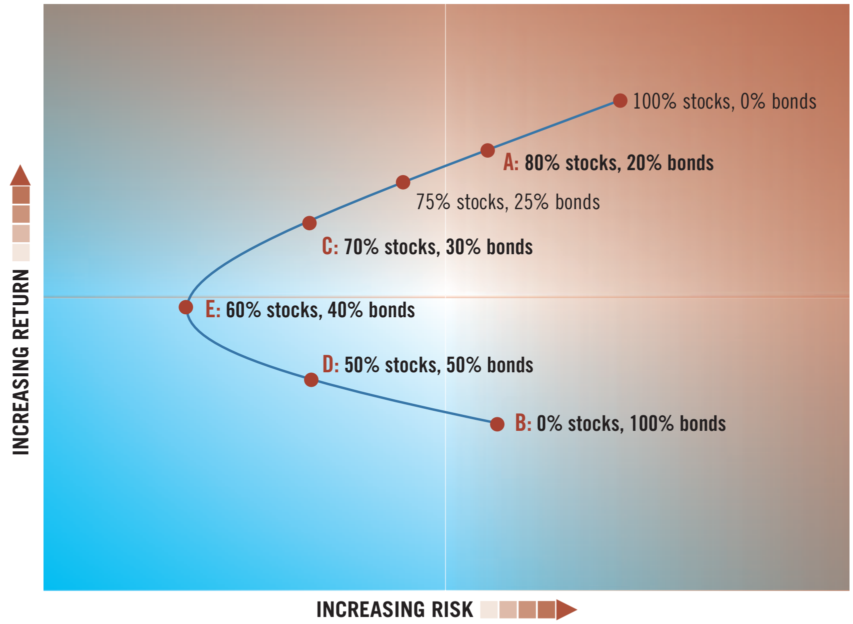
An overlooked strategy (that usually lacks an advocate) is to reduce overall risk to everyone.

WE IDENTIFY SEVEN ESSENTIAL STRATEGIES THAT REGULATORS CAN EMPLOY TO MINIMIZE RISK:

1. **DIVERSIFYING UTILITY SUPPLY PORTFOLIOS** with an emphasis on low-carbon resources;
2. **UTILIZING ROBUST PLANNING PROCESSES** for all utility investment (i.e., generation, transmission, distribution, and demand-side resources like energy efficiency);
3. **EMPLOYING TRANSPARENT RATEMAKING PRACTICES** that reveal risk;
4. **USING FINANCIAL AND PHYSICAL HEDGES**, including long-term contracts;
5. **HOLDING UTILITIES ACCOUNTABLE** for their obligations and commitments;
6. **OPERATING IN ACTIVE, "LEGISLATIVE" MODE**, continually seeking out and addressing risk;
7. **REFORMING AND RE-INVENTING RATEMAKING POLICIES** as appropriate.

Figure 18

RISK/RETURN RELATIONSHIPS AMONG DIFFERENT FINANCIAL PORTFOLIOS
(Illustrative)



We now discuss each of these strategies in more detail.

1. DIVERSIFYING UTILITY SUPPLY PORTFOLIOS

The concept of diversification plays an important role in finance theory. Diversification—investing in different asset classes with different risk profiles—is what allows a pension fund, for example, to reduce portfolio volatility and shield it from outsized swings in value.

Properly chosen elements in a diversified portfolio can increase return for the same level of risk, or, conversely, can reduce risk for a desired level of return. The simple illustration in **Figure 18** allows us to consider the relative risk and return for several portfolios consisting of stocks and bonds. Portfolio A (80% stocks, 20% bonds) provides a higher predicted return than Portfolio B (0% stocks, 100% bonds) even though both portfolios have the same degree of risk. Similarly, Portfolios C and D produce different returns at an identical level of risk that is lower than A and B. Portfolio E (60% stocks, 40% bonds) has the lowest risk, but at the cost of a lower return than Portfolios A and C. The curve in Figure 18 (and the corresponding surface in higher dimensions) is called an *efficient frontier*.

We could complicate the example—by looking at investments in cash, real estate, physical assets, commodities or credit default swaps, say, or by distinguishing between domestic and international stocks, or between bonds of various maturities—but the general lesson would be the same: diversification helps to lower the risk in a portfolio.

Portfolios of utility investments and resource mixes can be analyzed similarly. Instead of return and risk, the analysis would examine cost and risk. And instead of stocks, bonds, real estate and gold, the elements of a utility portfolio are different types of power plants, energy efficiency, purchased power agreements, and distributed generation, among many other potential elements. Each of these elements can be further distinguished by type of fuel, size of plant, length of contract, operating characteristics, degree of utility dispatch control, and so forth. Diversification in a utility portfolio means including various supply and demand-side resources that behave independently from each other in different future scenarios. Later we will consider these attributes in greater detail and discuss what constitutes a diversified utility portfolio.

For a real-world illustration of how diversifying resources lowers cost and risk in utility portfolios, consider the findings of the integrated resource plan recently completed by the Tennessee Valley Authority (TVA).[67] TVA evaluated five resource strategies that were ultimately refined into a single "recommended planning direction" that will guide TVA's resource investments. The resource strategies that TVA considered were:

- **Strategy A:** Limited Change in Current Resource Portfolio[68]
- **Strategy B:** Baseline Plan Resource Portfolio
- **Strategy C:** Diversity Focused Resource Portfolio
- **Strategy D:** Nuclear Focused Resource Portfolio
- **Strategy E:** EEDR (Energy Efficiency/Demand Response) and Renewables Focused Resource Portfolio

67 TVA, a corporation owned by the federal government, provides electricity to nine million people in seven southeastern U.S. states; see http://www.tva.com/abouttva/index.htm.

68 As of spring 2010, TVA's generation mix consisted mainly of coal (40 percent), natural gas (25 percent) and nuclear (18 percent); see TVA, 73.

Figure 19

TVA ANALYSIS OF RESOURCE PLAN COSTS & FINANCIAL RISK

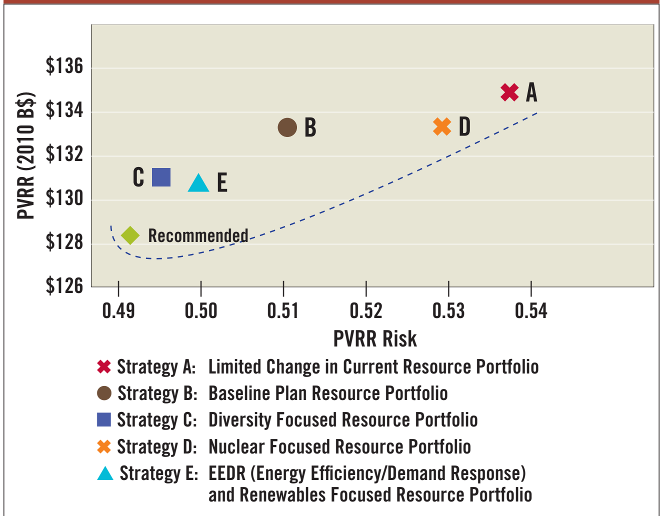


Figure 19 illustrates how these strategies mapped out along an "efficient frontier" according to TVA's analysis of cost and risk.[69] The lowest-cost, lowest-risk strategies were the ones that diversified TVA's resource portfolio by increasing TVA's investment in energy efficiency and renewable energy.[70] The highest-cost, highest-risk strategies were those that maintained TVA's current resource portfolio (mostly coal, natural gas and nuclear) or emphasized new nuclear plant construction.

The TVA analysis is very careful and deliberate. To the extent that other analyses reached conclusions thematically different from TVA's, we would question whether the costs and risks of all resources had been properly evaluated. We would also posit that resource investment strategies that differ directionally from TVA's "recommended planning direction" would likely expose customers (and, to some extent, investors) to undue risk. Finally, given the industry's familiarity with traditional resources—and the possibility that regulators and utilities may therefore underestimate the costs and risks of those resources—the TVA example illustrates how careful planning reveals the costs and risks of maintaining resource portfolios that rely heavily on large base load fossil and nuclear plants.

Robust planning processes like TVA's are therefore essential to making risk-aware resource choices. It is to these planning processes that we now turn.

2. UTILIZING ROBUST PLANNING PROCESSES

In the U.S., there are two basic utility market structures: areas where utilities own or control their own generating resources (the "vertically integrated" model), and areas where competitive processes establish wholesale prices (the "organized market" model).

In many vertically integrated markets and in some organized markets, regulators oversee the capital investments of utilities with a process called "integrated resource planning," or IRP. Begun in the 1980s, integrated resource planning is a tool to ensure that the utilities, regulators and other stakeholders have a common understanding of a full spectrum of possible utility resources; that the options are examined in a structured, disciplined way in administrative proceedings; that demand-side resources get equal consideration alongside supply-side resources; and that the final resource plan is understood (if not necessarily accepted) by all.

Elements of a Robust IRP Process

IRP oversight varies in sophistication, importance and outcomes across the states. Because a robust IRP process is critical to managing risk in a utility, we describe a model IRP process that is designed to produce utility portfolios that are lower risk and lower cost.[71]

These elements characterize a robust IRP process:

- The terms and significance of the IRP approval (including implications for cost recovery) are clearly stated at the outset, often in statute or in a regulatory commission's rules.
- The regulator reviews and approves the modeling inputs used by the utility (e.g., demand and energy forecasts, fuel cost projections, financial assumptions, discount rate, plant costs, fuel costs, energy policy changes, etc.).
- The regulator provides guidance to utility as to the policy goals of the IRP, perhaps shaping the set of portfolios examined.
- Utility analysis produces a set of resource portfolios and analysis of parameters such as future revenue requirement, risk, emissions profile, and sensitivities around input assumptions.
- In a transparent public process, the regulator examines competing portfolios, considering the utility's analysis as well as input from other interested parties.
- Demand resources such as energy efficiency and demand response are accorded equal status with supply resources.
- The regulator approves a plan and the utility is awarded a "presumption of prudence" for actions that are consistent with the approved IRP.
- The utility acquires (i.e., builds or buys) the resources approved in the IRP, possibly through a competitive bidding regime.
- Future challenges to prudence of utility actions are limited to the execution of the IRP, not to the selection of resources approved by the regulator.

69 TVA, 161.

70 In the end, TVA settled on a "recommended planning direction" that calls for demand reductions of 3,600 to 5,100 MW, energy efficiency savings of 11,400 to 14,400 GWh, and renewable generating capacity additions of 1,500 to 2,500 MW by 2020. At the same time, TVA plans to retire 2,400 to 4,700 MW of coal-fired capacity by 2017. See TVA, 156.

71 For an example of an IRP that uses sophisticated risk modeling tools, see PacifiCorp, *2011 Integrated Resource Plan* (Portland, OR: PacifiCorp, 2011), http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/2011IRP-MainDocFinal_Vol1-FINAL.pdf.

IRP: "Accepted" vs. "Approved" Plans

There are two varieties of IRP plans: "accepted plans" and "approved plans." Accepted plans are those where regulators examine the utility's process for developing its proposed plan. This can be a thorough review in which the Commission solicits the opinion of other parties as to whether the utility undertook a transparent, inclusive, and interactive process. If the regulator is convinced, the regulator "accepts" the utility's plan. This allows the utility to proceed but does not include any presumption about the Commission's future judgment concerning the prudence of actions taken under the plan.

With an "approved plan" the regulator undertakes a thorough review of the utility's preferred plan, possibly along with competing IRP plans submitted by other parties. Typically the scrutiny is more detailed and time-consuming in this version of IRP and the regulatory agency is immersed in the details of competing plans. At the end of the process, the regulator "approves" an IRP plan. This approval typically carries with it a presumption that actions taken by the utility consistent with the plan (including its approved amendments) are prudent. Over time, a Commission that approves an IRP plan will typically also examine proposed changes to the plan necessitated by changing circumstances.

In this report, we will focus on the "approved plan" process, although many of our findings apply equally to regulators that employ the "accepted plan" process.

A few of these elements deserve more elaboration.

Significance. The IRP must be meaningful and enforceable; there must be something valuable at stake for the utility and for other parties. From the regulator's point of view, the resource planning process must review a wide variety of portfolio choices whose robustness is tested and compared under different assumptions about the future. From the utilities' perspective, acceptance or approval of an IRP should convey that regulators support the plan's direction, even though specific elements may evolve as circumstances change. If a utility ignores the approved IRP or takes actions that are inconsistent with an IRP without adequate justification, such actions may receive extra scrutiny at the point where the utility seeks cost recovery.

Multiple scenarios. Many different scenarios will allow a utility to meet its future load obligations to customers. These scenarios will differ in cost, risk, generation characteristics, fuel mix, levels of energy efficiency, types of resources, sensitivity to changes in fuel cost, and so forth. While one scenario might apparently be lowest cost under baseline assumptions, it may not be very resilient under different input assumptions. Further, scenarios will differ in levels of risk and how that risk may be apportioned to different parties (e.g., consumers or shareholders). Regulators, with input from interested parties, should specify the types of scenarios that utilities should model and require utilities to perform sensitivity analyses, manipulating key variables.

Consistent, active regulation. An IRP proceeding can be a large, complex undertaking that occurs every two or three years, or even less frequently. It is critical that regulators become active early in the process and stay active throughout. The regulator's involvement should be consistent, even-handed and focused on the big-ticket items. Of course, details matter, but the process is most valuable when it ensures that the utility is headed in the right direction and that its planning avoids major errors. The regulator should then monitor a utility's performance and the utility should be able to trust the regulator's commitment to the path forward laid out in the IRP.

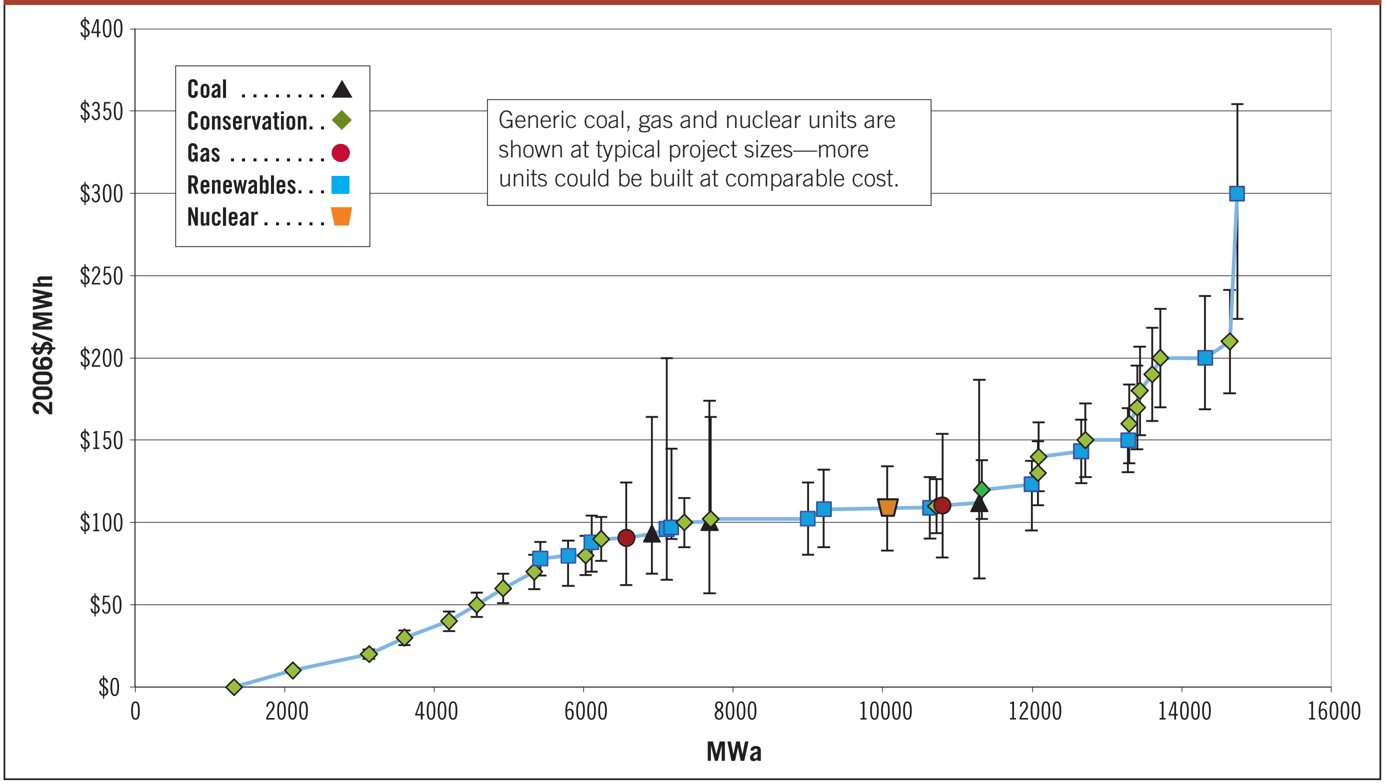
Stakeholder involvement. There are at least two good reasons to encourage broad stakeholder involvement in an IRP process. First, parties besides the utility will bring new ideas, close scrutiny and contrasting analysis to the IRP case, all of which helps the regulator to make an informed, independent decision. Second, effective stakeholder involvement can build support for the IRP that is ultimately approved, heading off collateral attacks and judicial appeals. An approved IRP will affect the fortunes of many and will signal the direction that the regulator wishes the utility to take with its supply-side and demand-side resources. Because an IRP decision is something of a political document in addition to being a working plan, regulators will be well-served to include as broad a group of stakeholders as possible when developing the IRP.

An approved IRP will affect the fortunes of many and will signal the direction that the regulator wishes the utility to take with its supply-side and demand-side resources… [R]egulators will be well-served to include as broad a group of stakeholders as possible when developing the IRP.

Transparency. Regulators must ensure that, to the greatest extent possible, all parties participating in the IRP process have timely access to utility data. Certain data may be competitively sensitive and there is often pressure on the regulator to restrict unduly the access to such data. One possible solution to this challenge is to use an "independent evaluator" who works for the commission, is trusted by all parties and has access to all the data, including proprietary data. The independent evaluator can verify the modeling of the utility and assist the regulator in making an informed decision. The cost of an independent evaluator will be small in comparison to the benefits (or avoided mistakes) that the evaluator will enable. An independent evaluator will also add

Figure 20

PORTFOLIO ANALYSIS ON ONE PAGE
How Energy Efficiency Can Substitute for Generation Resources



credibility to the regulators' decision. In any event, the integrity of the IRP process will depend on regulators' ability to craft processes that are trusted to produce unbiased results.

Competitive bidding. A successful IRP will lower risk in the design of a utility resource portfolio. After the planning process, utilities begin acquiring approved resources. Some states have found it beneficial to require the utility to undertake competitive bidding for all resources acquired by a utility pursuant to an IRP. If the utility will build the resource itself, the regulator may require the utility to join the bidding process or commit to a cap on the construction cost of the asset.[72]

Role of Energy Efficiency. A robust IRP process will fully consider the appropriate levels of energy efficiency, including demand response and load management, that a utility should undertake. Properly viewed and planned for, energy efficiency can be considered as equivalent to a generation resource. Regulators in some states list projected energy efficiency savings on the "loads and resources table" of the utility, adjacent to base load and peaking power plants. In Colorado, energy efficiency is accorded a "reserve margin" in the integrated resource plan, as is done with generation resources.[73]

Since its inception in 1980, the Northwest Power and Conservation Council, which develops and maintains a regional power plan for the Pacific Northwest, has stressed the role of energy efficiency in meeting customers' energy needs. **Figure 20** shows the Council's analysis, demonstrating the elements of a diversified energy portfolio and the role that energy efficiency (or "conservation") can play in substituting for generation resources at various levels of cost.[74]

Appendix 2 contains additional discussion of some of the modeling tools available to regulators.

3. EMPLOYING TRANSPARENT RATEMAKING PRACTICES

Economist Alfred Kahn famously observed that "all regulation is incentive regulation," meaning that any type of economic regulation provides a firm with incentives to make certain choices. Indeed, utility rate regulation's greatest effect may not be its ability to limit prices for consumers in the short run, but rather the incentives it creates for utilities in the longer run.

72 For a discussion of the use of competitive bidding in resource acquisition, see Susan F. Tierney and Todd Schatzki, *Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices* (Boston, MA: Analysis Group, 2008), http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/Competitive_Procurement.pdf.

73 For Xcel Energy in Colorado, energy efficiency is listed on the "loads and resources" table as a resource. As such, it is logical that some fraction of the planned-for load reduction might not materialize. That portion is then assigned the standard resource reserve margin of approximately 15 percent. The planning reserve margin is added to the projected peak load, which must be covered by the combined supply-side and demand-side resources in the table.

74 Tom Eckman, "The 6th Power Plan… and You" (presentation at the Bonneville Power Administration Utility Energy Efficiency Summit, Portland, Ore., March 17, 2010), http://www.bpa.gov/Energy/N/utilities_sharing_ee/Energy_Smart_Awareness/pdf/0A_EESummit_Gen-Session_Public_Power.pdf.

There have been many debates through the years about the incentives that utility cost of service regulation provides. These range from the academic and formal (e.g., the aforementioned Averch-Johnson effect, which says that rate-regulated companies will have an inefficiently high ratio of capital to labor) to the common sense (e.g., price cap regulation can induce companies to reduce quality of service; the throughput incentive discourages electric utilities from pursuing energy efficiency, etc.).

While regulators may want to limit their role to being a substitute for the competition that is missing in certain parts of the electric industry, it is rarely possible to limit regulation's effects that way. The question is usually not how to eliminate stray incentives in decisions, but rather which ones to accept and address.

To contain risk and meet the daunting investment challenges facing the electric industry, regulators should take care to examine exactly what incentives are being conveyed by the details of the regulation they practice. We examine four components of cost of service regulation that affect a utility's perception of risk, and likely affect its preference for different resources.

Current Return on Construction Work in Progress. There is a long-standing debate about whether a utility commission should allow a utility to include in its rates investment in a plant during the years of its construction. Construction Work in Progress, or "CWIP," is universally favored by utility companies and by some regulators, but almost universally opposed by advocates for small and large consumers and by other regulators. CWIP is against the law in some states, mandated by law in others.

The main argument against CWIP is that it requires consumers to pay for a plant often years before it is "used and useful," so that there isn't a careful match between the customers who pay for a plant and those who benefit from it. Proponents of CWIP point out that permitting a current return on CWIP lessens the need for the utility to issue debt and equity, arguably saving customers money, and that CWIP eases in the rate increase, compared to the case where customers feel the full costs of an expensive plant when the plant enters service. Opponents counter by noting that customers typically have a higher discount rate than the utilities' return on rate base, so that delaying a rate hike is preferred by consumers, even if the utility borrows more money to finance the plant until it enters service.

Setting aside the near-religious debate about the equity of permitting CWIP in rate base, there is another relevant consideration. Because CWIP can help utilities secure financing and phase in rate increases, CWIP is often misunderstood as a tool for reducing risk. This is not true.

CWIP, Risk Shifting and Progress Energy's Levy Nuclear Plant

In late 2006, Progress Energy announced plans to build a new nuclear facility in Levy County, Florida, a few months after the state legislature approved construction work in progress (CWIP) customer financing. The site is about 90 miles north of Tampa, near the Gulf of Mexico. In 2009, Progress customers began paying for the Levy plant, which was expected to begin service in 2016 and be built at a cost of $4-6 billion. By the end of 2011, Progress customers had paid $545 million toward Levy's construction expenses.

The Levy plant is now projected to cost up to $22 billion, roughly four times initial estimates, and that number could keep climbing. (In March 2012, Progress Energy's market value as a company was almost $16 billion; the combined market value of Duke Energy and Progress Energy, which are seeking to merge and are pursuing construction of five nuclear facilities between them, is about $44 billion.) Levy's expected in-service date has pushed beyond 2021 and possibly as late as 2027—eighteen years after Progress customers began paying for the plant. Progress has estimated that by 2020, Levy-related expenses could add roughly $50 to the average residential customer's monthly bill.

The Levy plant's development appeared to take a step forward in December 2011 when the Nuclear Regulatory Commission approved its reactor design. But in February 2012, the Florida Public Service Commission approved a settlement agreement allowing Progress to suspend or cancel Levy's construction and recover $350 million from customers through 2017.

It is unclear whether Levy will ever be built. If the plant is canceled, Progress customers will have paid more than $1 billion in rates for no electricity generation, and Florida state law prohibits their recouping any portion of that investment. Such an outcome could help to deteriorate the political and regulatory climate in which Progress operates, which could ultimately impact credit ratings and shareholder value.

CWIP does nothing to actually reduce the risks associated with the projects it helps to finance. Construction cost overruns can and do still occur (see the text box about Progress Energy's Levy County nuclear power plant); O&M costs for the plant can still be unexpectedly high; anticipated customer load may not actually materialize; and so forth. What CWIP does is to reallocate part of the risk from utilities (and would-be bondholders) to customers. CWIP therefore provides utilities with both the incentive and the means to undertake a riskier investment than if CWIP were unavailable.

Regulators must be mindful of the implications of allowing a current return on CWIP, and should consider limiting its use to narrow circumstances and carefully drawn conditions of oversight. Regulators should also pay close attention to how thoroughly utility management has evaluated the risks associated with the projects for which it requests CWIP. Regardless of CWIP's other merits or faults, an important and too-often unacknowledged downside is that it can obscure a project's risk by shifting, not reducing, that risk.

Use of Rider Recovery Mechanisms. Another regulatory issue is the use by utilities of rate "riders" to collect investment or expenses. This practice speeds up cash flow for utilities, providing repayment of capital or expense outlays more rapidly than would traditional cost of service regulation. This allows utilities to begin collecting expenses and recovering capital without needing to capitalize carrying costs or file a rate case. Once again, regulators must consider whether these mechanisms could encourage a utility to undertake a project with higher risk, for the simple reason that cost recovery is assured even before the outlay is made.

Allowing a current return on CWIP, combined with revenue riders, is favored by many debt and equity analysts, who perceive these practices as generally beneficial to investors. And indeed, these mechanisms allow bondholders and stock owners to feel more assured of a return of their investment. And they might marginally reduce the utility's cost of debt and equity. But these mechanisms (which, again, transfer risk rather than actually reducing it) could create a "moral hazard" for utilities to undertake more risky investments. A utility might, for example, proceed with a costly construction project, enabled by CWIP financing, instead of pursuing market purchases of power or energy efficiency projects that would reduce or at least delay the need for the project. If negative financial consequences of such risky decisions extended beyond customers and reached investors, the resulting losses would be partially attributable the same risk-shifting mechanisms that analysts and investors originally perceived as beneficial.

Construction Cost Caps. Some regulatory agencies approve a utility's proposed infrastructure investments only after a cap is established for the amount of investment or expense that will be allowed in rates. Assuming the regulator sticks to the deal, this action will apportion the risk between consumers and investors. We wouldn't conclude that this actually reduces risk except in the sense that working under a cap might ensure that utility management stays focused on the project, avoiding lapses into mismanagement that would raise costs and likely strain relationships with regulators and stakeholders.

Rewarding Energy Efficiency. Another relevant regulatory practice concerns the treatment of demand-side resources like energy efficiency and demand response. It is well understood that the "throughput incentive" can work to keep a utility from giving proper consideration to energy efficiency; to the extent that a utility collects more than marginal costs in its unit price for electricity, selling more electricity builds the bottom line while selling less electricity hurts profitability. There are several adjustments regulation can make, from decoupling revenues from sales, to giving utilities expedited cost recovery and incentives for energy efficiency performance. Decoupling, which guarantees that a utility will recover its authorized fixed costs regardless of its sales volumes, is generally viewed by efficiency experts and advocates as a superior approach because it neutralizes the "throughput incentive" and enables utilities to dramatically scale up energy efficiency investment without threatening profitability. Ratings agencies view decoupling mechanisms as credit positive because they provide assurance of cost recovery, and Moody's recently observed "a marked reduction in a company's gross profit volatility in the years after implementing a decoupling type mechanism."[75] Whatever the chosen approach, the takeaway here is that without regulatory intervention, energy efficiency will not likely be accorded its correct role as a low cost and low risk strategy.[76]

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4. USING FINANCIAL AND PHYSICAL HEDGES

Another method for limiting risk is the use of financial and physical hedges. These provide the utility an opportunity to lock in a price, thereby avoiding the risk of higher market prices later. Of course, this means the utility also foregoes the opportunity for a lower market price, while paying some premium to obtain this certainty.

Financial hedges are instruments such as puts, calls, and other options that a utility can purchase to limit its price exposure (e.g., for commodity fuels) to a certain profile. If the price of a commodity goes up, the call option pays off; if the price goes down, the put option pays off. Putting such a collar around risk is, of course, not free: the price of an option includes transaction costs plus a premium reflecting the instrument's value to the purchaser. Collectively these costs can be viewed as a type of insurance payment.

Another example of a financial hedge is a "temperature" hedge that can limit a utility's exposure to the natural gas price spikes that can accompany extreme weather conditions. A utility may contract with a counter-party so that, for an agreed price, the counter-party agrees to pay a utility if the number of heating-degree-days exceeds a certain level during a certain winter period. If the event never happens,

75 Moody's Investors Service, *Decoupling and 21st Century Rate Making* (New York: Moody's Investors Service, 2011), 4.

76 For a discussion of regulatory approaches to align utility incentives with energy efficiency investment, see Val Jensen, *Aligning Utility Incentives with Investment in Energy Efficiency*, ICF International (Washington, DC: National Action Plan for Energy Efficiency, 2007), http://www.epa.gov/cleanenergy/documents/suca/incentives.pdf.

Long-term Contracts for Natural Gas

In recent decades, utilities have mostly used financial instruments to hedge against volatile natural gas prices, and natural gas supply used for power generation has not been sold under long-term contracts. An exception is a recent long-term contract for natural gas purchased by Xcel Energy in Colorado. The gas will be used to fuel new combined cycle units that will replace coal generating units. The contract between Xcel Energy and Anadarko contained a formula for pricing that was independent of the market price of natural gas and runs for 10 years.

The long-term natural gas contract between Xcel Energy and Anadarko was made possible by a change in Colorado's regulatory law. For years, utilities and gas suppliers had expressed concern that a long-term contract, even if approved initially as prudent, might be subject to a reopened regulatory review if the price paid for gas under the contract was, at some future date, above the prevailing market price. Colorado regulators supported legislation making it clear in law that a finding of prudence at the outset of a contract would not be subject to future review if the contract price was later "out of the money." An exception to this protection would be misrepresentation by the contracting parties.

the utility forfeits the payment made for the hedge. If the event does happen, the utility might still need to purchase natural gas at an inflated price; even so, the hedge would pay off because it has reduced the company's total outlay. Simply stated, financial hedges can be used by a utility to preserve an expected value.

An illustration of a physical hedge would be when a utility purchases natural gas at a certain price and places it into storage. The cost of that commodity is now immune to future fluctuations in the market price. Of course, there is a cost to the utility for the storage, and the utility forgoes the possible advantage of a future lower price. But in this case the payment (storage cost) is justifiable because of the protection it affords against the risk of a price increase.

Long-term contracts can also serve to reduce risk. These instruments have been used for many years to hedge against price increases or supply interruptions for coal. Similarly, long-term contracts are used by utilities to lock in prices paid to independent power producers. Many power purchase agreements (PPAs) between distribution utilities and third party generators lock in the price of capacity, possibly with a mutually-agreed price escalator. But due to possible fuel price fluctuations (especially with natural gas), the fuel-based portion of the energy charge is not fixed in these contracts. So PPAs can shield utilities from some of the risks of owning the plants, but they do not hedge the most volatile portion of natural gas generation: the cost of fuel.

Regulated utilities and their regulators must come to an understanding about whether and how utilities will utilize these options to manage risk, since using them can foreclose an opportunity to enjoy lower prices.

5. HOLDING UTILITIES ACCOUNTABLE

From the market's perspective, one of the most important characteristics of a public utilities commission is its consistency. Consumers don't like surprises, and neither do investors. Financial analysts who rate regulatory climates across the states typically rank stability as one of the highest virtues for regulators. Indeed, this quality is often viewed to be as important as the absolute level of return on equity approved by a commission.

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Effective regulation—regulation that is consistent, predictable, forward-thinking and "risk-aware"—requires that regulators hold utilities accountable for their actions. Earlier, we stressed the value of regulators being actively involved in the utility resource planning process. But this tool works well only if regulators follow through—by requiring utilities to comply with the resource plan, to amend the resource plan if circumstances change, to live within an investment cap, to adhere to a construction schedule, and so forth. If the utility doesn't satisfy performance standards, regulatory action will be necessary.

This level of activity requires a significant commitment of resources by the regulatory agency. Utility resource acquisition plans typically span ten years or more, and a regulator must establish an oversight administrative structure that spans the terms of sitting commissioners in addition to clear expectations for the regulated companies and well-defined responsibilities for the regulatory staff.

6. OPERATING IN ACTIVE, "LEGISLATIVE" MODE

As every commissioner knows, public utility regulation requires regulators to exercise a combination of judicial and legislative duties. In "judicial mode," a regulator takes in evidence in formal settings, applies rules of evidence, and decides questions like the interpretation of a contract or the level of damages in a complaint case. In contrast, a regulator operating in "legislative mode" seeks to gather all information relevant to the inquiry at hand and to find solutions to future challenges. Judicial mode looks to the past, legislative mode

to the future. In his 1990 essay, former Ohio utilities regulator Ashley Brown put it this way:

> *Gathering and processing information is vastly different in judicial and legislative models. Legislating, when properly conducted, seeks the broadest data base possible. Information and opinions are received and/or sought, heard, and carefully analyzed. The process occurs at both formal (e.g., hearings) and informal (e.g., private conversation) levels. The goal is to provide the decision maker with as much information from as many perspectives as possible so that an informed decision can be made. Outside entities can enhance, but never be in a position to limit or preclude, the flow of information. The decision maker is free to be both a passive recipient of information and an active solicitor thereof. The latter is of particular importance in light of the fact that many of the interests affected by a decision are not likely to be present in the decision making forum.*[77]

Being a risk-aware regulator requires operating in legislative mode in regulatory proceedings, and especially in policy-making proceedings such as rulemakings. But the courts have also found that ratemaking is a proper legislative function of the states.[78] And since this state legislative authority is typically delegated by legislatures to state regulators, this means that, to some extent, regulators may exercise "legislative" initiative even in rate-setting cases.

In a recent set of essays, Scott Hempling, the former executive director of the National Regulatory Research Institute, contrasts regulatory and judicial functions and calls for active regulation to serve the public interest:

> *Courts and commissions do have commonalities. Both make decisions that bind parties. Both base decisions on evidentiary records created through adversarial truth-testing. Both exercise powers bounded by legislative line-drawing. But courts do not seek problems to solve; they wait for parties' complaints. In contrast, a commission's public interest mandate means it literally looks for trouble. Courts are confined to violations of law, but commissions are compelled to advance the public welfare.*[79]

Utility resource planning is one of the best examples of the need for a regulator to operate in legislative mode. When examining utilities' plans for acquiring new resources, regulators must seek to become as educated as possible. Up to a point, the more choices the better. The regulator should insist that the utility present and analyze multiple alternatives. These alternatives should be characterized fully, fairly, and without bias. The planning process should seek to discover as much as possible about future conditions, and the door should be opened to interveners of all stripes. Knowing all of the options—not simply the ones that the utility brings forward—is essential to making informed, risk-aware regulatory decisions.

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7. REFORM AND RE-INVENT RATEMAKING PRACTICES

It is increasingly clear that a set of forces is reshaping the electric utility business model. In addition to the substantial investment challenge discussed in this report, utilities are facing challenges from stricter environmental standards, growth in distributed generation, opportunities and challenges with the creation of a smarter grid, new load from electric vehicles, pressure to ramp up energy efficiency efforts—just to mention a few. As electric utilities change, regulators must be open to new ways of doing things, too.

77 Ashley Brown, "The Over-judicialization of Regulatory Decision Making," *Natural Resources and Environment* Vol. 5, No. 2 (Fall 1990), 15-16.

78 See, e.g., U.S. Supreme Court, *Munn vs. Illinois*, 94 U.S. 113 (1876), http://supreme.justia.com/cases/federal/us/94/113/case.html.

79 Scott Hempling, *Preside or Lead? The Attributes and Actions of Effective Regulators* (Silver Spring, MD: National Regulatory Research Institute, 2011), 22.

Today's energy industry faces disruptions similar to those experienced by the telecommunications industry over the past two decades. To deal with the digital revolution in telecommunications and the liberalization of those markets, regulators modernized their tools to include various types of incentive regulation, pricing flexibility, lessened regulation in some markets and a renewed emphasis on quality of service and customer education.

One area where electric utility regulators might profitably question existing practices is rate design. Costing and pricing decisions, especially for residential and small business customers, have remained virtually unchanged for decades. The experience in other industries (e.g., telecommunications, entertainment, music) shows that innovations in pricing are possible and acceptable to consumers. Existing pricing structures should be reviewed for the incentives they provide for customers and the outcomes they create for utilities.

The risk-aware regulator must be willing to think "way outside the box" when it comes to the techniques and strategies of effective regulation. Earlier we observed that effective regulators must be informed, active, consistent, curious and often courageous. These qualities will be essential for a regulator to constructively question status quo regulatory practice in the 21st century.

THE BENEFITS OF "RISK-AWARE REGULATION"

We have stressed throughout this report that effective utility regulators must undertake a lot of hard work and evolve beyond traditional practice to succeed in a world of changing energy services, evolving utility companies and consumer and environmental needs. What can regulators and utilities reasonably expect from all this effort? What's the payback if regulators actively practice "risk-aware regulation"?

- **FIRST**, there will be benefits to consumers. A risk-aware regulator is much less likely to enter major regulatory decisions that turn out wrong and hurt consumers. The most costly regulatory lapses over the decades have been approval of large investments that cost too much, failed to operate properly, or weren't needed once they were built. It's too late for any regulator to fix the problem once the resulting cost jolts consumers.
- **SECOND**, there will be benefits to regulated utilities. Risk aware regulation will create a more stable, predictable business environment for utilities and eliminate most regulatory surprises. It will be easier for these companies to plan for the longer-term. If regulators use a well-designed planning process, examining all options and assessing risks, utilities and their stakeholders will have greater reliance on the long-term effect of a decision.
- **THIRD**, investors will gain as well. Steering utilities away from costly mistakes, holding the companies responsible for their commitments and, most importantly, maintaining a consistent approach across the decades will be "credit-positive," reducing threats to cost-recovery. Ratings agencies will take notice, lowering the cost of debt, benefitting all stakeholders.
- **FOURTH**, governmental regulation itself will benefit. Active, risk-aware regulators will involve a wide range of stakeholders in the regulatory process, building support for the regulators' decision. Consistent, transparent, active regulation will help other state officials—governors and legislators—develop a clearer vision of the options for the state's energy economy.
- **FINALLY**, our entire society will benefit as utilities and their regulators develop a cleaner, smarter, more resilient electricity system. Regulation that faithfully considers all risks, including the future environmental risks of various utility investments, will help society spend its limited resources most productively. In other words, risk-aware regulation can improve the economic outcome of these large investments.

With two trillion dollars on the line, both the stakes and the potential benefits are high. If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Practicing risk-aware regulation will enable them to avoid expensive mistakes and identify the most important utility investments for realizing the promise of an advanced 21st century electricity system.

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APPENDIX 1:

UNDERSTANDING UTILITY FINANCE

MOST INVESTOR-OWNED UTILITIES (IOUS) IN THE UNITED STATES ARE IN A CONSTRUCTION CYCLE OWING TO THE NEED TO COMPLY WITH MORE STRINGENT AND EVOLVING ENVIRONMENTAL POLICIES AND TO IMPROVE AGING INFRASTRUCTURE. NEW INFRASTRUCTURE PROJECTS INCLUDE SMART GRID, NEW GENERATION AND TRANSMISSION. THE IOUS, THEREFORE, WILL BE LOOKING TO THE CAPITAL MARKETS TO HELP FINANCE THEIR RATHER LARGE CAPITAL EXPENDITURE PROGRAMS.

DEBT FINANCING

While the IOUs will be issuing some additional equity, a higher percentage of the new investment will be financed with debt. In general, utilities tend to be more leveraged than comparably-rated companies in other sectors (see the Rating Agencies section below). The electric utility sector's debt is primarily publicly issued bonds, including both first mortgage bonds (FMB) and senior unsecured bonds. While the utilities also issue preferred stock and hybrid debt securities, these instruments tend to represent a small portion of a company's capital structure. Non-recourse project finance is rare for utilities, but it is commonly used by unregulated affiliates.

Most regulated IOUs in the U.S. are owned by holding companies whose assets are primarily their equity interests in their respective subsidiaries. These operating company subsidiaries are typically wholly owned by the parent, so that all publicly-held stock is issued by the parent. Because most of these holding companies are quite large, the market for a holding company's stock is usually highly liquid.

In contrast to equity, bonds are issued by both the utility holding company and individual operating subsidiaries. Typically, holding and operating company bonds are non-recourse to affiliates. This means that each bond issuer within the corporate family will have its own credit profile that affects the price of the respective bonds. To illustrate this point, compare two American Electric Power subsidiaries, Ohio Power and Indiana Michigan. The companies have different regulators, generation mix, customer bases and, consequently, different senior unsecured Moody's bond ratings of Baa1 and Baa2, respectively. For this reason, each bond issuance of the corporate family trades somewhat independently.

Utility bonds trade in secondary markets and are traded over-the-counter rather than in exchanges like equities. For bond issuance of less than $300 million, the secondary market is illiquid and not very robust. Smaller utilities are frequently forced into the private placement market with their small issuances and accordingly pay higher interest rates compared to similarly-rated larger companies. Even if these smaller issues are placed in the public market, there is a premium for the expected lack of liquidity.

Secured debt in the form of FMBs is common in the electric utility sector. Such bonds are usually secured by an undivided lien on almost all of the assets of an operating utility. Bond documentation (called an "indenture") prohibits the issuance of such bonds in an amount that exceeds a specified percentage (usually in the range of 60 percent) of the asset value of the collateral. The maturities of these bonds are frequently as long as 30 years, and in rare occasions longer). While the lien on assets may limit a company's financing flexibility, the interest rate paid to investors is lower than for unsecured debt. The proceeds from FMBs are usually used to finance or refinance long-lived assets.

Senior unsecured bonds can be issued at any maturity, but terms of five and ten years are most common. These instruments are "junior" to FMBs, so that, in an event of default, these debt holders would be repaid only after the secured debt. But these bonds are "senior" to hybrids and preferred stock. In a bankruptcy, senior unsecured bonds are usually deemed equal in standing with trade obligations, such as unpaid fuel and material bills.

Utilities typically have "negative trade cycles," meaning that cash receipts tend to lag outlays. IOUs' short-term payables such as fuel purchases, salaries and employee benefits are due in a matter of days after the obligation is incurred. In contrast, the utility's largest short-term assets are usually customer receivables which are not due for 45—60 days after the gas or electricity is delivered. Therefore, utilities have short term cash needs referred to as "working capital" needs. To finance these short term needs utilities have bank credit lines and sometimes trade receivable facilities.

For larger utility corporate families, these bank lines can amount to billions of dollars. For example, American Electric Power has two large bank lines of $1.5 and $1.7 billion that mature in 2015 and 2016, respectively. AEP's lines and most of those of other utilities are revolving in nature. While termination dates typically range from one to five years for these lines, the utility usually pays down borrowings in a few months and accesses the line again when needed.

Interest on bank lines of credit is paid only when the lines are used, with a much lower fee paid on the unused portion of the lines. For financially weak utility companies, banks often require security for bank lines . But because utility operating companies are rarely rated below BBB-/Baa3, bank lines are, for the most part, unsecured.

Some larger utilities have receivable facilities in addition to revolving bank lines. The lender in a receivables facility usually purchases the customer receivables. There is an assumed interest expense in these transactions which is usually lower than the rate charged by banks for unsecured revolving lines.

Although preferred stock is a form of equity, it is usually purchased by a bond investor who is comfortable with the credit quality of the issuer and willing to take a junior position in order to get a higher return on its investment. There are also hybrid securities. Although they are technically debt instruments, they are so deeply subordinate and with such long repayment periods that investors and the rating agencies view these instruments much like equities. Frequently, hybrids allow the issuer to defer interest payments for a number of years. Some hybrids can be converted to equity at either the issuer's or investor's option.

S&P is the most rigorous of the rating agencies in treating the fixed component of power purchase agreements (PPA) as debt-like in nature. Also, some Wall Street analysts look at PPAs as liabilities with debt-like attributes. That being said, those analysts who do not consider PPAs as debt-like still incorporate in their analysis the credit implications of these frequently large obligations.

EQUITY FINANCING

In order to maintain debt ratings and the goodwill of fixed income investors, utility managers must finance some portion of their projects with equity. Managements are usually reluctant to go to market with large new stock issuances. Equity investors often see new stock as being dilutive to their interests, resulting in a decrease in the market price of the stock. But if a utility has a large capital expenditure program it may have no choice but to issue equity in order maintain its credit profile.

For more modest capital expenditure programs, a company may be able to rely on incremental increases to equity to maintain a desired debt to equity ratio. While the dividend payout ratios are high in this sector, they are rarely 100 percent, so that for most companies, equity increases, at least modestly, through retained earnings. Many companies issue equity in small incremental amounts every year to fulfill commitments to employee pension or rewards programs. Also, many utility holding companies offer their existing equity holders the opportunity to reinvest dividends in stock. For larger companies these programs can add $300 - $500 million annually in additional equity. Since these programs are incremental, stock prices are usually unaffected.

OTHER FINANCING

Project finance (PF) can also be used to fund capital expenditures. These instruments are usually asset-specific and non-recourse to the utility, so that the pricing is higher than traditional investment-grade utility debt. Project finance is usually used by financially weaker non-regulated power developers.

Some companies are looking to PF as a means of financing large projects so that risk to the utility is reduced. However, the potential of cost overruns, the long construction/development periods and use of new technology will make it hard to find PF financing for projects like new nuclear plants. This also applies to carbon capture/sequestration projects, as the technology is not seasoned enough for most PF investors. This means that, utilities may need to finance new nuclear and carbon capture/ sequestration projects using their existing balance sheets.

In order to reduce risk, a utility can pursue projects in partnership with other companies. Currently proposed large gas transport and electric transmission projects are being pursued by utility consortiums. Individual participants in gas transport projects in particular have used Master Limited Partnerships (MLPs) as a way to finance their interests. MLPs are owned by general and limited partners. Usually the general partner is the pipeline utility or a utility holding company. Limited partner units are sold to passive investors and are frequently traded on the same stock exchanges that list the parent company's common stock. One big difference between the MLP and an operating company is that earnings are not subject to corporate income tax. The unit holders pay personal income tax on the profits.

Companies have used both capital and operating lease structures to finance discrete projects, including power plants. The primary difference between an operating and capital lease is that the capital lease is reflected on the company's balance sheet. The commitment of the utility to the holder of the operating lease is deemed weaker. Most fixed income analysts, as well as the rating agencies, do not view these instruments as being materially different and treat operating leases for power plants as debt.

TYPICAL UTILITY INVESTORS

The largest buyers of utility equities and fixed income securities are large institutional investors such as insurance companies, mutual funds and pension plans. As of September 2011, 65 percent of utility equities were owned by institutions. While insurance companies and pension plans own utility equities, both trail mutual funds in the level of utility stock holdings. For example, the five largest holders of Exelon stock are mutual fund complexes.

Most retail investors own utility stock and bonds indirectly through mutual funds and 401k plans. But many individual investors also own utility equities directly, including utility employees. Small investors tend not to buy utility bonds because the secondary market in these instruments is rather illiquid, especially if the transaction size is small.

Common stock mutual funds with more conservative investment criteria are most interested in utility equities. While the market price of these stocks can vary, there is a very low probability of a catastrophic loss. Also, utility stocks usually have high levels of current income through dividend distributions. Another attractive attribute of these equities is that they are highly liquid. Essentially all utilities in the U.S. are owned by utility holding companies that issue common stock. Due to extensive consolidation in the sector over the past 20 years, these holding companies are large and have significant market capitalization. For these reasons, utility stocks are highly liquid and can be traded with limited transaction costs.

Utility fixed-income investments are far less liquid than equities. Thus, the typical bond investor holds onto the instruments much longer than the typical equity investor. Bonds are issued both by the utility holding company and individual operating subsidiaries. Because bonds are less liquid in the secondary market, investors in these instruments, such as pension plans and insurance companies, tend to have longer time horizons. Four of the top five investors in Exelon Corp bonds due 2035 are pension plans and insurance companies. Mutual bond funds tend to buy shorter-dated bonds.

The buyers of first mortgage bonds (FMBs) are frequently buy-and-hold investors. As FMBs are over-collateralized, bondholders are comfortable that they will be less affected by unforeseen negative credit events. It is not unusual for a large insurance company to buy a large piece of an FMB deal at issuance and hold it to maturity. Retail investors in utility bonds also tend to be buy-and-hold investors, as it is hard for them to divest their positions which are typically small compared to the large institutions. The relative illiquidity of utility bonds means that transaction costs can be high and greatly reduce the net proceeds from a sale.

Utility employees frequently own the stock of the companies for which they work. Employees with defined benefit pensions, however, are not large holders of utility stocks because pension plans hold little if any of an employer's stock owing to ERISA rules and prudent asset management practices. Mid-level non-unionized employees frequently have 401ks that are typically invested in mutual funds or similar instruments. However, it is not unusual for company matching of the employees' 401k contributions to be in company stock. Finally, senior management's incentive compensation is frequently paid in the company's common equity, in part to ensure that management's interests are aligned with those of the shareholders.

RATING AGENCIES

Most utilities have ratings from three rating agencies: Moody's Investors Services, Standard & Poor's Ratings Services, and Fitch Ratings. Having three ratings is unlike other sectors, which frequently use two ratings—Moody's or Standard & Poor's. Most utility bonds are held by large institutional investors who demand that issuers have at least Moody's and Standard & Poor's ratings.

Failing to have two ratings would cause investors to demand a very high premium on their investments, far more than the cost to utilities of paying the agencies to rate them. Having a third rating from Fitch usually slightly lowers the interest rate further. While investors have become less comfortable with the rating agencies' evaluations of structured finance transactions, this dissatisfaction has not carried over greatly into the corporate bond market, and especially not the utility bond market.

The agencies usually assign a rating for each company referred to as an *issuer rating*. They also rate specific debt issues, which may be higher or lower than the issuer rating. Typically a secured bond will have a higher rating than its issuer; preferred stock is assigned a lower rating than the issuer. Ratings range from AAA to D.[80] The "AAA" rating is reserved for entities that have virtually no probability of default. A "D" rating indicates that the company is in default.

The three agencies each take into account both the probability of default, as well as the prospects of recovery for the bond investor if there is a default. Utilities traditionally are considered to have high recovery prospects because they are asset-heavy companies. In other words, if liquidation were necessary, bond holders would be protected because their loans are backed by hard assets that could be sold to cover the debt. Further, the probability of default is low because utility rates are regulated, and regulators have frequently increased rates when utilities have encountered financial

80 Standard & Poor's and Fitch use the same ratings nomenclature. It was designed by Fitch and sold to S&P. For entities rated between AA and CCC the agencies break down each rating category further with a plus sign or a minus sign. For example, bonds in the BBB category can be rated BBB+, BBB and BBB-. Moody's ratings nomenclature is slightly different. The corresponding ratings in BBB category for Moody's are Baa1, Baa2 and Baa3. The agencies will also provide each rating with an outlook that is stable, positive or negative.

problems owing to events outside of companies' control. However, there are a few notable instances where commissions could not or would not raise rates to avoid defaults including the bankruptcies of Public Service of New Hampshire and Pacific Gas and Electric.

It is unusual for a utility operating company to have a non-investment grade rating (Non-IG, also referred to as high yield, speculative grade, or junk). Typically Non-IG ratings are the result of companies incurring sizable expenses for which regulators are not willing or able to give timely or adequate rate relief. Dropping below IG can be problematic for utilities because interest rates increase markedly. Large institutional investors have limited ability to purchase such bonds under the investment criteria set by their boards. Another problem with having an Non-IG rating is that the cost of hedging rises owing to increased collateral requirements as counterparties demand greater security from the weakened credit.

In developing their ratings, the agencies consider both quantitative and more subjective factors. The quantitative analysis tends to look at cash flow "coverage" of total debt and of annual fixed income payment obligations, as well as overall debt levels. In contrast, the typical equity analyst focuses on earnings. The rating agencies are less interested in the allowed returns granted by regulators than they are in the size of any rate decrease or increase and its effect on cash flow.

That said, the rating agency may look at allowed returns to evaluate the "quality" of regulation in a given state. All things being equal, they may give a higher rating to a company in a state with "constructive" regulation than to a company in a state with a less favorable regulatory climate. Constructive regulation to most rating agencies is where regulatory process is transparent and consistent across issuers in the state. Also, the agencies favor regulatory constructs that use forward-looking test years and timely recovery of prudently-incurred expenses. The agencies consider tracking mechanisms for fuel and purchased power costs as credit supportive because they help smooth out cash fluctuations. The agencies believe that while trackers result in periodic changes in rates for the customer, these mechanisms are preferable for consumers than the dramatic change in rates caused by fuel factors being lumped in with other expenses in a rate case.

Analysts also will look to see how utility managers interact with regulators. The agencies deem it a credit positive if management endeavors to develop construct relationships with regulators. The agencies may become concerned about the credit quality of a company if the state regulatory process becomes overly politicized. This may occur if a commission renders decisions with more of an eye toward making good press than applying appropriate utility regulatory standards. Politicized regulatory environments can also occur when a commission is professional and fair, but outside political forces, such as governors, attorneys general or legislators challenge a prudently decided case.

The rating agencies themselves can at times act as *de facto* regulators. Because utilities are more highly levered than most any other sector, interest expenses can be a significant part of a company's cost structure. Ratings affect interest rates. The agencies will look negatively at anything that increases event risk. The larger an undertaking, the greater the fallout if an unforeseen event undermines the project. A utility embarking on the development of a large facility like a large generation or transmission project, especially if is not preapproved by the regulators, might result in a heightened focus on the company by the agencies. The rating action could merely be change in outlook from stable to negative, which could in turn have a negative impact on the market price of outstanding bonds, interest rates on new issuances and even on equity prices. Many utility stock investors are conservative and pay more attention to rating agency comments and actions than investors with holdings in more speculative industries.

APPENDIX 2:

TOOLS IN THE IRP PROCESS

REGULATORS HAVE SEVERAL TOOLS AT THEIR DISPOSAL IN THE IRP PROCESS. ONE OF THE MOST IMPORTANT IS THE UTILITY REDISPATCH MODEL. THIS IS A COMPLEX COMPUTER PROGRAM THAT SIMULATES THE OPERATION OF A UTILITY'S SYSTEM UNDER INPUT ASSUMPTIONS PROVIDED BY THE USER. THE TERM "REDISPATCH" REFERS TO THE FACT THAT THE SOFTWARE MIMICS THE OPERATION OF AN ACTUAL UTILITY SYSTEM, "DISPATCHING" THE HYPOTHETICAL GENERATION RESOURCES AGAINST A MODEL LOAD SHAPE, OFTEN HOUR-BY-HOUR FOR MOST COMMONLY USED MODELS.

Three examples of these models are Prosym, licensed by Henwood Energy Services; Strategist, licensed by Ventyx; and GE MAPS, licensed by General Electric.

A model typically creates a 20- or 40-year future utility scenario, based on load projections provided by the user. The utility's energy and peak demand is projected for each hour of the time period, using known relationships about loads during different hours, days of the week and seasons of the year. The model then "dispatches" the most economic combination of existing or hypothetical new resources to meet the load in every hour of that time period.

The operating characteristics of each generating resource is specified as to its availability, fuel efficiency, fuel cost, maintenance schedule, and, in some models, its emissions profile. The resources available to the model will be a mixture of existing plants, taking note of their future retirement dates, plus any hypothetical new resources required by load growth. The model incorporates estimates of regional power purchases and their price, transmission paths and their constraints, fuel contracts, the retirement of existing facilities, etc.

In this way, the user of the model can test various combinations (scenarios) of proposed new generating plants, including base load plants, intermediate and peaking plants, intermittent renewable resources, etc. The model will calculate the utility's revenue requirement, fuel costs, and purchased power expenses in each scenario. The model might be used to estimate the cost of operating the system with a specific hypothetical portfolio, predict the level of emissions for a portfolio, measure the value of energy efficiency programs, test the relative value of different resources, measure the reliability of the system, etc.

The reader might analogize this modeling to "fantasy" baseball, where hypothetical teams play hypothetical games, yielding win-loss records, batting averages and pennant races.

As powerful as these modeling tools are, they are *production* models, first and foremost. As such, they are not particularly good at dealing with assumptions about energy efficiency and demand response. In using such models, the regulator must insist that the utility gives appropriate treatment to demand-side resources. It may be possible to re-work models to do this, or it may be necessary to conduct extra sensitivity analyses at varying levels of energy efficiency and demand response.

IRP SENSITIVITY ANALYSES

A redispatch modeling tool allows a utility and the regulator to test the resilience of portfolios against different possible futures. For example, a regulator might want to know how five different generation portfolios behave under situations of high natural gas prices, or tougher environmental regulations. By varying the input assumptions while monitoring the relevant output (e.g., net present value of future revenue requirements) the regulator can assess the risk that contending portfolios pose to future rates if, for example, fuel prices vary from their predicted levels.

To illustrate this idea, consider the following material from a case in Colorado. **Figure Appendix - 1** is a page excerpted from Xcel Energy's 2009 analysis in support of a resource plan filed before the Colorado Public Utilities Commission. The page shows the results of sensitivity analyses for the price of natural gas (high and low) and the cost of carbon emissions (high and low) for twelve different portfolios being considered by the Colorado PUC.

In all, the Colorado PUC studied 48 different generation portfolios in this IRP case. The portfolios differed based on how much natural gas generation was added, how much wind and solar generation was added, the schedule for closing some existing coal-fired power plants, the level of energy efficiency assumed, etc. (The actual generation units in each portfolio are not identified in this public document.

Figure Appendix - 1

EXAMPLE OF IRP SENSITIVITY ANALYSES

Base Scenario Assumption: High Efficiency, Medium Solar

Representative of Preferred Plan

Primary Scenario
High DSM (130% Goal)
Medium Section 123 (200 MW)
Base Load

Portfolios 1-12

Key Portfolio Characteristic		1	2	3	4	5	6	7	8	9	10	11	12
Portfolio Number		1	2	3	4	5	6	7	8	9	10	11	12
Portfolio Rank within Scenario (PVRR)		1	2	3	4	5	6	7	8	9	10	11	12
Wind (MW)													
Solar (MW)													
Intermittent (MW)													
Solar Storage (MW)													
Gas (MW)													
Other (MW)	1												
Total (MW)		1,872	1,902	1,907	1,932	1,977	1,966	1,911	1,860	1,936	2,039	1,982	2,078
Owned %													
Owned MW													
Total 123 (MW)													
CO2 (M ton)	2	26.8	26.7	26.8	26.7	26.6	26.8	26.8	26.8	26.9	26.6	26.5	26.6
% New Build	3												
Externalities	4	2	2	2	2	2	1	2	2	1	2	3	2
PVRR & Rank													
PVRR rank		1	2	3	4	5	6	7	8	9	10	11	12
PVRR ($M)	5	49,344	49,361	49,365	49,387	49,402	49,478	49,490	49,526	49,645	49,675	49,675	49,822
PVRR Delta ($M)	6	-	17	21	43	58	134	146	182	301	331	331	478
PV Rate ($/MWh)	7	71.87	71.90	71.90	71.94	71.96	72.07	72.09	72.14	72.31	72.36	72.36	72.57
CO2 Delta (M ton)	8	-	(0.30)	(0.02)	(0.50)	(0.68)	1.79	(0.09)	(0.04)	0.80	(0.57)	(0.81)	(0.65)
$10/ton CO2 Sensitivity													
PVRR rank	9	1	3	2	4	5	6	7	8	9	10	11	12
PVRR ($M)	5	43,695	43,722	43,716	43,758	43,786	43,805	43,845	43,877	43,981	44,054	44,080	44,203
Change ($M)	10	(5,649)	(5,638)	(5,649)	(5,628)	(5,616)	(5,673)	(5,645)	(5,649)	(5,664)	(5,622)	(5,596)	(5,619)
PVRR Delta ($M)	11	-	27	21	63	91	110	150	182	286	358	384	508
$40/ton CO2 Sensitivity													
PVRR rank	9	3	2	5	4	1	7	6	8	11	10	9	12
PVRR ($M)	5	60,066	60,061	60,087	60,067	60,056	60,247	60,204	60,250	60,392	60,311	60,285	60,451
Change ($M)	10	10,723	10,701	10,723	10,680	10,654	10,769	10,714	10,724	10,747	10,636	10,610	10,629
PVRR Delta ($M)	11	10	5	31	11	-	191	148	194	336	255	229	395
Low Gas Price Sensitivity													
PVRR rank	9	1	3	2	4	5	6	7	8	10	9	11	12
PVRR ($M)	5	47,935	47,959	47,956	47,992	48,016	48,055	48,075	48,118	48,234	48,230	48,318	48,371
Change ($M)	10	(1,409)	(1,402)	(1,409)	(1,395)	(1,386)	(1,423)	(1,415)	(1,407)	(1,411)	(1,445)	(1,357)	(1,451)
PVRR Delta ($M)	11	-	24	22	57	81	121	140	184	299	295	383	436
High Gas Price Sensitivity													
PVRR rank	9	5	4	6	3	1	7	8	10	9	11	2	12
PVRR ($M)	5	57,122	57,091	57,144	57,070	57,025	57,295	57,326	58,234	57,421	58,268	57,059	58,464
Change ($M)	10	7,778	7,730	7,780	7,684	7,623	7,817	7,836	8,708	7,776	8,593	7,384	8,642
PVRR Delta ($M)	11	97	66	120	46	-	270	302	1,209	396	1,244	34	1,439

Otherwise, it would have created problems for the competitive bidding process used to award contracts to supply the power to the utility.)

Each column in the table represents a different portfolio, numbered 1 to 12. Portfolio 2 is the Xcel's preferred plan. The rows show the modeling results for each portfolio. For example, the Present Value of Revenue Requirements (PVRR) is calculated for each portfolio and is shown the line indicated by the first PVRR arrow, along with the ranking of that portfolio. The lower half of the chart shows the cost of each portfolio under different assumptions about the cost of carbon emissions (higher or lower than base case predictions) and for natural gas prices (higher or lower than base case predictions).

CAVEATS

Models are a terrific way to keep track of all the moving parts in the operation of a utility portfolio. But it is one thing to know that each resource has certain operating characteristics; it is quite another to see these qualities interact with each other in dynamic fashion. And while utility modeling tools, such as production cost models can be helpful, care must be taken with their use.

Obviously the models are helpful only to the extent that the inputs are reasonable and cover the range of possibilities the regulator wishes to examine. Load forecast must be developed with care; assumptions about future fuel costs are really educated guesses, and should be bracketed with ranges of sensitivity.

Because there are so many possible combinations, variations and sensitivities, the regulator in an IRP case must make a decision early in the process about the scope of the portfolios to be examined. The utility should be directed to analyze and present all scenarios requested by the regulator, together with any portfolios preferred by the utility.

Finally, the model's best use is to inform judgment, not substitute for it. The amount of data produced by models can be overwhelming and may give a false sense of accuracy. The risk-aware regulator will always understand the fundamental uncertainties that accompany projections of customer demand, future fuel costs and future environmental requirements.

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Lansing Smith Electric Generating Plant

Lynn Haven, Florida

Sierra Club Evaluation of Compliance with 1-hour SO_2 NAAQS

June 26, 2012

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1. Introduction

The Sierra Club prepared an air modeling impact analysis to help USEPA, state and local air agencies identify facilities that are likely causing violations of the 1-hour sulfur dioxide (SO_2) national ambient air quality standard (NAAQS). This document describes the results and procedures for an evaluation conducted for the Lansing Smith Electric Generating Plant located in Lynn Haven, Florida.

The dispersion modeling analysis predicted ambient air concentrations for comparison with the one hour SO_2 NAAQS. The modeling was performed using the most recent version of AERMOD, AERMET, and AERMINUTE, with data provided to the Sierra Club by regulatory air agencies and through other publicly-available sources as documented below. The analysis was conducted in adherence to all available USEPA guidance for evaluating source impacts on attainment of the 1-hour SO_2 NAAQS via aerial dispersion modeling, including the AERMOD Implementation Guide; USEPA's Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard, August 23, 2010; modeling guidance promulgated by USEPA in Appendix W to 40 CFR Part 51; and, USEPA’s March 2011 Modeling Guidance for SO_2 NAAQS Designations, available at http://www.epa.gov/ttn/scram/SO2%20Designations%20Guidance%202011.pdf.

2. Compliance with the 1-hour SO_2 NAAQS

2.1 1-hour SO_2 NAAQS

The 1-hour SO_2 NAAQS takes the form of a three-year average of the 99^{th}-percentile of the annual distribution of daily maximum 1-hour concentrations, which cannot exceed 75 ppb.[1] Compliance with this standard was verified using USEPA’s AERMOD air dispersion model, which produces air concentrations in units of $\mu g/m^3$. The 1-hour SO_2 NAAQS of 75 ppb equals 196.2 $\mu g/m^3$, and this is the value used for determining whether modeled impacts exceed the NAAQS.[2] The 99^{th}-percentile of the annual distribution of daily maximum 1-hour concentrations corresponds to the fourth-highest value at each receptor for a given year.

2.2 Modeling Results

Modeling results for Lansing Smith Electric Generating Plant are summarized in Table 1. It was determined that based on either currently permitted emissions or measured actual emissions, the Lansing Smith Electric Generating Plant is estimated to create downwind SO_2 concentrations which

[1] USEPA, Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard, August 23, 2010.
[2] The ppb to $\mu g/m^3$ conversion is found in the source code to AERMOD v. 11103, subroutine Modules. The conversion calculation is $75/0.3823 = 196.2\ \mu g/m^3$.

exceed the 1-hour NAAQS.

The currently permitted emissions and measured actual emissions used for the modeling analysis are summarized in Table 2. Based on the modeling results, emission reductions from current rates considered necessary to achieve compliance with the 1-hour NAAQS were calculated and presented in Table 3.

Predicted exceedences of the 1-hour NAAQS for SO_2 extend throughout the region to a maximum distance of 50 kilometers.

Figure 1 provided at the end of this report shows the extent of NAAQS violations throughout the entire 50 kilometer modeling domain.

Figure 2 provides a close-up local view of NAAQS violations.

Air quality impacts in Florida are based on a background concentration of 5.2 $\mu g/m^3$. This is the 2008-10 design value for Miami - Dade County, Florida - the lowest measured background concentration in the state. This is the most recently available design value.

2.3 Conservative Modeling Assumptions

A dispersion modeling analysis requires the selection of numerous parameters which affect the predicted concentrations. For the enclosed analysis, several parameters were selected which under-predict facility impacts.

Assumptions used in this modeling analysis which likely under-estimate concentrations include the following:

- Allowable emissions are based on a limitation with an averaging period which is greater than the 1-hour average used for the SO_2 air quality standard. Emissions and impacts during any 1-hour period may be higher than assumed for the modeling analysis.
- No consideration of facility operation at less than 100% load. Stack parameters such as exit flow rate and temperature are typically lower at less than full load, reducing pollutant dispersion and increasing predicted air quality impacts.
- No consideration of building or structure downwash. These downwash effects typically increase predicted concentrations near the facility.
- No consideration of off-site sources. These other sources of SO_2 will increase the predicted impacts.

Table 1 - SO_2 Modeling Results for Lansing Smith Electric Generating Plant

Emission Rates	Averaging Period	99th Percentile 1-hour Daily Maximum (µg/m³)				Complies with NAAQS?
		Impact	Background	Total	NAAQS	
Allowable	1-hour	853.2	5.2	858.4	196.2	No
Maximum	1-hour	341.3	5.2	346.5	196.2	No

Table 2 - Modeled SO_2 Emissions from Lansing Smith Electric Generating Plant [3,4]

Stack ID	Unit ID	Allowable Emissions Monthly Average (lbs/hr)	Maximum Emissions 1-hour Average (lbs/hr)
S01	Unit 1	8,751.6	-
	Unit 2	10,107.9	-
Stack Total	All Units	18,859.5	7,543.5

Table 3 - Required Emission Reductions for Compliance with 1-hour SO_2 NAAQS

Acceptable Impact (NAAQS - Background) 99th Percentile 1-hour Daily Max (µg/m³)	Required Total Facility Reduction Based on Allowable Emissions (%)	Required Total Facility Emission Rate (lbs/hr)	Required Total Facility Emission Rate (lbs/mmbtu)
191.0	77.6%	4,221.9	1.0

[3] Florida Department of Environmental Protection, Division of Air Resource Management, Title V Air Operation Permit No. 0050014-018-AV, January 1, 2010. The emissions limit for Units 1 and 2 is 4.5 lbs/mmbtu.
[4] Maximum emissions are measured hourly rates reported for 2011 in USEPA, Clean Air Markets - Data and Maps.

3. Modeling Methodology

3.1 Air Dispersion Model

The modeling analysis used USEPA's AERMOD program, version 12060. AERMOD, as available from the Support Center for Regulatory Atmospheric Modeling (SCRAM) website, was used in conjunction with a third-party modeling software program, *AERMOD View*, sold by Lakes Environmental Software.

3.2 Control Options

The AERMOD model was run with the following control options:

- 1-hour average air concentrations
- Regulatory defaults
- Flagpole receptors

To reflect a representative inhalation level, a flagpole height of 1.5 meters was used for all modeled receptors. This parameter was added to the receptor file when running AERMAP, as described in Section 4.4.

An evaluation was conducted to determine if the modeled facility was located in a rural or urban setting using USEPA's methodology outlined in Section 7.2.3 of the Guideline on Air Quality Models.[5] For urban sources, the URBANOPT option is used in conjunction with the urban population from an appropriate nearby city and a default surface roughness of 1.0 meter. Methods described in Section 4.1 to determine whether rural or urban dispersion coefficients were used.

3.3 Output Options

The AERMOD analysis was based on five years of recent meteorological data. The modeling analyses used one run with five years of sequential meteorological data from 2005-2009. Consistent with USEPA's Modeling Guidance for SO_2 NAAQS Designations, AERMOD provided a table of fourth-high 1-hour SO_2 impacts concentrations consistent with the form of the 1-hour SO_2 NAAQS.[6]

Please refer to Table 1 for the modeling results.

---

[5] USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, November 9, 2005.
[6] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, pp. 24-26.

4. Model Inputs

4.1 Geographical Inputs

The "ground floor" of all air dispersion modeling analyses is establishing a coordinate system for identifying the geographical location of emission sources and receptors. These geographical locations are used to determine local characteristics (such as land use and elevation), and also to ascertain source to receptor distances and relationships.

The Universal Transverse Mercator (UTM) NAD83 coordinate system was used for identifying the easting (x) and northing (y) coordinates of the modeled sources and receptors. Stack locations were obtained from facility permits and prior modeling files provided by the state regulatory agency. The stack locations were then verified using aerial photographs.

The facility was evaluated to determine if it should be modeled using the rural or urban dispersion coefficient option in AERMOD. A GIS was used to determine whether rural or urban dispersion coefficients apply to a site. Land use within a three-kilometer radius circle surrounding the facility was considered. USEPA guidance states that urban dispersion coefficients are used if more than 50% of the area within 3 kilometers has urban land uses. Otherwise, rural dispersion coefficients are appropriate.[7]

USEPA's AERSURACE model Version 08009 was used to develop the meteorological data for the modeling analysis. This model was also used to evaluate surrounding land use within 3 kilometers. Based on the output from the AERSURFACE, approximately 26% of surrounding land use around the airport was of urban land use types including: 21 – Low Intensity Residential, 22 – High Intensity Residential, and 23 - Commercial/Industrial/Transportation.

This is less than the 50% value considered appropriate for the use of urban dispersion coefficients. Based on the AERSURFACE analysis, it was concluded that the rural option would be used for the modeling summarized in this report. Please refer to Section 4.5.3 for a discussion of the AERSURFACE analysis.

4.2 Emission Rates and Source Parameters

The modeling analyses only considered SO_2 emissions from the facility. Off-site sources were not considered. Concentrations were predicted for two scenarios shown in Table 2:

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[7] USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, November 9, 2005, Section 7.2.3.

1) approved or allowable emissions based on permits issued by the regulatory agency, and

2) measured actual hourly SO_2 emissions obtained from USEPA's Clean Air Markets Database. To assure realistic emission rates were used, emissions from all units at the facility were combined and the hour with the maximum total facility emissions was used to determine the actual emissions.

Stack parameters and emissions used for the modeling analysis are summarized in Table 4.

Table 4 – Facility Stack Parameters and Emissions [8]

Stack	S12
Description	Units 1 and 2
X Coord. [m]	625046
Y Coord. [m]	3349251
Base Elevation [m]	3.72
Release Height [m]	60.66
Gas Exit Temperature [°K]	399.817
Gas Exit Velocity [m/s]	31.302
Inside Diameter [m]	5.486
Allowable Emission Rate [g/s]	2376
Maximum Emission Rate [g/s]	950.5

The above stack parameters and emissions were obtained from regulatory agency documents and databases identified in Section 2.3. The analysis was conducted based on 100% operating load using maximum exhaust flow rates and emission rates. Operation at less than full capacity loads was not considered. This assumption tends to under-predict impacts since stack parameters such as exit flow rate and temperature are typically lower at less than full load, reducing pollutant dispersion and increasing predicted air quality impacts. Stack location, height and diameter were verified using aerial photographs, and flue gas flow rate and temperature were verified using combustion calculations.

4.3 Building Dimensions and GEP

No building dimensions or prior downwash evaluations were available. Therefore this modeling analysis did not address the effects of downwash which may increase predicted concentrations.

[8] Florida Department of Environmental Protection, Division of Air Resource Management, Title V Air Operation Permit No. 0050014-018-AV, January 1, 2010.

4.4 Receptors

For Lansing Smith Electric Generating Plant, three receptor grids were employed:

1. A 100-meter Cartesian receptor grid centered on Lansing Smith Electric Generating Plant and extending out 5 kilometers.
2. A 500-meter Cartesian receptor grid centered on Lansing Smith Electric Generating Plant and extending out 10 kilometers.
3. A 1,000-meter Cartesian receptor grid centered on Lansing Smith Electric Generating Plant and extending out 50 kilometers. 50 kilometers is the maximum distance accepted by USEPA for the use of the AERMOD dispersion model.[9]

A flagpole height of 1.5 meters was used for all these receptors.

Elevations from stacks and receptors were obtained from National Elevation Dataset (NED) GeoTiff data. GeoTiff is a binary file that includes data descriptors and geo-referencing information necessary for extracting terrain elevations. These elevations were extracted from 1 arc-second (30 meter) resolution NED files. The USEPA software program AERMAP v. 11103 is used for these tasks.

4.5 Meteorological Data

To improve the accuracy of the modeling analysis, recent meteorological data for the 2005 to 2009 period were prepared using the USEPA's program AERMET which creates the model-ready surface and profile data files required by AERMOD. Required data inputs to AERMET included surface meteorological measurements, twice-daily soundings of upper air measurements, and the micrometeorological parameters surface roughness, albedo, and Bowen ratio. One-minute ASOS data were available so USEPA methods were used to reduce calm and missing hours.[10] The USEPA software program AERMINUTE v. 11325 is used for these tasks.

This section discusses how the meteorological data was prepared for use in the 1-hour SO_2 NAAQS modeling analyses. The USEPA software program AERMET v. 11059 is used for these tasks.

4.5.1 Surface Meteorology

Surface meteorology was obtained for Panama City-Bay County International Airport located near

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[9] USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, Section A.1.(1), November 9, 2005.

[10] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, p. 19.

the Lansing Smith Electric Generating Plant. Integrated Surface Hourly (ISH) data for the 2005 to 2009 period were obtained from the National Climatic Data Center (NCDC). The ISH surface data was processed through AERMET Stage 1, which performs data extraction and quality control checks. Typically the most recent years of data (i.e. 2007 to 2011) would be used for the modeling analysis. However, the Panama City station stopped collecting surface measurements in June of 2010 so the 2005 to 2009 period is most recent complete five year data.

4.5.2 Upper Air Data

Upper-air data are collected by a "weather balloon" that is released twice per day at selected locations. As the balloon is released, it rises through the atmosphere, and radios the data back to the surface. The measuring and transmitting device is known as either a radiosonde, or rawindsonde. Data collected and radioed back include: air pressure, height, temperature, dew point, wind speed, and wind direction. The upper air data were processed through AERMET Stage 1, which performs data extraction and quality control checks.

For Lansing Smith Electric Generating Plant, the concurrent 2005 through 2009 upper air data from twice-daily radiosonde measurements obtained at the most representative location were used. This location was the Tallahasee, Florida measurement station. These data are in Forecast Systems Laboratory (FSL) format and were downloaded in ASCII text format from NOAA's FSL website.[11] All reporting levels were downloaded and processed with AERMET.

4.5.3 AERSURFACE

AERSURFACE is a non-guideline program that extracts surface roughness, albedo, and daytime Bowen ratio for an area surrounding a given location. AERSURFACE uses land use and land cover (LULC) data in the U.S. Geological Survey's 1992 National Land Cover Dataset to extract the necessary micrometeorological data. LULC data was used for processing meteorological data sets used as input to AERMOD.

AERSURFACE v. 08009 was used to develop surface roughness, albedo, and daytime Bowen ratio values in a region surrounding the meteorological data collection site. AERSURFACE was used to develop surface roughness in a one kilometer radius surrounding the data collection site. Bowen ratio and albedo was developed for a 10 kilometer by 10 kilometer area centered on the meteorological data collection site. These micrometeorological data were processed for seasonal periods using 30-degree sectors. Seasonal moisture conditions were considered average with no months with continuous snow cover.

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[11] Available at: http://esrl.noaa.gov/raobs/

4.5.4 Data Review

Missing meteorological data were not filled as the data file met USEPA's 90% data completeness requirement.[12] The AERMOD output file shows there were 3.4% missing data.

The representativeness of airport meteorological data is a potential concern in modeling industrial source sites.[13] The surface characteristics of the airport data collection site and the modeled source location were compared. Since the Panama City-Bay County International Airport is located close to Lansing Smith Electric Generating Plant (i.e. 4 miles), this meteorological data set was considered appropriate for this modeling analysis.

5. Background SO_2 Concentrations

Background concentrations were determined consistent with USEPA's Modeling Guidance for SO_2 NAAQS Designations.[14] To preserve the form of the 1-hour SO_2 standard, based on the 99th percentile of the annual distribution of daily maximum 1-hour concentrations averaged across the number of years modeled, the <u>background</u> fourth-highest daily maximum 1-hour SO_2 concentration was added to the <u>modeled</u> fourth-highest daily maximum 1-hour SO_2 concentration.[15]

Background concentrations were based on the 2008-10 design value measured by the ambient monitors located in Florida.[16]

6. Reporting

All files from the programs used for this modeling analysis are available to regulatory agencies. These include analyses prepared with AERSURFACE, AERMET, AERMAP, and AERMOD.

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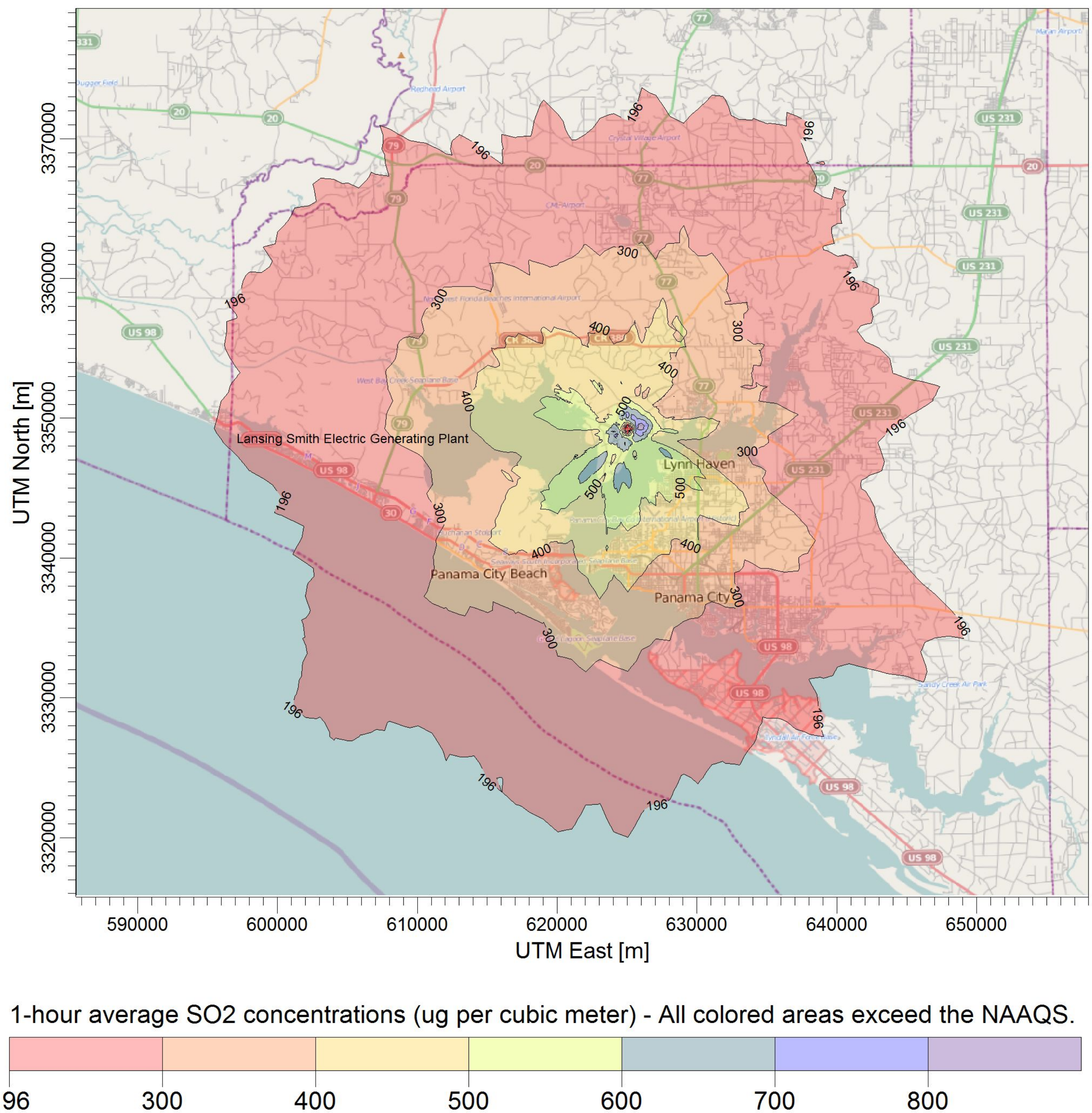
[12] USEPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, Section 5.3.2, pp. 5-4 to 5-5.
[13] USEPA, AERMOD Implementation Guide, March 19, 2009, pp. 3-4.
[14] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, pp. 20-23.
[15] USEPA, Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard, August 23, 2010, p. 3.
[16] http://www.epa.gov/airtrends/values.html

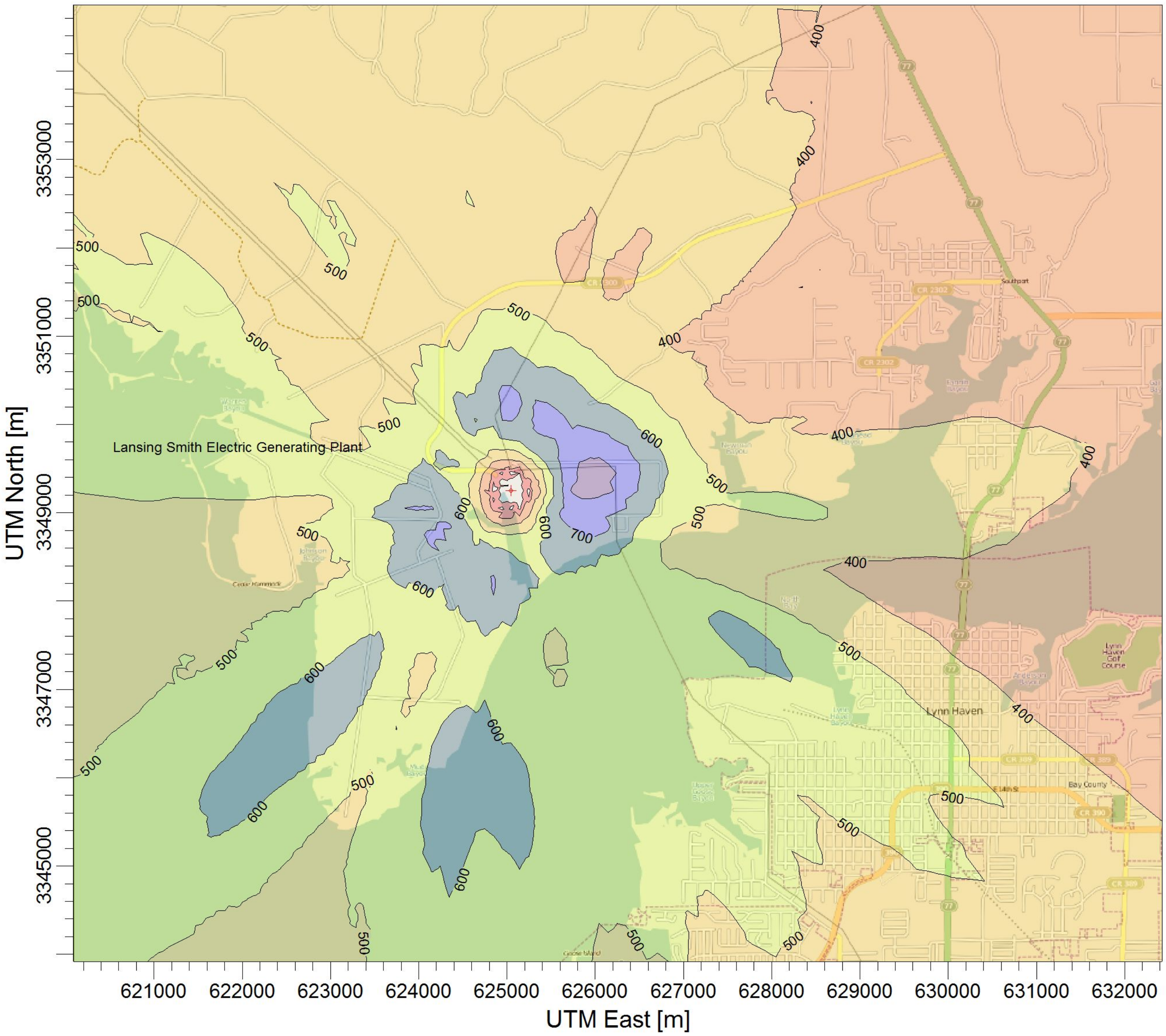
Lansing Smith Electric Generating Plant - Lynn Haven, Florida
Evaluation of Compliance with the 1-hour NAAQS for SO2



All concentrations include a background of 5.2 ug/m3. This figure is based on allowable emissions.	Total Sources **2**	**Conducted on behalf of the Sierra Club**	
	Total Receptors **22084**	**by Wingra Engineering, S.C.**	
	Output Type **Concentration**	SCALE: 1:455,316 0 — 10 km	
	Maximum **858.44834 ug/m^3**	DATE: **6/25/2012**	

AERMOD View - Lakes Environmental Software

Lansing Smith Electric Generating Plant - Lynn Haven, Florida
Evaluation of Compliance with the 1-hour NAAQS for SO2



1-hour average SO2 concentrations (ug per cubic meter) - All colored areas exceed the NAAQS.

196 300 400 500 600 700 800

All concentrations include a background of 5.2 ug/m3. This figure is based on allowable emissions.	Total Sources **2**	**Conducted on behalf of the Sierra Club**	
	Total Receptors **22084**	**by Wingra Engineering, S.C.**	
	Output Type **Concentration**	SCALE: 1:77,587 0 3 km	
	Maximum **858.44834 ug/m^3**	DATE: **6/25/2012**	

AERMOD View - Lakes Environmental Software

Progress Energy

Jamie Hunter
Lead Environmental Specialist
Environmental Services & Strategy

June 15, 2012

RECEIVED
JUN 18 2012
DIVISION OF AIR
RESOURCE MANAGEMENT

Mr. Jon Holtom, P.E.
Title V Administrator
Florida Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road, MS#5505
Tallahassee, Florida 32399-2400

RE: Progress Energy Florida – Crystal River Power Plant Units 1&2
BART Implementation Plan for Crystal River Power Plant Units 1&2
Facility ID No. 0170004 Project No.: 0170004-036-AC

Dear Mr. Holtom:

Enclosed please find the BART implementation plan for Crystal River Units 1&2.

If you have any questions regarding these documents please contact Jamie Hunter at (727) 820-5764 or at John.Hunter@PGNmail.com.

Sincerely,

Jamie Hunter
Lead Environmental Specialist
Environmental Services & Strategy

RECEIVED
JUN 18 2012
DIVISION OF AIR
RESOURCE MANAGEMENT

REPORT

BART IMPLEMENTATION PLAN FOR CRYSTAL RIVER POWER PLANT UNITS 1 AND 2

Progress Energy Florida, Inc.

Prepared For: Progress Energy Florida, Inc.
Environmental Services Section
299 First Avenue North, PEB PEF-903
St. Petersburg, FL 33701

Submitted By: Golder Associates Inc.
5100 West Lemon Street
Suite 208
Tampa, FL 33609 USA

Distribution: 4 Copies – Florida Department of Environmental Protection
1 Copy – PEF
1 Copy – Golder Associates Inc.

June 2012

123-89547

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Table of Contents

1.0 BACKGROUND

The 1977 Clean Air Act Amendments established a national goal of "preventing future, and remedying existing, visibility impairment" in 156 national parks and wilderness areas referred to as "mandatory Class I Federal areas." In response to this congressional mandate, the U.S. Environmental Protection Agency (EPA) promulgated its Regional Haze Rule (RHR) on July 1, 1999, codified at 40 CFR 51.300, et seq. 64 Fed. Reg. 35714. The RHR set a long-term ultimate goal of returning visibility in the Class I areas to "natural conditions" by the year 2064. A key component of the RHR was a requirement for certain existing emission sources (i.e., those determined to cause or contribute to visibility impairment in the mandatory Class I areas) to install Best Available Retrofit Technology (BART). BART determinations are made according to EPA guidelines promulgated in July 2005 (70 Fed. Reg. 39104).

BART determinations consist of three basic components: (1) an identification of all BART-eligible sources; (2) an assessment of whether those BART-eligible sources are in fact subject to BART; and (3) a determination of any BART controls.

A source is BART-eligible if it has the potential to emit 250 tons or more of a visibility-impairing air pollutant, was placed into operation between August 7, 1962 and August 7, 1977, and is included within one of 26 specifically listed source categories. Units 1 and 2 at Progress Energy Florida's (PEF's) Crystal River Power Plant meet these criteria and thus are BART-eligible sources subject to this rule.

BART-eligible sources are subject to BART if they are reasonably anticipated to cause or contribute to any visibility impairment in any Class I area. Thus, a BART-eligible source may be exempt from BART if modeling demonstrates that the source's sulfur dioxide (SO_2), nitrogen oxide (NO_x) and particulate matter (PM) emissions do not contribute to visibility impairment in any Class I area.

A BART determination analysis for PM emissions from the BART-eligible emissions units (i.e., Unit Nos. 1 and 2) at the Crystal River Power Plant was previously submitted to the Florida Department of Environmental Protection (FDEP) in 2007. The visibility assessment only evaluated impacts from PM because Crystal River is subject to EPA's Clean Air Interstate Rule (CAIR) for SO_2 and NO_x, which EPA determined was "better-than-BART," alleviating the need to include SO_2 and NO_x in BART exemption modeling for PM. A BART permit was issued on February 25, 2009 (permit No. 0170004-017-AC), which imposed a revised allowable PM emission limit. Specifically, PM emissions from Unit Nos. 1 and 2 combined are not to exceed 0.04 lb/mmBtu on a weighted average basis of the total heat input during steady state operations and 0.12 lb/mmBtu on a weighted average basis of the total heat input (not to exceed 3 hours in any 24-hour period) during steady state operations. Compliance with these revised standards is to be demonstrated no later than December 31, 2013. Further, the permit assumes that Unit Nos. 1 and 2 will cease to be operated as coal-fired units by December 31, 2020. The permit requires Progress Energy Florida to notify the Department of any developments that would delay the shutdown (or repowering) of Unit Nos. 1 and 2 beyond this date.

In 2008, CAIR was remanded by the U. S. Circuit Court for the District of Columbia and, in response, on July 6, 2011, EPA issued CAIR's successor, the Cross-State Air Pollution Rule (CSAPR). On December 30, 2011, the court stayed CSAPR, however, leaving CAIR in effect pending judicial review of CSAPR. A decision on CSAPR is expected this Summer.

This circumstance results in some uncertainty for RHR purposes because while EPA issued a final determination that – like CAIR – CSAPR is better-than-BART, CSAPR applies differently in Florida; only regulating ozone-season NO_x and not annual NO_x or SO_2. As a result, if CSAPR is upheld as is, a BART analysis may be necessary for SO_2 and PM emissions. In light of this uncertainty, FDEP has requested a BART analysis for SO_2, NO_x and PM emissions from Crystal River Units 1 and 2.

Accordingly, this application is made in a cooperative effort to address RHR implementation issues resulting from recent regulatory developments related to EPA's CAIR and its successor, CSAPR. Depending on the court's decision on CSAPR, Progress Energy Florida may revisit, revise or withdraw this analysis and application.

2.0 CRYSTAL RIVER BART IMPLEMENTATION PLAN

BART-eligible sources determined to be subject to BART must conduct a five-factor analysis to determine required controls unless it is demonstrated that the source: (1) is subject to a better-than-BART alternative pursuant to 40 CFR 51.308(e)(2)-(3); or, (2) already has top-level controls in use.

The Crystal River Power Plant BART Implementation Plan includes the following components:

- Progress Energy Florida will complete a BART five-factor analysis for Crystal River Unit Nos. 1 and 2 relative to visibility impairment at the Class I areas within 300 km of the plant, including:
  - Saint Marks National Wilderness Area (NWA) - 174 km
  - Chassahowitzka NWA - 21 km
  - Wolf Island NWA - 293 km
  - Okefenokee NWA- 178 km

  The analysis will include cost, remaining useful life and visibility improvement factors focusing on maximum level control-technology for SO_2, NOx and PM.
- Progress Energy Florida will make a final decision by January 1, 2015 or within 2 years of EPA's final approval of Florida's final Regional Haze SIP, whichever is later, on the Crystal River BART Implementation Plan which includes, at a minimum, either the installation of BART control equipment or commitment to a unit-specific retirement date in order to meet BART requirements or taking a permit limit sufficient to exempt out of BART. To implement this decision, Progress Energy Florida is applying for a Florida Air Construction Permit for Crystal River Units 1 and 2 to:
  - Install and operate a SO_2 Flue Gas Desulfurization (FGD) scrubber system before January 1, 2018 or within 5 years of EPA's final approval of Florida's final Regional Haze SIP, whichever is later. This system will be designed to meet either 95 percent removal efficiency of SO_2 from Crystal River Units 1 and 2 or an emission rate limit of 0.15 lb/mmBtu (presumptive BART) from Crystal River Units 1 and 2; or
  - Commit to retire the operations of Crystal River Units 1 and 2 by December 31, 2020 based upon a "remaining useful life" cost-effectiveness evaluation; or
  - Agree to a permit limit for SO_2 by January 1, 2018 or within 5 years of EPA's final approval of Florida's final Regional Haze SIP, whichever is later, at a level sufficient to exempt out of BART or meet other control options identified in the BART five-factor analysis.
- Progress Energy Florida will request that such conditions be included in a federally enforceable air construction permit and incorporated into the Crystal River Title V Permit as a specific operating condition.

ATTACHMENT A
APPLICATION FOR AIR PERMIT—LONG FORM
DEP FORM NO. 62-210.900(1)

Department of Environmental Protection

RECEIVED
JUN 18 2012
DIVISION OF AIR RESOURCE MANAGEMENT

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit:

- For any required purpose at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air operation permit;
- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment new source review, or maximum achievable control technology (MACT);
- To assume a restriction on the potential emissions of one or more pollutants to escape a requirement such as PSD review, nonattainment new source review, MACT, or Title V; or
- To establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

- An initial federally enforceable state air operation permit (FESOP); or
- An initial, revised, or renewal Title V air operation permit.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **FLORIDA POWER CORPORATION DBA PROGRESS ENERGY, INC.**	
2. Site Name: **CRYSTAL RIVER POWER PLANT**	
3. Facility Identification Number: **0170004**	
4. Facility Location... Street Address or Other Locator: **NORTH OF CRYSTAL RIVER, WEST OF U.S. 19** City: **CRYSTAL RIVER** County: **CITRUS** Zip Code: **34428**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **JAMIE HUNTER, LEAD ENVIRONMENTAL SPECIALIST**
2. Application Contact Mailing Address... Organization/Firm: **PROGRESS ENERGY FLORIDA** Street Address: **299 FIRST AVENUE, NORTH, PEF 903** City: **ST. PETERSBURG** State: **FL** Zip Code: **33701**
3. Application Contact Telephone Numbers... Telephone: **(727) 820-5764** ext. Fax: **(727) 820-5292**
4. Application Contact E-mail Address: **John.Hunter@PGNmail.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 06-18-2012	3. PSD Number (if applicable):
2. Project Number(s): 0170004-036-AC	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

This application for air permit is being submitted to obtain: (Check one)

Air Construction Permit

- ☒ Air construction permit.
- ☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).
- ☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

- ☐ Initial Title V air operation permit.
- ☐ Title V air operation permit revision.
- ☐ Title V air operation permit renewal.
- ☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.
- ☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

- ☐ Air construction permit and Title V permit revision, incorporating the proposed project.
- ☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

- ☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Florida Power Corporation, doing business as Progress Energy Florida, Inc. (PEF), has conducted a five-factor best available retrofit technology (BART) determination analysis for the Crystal River Power Plant. As part of this analysis, PEF has developed a BART Implementation Plan which includes the installation of BART control equipment or commitment to a unit specific retirement date in order to meet BART requirements or taking a permit limit sufficient to exempt out of BART. PEF is applying for an Air Construction Permit for Crystal River Units 1 and 2 in order to implement the options included in the BART Implementation Plan.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
001	Unit 1 Fossil Fuel Steam Generator (FFSG)	AC1F	NA
002	Unit 2 FFSG	AC1F	NA

Application Processing Fee

Check one: ☐ Attached - Amount:________________ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : **ROBBY ODOM, PLANT MANAGER**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **PROGRESS ENERGY FLORIDA** Street Address: **299 FIRST AVENUE, NORTH, CN77** City: **ST PETERSBURG** State: **FLORIDA** Zip Code: **33701**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(352) 501-5682** ext. Fax: **(352) 501-5787**
4.	Owner/Authorized Representative E-mail Address: **ROBBY.ODOM@PGNMAIL.COM**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.* Signature 6/14/12 Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial, revised, or renewal Title V air operation permit or concurrent processing of an air construction permit and revised or renewal Title V air operation permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):

- ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.
- ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
- ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.
- ☐ The designated representative at an Acid Rain source or CAIR source.

3. Application Responsible Official Mailing Address...
Organization/Firm:
Street Address:
City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...
Telephone: ext. Fax:

5. Application Responsible Official E-mail Address:

6. Application Responsible Official Certification:

I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

Signature   Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **Scott H. Osbourn**
   Registration Number: **57557**
2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates Inc.***
   Street Address: **5100 West Lemon St., Suite 208**
   City: **Tampa** State: **FL** Zip Code: **33609**
3. Professional Engineer Telephone Numbers...
   Telephone: **(813) 287-1717** ext. **53304** Fax: **(813) 287-1716**
4. Professional Engineer E-mail Address: **sosbourn@golder.com**
5. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

[illegible]
Signature

6/13/12
Date

(seal)

SCOTT OSBOURN
LICENSE
No. 57557
STATE OF FLORIDA
PROFESSIONAL ENGINEER

*** Board of Professional Engineers Certificate of Authorization # 00001670**

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone 17 East (km) 334.3 North (km) 3204.5		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) 28/57/34 Longitude (DD/MM/SS) 82/42/01	
3. Governmental Facility Code: 0	4. Facility Status Code: A	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: JAMIE HUNTER, LEAD ENVIRONMENTAL SPECIALIST
2. Facility Contact Mailing Address... Organization/Firm: PROGRESS ENERGY FLORIDA Street Address: 299 FIRST AVENUE, NORTH, PEF 903 City: ST PETERSBURG State: FLORIDA Zip Code: 33701
3. Facility Contact Telephone Numbers: Telephone: (727) 820-5764 ext. Fax:
4. Facility Contact E-mail Address: John.Hunter@PGNmail.com

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official E-mail Address:

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☒ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☒One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment:	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
$PM/PM_{10}/PM_{2.5}$	A	N
CO	A	N
VOC	A	N
SO_2	A	N
NO_x	A	N
SAM	A	N

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility-Wide Cap [Y or N]? (all units)	3. Emissions Unit ID's Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ______ ☒ Previously Submitted, Date: **May 20, 2009**
2.	Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ______ ☒ Previously Submitted, Date: **May 20, 2009**
3.	Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ______ ☒ Previously Submitted, Date: **May 20, 2009**

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☐ Attached, Document ID:__________ ☒ Not Applicable (existing permitted facility)
2. Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☒ Attached, Document ID: **CR-FI-C2**
3. Rule Applicability Analysis: ☐ Attached, Document ID: **NA**
4. List of Exempt Emissions Units: ☐ Attached, Document ID:__________ ☒ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification: ☐ Attached, Document ID:__________ ☒ Not Applicable
6. Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for FESOP Applications -- NA

1.	List of Exempt Emissions Units: ☐ Attached, Document ID:__________ ☐ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications - NA

1.	List of Insignificant Activities: (Required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☐ Not Applicable (revision application)
2.	Identification of Applicable Requirements: (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought) ☐ Attached, Document ID:__________ ☐ Not Applicable (revision application with no change in applicable requirements)
3.	Compliance Report and Plan: (Required for all initial/revision/renewal applications) ☐ Attached, Document ID:____ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4.	List of Equipment/Activities Regulated under Title VI: (If applicable, required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☐ Equipment/Activities Onsite but Not Required to be Individually Listed ☐ Not Applicable
5.	Verification of Risk Management Plan Submission to EPA: (If applicable, required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☐ Not Applicable
6.	Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:__________ ☐ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Facilities Subject to Acid Rain, CAIR, or Hg Budget Program

1. Acid Rain Program Forms:

   Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)):
   ☐ Attached, Document ID: ☒ Previously Submitted, Date: **May 20, 2009**
   ☐ Not Applicable (not an Acid Rain source)

   Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.):
   ☐ Attached, Document ID:__________ ☒ Previously Submitted, Date: **May 20, 2009**
   ☐ Not Applicable

   New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.):
   ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☒ Not Applicable

2. CAIR Part (DEP Form No. 62-210.900(1)(b)):
   ☐ Attached, Document ID: ☒ Previously Submitted, Date: **May 20, 2009**
   ☐ Not Applicable (not a CAIR source)

Additional Requirements Comment

Crystal River Power Plant

Crystal River, Florida

Sierra Club Evaluation of Compliance with 1-hour SO_2 NAAQS

June 25, 2012

Conducted by:

Steven Klafka, P.E., BCEE

Wingra Engineering, S.C.

Madison, Wisconsin

1. Introduction

The Sierra Club prepared an air modeling impact analysis to help USEPA, state and local air agencies identify facilities that are likely causing violations of the 1-hour sulfur dioxide (SO_2) national ambient air quality standard (NAAQS). This document describes the results and procedures for an evaluation conducted for the Crystal River Power Plant located in Crystal River, Florida.

The dispersion modeling analysis predicted ambient air concentrations for comparison with the one hour SO_2 NAAQS. The modeling was performed using the most recent version of AERMOD, AERMET, and AERMINUTE, with data provided to the Sierra Club by regulatory air agencies and through other publicly-available sources as documented below. The analysis was conducted in adherence to all available USEPA guidance for evaluating source impacts on attainment of the 1-hour SO_2 NAAQS via aerial dispersion modeling, including the AERMOD Implementation Guide; USEPA's Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard, August 23, 2010; modeling guidance promulgated by USEPA in Appendix W to 40 CFR Part 51; and, USEPA's March 2011 Modeling Guidance for SO_2 NAAQS Designations, available at http://www.epa.gov/ttn/scram/SO2%20Designations%20Guidance%202011.pdf.

2. Compliance with the 1-hour SO_2 NAAQS

2.1 1-hour SO_2 NAAQS

The 1-hour SO_2 NAAQS takes the form of a three-year average of the 99^{th}-percentile of the annual distribution of daily maximum 1-hour concentrations, which cannot exceed 75 ppb.[1] Compliance with this standard was verified using USEPA's AERMOD air dispersion model, which produces air concentrations in units of $\mu g/m^3$. The 1-hour SO_2 NAAQS of 75 ppb equals 196.2 $\mu g/m^3$, and this is the value used for determining whether modeled impacts exceed the NAAQS.[2] The 99^{th}-percentile of the annual distribution of daily maximum 1-hour concentrations corresponds to the fourth-highest value at each receptor for a given year.

2.2 Modeling Results

Modeling results for Crystal River Power Plant are summarized in Table 1. It was determined that based on either currently permitted emissions or measured actual emissions, the Crystal River Power Plant is estimated to create downwind SO_2 concentrations which exceed the 1-hour NAAQS.

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[1] USEPA, Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard, August 23, 2010.

[2] The ppb to $\mu g/m^3$ conversion is found in the source code to AERMOD v. 11103, subroutine Modules. The conversion calculation is 75/0.3823 = 196.2 $\mu g/m^3$.

The currently permitted emissions and measured actual emissions used for the modeling analysis are summarized in Table 2. Based on the modeling results, emission reductions from current rates considered necessary to achieve compliance with the 1-hour NAAQS were calculated and presented in Table 3.

Predicted exceedences of the 1-hour NAAQS for SO_2 extend throughout the region to a maximum distance of 40 kilometers.

Figure 1 provided at the end of this report shows the extent of NAAQS violations throughout the entire 50 kilometer modeling domain.

Figure 2 provides a close-up local view of NAAQS violations.

Air quality impacts in Florida are based on a background concentration of 5.2 $\mu g/m^3$. This is the 2008-10 design value for Miami - Dade County, Florida - the lowest measured background concentration in the state. This is the most recently available design value.

2.3 Conservative Modeling Assumptions

A dispersion modeling analysis requires the selection of numerous parameters which affect the predicted concentrations. For the enclosed analysis, several parameters were selected which under-predict facility impacts.

Assumptions used in this modeling analysis which likely under-estimate concentrations include the following:

- Allowable emissions are based on a limitation with an averaging period which is greater than the 1-hour average used for the SO_2 air quality standard. Emissions and impacts during any 1-hour period may be higher than assumed for the modeling analysis.
- No consideration of facility operation at less than 100% load. Stack parameters such as exit flow rate and temperature are typically lower at less than full load, reducing pollutant dispersion and increasing predicted air quality impacts.
- No consideration of building or structure downwash. These downwash effects typically increase predicted concentrations near the facility.
- No consideration of off-site sources. These other sources of SO_2 will increase the predicted impacts.

Table 1 - SO_2 Modeling Results for Crystal River Power Plant Modeling Analysis

Emission Rates	Averaging Period	99th Percentile 1-hour Daily Maximum (µg/m³)				Complies with NAAQS?
		Impact	Background	Total	NAAQS	
Allowable	1-hour	915.8	5.2	921.0	196.2	No
Maximum	1-hour	529.4	5.2	534.6	196.2	No

Table 2 - Modeled SO_2 Emissions from Crystal River Power Plant [3,4]

Stack ID	Unit ID	Allowable Emissions 24-hour Average (lbs/hr)	Maximum Emissions 1-hour Average (lbs/hr)
S01	Unit 1	7,875.0	4,319.0
S02	Unit 2	10,069.5	5,092.0
S45	Units 4 and 5	17,280.0	10,531.0
Stack Total	All Units	32,224.5	19,942.0

Table 3 - Required Emission Reductions for Compliance with 1-hour SO_2 NAAQS

Acceptable Impact (NAAQS - Background) 99th Percentile 1-hour Daily Max (µg/m³)	Required Total Facility Reduction Based on Allowable Emissions (%)	Required Total Facility Emission Rate (lbs/hr)	Required Total Facility Emission Rate (lbs/mmbtu)
191.0	79.1%	6,720.8	0.25

[3] Florida Department of Environmental Protection, Division of Air Resource Management, Title V Air Operation Permit No. 0170004-025-AV, April 11, 2011. All units have an emission limitation of 1.2 lbs/mmbtu.
[4] Maximum emissions are measured hourly rates reported for 2011 in USEPA, Clean Air Markets - Data and Maps.

3. Modeling Methodology

3.1 Air Dispersion Model

The modeling analysis used USEPA's AERMOD program, version 12060. AERMOD, as available from the Support Center for Regulatory Atmospheric Modeling (SCRAM) website, was used in conjunction with a third-party modeling software program, *AERMOD View*, sold by Lakes Environmental Software.

3.2 Control Options

The AERMOD model was run with the following control options:

- 1-hour average air concentrations
- Regulatory defaults
- Flagpole receptors

To reflect a representative inhalation level, a flagpole height of 1.5 meters was used for all modeled receptors. This parameter was added to the receptor file when running AERMAP, as described in Section 4.4.

An evaluation was conducted to determine if the modeled facility was located in a rural or urban setting using USEPA's methodology outlined in Section 7.2.3 of the Guideline on Air Quality Models.[5] For urban sources, the URBANOPT option is used in conjunction with the urban population from an appropriate nearby city and a default surface roughness of 1.0 meter. Methods described in Section 4.1 to determine whether rural or urban dispersion coefficients were used.

3.3 Output Options

The AERMOD analysis was based on five years of recent meteorological data. The modeling analyses used one run with five years of sequential meteorological data from 2007-2011. Consistent with USEPA's Modeling Guidance for SO_2 NAAQS Designations, AERMOD provided a table of fourth-high 1-hour SO_2 impacts concentrations consistent with the form of the 1-hour SO_2 NAAQS.[6]

Please refer to Table 1 for the modeling results.

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[5] USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, November 9, 2005.
[6] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, pp. 24-26.

4. Model Inputs

4.1 Geographical Inputs

The "ground floor" of all air dispersion modeling analyses is establishing a coordinate system for identifying the geographical location of emission sources and receptors. These geographical locations are used to determine local characteristics (such as land use and elevation), and also to ascertain source to receptor distances and relationships.

The Universal Transverse Mercator (UTM) NAD83 coordinate system was used for identifying the easting (x) and northing (y) coordinates of the modeled sources and receptors. Stack locations were obtained from facility permits and prior modeling files provided by the state regulatory agency. The stack locations were then verified using aerial photographs.

The facility was evaluated to determine if it should be modeled using the rural or urban dispersion coefficient option in AERMOD. A GIS was used to determine whether rural or urban dispersion coefficients apply to a site. Land use within a three-kilometer radius circle surrounding the facility was considered. USEPA guidance states that urban dispersion coefficients are used if more than 50% of the area within 3 kilometers has urban land uses. Otherwise, rural dispersion coefficients are appropriate.[7]

USEPA's AERSURACE model Version 08009 was used to develop the meteorological data for the modeling analysis. This model was also used to evaluate surrounding land use within 3 kilometers. Based on the output from the AERSURFACE, approximately 20.2% of surrounding land use around the airport was of urban land use types including: 21 – Low Intensity Residential, 22 – High Intensity Residential, and 23 - Commercial/Industrial/Transportation.

This is less than the 50% value considered appropriate for the use of urban dispersion coefficients. Based on the AERSURFACE analysis, it was concluded that the rural option would be used for the modeling summarized in this report. Please refer to Section 4.5.3 for a discussion of the AERSURFACE analysis.

[7] USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, November 9, 2005, Section 7.2.3.

4.2 Emission Rates and Source Parameters

The modeling analyses only considered SO_2 emissions from the facility. Off-site sources were not considered. Concentrations were predicted for two scenarios shown in Table 2:

1) approved or allowable emissions based on permits issued by the regulatory agency, and

2) measured actual hourly SO_2 emissions obtained from USEPA's Clean Air Markets Database. To assure realistic emission rates were used, emissions from all units at the facility were combined and the hour with the maximum total facility emissions was used to determine the actual emissions.

Stack parameters and emissions used for the modeling analysis are summarized in Table 4.

Table 4 – Facility Stack Parameters and Emissions [8]

Stack	S01	S02	S45
Description	Unit 1	Unit 2	Units 4 and 5
X Coord. [m]	334265.16	334329.64	334783.6
Y Coord. [m]	3204413.63	3204413.63	3205565.58
Base Elevation [m]	2.74	2.96	2.89
Release Height [m]	152.1	153.01	167.64
Gas Exit Temperature [°K]	417.039	422.039	327.594
Gas Exit Velocity [m/s]	40.473	48.796	15.333
Inside Diameter [m]	4.572	4.877	9.296
Allowable Emission Rate [g/s]	992.2	1,269.0	2,177.0
Maximum Emission Rate [g/s]	544.2	641.6	1,327.0

The above stack parameters and emissions were obtained from regulatory agency documents and databases identified in Section 2.3. The analysis was conducted based on 100% operating load using maximum exhaust flow rates and emission rates. Operation at less than full capacity loads was not considered. This assumption tends to under-predict impacts since stack parameters such as exit flow rate and temperature are typically lower at less than full load, reducing pollutant dispersion and increasing predicted air quality impacts. Stack location, height and diameter were verified using aerial photographs, and flue gas flow rate and temperature were verified using combustion calculations.

[8] Florida Department of Environmental Protection, Division of Air Resource Management, Title V Air Operation Permit No. 0170004-025-AV, April 11, 2011.

4.3 Building Dimensions and GEP

No building dimensions or prior downwash evaluations were available. Therefore this modeling analysis did not address the effects of downwash which may increase predicted concentrations.

4.4 Receptors

For Crystal River Power Plant, three receptor grids were employed:

1. A 100-meter Cartesian receptor grid centered on Crystal River Power Plant and extending out 5 kilometers.
2. A 500-meter Cartesian receptor grid centered on Crystal River Power Plant and extending out 10 kilometers.
3. A 1,000-meter Cartesian receptor grid centered on Crystal River Power Plant and extending out 50 kilometers. 50 kilometers is the maximum distance accepted by USEPA for the use of the AERMOD dispersion model.[9]

A flagpole height of 1.5 meters was used for all these receptors.

Elevations from stacks and receptors were obtained from National Elevation Dataset (NED) GeoTiff data. GeoTiff is a binary file that includes data descriptors and geo-referencing information necessary for extracting terrain elevations. These elevations were extracted from 1 arc-second (30 meter) resolution NED files. The USEPA software program AERMAP v. 11103 is used for these tasks.

4.5 Meteorological Data

To improve the accuracy of the modeling analysis, recent meteorological data for the 2007 to 2011 period were prepared using the USEPA's program AERMET which creates the model-ready surface and profile data files required by AERMOD. Required data inputs to AERMET included surface meteorological measurements, twice-daily soundings of upper air measurements, and the micrometeorological parameters surface roughness, albedo, and Bowen ratio. One-minute ASOS data were available so USEPA methods were used to reduce calm and missing hours.[10] The USEPA software program AERMINUTE v. 11325 is used for these tasks.

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[9] USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, Section A.1.(1), November 9, 2005.

[10] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, p. 19.

This section discusses how the meteorological data was prepared for use in the 1-hour SO_2 NAAQS modeling analyses. The USEPA software program AERMET v. 11059 is used for these tasks.

4.5.1 Surface Meteorology

Surface meteorology was obtained for Hernando County Airport located near the Crystal River Power Plant. Integrated Surface Hourly (ISH) data for the 2007 to 2011 period were obtained from the National Climatic Data Center (NCDC). The ISH surface data was processed through AERMET Stage 1, which performs data extraction and quality control checks.

4.5.2 Upper Air Data

Upper-air data are collected by a "weather balloon" that is released twice per day at selected locations. As the balloon is released, it rises through the atmosphere, and radios the data back to the surface. The measuring and transmitting device is known as either a radiosonde, or rawindsonde. Data collected and radioed back include: air pressure, height, temperature, dew point, wind speed, and wind direction. The upper air data were processed through AERMET Stage 1, which performs data extraction and quality control checks.

For Crystal River Power Plant, the concurrent 2007 through 2011 upper air data from twice-daily radiosonde measurements obtained at the most representative location were used. This location was the Tampa Bay/Ruskin, Florida measurement station. These data are in Forecast Systems Laboratory (FSL) format and were downloaded in ASCII text format from NOAA's FSL website.[11] All reporting levels were downloaded and processed with AERMET.

4.5.3 AERSURFACE

AERSURFACE is a non-guideline program that extracts surface roughness, albedo, and daytime Bowen ratio for an area surrounding a given location. AERSURFACE uses land use and land cover (LULC) data in the U.S. Geological Survey's 1992 National Land Cover Dataset to extract the necessary micrometeorological data. LULC data was used for processing meteorological data sets used as input to AERMOD.

AERSURFACE v. 08009 was used to develop surface roughness, albedo, and daytime Bowen ratio values in a region surrounding the meteorological data collection site. AERSURFACE was used to develop surface roughness in a one kilometer radius surrounding the data collection site. Bowen ratio and albedo was developed for a 10 kilometer by 10 kilometer area centered on the meteorological data collection site. These micrometeorological data were processed for seasonal

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[11] Available at: http://esrl.noaa.gov/raobs/

periods using 30-degree sectors. Seasonal moisture conditions were considered average with no months with continuous snow cover.

4.5.4 Data Review

Missing meteorological data were not filled as the data file met USEPA's 90% data completeness requirement.[12] The AERMOD output file shows there were 6.0% missing data.

The representativeness of airport meteorological data is a potential concern in modeling industrial source sites.[13] The surface characteristics of the airport data collection site and the modeled source location were compared. Since the Hernando County Airport is located close to Crystal River Power Plant, this meteorological data set was considered appropriate for this modeling analysis.

5. Background SO_2 Concentrations

Background concentrations were determined consistent with USEPA's Modeling Guidance for SO_2 NAAQS Designations.[14] To preserve the form of the 1-hour SO_2 standard, based on the 99th percentile of the annual distribution of daily maximum 1-hour concentrations averaged across the number of years modeled, the <u>background</u> fourth-highest daily maximum 1-hour SO_2 concentration was added to the <u>modeled</u> fourth-highest daily maximum 1-hour SO_2 concentration.[15]

Background concentrations were based on the 2008-10 design value measured by the ambient monitors located in Florida.[16]

6. Reporting

All files from the programs used for this modeling analysis are available to regulatory agencies. These include analyses prepared with AERSURFACE, AERMET, AERMAP, and AERMOD.

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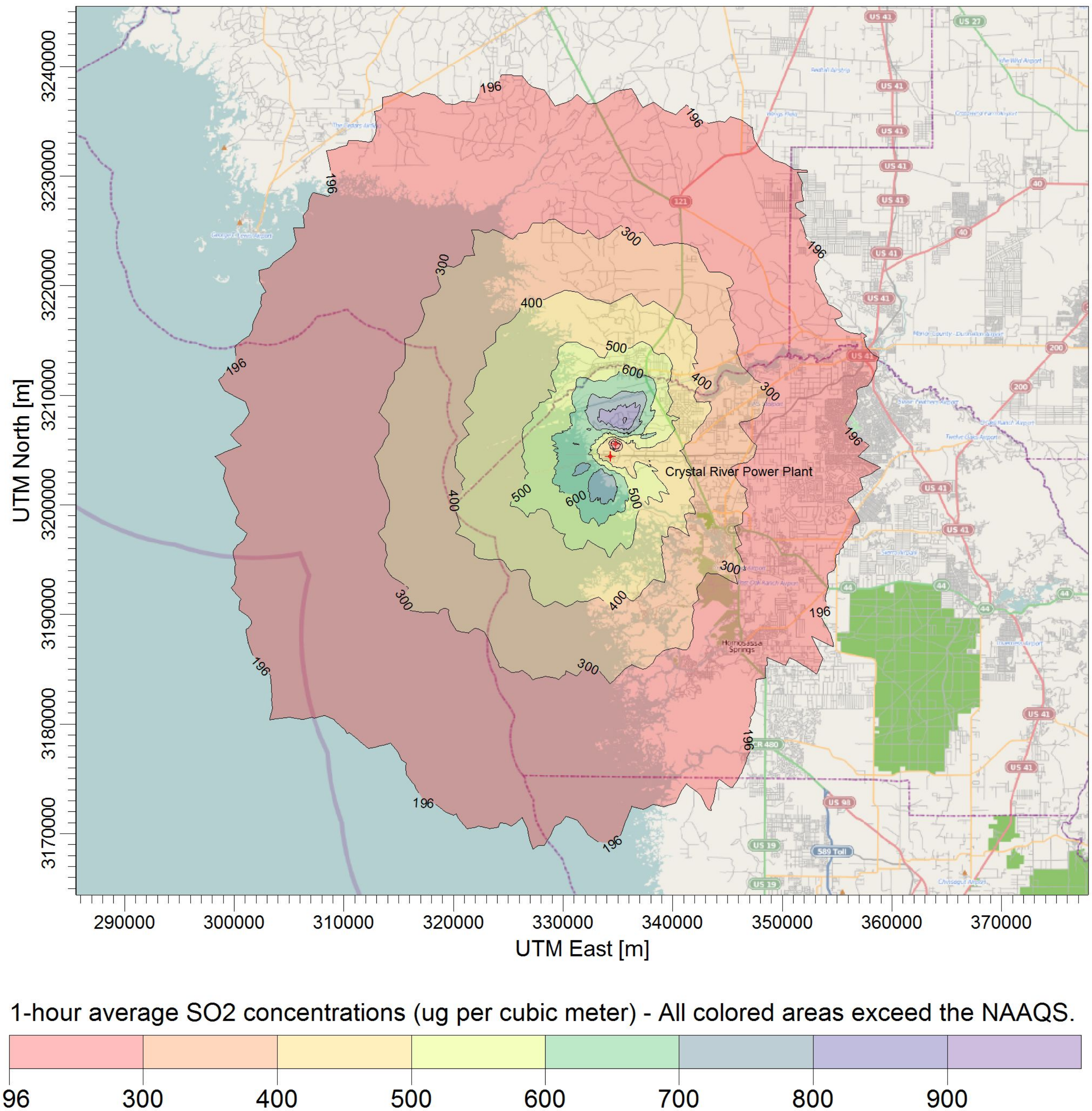
[12] USEPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, Section 5.3.2, pp. 5-4 to 5-5.
[13] USEPA, AERMOD Implementation Guide, March 19, 2009, pp. 3-4.
[14] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, pp. 20-23.
[15] USEPA, Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard, August 23, 2010, p. 3.
[16] http://www.epa.gov/airtrends/values.html

Crystal River Power Plant - Crystal River, Florida
Evaluation of Compliance with the 1-hour NAAQS for SO2



All concentrations include a background of 5.2 ug/m3. This figure is based on allowable emissions.	Total Sources **6**	**Conducted on behalf of the Sierra Club**
	Total Receptors **22083**	**by Wingra Engineering, S.C.**
	Output Type **Concentration**	SCALE: 1:580,926 0 — 20 km
	Maximum **921.02714 ug/m^3**	DATE: **6/25/2012**

AERMOD View - Lakes Environmental Software

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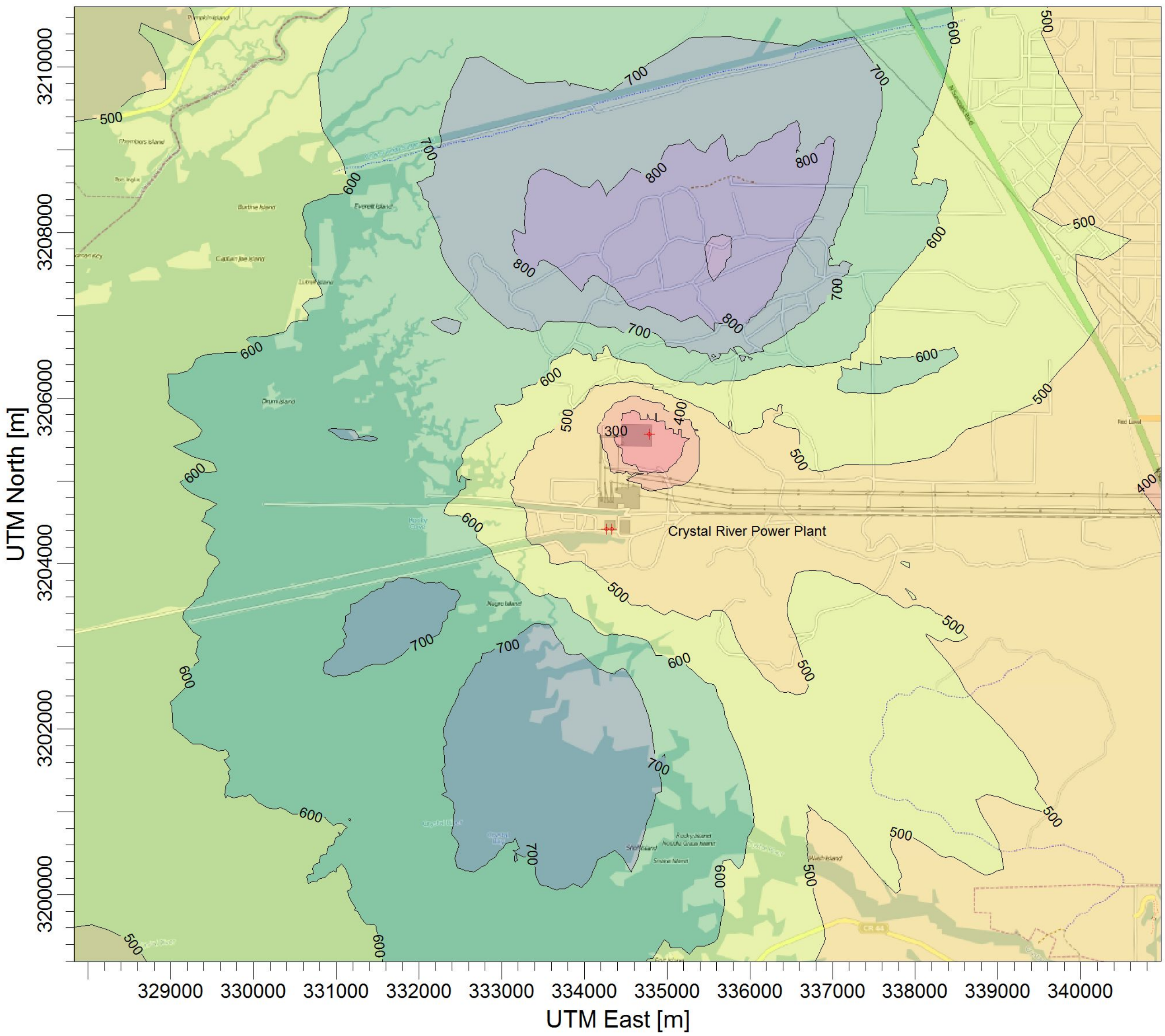
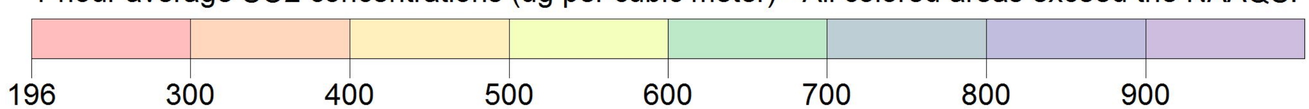


1-hour average SO2 concentrations (ug per cubic meter) - All colored areas exceed the NAAQS.



All concentrations include a background of 5.2 ug/m3. This figure is based on allowable emissions.	Total Sources **6**	**Conducted on behalf of the Sierra Club**	
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ARTICLE

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Investigation of Local Mercury Deposition from a Coal-Fired Power Plant Using Mercury Isotopes

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Supporting Information

ABSTRACT: Coal combustion accounts for approximately two-thirds of global anthropogenic mercury (Hg) emissions. Enhanced deposition of Hg can occur close to coal-fired utility boilers (CFUBs), but it is difficult to link specific point sources with local deposition. Measurement of Hg stable isotope ratios in precipitation holds promise as a tool to assist in the identification of local Hg deposition related to anthropogenic emissions. We collected daily event precipitation samples in close proximity to a large CFUB in Crystal River, Florida. Precipitation samples collected in Crystal River were isotopically distinct and displayed large negative δ^{202}Hg values (mean = −2.56‰, 1 SD = 1.10‰, n = 28). In contrast, precipitation samples collected at other sites in FL that were not greatly impacted by local coal combustion were characterized by δ^{202}Hg values close to 0‰ (mean = 0.07‰, 1 SD = 0.17‰, n = 13). These results indicate that, depending on factors such as powdered coal isotopic composition and efficiency of Hg removal from flue gas, Hg deposited near CFUBs can be isotopically distinct. As this tool is further refined through future studies, Hg stable isotopes may eventually be used to quantify local deposition of Hg emitted by large CFUBs.

INTRODUCTION

Mercury (Hg) is a bioaccumulative neurotoxin that can enter aquatic ecosystems via atmospheric deposition.[1,2] Complex atmospheric Hg chemistry and the mixing of emissions from local, regional, and long-range sources make it challenging to directly trace Hg pollution from sources to receptor sites. Gaseous elemental Hg (GEM) has a relatively long atmospheric residence time and can be transported regionally and globally, whereas reactive gaseous Hg (RGM) and fine particle-bound Hg ($Hg_{(p)}$) are more water-soluble and particle reactive.[3,4] As a result, these forms of Hg are rapidly scavenged from the atmosphere and deposited to surface environments.[5,6] Mercury deposition near point sources and urban areas can be enhanced because RGM and $Hg_{(p)}$ are often emitted in higher proportions from anthropogenic sources.[7−11] However, the relative contribution to Hg deposition from local, regional, and long-range sources is location-specific and depends on a number of factors including the types and quantities of local and regional sources, atmospheric transport patterns, atmospheric oxidants, and local meteorology.[9,12,13]

Multivariate receptor models based on ratios of trace element co-pollutants in combination with meteorological data have been used to quantify the relative impact of local sources on Hg deposition.[9,11,13−15] A number of studies have utilized these techniques to investigate Hg deposition in Florida (FL), USA.[9,13,14,16,17] Elevated levels of Hg have been found across FL in freshwater fish,[18,19] wading birds,[20] and precipitation.[13,21] Mercury concentrations in FL precipitation can be an order of magnitude greater than those in the urban midwestern USA,[12,13,22] especially during the summer months.[13,23] In the 1990s, researchers found that local sources of Hg including coal-fired utility boilers (CFUBs), oil-fired utility boilers, municipal and medical waste incinerators, and cement manufacturing facilities contributed significantly to Hg deposition in south FL.[9,13,14] Recent regulations on emissions from municipal and medical waste incinerators have significantly reduced Hg emissions from those sources.[24−26] Despite these emissions reductions, Hg wet deposition remains elevated across FL, and the current relative impact of local versus long-range transported emissions is not well understood.

The measurement of Hg stable isotope ratios in atmospheric samples has the potential to assist in the identification of Hg emissions from local point sources.[27−31] This study represents the first use of Hg stable isotope ratios to investigate near-source Hg deposition resulting from coal combustion. This research was performed in collaboration with a study conducted to understand current Hg deposition patterns across FL and provide Hg total maximum daily load estimates.

Mercury Stable Isotopes. There are seven stable isotopes of Hg (196, 198, 199, 200, 201, 202, and 204 amu), and isotopic variation has been documented in reservoirs including fossil fuels[29] and the atmosphere.[27,28] Mercury isotope ratios are reported

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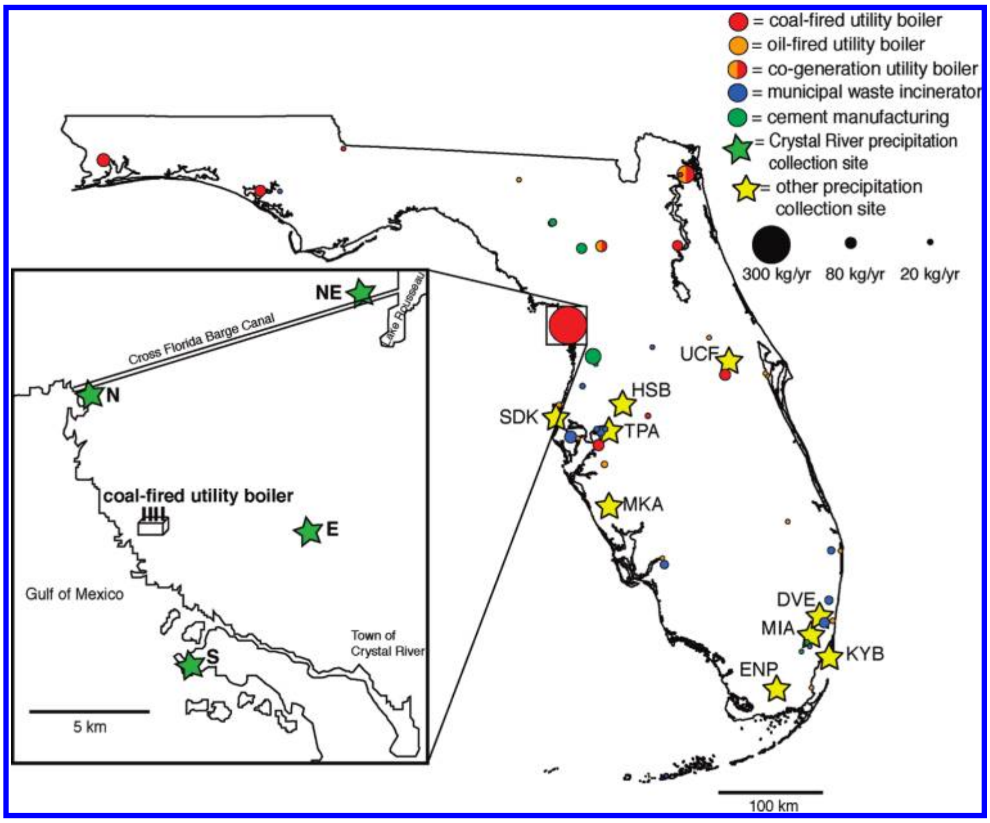

Figure 1. Map of Hg emissions sources and sample collection sites with inset showing sites surrounding Crystal River utility. Symbols for point sources are scaled linearly (with respect to radius) according to total estimated Hg emissions relative to the largest source.[8] Only sources emitting >1 kg of Hg per year are shown. Precipitation collection sites surrounding the Crystal River CFUB (green stars) are labeled as N, NE, S, and E. The other precipitation collection sites are shown as yellow stars.

using delta notation as

$$\delta^{xxx}\mathrm{Hg}(‰) = ([({}^{xxx}\mathrm{Hg}/{}^{198}\mathrm{Hg})_{sample}/({}^{xxx}\mathrm{Hg}/{}^{198}\mathrm{Hg})_{SRM3133}] - 1) \times 1000 \tag{1}$$

where ^{xxx}Hg is an isotope of Hg and SRM 3133 is a NIST Hg standard.[32] Mercury isotopes can undergo mass-dependent fractionation (MDF) during processes such as photochemical reduction and evasion from aqueous solutions.[33,34] Following previous work, we report MDF of Hg isotopes using δ^{202}Hg.[35] Mercury isotopes can also undergo mass-independent fractionation (MIF). A relatively small amount of MIF (<~0.5‰) can be caused by differences in nuclear charge radii between the isotopes (the nuclear field shift effect).[33,36−38] A greater magnitude of MIF can occur during spin-selective photochemical reactions involving radical pairs (the magnetic isotope effect) in which the even and odd-mass-number isotopes react at different rates.[28,39−41] MIF is reported as the deviation of a measured delta value from that theoretically predicted to result due to kinetic MDF according to the equation:

$$\Delta^{xxx}\mathrm{Hg} = \delta^{xxx}\mathrm{Hg} - (\delta^{202}\mathrm{Hg} \times \beta) \tag{2}$$

where β is equal to 0.252 for ^{199}Hg, 0.502 for ^{200}Hg, and 0.752 for ^{201}Hg.[32]

EXPERIMENTAL SECTION

Site Descriptions. During July 2009 daily event precipitation samples were collected at four sites (designated N, NE, S, and E) surrounding the CFUB in Crystal River, FL, at distances of 5.0 to 10.6 km (Figure 1 and Table S1 of Supporting Information). These sites and the CFUB were located in close proximity to the Gulf of Mexico coast. As depicted in Figure 1, the only significant point source of Hg emissions (>1 kg of Hg per year) within ~50 km of the Crystal River area is the CFUB. Additionally, according to the 2005 U.S. EPA National Emissions Inventory (NEI), the Crystal River CFUB is the largest point source of total Hg emissions in FL and emitted a total of ~300 kg of Hg per year during the period of our study.[8] It is important to consider the speciation of these emissions because RGM and $Hg_{(p)}$ species are readily deposited near point sources and air pollution control devices (APCDs) can impact Hg speciation. For example, selective catalytic reduction units (SCRs) promote oxidation of GEM to reactive species[42] that are efficiently removed from the flue gas in wet flue-gas desulfurization units or electrostatic precipitators.[42,43] For this reason, CFUBs with SCRs and flue-gas desulfurization units are predicted to release a lower percentage of Hg as RGM than those without these APCDs (Table S2 of Supporting Information). In contrast, because the Crystal River CFUB had only limited APCDs in July 2009, an estimated 68% of the Hg emissions from the CFUB were RGM species (Table S2).[8] Because the Crystal River CFUB is a large point source of RGM emissions isolated from other emissions sources, the area surrounding the utility was a good location to isolate and measure the isotopic composition of locally deposited Hg emitted by a CFUB.

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Between July and September 2009, daily event precipitation samples were also collected at nine other sites across FL (Figure 1 and Table S1). These sites were located near a variety of anthropogenic Hg sources and, depending on meteorological conditions and source characteristics, Hg deposition at these sites may have been influenced by a mixture of local sources and non-local, long-range transported Hg. It is possible that local coal combustion may have impacted samples collected at several of the sites including TPA and UCF. However, not only do the CFUBs near those sites emit much less total Hg than the Crystal River CFUB, but also, due to their APCDs, it is estimated that only ~8% of their Hg emissions are RGM species (Table S2). We do not expect, therefore, that these sites were influenced by local coal combustion to the same degree as the Crystal River sites. The Sand Key Park (SDK) site was chosen because it was located on the Gulf of Mexico coast, and during specific meteorological conditions, Hg deposition at that site was primarily composed of non-local, long-range transported Hg.

Sample Collection. Precipitation samples were collected daily using manually deployed tripods (~2 m above ground level) with sampling trains that were similar to those previously deployed in automated collectors.[11,21,44] Tipping bucket rain gauges (R. M. Young) were mounted on the tripods. At each of the four Crystal River sites, three Hg sampling trains were deployed per event to ensure collection of sufficient Hg for isotope analyses (see Supporting Information). These sites were maintained daily from 7/4/09 through 7/24/09; after 7/24/09, samples were collected only at the NE site. Two field blanks were collected at each site during the course of the study (see Supporting Information).

Five coal samples were obtained from the Pennsylvania State University Coal Sample Bank. These coal samples were from the same regions in eastern Kentucky (KY) and West Virginia (WV), but not necessarily the same mines, as those that supplied coal to the Crystal River CFUB during July 2009[45] (Table S2).

Meteorological Analysis. The precipitation events included in this study were analyzed meteorologically using GRLevel2 Analyst software[46] with archived NEXRAD Level II radar data[47] (see Supporting Information). Using these data, we measured a variety of parameters including storm motion, maximum rainfall intensity, maximum echo top height, and average precipitating cell size at 5-min intervals throughout each event. We characterized surface wind direction using surface meteorological maps[48] and air sounding data.[5] Air mass transport to the sites was additionally modeled using the NOAA Hybrid Single-Particle Lagrangian Integrated Trajectory (HYSPLIT) model.[49] The hour of maximum precipitation was used as the starting time for each back trajectory, and trajectories were calculated using starting heights of 500 and 1000 m above ground level.

Sample Processing and Analysis. After collection, precipitation samples were oxidized to a concentration of 1% BrCl (v/v) and stored in a cold room for four months. Mercury concentrations were then measured in the field blanks and a subset of the samples by atomic absorption spectrometry (AAS; MA-2000, Nippon Instruments) (see Supporting Information). The method detection limit (MDL) for these analyses was 0.82 ng/L (3 SD of blank analyses), and all sample replicates were within 8.1% relative percent difference (RPD) (mean RPD = 2.0 ± 1.9%, 1 SD, n = 78). The Crystal River field blanks contained an average of 0.39 ng of Hg (1 SD = 0.46 ng, n = 8) while field blanks collected at the other sites in FL contained an average of 0.07 ng of Hg (1 SD = 0.10 ng, n = 43). The field blanks collected at the Crystal River sites may be somewhat higher because equipment limitations only allowed cleaning of the funnels and adapters in 5% HNO_3 for 4−8 h compared to 24 h at the other sites. However, the Hg in the Crystal River field blanks represents only a small percentage of the average amount of Hg contained in precipitation samples collected at those sites (mean = 1.8%, 1 SD = 1.8%, n = 8), and this amount of contamination could not have significantly influenced the isotopic compositions of the samples (see Supporting Information).

Mercury in the precipitation samples with sufficient mass for isotopic analyses (i.e., >8 ng) was concentrated into acidic 1% $KMnO_4$ solutions (w/w, Alfa Aesar). Each sample was poured into a 2 L Pyrex bottle, and 0.3 mL of 30% $NH_2OH \cdot HCl$ was added and allowed to react for 30 min. A peristaltic pump was then used to add 100 mL of 5% $SnCl_2$ at a rate of 10 mL/min. Mercury-free air was pulled through the sample and carried the resulting GEM into the trapping solution at a rate of 0.7 L/min for 4 h. Procedural standards (NIST SRM 3133) and blanks were processed in the same manner (see Supporting Information). Each of four sample replicates were processed by separating the total sample volume in half and processing the two splits in parallel. After transfer into the $KMnO_4$ solutions, final Hg concentrations were measured by AAS and used to determine Hg concentrations in the original precipitation samples. Mercury in procedural standards was consistently recovered completely in the final solutions (mean = 94%, 1 SD = 6%, n = 23; see Supporting Information).

Hg in the coal samples was thermally released and concentrated into 1% $KMnO_4$ solutions according to previously reported methods.[29] Briefly, the samples were crushed to a fine powder, weighed into ceramic boats, and combusted over 5.75 h in a two-stage quartz tube furnace in which the temperature of the first furnace was incrementally increased to 550 °C while the second furnace was held at 1000 °C. The resulting GEM was swept by O_2 gas into the $KMnO_4$ solution. Procedural standards (NIST SRM 1632c) and blanks were processed using the same methods. Mercury in procedural standards was consistently recovered completely in the final solutions (mean = 94%, 1 SD = 5%, n = 7; see Supporting Information).

Hg isotopic compositions were measured using continuous-flow cold vapor generation MC-ICP-MS (Nu Instruments) according to previously published methods.[32,39] We estimate the maximum sample analytical uncertainty of a given isotope ratio as 2 SD of the measurement of the ratio in procedural standards (e.g., δ^{202}Hg uncertainty = 0.13‰, 2 SD). Replicate analyses of the UM-Almadén secondary standard (n = 37) and precipitation sample replicates (n = 4) were reproducible within this uncertainty (Table S4 of Supporting Information).

■ RESULTS AND DISCUSSION

Precipitation Events. To better interpret the results of our isotopic analyses, we analyzed the meteorological conditions during each precipitation event in Crystal River (Table S3 of Supporting Information). The observed precipitation events fell broadly into two categories based on meteorological conditions. We further characterized the events in "Event Group 1" into three subcategories, 1A, 1B, and 1C as follows. During the first week of the study (7/4/09 to 7/9/09) and on 7/20/09 (Table S3, Event Group 1A), slow-moving cold and stationary fronts persisted over northern FL and southern Georgia. Predominantly westerly winds transported air masses onshore from over the Gulf of Mexico, and westerly and southwesterly surface winds transported emissions from the CFUB over the collection sites. These events were characterized by large convective cells that covered the entire study area and resulted in precipitation at all of the Crystal River sites. The events on 7/17/09 and 7/18/09 (Table S3, Event Group 1B) similarly were related to the presence of a cold front over southern Georgia and were characterized by westerly surface winds. In contrast to the earlier events, during the events on 7/17/09 and 7/18/09, large isolated precipitating convective cells (~6 to 10 km in diameter) passed over the CFUB and only resulted in precipitation at some of the sites. Finally, the event on 7/12/11 (Table S3, Event Group 1C) was characterized by a local high pressure system and a north—south band of convective precipitating cells (~26 km in north—south length) that moved inland from the west over the CFUB and impacted the NE and E sites. In general, the Group 1 precipitation events (7/4/09 to 7/20/09) were characterized by persistent cold and stationary fronts over northern FL and central Georgia, westerly/southwesterly storm motion and surface winds, and large convective precipitating cells that often impacted the entire study area. Under these conditions, RGM emitted by the CFUB was likely incorporated into cloud droplets,[23] and because the precipitating cells were larger in diameter than the distance between the collection sites, this Hg was likely deposited at all of the Crystal River sites.

The precipitation events on 7/30/09 and 7/31/09 ("Event Group 2") were meteorologically different than the preceding events (Table S3). The event on 7/30/09 was not related to a frontal system. During that event, convective cells formed over central FL and were transported into the Crystal River area by southeasterly winds. Southerly surface winds transported emissions from the Crystal River CFUB to the north. On 7/31/09, precipitating cells were transported into the area from the northwest and southerly surface winds similarly transported the CFUB emissions to the north. Especially on 7/30/09 it is unlikely that local emissions from the Crystal River CFUB were incorporated into the precipitating cells that impacted the NE site. We hypothesize that Hg deposited during these events at the NE site was transported to the area from non-local sources.

We also analyzed the meteorological conditions during events sampled at the Sand Key Park (SDK) site on the Gulf of Mexico coast (Figure 1). On 7/26/09, southwesterly onshore flow transported air masses to the area that had spent the previous two days over the Gulf of Mexico. Convective heating caused the formation of offshore cells that moved inland and caused precipitation at the site. Given these conditions and the coastal location of the SDK site, Hg deposited during this event was primarily of non-local origin and transported from over the Gulf of Mexico.

Mercury Concentrations. Mercury concentrations in precipitation are presented in Table S4. Mercury concentrations in samples collected in Crystal River that were analyzed for Hg isotopic composition ranged from 4.0 to 130 ng/L and concentrations in samples collected at the other sites that were analyzed for Hg isotopic composition ranged from 18 to 69 ng/L. Volume-weighted mean (VWM) sample Hg concentrations at each of the Crystal River sites were calculated by dividing the total amount of Hg deposited by the total volume of precipitation. The VWM concentrations for the four sites were 41 ng/L (N), 27 ng/L (NE), 44 ng/L (E), and 51 ng/L (S). These VWM concentrations are relatively high compared to those reported by previous studies conducted during the summer in south FL (13—27 ng/L)[21] and those measured at the FL Mercury Deposition Network sites in

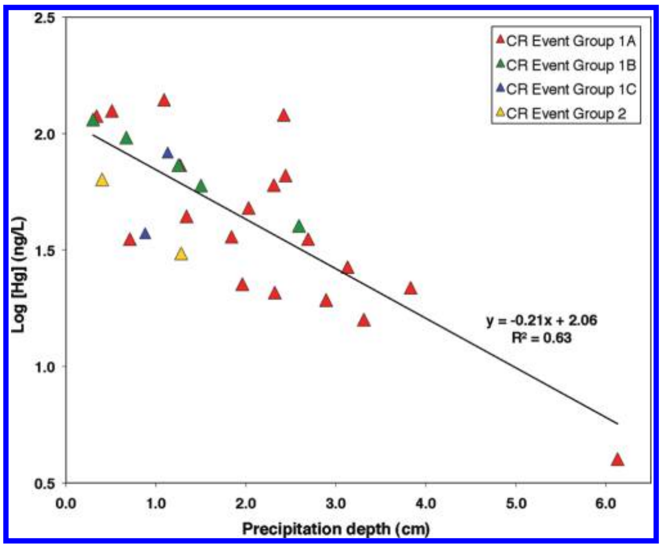

Figure 2. Precipitation depth (cm) versus log Hg concentration (ng/L). Precipitation samples collected at sites in Crystal River, FL are shown as triangles. Precipitation events are colored according to Event Group: Event Group 1A (red triangles) includes events from 7/4/09 to 7/9/09 and 7/20/09, Event Group 1B (green triangles) includes the events on 7/17/09 and 7/18/09, Event Group 1C (blue triangles) represents the event on 7/12/09, and Event Group 2 (yellow triangles) includes the events on 7/30/09 and 7/31/09. A linear regression through all of the data points is shown.

July 2009 (15—26 ng/L).[50] The lower VWM Hg concentration at the NE site and higher VWM concentration at the S site may be partly explained by differences in total precipitation amount collected at these sites during individual events. To assess this relationship, precipitation depth (cm) was regressed against the logarithm of Hg concentrations (Figure 2; see Supporting Information). As shown in Figure 2, the slope of the relationship between precipitation depth and Hg concentration is negative (slope = −0.21 ± 0.03, 1 SE; $t = -6.62$, $p < 0.0001$, $r^2 = 0.63$, $n = 28$) and 63% of the variation in concentration is explained by differences in precipitation depth.[51] Although the high volume sample collected at the NE site on 7/4/09 falls outside of the range of the rest of the data, it had little influence on the slope estimate (slope without NE 7/4/09 = −0.19 ± 0.04, 1 SE; $t = -4.40$, $p = 0.0002$, $r^2 = 0.44$, $n = 27$). Similar relationships between Hg concentration and precipitation amount have been observed in previous studies.[13,21,22,52] Several of these studies suggest that at locations impacted to varying degrees by Hg from local sources, variations in Hg concentration are largely controlled by the magnitude of local source impacts and not by differences in precipitation amount.[11,13] The correlation between Hg concentration and precipitation depth in the Crystal River samples suggests that variations in Hg concentration were not caused by varying impacts from the local CFUB. Instead, on the basis of meteorological analyses, high Hg concentrations, and Hg isotopic analyses, we argue that this correlation resulted because of deposition of Hg from the CFUB at all of the collection sites.

Mercury Isotopic Compositions. Complete isotopic data are presented in Table S4. As depicted in Figure 3, precipitation samples collected in Crystal River were characterized by negative δ^{202}Hg values as low as −4.37 ± 0.13‰, 2 SD (mean = −2.56‰, 1 SD = 1.10‰, $n = 28$) and slightly positive Δ^{199}Hg values (mean = 0.32‰, 1 SD = 0.12‰, $n = 28$). In contrast, precipitation collected at the other sites in FL did not exhibit large

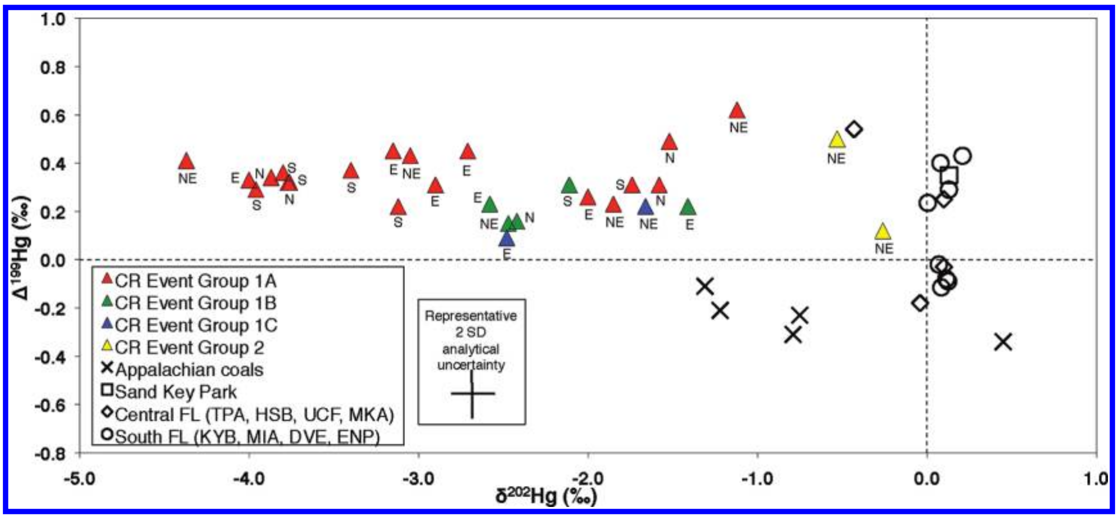

Figure 3. δ^{202}Hg (‰) versus Δ^{199}Hg (‰) measured in precipitation and coal samples. Precipitation samples collected at sites in Crystal River, FL are shown as solid triangles and secondarily labeled by collection site location (N, NE, S, E). Precipitation events are grouped according to Event Group (1A = 7/4/09 to 7/9/09 and 7/20/09; 1B = 7/17/09 and 7/18/09; 1C = 7/12/09; 2 = 7/30/09 and 7/31/09). Precipitation samples collected at other sites are shown as open symbols where the Sand Key Park sample is a square, central FL site samples are diamonds, and south FL site samples are circles. Representative Appalachian coal samples are shown as black X's. Precipitation sample analytical uncertainty based on replicate analyses of procedural standards (2 SD) is depicted. Black dashed lines depict the zero values for both axes.

negative δ^{202}Hg values (mean = 0.07‰, 1 SD = 0.17‰, n = 13) and had a wider range of Δ^{199}Hg values (mean = 0.15‰, 1 SD = 0.25‰, n = 13). All of the precipitation samples exhibited slightly positive Δ^{200}Hg values (mean = 0.11‰, 1 SD = 0.07‰, n = 41) that were similar in magnitude to those reported for Midwest precipitation[27] (see Supporting Information).

Four of the five coal samples from mines similar to those that supplied the Crystal River CFUB also displayed negative δ^{202}Hg values as low as -1.31 ± 0.13‰, 2 SD (mean = -0.72‰, 1 SD = 0.70‰, n = 5) but exhibited negative Δ^{199}Hg values (mean = -0.24‰, 1 SD = 0.09‰, n = 5). These samples did not display MIF of ^{200}Hg (mean Δ^{200}Hg = -0.02‰, 1 SD = 0.03‰, n = 5).

The magnitude of the negative δ^{202}Hg values measured in samples collected in Crystal River greatly exceeds that previously reported for atmospheric samples.[27,28,53] With the exception of the two precipitation samples collected at the NE site on 7/30/09 and 7/31/09 (Table S3, Event Group 2), all of the Crystal River samples exhibited δ^{202}Hg values lower than -1.10‰ and there are no clear differences between the four Crystal River collection sites in terms of isotopic composition (Figure 3). This is likely due to the fact that large precipitating cells covered the study area during these events and all of the collection sites were similarly impacted by emissions from the CFUB.

Factors Influencing Hg Isotopic Compositions. The Hg isotopic composition of any particular precipitation sample is the result of mixing of Hg from different sources combined with the effects of in-source and post-emission fractionation.[27] Here we address these factors and their potential influence on the observed Hg isotopic compositions of the collected precipitation samples.

Source Isotopic Composition. Mercury deposited in precipitation at the Crystal River sites was a mixture of local CFUB-emitted Hg and Hg from non-local sources. During the Event Group 1 precipitation events (7/4/09 through 7/20/09), storm motion was primarily from the west and any non-local Hg deposited at the collection sites was transported to the area from over the Gulf of Mexico. To estimate the isotopic composition of this Hg, we analyzed Hg in precipitation collected at the SDK site on 7/26/09. On the basis of meteorological analyses, Hg deposited during that event was primarily non-local and transported from over the Gulf of Mexico. This sample was characterized by a slightly positive δ^{202}Hg value (0.13 ± 0.13‰, 2 SD). Therefore, it is unlikely that the large negative δ^{202}Hg values observed in Crystal River precipitation are due to the influence of non-local Hg transported from over the Gulf of Mexico. Instead, we argue that local deposition of Hg emitted by the Crystal River CFUB resulted in the observed negative δ^{202}Hg values.

The isotopic composition of Hg emitted by a CFUB could be affected by several factors including (1) original source coal isotopic composition, (2) coal cleaning, and (3) in-system fractionation within the power plant. Although we did not have access to coal burned at the Crystal River CFUB during the sampling period, coal samples from mines in the same region as those that supplied coal to the CFUB displayed negative δ^{202}Hg values and negative Δ^{199}Hg values. Biswas et al.[29] measured similarly negative δ^{202}Hg values (mean = -1.23‰, 1 SD = 0.29‰, n = 6) and slightly negative Δ^{199}Hg values (mean = -0.13‰, 1 SD = 0.01‰, n = 2) in other Appalachian coals. Assuming that these values represent the isotopic composition of the original bulk source coal delivered to the Crystal River CFUB in July 2009, additional negative MDF and positive MIF of Hg are required to produce the observed precipitation Hg isotopic compositions.

Coal cleaning prior to combustion may result in powdered coal that displays δ^{202}Hg values lower than that of the original bulk source coal. To reduce sulfur concentrations, high sulfur Appalachian coals are generally cleaned at the mine prior to shipment using fluidized density separation.[54] During this process, denser minerals such as Hg-rich sulfides sink and are removed.[54] Secondary coal cleaning is also conducted at many CFUBs (including the Crystal River CFUB) wherein the more coarse and dense sulfides are rejected at the coal pulverizer

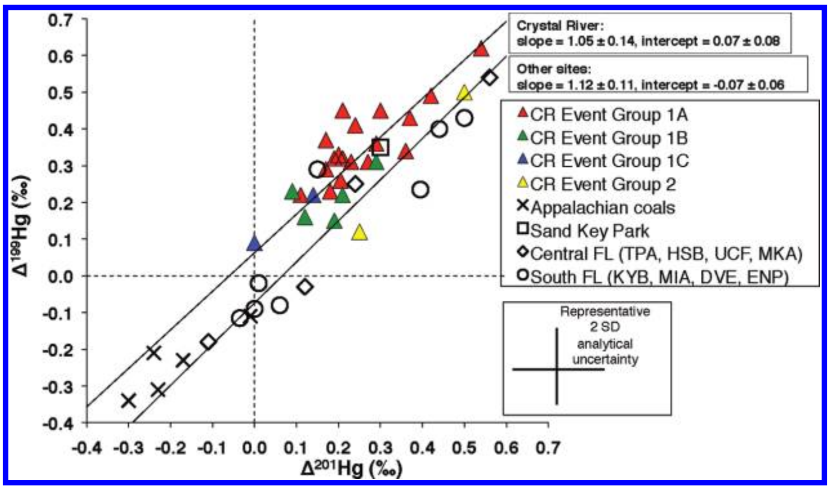

Figure 4. Δ^{201}Hg (‰) versus Δ^{199}Hg (‰) in precipitation and coal samples. Precipitation samples collected at sites in Crystal River, FL are shown as solid triangles. Precipitation events are grouped according to Event Group (1A = 7/4/09 to 7/9/09 and 7/20/09; 1B = 7/17/09 and 7/18/09; 1C = 7/12/09; 2 = 7/30/09 and 7/31/09). Precipitation samples collected at other sites are shown as open symbols where the Sand Key Park sample is a square, central FL site samples are diamonds, and south FL site samples are circles. Representative Appalachian coal samples are shown as black X's. Δ^{199}Hg/Δ^{201}Hg ratios calculated for samples collected in Crystal River and samples collected at the other sites using York regressions[67] are shown as solid lines. Representative sample analytical uncertainty for precipitation samples based on replicate analyses of procedural standards (2 SD) is depicted. Black dashed lines depict the zero values for both axes.

during crushing.[55−58] Because a large percentage of Hg in coal is associated with sulfides,[54,59] these processes can remove a significant amount of Hg from the original source coal.[54] A recent study of coals from the Illinois basin found that sulfide-associated Hg had much higher δ^{202}Hg values (mean = −0.11‰, 1 SD = 0.05‰, n = 3) than that of Hg associated with coexisting organic matter (mean = −1.46‰, 1 SD = 0.34‰, n = 21).[60] Removal of sulfides through coal cleaning may, therefore, result in the preferential removal of the heavier isotopes of Hg and produce powdered coal with a lower δ^{202}Hg value than that of the original bulk source coal.

In-System Fractionation. Essentially all of the Hg liberated during coal combustion is expected to be GEM.[58] As the flue gas leaves the boiler and enters the APCDs, it cools to ~130 °C, and some portion of the GEM is oxidized to RGM through gas-phase reactions or via heterogeneous reactions on particles.[42,58] The reactive Hg species can subsequently be removed to varying degrees by the APCDs.[42,58] MDF of heavy metals (including Zn, Cd, and Hg) has been observed at similarly high temperatures during industrial and volcanic processes.[53,61−64] Zambardi et al.[53] observed MDF of Hg isotopes in volcanic fumerole emissions and found that downwind of the vents, oxidized plume $Hg_{(p)}$ displayed higher δ^{202}Hg values (−0.11 ± 0.18‰, 2 SD) than that of total gaseous Hg (−1.74 ± 0.36‰, 2 SD).[53] The authors hypothesized that this was due to the preferential equilibrium oxidation of the heavy isotopes of Hg.[53] If a similar process occurs in CFUB flue gas, the heavier isotopes of Hg would be progressively oxidized, adsorbed onto particles, and removed in electrostatic precipitators and baghouses.[42,58] This process would result in MDF of Hg isotopes such that the Hg remaining in the flue gas would exhibit progressively lower δ^{202}Hg values relative to the powdered coal that was combusted. Unfortunately, because we cannot determine the Hg removal efficiency from the flue gas at the Crystal River CFUB and because we do not know the exact isotopic composition of the powdered coal that was combusted, we are not able to model this fractionation process.

Post-Emission Atmospheric Fractionation. In addition to source isotopic composition and in-system fractionation, post-emission atmospheric processes may cause additional MDF and MIF. To our knowledge, the effects of atmospheric reactions on Hg isotopes have not been studied.[35] However, once emitted to the atmosphere, RGM is strongly scavenged by aqueous droplets.[3] Thus, we do not expect that significant secondary MDF affects RGM emitted by the Crystal River CFUB prior to deposition. It is, however, possible that atmospheric processes could have played a role in modifying the observed Δ^{199}Hg values in the precipitation samples. The Crystal River precipitation samples displayed higher Δ^{199}Hg values (~0.5‰) than that of the representative source coal samples (mean coal Δ^{199}Hg = −0.24‰, 1 SD = 0.09‰, n = 5; mean precipitation Δ^{199}Hg = 0.32‰, 1 SD = 0.12‰, n = 28). Although this magnitude of MIF could have occurred in the power plant system during reactions influenced by the nuclear field shift (NFS) effect,[33] it is more likely that photochemical reactions in the atmosphere caused the observed positive MIF.

Gratz et al.[27] hypothesized that a difference between near-zero Δ^{199}Hg values in total gaseous Hg (mean = −0.09‰, 1 SD = 0.09‰, n = 7) and positive Δ^{199}Hg values observed in Midwest precipitation (mean = 0.30‰, 1 SD = 0.14‰, n = 20) could be the result of the magnetic isotope effect (MIE) occurring during photochemical reduction and evasion of Hg from cloud droplets. In experimental studies, the MIE has been demonstrated to result in a Δ^{199}Hg/Δ^{201}Hg ratio between 1.0 and 1.3.[33,39] In contrast, the NFS effect has been theoretically calculated and experimentally demonstrated to result in a higher Δ^{199}Hg/Δ^{201}Hg ratio between 1.6 and 2.5.[33,36,37,65,66] Precipitation samples collected during this study were characterized by Δ^{199}Hg/Δ^{201}Hg ratios within error of 1.0 (Crystal River samples = 1.05 ± 0.14, 1 SD; other precipitation samples = 1.12 ± 0.11, 1 SD;[67] Figure 4). This suggests that the MIE occurring during photochemical processes in the atmosphere is at least partially responsible for the observed Δ^{199}Hg values in the precipitation samples.

This study of Hg deposited in precipitation across the state of FL provides evidence that Hg isotopes may be useful as a tool to help identify locally deposited Hg emitted by large CFUBs. We hypothesize that the isotopic composition of source coal, coal cleaning, and processes inherent to the removal of Hg from the flue gas stream caused the emission of Hg with extreme negative δ^{202}Hg values from the Crystal River CFUB. It is likely that the isotopic composition of Hg emissions varies between CFUBs depending on a number of factors such as powdered coal isotopic composition, thermal profile of the power plant system, properties of particles in the flue gas, type of APCDs, and efficiency of Hg removal by APCDs. It is also likely that local Hg deposition near other types of anthropogenic point sources is isotopically different than that measured near the Crystal River CFUB. Future measurements of the Hg isotopic composition of powdered coal and flue gas emissions, percentage of RGM in emissions, and efficiency of Hg removal by APCDs would enable more quantitative estimates of the contribution of local coal combustion to Hg deposition. Additionally, future measurements of the isotopic composition of dry deposited Hg may help to further quantify the impact of anthropogenic point sources on local Hg deposition. In areas surrounding large CFUBs such as Crystal River, FL, the anomalous Hg isotope signature of local CFUB emissions may be useful in tracing the impact of this pollution on local ecosystems.

■ ASSOCIATED CONTENT

S Supporting Information. Detailed experimental methods and supporting data. This material is available free of charge via the Internet at http://pubs.acs.org.

■ AUTHOR INFORMATION

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Notes

§Author deceased prior to publication.

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Florida Department of Environmental Protection

Memorandum

TO: Joseph Kahn, Division of Air Resource Management

THROUGH: Trina Vielhauer, Bureau of Air Regulation TV

FROM: Jon Holtom, Title V Section JH.

DATE: February 24, 2009

SUBJECT: Air Permit No. 0170004-017-AC
Progress Energy Florida
Crystal River
Final BART Permit

The final permit for this BART project is attached for your approval and signature.

The attached final determination identifies issuance of the draft permit, summarizes the publication process, and provides the Department's response to comments (if any) on the draft permit. The Department granted an extension of time to file a petition for an administrative hearing on February 13th. The extension of time request was withdrawn on February 24th.

I recommend your approval of the attached final permit for this project.

Attachments

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Progress Energy Florida
100 Central Avenue CN 77
St. Petersburg, Florida 33701
Authorized Representative:
Mr. Bernie Cumbie, Plant Manager

Air Permit No. 0170004-017-AC
Crystal River Power Plant
BART Project
Citrus County

Enclosed is final permit No. 0170004-017-AC. This air construction permit is being issued to satisfy the requirements of Best Available Retrofit Technology (BART) in Rule 62-296.340, Florida Administrative Code (F.A.C.) for the eligible units at the facility identified above. For the existing Crystal River Power Plant, the BART-eligible units are coal-fired Units 1 and 2. The Department of Environmental Protection (Department) reviewed the application and establishes BART emissions standards for particulate matter. The existing facility is located in Citrus County on Power Line Road, West of U.S. Highway 19, in Crystal River, Florida. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

TLV/jh

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final Permit and Final Determination), or a link to these documents available electronically on a publicly accessible server, was sent by electronic mail with received receipt requested to the persons listed below:

Mr. Bernie Cumbie, Plant Manager, Progress Energy Florida (bernie.cumbie@pgnmail.com)
Mr. Dave Kellermeyer, Northern Star Generation (dave.kellermeyer@northernstargen.com)
Mr. Scott Osbourn, P.E., Golder Associates (sosbourn@golder.com)
Mr. Mike Halpin, P.E., DEP-PPS (mike.halpin@dep.state.fl.us)
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Mr. Dee Morse, NPS (dee_morse@nps.gov)
Ms. Barbara Friday, DEP BAR: barbara.friday@dep.state.fl.us (for posting with U.S. EPA, Region 4)
Ms. Victoria Gibson, DEP BAR: victoria.gibson@dep.state.fl.us (for reading file)

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

2/26/09

(Clerk) (Date)

PERMITTEE

Progress Energy Florida
100 Central Avenue CN 77
St. Petersburg, Florida 33701

PERMITTING AUTHORITY

Florida Department of Environmental Protection (Department)
Division of Air Resource Management
Bureau of Air Regulation, Title V Section
2600 Blair Stone Road, MS #5505
Tallahassee, Florida 32399-2400

PROJECT

Air Permit No. 0170004-017-AC
Crystal River Power Plant BART Determination

The purpose of this air construction permit is to satisfy the requirements of Best Available Retrofit Technology (BART) in Rule 62-296.340, Florida Administrative Code (F.A.C.) for the eligible units at the facility identified above. For the existing Crystal River Power Plant, the BART-eligible units are coal-fired Units 1 and 2. The Department of Environmental Protection (Department) reviewed the application and establishes BART emissions standards for particulate matter. The existing facility is located in Citrus County on Power Line Road, West of U.S. Highway 19, in Crystal River, Florida. This permit is issued pursuant to Chapter 403, Florida Statutes.

NOTICE AND PUBLICATION

The Department distributed an Intent to Issue Permit package on December 19, 2008. The applicant published the Public Notice of Intent to Issue in the Citrus County Chronicle on January 14, 2009. The Department received the proof of publication on January 27, 2009. The Department granted an extension of time to file a petition for an administrative hearing on February 13th. The extension of time request was withdrawn on February 24th.

COMMENTS

No comments on the Draft Permit were received from the public, the Department's SW District Office, the EPA Region 4 Office or the National Park Service; however, on January 27, 2009, the Department received comments from the applicant. The following summarizes the comments and the Department's response. Revised language added to the permit is indicated by a double underline format.

1. The applicant commented that the excess emissions provisions listed in condition 7 do not recognize the fact that Boilers 1 and 2 meet the definition of existing units contained in Rule 62-210.700(2), F.A.C. and has requested that condition 7 be revised accordingly. This provision is already contained within the Title V permit and it was not intended for this permit to alter that provision. However, at the applicant's request for clarity, condition 7 is revised as follows:

   7. Excess Emissions Allowed. Unless otherwise specified by permit, excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the Department for longer duration.

      Excess emissions from existing fossil fuel steam generators resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration

of excess emissions shall be minimized.
[Rules 62-210.700(1) & (2), F.A.C.]

CONCLUSION

The final action of the Department is to issue the permit with the minor revisions, corrections, and clarifications as described above.

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

PERMITTEE

Progress Energy Florida (PEF)
100 Central Avenue CN 77
St. Petersburg, Florida 33701

Air Permit No. 0170004-017-AC
Expiration Date: 07/01/2014
Crystal River Power Plant
BART Project

Authorized Representative:
Bernie Cumbie, Plant Manager

PLANT AND LOCATION

Progress Energy Florida operates the Crystal River Power Plant, which is a located on Power Line Road, West of U.S. Highway 19, Crystal River, Citrus County, Florida. The UTM coordinates are Zone 17, 334.3 km East and 3204.5 km North. The facility is an existing coal-fired power plant, which is identified by Standard Industrial Classification code No. 4911.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). Specifically, this project is subject to Rule 62-296.340, F.A.C., which requires a determination of the Best Available Retrofit Technology (BART) for each BART-eligible source as defined in 40 CFR 51.301. The state rule implements the federal provisions of Appendix Y in 40 CFR Part 51, "Guidelines for BART Determinations Under the Regional Haze Rule". The affected visibility-impairing pollutants include only particulate matter (PM) for electric utilities subject to CAIR. Pursuant to Rule 62-296.340, F.A.C., the permittee shall install or modify the air pollution control equipment to achieve the specified BART standards.

EFFECTIVE DATE

Unless otherwise specified by this permit, the BART-eligible sources shall demonstrate compliance with the conditions of this permit no later than December 31, 2013. [Rule 62-296.340(3)(b)2, F.A.C.]

Executed in Tallahassee, Florida

Joseph Kahn, Director
Division of Air Resource Management

2/25/09
(Date)

JK/tlv/jh

FACILITY DESCRIPTION

Progress Energy Florida, operates an existing coal-fired power plant, which consists of four coal-fired fossil fuel steam generating (FFSG) units and associated equipment.

FACILITY REGULATORY CLASSIFICATIONS

- The facility is a major source of hazardous air pollutants (HAP).
- The facility operates units subject to the acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.
- The facility is a major stationary source pursuant to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.
- The facility operates BART-eligible units subject to Rule 62-296.340 (BART), F.A.C.

BART-ELIGIBLE EMISSIONS UNITS

This permitting action affects the following BART-eligible emissions units at the plant.

EU No.	Emission Unit Description
-001	Fossil Fuel Steam Generator Unit 1
-002	Fossil Fuel Steam Generator Unit 2

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1. Permitting Authority. The Permitting Authority for this project is the Bureau of Air Regulation in the Division of Air Resource Management of the Florida Department of Environmental Protection. The mailing address for the Bureau of Air Regulation is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400.
2. Compliance Authority. All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department of Environmental Protection's Southwest District Office. The mailing address and phone number of the Southwest District Office is: 13051 North Telecom Parkway, Temple Terrace, FL 33637-0926, telephone: 813/632-7600, fax: 813/632-7668.
3. Appendices. The following Appendices are attached as an enforceable part of this permit: Appendix A (Citation Formats), Appendix B (General Conditions), and Appendix C (Standard Testing Requirements).
4. Applicable Regulations, Forms and Application Procedures. Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to the applicable provisions of: Chapter 403, Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297, Florida Administrative Code (F.A.C.); and the applicable parts and subparts of Title 40, Code of Federal Regulations (CFR). Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.
5. Title V Permit. This permit authorizes specific modifications and/or new construction on the affected emissions units as well as initial operation to determine compliance with conditions of this permit. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit **on or before December 31, 2013**. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Bureau of Air Regulation with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]
6. Records Retention. All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least 5 years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rule 62-213.440(1)(b)2, F.A.C.]
7. Annual Operating Report. The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(3), F.A.C.]

This subsection addresses the following affected emissions unit.

ID No.	Emissions Unit Description
-001 and -002	*Description*: -001: 3,750 MMBtu/hr pulverized coal, dry bottom, tangentially-fired boiler. -002: 4,795 MMBtu/hr pulverized coal, dry bottom, tangentially-fired boiler. *Fuels*: The fuels allowed to be burned in these units are: bituminous coal; a bituminous coal and bituminous coal briquette mixture, on-specification used oil, and distillate fuel oil for startup. These units may also burn up to 2%, by weight, of oily fly ash generated by Unit 1 at the Bartow Power Plant. *Controls*: Emissions of particulate matter are controlled from each unit with a high efficiency electrostatic precipitator, manufactured by Buell Manufacturing Company, Inc. *Monitors*: Continuous opacity monitor systems (COMS) are used to measure opacity in conformance with 40 CFR Part 75. *Unit 1 Stack Parameters*: Exhaust gas exits at 291° F and 1,407,923 acfm through a 15-foot diameter stack that is 499 feet tall. *Unit 2 Stack Parameters*: Exhaust gas exits at 300° F and 1,931,324 acfm through a 16-foot diameter stack that is 502 feet tall.

Pursuant to Rule 62-296.340 (BART), F.A.C., the following standards represent the Best Available Retrofit Technology. These standards apply to each BART-eligible unit and are in addition to, and supplement, all other applicable standards.

CONTROL EQUIPMENT

1. Particulate Controls. To control emissions of particulate matter (PM), the permittee shall continue to operate and maintain the existing electrostatic precipitators (ESP) for Units 1 and 2 to meet the BART standards specified in this permit. This permit authorizes any upgrades to the ESP for Unit 2 necessary to meet the BART emissions limits, below. [Rule 62-296.340 (BART), F.A.C.]

2. Circumvention. The permittee shall not circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly. [Rule 62-210.650, F.A.C.]

BART EMISSIONS STANDARDS

3. Particulate Matter Emissions Standard – Steady State Operations. As determined by EPA Method 5 or 17, particulate matter emissions from Units 1 and 2 combined shall not exceed 0.04 lb/MMBtu, on a weighted average basis of the total heat input. Compliance shall be demonstrated based on the average of the 3 required 1-hour test runs. [Rule 62-296.340 (BART), F.A.C.]

4. Particulate Matter Emissions Standard – Soot Blowing and Load Change Operations. As determined by EPA Method 5 or 17, particulate matter emissions from Units 1 and 2 combined shall not exceed 0.12 lb/MMBtu, on a weighted average basis of the total heat input, not to exceed 3 hours in any 24-hour period. Compliance shall be demonstrated based on the average of the 3 required 1-hour test runs. [Rule 62-296.340 (BART), F.A.C.]

5. Opacity Standard – Steady-State Operations. As determined by data collected from the existing COMS or EPA Method 9, visible emissions during steady-state operations from: Unit 1 shall not exceed 30% opacity

based on a 6-minute average except for one 6-minute average per hour not to exceed 35% opacity; Unit 2 shall not exceed 15% opacity based on a 6-minute average except for one 6-minute average per hour not to exceed 20% opacity. [Rule 62-296.340 (BART), F.A.C.]

6. Opacity Standard – Soot-Blowing and Load Change Operations. As determined by data collected from the existing COMS or EPA Method 9, visible emissions resulting from soot-blowing and load change operations shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized. In no case shall the duration of such emissions s exceed 3 hours in any 24-hour period and visible emissions from: Unit 1 shall not exceed 40% opacity based on a 6-minute average; Unit 2 shall not exceed 25% opacity based on a 6-minute average. A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more. [Rule 62-296.340 (BART), F.A.C.]

EXCESS EMISSIONS

7. Excess Emissions Allowed. Unless otherwise specified by permit, excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the Department for longer duration.

   Excess emissions from existing fossil fuel steam generators resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.

   [Rules 62-210.700(1) & (2), F.A.C.]

8. Excess Emissions Prohibited. Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

9. Excess Emissions Notification. In case of excess emissions resulting from malfunctions, the permittee shall notify the Compliance Authority in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]

MONITORING REQUIREMENTS

10. Control Equipment Monitoring. The ESPs used for the control of particulate matter emissions from these units are subject to the Compliance Assurance Monitoring (CAM) provisions contained in 40 CFR 64. The CAM parameter ranges to be monitored (total ESP power and continuous VE) shall be re-established during the initial testing required in Condition 13 and shall be submitted with the Title V operation permit revision application required by Section 2, Condition 5. Adherence to an approved CAM plan will satisfy the BART control equipment monitoring requirement. [Rules 62-296.340 (BART) and 62-4.070(3), F.A.C.; and 40 CFR 64]

    {Permitting Note: Because these units are subject to CAM, sufficient testing shall be conducted prior to submitting an application for a Title V permit revision to support the chosen CAM excursion indicators and ranges.}

EMISSIONS PERFORMANCE TESTING

11. Test Methods. The following reference methods (or more recent versions) shall be used to conduct any

required emissions tests.

Method	Description of Method and Comments
1 - 4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
5 or 17	Determination of PM Emissions from Stationary Sources
9	Visual Determination of Opacity from Stationary Sources

EPA Methods 1, 2, 3, 4, and 19 shall be used as necessary to support the other test methods. The above methods are described in 40 CFR 60, Appendix A, which is adopted by reference in Rule 62-204.800, F.A.C. No other methods shall be used without prior written approval from the Permitting Authority. [Rules 62-204.800 and 62-297.100, F.A.C.; and 40 CFR 60, Appendix A]

12. Standard Testing Requirements. All required emissions tests shall be conducted in accordance with the requirements specified in Appendix C (Standard Testing Requirements) of this permit. [Rules 62-204.800 and 62-297.100, F.A.C.; and 40 CFR 60, Appendix A]

13. Compliance Tests. During each federal fiscal year (October 1st to September 30th), the permittee shall conduct tests on Units 1 and 2 to demonstrate compliance with the BART standards for particulate matter and opacity. Initial compliance tests shall be conducted during federal fiscal year 2012/2013 (following the upgrades to the Unit 2 ESP) and a test report demonstrating compliance shall be submitted before October 1, 2013. [Rules 62-204.800, 62-296.340(3)(b)2 and 62-297.310(7)(a)4, F.A.C.; and 40 CFR 60, Appendix A, Method 9]

NOTIFICATIONS, RECORDS AND REPORTS

14. Plant Operation - Problems. If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

15. BART Permit Application for SO_2 and NO_X. In the event that CAIR is vacated by the Federal courts, the Department reserves the right to require the submission of a BART application for SO_2 and NO_X within 60 days of notification by the Department. [Rule 62-296.340, F.A.C.]

16. Shut Down of Units 1 and 2. Units 1 and 2 shall cease to be operated as coal-fired units by December 31, 2020. This date assumes timely licensing, construction and commencement of commercial operation of PEF's proposed new nuclear units (Levy County Units 1 and 2). The shutdown (or repowering) of Units 1 and 2 coal-fired units is contingent upon completion of the first fuel cycle for Levy County Unit 2. PEF shall timely advise the Department of any developments that would delay the shutdown (or repowering) of Units 1 and 2 beyond the completion of the first fuel cycle for Levy County Unit 2. [Rule 62-296.340 (BART), F.A.C. and Applicant Request]

SECTION 4. APPENDICES

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SECTION 4. APPENDIX A
CITATION FORMATS

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001"identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CRF 60.7]

Means: Title 40, Part 60, Section 7

SECTION 4. APPENDIX B
GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.
4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.
6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:
   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

   Reasonable time may depend on the nature of the concern being investigated.
8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:
   a. A description of and cause of non-compliance; and
   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.
10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.
11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
    a. Determination of Best Available Control Technology (Not Applicable);
    b. Determination of Prevention of Significant Deterioration (Not Applicable); and
    c. Compliance with New Source Performance Standards (Not Applicable).
14. The permittee shall comply with the following:
    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
    c. Records of monitoring information shall include:
        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.
15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

STANDARD CEMS REQUIREMENTS

Unless otherwise specified by permit, all emissions units that require testing are subject to the following conditions as applicable.

1. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]
2. Operating Rate During Testing: Unless otherwise stated in the applicable emission limiting standard rule, testing of emissions shall be conducted with the emissions unit operating at permitted capacity as defined below. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
   a. *Combustion Turbines.* (Reserved)
   b. *All Other Sources.* Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit.

   [Rule 62-297.310(2), F.A.C.]
3. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]
4. Applicable Test Procedures:
   a. *Required Sampling Time.*
      1) Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
      2) Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
         a) For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation

shall be equal to the duration of the batch cycle or operation completion time.

b) The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

c) The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

b. *Minimum Sample Volume.* Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

c. *Required Flow Rate Range.* For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

d. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1.

e. *Allowed Modification to EPA Method 5.* When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

TABLE 297.310-1 CALIBRATION SCHEDULE			
Item	Minimum Frequency	Reference Instrument	Tolerence
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent or thermometric points	± 2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass	5° F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5° F
Barometer	Monthly	Hg barometer or NOAA station	± 1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	± 0.001" mean of at least three readings; maximum deviation between readings, 0.004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, when 5% change observed, annually	Spirometer or calibrated wet test or dry gas test meter	2%
	2. One Point: Semiannually		
	3. Check after each test series	Comparison check	5%

[Rule 62-297.310(4), F.A.C.]

5. Determination of Process Variables:

   a. *Required Equipment*. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

   b. *Accuracy of Equipment*. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

   [Rule 62-297.310(5), F.A.C.]

6. Required Stack Sampling Facilities: Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must meet any Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

   a. *Permanent Test Facilities*. The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

   b. *Temporary Test Facilities*. The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

   c. *Sampling Ports*.

      1) All sampling ports shall have a minimum inside diameter of 3 inches.

      2) The ports shall be capable of being sealed when not in use.

      3) The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

      4) For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

      5) On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

d. *Work Platforms.*

1) Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

2) On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.

3) On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

4) All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toeboard, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

e. *Access to Work Platform.*

1) Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

2) Walkways over free-fall areas shall be equipped with safety rails and toeboards.

f. *Electrical Power.*

1) A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.

2) If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

g. *Sampling Equipment Support.*

1) A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

   a) The bracket shall be a standard 3 inch × 3 inch × one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

   b) A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

   c) The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

2) A complete monorail or dualrail arrangement may be substituted for the eyebolt and bracket.

3) When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

7. Frequency of Compliance Tests: The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

   a. General Compliance Testing.

      1) The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

      2) For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

      3) The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to sub-subparagraph 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

         a) Did not operate; or

         b) In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours,

      4) During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

         a) Visible emissions, if there is an applicable standard;

         b) Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

         c) Each NESHAP pollutant, if there is an applicable emission standard.

      5) An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

      6) For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.

      7) For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to paragraph 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.

      8) Any combustion turbine that does not operate for more than 400 hours per year shall conduct a

visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

9) The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

10) An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., F.A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.

b. Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

8. Test Reports:

a. The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

b. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.

c. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1) The type, location, and designation of the emissions unit tested.

2) The facility at which the emissions unit is located.

3) The owner or operator of the emissions unit.

4) The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.

5) The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.

6) The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.

7) A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.

8) The date, starting time and duration of each sampling run.

9) The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.

10) The number of points sampled and configuration and location of the sampling plane.

11) For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.

12) The type, manufacturer and configuration of the sampling equipment used.

13) Data related to the required calibration of the test equipment.

14) Data on the identification, processing and weights of all filters used.

15) Data on the types and amounts of any chemical solutions used.

16) Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.

17) The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.

18) All measured and calculated data required to be determined by each applicable test procedure for each run.

19) The detailed calculations for one run that relate the collected data to the calculated emission rate.

20) The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit plus the test result in the same form and unit of measure.

21) A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

9. Stack: The terms stack and duct are used interchangeably in this rule. [Rule 62-297.310(9), F.A.C.]

Walker, Elizabeth (AIR)

From:	Exchange Administrator
Sent:	Thursday, February 26, 2009 5:13 PM
To:	Walker, Elizabeth (AIR)
Subject:	Delivery Status Notification (Relay)
Attachments:	ATT239233.txt; FW: CRYSTAL RIVER POWER PLANT; 0170004-017-AC/BART

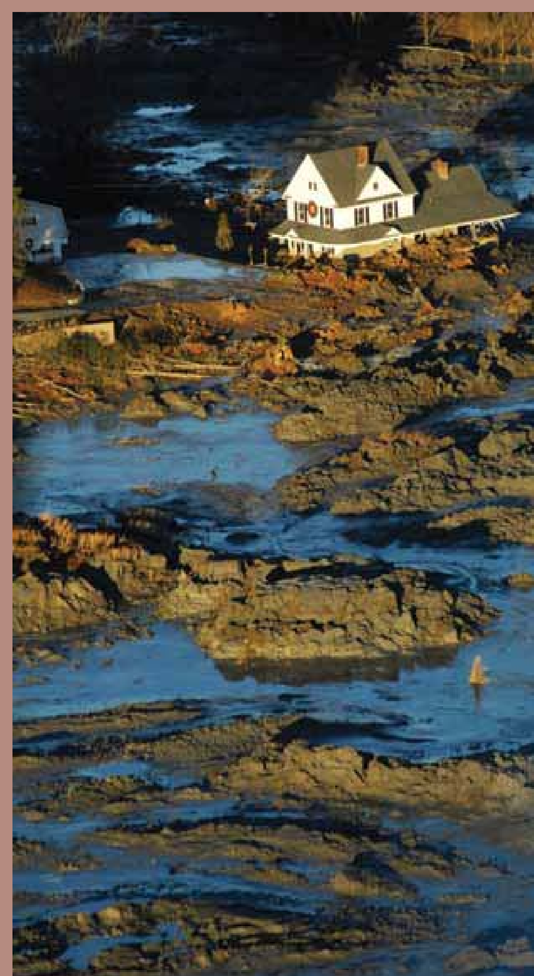
This is an automatically generated Delivery Status Notification.

Your message has been successfully relayed to the following recipients, but the requested delivery status notifications may not be generated by the destination.

bernie.cumbie@pgnmail.com

EPA's Blind Spot: Hexavalent Chromium in Coal Ash

Coal ash may be the secret source of cancer-causing chromium in your drinking water



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EIP ENVIRONMENTAL INTEGRITY PROJECT

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February 1, 2011

Introduction

Hexavalent chromium is again in the headlines. In the 1990s, Erin Brockovich achieved fame by uncovering the presence of extraordinarily high levels of industrial hexavalent chromium contamination in the drinking water of a small desert town ravaged by cancer. Today, attention to the deadly chemical is fueled by new data and extensive scientific research. In December 2010, the Environmental Working Group released a report documenting the cancer-causing chemical in tap water in 31 of 35 cities tested in the United States.[1] Days later, on December 31, 2010, the California Office of Environmental Health Hazard Assessment (OEHHA) completed a multi-year, peer-reviewed examination of the oral toxicity of the chemical, involving scientists in both the public and private sectors, and released a ground breaking proposal to establish a public health goal for hexavalent chromium in drinking water of just 0.02 parts per billion (or ug/L), 5,000 times lower than the current federal drinking water standard for total chromium.[2]

On January 11, 2011, on the heels of these announcements, the U.S. Environmental Protection Agency (EPA) issued new guidelines recommending that public water utilities nationwide test drinking water for hexavalent chromium (Cr(VI)).[3] EPA's swift reaction to the widespread presence of hexavalent chromium in American tap water is laudable. However, EPA's well-placed concern for protection of public health has a dangerous blind spot. While government regulators express concern for small quantities of the cancer-causing substance in our water, they are ignoring one of the largest sources of the hazardous chemical—coal combustion waste (or coal ash)[4] from the nation's coal burning power plants.

This report documents the connection between coal ash and hexavalent chromium. It reviews the sources, toxicity, and known coal ash dump sites where chromium has been found in groundwater. The report identifies studies of numerous power plants where testing of coal ash leachate found extremely high levels of hexavalent chromium. The report also identifies 28 coal ash disposal sites in 17 states where groundwater was documented to exceed existing federal or state standards for chromium and to exceed by many orders of magnitude the proposed California drinking water goal for hexavalent chromium. These contaminated coal ash dump sites are likely the tip of the iceberg. The threat of drinking water contamination by hexavalent chromium is present in hundreds of communities near unlined coal ash disposal sites across the United States. While the EPA doesn't need another reason to define coal ash as a hazardous waste when disposed, it certainly has one now.

Hexavalent Chromium and Coal Ash: The Deadly Connection

It has long been known that chromium readily leaches from coal ash.[5] Chromium, however, occurs primarily in two forms: trivalent chromium, which is an essential nutrient in small amounts, and hexavalent chromium, Cr(IV), which is highly toxic even in small doses. In EPA's latest report on the hazardous contaminants in coal ash, the agency made two important findings:

• Coal ash leaches chromium in amounts that can greatly exceed EPA's threshold for hazardous waste at 5000 parts per billion (ppb),[6] and

• The chromium that leaches from coal ash is "nearly 100 percent [hexavalent] Cr(VI)."[7]

Remarkably, the U.S. Department of Energy (DOE) and the energy industry have also known for years about the aggressive leaching of hexavalent chromium from coal ash. In a 2006 report co-sponsored by DOE, the Electric Power Research Institute (EPRI) found that the chromium that leaches from coal ash (including flue gas desulfurization (FGD) sludge) is typically close to 100% hexavalent chromium.[8]

These findings, buried in government reports, need to see the light of day. Hundreds – maybe thousands – of leaking and unlined coal ash dumps are situated near water supplies. EPA and DOE have demonstrated that the contaminated leachate (the liquid leaking from coal ash landfills and ponds) is often rich in this cancer-causing chemical. Therefore it is imperative that EPA Administrator Lisa Jackson act decisively to protect U.S. communities from this significant source of hexavalent chromium.

Hexavalent Chromium's Deadly Link to Cancer

In 2008, a two-year study by the U.S. Department of Health and Human Services' National Toxicology Program (NTP)[9] demonstrated that hexavalent chromium in drinking water causes cancer in laboratory animals.[10] While it has long been known that hexavalent chromium causes lung cancer when inhaled, the NTP undertook a study of Cr(VI) ingestion following a request from California's Office of Environmental Health Hazard Assessment (OEHHA). Based on a variety of cancerous oral and intestinal tumors, the NTP study definitively concluded "hexavalent chromium can also cause cancer in animals when administered orally."[11]

Furthermore, scientists believe chronic ingestion of minute amounts of Cr(VI) can be harmful. In fact, after an extensive peer-reviewed study, the California Office of Environmental Health Hazard Assessment lowered its original hexavalent chromium draft goal by 66 percent this year to account for the special sensitivity of infants and children to carcinogens. California's proposed public health goal, 0.02 parts per billion, is a mere 0.02% of the present federal drinking water standard for total chromium. If the current federal drinking water standard (100 parts per billion) is compared to a 100-yard football field, California's proposed goal for Cr(VI)would be a distance of three-quarters of an inch.

According to EPA's 2010 draft toxicological review of hexavalent chromium, EPA agrees with the estimate of cancer potency used by California's Office of Environmental Health Hazard Assessment. California's Draft Public Health Goal[12] and the U.S. EPA Draft Toxicological Review of Hexavalent Chromium[13] both use the same cancer potency value for ingested hexavalent chromium of 0.5 $(mg/kg\text{-}d)^{-1}$. Using EPA's default assumptions for body weight and drinking water ingestion rate, it is possible to estimate the lifetime cancer risk associated with drinking water at the current federal drinking water standard for total chromium of 100 ppb (established in 1991) – the risk is 1.4 in 1,000 people.[14] This risk is 140 – 1400 times greater than EPA's range of acceptable cancer risk (between1 in 100,000 and 1 in 1,000,000 people).[15] Clearly, in view of this elevated risk recognized by both EPA and OEHHA, the 1991 federal drinking water standard of 100 ppb for total chromium is not sufficiently protective of human health from ingestion of hexavalent chromium. While a new federal drinking water standard for hexavalent chromium may be higher than California's proposed goal of 0.02 ppb, this health-protective level, as well as the current federal standard, are used as a comparison to coal ash-contaminated waters in this report.

Ingestion of Hexavalent Chromium Is Missing from EPA's Coal Ash Risk Assessment

Although the cancer risk associated with Cr(VI) in groundwater is substantial, EPA completely ignored this risk in its proposed coal ash rulemaking. While Cr(VI) was discussed in the preamble to the proposed rule, it was treated as a carcinogen by inhalation only. For purposes of calculating the human health risk by ingestion, Cr(VI) was treated as a non-carcinogen.[16] Despite the clear findings of NTP's 2008 studies, the cancer risk of ingested Cr(VI) was not mentioned once in EPA's 400-page "*Health and Ecological Risk Assessment for Coal Combustion Wastes*."

Coal Ash Dump Sites Are Significant Sources of Hexavalent Chromium

Coal ash can leach deadly quantities of Cr(VI) to drinking water.[17] For example, in the 2006 study[18] by the Electric Power Research Institute, an organization that vehemently opposes a hazardous designation for coal ash, EPRI tested leachate—liquid collected from wells, ponds or seeps at coal ash dumps—at 29 coal ash landfills and ponds and found hexavalent chromium at hundreds of times the proposed California drinking water goal at 15 coal ash disposal sites. Their findings included three landfills where leachate exceeded the proposed drinking water goal by 5,000 times, with two landfills exceeding that goal by 100,000 and 250,000 times. The location of these potentially deadly dumps is not known, but the high levels of hexavalent chromium at the sites may pose a danger to those living near the landfills. Table A lists the coal ash dump sites where leachate was found containing hexavalent chromium over 5,000 times the proposed California health goal.

Table A

Coal Ash Dump Sites Identified by the Electric Power Research Institute with Leachate containing Hexavalent Chromium (Cr(VI))

Coal ash Dump Site (Location Undisclosed)	Type of Dump Site	Type of Coal Ash Waste	Amount of Hexavalent Chromium Found in Landfill Leachate (parts per billion (ppb))	Number of Times By Which Cr(VI) Level Exceeds California Drinking Water Goal	Amount of Cr(VI) over the Federal Drinking Water Standard
EPRI Id. No. 50213	Landfill	Fly Ash	5090 ppb	254,500 times	50.9 times
EPRI Id. No. 27413	Landfill	Fly Ash	109 ppb	5,450 times	1.09 times
EPRI Id. No. 50212	Landfill	Fly Ash	2230 ppb	111,500 times	223 times

Source: Electric Power Research Institute, Characterization of Field Leachates at Coal Combustion Product Management Sites, EPRI Report 1012578 (2006).

In addition, data from **known coal ash disposal sites** obtained from EPA reports[19] and recent studies by Earthjustice, the Environmental Integrity Project (EIP) and the Sierra Club[20] make it eminently clear that the threat is widespread and serious. For example, chromium in groundwater contaminated by a coal ash landfill in Ohio reached 1.68 parts per million – a level 84,000 times California's proposed drinking water goal (if nearly all the chromium measured was hexavalent, as predicted in both EPA's and EPRI's reports). Table B lists 28 coal ash dump sites in 17 states where coal ash contaminated groundwater was found to contain chromium at levels exceeding the current federal drinking water standard (100 ppb) or an applicable state standard (50 ppb for groundwater in North Carolina). Often EPA did not provide a specific value for the chromium found in groundwater wells, but simply indicated that it was greater than the federal standard of 100 ppb. These chromium concentrations, if 100 percent hexavalent chromium, represent a level 5,000 times higher than the proposed California goal. In Table B, all chromium is assumed to be hexavalent chromium, a premise supported by the studies conducted by EPA, DOE and EPRI. In addition, most of the coal ash ponds, landfills and fill sites listed below are unlined – a factor that greatly increases the danger to neighboring communities. Lastly, while many of the sites below have undergone some form of remediation under Superfund or state authorities, in most cases the contamination has been left in place, and there may be little attempt to monitor its migration off-site to protect well users from harmful exposure to hexavalent chromium or other toxic metals commonly found in coal ash leachate.

Table B

Name and Location of Coal Ash Disposal Site	Type of Dump Site	Level of Chromium (Highest Level Reported)	Number of Times By Which Cr(VI) Level Exceeds California Drinking Water Goal	Amount of Chromium Above Federal Drinking Water Standard	Source
TVA Colbert Fossil Fuel Plant **Tuscambia, Alabama**	Unlined Pond	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA[a]
2. TVA Widows Creek Fossil Plant **Stevenson, Alabama**	Unlined Pond	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
3. Flint Creek Power Plant **Gentry, Arkansas**	Landfill	128 ppb	6,400 times	1.28 times	EJ/EIP/ SC[b]
4. Indian River Power Station **Millsboro, Delaware**	Unlined Landfill (closed)	211 ppb	10,550 times	2.11 times	EJ/EIP[c]
5. FP&L Lansing Smith Plant **Southport, Florida**	unknown	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
6. Rocky Acres/Grays Siding Coal Combustion Byproduct Landfill **Oakwood, Illinois**	Unlined Fill Site	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EJ/EIP
7. Merom Generating Station Coal Combustion Waste Landfill **Sullivan, Indiana**	Landfill	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
8. Xcel Energy/Southern Minnesota Municipal Power Agency - Sherburne County (Sherco) Generating Plant **Becker, Minnesota**	unknown	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
9. Salem Acres Site, **Salem Massachusetts**	Unlined Landfill (closed)	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
10. Brayton Point Power Station, **Somerset, Massachusetts**	Unlined Landfill	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
11. Duke Dan River Steam Station **Eden, North Carolina**	Unlined Ponds and Landfill	61 ppb	3,050 times	22% over NC groundwater standard	EJ/EIP/

Name and Location of Coal Ash Disposal Site	Type of Dump Site	Level of Chromium (Highest Level Reported)	Number of Times By Which Cr(VI) Level Exceeds California Drinking Water Goal	Amount of Chromium Above Federal Drinking Water Standard	Source
12. Progress Energy Asheville Steam Electric Plant **Asheville, North Carolina**	Unlined Pond	83 ppb	4,150 times	66% over NC groundwater standard	EJ/EIP
13. Progress Energy Cape Fear Steam Plant **Montcure, North Carolina**	Unlined Pond	100 ppb	5,000 times	Equal to federal maximum	EJ/EIP
14. Basin Electric Power Cooperative W.J. Neal Station Surface Impoundment **Velva, North Dakota**	Unlined Pond	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
15. Reid Gardner Generating Facility **Moapa, Nevada**	Landfill	110 ppb	5,500 times	1.1 time	EJ/EIP
16. Conesville Fixed FGD Sludge Landfill **Coshocon County, Ohio**	Unlined Landfill	Above 100 ppb	Over 5000 times	Above standard, but degree unknown	EPA
17. Industrial Excess Landfill **Uniontown, OH**	Unlined Landfill	1680 ppb	84,000 times	1.68 times	EJ/EIP/
18. American Electric Power Northeastern Station **Oologah, Oklahoma**	Unlined Landfill and Pond	417 ppb	20,850 times	4.17 times	EJ/EIP/
19. Allegheny Energy Hatfield Ferry Power Station **Masontown, Pennsylvania**	Landfill	104 ppb	5,200 times	1.04 times	EJ/EIP/
20. Seward Generating Station **New Florence, Pennsylvania**	Unlined Pond and Landfill	330 ppb	16,500 times	3.3 times	EJ/EIP
21. PPL Martins Creek Power Plant **Martins Creek, Pennsylvania**	Unlined Pond	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
22. TVA Johnsonville Fossil Plant **New Johnsonville, Tennessee**	Unlined Pond	620 ppb	31,000 times	6.2 times	EJ/EIP/
23. Trans-Ash, Inc CCW Landfill, **Camden, Tennessee**	Partially Unlined Landfill	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EJ/EIP

Name and Location of Coal Ash Disposal Site	Type of Dump Site	Level of Chromium (Highest Level Reported)	Number of Times By Which Cr(VI) Level Exceeds California Drinking Water Goal	Amount of Chromium Above Federal Drinking Water Standard	Source
24. TVA Kingston Fossil Plant **Harriman, Tennessee**	Unlined Pond	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
25. Battlefield Golf Course **Chesapeake, Virginia**	Unlined Fill	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
26. Virginia Power Yorktown Power Station Chisman Creek Disposal Site **Yorktown, Virginia**	Unlined Landfill	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
27. Dairyland Power Cooperative E.J. Stoneman Generating Station Ash Disposal Pond **Cassville, Wisconsin**	Unlined Pond	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
28. Lemberger Landfill, **Wisconsin**	Unlined Landfill	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA

a: U.S. EPA, Damage Case Report for Coal Combustion Wastes (August 2007) and additional damage cases described in EPA's Proposed Coal Ash Rule, 75 Fed. Reg. 35128.
b: Earthjustice, Environmental Integrity Project, and Sierra Club. In Harm's Way: Lack of Federal Coal Ash Regulations Endangers Americans and their Environment (August 2010).
c: Earthjustice and Environmental Integrity Project. Out of Control: Mounting Damages from Coal Ash Waste Sites (May 2010).

Uniontown, Ohio: A Coal Ash Site Where Health May be Endangered

The **Industrial Excess Landfill**, near Uniontown, Ohio is an example of the kind of site that may be posing a threat to the surrounding community from contamination of drinking water with hexavalent chromium. The landfill is a Superfund site surrounded on three sides by residential neighborhoods. Roughly one million tons of coal ash were dumped at the landfill in the 1960s. The landfill was closed in 1980, and EPA listed it as a Superfund site in 1986. Groundwater monitoring since then has shown chromium concentrations to be increasing to very dangerous levels. Systematic groundwater monitoring began in 1987, and chromium was detected at concentrations up to 180 ppb in off-site wells. Sampling in the early 1990s found concentrations of chromium over 100 ppb in eight monitoring wells, with concentrations up to 739 ppb. Monitoring through 2001 detected chromium at up to 1,680 ppb in off-site wells located in or near residential areas- over 15 times the federal drinking water standard. Residents report many incidences of cancer in the affected neighborhoods.

Despite alarming evidence of off-site groundwater contamination with heavy metals, including chromium, metals monitoring was phased out around 2001, and remedial actions stopped in 2005. And yet the potential for human exposure to this contamination is very high—there are almost 4,000 private drinking water wells within two miles of the site, and about 90 wells within 1,500 feet. Some homes have been provided with alternative water supplies, but many have not. The cancer risk associated with drinking water having chromium concentrations over 100 ppb is greater than 1 in 1,000. The risk associated with the highest known concentration, 1,680 ppb, would be greater than 1 in 50. Furthermore, this cancer risk would be amplified by the presence of arsenic and other carcinogens in the coal ash contaminant plume.

EPA Laboratory Testing of Coal Ash Reveals Dramatic Chromium Leaching

EPA also found that leachate produced in the laboratory from coal ash at a variety of plants contained sky-high chromium. In a 2009 report, EPA tested coal ash leachate by obtaining waste from numerous operating power plants.[21] EPA found that many ashes and sludges produce leachate extremely rich in chromium. The table below provides EPA's results from five plants. These results represent the highest level of chromium in leachate determined by EPA lab tests. Unlike the EPRI data in Table A and the groundwater and surface water data in Table B, the results below were not field samples. However, EPA used a leach test that mimics field conditions in order to determine the range of chromium that would leach from coal ash disposed under real-world conditions. If this leachate were seeping or leaking into groundwater from a landfill or pond, it could threaten drinking water wells and human health. While the public is not likely to be exposed to coal ash leachate at full strength, leachate this rich in chromium, even if it is diluted as it flows through groundwater, can still pose a significant hazard when it reaches drinking water wells.

Table C

Name and Location of Power Plant	Level of Chromium In Leachate	Number of Times Cr(VI) Level Exceeds CA Drinking Water Goal	Number of Times Above Federal Drinking Water Standard
DTE Energy St. Clair Power Plant **East China, Michigan**	1140 ppb (all Cr(VI))	57,000 times	11.4 times
TVA's Widows Creek Plant **Stevenson, Alabama**	7370 ppb	368,500 times	73.7 times
Progress Energy Roxboro Plant **Semora, North Carolina**	1850 ppb	92,500 times	18.5 times
Southern Company Crist Plant **Pensacola, Florida**	1920 ppb	96,000 times	19.2 times
WE Energies Pleasant Prairie Plant **Kenosha, Wisconsin**	3443 ppb	172,150 times	34.3 times

How much chromium is released by U.S. Coal-Fired Power Plants each year?

The amount of chromium released by our nation's coal-burning power plants dwarfs all other industrial sources. According to EPA's Toxic Release Inventory, the electric power industry dumps over ten million pounds of chromium and chromium compounds in on-and off-site disposal sites each year. Between 2000 and 2009, **over 116 million pounds** of chromium and chromium compounds were released from coal-fired power plants. The overwhelming majority of this chromium ends up in unlined or inadequately lined coal ash landfills, ponds, and mines. See Table D.

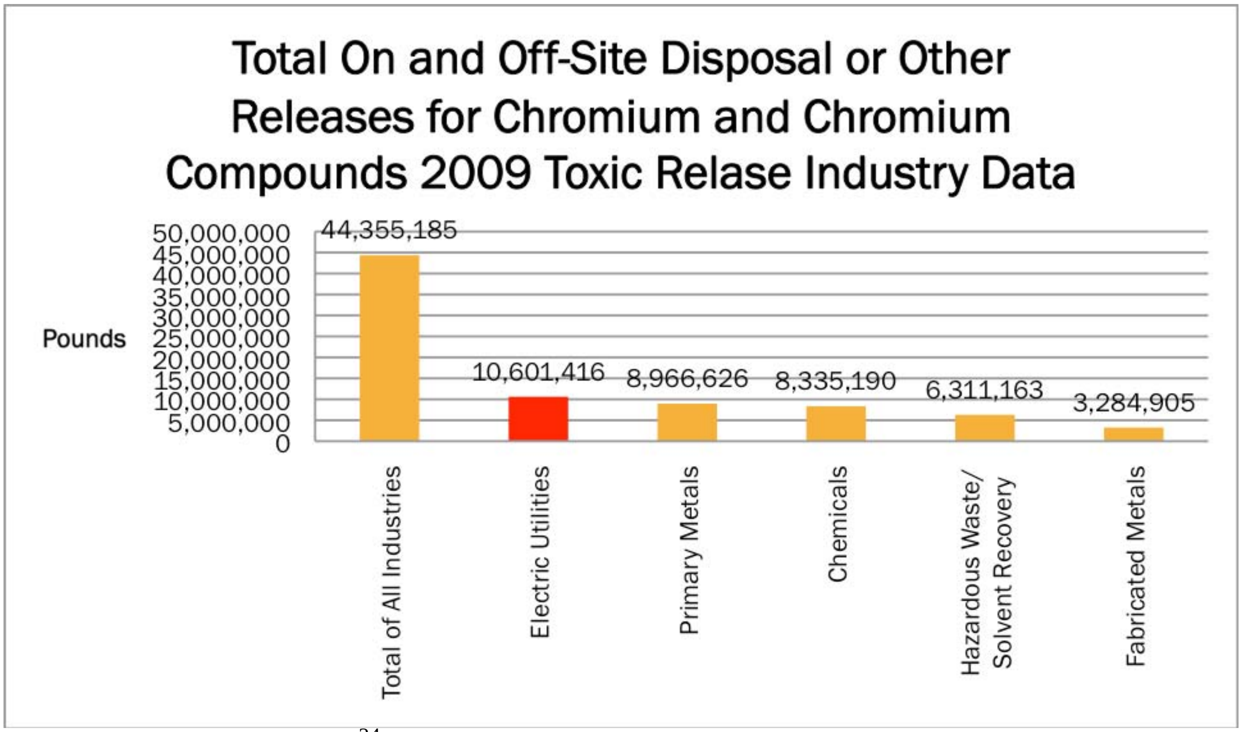
Table D

Chromium and Chromium Compound Disposal Reported to TRI By Year (pounds) 2000-2009		
YEAR	RELEASES TO DISPOSAL UNITS	TOTAL AMOUNT RELEASED
2009	10,161,172	10,601,419
2008	11,502,282	12,102,656
2007	11,459,398	11,871,535
2006	10,877,609	11,220,349
2005	11,577,014	11,960,425
2004	11,537,051	11,963,400
2003	11,607,647	12,057,221
2002	11,720,460	12,285,721
2001	10,293,621	12,202,505
2000	8,375,845	10,221,991
Total	109,112,099	116,487,222

In 2009, the electric power industry reported 10.6 million pounds of chromium and chromium compounds were released to the environment (10.1 million of which was dumped in disposal sites). These 10.6 million pounds represent **24 percent** of the total chromium and chromium compounds released by **all industries** in 2009. See Chart, below. In fact, the top ten chromium-releasing coal-fired power plants alone released almost 1.8 million pounds of chromium and chromium compounds in 2009, and each of these has at least one – if not, more than one – unlined coal ash disposal unit. Despite the obvious significance of this source of chromium, coal-fired power plants are rarely tagged as a source of hexavalent chromium.

As the Air Gets Cleaner, the Threat to Drinking Water Increases

EPA has found that as power plants reduce their emissions of nitrogen oxides (NO_X) by employing pollution controls at the power plant stacks, more hexavalent chromium is found in the flue gas desulfurization (FGD) sludge.[22] According to EPA, over half of the U.S. coal-fired capacity is projected to be equipped with SCR and/or FGD technology by 2020.[23] In fact, EPA anticipates an increase of approximately 16%



in scrubbed units by 2015.[24] Thus as the Clean Air Act requires more and more plants to install pollution controls, we may experience a much greater threat to our drinking water from hexavalent chromium if disposal of the increased volume of FGD sludge is not properly controlled.

EPA Must Determine that Coal Ash is Hazardous When Disposed

Although coal ash readily leaches hexavalent chromium, the waste is currently not federally regulated and is routinely dumped in unlined ponds and pits and used as construction fill without restriction. **EPA must keep this dangerous chemical out of our water – by regulating coal ash, when disposed, as a hazardous waste, thereby requiring its disposal in safe, secure landfills.**

In addition, EPA should immediately investigate the ponds, landfills and fill sites identified in this report to determine if public health is being threatened by exposure to hexavalent chromium, including:

- The three landfills identified in the DOE/EPRI report where Cr(VI) levels in leachate exceed proposed drinking water goals by thousands to hundreds of thousands of times (Table A);

- The 28 landfills, ponds and fill sites where groundwater has been contaminated with chromium over the current federal drinking water standard (Table B) and thousands of times over the proposed drinking water goal (Table B); and

- The disposal sites at the five plants where EPA's laboratory tests document the potential for dangerous levels of Cr(VI) to leach from ash and sludge (Table C).

EPA must conduct these investigations to ensure that highly contaminated leachate from these coal ash disposal sites is not leaking into drinking water and threatening human health. However, it is important to understand that these sites do not represent the universe of coal ash sites that have contaminated groundwater with chromium. Most coal ash disposal sites in the U.S. is are not monitored sufficiently to determine whether they are contaminating groundwater, and certainly very few coal ash sites are monitored for hexavalent chromium at all. Ultimately only the regulation of coal ash under subtitle C of the Resource Conservation and Recovery Act will ensure that these disposal sites, as well as every coal ash dump in the nation, are constructed securely and monitored sufficiently to keep hexavalent chromium out of our drinking water.

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[1] Envtl. Working Group, Chromium-6 Is Widespread in U.S. Tap Water, http://static.ewg.org/reports/2010/chrome6/html/home.html.

[2] California Environmental Protection Agency, Office of Environmental Health and Hazard Assessment, Press Release: OEHHA Releases Revised Draft Public Health Goal for Hexavalent Chromium (Dec. 31, 2010), *available at* http://oehha.ca.gov/water/phg/pdf/Chrom6press123110.pdf.

[3] U.S. Envtl. Protection Agency (U.S. EPA), Press Release: EPA Issues Guidance for Enhanced Monitoring of Hexavalent Chromium in Drinking Water (Jan. 11, 2011), *available at*

http://yosemite.epa.gov/opa/admpress.nsf/a883dc3da7094f97852572a00065d7d8/93a75b03149d30b08525781500600f62!OpenDocument.

[4]Coal ash is commonly used to encompass the entire solid waste stream resulting from the combustion of coal, including fly ash, flue gas desulfurization (FGD) sludge, bottom ash and boiler slag.

[5] *Office of Solid Waste & Emergency Response, U.S. EPA, Report to Congress: Wastes from the Combustion of Fossil Fuels* (Mar. 1999).

[6] *Office of Research & Dev., U.S. EPA, Characterization of Coal Combustion Residues from Electric Utilities – Leaching and Characterization Data* (EPA-600/R-09/151) at xiv, 91 (Dec. 2009), http://www.epa.gov/nrmrl/pubs/600r09151/600r09151.pdf.

[7] *Id*. at 91.

[8] *Electric Power Research Institute, Characterization of Field Leachates at Coal Combustion Product Management Sites, Arsenic, Selenium, Chromium, and Mercury Speciation* (Nov. 2006) at 5–26.

[9] The NTP, established in 1978, is an interagency program whose mission is to evaluate agents of public health concern by developing and applying tools of modern toxicology and molecular biology. According to HHS, "The program maintains an objective, science-based approach in dealing with critical issues in toxicology and is committed to using the best science available to prioritize, design, conduct, and interpret its studies." *See* Nat'l Toxicology Program, Dep't Health & Human Serv., History of the NTPhttp://ntp.niehs.nih.gov/?objectid=720163C9-BDB7-CEBA-FE4B970B9E72BF54.

[10] Nat'l Toxicology Program, Dep't Health & Human Serv., Hexavalent Chromium, http://ntp.niehs.nih.gov/files/NTPHexaVChrmFactR5.pdf.

[11] *Id.*

[12] Cal. Envtl. Prot. Agency, Public Health Goal for Hexavalent Chromium in Drinking Water, 1, 75–77 (draft, Dec. 2010).

[13] U.S. EPA, Toxicological Review of Hexavalent Chromium, 240 (external review draft, Sept. 2010).

[14] It is standard practice when converting a cancer potency estimate to a unit risk (risk per ug/L) or a risk estimate to assume a 70 kg body weight and a drinking water ingestion rate of 2 L/d. *See, e.g., U.S. EPA, Exposure Factors Handbook* (Aug. 1997), *available at* http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=12464.

[15] U.S. EPA, Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities75 Fed. Reg. 35,128, 35,169–70 (proposed June 21, 2010).

[16] U.S. EPA, Human and Ecological Risk Assessment of Coal Combustion Wastes (draft, Apr. 2010)

[17] U.S. EPA, *Characterization of Coal Combustion Residues from Electric Utilities – Leaching and Characterization Data* (EPA-600/R-09/151), at 7 (Dec. 2009).

[18] *Electric Power Research Institute, Characterization of Field Leachates at Coal Combustion Product Management Sites, Arsenic, Selenium, Chromium, and Mercury Speciation* (Nov. 2006).

[19] *U.S. EPA, Coal Combustion waste Damage Cases* (July 9, 2007); *Office of Research & Dev., U.S. EPA, Characterization of Coal*
Combustion Residues from Electric Utilities – Leaching and Characterization Data (EPA-600/R-09/151) (Dec. 2009).

[20] *The Environmental Integrity Project, Earthjustice, & Sierra Club, In Harm's Way: How Lack of Federal Coal Ash Regulations Endangers Americans and Their Environment* (Aug. 26, 2010), *available at* http://earthjustice.org/sites/default/files/files/report-in-harms-way.pdf; *The Environmental Integrity Project and Earthjustice, Out of Control: Mounting Damages from Coal Ash Waste Sites* (Feb. 24, 2010), *available at* http://www.environmentalintegrity.org/news_reports/documents/OutofControl-MountingDamagesFromCoalAshWasteSites.pdf.

[21] *Office of Research & Dev., U.S. EPA, Characterization of Coal*
Combustion Residues from Electric Utilities – Leaching and Characterization Data (EPA-600/R-09/151) (Dec. 2009).

[22] *Id.* at 91.

[23] *Id.* at 7.

[24] U.S. EPA, *Steam Electric Power Generating Point Source Category: Final Detailed Study Report* 4-1-4-6 (2009).

JUNE 2011

LEVELIZED COST OF ENERGY ANALYSIS – VERSION 5.0

LAZARD

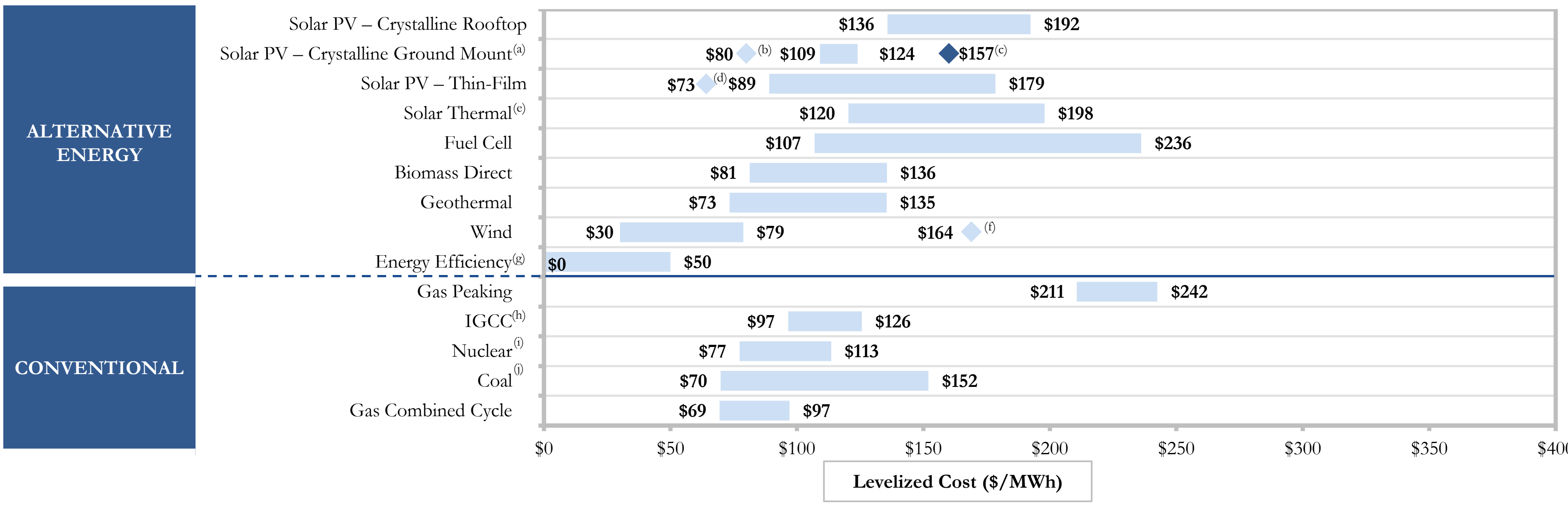
Introduction

Lazard's Levelized Cost of Energy Analysis ("LCOE") addresses the following topics:

- **Comparative "levelized cost of energy" for various technologies on a $/MWh basis, including sensitivities, as relevant, for:**
  - Fuel costs
  - U.S. federal tax subsidies
  - Anticipated capital costs, over time
- **Illustration of how the costs of solar-produced energy compare against peak power costs in large metropolitan areas of the United States**
- **Comparison of assumed capital costs on a $/kW basis for various generation technologies**
- **Decomposition of the levelized costs of energy for various generation technologies by capital costs, fixed operations & maintenance expense, variable operations & maintenance expense, and fuel costs, as relevant**
- **Considerations regarding the applicability of various generation resources, taking into account factors such as location requirements/constraints, dispatch characteristics, land and water requirements and other contingencies**
- **Summary assumptions for the various generation technologies examined**
- **Summary of Lazard's approach to comparing the levelized cost of energy for various conventional and Alternative Energy generation technologies, including identification of key potential sensitivities not addressed in the scope of this presentation**

Levelized Cost of Energy Comparison

Certain Alternative Energy generation technologies are becoming increasingly cost-competitive with conventional generation technologies under some scenarios, before factoring in environmental and other externalities (e.g., RECs, transmission and back-up generation/system reliability costs) as well as construction and fuel costs dynamics affecting conventional generation technologies



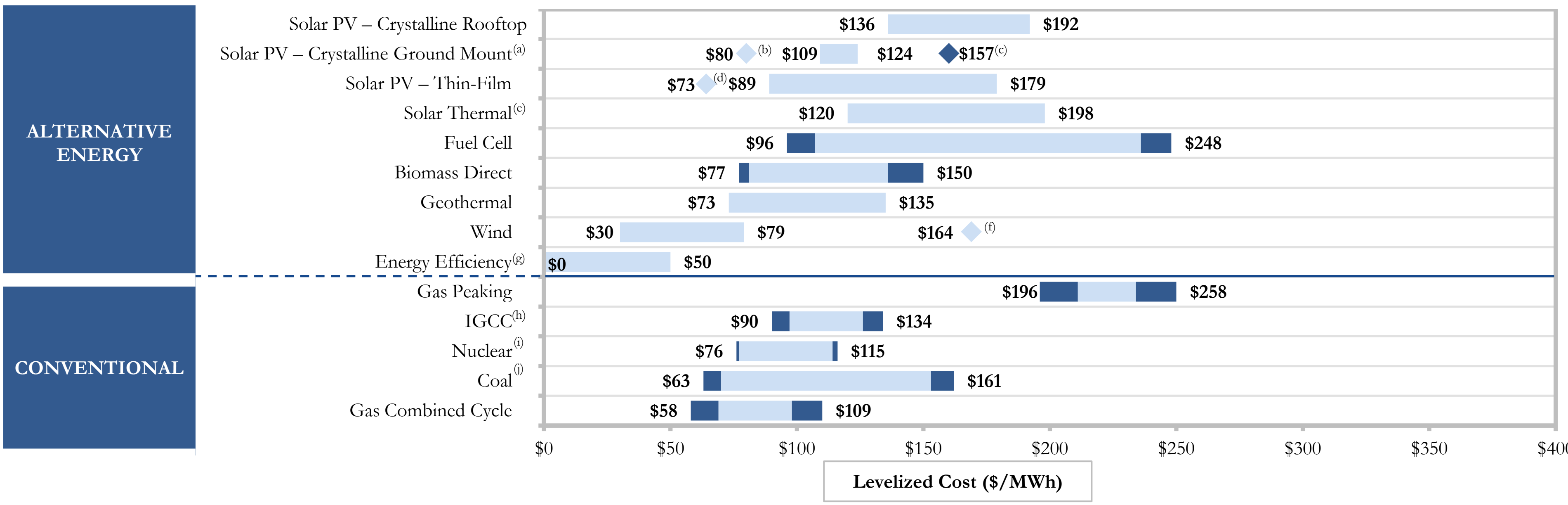
Source: Lazard estimates.

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2010 dollars, 20-40-year economic life, 40% tax rate and 5-40 year tax life. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $5.50 per MMBtu.

(a) Low end represents single-axis tracking crystalline. High end represents fixed installation.
(b) Represents estimated implied levelized cost of energy in 2012, assuming a total system cost of $2.50 per watt for single-axis tracking crystalline.
(c) Represents a leading concentrating photovoltaic company's targeted levelized cost of energy, assuming a total system cost of approximately $4.00 per watt.
(d) Represents a leading thin-film company's targeted implied levelized cost of energy in 2012, assuming a total system cost of $2.00 per watt.
(e) Represents both solar tower and solar trough, each with 3 hour storage capability.
(f) Represents estimated midpoint of off-shore wind's levelized cost of energy, assuming a range of total system cost of $3.10 – $5.00 per watt.
(g) Estimates per National Action Plan for Energy Efficiency; actual cost for various initiatives varies widely.
(h) High end incorporates 90% carbon capture and compression.
(i) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(j) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression.

Levelized Cost of Energy Comparison – Sensitivity to Fuel Prices

Variations in fuel prices can materially affect the levelized cost of energy for conventional generation technologies, but direct comparisons against "competing" Alternative Energy generation technologies must take into account issues such as dispatch characteristics (e.g., baseload and/or dispatchable intermediate load vs. peaking or intermittent technologies)



Source: Lazard estimates.

Note: Darkened areas in horizontal bars represent low end and high end levelized cost of energy corresponding with ±25% fuel price fluctuations

(a) Low end represents single-axis tracking crystalline. High end represents fixed installation.

(b) Represents estimated implied levelized cost of energy in 2012, assuming a total system cost of $2.50 per watt for single-axis tracking crystalline.

(c) Represents a leading concentrating photovoltaic company's targeted levelized cost of energy, assuming a total system cost of approximately $4.00 per watt.

(d) Represents a leading thin-film company's targeted implied levelized cost of energy in 2012, assuming a total system cost of $2.00 per watt.

(e) Represents both solar tower and solar trough, each with 3 hour storage capability.

(f) Represents estimated midpoint of off-shore wind's levelized cost of energy, assuming a range of total system cost of $3.10 – $5.00 per watt.

(g) Estimates per National Action Plan for Energy Efficiency; actual cost for various initiatives varies widely.

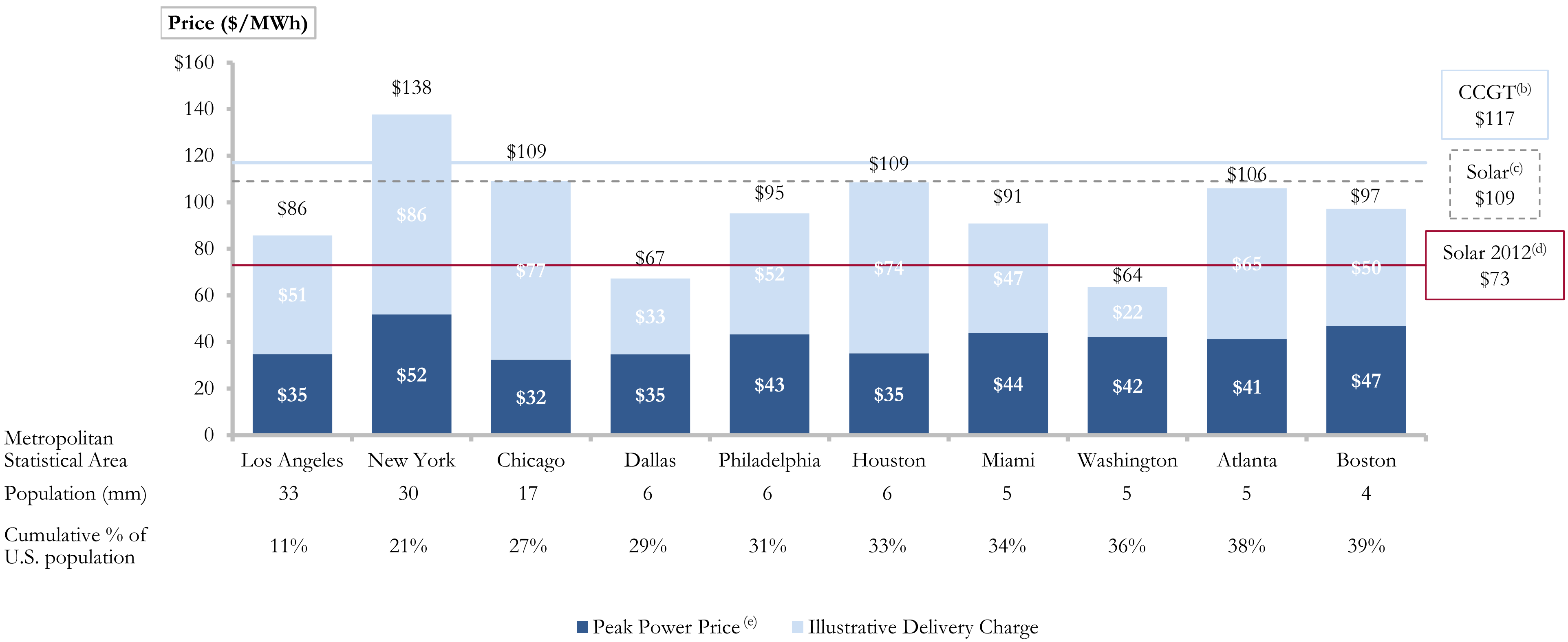
(h) High end incorporates 90% carbon capture and compression.

(i) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

(j) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression.

Peak Pricing for the 10 Largest U.S. Metropolitan Areas[(a)]

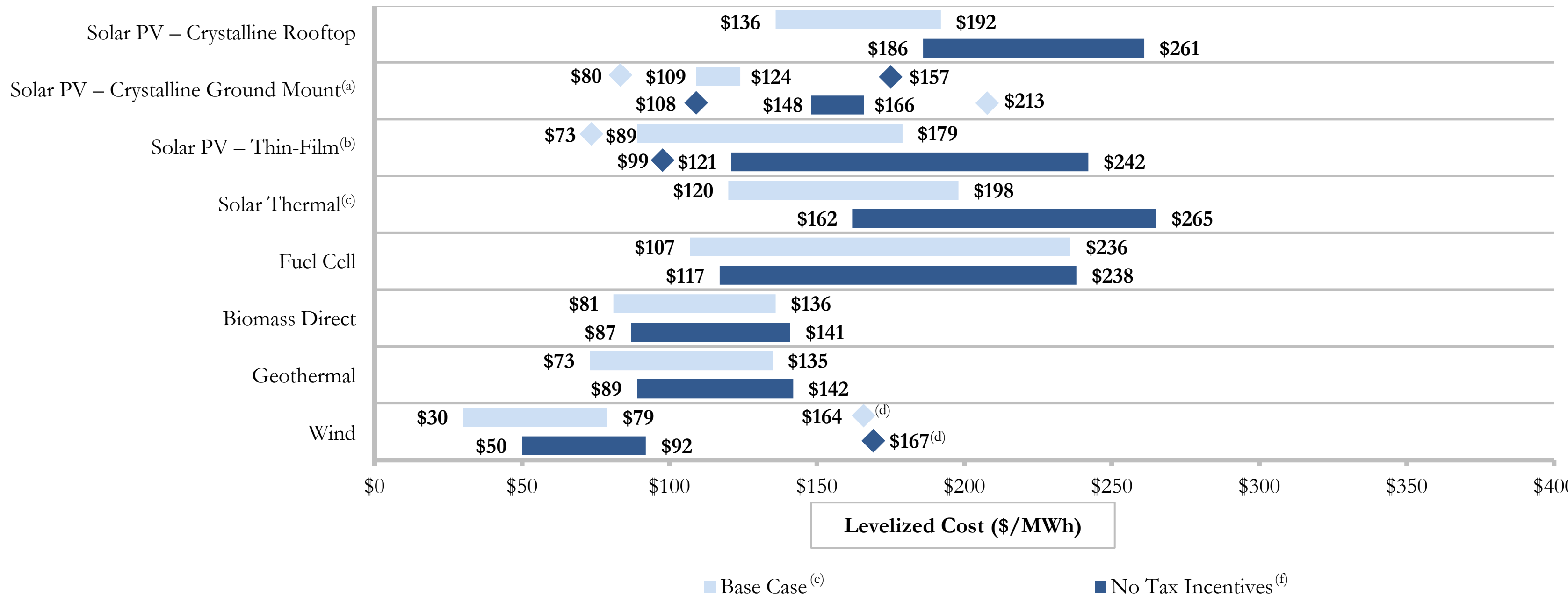
Setting aside the legislatively-mandated demand for solar and other Alternative Energy resources, solar is becoming a more economically viable peaking energy product in many areas of the U.S., and, as pricing declines, could become economically competitive across a broader array of geographies; this observation, however, does not take into account the full costs of incremental transmission and back-up generation/system reliability costs



(a) Defined as 10 largest Metropolitan Statistical Areas per the U.S. Census Bureau for a total population of 119 million.
(b) Assumes 25% capacity factor.
(c) Represents low end of solar PV crystalline.
(d) Represents a leading thin-film company's targeted implied levelized cost of energy in 2012.
(e) Represents the average of the hourly wholesale prices between 12 noon and 6pm at a normalized natural gas price.

Levelized Cost of Energy – Sensitivity to U.S. Federal Tax Subsidies

U.S. federal tax subsidies remain an important component of the economics of Alternative Energy generation technologies (and government incentives are important in all regions); future cost reductions in technologies such as solar PV, solar thermal and fuel cells have the potential to enable these technologies to approach "grid parity" without tax subsidies and wind currently reaches "grid parity" under certain conditions (albeit such observation does not take into account issues such as dispatch characteristics, the cost of incremental transmission and back-up generation/system reliability costs or other factors)



Source: Lazard estimates.

Note: Assumes 2010 dollars, 60% debt at 8.0% interest rate and 40% common equity at 12% cost, 20-year economic life and 40% tax rate. Assumes natural gas price of $5.50 per MMBtu.

(a) Low end represents single-axis tracking crystalline. High end represents fixed installation. Diamonds represent estimated implied levelized cost of energy in 2012, assuming a total system cost of $2.50 per watt for single-axis tracking crystalline and a leading concentrating photovoltaic company's targeted levelized cost of energy, assuming a total system cost of approximately $4.00 per watt.

(b) Diamonds represent a leading thin-film company's targeted implied levelized cost of energy in 2012, assuming a total system cost of $2.00 per watt.

(c) Represents both solar tower and solar trough, each with 3 hour storage capability.

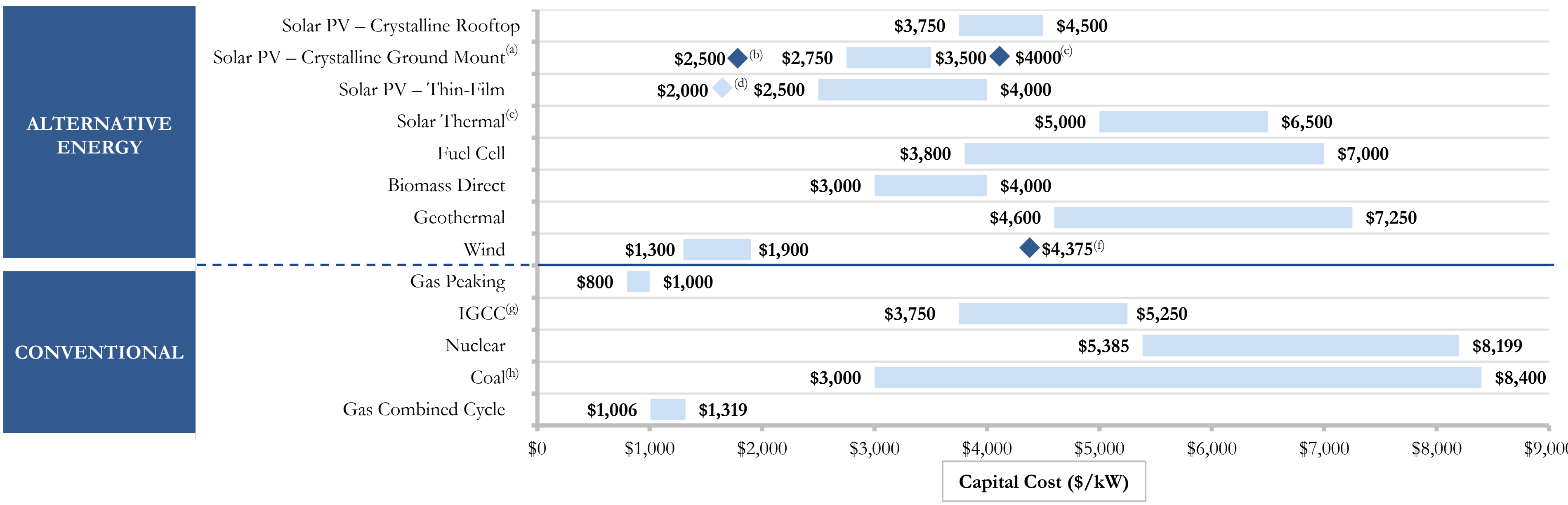
(d) Represents midpoint of off-shore wind's levelized cost of energy, assuming a range of total system cost of $3.10 – $5.00 per watt.

(e) Reflects production tax credit, investment tax credit, and accelerated asset depreciation, as applicable.

(f) Illustrates levelized cost of energy in the absence of U.S. federal tax incentives such as investment tax credits, production tax credits and assuming 20-year tax life for conventional technologies and 5-year MACRS for renewables technologies.

Capital Cost Comparison

While capital costs for a number of Alternative Energy generation technologies (e.g., solar PV, solar thermal) are currently in excess of conventional generation technologies (e.g., gas, coal), declining costs for many Alternative Energy generation technologies, coupled with rising long-term construction and uncertain long-term fuel costs for conventional generation technologies, are working to close formerly wide gaps in electricity costs. This assessment, however, does not take into account issues such as dispatch characteristics, capacity factors, fuel and other costs needed to compare generation technologies



Source: Lazard estimates.

(a) Low end represents single-axis tracking crystalline. High end represents fixed installation.

(b) Represents estimated implied levelized cost of energy in 2012, assuming a total system cost of $2.50 per watt for single-axis tracking crystalline.

(c) Represents a leading concentrating photovoltaic company's total system cost of approximately $4.00 per watt.

(d) Based on a leading thin-film company's guidance of 2012 total system cost of $2.00 per watt.

(e) Low end represents solar trough without storage, high end represents solar trough with 3 hour storage capability.

(f) Represents estimated midpoint of off-shore wind's levelized cost of energy, assuming a range of total system cost of $3.10 – $5.00 per watt.

(g) High end incorporates 90% carbon capture and compression.

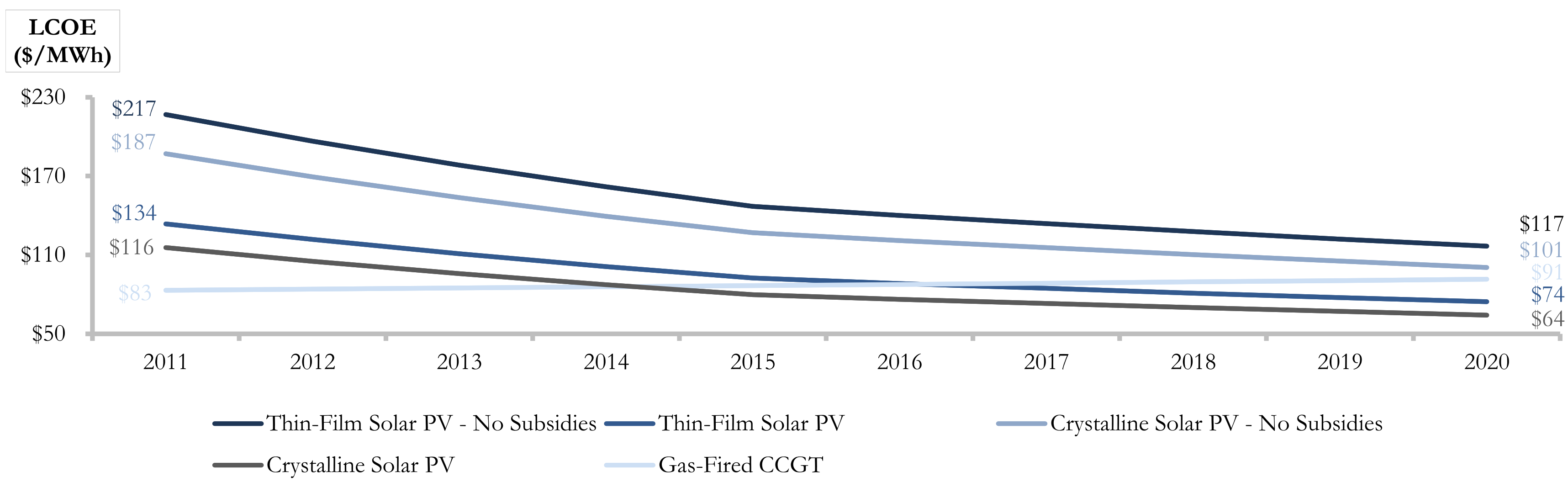
(h) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression.

Appendix A

Levelized Cost of Energy – Sensitivity to Capital Costs[(a)]

An important finding in respect of solar PV technologies is the potential for significant cost reductions over time as manufacturing scale along the entire production value chain increases; by contrast, conventional generation technologies are experiencing capital cost inflation, driven by long-term global demand for conventional generation equipment, where potentially cost-reducing manufacturing improvements for these mature technologies are largely incremental in nature

- **This assessment, however, does not take into account the intermittent nature of solar PV as compared with the dispatchable nature of conventional generation; the key finding in this regard is that solar PV technologies will play an increasingly *complementary* role in generation portfolios**



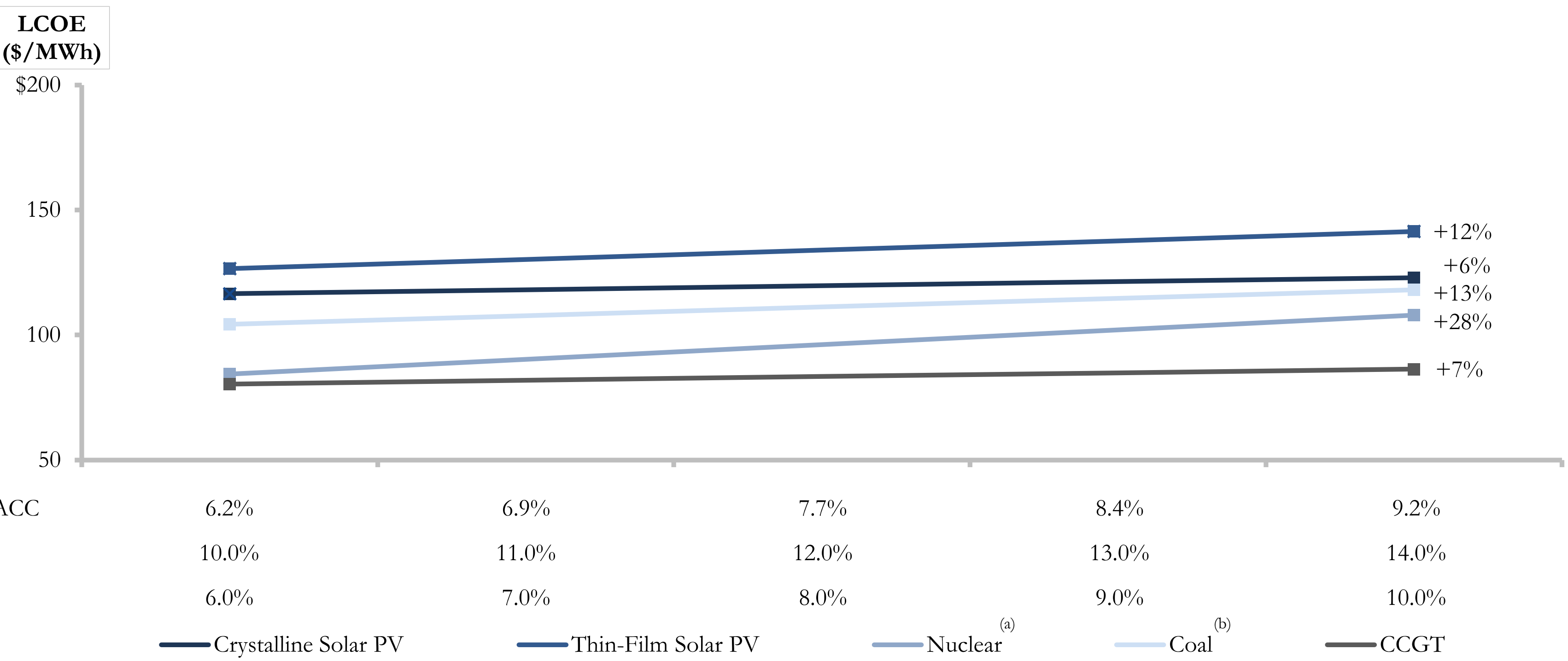
Source: *Lazard estimates.*

Note: Reflects investment tax credit and accelerated asset depreciation, as applicable. Assumes 2010 dollars, 20-year economic life and 40% tax rate. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes natural gas price of $5.50 per MMBtu. Assumes midpoint of analysis conducted earlier.

(a) Assumes capital costs for thin-film and crystalline solar PV decline by 10% annually through 2014 and 5% annually thereafter. Assumes capital costs for gas-fired CCGT increase by 2.5% annually.

Levelized Cost of Energy – Sensitivity to Cost of Capital

A key issue facing Alternative Energy generation technologies resulting from the potential for intermittently disrupted capital markets is the reduced availability, and increased cost, of capital; these dynamics have a greater relative impact on Alternative Energy generation technologies, whose costs reflect essentially only return on, and of, the capital investment required to build them

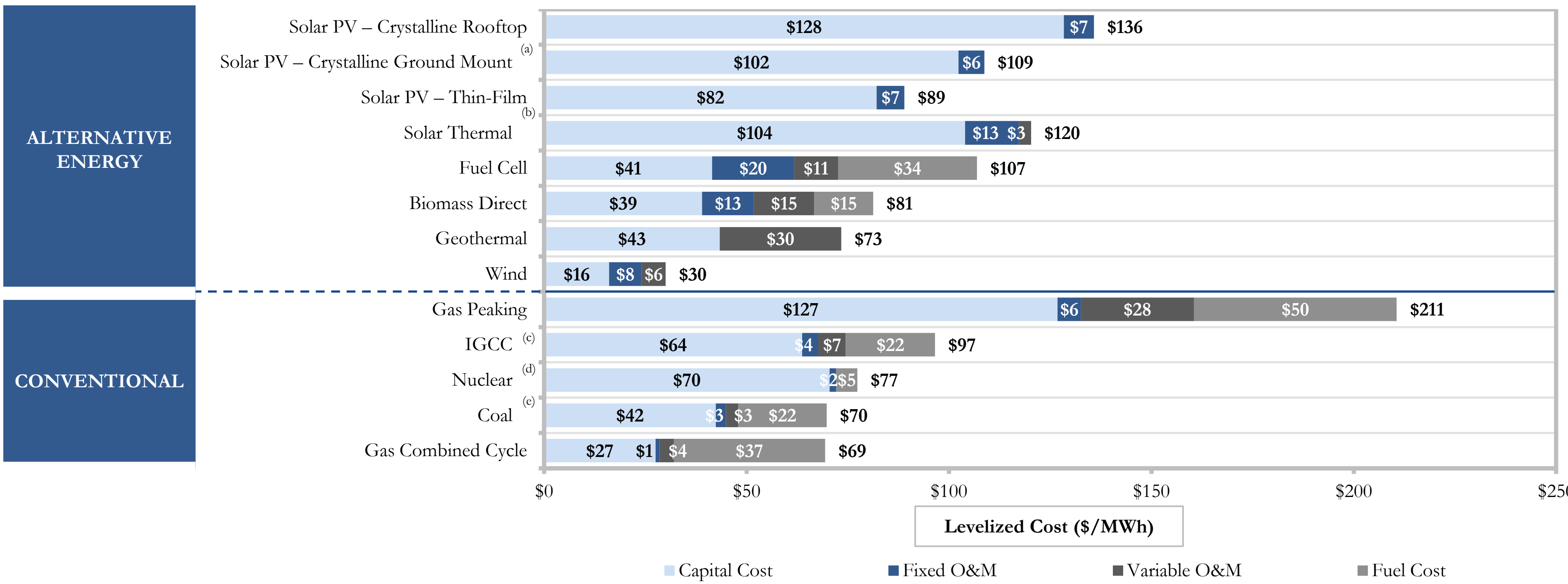


After-Tax IRR/WACC	6.2%	6.9%	7.7%	8.4%	9.2%
Cost of Equity	10.0%	11.0%	12.0%	13.0%	14.0%
Cost of Debt	6.0%	7.0%	8.0%	9.0%	10.0%

Source: *Lazard estimates.*
Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2010 dollars, 20-year economic life, 40% tax rate and 5-40 year tax life. Assumes 30% debt at the stated interest rate, 20% common equity at the stated cost and 50% tax equity at 8.5% cost for Alternative Energy generation technologies. Assumes 60% debt at the stated interest rate and 40% equity at the stated cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $5.50 per MMBtu.
(a) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(b) Based on advanced supercritical pulverized coal.

Levelized Cost of Energy Components – Low End

Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of currently more expensive Alternative Energy technologies is the ability of technological development and increased production volumes to materially lower the capital costs of certain Alternative Energy technologies, and their levelized cost of energy, over time (e.g., as is anticipated with solar PV technologies)



Source: Lazard estimates.

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2010 dollars, 20-40-year economic life, 40% tax rate and 5-40 year tax life. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $5.50 per MMBtu.

(a) Low end represents single-axis tracking crystalline. High end represents fixed installation.

(b) Represents both solar tower and solar trough, each with 3 hour storage capability.

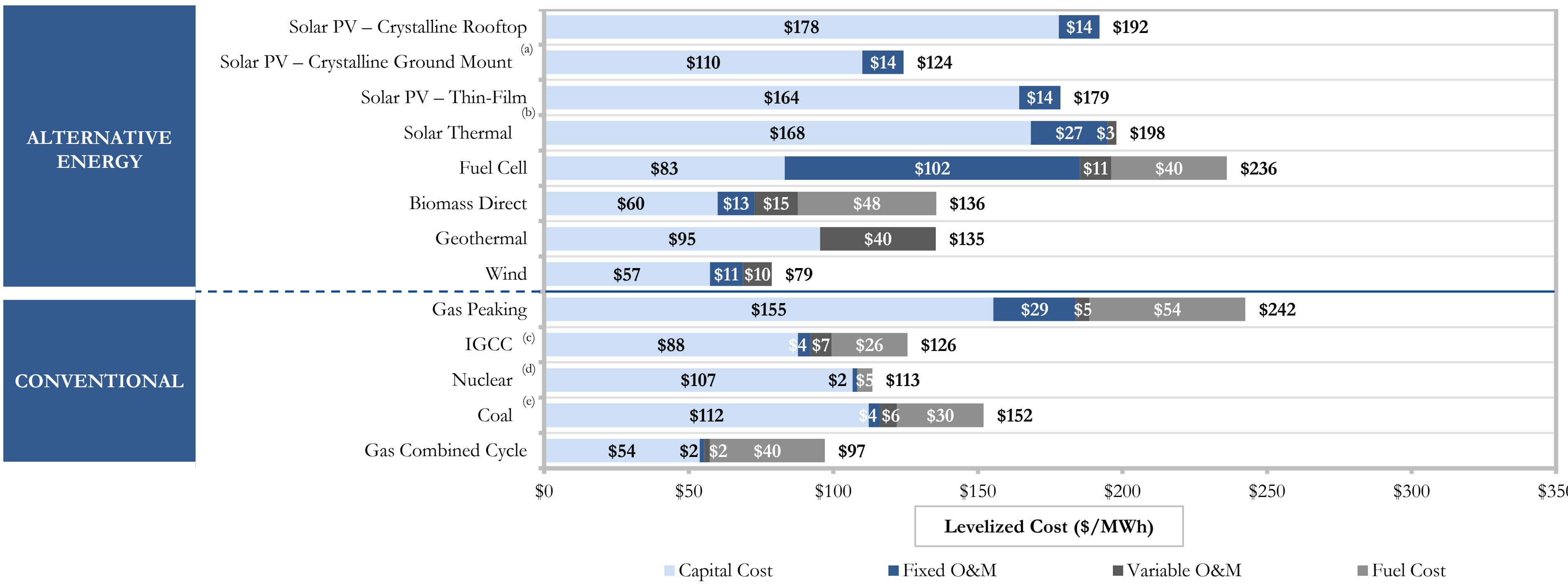
(c) Incorporates no carbon capture and compression.

(d) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

(e) Based on advanced supercritical pulverized coal. Incorporates no carbon capture and compression.

Levelized Cost of Energy Components – High End

Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of currently more expensive Alternative Energy technologies is the ability of technological development and increased production volumes to materially lower the capital costs of certain Alternative Energy technologies, and their levelized cost of energy, over time (e.g., as is anticipated with solar PV technologies)



Source: Lazard estimates.

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2010 dollars, 20-40-year economic life, 40% tax rate and 4–20 year tax life. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $5.50 per MMBtu.

(a) Low end represents single-axis tracking crystalline. High end represents fixed installation.

(b) Low end represents solar tower, high end represents solar trough, each with 3 hour storage capability.

(c) Incorporates 90% carbon capture and compression.

(d) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

(e) Based on advanced supercritical pulverized coal. Incorporates 90% carbon capture and compression.

Energy Resources: Matrix of Applications

While the levelized cost of energy for Alternative Energy generation technologies is becoming increasingly competitive with conventional generation technologies, direct comparisons must take into account issues such as location (e.g., central station vs. customer-located) and dispatch characteristics (e.g., baseload and/or dispatchable intermediate load vs. peaking or intermittent technologies)

					LOCATION			DISPATCH			
		LEVELIZED COST OF ENERGY	CARBON NEUTRAL/ REC POTENTIAL	STATE OF TECHNOLOGY	CUSTOMER LOCATED	CENTRAL STATION	GEOGRAPHY	INTERMITTENT	PEAKING	LOAD-FOLLOWING	BASE-LOAD
ALTERNATIVE ENERGY	FUEL CELL	$107-236	?[a]	Emerging/ Commercial	✓		Universal				✓
	SOLAR PV	$89-192	✓	Commercial/ Evolving	✓	✓	Universal[b]	✓	✓		
	SOLAR THERMAL	$120-198	✓	Emerging		✓	Southwest	✓	✓	✓	
	BIOMASS DIRECT	$81-136	✓	Mature		✓	Universal			✓	✓
	GEOTHERMAL	$73-135	✓	Mature		✓	Varies				✓
	ONSHORE WIND	$30-79	✓	Mature		✓	Varies	✓			
CONVENTIONAL	GAS PEAKING	$211-242	×	Mature	✓	✓	Universal		✓		
	IGCC	$97-126	×[c]	Emerging[d]		✓	Co-located or rural				✓
	NUCLEAR	$77-113	✓	Mature/ Emerging		✓	Co-located or rural				✓
	COAL	$70-152	×[c]	Mature[d]		✓	Co-located or rural				✓
	GAS COMBINED CYCLE	$69-97	×	Mature	✓	✓	Universal			✓	✓

Source: Lazard estimates.
(a) Qualification for RPS requirements varies by location.
(b) LCOE study capacity factor assumes Southwest location.
(c) Could be considered carbon neutral technology, assuming carbon capture and compression.
(d) Carbon capture and compression technologies are in emerging stage.

Levelized Cost of Energy – Key Assumptions

		Solar PV			Solar Thermal		
	Units	Thin-Film Utility[b]	Crystalline Ground Mount[c]	Crystalline Rooftop	Trough-No Storage[d]	Trough 3 Hours Storage	Tower[e]
Net Facility Output	MW	10	10	10	250	250	120 - 100
EPC Cost	$/kW	$2,500 - $4,000	$3,500 - $2,750	$3,750 - $4,500	$3,700 - $5,400	$4,600 - $4,700	$5,600 - $6,300
Capital Cost During Construction	$/kW	included	included	included	included	included	included
Other Owner's Costs	$/kW	included	included	included	$1,300 - included	$1,700 - $1,800	included
Total Capital Cost[a]	$/kW	$2,500 - $4,000	$3,500 - $2,750	$3,750 - $4,500	$5,000 - $5,400	$6,300 - $6,500	$5,600 - $6,300
Fixed O&M	$/kW-yr	$15.00 - $25.00	$15.00 - $25.00	$15.00 - $25.00	$34.00 - $66.00	$60.00	$50.00 - $70.00
Variable O&M	$/MWh	—	—	—	—	—	$3.00
Heat Rate	Btu/kWh	—	—	—	—	—	—
Capacity Factor	%	25% - 20%	27% - 20%	23% - 20%	29% - 26%	34% - 30%	43% - 30%
Fuel Price	$/MMBtu	—	—	—	—	—	—
Construction Time	Months	12	12	12	24	24	24
Facility Life	Years	20	20	20	20	20	20
CO_2 Equivalent Emissions	Tons/MWh	—	—	—	—	—	—
Investment Tax Credit	%	30%	30%	30%	30%	30%	30%
Production Tax Credit	$/MWh	—	—	—	—	—	—
Levelized Cost of Energy	$/MWh	$89 - $179	$109 - $124	$136 - $192	$146 - $191	$167 - $198	$120 - $198

Source: *Lazard estimates.*

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2010 dollars, 20-40-year economic life, 40% tax rate and 5-40 year tax life. Assumes 2.5% annual escalation for production tax credit, O&M costs and fuel prices. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $5.50 per MMBtu.

(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.
(b) An illustrative manufacturer of Thin-Film PV would be FirstSolar.
(c) Left side represents single-axis tracking crystalline; right side represents fixed installation. An illustrative manufacturer of high-efficiency Crystalline PV would be SunPower.
(d) Left side represents wet-cooled; right side represents dry-cooled. Illustrative manufacturers/developers of Trough Solar Thermal would be Abengoa Solar, Flagsol, Solar Millennium and Siemens.
(e) Represents a range of solar thermal tower estimates. Illustrative manufacturers/developers of Solar Thermal Tower would be BrightSource Energy, eSolar and SolarReserve.

Levelized Cost of Energy – Key Assumptions (cont'd)

	Units	IGCC[b]	Gas Combined Cycle	Gas Peaking[c]	Coal[d]	Nuclear[e]
Net Facility Output	MW	580	550	152 - 34	600	1,100
EPC Cost	$/kW	$3,054 - $4,193	$743 - $1,004	$580 - $700	$2,027 - $6,067	$3,750 - $5,250
Capital Cost During Construction	$/kW	$696 - $1,057	$107 - $145	included	$487 - $1,602	$1,035 - $1,449
Other Owner's Costs	$/kW	included	$156 - $170	$220 - $300	$486 - $731	$600 - $1,500
Total Capital Cost[a]	$/kW	$3,750 - $5,250	$1,006 - $1,319	$800 - $1,000	$3,000 - $8,400	$5,385 - $8,199
Fixed O&M	$/kW-yr	$26.40 - $28.20	$6.20 - $5.50	$5.00 - $25.00	$20.40 - $31.60	$12.80
Variable O&M	$/MWh	$6.80 - $7.30	$3.50 - $2.00	$28.00 - $4.70	$3.00 - $5.90	—
Heat Rate	Btu/kWh	8,800 - 10,520	6,800 - 7,220	9,100 - 9,800	8,750 - 12,000	10,450
Capacity Factor	%	75%	70% - 40%	10%	93%	90%
Fuel Price	$/MMBtu	$2.50	$5.50	$5.50	$2.50	$0.50
Construction Time	Months	57 - 63	36	25	60 - 66	69
Facility Life	Years	40	20	20	40	40
CO_2 Equivalent Emissions	Tons/MWh	0.74 - 0.89	0.40 - 0.42	0.63 - 0.60	0.95 - 1.27	—
Investment Tax Credit	%	—	—	—	—	—
Production Tax Credit	$/MWh	—	—	—	—	—
Levelized Cost of Energy	$/MWh	$97 - $126	$69 - $97	$211 - $242	$70 - $152	$77 - $113

Source: *Lazard estimates.*

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2010 dollars, 20-40-year economic life, 40% tax rate and 5-40 year tax life. Assumes 2.5% annual escalation for production tax credit, O&M costs and fuel prices. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $5.50 per MMBtu.

(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.
(b) High end incorporates 90% carbon capture and compression.
(c) Low end represents assumptions regarding GE 7FA. High end represents assumptions regarding GE LM6000PC.
(d) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression.
(e) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

Levelized Cost of Energy – Key Assumptions (cont'd)

	Units	Fuel Cell[(a)]	Biomass Direct	Wind	Off-Shore Wind	Geothermal
Net Facility Output	MW	2.4	35	100	210	30
EPC Cost	$/kW	$3,000 - $7,000	$2,641 - $3,522	$1,000 - $1,500	$2,500 - $4,120	$4,050 - $6,383
Capital Cost During Construction	$/kW	included	$359 - $478	included	included	$550 - $867
Other Owner's Costs	$/kW	$800 - included	included	$300 - $400	$600 - $880	included
Total Capital Cost[(b)]	$/kW	$3,800 - $7,000	$3,000 - $4,000	$1,300 - $1,900	$3,100 - $5,000	$4,600 - $7,250
Fixed O&M	$/kW-yr	$169 - $850	$95.00	$30.00 - $30.00	$60.00 - $100.00	—
Variable O&M	$/MWh	$10.83	$15.00	—	$13.00 - $18.00	$30.00 - $40.00
Heat Rate	Btu/kWh	6,239 - 7,260	14,500	—	—	—
Capacity Factor	%	95%	85%	41% - 30%	45% - 32%	90% - 80%
Fuel Price	$/MMBtu	$5.50	$1.00 - $3.30	—	—	—
Construction Time	Months	3	36	12	12	36
Facility Life	Years	20	20	20	20	20
CO_2 Equivalent Emissions	Tons/MWh	0.26 - 0.42	—	—	—	—
Investment Tax Credit	%	30%	—	—	—	—
Production Tax Credit	$/MWh	—	$10	$20	$20	$20
Levelized Cost of Energy	$/MWh	$107 - $236	$81 - $136	$30 - $79	$94 - $235	$73 - $135

Source: *Lazard estimates.*

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2010 dollars, 20-40-year economic life, 40% tax rate and 5-40 year tax life. Assumes 2.5% annual escalation for production tax credit, O&M costs and fuel prices. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $5.50 per MMBtu.

(a) Low end incorporates illustrative economic and efficiency benefits of combined heat and power ("CHP") applications.

(b) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

Summary Considerations

Lazard has conducted this study comparing the levelized cost of energy for various conventional and Alternative Energy generation technologies in order to understand which Alternative Energy generation technologies may be cost-competitive with conventional generation technologies, either now or in the future, and under various operating assumptions, as well as to understand which technologies are best suited for various applications based on locational requirements, dispatch characteristics and other factors. We find that Alternative Energy technologies are complementary to conventional generation technologies, and believe that their use will be increasingly prevalent for a variety of reasons, including government subsidies, RPS requirements, and continuously improving economics as underlying technologies improve and production volumes increase.

In this study, Lazard's approach was to determine the levelized cost of energy, on a $/MWh basis, that would provide an after-tax IRR to equity holders equal to an assumed cost of equity capital. Certain assumptions (e.g., required debt and equity returns, capital structure, and economic life) were identical for all technologies, in order to isolate the effects of key differentiated inputs such as investment costs, capacity factors, operating costs, fuel costs (where relevant) and U.S. federal tax incentives on the levelized cost of energy. These inputs were developed with a leading consulting and engineering firm to the Power & Energy Industry, augmented with Lazard's commercial knowledge where relevant.

Lazard has not manipulated capital costs or capital structure for various technologies, as the goal of the study was to compare the current state of various generation technologies, rather than the benefits of financial engineering. The results contained in this study would be altered by different assumptions regarding capital structure (e.g., increased use of leverage) or capital costs (e.g., a willingness to accept lower returns than those assumed herein).

Key sensitivities examined included fuel costs and tax subsidies. Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include scale benefits or detriments, the value of Renewable Energy Credits ("RECs") or carbon emissions offsets, the impact of transmission costs, second-order system costs to support intermittent generation (e.g., backup generation, voltage regulation, etc.), and the economic life of the various assets examined.

Attachment 3

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: November 7, 2012

TO: Braulio L. Baez, Executive Director

FROM: Benjamin Crawford, Public Utility Analyst II, Office of Industry Development and Market Analysis BC m7

RE: Draft Report on Electric Vehicle Charging

CRITICAL INFORMATION: Please place on the November 28, 2012 Internal Affairs agenda. Approval by the Commission is required by December 31, 2012.

Pursuant to Section 366.94(4), F.S., the Commission is required to submit a report on the potential effects of public charging stations and privately owned electric vehicle charging on both energy consumption and the impact on the electric grid in the state. The report must also investigate the feasibility of using off-grid solar photovoltaic power as a source of electricity for the electric vehicle charging stations. The attached draft satisfies this requirement, and its approval by the Commission is sought.

Please let me know if you have any questions or need additional information in reference to the main document or the appendices.

Thank you.

BJMC/

Attachment

cc: Mark Futrell
David Dowds
Bob Trapp
Tom Ballinger
Jim Dean
Chuck Hill

DRAFT

Report On Electric Vehicle Charging

Submitted to the Governor,
the President of the Senate, and
the Speaker of the House of Representatives
To Fulfill the Requirements of Section 366.94, Florida Statutes

Florida Public Service Commission
Tallahassee, Florida
December 2012

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Section 1. Executive Summary

By Section 366.94(4), Florida Statutes (F.S.), the Legislature directs the Florida Public Service Commission (FPSC) to conduct a study on the effects of electric vehicle (EV) charging on both energy consumption and the electric grid, as well as to examine the feasibility of off-grid solar photovoltaic (PV) charging. In order to meet this requirement, the FPSC has gathered information through Florida's electric utilities, a staff workshop, and independent research.

While EVs are still a niche product, they have become more commercially viable due to tax credits and the introduction of gasoline-electric hybrid technology and improved battery technology. In part because of the higher up-front costs associated with batteries, EVs have faced challenges to expanded use. As the technology becomes more established, EVs may become a more realistic alternative to gasoline and diesel-fueled vehicles. The impact of EVs on energy consumption and demand on the electric grid will depend on a number of factors, including the rate of growth in EV sales, EV clustering, the impact of higher voltage "quick-charge" stations on local distribution systems, and the extent to which EV charging corresponds with times of electric system peak demand.

Background Data for Electric Vehicles

Current estimates of the number of EVs in Florida as provided by utilities and other organizations range from roughly 1,000 to 6,000. Because no agency tracks these figures formally, it is difficult to pinpoint the number more precisely, and future projections are even more speculative. Currently, there are EV charging station locators, no source appears to provide a truly exhaustive list of public charging stations. Moving forward, government and manufacturer incentives, combined with rising Corporate Average Fuel Economy (CAFE) standards, may result in increased sales of EVs in the future. Additionally, technological breakthroughs or changes in commodity prices, especially oil prices, could affect EV prices and adoption.

Effects on Energy Consumption

Because relatively few EVs are currently on the road and being charged in Florida, they are having very little impact on total energy consumption in Florida. Based on an estimate of 5,531 EVs, FPSC staff estimate that EVs will result in approximately 22.1 Gigawatt-hours (GWh) of energy consumption during 2012. Total energy consumption in 2012 for Florida is estimated at 238,645 GWh, so the additional amount due to EVs is less than 0.01 percent. The impact of EVs on electricity consumption is expected to rise to 909.3 GWh in 2021, which represents approximately 0.33 percent of the total 275,519 GWh of electricity expected to be consumed that year.

EVs are also expected to reduce gasoline consumption in Florida. Current FPSC estimates place gasoline savings at 356 gallons per year per plug-in hybrid EV and at 480 gallons per year per fully electric vehicle. As a result, the FPSC estimates approximately 2,131,728 gallons of gasoline saved by EVs in 2012, increasing to approximately 89,447,402 gallons in 2021.

Additionally, EVs are not expected to drive any new need for generation within the ten-year planning horizon. Current estimates place the impact on summer peak demand for the four generating investor-owned utilities (IOUs) and two largest municipal utilities (jointly referred to throughout this document as the large utilities) at approximately 4 megawatts (MW) in total in 2012.[1] Summer peak demand for these utilities was estimated at 39,127 MW in 2012, for an impact due to EVs of approximately 0.01 percent. Since reserves for those utilities are estimated at 11,860 MW for 2012, the additional load from EVs will not adversely impact reliability in the ten-year planning timeframe.

In 2021, the estimated impact of EV charging at peak is 185 MW, with reserves estimated at 10,062 MW. As a result, the FPSC does not envision EVs resulting in a need for new generation over the ten-year planning timeframe. Beyond the planning timeframe, if EVs do begin to significantly impact generation in Florida, increased use of rate structures such as time-of-use rates may help shift EV charging to hours of low demand.

Impact on the Electric Grid

While individual EV chargers are expected to have a negligible impact on grid reliability, clustering of EVs in residential neighborhoods could potentially require the replacement of equipment in the distribution system. Responses from Florida utilities indicate that the smaller residential transformers could exceed their design limits if multiple chargers, especially higher-voltage chargers, operate on a single transformer. Higher voltage home EV chargers, which may draw up to 20 kilowatts (kW), may result in the need for larger capacity distribution facilities depending upon a number of factors, including the location of the system and clustering of chargers.

Public "quick-charge" stations may also impact the distribution system. These stations are likely to create an electric demand of 50 kW or more, and may operate during times of peak demand. The installation and use of these higher voltage "quick-charge" stations may require upgrading distribution-level facilities to ensure reliability. Because EVs are such a new and emerging technology and higher-voltage chargers are only starting to be installed, the impacts on local distribution systems can not be estimated at this time.

Feasibility of Solar PV for Off-Grid Charging

The use of off-grid solar PV power for EV charging does not appear to be a feasible alternative to grid-tied solar PV systems at present. Solar production times do not align with expected EV charge times. In addition, to match charging demand with the requirements of high voltage charging stations would require large sized EV systems of substantial physical size. While energy storage would make off-grid solar PV car charging more practical, costs are estimated at roughly $10,000 for a battery that can charge one car per day, and larger batteries scale up at that cost as well. As a result, in Florida, the cost of energy storage will generally exceed the cost of tying a solar PV system to the electric grid.

[1] The four generating IOUs are Florida Power and Light Company (FPL); Progress Energy Florida, Inc. (PEF); Tampa Electric Company (TECO); and Gulf Power Company (Gulf). The two largest municipal utilities are JEA (Jacksonville) and Orlando Utilities Commission (OUC).

Conclusion

EV charging is expected to have a negligible effect on electricity consumption in Florida within the ten-year planning horizon. At the same time, EV owners should reduce the consumption of gasoline in Florida by more than two million gallons in 2012. EVs are also not currently expected to cause a significant increase in electric demand or contribute significantly to a need for new generation until well past 2021. Clusters of electric vehicles charging simultaneously on a single residential transformer could potentially require upgrades to that transformer, but individual vehicles are not expected to affect the distribution system. “Quick-charge” stations may pose potential challenges for the distribution system. The use of off-grid solar photovoltaics for EV charging is technically feasible, but it may only be practical in unique circumstances due to economic considerations.

Section 2. Introduction

Section 366.94(4), F.S., reads as follows:

> The Public Service Commission is directed to conduct a study of the potential effects of public charging stations and privately owned electric vehicle charging on both energy consumption and the impact on the electric grid in the state. The Public Service Commission shall also investigate the feasibility of using off-grid solar photovoltaic power as a source of electricity for the electric vehicle charging stations. The commission shall submit the results of the study to the President of the Senate, the Speaker of the House of Representatives, and the Executive Office of the Governor by December 31, 2012.

During the 2012 Regular Session, the Florida Legislature enacted HB 7117, Chapter 2012-117, Laws of Florida, addressing energy policy in the State of Florida. Section 11 of the law created Section 366.94, F.S., instructing the FPSC to conduct a study of the potential effects of public charging stations and privately-owned electric vehicle charging on both energy consumption and the impact on the electric grid in the state. Additionally, the FPSC is required to investigate the feasibility of using off-grid solar photovoltaic power as a source of electricity for the electric vehicle charging stations. This report is due to the President of the Senate, the Speaker of the House of Representatives, and the Executive Office of the Governor by December 31, 2012.

In preparation for this report, FPSC staff submitted a data request to many of Florida's electric utilities in May 2012. FPSC staff also conducted a workshop in September 2012 to provide an opportunity for discussion on relevant issues. Entities presenting at the workshop included the Electric Power Research Institute, General Motors Company, General Electric Company, SPX Corporation, the Florida Solar Energy Center, four Florida IOUs, and the Orlando Utilities Commission. In addition, FPSC staff conducted a literature and data search for relevant information.

Based on the research described above, the following report addresses electric vehicle charging's effect on: (1) energy consumption, focusing on increased electricity consumption and offsetting motor gasoline consumption, as well as electric demand, (2) impact on the electric grid, primarily the distribution system, and (3) the feasibility of using off-grid solar photovoltaic power for electric vehicle charging.

This report is organized into the following sections:
Section 1. Executive Summary
Section 2. Introduction
Section 3. Background Data for Electric Vehicles
Section 4. Effects on Energy Consumption
Section 5. Impact on the Electric Grid
Section 6. Feasibility of Solar PV for Off-Grid Charging
Section 7. Conclusion
Appendix A. Bibliography
Appendix B. Corporate Average Fuel Economy Standards
Appendix C. State Policies Related to Electric Vehicles

Section 3. Background Data for Electric Vehicles

The data used to prepare this report was primarily provided by Florida electric utilities' responses to the FPSC staff data request issued in May 2012. Where necessary, FPSC staff extrapolated from utility data other reliable sources, such as other Florida or federal agencies. Data from automotive manufacturers also provided much of the background for specific EV models.

Electric Vehicles in Florida

While electric vehicles date back to the late nineteenth century, the current wave of mass produced electric vehicles begins with the introduction of the Chevrolet Volt, from General Motors Company (GM), and the Nissan Motor Company (Nissan) Leaf in 2010. Although hybrid electric vehicles (HEVs), such as the original Toyota Motor Corporation (Toyota) Prius, existed prior to these models, HEVs use electricity generated by the gasoline engine and are not powered by electricity from the grid. Because HEVs are not charged through a connection to the electric grid, they are not addressed in this report. Instead, this report focuses on plug-in hybrid electric vehicles (PHEVs), which primarily rely on energy from the grid but can use gasoline for longer distances, and all-electric vehicles, which rely entirely on grid-provided energy. For purposes of this report, the term "EVs" will refer collectively to PHEVs and all-electric vehicles, but will exclude HEVs.

The Chevrolet Volt, a PHEV introduced in 2010, was the first of the current wave of EVs to become widely available. The Volt has an Environmental Protection Agency (EPA) estimated 38 mile range running solely on its battery power. It also has a gasoline engine for longer trips; GM estimates that Volt owners average 900 miles between fill-ups. The Nissan Leaf, which was released shortly after the Volt, is an all electric vehicle with an EPA-estimated 92 mile range. The Leaf will therefore be more reliant on public charging stations on longer trips, especially on "quick-charge" stations that function for EVs similarly to how gasoline stations work for gasoline vehicles.

Additionally, other EVs have become available in recent years or will become so in the near future. The Tesla Motors (Tesla) Roadster, released in 2008, is all-electric with a 245 mile range. Tesla also has a new model, the Model S, which was first delivered in June 2012. It is also all-electric with a range of 160-300 miles depending on which battery the owner chooses. Tesla also has a third model, the Model X, scheduled for release in 2014. Tesla is the only EV manufacturer at present to offer the largest at-home chargers, capable of charging a vehicle in only a few hours as opposed to the 8-12 hours many other EV chargers require. Because Tesla has a much smaller manufacturing capability than the large automotive manufacturers, its models generally require reservations and have long waiting lists.

Numerous other automobile manufacturers have released PHEVs or all-electric EVs during 2012. Mitsubishi Motors (Mitsubishi) released the i-MiEV, an all-electric vehicle with a 62 mile range. Toyota also released a PHEV version of the Prius with a 62 mile range, though it is only available in certain states in the Northeast and West. It is scheduled to be available nationwide in 2013. Ford Motor Company (Ford) released an all-electric version of the Focus in 2012 with a 100 mile range. The Focus EV also has been made available initially only in certain markets, including several throughout Florida, with more planned in the future. An all-electric version of the Toyota Rav4 with a 103 mile range has also been released, but only in California. It is unclear if the Rav4 EV will be made available in other states. Finally, Honda Motor Company (Honda) has released an all-electric version of the Fit, which is currently only available in California.

Other car manufacturers have models planned for release over the next few years, including smaller, specialty manufacturers like Coda Automotive (Coda), which released an all-electric sedan in 2012 with a 125 mile range. Additionally, traditional manufacturers have EVs scheduled for release in 2013 or 2014. These newer EVs are expected to contribute to the growth of the EV market, which to date has been dominated by the Volt and the Leaf. Table 1, below, compares several of the models released to date.

Table 1. EV Model Comparison

Make	Model	Year Released	Type	Electric Range (Miles)	Battery Size (kWh)	Home Charger Size (kW)	Availability
Chevrolet	Volt	2010	PHEV	38	16.5	3.3	Wide
Nissan	Leaf	2010	All-Electric	92	24	3.3	Wide
Tesla	Roadster	2008	All-Electric	245	56	16.8	Limited
Tesla	Model S	2012	All-Electric	160/230/300	40/60/85	20	Limited
Mitsubishi	i-MiEV	2012	All-Electric	62	16	3.3	Wide
Toyota	Prius EV	2012	PHEV	62	4.4	3.8	West and NE
Ford	Focus EV	2012	All-Electric	100	23	6.6	Includes Florida
Toyota	Rav4 EV	2012	All-Electric	103	41.8	9.6	California
Honda	Fit EV	2012	All-Electric	82	20	6.6	California
Coda	Sedan	2012	All-Electric	125	31	7.2	California

Source: Auto maker data

The number of EVs currently being driven in Florida is difficult to gauge. The Florida Department of Highway Safety and Motor Vehicles (FHSMV) keeps a listing of vehicles with the fuel type of "electric," but this listing is based on a voluntary check box and does not distinguish between EVs, PHEVs, and HEVs. FHSMV has 28,403 vehicles listed with that fuel type in Florida as of October 2012. This option was added to the car registration process in recent years and may not capture all EVs and HEVs registered in Florida.

Estimating the number of plug-in EVs likewise is imprecise. Table 2 shows the large utilities' projections for EVs in their service area through 2021. It is important to note that these projections should be considered preliminary. Some of the utilities noted in their responses that these preliminary estimates may overstate the number of EVs likely to be deployed during the planning timeframe.

Table 2. Projected Number of EVs in Florida by Utility Service Area

Year	FPL	PEF	TECO	Gulf	OUC	JEA	Total
2012	3,024	238	1,165*	380**	293	431	**5,531**
2013	5,852	1,054	1,808	895	830	651	**11,090**
2014	10,021	2,361	2,634	1,553	1,624	876	**19,069**
2015	15,874	4,045	3,479	2,326	2,689	1,104	**29,517**
2016	23,811	6,274	4,541	3,220	4,037	2,006	**43,889**
2017	36,510	9,500	5,887	4,201	5,685	2,924	**64,707**
2018	49,289	13,816	7,407	5,342	7,646	3,860	**87,360**
2019	65,554	19,337	8,854	6,646	9,937	4,813	**115,141**
2020	98,332	26,204	10,292	8,117	12,574	5,783	**161,302**
2021	147,497	34,576	11,699	9,654	15,570	7,583	**226,579**

Source: Utility data responses

* TECO notes in its estimate that it estimated 55 vehicles in its service area at the time of the data response (May 2012). The 1,165 figure, as well as future projections, are based on a 2011 estimate.
** Gulf noted that it was aware of 8 EVs at the time of its response in its territory but did not consider that figure exhaustive.

The utility projections in Table 2 come from a variety of sources. Florida Power and Light Company (FPL) generated its own estimates for its own service area and for Florida as a whole using market forecasts. FPL estimated that 50 percent of EVs in Florida would be owned by customers in its service area. This figure is reported in Table 2. Progress Energy Florida, Inc. (PEF) used Electric Power Research Institute (EPRI) projections that included a range of three forecasts. PEF submitted the medium EPRI estimate for its service area. This estimate gave a value for 2012 (238) that was slightly above the range PEF estimated in its service area at the time of submission (150-200). Tampa Electric Company (TECO) had estimated EVs in its own territory in 2011 and noted that its projection for 2012 was much higher than the actual number it offered at the time of its data response (55). Gulf Power Company (Gulf) based its numbers through 2017 on a Pike research survey from 2011. For the rest of the period, Gulf estimated that EV penetration would reach 5 percent of all vehicles in its service area in 2023 and grow linearly until then. Orlando Utilities Commission (OUC) conducted its projection in 2010 and characterizes it as “overly optimistic” at present. JEA (Jacksonville) extrapolated from EPRI data, using the “low” scenario.

Table 3 compares the large utilities’ forecast methodologies when extrapolated statewide. It includes both EPRI’s and FPL’s statewide estimates, including all three EPRI scenarios. It also includes an extrapolation of the statewide total from the IOUs’ estimates, based on expanding the IOU-reported numbers to the portion of the state served by other utilities. Table 3 also includes an extrapolation of Gulf’s assumption that EVs would reach 5 percent of all vehicles by 2023. This estimate incorporates FHSMV data of vehicles registered for 2011-2012, plus the 2.2 percent yearly census growth figure it uses for its own projections. Finally, Table 3 also includes the FHSMV projections of total vehicles in Florida for the forecast period.

Table 3. Comparison of EV Estimates

	EPRI Estimate (Low)	EPRI Estimate (Medium)	EPRI Estimate (High)	FPL Forecast	Gulf Estimate Method Extrapolation	Extrapolation from IOU Total	FHSMV Total Vehicles Statewide
2012	1,048	1,710	5,585	6,048	*5,531	6,222	18,735,044
2013	3,225	7,585	16,097	11,704	90,499	12,650	19,147,215
2014	7,165	16,986	33,341	20,042	179,203	21,324	19,568,454
2015	13,486	29,109	58,814	31,748	271,767	33,116	19,998,960
2016	22,902	45,145	94,531	47,622	368,316	48,924	20,438,937
2017	36,142	68,475	142,953	73,020	468,982	72,661	20,888,593
2018	53,928	99,814	207,105	98,578	573,899	98,386	21,348,142
2019	76,564	140,020	289,110	131,108	683,206	129,571	21,817,802
2020	104,210	190,133	391,042	196,664	797,044	184,709	22,297,793
2021	136,959	251,326	514,990	294,994	915,560	263,310	22,788,345

Source: Utility data responses, FPSC statistics, and FHSMV

*5,531 figure based on Table 2's total for 2012

As Table 3 shows, there are wide estimates for the rate of EV adoption in Florida. Additionally, there is no central source that reliably tracks EV sales in Florida. While official car registration data from FHSMV may help provide a baseline, it does not at present distinguish between HEVs and PHEVs. The U.S. Department of Energy (DOE) and other national organizations continue to provide forecasts but these must be viewed in light of market adoption uncertainties. Additionally, Florida utilities have no means of knowing when a customer purchases an EV aside from voluntary disclosure. In order to accurately track the registration and sales of the different types of EVs in Florida, either owners, dealers, or manufacturers will need to disclose additional data to FHSMV.

Projections of EV sales vary because of the uncertainty of many of the factors that will affect the market and contribute to growths of EVs. These factors include the cost of ownership of an EV compared to the cost of a similar vehicle using petroleum-based fuel. For example, if the federal rebate program that gives EV buyers up to $7,500 for buying an EV is discontinued in the future, this would depress EV sales with all other factors being equal. High petroleum prices could help motivate EV sales, as could a reduction in the price of batteries. Any potential buyer who needs to make longer trips in an EV may be reluctant to purchase an EV until more infrastructure is in place to allow longer drives.

Electric Vehicle Chargers in Florida

EV chargers are the devices that transmit energy from the grid into the EV batteries. The National Electric Code categorizes EV chargers broadly into three types. Level 1 chargers are rated at the lowest voltage and are primarily located at homes. Level 2 chargers have higher voltage, and they can serve as home chargers or public chargers. Level 2 chargers can be differentiated between Level 2 and Level 2+, as some of the larger chargers in the Level 2+ category draw more electricity and thus have shorter charge times than the more typical Level 2 chargers. Level 3 chargers are intended for stations that perform akin to a typical gasoline station, charging in very short periods of time. Table 4 provides the electric load requirements for each level of charger, along with a typical charge time. Charge times depend on both the capacity of the charger and of the EV battery, which will vary depending on the model of car, as shown on Table 1. Given charge times assume a 11 kilowatt-hour (kWh) typical daily charge.

Table 4. Charger Level Classifications

Charger Level	Load	Charge Time	Voltage in Alternating Current (VAC)
Level 1 (Home)	1.1-1.8 kW	6-10 hours	120
Level 2 (Home and Work)	3.3 kW	3-4 hours	208/240
Level 2+ (Home and Work)	6.6-19.2 kW	30 mins – 2 hours	
Level 3 (Recharging Station)	50-150 kW	15-30 minutes	480

Source: National Electric Code Article 625

Level 1 chargers use 120 Voltage in Alternating Current (VAC), and thus can plug in to a standard wall socket. Level 1 chargers are the easiest to install. Level 2 and 2+ chargers require 208 VAC or 240 VAC, which many large appliances also require. Thus, Level 2 charging is available in most homes, but it will require the installation of the larger 208/240 VAC plug. Level 3 chargers draw much more current than Level 1 or 2 chargers. Because this much current is not generally available in residential areas, any installation of Level 3 chargers may be limited.

FPSC staff asked Florida's electric utilities in its May 2012 data request to report the number of chargers presently installed in their service areas. Table 5 provides the numbers reported by Florida's large utilities. Table 5 does not differentiate between Level 2 and Level 2+ chargers.

Table 5. Number of Charging Stations by Utility Territory

Utility	Level 1	Level 2
FPL	490	408
PEF	76	198
TECO	90	80
GULF	8	0
OUC	1	108
JEA	0	0
Total	**665**	**794**

Source: Utility data responses

These numbers represent the best estimates available for this report. Utilities may have difficulties obtaining accurate estimates for numbers of privately-owned chargers in their service area. As a result, all of the caveats discussed regarding utility estimates of the number of EVs in their territory apply equally to estimates of the number of chargers. Additionally, many of the public charging stations were funded by grants from the American Recovery and Reinvestment Act (ARRA), and many are lightly utilized at present. Because this ARRA funding has come to an end, public charger growth may slow until demand from EV owners results in new investment.

To date, the utilities report that no Level 3 charging stations have been installed in Florida. As a result, any forecasts of both the numbers of Level 3 chargers and the effects on the electric grid are speculative. It is not clear whether enough EV owners will have a need for Level 3 quick-charging to incent a prospective investor to build infrastructure to support Level 3 charging stations in Florida. A few Level 3 stations are being installed elsewhere in the U.S., including several set for installation in Chicago. Information on these stations' utilization may provide a better glimpse into the demand for such stations when data is available. Currently, Florida utilities have no experience with Level 3 chargers.

Section 4. Effects on Energy Consumption

Section 366.94(4), F.S., directs the FPSC to study the effects of EV charging on energy consumption in the state of Florida. The net effect of EVs is expected to be an increase in the total consumption of electricity and a decrease in the total consumption of petroleum-based fuels. In addition, EVs may also increase the consumption of electricity at times of high demand.

This section of the report examines these changes in energy consumption patterns. Any impact on energy consumption will be a direct result of the actual number of EVs driven in Florida. As a result, the conclusions drawn in this report should be considered preliminary, and are dependant on actual EVs purchased.

Effect of Electric Vehicles on Electricity Consumption

The immediate effects of EV charging are expected to be an increase in total electrical energy consumption combined with a decrease in consumption of petroleum-based fuels, primarily gasoline and diesel fuel. While the effect on both forms of energy consumption will be limited at first, they will grow proportionately as EV deployment increases. Table 6, below, shows the estimated additional electricity consumption attributable to EVs.

Table 6. EV Effect on Electricity Consumption

Year	Total EVs in Florida	Additional Electricity Consumption from EVs (GWh)	Total Electricity Consumption in Florida (GWh)	Percent Increase due to EVs
2012	5,531	22.1	238,645	0.009
2013	11,090	44.4	241,632	0.018
2014	19,069	76.3	245,318	0.031
2015	29,517	118.1	250,598	0.047
2016	43,889	175.6	254,549	0.069
2017	64,707	258.8	258,198	0.100
2018	87,360	349.4	261,484	0.134
2019	115,141	460.6	265,337	0.174
2020	161,302	645.2	270,297	0.239
2021	226,579	906.3	275,519	0.329

Source: Utility data responses and 2012 FRCC Load and Resource Plan

The increase in electrical energy consumption from is minimal to date and is likely to be minimal for the next few years. Average electricity consumption per year is estimated to be approximately 4,000 kWh per EV, or approximately 11 kWh per day. In its data response, FPL reported an estimate of 12.3 kWh per day per EV, based on driving data for the Leaf and Volt. This figure equals approximately 4,490 kWh per year. For the sake of comparison, a typical Florida residence consumed 13,567 kWh per year in 2011. In its data response for total electric consumption from EVs, FPL used a higher value, which generally grew over time but averaged over 7,000 kWh per vehicle per year. FPL does not explain this discrepancy in its data response. Gulf estimated 10 kWh per vehicle per day, which is equivalent to 3,650 kWh per year. Gulf, however, included the Prius EV in its estimate in addition to the Volt and Leaf. Table 1 shows that the Prius EV has the lowest capacity battery of any EV listed.

In their workshop presentations, both FPL and Gulf included results from EV studies. Both utilities reported values of approximately 5.5 kWh per charging session. Assuming one charging session per day, these values result in a yearly average of approximately 2,000 kWh per vehicle per year. These values both come with caveats. FPL reports a median charging session of approximately 1.5 hours and 5.4 kWh per charge. For calculating total energy consumption, however, the average charging session would be a more accurate value than the median. Gulf's study was based on a single 2009 Prius converted into a PHEV, not a production model EV. As a result, it is unclear whether these figures can be extrapolated to estimate yearly kWh consumption. Neither FPL nor Gulf based their yearly estimates on a figure in line with a 5.5 kWh per day charging average.

Additionally, the DOE estimates 0.34 kWh per mile for the Leaf. If this value is applied to driving 12,000 miles per year, it works out to 4,080 kWh per year. DOE also estimates 0.36 kWh per mile for the Volt. Since the Volt is a PHEV, DOE assumes 70 percent of its mileage is driven using electricity, resulting in approximately 3,024 kWh total energy consumption for 12,000 miles per year driving. DOE did not provide estimates for any other EVs.

Collectively, these various sources provide an average of approximately 4,000 kWh per vehicle per year, which is close to several of the estimates. This estimate assumes an average charge of approximately 11 kWh per vehicle per day, or approximately 30 miles driven on electricity per day for a Volt or Leaf based on DOE values. The values in Table 6 are based upon that figure.

The increase in total electricity consumption will not necessarily result in higher costs for any ratepayers except EV owners. If EV charging is primarily done off-peak, it could lead to better use of existing generation assets. Thus, while EV owners would incur higher electric bills due to their own higher energy use, EV charging may result in no other charges to other ratepayers and could even contribute to improved system utilization. If EVs are charged at peak, it could cause a need for new generation. This potential impact is discussed below.

Effect of Electric Vehicles on Motor Fuel Consumption

The increase in consumption of electricity is also expected to result in a decrease in the consumption of petroleum-based fuels in Florida. One of the primary arguments by EV advocates for investment in electric vehicles has consistently been to reduce American dependence on oil imports. FPSC staff has estimated that a plug-in hybrid electric vehicle, such as the Chevy Volt, driven 12,000 miles per year, saves approximately 356 gallons of petroleum-based fuel per year. A fully electric vehicle would save 480 gallons of petroleum-based fuel per year. Both of these values assume they are replacing a vehicle getting 25 miles per gallon of petroleum-based fuel and driven 12,000 miles per year. Table 7, below, uses these assumptions to determine how many gallons of gasoline will be saved statewide based on the projected EV adoption rates. The gasoline savings assume a fifty/fifty mix of PHEVs and all-electric vehicles.

Table 7. EV Effect on Florida Motor Fuel Consumption

Year	Total EVs	Gasoline Saved (gallons)	Percentage of 2011 Motor Fuel Consumption Saved
2012	5,531	1,969,036	0.024
2013	11,090	4,024,438	0.050
2014	19,069	7,051,292	0.087
2015	29,517	11,118,070	0.137
2016	43,889	16,833,870	0.207
2017	64,707	25,264,489	0.311
2018	87,360	34,711,040	0.428
2019	115,141	46,542,551	0.574
2020	161,302	66,313,044	0.817
2021	226,579	94,710,022	1.167

Source: Utility data responses and FPSC Staff calculations

Table 7 shows 2.0 million gallons of petroleum-based fuel saved in Florida due to EV use in 2012. Florida Department of Agriculture and Consumer Services reports that 8,114 million gallons of motor fuel were consumed in Florida in 2011, down slightly from 2010.[2] As a result, estimated 2012 EV motor fuel savings are about 0.024 percent in 2012. In 2021, Floridians in the areas served by the large utilities are expected to avoid using nearly 90 million gallons of petroleum-based fuel, or approximately 1.167 percent of 2011 usage of motor fuel. Additionally, any reduction in demand for petroleum-based fuels should help place downward pressure on its prices for everyone, which could provide further benefit for the economy.

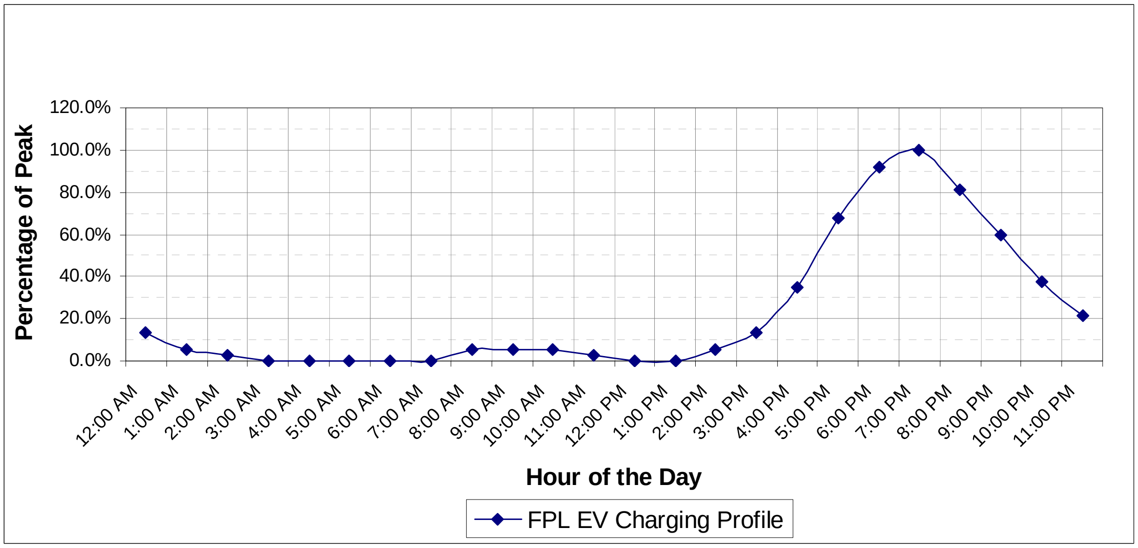
Additionally, DOE data provides a value for EV electricity consumption of approximately .35 kWh per mile. A gasoline-fueled car that gets 25 miles per gallon uses 0.04 gallons per mile. At an electricity cost of 10 cents per kWh, and a gasoline cost of $3.50 per gallon, the EV will cost 3.5 cents per mile to drive, while a gasoline-fueled car will cost 14 cents per mile. If an EV owner drives 12,000 miles per year, saving 10.5 cents per mile, they save approximately $1,260 per year in fuel costs.

Effect of Electric Vehicles at Times of Peak System Demand

Utility data responses suggest that most EV owners are likely to begin charging their vehicles when they return home from work. As a result, vehicle charging is likely to have the greatest effect on generation demand during the evening period. Figure 1, below, shows actual EV charging data provided by FPL. It shows a typical EV charge profile for a customer taking service under non-time-of-use rates.

[2] The Balmoral Group, "2011 Florida Motor Gasoline and Diesel Fuel Report," prepared for the Florida Department of Agriculture and Consumer Services, August 2012.

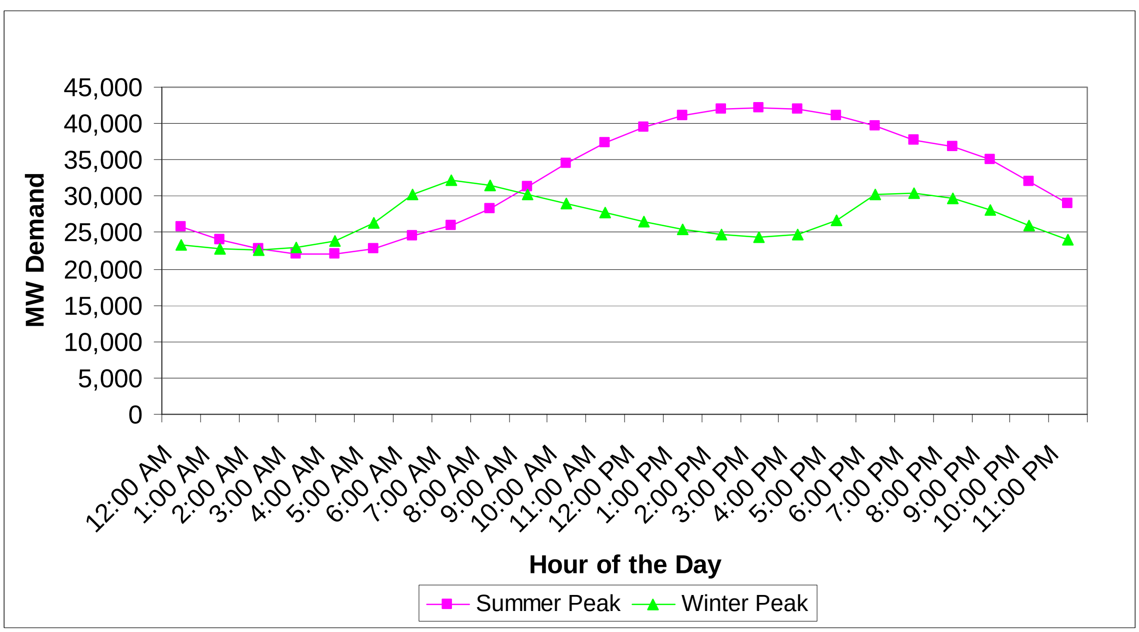
Figure 1. FPL EV Charge Profile



Source: FPL data response

EV owners are typically charging their vehicles on weekdays after work, which results in an increase in demand starting at approximately 5:00 p.m. and peaking around 7:30 p.m. before declining. As a result, the period of EV peak demand shown in Figure 1 may correspond closely with the system's summer peak. Figure 2, below, shows when summer and winter peaks occurred in 2011 for Florida utilities.

Figure 2. Summer and Winter Peak Values



Source: Utility Ten-Year Site Plan data

As Figure 2 shows, summer peak demand runs generally from 2:00 PM to 7:00 PM, while, as displayed in Figure 1, EV charging typically begins around 4:00 PM and ends around midnight. Because many EV owners are likely to plug their vehicles in as they get home from work, EVs will likely add to this peak demand period. While Figure 1's charge profile does not overlap with the entirety of the summer peak period, it does show some overlap with the last two hours, from approximately 6:00-8:00 PM. If EVs emerge in substantial quantities, this later period is where utilities will experience the greatest impact on generation demand.

This overlap between summer peak and EV charging periods may limit the beneficial aspects of EVs for the grid at peak. During the initial rollout for EVs, some believed that EV batteries could be used to store electricity that could then be sold back to the grid at peak, thus using EV batteries to lower need for generation at peak. Because EVs are likely to need their batteries for the drive home from work around that period, it seems unlikely at present that EVs can be used to reduce summer peak. Even during winter peak, coming roughly 7:00 AM to 9:00 AM, EV batteries will frequently be either in use, about to be in use, or drained due to the morning commute.

As previously discussed, electric demand from EVs is expected to be insignificant at both peak and non-peak periods. Florida's large utilities estimate that the impact of EVs is approximately 4 MW at peak demand in 2012. Summer peak demand for these utilities is estimated at approximately 39,000 MW in 2012, thus the impact from EVs is approximately 0.01 percent. The IOUs expect that effect to grow exponentially over the next decade, reaching 185 MW by 2021. Table 8, below, shows the projected total impact on peak demand to Florida's large utilities from EVs through 2021:

Table 8. EV Contribution to Summer Peak in MW

Year	FPL	PEF	TECO	GULF	OUC	JEA	Total
2012	2.9	0.1	0.4	0.1	0.2	0	**4**
2013	6.0	0.3	0.6	0.3	0.3	0	**8**
2014	11.1	0.8	0.9	0.5	0.5	0	**14**
2015	19.2	1.3	1.1	0.8	0.4	0	**23**
2016	29.8	2.1	1.5	1.1	0.5	1	**36**
2017	44.3	3.1	1.9	1.4	0.6	1	**52**
2018	60.6	4.6	2.4	1.8	0.7	1	**71**
2019	80.8	6.4	2.9	2.2	0.8	1	**94**
2020	114.8	8.6	3.4	2.7	0.9	2	**132**
2021	162.6	11.4	3.9	3.2	1.0	3	**185**

Source: Utility data responses

Need for New Generation Due to Electric Vehicle Deployment

As Table 7 shows, the projected impact on peak demand from EVs ranges from 4 MW in 2012 to 185 MW in 2021. Even the 185 MW statewide figure does not represent a concern or impact the need for new generation. Due in part to the softer economy in recent years, reduced customer growth, and a trend of electricity use per customer declining, Florida presently has ample generation capacity. Table 9, below, shows the projected reserve margins for each of Florida's large utilities through 2021. Reserve margin is defined as the amount of total generation capacity available that exceeds the expected peak demand of the system.

Table 9. Summer Reserve Margin in MW

Year	FPL	PEF	TECO	Gulf	OUC	JEA	Total
2012	6,238	3,081	1,019	367	416	739	**11,860**
2013	6,329	3,186	949	340	388	734	**11,926**
2014	6,454	3,009	910	693	362	698	**12,126**
2015	6,113	2,972	874	662	333	660	**11,614**
2016	5,739	2,231	810	635	295	630	**10,340**
2017	5,281	1,999	952	600	264	691	**9,787**
2018	5,268	1,839	912	564	305	747	**9,635**
2019	5,032	2,195	898	515	273	1,078	**9,991**
2020	4,683	2,037	856	466	241	1,028	**9,311**
2021	4,572	3,068	817	424	208	973	**10,062**

Source: Utility Ten-Year Site Plan data

Table 9 indicates that the large utilities expect to have sufficient capacity to reliably serve the incremental demand created by the deployment of EVs. In 2021, the EV impact on peak demand is projected to represent only 1.8 percent of that year's expected reserve margin. Even in the years when the EV impact is at its highest, there appears to be little chance of an impact on reliability. In 2021, FPL projects an impact of 162.6 MW from EVs and has a reserve margin of 4,572 MW. In 2021, EV impact is at its highest and reserve margin is at its lowest, and the EV impact is only 3.6 percent of the reserve margin. In no other year does this percentage reach a higher figure, either for a given utility or in total.

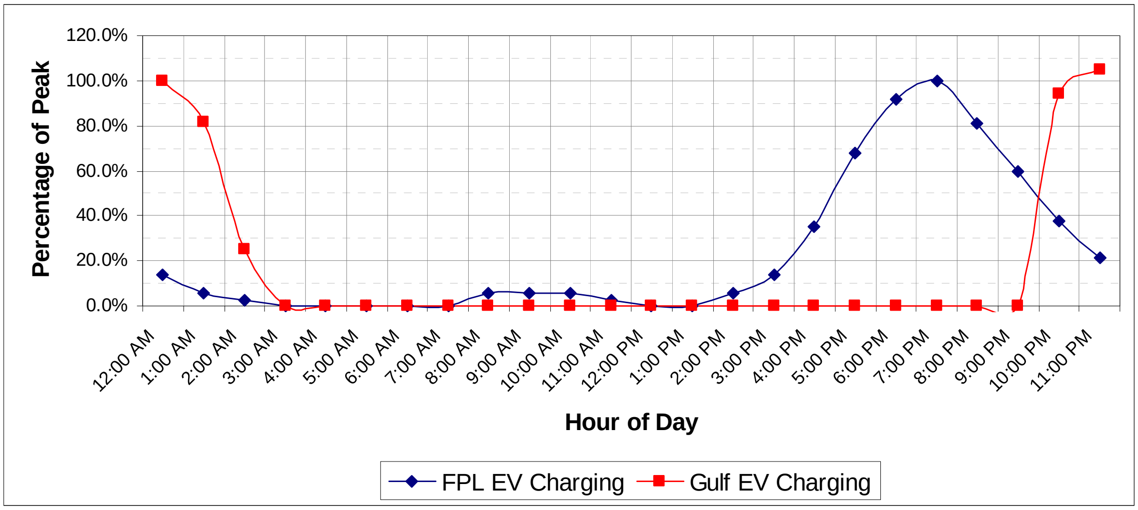
Accordingly, Florida's utilities are unlikely to add new generation during this period solely due to EVs. Distribution expenses will be addressed in the next section of the report.

Time-of-Use Rates and Electric Vehicle Charging

If massive deployment of EVs did create additional demand for new capacity, time-of-use rates can help shift EV charging times away from peak to off-peak periods. A time-of-use rate is a rate structure under which a customer pays a reduced rate for consuming electricity at off-peak times, while paying a higher rate at peak times. Time-of-use rates can be structured to reflect the costs of generating energy at different times. Implemented correctly, time-of-use rates can help manage peak demand with beneficial consequences for customers and the utility.

Figure 3 shows the potential impact of a time-of-use rate on customer EV charging behavior. The blue line is the FPL charger use profile shown earlier as Figure 1. This line can be considered a typical usage pattern under a traditional rate. The red line is the usage for a Gulf customer on a time-of-use rate.

Figure 3. FPL and Gulf Charging Times



Source: FPL and Gulf data responses

Figure 3 shows that the Gulf customer completely avoids charging during the peak period. Usage first registers at approximately 11:00 PM, which is when Gulf's time-of-use rate kicks into the lowest rate period. While this is a limited example, it does illustrate the potential of using time-of-use rates if EV charging significantly exceeds estimates.

Conclusion

EV charging will affect energy consumption in Florida by increasing electricity consumption and lowering petroleum-based fuel consumption. While EVs will add new demand to the grid in Florida, the high reserve margins of Florida's large utilities should stave off any need for new generation for some time. EV charging does coincide with the tail end of the period of peak electric demand, however, which could potentially cause some upward pressure on generation past the current ten-year planning horizon. Time-of-use rates could be a valuable tool for mitigating any potential increase in peak demand.

Section 5. Impact on the Electric Grid

In the short term, EVs are likely to have more significant effect on the electric distribution network than they will on generation or the transmission system. The distribution system moves power from the transmission system to end-use customers and consists of local distribution lines, transformers, and other equipment to transform the high-voltage power in the transmission system into the lower voltage power carried by end-use electric customers. To use a metaphor, the transmission system is akin to the Federal highway system, while the distribution system is the system of surface roads.

The electric grid consists of three primary areas: the generation, transmission, and distribution systems. The generation system consists of a mixture of types of power plants and other generation units, and generates the electricity that will eventually be consumed by end-use customers from a variety of fuel types. This electricity is usually generated at high amperage but a low voltage, with larger units in the range of 13,800 to 26,000 Volts (V). The generation system also consists of transformers to "step up" the electricity to the higher voltage used by the transmission to minimize losses. The transmission system consists of transmission lines that move electricity between the generation and distribution systems. The transmission system carries electricity at voltages ranging from 69,000 V to 500,000 V. The distribution system consists of substations and transformers, which step this electricity back down to a level usable by end-use customers, usually 120 V or 240 V, though larger for some industrial customers.

As a single contributor to new demand, EVs will not affect the timing or size of new transmission facilities. If additional transmission facilities are installed, they would follow additional generation needs, which are not anticipated at this time. Thus, this section of the report will focus instead on the expected impact of EVs on the distribution network.

Two elements of EV charging could affect distribution systems. The first element is the clustering of electric vehicles chargers. Multiple EV chargers operating simultaneously on a single residential transformer can collectively draw a fairly high electric load. Therefore, some residential transformers may need to be upgraded or replaced in order to handle this higher demand. While this effect is unlikely to result from a single Level 1 or Level 2 charger, multiple EV chargers operating simultaneously on a single transformer may exceed the design limitations of certain residential transformers.

The second element is public “quick-charge” Level 3 EV charging stations. The best information currently available indicates that none of these stations are operating in Florida. However, any future installations have the potential to require upgrades to the distribution network. “Quick-charge” stations can draw a very high electric load of 50 kW or more and may need that power at times of high demand. This section will also examine other factors that can impact the electric grid, including public charging.

Impact on Residential Transformers from Clustering of Electric Vehicles

Most EVs currently on the market and available in Florida use Level 1 or Level 2 chargers. While Tesla vehicles are compatible with larger Level 2+ chargers, these EVs still have very limited availability. As a result, most EVs generally available in Florida can charge only at 3.3

kW or below, with the Teslas and the Ford Focus EV at 6.6 kW or more. Most residential EV charging can thus be expected to take place at Level 1 or Level 2, with a smaller amount of Level 2+ charging. No Level 3 residential charging is anticipated.

A single EV charging at 3.3 kW or below is unlikely to pose any real challenge to even a small residential transformer. Even a 15 kilovolt-ampere (kVA) transformer, which is the smallest commonly-deployed size, is capable of handling the extra load required by an EV charging at 3.3 kW or below. For comparison's sake, a typical microwave oven, hair dryer, or space heater can run at 1 kW, only slightly less than a Level 1 charger. A 3.3 kW charger draws an amount of electricity comparable to running three of those devices at once, or a single typical electric dryer.

Multiple EVs charging simultaneously on the same transformer, even at 3.3 kW or below, could potentially exceed the design limitations of a transformer. Table 10 contains an initial estimate made by PEF of the number of chargers of a particular size that can be supported by each class of transformer in addition to its normal load. It is important to note, however, that the data in Table 9 represents an initial estimate and should not be considered definitive. In their post-workshop comments, representatives of FPL, PEF, and TECO all cautioned that this data might overstate the need for utility upgrades to the distribution system because of EVs. Nevertheless, in the absence of other data, it can be considered a starting point from which to analyze the grid impact of EVs.

Table 10. Number of Chargers Supportable Simultaneously by Transformer Class

Transformer kVA Class	1.4 kW (Level 1) EV Charger	3.3 kW (Level 2) EV Charger	6.6 kW (Level 2+) EV Charger
15	1	1	0
25	2	1	1
50	3	2	1
75	4	2	1
100	5	2	1

Source: PEF data response

Table 10 shows that even the lowest-capacity transformers should be adequate to handle any additional load from a single Level 1 or even 3.3 kW Level 2 EV charger. However, multiple 3.3 kW or larger chargers operating simultaneously could exceed a smaller transformer's design limits, requiring it to be replaced with a larger unit. Additionally, larger Level 2+ chargers, especially the 19.2 kW chargers that Tesla is making available to their customers, could potentially overwhelm even larger residential transformers. While there are no reports of EVs overloading transformers to date, they could begin to in neighborhoods with clusters of EVs.

Florida's three largest IOUs provided data in their post-workshop comments on the prevalence of residential transformer sizes. This data, shown below in Table 11, illustrates the number of transformers that could potentially be overloaded by larger or multiple EV chargers.

Table 11. Number of Transformers Reported by Size

Transformer kVA Class	FPL	*PEF	TECO	Total	Percent
10	7,364	0	0	7,364	1.00
15	39,905	83	9,265	49,253	6.66
25	142,592	13,060	22,746	178,398	24.11
37.5	77,918	16,833	17,114	111,865	15.12
50	204,739	29,461	16,273	250,473	33.85
75	79,615	9,589	3,600	92,804	12.54
100	35,849	3,310	953	40,112	5.42
125	0	6	0	6	0.00
167	8,143	1,502	0	9,645	1.30
Total	596,125	73,844	69,951	739,920	100.00

Source: Utility post-workshop comments
**PEF noted that it did not include some 25 kVA overhead transformers in its reported figures.*

Table 11 shows that roughly 75 percent of transformers in Florida are in the 25 to 50 kVA class. These transformers could potentially need to be upgraded once Level 2+ or larger chargers begin to emerge in significant numbers. The smaller Level 2 chargers are unlikely to require utility action unless several of them are operating simultaneously on a single transformer.

TECO, in its post-workshop comments, indicated that a single residential transformer can serve the equivalent of anywhere from 1-12 1,500 to 2,000 square foot homes. TECO noted that a 15 kVA transformer can serve from 1-3 such homes and a 100 kVA transformer can serve 10-12 such homes. Larger homes are also likelier to be served by larger transformers and smaller homes by smaller transformers, so a typical residential transformer might serve 3-4 homes.

FPSC staff is not aware of data indicating the presence of EV clustering in Florida. Eventually, however, either due to neighbors that share a transformer both buying EVs or individual households buying multiple EVs, clustering will likely eventually affect some transformers in Florida. As Florida's utilities gain more experience with EVs, they can be expected to refine their data and better project any effects EV clustering may have on the distribution system.

Impact of Public Charging Stations on the Transmission and Distribution Network

Currently, all public charging stations in Florida are Level 1 to Level 2+ stations. Some of these chargers were built for EV fleets, while others are located at businesses to serve employees or customers. While FPSC staff was unable to locate any data on the use of these chargers, anecdotal data suggests that many are used infrequently. As EVs become more common, these chargers will probably see greater usage. Because of the low power requirements of these chargers, as well as their placement on the typically larger commercial and industrial transformers, they are unlikely to drive a need for transformer upgrades.

Level 3 stations are likely to function as the EV equivalent of gasoline filling stations and may see similar times of use. Filling stations frequently see their highest weekday usage during morning and evening commutes, which coincide closely with winter and summer peak demand periods, respectively. As a result, Level 3 charging stations may place upward pressure on the generation system at times of peak demand as well. Also, similar to gasoline stations, quick-charge stations may prove essential for long-distance driving in electric-only EVs.

Because most charging in the near-term is likely to be either residential or lower voltage at-work charging, sufficient demand for quick-charge stations may not emerge in Florida for some time. The demand for quick-charge stations is expected to be driven both by EV owners who want to take longer trips in their EVs, and by EV owners who lack a garage or other reliable location to charge their vehicles both at home and at work. Once this demand emerges, utilities and other stakeholders will be able to gain better knowledge regarding their operation.

At-Work Charging

All known currently installed public EV chargers in Florida are Level 1 to Level 2+ chargers. Because EVs charging at these levels likely require multi-hour charges, they will probably see usage mainly from people parking their cars while at work. At present, most information on the usage of these chargers appears to be anecdotal, but it indicates that the majority of these chargers also see limited use.

The 4-8 hour charge times required by Level 1 and Level 2 chargers is convenient for the typical work schedule. Higher level chargers cost more and may require more extensive electrical upgrades, resulting in greater costs to their owners. As such, there is currently no reason to expect higher-level chargers to become commonplace for workplace charging. Because the distribution system equipment that serves commercial and industrial customers usually includes larger transformers capable of handling a much greater electric load, it is unlikely that the clustering of several EVs at one workplace will cause the same concerns it does for residential transformers. Additionally, many workplaces are demand metered and have meters that measure capacity, meaning that their utility can track any higher loads being drawn as a result of EVs and perform any needed upgrades to the distribution network. As EVs become more common, there is no reason to expect workplace charging at Level 1 to Level 2+ to drive the need for any upgrades to the distribution system.

Workplace charging may reduce the need for utility investment in both the distribution and generation systems. Workplace charging could shift demand away from the evening peak times currently expected to see the heaviest amounts of EV charging. Workplace charging could also effectively double the electric range of EVs. These facilities would permit partial to full recharging for the return trip home.

Workplaces concerned about any upward pressure EVs place on their overall power usage may wish to establish a method for recovering costs from employees if EVs become commonplace. Alternately, employers could view EV charging as an employee benefit. In the foreseeable future, workplace charging can be expected to be more beneficial to the electric grid in comparison to either at-home charging or public quick-charging, by shifting charging times away from peak hours and reducing pressure on residential transformers.

Conclusion

EVs are more likely to require utility investment in upgrades to the distribution system than to trigger any need for additional generation. However, any needs for distribution upgrades that do emerge are likely to be localized and isolated. The two aspects of EV charging most likely to require action by electric utilities on the distribution system are clustering of electric vehicles in residential areas and quick-charge stations elsewhere. At-work charging could ameliorate any chance of home charging exceeding the design limits of residential transformers.

Section 6. Feasibility of Solar PV for Off-Grid Charging

Section 366.94(4), F.S., also directed the FPSC to “investigate the feasibility of using off-grid solar photovoltaic power as a source of electricity for the electric vehicle charging stations.” Solar photovoltaic (PV) technology transforms sunlight directly into electricity through the use of solar panels. Solar PV is a different type of technology than solar thermal power or concentrated solar power (CSP). The latter types of solar power directly convert the light from the sun into heat. This heat can be used to heat water, in the case of solar thermal power, or to generate steam to turn a turbine to generate electricity, as in CSP.

Off-grid solar PV refers to installations in which the solar system is not connected to the electric grid and are frequently located in remote locations without electrical service. Most solar PV systems in Florida are connected to the grid. Solar PV first benefits homeowners and business owners by reducing the amount of energy purchased from the utility. Excess solar PV energy not consumed by the customer may be sold back to the utility by those interconnected systems. The interconnection with the utility ensures a reliable source of electricity during times when solar PV energy production cannot meet a customer’s requirements.

This section of the report will first examine the amount of solar energy an off-grid station would need in order to adequately charge an EV and then will compare the solar PV energy production curve to EV demand as shown earlier in the report. Finally the report presents options for utilizing energy from solar PV for EV charging.

Generation Needed per Station

The physical dimensions of solar panels required to meet the wattage demands of EV chargers is relatively large compared to other power generation technologies. For example, a 220 watt solar panel is approximately 18 square feet, or approximately 12 watts per square foot. For the sake of comparison, a 1,210 MW natural gas combined cycle (NGCC) plant site (including all facilities) requires approximately 38 acres, or 1,655,280 square feet, for a value of 731 watts per square foot. A 1,210 MW solar plant would take up approximately 2,315 acres, or 3.6 square miles, for the panels alone. Despite the much larger footprint, the solar plant would actually produce only a fraction of the energy (MWh) of the NGCC plant due to its much smaller capacity factor.

Solar PV installed at a site with full sun exposure usually has a capacity factor in the range of 20-25 percent. Capacity factor is the percentage of energy a generator produces divided by the theoretical maximum it could produce running at full capacity all of the time. To explain the application of capacity factors further, a 100 kW facility operating at 100 percent capacity factor would produce 2400 kWh in a 24-hour period. A 100 kW facility operating at 25 percent capacity factor for 24 hours would only produce 600 kWh. A typical base load electric plant usually has a capacity factor of 80-85 percent and some nuclear plants achieve a 95-99 percent capacity factor.

Table 12 describes how many solar panels and how much minimum area would be required to generate a given EV charge value at peak output. It is important to note that these values are the minimums needed to generate the given charge value at their peak of production.

Table 12. Area Required for Solar PV EV Charging

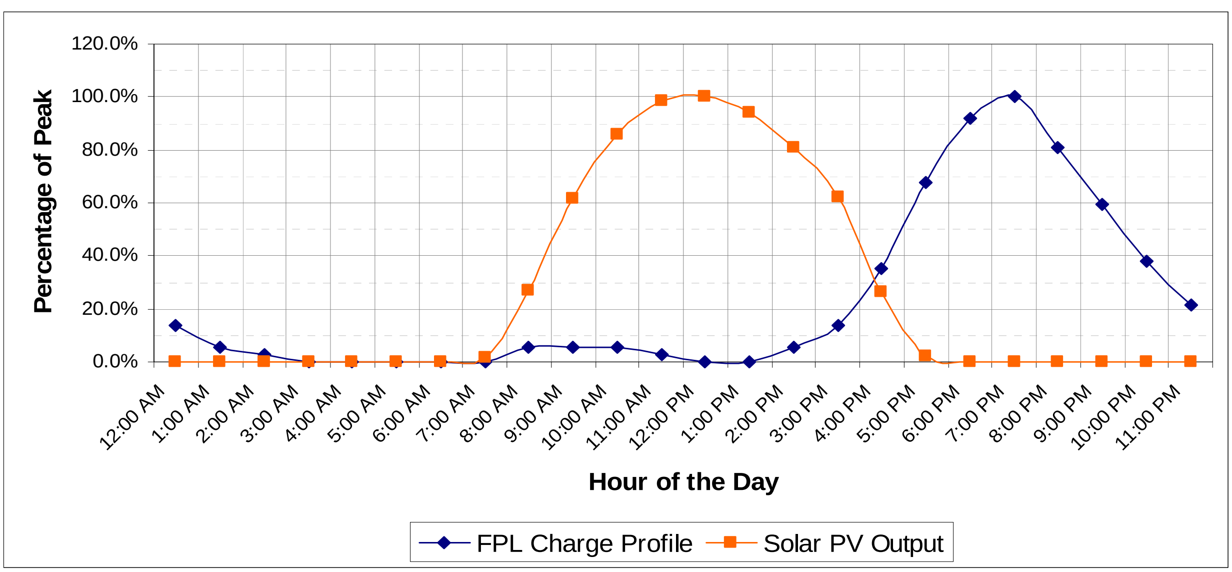
Charger Type	220 W Panels	Area (Sq. Ft.)
1.2 kW (Level 1)	4-6	89
3.3 kW (Level 2)	10-15	213
6.6 kW (Level 2+)	20-30	444
10.2 kW (Level 2+)	47	835
19.2 kW (Level 2+)	88	1563
25 kW (Level 2+)	114	2025
50 kW (Level 3)	151-228	3375

Source: Utility data responses

Relationship between Solar Production Times and Charging Demand Times

EV charging capacity powered by solar PV is maximized during full solar radiation. As Figure 4 below demonstrates, optimal output is limited chiefly to the middle hours of the day, and it does not align with the typical EV charge profile introduced earlier. In addition, high humidity, dust, and other atmospheric conditions limit the full output in these areas.

Figure 4. Solar PV Energy Production and EV Charging



Source: FPL data response and FPL Space Coast Next Generation Solar Energy Center

While there is some concurrence between the end of the maximum solar PV energy production and the primary period for EV charging, this overlap is minimal. To overcome the limitations of "live" solar PV charging, owners of these stations will need to find a way to decouple times of energy production from charge times. Provided that these stations remain off-grid, this approach would require some kind of energy storage.

Additionally, limiting EV charging at these stations to the solar PV energy production schedule could make the stations less available. These stations would produce more power in the summer than in the winter, which could mean that power goes to waste at certain times and is insufficient at others. Also, an extended cloudy period could depress solar PV energy production for an extended period of time, again limiting the stations' ability to meet demand. A tie to the electric grid provides a back-up source of power that helps overcome these difficulties.

Potential for Energy Storage

Energy storage is any technology that allows electricity generated at one time to be used later. While there are many different energy storage technologies, batteries are likely to be the most useful for solar PV EV charging. Most utility-scale energy storage technologies - such as pumped water storage, pumped air storage, flywheels, and fuel cells - are either unsuited to Florida's geography, unsuited to this scale, or still too new to be deployed at reasonable cost.

One specific form of energy storage that has been proposed is battery swaps. Under this method, EVs have interchangeable, standardized batteries which can be removed from the vehicle and replaced with a fully charged one, while the spent battery is charged over time until it is placed in a different vehicle. The EV models in the United States do not appear to have been designed with battery swaps in mind, which limits this method's deployment. Without an industry-wide attempt at standardizing EV batteries and their installation in order to facilitate battery swaps, they are unlikely to be an option for energy storage over the near term.

An alternative strategy is central battery energy storage offered near the charging station. General Electric Corporation (GE) provided estimates of the costs of this type of storage. GE estimated current energy storage costs at approximately $600 per kWh, with about two-thirds of that for the cost of the battery and one-third for other equipment. Furthermore, these estimates indicate a cost per vehicle served by a given charging station at approximately $10,800 per vehicle, which is approximately 18 kWh of storage per vehicle at the cited costs.[3] This cost is solely for the energy storage and does not include any of the costs of the solar system itself, and scales up proportionately. The storage costs for a typical worksite charger capable of serving eight vehicles per day would be approximately $86,400. Sufficient energy storage to serve a public EV quick-charge station that serves 40 vehicles per day would cost approximately $432,000. These costs are for energy storage only and do not include the costs of solar panels or other equipment. Additionally, by keeping these systems off-grid, charger owners would be limiting the number of EVs they could charge in a given day to the size of the system.

[3] This 18 kWh figure was provided by GE and is higher than the 11 kWh assumed by the FPSC in energy consumption calculations. Off grid charging behavior is likely to differ from that of EV owners charging at home. The 18 kWh figure is probably more reflective of how these batteries will be used.

Energy storage costs are sufficiently high that it is probably more efficient to tie these stations to the electric grid. Running a service line to an area already served by electric utilities in Florida will likely only cost hundreds of dollars in most situations. Running distribution lines to all but the most remote areas of Florida is likely to cost less than installing energy storage sufficient for an EV charging station and will offer more options to the charging station owner.

Off-grid solar PV charging will only be economically viable in areas not currently served by electric service. While the most isolated islands of the state might be able to justify the costs of making an off-grid EV charging station, the cost of grid-tying a solar PV system will be lower than the cost of energy storage for nearly the entire state of Florida.

Conclusion

While solar PV may be used to charge EVs, solar energy production is limited to daytime hours with adequate solar exposure. Energy storage allows the stations to overcome that limitation, but the costs of energy storage typically exceed the costs of connecting a charging station to the electric grid. Off grid solar PV installation may be sited in remote locations for purposes such as signage or lighting. Individuals and businesses using solar PV for EV charging will reap greater benefits by interconnecting with the grid to take advantage of utility net metering programs.

The use of off-grid solar PV for EV charging may be limited given that the hours of maximum generation from solar PV do not entirely match the peak hours of EV charging, which are expected to occur primarily during evening hours at residential locations. An increase in EV sales and expansion of EV charging stations may result in additional opportunities for solar PV as a source of electricity. Daytime charging at work locations or other non-residential locations would better align with the availability of solar energy. The cost of solar PV, while at historically low levels, remains a higher cost resource compared to traditional sources of electricity. Off-grid solar PV will face the challenge of being entirely dependent on solar exposure cycles and thus is not expected to be a feasible option, with the possible exception of remote locations without grid access.

Section 7. Conclusion

Electric vehicle charging is still a new frontier in Florida. Prior to the introduction of the most recent wave of mass-market models, EVs remained a niche product that did not exist in large enough numbers to affect the electric grid. While information on EVs at present is very limited, as the market grows methods of estimating the numbers of EVs being charged in Florida should become easier to determine, as well as their effects on energy consumption and the electric grid.

EVs do not appear to pose any chance over the ten-year planning horizon of contributing significantly to driving a need for new generation in Florida. The electricity needed to charge EVs will contribute relatively little to Florida's total energy consumption. EVs should help reduce Florida's dependence on imported oil for gasoline and diesel fuel. While EV charging may align with the later hours of peak demand, the combination of adequate utility reserves and limited aggregate effects from EVs should limit generation effects, even at peak. If and when EVs do drive the need for new generation, rate structures such as time-of-use pricing may serve as valuable tools for shifting EV load to off-peak times.

EV charging could require utilities to address the capacity of certain elements of the distribution system. Multiple EVs charging simultaneously on the same transformer could potentially overload the design limits of some transformers. Any required utility action is only likely to emerge with smaller residential chargers. Utilities will have a better sense of how significant the likelihood is once they have gained more EV charging experience. Quick-charge stations may also require utility attention on transformers that primarily serve industrial and commercial customers. No quick-charge stations have been installed in Florida, and few have been installed nationwide, so their future impact is still uncertain.

Off-grid solar photovoltaic EV charging may be technically feasible, but economically impractical, at present. Solar PV charging stations are more economical if tied to the electric grid, because the high energy storage costs necessary for an off-grid system to function throughout the day cost significantly more than the costs to interconnect with the electric grid. Off-grid solar energy on that scale might be practical in islands and other isolated areas removed from the electric grid, but not throughout most of mainland Florida.

Appendix A: Bibliography

The FPSC relied primarily on three sources of information for this report: a literature review, a data request sent to many of Florida's electric utilities in May 2012, and a staff workshop held on September 6, 2012. Staff also consulted internet resources as well. These sources will each be discussed in depth in this appendix.

Literature Review

The purpose of the literature review was primarily to familiarize FPSC staff with the basics of EV charging. While much of the technical information found by the FPSC was useful for background information, relatively little from this initial review was directly applicable to the tasks assigned to the Commission under 366.94(4) F.S. Rather, the literature review helped formulate the staff data request and resulted in more Florida-specific information.

The list that follows contains some of the sources that best helped to inform FPSC staff in developing both its background information and in creating the information request sent to Florida's electric utilities. While this list is by no means exhaustive, it contains a number of reports and articles that might provide a good starting point for anyone wishing to learn more about EVs nationwide.

Edison Electric Institute, "The Utility Guide to Plug-in Electric Vehicle Readiness," November 2011.

Electric Power Research Institute, "Transportation Electrification: A Technology Overview," 2011.

Markel, T. "Plug-in Electric Vehicle Infrastructure: A Foundation for Electrified Transportation," National Renewable Energy Laboratory, April 8, 2010.

Serra, João Vitor Fernandes, *Electric Vehicles: Technology, Policy, and Commercial Development.* Earthscan, London 2012.

U.S. Department of Energy, "Plug-In Hybrid Electric Vehicle R&D Plan," June 2007.

U.S. Department of Energy, "One Million Electric Vehicles by 2015: February 2011 Status Report," February 2011.

Staff Data Request

Responses to the FPSC staff data request were the most significant source of information used in this report. On May 1, 2012, FPSC staff submitted a data request consisting of 27 questions, some of which were multi-part, to many of Florida's electric utilities. The recipients included: Florida's five IOUs, the five largest municipal utilities (JEA, OUC, Tallahassee, Lakeland, and

Gainesville), Florida Electric Cooperatives Association (FECA), Florida Municipal Electric Association, Florida Municipal Power Agency (FMPA), and Seminole Electric Cooperative, Inc. The FECA also distributed the request to its members.

Responses to the data request were due June 1, 2012. FPSC staff received responses from the five IOUs, the five municipal utilities listed, Seminole, FMPA, and six cooperative utilities. The most extensive responses came from the six large utilities cited throughout the report. These responses formed the backbone of the report as written. The nature of the responses helped shape the scope of the report as well. For example, the utilities were reluctant to conjecture about the effects of EV deployment significantly beyond the range of projections, largely because they considered such examination too speculative and unrealistic. As a result, FPSC staff decided to limit the scope of the report to the range of projections for the EV rollout.

Much of the data in the final report originated from these utility responses. FPSC staff used utility responses for EV projections, charger deployment, charger usage data, and other critical pieces of the report. PEF's data on transformer EV capacity served as the starting point for estimates related to residential transformer EV charger capacity. The data from the large utilities also strongly informed FPSC staff's presentation at the September workshop.

Staff Workshop

FPSC staff conducted a workshop on September 6, 2012, to provide an opportunity for a discussion on issues relevant to the study. Parties presenting at the workshop included the Electric Power Research Institute (EPRI), General Motors Company (GM), General Electric Company (GE), SPX Corporation, the Florida Solar Energy Center (FSEC), four Florida IOUs, and OUC. The workshop began with presentations by each of the ten presenters, followed by a roundtable discussion, and closed with a brief public comment period.

Information on this workshop, including presentations, a transcript, audio and video coverage of the event, and post-workshop comments, can be found at the following webpage:
http://www.floridapsc.com/utilities/electricgas/electricvehicles/09_06_2012/index.aspx

Mark Duvall of EPRI gave a general overview of EV sales and electrical system impacts nationwide and in Florida. He spoke first on the growth of EV sales, noting that EVs are actually selling faster than HEVs did by the same time following their launch. He also discussed system impacts, noting that the distribution system would be affected first, and that this impact would be based on charge levels, not time of day. He also spoke regarding system costs and charger deployment, noting that the latter will follow EV sales.

Britta Gross from GM discussed her company's Chevy Volt PHEV and its capabilities and sales figures. She then discussed her company's partnerships with EPRI and the Edison Electric Institute in promoting EVs. Ms. Gross then discussed some more general information relating to EV charging, including types of chargers and GM's projections of where charging takes place. She closed her presentation by discussing some of GM's outreach activities.

Joshua Caillavet from GE discussed GE's EV chargers, how they are used, and some of their interface options. He then discussed some of his company's forecasts for EV sales, which included an estimated 11,000 EVs in Miami by 2019. Mr. Caillavet also provided information on load management, in conjunction with solar power and energy storage, to flatten out load curves and reduce the peak impact of EVs. He closed his presentation by introducing the possibility for solar carports and energy storage to assist in managing load.

Charlie Yankitis, from SPX, a company that manufactures and installs EV chargers, noted his company's installations in Florida, which include 97 homes and 425 chargers in total. He also described SPX's support of its chargers and the services it offers to potential customers. Mr. Yankitis shared some statistics regarding the types of homes on which SPX has performed installations, and regarding the nature of the installations. The presenter concluded with a description some of the charger options offered by his company.

Robert Reedy, of FSEC, focused primarily on solar PV charging. He noted the cost savings offered by EVs, showing that EV charging costs an estimated equivalent of 97 cents a gallon of gasoline. He also noted that the price of solar PV has been dropping for some time and claimed that it offered the equivalent of $1.08/gallon of gasoline. He also noted that the price of gasoline was rising as the price of solar was falling and projected gasoline costs of $8.60/gallon in 2025. Mr. Reedy then examined the advantages and disadvantages of various kinds of solar installations including grid-tied and off-grid.

The final five speakers represented Florida's large utilities: Brian Hanrahan from FPL, Christopher Gillman from PEF, Keith Gruetzmacher from TECO, Bob McGee from Gulf, and Jennifer Szaro from OUC. Each of the speakers discussed their utility's experiences with EVs including any expectations, studies, and programs. The presentations had a certain degree of overlap but each brought a unique utility perspective. All speakers expressed confidence that generation shortfalls would not be a problem. Some did express concern that distribution system upgrades could potentially be required during the planning timeframe. Most of the speakers also discussed their own EV fleets and how those fleets were giving them knowledge that would help inform them going forward.

Mr. Hanrahan described an ongoing EV study FPL was conducting, though the results would not be complete in time for this report. He also noted that his company saw benefits to solar PV EV charging, but that grid-tying was a requirement for it to be effective. Mr. Gillman noted PEF's outreach activities and the opportunities offered by the merger with Duke Energy. Mr. Gruetzmacher noted TECO's residential grid impact survey that indicated that it is likely to be years before any significant utility action is required. Mr. McGee discussed Gulf's time-of-use rate option and how an EV owner using that option shifted his charging times to off-peak hours. Finally, Ms. Szaro discussed OUC's partnership with Charge Point America. Through this partnership, OUC has installed 78 utility-owned public EV charging stations in Orlando, and has identified numerous challenges that will help them adapt when EVs become more common.

Following the morning presentations, FPSC staff led a roundtable discussion with all of the presenters. This discussion kept largely to the structure of the report, with the discussion divided into the same four sections as the body of the report: background data for EVs, effects on energy consumption, impact on the electric grid, and the feasibility of solar PV for off-grid charging. Staff discussed with presenters many of the same ideas that are found in the report. Specifically, discussion included the difficulty of getting reliable data, the limited effect EVs will have on generation, the potential for EV clustering to overload residential transformers, the effects of quick-charge stations, and whether making solar PV stations off-grid was worth the cost and difficulty. Speakers reached a consensus on most of these issues, which are reflected in this report. Notably, some of the utility representatives expressed some hesitation using PEF's data on residential transformer EV charging limits, but they did not have better data to substitute.

The workshop closed with a brief public comment period. Only one speaker, Helda Rodriguez, asked to speak. She discussed her business, NovaCharge, a Florida-based business that installs charging stations. She also shared some of her experiences with EV charging installations in Florida. One of her points of emphasis was that, because many of her customers lacked garages, she found that commercial charging stations were receiving a higher percentage of use than had been anticipated. She also advocated for a streamlining of the permit process to make EV charging installations easier.

At the workshop, FPSC staff asked for any post-workshop comments to be submitted by September 27, 2012. Staff asked for additional data on any possible challenges to the distribution system, data from utilities on numbers of types of residential transformers deployed, and information on energy storage. Staff received responses from FPL, PEF, and TECO on the due date, while GE provided information on energy storage in October. In their post-workshop comments, all three utilities expressed concern with PEF's chart regarding the number of EV chargers supportable by residential transformers. Accordingly, staff noted this concern in the report. All three utilities also provided a breakdown of the numbers of types of residential transformers they have deployed in their territory. FPL also noted their ongoing EV study, and stated that they could better answer some of the distribution questions when it was completed. PEF, who provided the original slide on transformers, noted that they provided it for discussion purposes and it did not reflect real-world data. TECO wrote that their own study indicated that any significant grid effects from EVs were years away. These comments are available on the PSC website at www.floridapsc.com.

Internet Resources

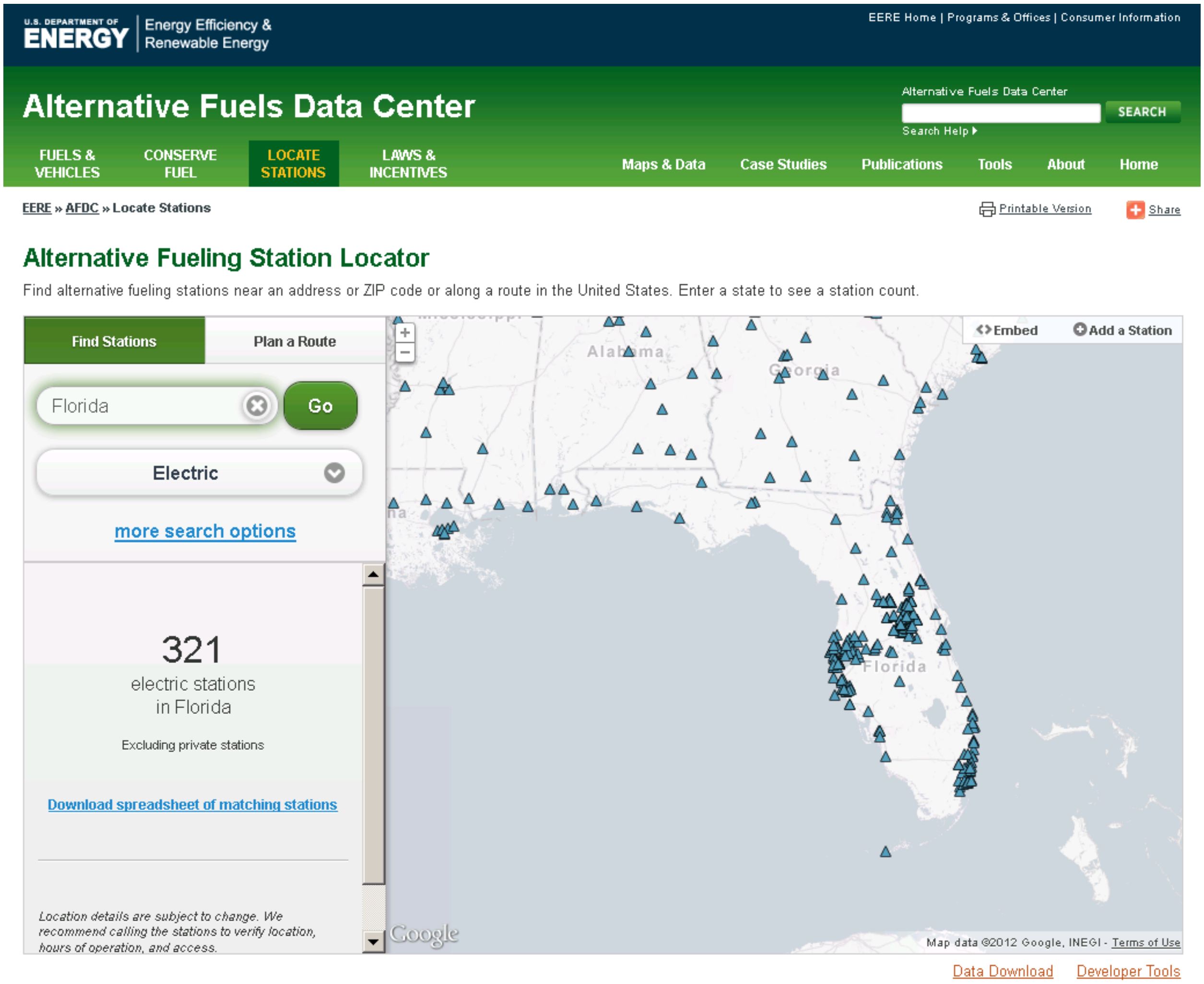
Most of the information for statistics on individual models of EVs came from the websites of their automotive manufacturers as of October 2012. In most cases, this data reflects the most recent model of the EV.

The DOE has internet resources for alternative fuel vehicles, including EVs, which FPSC staff consulted in preparation for the study. The DOE's Alternative Fuels Data Center includes numerous publications on EVs, including general guides to terminology and technology, and references for consumers considering purchase of an EV. The website also includes a summary of state incentives and policies regarding EVs.

The DOE also offers an EV charging station map that updates every two weeks. As of October 18, 2012, the locator lists 321 EV charging stations in Florida, clustered heavily in the Miami, Tampa, and Orlando areas, but existing statewide. The data does appear to be incomplete, at least regarding certain fuels. The website, which tracks all alternative fuels, is available at: http://www.afdc.energy.gov/locator/stations/

The following picture is a screenshot of the site, showing where it lists stations in Florida. More detailed information listing specific locations for individual station sites is available from the website.

Figure 5. Alternative Fuels Data Center



(Site was accessed October 18, 2012)

Appendix B: Corporate Average Fuel Economy Standards

The recently-approved Corporate Average Fuel Economy standards (CAFE standards) require vehicle manufacturers to significantly improve fuel economy. Manufacturers that do not achieve these standards are subject to substantial financial penalties. One strategy for vehicle manufacturers to meet these more stringent fuel economy standards is to increase production and sales of alternative fuel vehicles, such as EVs. As a result, rising CAFE standards will likely spur car manufacturers to promote greater EV sales in coming years as a means to comply with the new CAFE standards.

CAFE standards were introduced in the wake of the 1973 OPEC Oil Embargo when Congress enacted the Energy Policy and Conservation Act of 1975, which established the CAFE standards. The purpose of these standards is to improve the manufacturer's fleet average fuel economy of new cars and light-duty trucks (including vans and sport utility vehicles) sold in the United States. CAFE standards set the average fuel economy for each new vehicle model year, measured in miles per gallon (MPG), that each car manufacturer's fleet is required to achieve. Vehicle manufacturers that fail to meet the standard are subject to financial penalties. The current penalty is $5.50 per 0.1 MPG under the standard, multiplied by the manufacturer's total production for the domestic market. In addition, a "gas guzzler tax" is imposed on manufacturers of new cars (not minivans, sport utility vehicles, or pick-up trucks) that do not meet required fuel economy levels, to discourage the production and purchase of fuel-inefficient vehicles. The tax is collected by the Internal Revenue Service and paid by the manufacturer. The amount of the tax is displayed on the vehicle's fuel economy label (the window sticker on new cars). [4]

The first CAFE standards were set to increase passenger vehicle efficiency to 27.5 MPG within 10 years (1975-85). The National Highway Traffic Safety Administration was given the authority to set a separate standard for light trucks, which resulted in raising fuel economy for these vehicles from 11.6 to 19.5 MPG by 1985.

New CAFE Standards

On January 26, 2009, President Obama directed the Department of Transportation (DOT) to review relevant technological and scientific considerations associated with establishing a more stringent fuel economy standard. On May 19, 2009, President Obama also proposed a new national fuel economy program that adopts uniform federal standards to regulate both fuel economy and greenhouse gas emissions while preserving the legal authorities of the DOT, the Environmental Protection Agency (EPA), and the State of California.[5]

On July 29, 2011, an agreement was reached between the federal government, state regulators, the United Auto Workers, and thirteen large automakers to increase CAFE Standards to 54.5

[4] Environmental Protection Agency, "Gas Guzzler Tax Overview," September, 2012.
[5] National Highway Traffic Safety Administration, "Average Fuel Economy Standards Passenger Cars and Light Trucks Model Year 2011: Final Rule," March 30, 2009.

MPG for cars and light-duty trucks by model year 2025. The agreement will result in the most significant fuel efficiency improvements in more than 30 years and the first-ever global warming pollution standards for light-duty trucks. The CAFE standards will be expressed as mathematical functions depending on each vehicle's "footprint," a measure of vehicle size determined by multiplying the vehicle's wheelbase by its average track width. For example, under the CAFE standards, the 2012 Honda Fit with a footprint of 40 square feet (sq. ft.) must achieve fuel economy of 36 MPG, while a Ford F-150 truck with its footprint of 65–75 sq. ft., must achieve CAFE fuel economy of 22 MPG. The fuel economy performance of advanced technology vehicles, such as EVs, is typically higher than a manufacturer's CAFE standard. For example, the 2017 CAFE target fuel economy for passenger cars of 39.5 MPG compares to the 2012 actual advanced vehicle performance of a Prius hybrid at 50 MPG, a plug-in Prius hybrid at 95 miles per gallon gasoline equivalent (MPGe), and a LEAF electric vehicle at 99 MPGe.[6]

Table 13 displays examples of footprint targets for popular vehicle models. The table demonstrates that different vehicle sizes will have varying fuel economy targets under the footprint-based standards.

Table 13. Model Year 2025 Fuel Economy Targets for Representative Vehicles

Vehicle Type	Example Models	Example Model Footprint (sq. ft.)	NHTSA Fuel Economy Target (MPG)
Example Passenger Cars			
Compact car	Honda Fit	40	61.1
Mid-size car	Ford Fusion	46	54.9
Full-size car	Chrysler 300	53	48.0
Example Light-duty Trucks			
Small SUV	4WD Ford Escape	43	47.5
Mid-size crossover	Nissan Murano	49	43.4
Minivan	Toyota Sienna	56	39.2
Large pickup truck	Chevy Silverado (extended cab)	67	33.0

Source: Environmental Protection Agency, "EPA and NHTSA Set Standards to Reduce Greenhouse Gases and Improve Fuel Economy for Model Years 2017-2025 Cars and Light Trucks." EPA-420-F-12-051, August 2012

Current federal regulations set a performance target for every vehicle model, which includes both the CAFE fuel economy standards discussed above and CO_2 emissions standards set by the EPA based on the vehicle's footprint. Each manufacturer's fleet average performance is then determined by the production-weighted footprint average of those targets.

[6] NHTSA Press Release: "President Obama Announces Historic 54.5 mpg Fuel Efficiency Standard," Friday, July 29, 2011

Incentives for Alternative Fuel Vehicles

In order to encourage early adoption and introduction in the marketplace of EVs and other alternative fuel vehicles, the CAFE standard will provide manufacturers with extra credit for sales of EVs, PHEVs, and fuel-cell vehicles. These vehicles have high CAFE ratings, as they use little or no gasoline. To further encourage their sales, the government will factor each sale of an electric vehicle by 2.0 beginning in model year 2017. In other words, if a manufacturer sells 10,000 electric vehicles, either battery powered or fuel cell, these vehicles will be counted as 20,000 when calculating that company's fleet fuel economy. This incentive factor will phase down to a multiplier of 1.5 by 2021. For plug-in hybrids, the factor will start at 1.6 in 2017 and phase down to 1.3 in 2021.[7]

The table below displays the incentive multipliers established by the new CAFE standards for all-electric, fuel cell (FCV) and PHEVs.

Table 14. All-Electric, FCV and PHEV Incentive Multipliers for Model Years 2017-2021

Model Year(s)	All-Electric and FCVs	PHEVs
2017-2019	2.0	1.6
2020	1.75	1.45
2021	1.5	1.3

Source: Federal Register/ Vol. 77 No. 199 / Monday, Oct. 15, 2012 / Book 2 of 2 page 62813

Major auto manufacturers are developing advanced technologies that can significantly reduce fuel use and greenhouse gas emissions beyond the existing model year 2012-2016 standards. The high CAFE standards of EVs, along with the incentive multipliers, are designed to encourage manufacturers to produce these alternative fuel vehicles in order to meet the more-stringent CAFE standards. In addition, a wide range of technologies are currently available for automakers to meet the new standards, including advanced gasoline engines and transmissions, vehicle weight reduction, lower tire rolling resistance, improvements in aerodynamics, diesel engines, more efficient accessories, and improvements in air conditioning systems.

In addition to incentive multipliers for EVs, the CAFE standard program also includes targeted incentives to encourage early adoption of other advanced technologies to dramatically improve vehicle performance, including the following:

- Incentives for hybrid technologies for large pickups and for other technologies that achieve high fuel economy levels on large pickups;

- Incentives for natural gas-fueled vehicles; and

- Credits for technologies with potential to achieve real-world greenhouse gas reductions and fuel economy improvements that are not captured by the standards' test procedures.

[7] Berkowitz, Justin, and Csaba Csere, "The CAFE Numbers Game: Making Sense of the New Fuel-Economy Regulations," *Car & Driver*, August 29, 2012.

Conclusion – Expected Impact of CAFE Standards on EV Sales

The recently-approved CAFE standards require vehicle manufacturers to significantly improve the fuel economy of their fleets. Manufacturers that do not achieve these standards are subject to substantial financial penalties. One strategy for manufacturers to meet these more stringent standards is to increase the production and sales of alternative fuel vehicles, including EVs. The fuel economy performance of advanced technology vehicles, such as EVs and PHEVs, are typically higher than a manufacturer's CAFE standard. In addition, manufacturers will be further encouraged to increase production and sales of EVs due to the incentive factors included in the new CAFE program.

Appendix C: State Policies Related to Electric Vehicles

In order to collect information on state policies in the U.S. regarding EVs, the FPSC sent a survey to all 49 other state public utility commissions. The survey requested information concerning laws, rules, and procedures dealing with EVs, EV charging stations, and the potential impact on electric reliability. The distribution of the survey was facilitated by the staff of the National Association of Regulatory Utility Commissioners.

The FPSC received 17 responses to the survey. Out of the 17 responses received, only 6 states indicated that they have written rules or promulgated laws concerning the subject. These states are: Alabama, Hawaii, New York, North Carolina, South Carolina, and Virginia. The following states returned surveys indicating that they currently have no EV policies in place: Kansas, Kentucky, Maine, Missouri, Montana, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, and Vermont.

Although California and Illinois did not respond to the survey, the FPSC staff was aware that these states have significant EV activities and conducted independent research on these states. A discussion of EV-related policies in Georgia is also included due to its shared border with Florida.

In addition to the survey, the FPSC also reviewed other sources of information regarding the EV policies in other states. In particular, the FPSC made use of the DOE's Alternative Fuels Data Center website, which includes a summary of state incentives and policies regarding EVs.

Alabama

In February 2012, the Alabama Legislature established a "Green Fleets Policy" designed to increase fuel economy and reduce greenhouse emissions of the state vehicle fleet. The policy could result in an increase in EV demand in the state because it requires each state agency to take fuel economy into account when purchasing vehicles. State fleet managers must classify their vehicle inventory for compliance with the policy and submit annual plans for procuring fuel-efficient vehicles. These plans must reflect a 4 percent annual increase in average fleet fuel economy for light-duty vehicles, a 3 percent annual increase in average fleet fuel economy for medium-duty vehicles, and a 2 percent annual increase in average fleet fuel economy for heavy-duty vehicles per fiscal year.

The Alabama Public Service Commission has approved a time-of-use rate for Alabama Power for charging EVs owned by businesses. Alabama Power offers the Business Electric Vehicle Time-of-Use rate for electricity purchased to charge EVs used for non-residential purposes. The electricity used for vehicle charging is metered separately from all other electricity use. By providing lower rates for off-peak hours, the time-of-use rate encourages business customers to avoid charging during peak demand periods.

Alabama, Georgia, and South Carolina are participating in an initiative to develop a tri-state plan to enable EVs. The initiative is funded by the U.S. Department of Energy and is being coordinated by the South Carolina Institute for Energy Studies.

California

California has multiple EV-related policies and programs that are designed to encourage adoption of EVs, including state laws, state incentives, and electric utility programs. For example, in 2011, the California Legislature amended Section 216 of the Public Utilities Code to remove a regulatory barrier to EV charging stations. The amendment provides that a corporation or individual that owns, controls, operates, or manages a facility that supplies electricity to the public exclusively to charge light-duty battery electric and plug-in hybrid electric vehicles is not defined as a public utility.

The California Air Resources Board administers the State's Zero Emission Vehicle (ZEV) program. This program is designed to assist California in meeting its greenhouse gas and ozone reduction goals by encouraging the adoption of low emission vehicles, including EVs. The program defines ZEVs as new passenger cars, light-duty trucks, and medium-duty passenger vehicles that produce zero exhaust emissions of any criteria pollutant (or precursor pollutant) under any and all possible operational modes and conditions. Manufacturers with annual sales greater than 60,000 vehicles must produce and deliver for sale in California a minimum percentage of ZEVs for each model year as follows:

- 11 percent during 2010-2011
- 12 percent during 2012-2014
- 14 percent during 2015-2017
- 16 percent during 2018 and beyond

Manufacturers with annual sales between 4,501 and 60,000 vehicles have multiple alternative compliance options to meet the ZEV requirements, including obtaining ZEV credits. Manufacturers with annual sales of 4,500 vehicles or less are not subject to the ZEV regulation. As of December 2011, all manufacturers subject to the ZEV regulations appear to be meeting the required goals.[8]

Beginning in 2012, manufacturers subject to the policy that do not meet the minimum percentage goals or obtain sufficient credits are penalized $5,000 per unit underage.[9] The production and sales requirements for manufacturers, coupled with these steep penalties, may encourage manufacturers to offer ZEVs at discounted prices in California. Increased production could also provide economies of scale, resulting in further downward pressure on vehicle prices. This could have implications for ZEV adoption in other states, as residents from other states may purchase lower-priced ZEVs in California.

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[8] *Staff Report: Initial Statement of Reasons, Advanced Clean Cars, 2012 Proposed Amendments to the California Zero Emission Vehicle Program Regulations*; California Environmental Protection Agency Air Resources Board; December 7, 2011.
[9] California Air Resources Board, AB 32 and the Cap-and-Trade program, "Air Quality Legislation," October 2012, page 103.

In March 2012, Governor Edmund Brown, Jr. issued an Executive Order requiring all state agencies to support and facilitate the rapid commercialization of ZEVs in California. The Executive Order also required the California Air Resources Board, the California Energy Commission, the Public Utilities Commission and other relevant agencies and collaboratives to establish benchmarks to achieve the specified goals outlined in the order. These benchmarks include the following:

- By 2015, all major metropolitan areas in California must be able to accommodate ZEVs and have infrastructure plans and streamlined permitting in place;

- By 2020, the state must have established adequate infrastructure to support one million ZEVs;

- By 2025, there must be 1.5 million ZEVs on the road in California and clean, efficient vehicles must displace 1.5 billion gallons of petroleum fuels annually; and

- By 2050, greenhouse gas emissions from the transportation sector must be 80 percent less than 1990 levels.

Governor Brown also directed state agencies to increase the number of ZEVs in the fleet through gradual vehicle replacement. By 2015, ZEVs should make up at least 10 percent of fleet light-duty vehicle purchases and by 2020, at least 25 percent of fleet light-duty vehicle purchases should be ZEVs.[10]

California SB 209, enacted in 2011, addresses EV charging stations at common interest developments. The bill prohibits Home Owners Associations from unreasonably restricting the installation of charging stations. Specifically, the bill provides that any covenant, restriction, or condition contained in any deed or contract affecting the transfer or sale of any interest in a common interest development that effectively prohibits or restricts the installation or use of an EV charging station is void and unenforceable.

California also directed a national effort to coordinate the design of EV charging and supply equipment by industry with safety as the primary concern. This effort has resulted in new EV supply equipment intended to meet safety, durability, and convenience concerns. Additionally, this effort has helped to revise equipment standards with the Society of Automotive Engineers (SAE) and Underwriters Laboratories, and safety standards with the National Fire Protection Association, the National Electrical Code (NEC), and California Building Codes.

The NEC and California Building Codes require four main safety devices and constructional features to address shock hazards and battery off-gassing concerns. The codes require approved or listed equipment be used for charging electric vehicles. New plug-in EVs must be equipped with a conductive charger inlet port that meets the specifications contained in SAE Standard J1772. EVs must be equipped with an on-board charger with a minimum output of 3.3 kilovolt

[10] California Executive Order No. B-16-2012; Governor Edmund G. Brown, Jr.; Issued March 23, 2012.

amps. These requirements do not apply to EVs that are only capable of Level 1 charging, which has a maximum power of 12 amperes, a branch circuit rating of 15 amperes, and continuous power of 1.44 kW.

Other California EV-related policies include the following:

- Electric vehicle purchasers in California are eligible for a $2,500 rebate from the Clean Vehicle Rebate Project during Fiscal Year 2011-2012 or until funds are exhausted.

- Electric car owners can use California's High Occupancy Vehicle (HOV) lanes without meeting the occupancy restriction.

- The California Department of Motor Vehicles may disclose to an electrical corporation or local publicly-owned utility an EV owner's address and vehicle type if the information is used exclusively to identify where the vehicle is registered.

Georgia

Georgia offers a state income tax credit to individuals who purchase or lease a new ZEV. The tax credit is 20 percent of the vehicle cost, up to $5,000. For the purpose of this credit, a ZEV is defined as a motor vehicle that has zero tailpipe and evaporative emissions, including a pure electric vehicle. Any portion of the credit not used in the year the ZEV is purchased or leased may be carried over for up to five years. Eligible businesses may also receive an income tax credit for the purchase or lease of qualified electric vehicle supply equipment provided that the equipment is located in the state and accessible to the public. The amount of the credit is 10 percent of the cost of the EVSE, up to $2,500.

EVs are eligible to use HOV lanes under Georgia's Alternative Fuel Vehicle HOV Lane Exemption. Alternative fuel vehicles displaying the proper alternative fuel license plate may use HOV lanes, regardless of the number of passengers.

Georgia is also participating with Alabama, and South Carolina in the tri-state initiative discussed earlier.

Hawaii

Hawaii began enacting supportive EV-related public policies in the late 1990s. According to the survey response, the following policies adopted by the Hawaii State Legislature were the first of their kind in the U.S. and have significantly contributed to the decision of EV manufacturers to target Hawaii as an early market for the introduction of EVs:

- Free EV parking at government facilities, including meters for vehicles with specialized EV plates.

- Limited exemptions from HOV lanes.

- Public accommodations with at least 100 parking spaces available for use by the general public shall have at least 1 parking space exclusively for EVs and be equipped with an EV charging system.

- EV charger requirements in multi-family residential dwellings.

Illinois

The Illinois Commerce Commission (ICC) Initiative on Plug-In Electric Vehicles (EV Initiative) was formed in September 2010, to ensure that the ICC is proactive in assessing the potential impacts of EVs on the State's electric system. The EV Initiative was also designed to guide the ICC in future regulatory considerations necessary to accommodate EVs.

As a part of the Initiative, the ICC held five EV policy-related stakeholder workshops focused on:

- the ICC's Integrated Distribution Company rules,
- customer education and outreach plans for EV purchasers,
- potential reliability impacts of EV usage,
- rate options for EV users, and
- the legal status of public charging stations.

The ICC also asked workshop participants to address several other specific areas that the ICC noted required further exploration, including reliability impacts and the potential need for revisions to the rules governing the utility marketing of EV-related programs. The Illinois EV Study Initiative has largely reaffirmed that many existing policies in Illinois are well suited for the introduction of EVs and that the regulatory issues that need to be addressed are either narrowly focused or longer-term in nature. The initial assessments, comments, transcripts, and other documents of the EV Initiative can be located at:
www.icc.illinois.gov/Electricity/PEV.aspx.

New York

EPRI conducted a comprehensive study to assess the energy, environmental, and distribution impacts of EVs in New York State. The study was a part of an initiative with the New York State Energy and Research Development Authority and Consolidated Edison. The final report, issued in June 2011, presents potential roles for electric utilities to consider when developing plans to accommodate the commercialization of EVs. The roles for electric utilities addressed in the report were designed with the objective of enabling utilities to: (1) demonstrate regional leadership in planning for transportation electrification, (2) support customer adoption of plug-in vehicles and supporting charging infrastructure, and (3) understand and minimize the system impacts from vehicle charging.

Key issues addressed in the study include the following:

- Identification of the 'base case' and realistic EV penetration scenarios of transmission/distribution capacity assuming no EV penetration,

- EV distribution impacts on the largest secondary network in Manhattan and another radial circuit in New York,

- Understanding the economic and emission impacts of EVs in New York State,

- Understanding the power quality impact of on-board charger systems to the grid, and

- Implications of EVs as a distributed resource for vehicle to grid applications or utility aggregated load control.

North Carolina

During the 2011 Legislative session, the North Carolina Legislature enacted House Bill 222 to encourage EV adoption. The bill authorized EVs to operate in HOV lanes and exempted EVs from state emissions inspections.

Several studies are also being conducted on EVs and the expected impact on North Carolina's grid. On March 22, 2011, the North Carolina Utilities Commission issued an order approving Duke Energy Carolina, LLC's (Duke) request to conduct a study on the impact of charging EVs on the North Carolina electric grid. The purpose of the study is to collect information regarding EV charging behavior. Duke intends to use this information to assist the utility in preparing for the increase in EVs such that the costs associated with meeting increased customer demand and installing potential system upgrades is lessened. As a part of the study, Duke will pay up to $1,000 toward the installation costs of Level 2 charging stations for 150 of its residential customers.

Progress Energy Carolinas is participating in EV-related research with EPRI and the National Resources Defense Council. The study will examine the environmental, greenhouse gas emissions, and air quality impacts associated with EVs.

Advanced Energy is also collecting EV-related data from customers that received a rebate for Nissan Leafs. Advanced Energy offered a $7,500 rebate to 40 Nissan LEAF owners, if the vehicles were purchased or leased by December 30, 2011, in the Greater Triangle, North Carolina area. Recipients of the rebates were required to allow Advanced Energy to monitor their vehicle usage and charging activity over a two-year period.

South Carolina

The South Carolina Energy Office has provided funding for a study to develop a statewide plan for EVs and EVSE rollout. The study is being conducted by the South Carolina Institute for Energy Studies (SCIES) at Clemson University, the Palmetto State Clean Fuels Coalition, and

Plug-In Carolina. Greenville County, South Carolina will serve as the pilot region to validate the planning process. In another project funded by the U.S. Department of Energy, SCIES is working with the same partners and representatives from Georgia and Alabama to develop a tri-state plan to enable EVs. See: http://www.clemson.edu/scies/Projects.htm

Virginia

In March 2011, the Virginia Legislature amended Sections 56-1 and 56-1.2, Code of Virginia, to address EVs and EV charging. The amendments remove a regulatory barrier to EV charging stations by excluding from the definition of a public utility any non-utility person that owns EV charging equipment or sells electricity at retail strictly for transportation purposes. This exclusion requires that the electricity used for EV charging must be procured from the public utility that is authorized by the Virginia State Corporation Commission (VSCC) to engage in the retail sale of electricity within the exclusive service area in which the service is provided. Providing electric vehicle charging service is also declared to be a permitted electric utility activity of certificated electric utilities in the State.

The amendments bar the VSCC from setting the rates, charges, and fees for the provision of retail EV charging service provided by non-utilities. In addition, public utilities are directed to evaluate options to develop and offer off-peak charging rates or other incentives to encourage owners of an electric vehicle to charge or recharge its battery during nonpeak times. Finally, the amendments authorize the VSCC to approve pilot programs conducted by public electric utilities. The pilot programs may offer special rates, contracts, or incentives to determine the feasibility of allowing time-of-use rates that encourage EV owners to charge vehicles during nonpeak periods. An electric utility that participates in a pilot program will be entitled to recover its program costs from ratepayers.

In 2011, the VSCC approved a pilot program offered by Dominion Virginia Power. The program is designed to collect information on EV charging and the impact of time-of-use rates. As a part of the pilot program, the VSCC approved two voluntary time-of-use rates for residential customers, including: (1) a time-of-use rate applied strictly to the energy used for EV charging, and (2) a "whole house" time-of-use rate that also allows customers to isolate the energy used for EV charging. Both rate options are designed to encourage residential customers that own EVs to shift EV charging to off peak hours.

Conclusion

The FPSC staff reviewed EV-related policies in each state that responded to the FPSC's survey and several additional states of interest totaling 20 states. California is clearly taking the lead in developing policies to encourage EV development, both in the number and breadth of state initiatives. California's programs, particularly its ZEV initiative, could have implications for EV adoption beyond the state's borders. New York, Illinois, South Carolina, and North Carolina have initiated significant studies designed to determine the expected impact of EVs and to develop plans to accommodate the growth of these vehicles. Additional studies are being performed by individual or coalitions of electric utilities. These studies often utilize customer data obtained from Public Utility Commission-approved pilot programs that establish time-of-use rates for EV charging or rebates for EV purchases.

Both California and Virginia have removed a regulatory barrier to EV adoption by exempting from state utility resale laws any non-utilities that own EV chargers or resell electricity strictly for transportation purposes. Several states also offer state rebates or income tax credits in order to encourage individuals and businesses to purchase EVs. Further, several states offer free parking or the use of HOV lanes to EV owners. A number of states also have policies that require or encourage state agencies to add EVs to their vehicle fleets.

Attachment 4

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: November 06, 2012

TO: Braulio L. Baez, Executive Director

FROM: James S. Polk, Regulatory Analyst II, Office of Telecommunications
Cynthia L. Muir, Director, Office of Consumer Assistance & Outreach

RE: 2012 Annual Lifeline Report regarding the Number of Customers Subscribing to Lifeline Service and the Effectiveness of Any Procedures to Promote Participation.

Critical Information: ACTION IS NEEDED – November 28, 2012 Internal Affairs. Commission Approval of the Lifeline draft report is sought. The 2012 Lifeline Final Report is due to the Governor, President of the Senate, and Speaker of the House by December 31, 2012.

Staff is seeking approval of the draft 2012 Annual Lifeline Report regarding the number of customers subscribing to Lifeline Service and the effectiveness of any procedures to promote participation. Section 364.10(2)(h), Florida Statutes, requires the FPSC to provide this report to the Governor, the President of the Senate, and the Speaker of the House of Representatives by December 31 each year. The report details regulatory actions impacting the Lifeline Program and Lifeline Awareness promotions in Florida.

The Lifeline program grew 9.7 percent during the July 2011 through June 2012 annual review period. As of June 30, 2012, 1,035,858 eligible customers participated in the Lifeline program. The attached report has been prepared to fulfill the federal legislative requirement. Staff seeks approval of the draft of the 2012 Annual Lifeline Report.

JSP

Attachment
cc: Charles Hill

DRAFT

LINK-UP FLORIDA LIFELINE ASSISTANCE

Number of Customers
Subscribing to Lifeline Service
and the Effectiveness of
Procedures to Promote Participation

Table of Contents

List of Tables

List of Acronyms

CFR	Code of Federal Regulations
CLEC	Competitive Local Exchange Carrier
DCF	Department of Children and Families
ETC	Eligible Telecommunications Carrier
FCC	Federal Communications Commission
FPG	Federal Poverty Guidelines
FPSC	Florida Public Service Commission
ILEC	Incumbent Local Exchange Carrier
NARUC	National Association of Regulatory Utility Commissioners
NASUCA	National Association of State Utility Consumer Advocates
NCPW	National Consumer Protection Week
OPC	Office of Public Counsel
SNAP	Supplemental Nutrition Assistance Program (formerly Food Stamps)
USAC	Universal Service Administrative Company
USF	Universal Service Fund

Executive Summary

The Florida Link-Up and Lifeline programs are part of the federal Universal Service Program designed to enable low-income households to obtain and maintain basic local telephone service in accordance with Section 364.10, Florida Statutes. The Lifeline program is designed to enable low-income households to obtain a $12.75 discount on their monthly phone bills or the option of receiving a free Lifeline cell phone and monthly minutes. The Link-Up program helps low-income consumers by reducing the telephone service installation charge and pays one-half (up to a maximum of $30) of the initial installation fee for a traditional wireline telephone or an activation fee for a wireless telephone if applicable. As of April 1, 2012, the Federal Communications Commission (FCC) eliminated the Link-Up program except for recipients on Tribal lands.

This report presents Lifeline participation data for the July 2011 through June 2012 program year, and evaluates procedures put in place to strengthen the Lifeline program and increase the number of participants. The number of eligible customers participating in the Lifeline program in Florida grew 9.7 percent during the July 2011 through June 2012 annual review period. As of June 30, 2012, 1,035,858 eligible customers participated in the Lifeline program. The five companies which accounted for 98 percent of Florida Lifeline customers are SafeLink Wireless, Assurance Wireless, BellSouth Telecommunications, LLC, d/b/a AT&T Florida (AT&T), Embarq Florida, Inc. d/b/a CenturyLink, and Verizon Florida LLC (Verizon). As of June 30, 2012, SafeLink Wireless had 430,048 Lifeline customers, and Assurance Wireless had 428,830, which together accounted for 83 percent of Florida Lifeline customers. The three largest incumbent local exchange carriers (ILECs), AT&T, CenturyLink, and Verizon had 102,363, 35,154, and 18,496 Lifeline customers, respectively.

Lifeline assistance participation in Florida continues to grow through the coordinated enrollment process with the involvement of the FPSC, DCF, OPC, and other state agencies that provide benefits to persons eligible for Lifeline service.[1] According to the U.S. Department of Agriculture Report ending June 30, 2012, Florida had the highest number of households in the nation participating in the Supplemental Nutrition Assistance Program (SNAP), with 1,864,183 households. SNAP continues to be the largest qualifying program for Lifeline assistance in Florida. Compared to last year's figure of 1,690,512 Lifeline-eligible households, this represents an increase of 10.3 percent. Staff anticipates that Lifeline enrollment of new customers will continue to grow due to the current economic conditions.

On February 6, 2012, the FCC released a Report and Order (Order FCC 12-11), and Further Notice of Proposed Rulemaking (FNPRM) addressing Lifeline and Link-Up Reform and Modernization. The stated purposes of FCC Order 12-11 are to strengthen protections against waste, fraud, and abuse; improve program administration and accountability; improve enrollment and consumer disclosures; initiate modernization of the program to include broadband; and constrain the growth of the program in order to reduce the burden on all who contribute to the

[1] Section 364.10(2)(g)1, Florida Statutes, requires each state agency that provides benefits to persons eligible for Lifeline service to undertake, in cooperation with the Department of Children and Families (DCF), the Department of Education, the Florida Public Service Commission (FPSC or Commission), the Office of Public Counsel (OPC), and eligible telecommunications carriers providing Lifeline services, the development of procedures to promote Lifeline participation.

Federal Universal Service Fund (USF). The FCC's goal is to save $200 million in 2012, and up to $2 billion over the next three years. Many of the modifications contained in Order FCC 12-11 have affected Florida's Lifeline program. Major changes which will be discussed in this report include elimination of the Link-Up program on non-tribal lands, elimination of Florida's Lifeline simplified certification process, reduction of the monthly Lifeline benefit, and initiation of a one-per-household rule for Lifeline benefits.

Stay Connected, Florida! was the slogan chosen by the FPSC for Florida's 2012 Lifeline Awareness Week, September 10-14, 2012. FPSC Chairman Ronald A. Brisé kicked off the week by hosting an informal workshop in Tallahassee with representatives from social service agencies whose clients benefit from the Lifeline program and state agencies that facilitate Lifeline's promotion and application process. Essential grassroots support from these agencies is imperative to reaching eligible residents. The workshop focused on ways to ensure that consumers enrolling in Lifeline are not already receiving the service and additional ways to contact potentially eligible consumers. The FPSC believes all eligible low-income consumers who qualify and desire to receive Lifeline assistance should be able to receive the Lifeline discount.

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I. Background

By December 31 each year, the FPSC is required to report to the Governor, the President of the Senate, and the Speaker of the House of Representatives on the number of customers subscribing to Lifeline service and the effectiveness of procedures to promote participation in the program.[2] This report is prepared pursuant to the requirements Section 364.10, Florida Statutes.

The FCC Lifeline and Link-Up Reform Order[3] made major changes in the Lifeline and Link-Up programs. Among them were elimination of the Link-Up program except for recipients on Tribal lands, and elimination of the Lifeline simplified self-certification enrollment process.[4] The simplified self-certification program allowed consumers to easily apply for and receive Lifeline benefits without documentation burdens. However, the Lifeline coordinated enrollment process,[5] currently implemented by FPSC and DCF, remains available to applicants in Florida. New changes by the FCC will create a national database for certification and program participation verification of Lifeline applicants. Florida Eligible Telecommunication Carriers (ETCs) are able to access a DCF web services interface[6] to confirm program participation for SNAP, Medicaid and Florida Temporary Cash Assistance (TCA).[7]

As of June 1, 2012, the FCC requires ETCs to document the eligibility of those consumers seeking to qualify for Lifeline under program-based criteria. However, if ETCs can access state or federal databases to make determinations about consumer eligibility for Lifeline, the FCC will not require ETCs to obtain a new subscriber's documentation of his or her participation in a qualifying program. If a database is used to determine eligibility, the ETC or its representative must note in its records what specific data was relied upon to confirm the consumer's initial eligibility for Lifeline (e.g., name of a state or Federal database.)[8]

Certification and verification can be accomplished using this process if the applicant, in the case of certification, or an existing Lifeline customer, in the case of verification, participates in the SNAP, TCA, or Medicaid programs which are administered by the DCF. If a program other than SNAP, TCA, or Medicaid is used for certification, the provider would have to turn to the agency administering that program, which could be the Florida Department of Education (free school lunch program), the Social Security Administration (Supplemental Security Income), a county-level agency (Low-Income Home Energy Assistance Plan or Section Eight Housing), or the Bureau of Indian Affairs for documentation. However, current data shows that

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[2] Section 364.10(2)(h), Florida Statutes.
[3] FCC Order 12-11, released February 6, 2012. In the Matter of Lifeline and Link Up Reform and Modernization. WC Docket No. 11-42.
[4] The simplified self-certification process approved by the FCC in 2004 and adopted by the FPSC allowed Lifeline applicants to self-certify participation in a Lifeline qualifying program.
[5] The Lifeline coordinated enrollment process was set up by the FPSC and DCF to allow an applicant for a DCF assistance program to request Lifeline assistance after approved for the DCF program.
[6] The Web services interface allows Florida ETCs a secure gateway into the DCF computer to verify that a Lifeline customer is participating in the SNAP, Medicaid, or Temporary Cash Assistance program administered by DCF. The ETC enters the person's first and last name, date of birth, and last four digits of the person's social security number. The DCF computer responds as to whether the person currently participates in one of the DCF programs without identifying the program because of confidentiality.
[7] Nationally known as Temporary Assistance for Needy Families (TANF).
[8] AT&T Florida has filed a petition at the FCC to confirm that the Florida process meets the FCC criteria and recordkeeping requirements.

over ninety percent of Florida applicants using the Lifeline Coordinated Enrollment Process use SNAP, TCA, or Medicaid for eligibility.

If an ETC does not have access to state or federal databases to make determinations about consumer eligibility, an ETC must review documentation to determine eligibility for new subscribers until such time a qualifying eligibility database is available. Acceptable documentation of program eligibility would include: (1) the current or prior year's statement of benefits from a qualifying state, federal or Tribal program; (2) a notice letter of participation in a qualifying state, federal or Tribal program; (3) program participation documents (e.g., the consumer's SNAP electronic benefit transfer card or Medicaid participation card (or copy thereof); or (4) another official document evidencing the consumer's participation in a qualifying state, federal or Tribal program.

Florida's proactive actions of having a Lifeline coordinated enrollment process and Lifeline web services interface for certification and verification will help ease the transition from Lifeline simplified certification. ETCs can still receive Lifeline applications through the coordinated enrollment process with DCF and the FPSC, and certify or verify participation in a DCF Lifeline-qualifying program through the DCF web services interface.

II. Program Support

The Florida Link-Up and Lifeline programs are part of the federal Universal Service Program designed to enable low-income households to obtain and maintain basic local telephone service as outlined in Section 364.10, Florida Statutes. Under the FCC rules, there were four tiers of monthly federal Lifeline support until June 1, 2012, as described below. The FCC Lifeline and Link-Up Reform Order replaced the first three tiers of support with a flat $9.25 credit per month.

- The first tier of federal support was a $6.50 monthly credit for the federal subscriber line charge, which was available to all eligible subscribers.

- The second tier of federal support was a $1.75 monthly credit that was available to subscribers in those states that have approved the credit.

- The third tier of federal support was one-half the amount of additional state support up to a maximum of $1.75 in federal support. Because Florida carriers provide an additional $3.50 credit to Lifeline customers' bills,[9] Florida Lifeline subscribers received a total monthly credit of $13.50, consisting of $10.00 ($6.50, $1.75, and $1.75) in federal support and $3.50 in state support. The telephone subscriber may have received a credit less than $13.50 if the subscriber's bill for basic local telephone service was less than the maximum available credit, or the ETC had an FCC approved subscriber line charges less than $6.50.

[9] Since Florida does not have a state Universal Service Fund, the $3.50 credit is absorbed by the ETC or Lifeline reseller providing service.

- The fourth tier of support, available only to eligible subscribers living on tribal lands, provides an additional credit up to $25.00 per month. This amount is limited so that the credit does not bring the basic local residential rate below $1.00 per month.

The Link-Up program helped low-income consumers by reducing the telephone service installation charge and paid one-half (up to a maximum of $30) of the initial installation fee for a traditional wireline telephone, or an activation fee for a wireless telephone if applicable. As of April 1, 2012, the FCC eliminated the Link-Up program except for recipients on Tribal lands.

Transitional Lifeline Assistance requires that ETCs provide former Lifeline customers a 30 percent discount off the residential basic local service rate. The customer may receive the subsidy for one year from the date the customer ceases to be qualified for Lifeline.[10]

III. Customer Eligibility

Program-Based

Eligibility for Lifeline in Florida can be determined by customer enrollment in any one of the following programs:[11]

- Temporary Cash Assistance
- Supplemental Security Income
- Supplemental Nutrition Assistance Program (SNAP)
- Medicaid
- Federal Public Housing Assistance (Section 8)
- Low-Income Home Energy Assistance Plan
- National School Lunch Program's (NSLP) Free Lunch
- Bureau of Indian Affairs Programs (Tribal Temporary Assistance for Needy Families (TANF), Head Start Subsidy, and NSLP)[12]

Income-Based

In addition to the program-based criteria, customers with annual incomes up to 150 percent of the Federal Poverty Guidelines (FPG) may be eligible to participate in the Florida Lifeline program. Section 364.10(2)(a) provides that each local exchange telecommunications company that has more than 1 million access lines and is an ETC shall provide Lifeline applicants, who meet an income eligibility test of up to 150 percent of the FPG with Lifeline service. In 2010, Section 364.10(2)(a), Florida Statutes, was revised to allow any commercial mobile radio service provider designated as an ETC pursuant to 47 U.S.C. §214(e), to provide Lifeline service to any customer who meets an income eligibility test of 150 percent or less of the FPG, upon filing a notice of election to do so with the FPSC. The U.S. Department of Health

[10] Section 364.105, Florida Statutes.
[11] Rule 25-4.0665(1) and (2), Florida Administrative Code.
[12] Eligible consumers living on tribal lands qualify if participating in one of the following federal assisted programs: (1) Tribal TANF, (2) National School Lunch Program's Free Lunch Program, or (3) Head Start Subsidy.

and Human Services made a decision to increase the 2012 FPG, as shown in Table 1 below.[13] The OPC certifies customer eligibility under the income test for customers requesting to be enrolled in the Lifeline program for those local exchange telecommunications companies designated as ETCs that have more than one million access lines as described above. The OPC can also do income certification for wireless ETCs who have filed a notice election to do so with the FPSC.[14]

Table 1 shows the monthly and yearly total household incomes at 150% of FPG necessary to qualify for Lifeline.

Table 1. 2012 U.S. Poverty Guidelines

Household (number of people)	2012 U.S. Poverty Guidelines Total Household Annual Income	150% of U.S. Poverty Guidelines Total Household Monthly Income	150% of U.S. Poverty Guidelines Total Household Annual Income*
1	$11,170	$1,396	$16,755
2	$15,130	$1,891	$22,695
3	$19,090	$2,386	$28,635
4	$23,050	$2,881	$34,575
5	$27,010	$3,376	$40,515
6	$30,970	$3,871	$46,455
7	$34,930	$4,366	$52,395
8	$38,890	$4,861	$58,335
*For families with more than 8 persons, add $5,940 for each additional person to the yearly amount.			

Source: Florida OPC Website, 2012.

IV. Carrier Eligibility

Section 54.201(b) of the Code of Federal Regulations (CFR) provides that a state commission shall, upon its own motion or upon request, designate a common carrier that meets certain requirements as an ETC[15] in a non-rural service area. Section 54.201(c) of the CFR provides that a state commission may, as long as the request is consistent with the public interest, convenience, and necessity, designate one or more common carrier(s) as ETC(s) in a rural service area.[16]

By Order FCC 11-161, released November 18, 2011, the FCC determined that it is appropriate to describe the core functionalities of universal service supported services as voice telephony service. Because consumers are increasingly obtaining voice services over broadband networks as well as over traditional circuit switched telephone networks, the FCC modified the definition of companies able to receive universal service support by simply shifting to a technologically neutral approach, allowing companies to provision voice service over any

[13] Federal Register: January 26, 2012 (Volume 77, Number 17), Notices.

[14] See Section 364.10(2)(a), Florida Statutes.

[15] House Bill 1231 removed the Florida Public Service Commission authority to designate ETC wireless telecommunications. providers. Effective July 1, 2012, wireless providers must directly apply for Florida ETC designation with the FCC.

[16] A state commission also has the authority to rescind the ETC status of any ETC designated by it that does not follow the requirements of the Lifeline Assistance program.

platform, including the Public Switched Telephone Network and Internet Protocol networks. A carrier that is granted ETC status is eligible to receive universal service support[17] pursuant to FCC rules.[18]

To qualify as an ETC, a common carrier must offer services that are supported by federal universal service support mechanisms, either using its own facilities or a combination of its own facilities and another carrier's resold service,[19] and the carrier must advertise the availability of such services and charges using mass media. Additionally, a company applying and qualifying for designation as an ETC must demonstrate good management and legitimate business practices to successfully administer the Lifeline program, ensuring that granting them ETC status is in the public interest to the citizens of Florida.

Twenty-seven companies have received ETC status in Florida and participated in the Lifeline Program as of June 30, 2012:

- Absolute Home Phone
- BellSouth Telecommunications, LLC, d/b/a AT&T Florida (AT&T)
- Ganoco, Inc., d/b/a American Dial Tone[20]
- Budget Prepay, Inc. d/b/a Budget Phone
- dPi Teleconnect, LLC
- Easy Telephone Services Company
- Embarq Florida, Inc. d/b/a CenturyLink
- Express Phone Service, Inc.
- GTC, Inc. d/b/a FairPoint Communications
- FLATEL, Inc.
- Global Connection Inc. of America
- Frontier Communications of the South, LLC
- ITS Telecommunications Systems, Inc.
- Knology of Florida, Inc.
- Midwestern Telecommunications, Inc.[21]
- Northeast Florida Telephone Company d/b/a NEFCOM
- Nexus Communications, Inc. d/b/a Nexus Communications TSI, Inc.
- Smart City Telecommunications LLC, d/b/a Smart City Telecom
- Sun-Tel USA, Inc.
- Quincy Telephone Company d/b/a TDS Telecom/Quincy Telephone
- T-Mobile South LLC d/b/a T-Mobile Wireless
- Tele Circuit Network Corporation

[17] Universal Service Funds are available to ETCs which provide Lifeline service; rendering service to schools and libraries; and provisioning, maintaining, and upgrading facilities and services for rural, insular (islands that are territories or commonwealths of the United States), and high cost areas.

[18] 47 CFR pt. 54 – Universal Service.

[19] Those services supported by Universal Service include the following: (1) voice grade access to the public switched network or its functional equivalent, (2) minutes of use for local service provided at no additional charge to end users, (3) toll limitation to qualifying low-income consumers, and (4) access to the emergency services 911 and enhanced 911 services to the extent the local government in an eligible carrier's service area has implemented 911 or enhanced 911 systems.

[20] American Dial Tone, Inc. – Certificate of Authority cancelled November 3, 2011.

[21] Midwestern Telecommunications, Inc. – Certificate of Authority cancelled April 27, 2012.

- TracFone Wireless, Inc. d/b/a SafeLink Wireless
- Verizon Florida LLC
- Verizon Wireless (former ALLTEL territory)[22]
- Virgin Mobile USA, L.P. d/b/a Assurance Wireless
- Windstream Florida, Inc.

Subsequent to June 30, 2012, i-wireless d/b/a Access Wireless was designated as an ETC in Florida by the FCC; and Cox Florida Telecom LP was designated by the FPSC as a Wireline ETC in Florida to provide Lifeline service to qualified households in its non-rural and rural service territories.[23]

V. Public Interest Determinations

Under Section 214 of the Act,[24] the FCC and state commissions must determine that an ETC designation is consistent with the public interest, convenience and necessity for rural areas. They also must consider whether an ETC designation serves the public interest consistent with Section 254 of the Act. Congress did not establish specific criteria to be applied under the public interest tests set forth in Section 214. The public interest benefits of a particular ETC designation must be analyzed in a manner that is consistent with the purposes of the Act itself, including the fundamental goals of preserving and advancing universal service; ensuring the availability of quality telecommunications services at just, reasonable, and affordable rates; and promoting the deployment of advanced telecommunications and information services to all regions of the nation, including rural and high-cost areas.[25] The FPSC continues to make an affirmative determination that such designation is in the public interest, regardless of whether the applicant seeks designation in an area served by a rural or nonrural carrier.

Beyond the principles detailed in the Act, the FCC and state commissions have used additional factors to analyze whether the designation of an ETC is in the public interest. A rigorous ETC designation process ensures that only fully qualified applicants receive designation as ETCs, and that all ETC designees are prepared to serve all customers within the designated service area.

[22] Verizon Wireless has provided notice that it will be relinquishing its ETC status in Florida as of December 31, 2012.

[23] The ETC designation for its rural areas will be effective upon FCC approval of a national petition by Cox for forbearance from the study area redefinition requirement. Redefinition of a rural study area is required to receive high-cost USF monies if an ETC is not going to serve the entire rural service area of a rural ILEC. The FCC has stated in previous orders redefinition does not need to be considered for Lifeline-only ETCs such as Cox Florida Telecom LP.

[24] The Telecommunications Act of 1996.

[25] In the Matter of Federal-State Joint Board on Universal Service, CC Docket No. 96-45, Order FCC 05-46 (¶40), adopted February 25, 2005, released March 17, 2005.

VI. Subscribership and Participation Rates

A. Lifeline

The number of customers enrolled in Lifeline increased by 92,004 during the July 2011 through June 2012, 12-month review period, representing a 9.7 percent increase. Table 2 shows the number of Lifeline subscribers from June 2009 through June 2012. The increase of Lifeline subscribers receiving benefits in 2012 is largely attributable to wireless companies and the current economic conditions in the state.

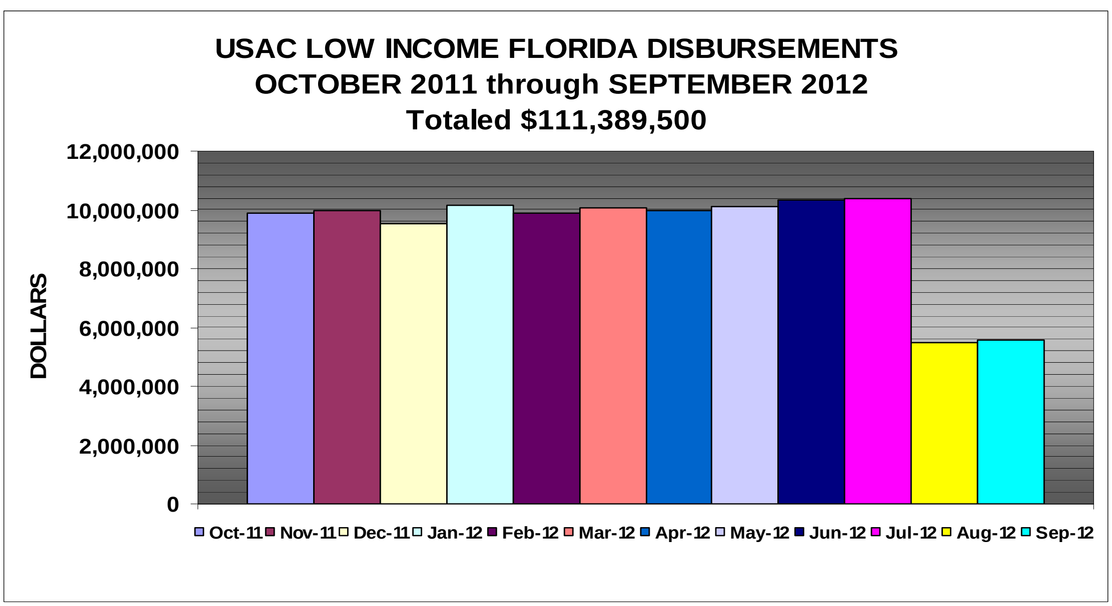
Table 2. Florida Lifeline Subscribership

	June 2009	June 2010	June 2011	June 2012	% Net Gain 2011-2012
Lifeline Subscribers	618,774	642,129	943,854	1,035,858	9.7%

Source: Industry responses to FPSC data requests (2009-12)

Table 3 reflects Universal Service Administrative Company (USAC) Florida Lifeline disbursements at an all time high for the 12-month period ending September 2012, totaling $111,389,500, an average of $9,282,458 per month over the period. These dollars enabled Florida citizens qualifying for Lifeline benefits to receive discounted monthly bills with a current credit of $12.75, or a free Lifeline wireless phone with 250 free monthly minutes. The Lifeline Reform Order required USAC to move low-income disbursements to payments based on actual subscriber counts, as opposed to projected payments by October 2012. As of October 31, 2012, all Low Income Program payments are based on actual support rather than based on projections made by USAC. Since ETCs would lose one month of cash flow because of the transition, ETCs were allowed to select which month to transition from projected to actual subscriber counts. As can be seen in Table 3, some ETCs transitioned in August 2012, and some in September 2012, which reduced overall disbursements for those two months.

Table 3. USAC Low Income Florida ETC Disbursements



Source: USAC Disbursement Data for Florida ETCs (September 2012)

Table 4 shows Lifeline participation rates for June 2009 through June 2012.[26] As of June 2012, the participation rate was 55.6 percent. Lifeline Enrollment increased 9.7 percent over the previous year due primarily to factors such as the continued economic conditions and the Lifeline participants of ETC wireless providers SafeLink Wireless and Assurance Wireless which accounted for 858,878 participants and 82.9 percent of Florida's total Lifeline customers as of June 30, 2012. Florida was the largest SNAP[27] recipient in the U.S. in June 2012 with 1,864,183 households receiving SNAP benefits. Since all SNAP recipients are eligible for Lifeline, the number of Lifeline-eligible households in Florida increased 10.3 percent over 2011.

Table 4. Lifeline Participation Rate
In Eligible Florida Households

Year	Lifeline Enrollment	Eligible Households	% Participation Rate
June 2012	1,035,858	1,864,183	55.6%
June 2011	943,854	1,690,512	55.8%
June 2010	642,129	1,422,837	45.1%
June 2009	618,774	1,185,516	52.2%

Sources: Report and Order and Further Notice of Proposed Rulemaking, WC Docket 03-109, In the Matter of Lifeline and Link-Up, Order No. FCC 04-87, released April 29, 2004; industry responses to FPSC data requests (2009-2012); and the U.S. Department of Agriculture data figures are as of September 28, 2012.

[26] The participation rate is determined by comparing the actual number of Lifeline participants to the number of estimated eligible households.

[27] United States Department of Agriculture, Supplemental Nutrition Assistance Program (SNAP), formerly Food Stamps. Data figures are as of September 29, 2012.

Table 5 represents the net participation of Lifeline enrollment of 1,035,858 from June 2008 through June 2012. Florida had a 9.7 net percent increase in enrollment as of June 30, 2012, over the previous year.

Table 5. Lifeline Net Participation

ETCs	June 2008	Net Growth Rate	June 2009	Net Growth Rate	June 2010	Net Growth Rate	June 2011	Net Growth Rate	June 2012	Net Growth Rate
SafeLink	N/A	N/A	393,036	N/A	396,114	0.80%	447,379	12.9%	430,048	-3.9%
Assurance						N/A	286,866	N/A	428,830	49.5%
AT&T	104,506	12.00%	126,090	20.70%	126,114	0.02%	122,849	-2.60%	102,363	-16.7%
CenturyLink	34,803	15.90%	39,855	14.50%	41,593	4.40%	39,524	-5.0%	35,154	-11.1%
Verizon	22,720	-5.00%	20,916	-7.90%	23,681	13.20%	22,307	-5.8%	18,496	-17.1%
Windstream	4,266	12.10%	4,807	12.70%	5,517	14.80%	6,249	13.3%	6,775	8.4%
Budget Phone	565	857.60%	1,134	100.70%	3,099	173.30%	2,912	-6.0%	1,399	-52.0%
Flatel	N/A	N/A	2,279	N/A	1,888	-17.20%	2,845	50.7%	1,469	-48.4%
FairPoint	2,179	7.30%	2,777	27.40%	3,093	11.40%	2,446	-20.9%	2,146	-12.3%
American Dial Tone[28]	1,847	0.40%	2,862	55.00%	18,127	533.40%	1,903	-89.5%	N/A	-100.0%
TDS Telecom	735	-0.10%	845	15.00%	920	8.90%	811	-11.8%	728	-10.2%
NEFCOM	638	0.50%	837	31.20%	769	-8.10%	795	3.4%	804	1.1%
Knology	221	75.40%	695	214.50%	959	38.00%	761	-20.6%	751	-1.3%
Sun-Tel						N/A	434	N/A	1,065	145.4%
Nexus	2,084	2.30%	1,038	-50.20%	333	-67.92%	201	-39.60%	132	-34.3%
ITS Telecom	101	27.80%	124	22.80%	147	18.50%	178	21.1%	190	6.7%
dPi	N/A	N/A	588	N/A	1273	116.50%	169	-86.7%	31	-81.7%
Frontier	172	14.70%	179	4.10%	159	-11.20%	157	-1.3%	174	10.8%
T-Mobile						N/A	70	N/A	232	231.4%
Smart City	9	12.50%	20	122.20%	18	-10.00%	23	27.8%	33	43.5%
Verizon Wireless[29]	32	-15.80%	66	106.30%	18	-72.70%	17	-5.6%	26	52.9%
Global Connection									594	100.0%
Absolute Home Phone									89	100.0%
TeleCircuit									1,497	100.0%
Midwestern[30]	465	167.20%	107	-77.00%	153	43.00%	16	-89.5%	N/A	-100.0%
Express	N/A	N/A	2,275	N/A	3,923	72.40%	1	-100.0%	N/A	-100.0%
Easy Telephone	N/A	N/A	N/A	N/A	376	N/A	0	-100.0%	4	100.0%
Non-ETC Reseller	8,551	N/A	18,073	121.60%	13,664	-24.40%	4,941	-63.8%	2,828	-42.8%
Total	183,972	15.70%	618,774	236.30%	642,129	3.80%	943,854	47.0%	1,035,858	9.7%

Sources: FPSC data requests (2008-2012)

[28] American Dial Tone, Inc. – Certificate of Authority cancelled November 3, 2011.
[29] Verizon Wireless has provided notice that it will be relinquishing its ETC status in Florida as of December 31, 2012.
[30] Midwestern Telecommunications, Inc. – Certificate of Authority cancelled April 27, 2012.

As presented in Table 6, the 5 Florida ETCs which had the largest number of Lifeline participants had a net customer gain in 2012 of 95,966 customers.

Table 6. SafeLink Wireless, Assurance Wireless, AT&T, CenturyLink, and Verizon Customer Gain/Loss

Company	June 2012 Customer Participation	Lifeline Customer Gain/Loss over 2011
SafeLink Wireless	430,048	-17,331
Assurance Wireless	428,830	141,964
AT&T	102,363	-20,486
CenturyLink	35,154	-4,370
Verizon	18,496	-3,811
Total	1,014,891	95,966

Source: Industry responses to FPSC data requests (2011-2012)

B. Link-Up

Florida's Link-Up program helps low-income consumers by reducing the telephone service installation charge. This program pays one-half (up to a maximum of $30) of the initial installation fee for a traditional wireline telephone or activation fee for a wireless telephone if applicable. Eligible residents of tribal lands may receive up to $100 in discounts on initial connection charges. The $100 maximum is based on the sum of the federally financed 50 percent discount (up to the $30 maximum) available to all qualified low-income individuals, plus a dollar-for-dollar match (up to $70) for connection charges above $60. As of April 1, 2012, the FCC eliminated the Link-Up program except for recipients on Tribal lands.

Table 7 displays Link-Up participants for AT&T, Verizon, and CenturyLink from June 2009 through June 2012. SafeLink Wireless and Assurance Wireless, cell phone providers of Florida Lifeline, accounted for 858,878 customers, and do not charge Link-Up or activation charges to Lifeline customers. The decrease in Link-Up participants in 2012 was significantly lower over the previous year due to the increase in SafeLink Wireless and Assurance Wireless customers and the elimination of non-tribal Link-Up applicants in April 2012.

Table 7. AT&T, Verizon, and CenturyLink Link-Up Participants

Year	AT&T, Verizon, and CenturyLink/Embarq Link-Up Customers
June 2012	2,319
June 2011	12,980
June 2010	53,078
June 2009	35,330

Source: Industry responses to FPSC data requests (2009-2012)

C. Transitional Lifeline

In accordance with Section 364.105, Florida Statutes, current customers who no longer meet eligibility criteria and are removed from Lifeline service receive a 30 percent discount on the residential basic local service rate for a period of 12 months after ending Lifeline service. For example, a former Lifeline customer with a phone bill that includes a $25.00 basic rate would receive a $7.50 monthly discount for one year. Transitioning from Lifeline service means that the consumer's socio-economic status may have improved, and the customer may have advanced beyond the qualifying eligibility criteria.

Table 8 presents data on Transitional Lifeline customers for AT&T, Verizon, and CenturyLink for June 2008 through June 2012. The slight increase in Transitional Lifeline participants in 2012 is attributable to improvement in the consumer's socio-economic status.

Table 8. AT&T, Verizon, and CenturyLink Transitional Lifeline Participants

Year	AT&T, Verizon, and CenturyLink/Embarq Participants
June 2012	3,566
June 2011	3,118
June 2010	3,710
June 2009	3,996
June 2008	8,822

Source: Industry responses to FPSC data requests (2008-2012)

D. Lifeline Coordinated Enrollment Process

Implementation of the Lifeline coordinated enrollment process has been a major success. The FPSC began formally tracking the number of Lifeline applications filed via the Lifeline coordinated enrollment process in July 1, 2007, and cumulative Lifeline coordinated enrollment applications as of June 30, 2012, totaled 476,481.

The coordinated enrollment process entails the DCF client checking a "yes" or "no" box on the DCF Web application, indicating an interest in receiving the Lifeline discount on his or her telephone service. If the client answers in the affirmative, the applicant identifies a telephone service provider from a drop-down box on the application and answers applicable questions. The DCF forwards to the FPSC the necessary information of those clients approved by DCF for benefits who have indicated a desire to receive Lifeline. The FPSC computers sort the information by ETC and place the applications on the FPSC's secure Web site for retrieval by the appropriate ETC.

All ETCs are required to enroll the subscriber in the Lifeline program as soon as practicable, but no later than 60 days from the receipt of the FPSC's automatic e-mail notification. In addition, upon completion of initial enrollment, the ETC is required to credit the subscriber's bill for Lifeline service as of the date the ETC received the FPSC's e-mail notification.

ETCs are required to provide the FPSC, within 20 calendar days of receiving the FPSC's e-mail notification, the names, addresses, telephone numbers, and date of the application for any misdirected applications; any applications for customers currently receiving Lifeline service; or any rejected applicants, including the reason(s) the applicants were rejected as shown in Rule 25-4.0665, F.A.C. The information filed by the ETCs is confidential and exempt from the public records requirement; however, the information contained in the response is disclosed to the Commission, pursuant to the criteria set forth in Section 364.107(3)(a)(4), Florida Statutes.

The implementation of initial enrollment and annual re-certification procedures will help to reduce duplicate Lifeline benefits. Furthermore, with more companies participating in the Lifeline program, the potential to continue to reach significantly greater numbers of eligible customers in coming years still exists.

VII. Regulatory Actions Impacting Florida's Lifeline Program

Key actions by the Florida Legislature, the FPSC, and FCC occurred during 2012. A discussion of these initiatives is presented below.

A. Florida Legislature

Current law provides that personal identifying information of a participant in Lifeline held by the FPSC is confidential and exempt from public record requirements. The information may be released as provided by law. An officer or employee of a telecommunications carrier who intentionally discloses the confidential and exempt information commits a misdemeanor of the second degree.

HB 7109 passed the House on February 23, 2012, and subsequently passed the Senate on March 9, 2012.The law reenacts this public record exemption, pursuant to the Open Government Sunset Review Act,[31] which requires the Legislature to review each public record and each public meeting exemption five years after enactment. In addition, HB 7109 expanded the list of entities subject to penalties for disclosing such information to include officers or employees of the FPSC. The bill was signed into law by the Governor on May 4, 2012. The effective date of the law was October 1, 2012.

[31] Section 119.15, Florida Statutes, the Open Government Sunset Review Act of 1995.

B. Federal Communications Commission

1. FCC Lifeline and Link-Up Reform and Modernization

On February 6, 2012, the FCC released a Report and Order (Order FCC 12-11) and FNPRM addressing Lifeline and Link-Up Reform and Modernization. The FCC's goal is to strengthen protections against waste, fraud, and abuse; improve program administration and accountability; improve enrollment and consumer disclosures; initiate modernization of the program to include broadband; and constrain the growth of the program in order to reduce the burden on all who contribute to the USF. The FCC's intent is to save $200 million in 2012, and up to $2 billion over the next three years. Many of the following modifications contained in Order FCC 12-11 will affect Florida's Lifeline program.

- <u>Lifeline Credit has been revised.</u> The Federal Communications Commission reduced the amount of monthly federal reimbursement a Lifeline provider can receive from the federal universal service fund from $10 to $9.25. The $3.50 state Lifeline credit which Lifeline providers are responsible for has not changed. Florida Lifeline customers will see their Lifeline credit reduced from $13.50 to $12.75 credit (or equal wireless minutes) effective April 1, 2012.

- <u>Lifeline benefit "one-per-household" rule initiated effective June 1, 2012.</u> A "household" is considered "any individual or group of individuals who are living together at the same address as one economic unit." An economic unit consists of all adult individuals contributing to and sharing in the income and expenses of a household. There can be more than one household at an address.

- <u>Elimination of Link-Up reimbursement on non-Tribal lands.</u> Link Up provided qualifying consumers with discounts of up to $30 off the initial costs of installing a single telecommunications connection. The FCC concluded that the dollars spent on Link Up in its current form can be better spent on other uses, such as modernizing the program and constraining the overall size of the fund. Declining costs and competitive pressures have led many Lifeline providers to stop assessing connection charges on low-income consumers. The FCC eliminated the Link-Up program effective April 2, 2012.

- <u>Phase out of toll-limitation service.</u> FCC Order 12-11 eliminates ETC toll limitation service (TLS) reimbursement from the USF effective January 1, 2014. For 2012, the reimbursement is $3, for 2013 it drops to $2, and in 2014 it reduces to $0. TLS is premised on the belief that one of the primary reasons subscribers lose access to telecommunications services is disconnection for failure to pay long distance (toll) bills. TLS historically has included both toll blocking, which prevents the placement of all long distance and international calls for which the subscriber would be charged, and toll control, which limits to a preset amount of long-distance calls.

- <u>New Eligibility Criteria requirement effective June 1, 2012.</u>

    - Program-based Eligibility - If a Lifeline provider can determine a prospective subscriber's program-based eligibility for Lifeline by accessing one or more databases containing information regarding enrollment in qualifying assistance programs, the provider must access such eligibility databases to determine whether the prospective subscriber qualifies for Lifeline based on participation in a qualifying assistance program.

If a Lifeline provider cannot determine a prospective subscriber's program-based eligibility for Lifeline by accessing eligibility databases, the applicant must provide documentation demonstrating that he/she qualifies for Lifeline under the program-based eligibility requirements. Because of these new FCC requirements, the Florida Lifeline simplified certification process has been eliminated.

- Initial Income-Based Eligibility - If a Lifeline provider can determine a prospective subscriber's income-based eligibility by accessing one or more databases containing information regarding the subscriber's income, the provider must access such income databases and determine whether the prospective subscriber qualifies for Lifeline.

  If a Lifeline provider cannot determine a prospective subscriber's income-based eligibility by accessing income databases, the applicant must provide documentation that establishes that he/she meets the income-eligibility criteria of 150% of the Federal Poverty Guidelines.

- Prepaid wireless Non-Usage rule, effective May 1, 2012. Applies to Lifeline Prepaid Service Providers that do not charge for service on a monthly basis and do not have a regular billing relationship with the subscriber, or other similar relationship to track activity by the subscriber. Examples would include SafeLink Wireless and Assurance Wireless.

  Some Lifeline customers abandon the service, transfer the service to someone else, or fail to use the service at all. Yet, the lifeline provider continues to get reimbursed each month from the federal universal service fund. This wastes Lifeline support, because the program is not actually benefiting the consumer for which it is intended. To address this situation, the FCC initiated a "non-usage" rule. If a Lifeline customer's account is considered inactive following non-usage in any 60-day period of time, service de-enrollment and deactivation will result

- National Lifeline Accountability Database. The FCC Lifeline and Link-Up Reform Order requires USAC to establish a National Lifeline Accountability Database by February 2013, to detect and prevent duplicative support in the Lifeline program. It is possible for a Lifeline customer to receive duplicate Lifeline benefits through two Lifeline providers since the ETCs do not have access to other ETCs customer bases. The National Lifeline Accountability Database will eliminate existing duplicative support and prevent duplicative support in the future.

  The database will have the ability to receive and process subscriber information provided by ETCs to identify whether a subscriber is receiving a Lifeline benefit from another ETC. The database will be capable of accepting queries from an ETC to enable them to determine if a prospective subscriber is already receiving Lifeline support from another ETC.

- National Lifeline Eligibility Database. The FCC directed the USAC to take all necessary actions so that, as soon as possible and no later than the end of 2013, there will be an automated means to determine Lifeline eligibility for, at a minimum, the three most common programs through which consumers qualify for Lifeline, Medicaid, SNAP, and SSI.

- Lifeline in areas zoned as "Commercial." There have been instances where otherwise eligible applicants have been denied Lifeline service because they live in facilities that are zoned for commercial, rather than residential use. Examples include group living facilities such as single-room occupancy buildings, lodging houses, rooming houses, and shelters, rather than individual residences.

  The new rule provides that if the consumer is otherwise eligible for Lifeline and the consumer certifies at enrollment that the address of record provided by the consumer is his or her residential address, the consumer should not be denied Lifeline because of residence in an area that is commercially zoned. Lifeline applicants must indicate whether the applicant's address on the application is temporary or permanent. If it is temporary, the Lifeline provider must verify with the subscriber every 90 days that he/she continues to rely on that address.

2. ETC Florida Wireless Applications submitted to the FCC

Effective July 1, 2011, the FPSC no longer has authority to designate wireless ETCs in the State of Florida. ETC applications for Florida now must be filed directly with the FCC. As of October 1, 2012, the following Florida ETC Wireless petitions were pending at the FCC:

- Airvoice Wireless, LLC
- Birch Communications d/b/a Now Communications
- Blue Jay Wireless, LLC
- Budget PrePay, Inc.
- Cintex Wireless, LLC
- Consumer Cellular
- EZ Reach Mobile, LLC
- Free Mobile, Inc
- Global Connection Inc. of America
- ICON Telecom, Inc.
- Kajeet, Inc.
- Linkup Telecom, Inc.
- Nexus Communications, Inc
- NewPhone Wireless, L.L.C.
- Platinum Tel Communications, LLC
- Q Link Wireless LLC
- TAG Mobile LLC (dPi Wireless)
- Tele Circuit Network Corporation

- Telrite Corporation
- TerraCom
- True Wireless, LLC
- Total Call Mobile, Inc.
- You Talk Mobile – Federal, LLC

C. Florida Public Service Commission

The FCC Lifeline and Link-Up Reform Order 12-11 made major changes to the Lifeline and Link-up programs which affect the Florida Link-up and Lifeline programs. The FPSC has been working with the industry and other agencies to implement the FCC changes.

1. Lifeline Work Group

The Lifeline Work Group was created by Section 364.10(2)(g)3, Florida Statutes, and includes the Commission, the Department of Children and Families, the Office of Public Counsel, and each eligible telecommunications carrier offering Lifeline and Link-Up services. Its purpose is to determine how the eligible Lifeline subscriber information will be shared, the obligations of each party with respect to the use of that information, and the procedures to be implemented to increase enrollment and verify eligibility in these programs.

A Lifeline Work Group meeting was held at the FPSC on November 7, 2011 to discuss procedures to be implemented to increase Lifeline enrollment, specifically, three items:

a) The new 2011 language contained in Section 364.10(2)(h), Florida Statutes, which states "The commission may undertake appropriate measures to inform low-income consumers of the availability of the Lifeline and Link-Up programs."

b) The 2011 Final Report by the National Regulatory Research Institute which recommends that the Commission staff should work with Florida telecommunications providers to determine how they can assume the majority of Lifeline outreach over the long term.

c) Recommendations from The Florida Legislature Office of Program Policy Analysis and Government Accountability that eligible telecommunications carriers develop outreach materials for specific consumer groups, such as young and rural populations, and wireless users; and develop outreach strategies.

A Lifeline Work Group meeting was also held at the FPSC on April 18, 2012. The purpose of this meeting was to solicit input for development of procedures to promote Lifeline participation. Specifically, staff sought input on:

a) Ideas to create a new process to make Lifeline enrollment as easy as possible for new applicants in light of the new FCC requirement that all ETCs, prior to enrolling a new subscriber in Lifeline, must access state or federal social services eligibility databases (where available) to determine a consumer's program-based eligibility, or in the alternative, document the eligibility of those consumers seeking to qualify for Lifeline under program-based criteria.

b) A means to make better use of the Florida DCF Web Services Interface for verification of consumer participation in a Lifeline qualifying DCF program.

c) Possible creation of a new streamlined Lifeline application that meets the new requirements of Order FCC 12-11.

d) Other ideas to streamline the Lifeline enrollment process for both the applicant and ETC.

2. Initiation of Rulemaking to Amend Rule 25-4.0665, Florida Administrative Code (FAC), Lifeline Service, and to Repeal Rule 25-4.113, FAC, Refusal or Discontinuance of Service by Company.

On January 18, 2012, the FPSC conducted a rule development workshop regarding the initiation of rulemaking to amend Rule 25-4.0665, Florida Administrative Code, to eliminate the requirement of Lifeline quarterly reporting, to require that a customer's Lifeline local service may not be discontinued if the charges, taxes and fees applicable to dial tone, local usage, dual tone multifrequency dialing, emergency services such as "911," and relay service are paid, and to clarify ETC responsibilities regarding record retention, resale of Lifeline lines, and advertising, including developing outreach materials for specific consumer groups and outreach strategies. Consistent with the 2011 changes made to Chapter 364, Florida Statutes, Rule 25-4.113, Florida Administrative Code, would be repealed.

On September 19, 2012, the FPSC held another rulemaking workshop to discuss implementation of new requirements contained in the FCC Lifeline and Link-Up Reform Order 12-11. The discussions included how Rule 25-4.0665 would be amended to require ETCs to comply with Lifeline subscriber eligibility determinations and certifications as contained in CFR §§54.409, 54.410, and 54.416, to eliminate Link-Up, to update Lifeline applications, and further discuss items from the January 18, 2012 workshop.

3. Cox Florida Telecom LP ETC Designation.

By Order PSC-12-0500-PAA-TP, issued September 28, 2012, and Order PSC-12-0552-PAA-TP, issued October 17, 2012, the FPSC granted ETC designation to Cox Florida Telecom LP. Cox Florida Telecom LP was approved as an ETC for the limited purpose of receiving federal universal service low income support for providing lifeline service to qualified households in its non-rural, and rural service territory in Florida.

4. FPSC Actions to Prevent Waste, Fraud and Abuse of the Federal USF.

Florida has been at the forefront in enforcing safeguards to prevent waste, fraud, and abuse of the USF. Florida's leadership in creating the National ETC Coordinating Group to monitor prospective and existing ETCs across the country, has enabled information sharing with all states,[32] to monitor new ETC petitioners and existing ETCs to prevent waste, fraud, and abuse of the USF on a national basis.

[32] The ETC State Coordinating group includes state commission members from forty eight states and the District of Columbia.

Florida was one of two states personally commended by FCC Chairman Julius Genachowski for its formidable efforts to identify and eliminate fraud in the Lifeline Assistance program. In the December 12, 2011 letter, Chairman Genachowski praised the states' efforts to end any potential fraud in the Universal Service Fund, specifically recognizing actions by Florida and Wisconsin, and also urged state commissions to join the FCC's national effort "to reform the Lifeline program…and to take swift and strong action when necessary to protect the program."

The FPSC strives to protect the integrity of the Lifeline program in the State of Florida and takes appropriate enforcement action when necessary. The Commission has statutory authority to grant landline ETC designations, and can also revoke ETC status when warranted. Protecting against waste, fraud, and abuse in the Lifeline program is contingent upon developing adequate safeguards to ensure that funds are being dispersed and expended according to state and federal regulations and guidelines. Unlawful and inappropriate USF disbursements are inconsistent with public trust and negatively impacts states like Florida, which contributes more into the USF than it receives. Establishing and enforcing protective Lifeline program safeguards continues to be a FPSC priority.

VIII. Lifeline Assistance Promotion, Pursuant to Section 364.10, F.S.

Promotional activities in 2012 featured National Lifeline Awareness Week, National Consumer Protection Week, the Connect Florida Campaign, and ongoing "grass roots" efforts to increase awareness and enrollment in the program**.**

Lifeline Across America. In 2012, the Lifeline Across America Working Group (FCC, NARUC, and NASUCA representatives) concentrated on the fourth annual National Telephone Discount Lifeline Awareness Week (LAW). The Group's national effort is to ensure that low-income families and individuals are aware of the Lifeline program and understand the participation requirements, including the requirement that eligible consumers may receive no more than one Lifeline discount. The FCC worked with its partners in the Lifeline Across America Working Group (LAAWG) and others to increase awareness among low-income consumers about the recent Lifeline program reforms and participation requirements. The LAAWG produced an outreach campaign to educate consumers about the new Lifeline rules, including an eligibility screening tool, an online tool to help consumers find companies providing Lifeline discounts, a consumer's guide, and public service announcements (PSAs, in English and Spanish). Important messages about the FCC's program changes--removing duplicative subscriptions and requiring proof of eligibility--were highlighted by the states during LAW. According to NARUC, more than 15 state public utility commissions issued press releases, received gubernatorial proclamations, released radio and television PSAs, and published letters-to-the-editor to help promote Lifeline.

Also, the technical sub-group of Lifeline Across America (FCC, NARUC, USAC, and state commission representatives) held conference calls to discuss special issues related to the administration of the Lifeline program. The FPSC shares information about Florida's Lifeline regulations and procedures and Florida's LAW with the Lifeline Across America sub-group.

<u>National Lifeline Awareness Week (September 10-14, 2012)</u>. *Stay Connected, Florida!* was the slogan chosen by the FPSC for Florida's 2012 Lifeline Awareness Week, September 10-14. In addition to increasing awareness among eligible citizens, this year, Florida's LAW aimed to educate FPSC partners on recent FCC rule changes to curb program abuse that limit benefits to one per eligible household, with annual recertification required to continue receiving the benefit. Now in its fourth year, LAW events were also held throughout Florida to help seniors and low-income Floridians learn about, and apply for, the program.

FPSC Chairman Ronald A. Brisé kicked off the week by hosting an informal workshop in Tallahassee with representatives from social service agencies, whose clients benefit from the Lifeline program, and state agencies that facilitate Lifeline's promotion and application process. Essential grassroots support from these agencies is imperative to reaching eligible residents. The workshop focused on ways to ensure that consumers enrolling in Lifeline are not already receiving the service and on additional ways to contact potentially eligible consumers. The FPSC believes all eligible low-income consumers who qualify and desire to receive Lifeline assistance should be able to receive the Lifeline discount. .

Workshop participants included the United Way of the Big Bend; Tallahassee Housing Authority; Agency for Health Care Administration; Florida Departments of Children and Families, Economic Opportunity, Education, Elder Affairs, and Health; Florida Telecommunications Relay, Inc.; 2-1-1 Big Bend; AARP; **WORK**FORCE*plus*; Tallahassee Urban League; Tallahassee Caribbean Association; and the Office of Public Counsel.

During LAW, FPSC staff visited senior centers in Jacksonville, Miami Gardens, Tampa, Riviera Beach, Palm Beach Gardens, and Lauderhill to explain the recent Lifeline program changes and help eligible seniors sign up for the program. The Commission partnered with Workforce centers in Carol City and Tampa to help Florida's unemployed residents get a phone to connect with job opportunities, businesses, and community services; to help them save money on their telephone and utility bills; and to share recent Lifeline rule changes. As of June 30, 2012, 1,035,858 eligible Florida telecommunications customers participated in the Lifeline program.

Each LAW event offered individual assistance to consumers applying for the program. Several telecommunications companies and Linking Solutions joined the FPSC at the senior centers and Workforce locations offering program information and assistance in signing up eligible residents.

<u>National Consumer Protection Week and Other Community Events</u>. The FPSC continuously seeks existing community events and new venues and opportunities where Lifeline educational materials can be distributed and discussed with citizens. The 14th Annual National Consumer Protection Week (NCPW), March 4-10, 2012, was a good backdrop for Lifeline outreach activities. NCPW, an annual consumer education campaign, encourages individuals to take advantage of their consumer rights. For this year's event, FPSC Chairman Brisé hosted a *Super Tuesday Consumer Forum* on Tuesday, March 6. Participating Cabinet offices and other agencies joined Chairman Brisé and staff to arm consumer agencies throughout Florida with helpful information for Florida residents. Chairman Brisé's goal for the Forum was to share important Lifeline information and some effective ways for Floridians to make wise spending choices, avoid scams, and conserve water and energy to help lower their utility bills. More than

15 consumer groups and state agencies attended the event, where they learned about the needs of Florida's consumer agencies and discussed ways to raise consumer awareness. Also during NCPW, FPSC staff made presentations to seniors in Fort Walton Beach, Jacksonville, and Tampa, showing them how to save money on their water and utility bills and how to sign up for Lifeline Assistance.

This year, the FPSC participated in a national project called Older Americans Month, celebrated each May to honor and recognize older Americans for the contributions they make to their families, communities, and society. *Never Too Old to Play* was this year's theme, and the FPSC held educational sessions with Florida senior centers in Tampa, Orlando, Jacksonville, Palm Beach Gardens, and Miami. The FPSC's educational sessions showed seniors ways to conserve energy and water and highlighted the Lifeline program. An FPSC article outlining the importance of Older Americans Month, the Commission's outreach activities, and the Lifeline program was featured in the July/August edition of the Florida Department of Elder Affairs' *Elder Update*.

Other events and locations where Lifeline information was shared included Ambassadors for Aging Day; Active Living Expo; Earth Day at the Capitol; Community Days in Hillsborough County and the cities of Hialeah, Melbourne, Sweetwater, Miami Gardens, Lake Park, Palatka, and Brooksville; Florida Departments of Elder Affairs and Health's Falls Prevention Awareness Day; Senior Days in Jacksonville, Tampa, Orlando, and Tallahassee; Lane Wiley Senior Center; Leroy Clemons Senior Center; Maxville Senior Center; Orange Park Senior Center; Wiegel Senior Center; Orange County Consumer Fraud Unit; Elder Care Services; Seniors in Service of Tampa Bay, Inc.; Elder Affairs SHINE Program of Putnam County; Community Legal Services of Mid-Florida, Inc.; Brevard Health Alliance in Melbourne; Palm Beach County Health Department; Senior Solutions of Southwest Florida; Senior Friendship Centers, Inc.; Discipline of Christ Family Day; Miami–Dade County Department of Human Services; Tampa Housing Authority; Alliance for Aging, Inc.; and Mid-County Senior Center.

Each year the FPSC provides educational packets, including publications and Lifeline brochures and applications in English, Spanish, and Creole to Florida public libraries across the state for consumer distribution. This year's Library Outreach Campaign reached 333 public libraries and branches throughout Florida.

Connect Florida Campaign. The Connect Florida Campaign (Campaign), established by Linking Solutions, Inc., OPC, and AT&T in 2004, continues to increase consumer awareness and participation in Lifeline. During the July 2011–June 2012 reporting period, Lifeline Partners joined AT&T and OPC in support of the initiative. Campaign event locations included Fort Pierce, Melbourne, Lake Park, Palatka, Orlando, Miami, Miami Gardens, Brooksville, Hialeah, Florida City, Vero Beach, Jacksonville, and Pensacola. In addition to the larger events, campaign activities included smaller training sessions with non-profit organizations, public agencies, faith based groups, community centers, and community activities. From July 2011–June 2012, the Linking Solutions Campaign held 168 sessions throughout Florida with 19,703 attendees and submitted 8,411 Link-Up Florida and Lifeline applications.

Community Services Block Grant Program. The Florida Department of Economic Opportunity (DEO) includes Lifeline services as an indicator in its work plan, allowing the Community Action Agencies to report the number of clients they help receive Lifeline services. During the sixth year of reporting, from October 2010–September 2011, an additional 2,382 households signed up for Lifeline benefits through 19 Community Action Agencies. Data for the October 2011 to September 2012 period is not available until early 2013.

Income-Based Lifeline Applicants. OPC provides assistance to consumers applying for Lifeline based upon income and receives an average of 3,625 calls per month. OPC staff processed over 43,500 calls from potential applicants from July 2011–June 2012. During that time, OPC also received 29,027 Florida OPC Lifeline applications and approved approximately 14,168 applications for customers of AT&T, CenturyLink, Verizon, SafeLink Wireless, and Assurance Wireless. The remaining applications were either denied, pending, or from customers of other companies. Applications that were received but not included in these totals were from out-of-state customers or were public assistance program-based applications and forwarded to the appropriate company. Since September 2008, OPC has been processing income-based applications for customers of TracFone/SafeLink Wireless and since October 2010, for customers of Virgin Mobile/Assurance Wireless.

Ongoing Lifeline Outreach. Ensuring easily accessible Lifeline information through the agencies and organizations having regular interaction with eligible consumers is crucial to the Lifeline awareness effort. The Lifeline Partners (listed in the next section) have continued to develop new partnerships, participate in local community events, offer training sessions, provide updates about program changes, and supply brochures and applications. The information provided in the 2003 through 2007 Lifeline Reports offers a detailed historical perspective and illustrates ongoing outreach efforts. Learn more about the Lifeline Partners and their valuable assistance in promoting Lifeline by visiting the FPSC's Web site at http://www.psc.state.fl.us/publications/reports.aspx#tele.

Lifeline Partners. The following local, state, and federal agencies, organizations, businesses, and telecommunications companies are involved in the collaborative effort to increase awareness and participation in the Lifeline program. Each month, the FPSC sends a cover letter and informational packet to two organizations to encourage continued Lifeline outreach to their eligible clientele. In an additional outreach effort, the FPSC attends two community events monthly to promote Lifeline.

Lifeline Partners include these local, state, and federal agencies, organizations, and businesses:

- AARP - Florida Chapter (formerly the American Association of Retired Persons)
- Ability Housing of Northeast Florida
- ACCESS Florida Community Network Partners
- Agency for Health Care Administration (AHCA)
- Agency for Persons with Disabilities
- Agency for Workforce Innovation (AWI) and Workforce Florida, Inc. (WFI)
- Area Agencies on Aging
- Big Bend 2-1-1 and other 2-1-1 Agencies
- Boley Centers, Inc.
- Braille and Talking Book Library
- Brain Injury Association of Florida, Inc.
- Bureau of Indian Affairs Programs

- Capital Area Community Action Agency, Inc. (CACAA)
- Centers for Independent Living
- City and County Consumer Assistance Departments
- City and County Housing Authorities
- Communities In Schools Foster Grandparent Program
- Community Partnership Group
- Faith Radio Station and other Florida radio stations
- Federal Social Security Administration (SSA) - Tallahassee District
- Florida Alliance for Information and Referral Services (FLAIRS)
- Florida Assisted Living Association
- Florida Association for Community Action (FACA)
- Florida Association of Community Health Centers
- Florida Association of Counties
- Florida Association of County Human Service Administrators
- Florida Association of Food Banks (FAFB)
- Florida Association of Housing and Redevelopment Officials (FAHRO)
- Florida Coalition for Children
- Florida Coalition for the Homeless
- Florida Council on Aging
- Florida Department of Children and Families (DCF)
- Florida Department of Community Affairs (DCA)
- Florida Department of Education (DOE)
- Florida Department of Elder Affairs (DEA)
- Florida Department of Revenue (DOR)
- Florida Department of Veterans' Affairs (DVA)
- Florida Developmental Disabilities Council
- Florida Elder Care Services
- Florida Home Partnership
- Florida Hospital Association
- Florida Housing Coalition
- Florida Housing Finance Corporation
- Florida League of Cities, Inc.
- Florida Low Income Housing Associates
- Florida Nurses Association
- Florida Office of Public Counsel (OPC)
- Florida Public Libraries
- Florida Public School Districts
- Florida Public Service Commission (FPSC)
- Florida Rural Legal Services, Inc.
- Florida Telecommunications Relay, Inc. (FTRI)
- Florida Voters League
- 1000 Friends of Florida, Inc.
- Habitat for Humanity – Florida
- HANDS of Central Florida
- Hemophilia Foundation of Greater Florida

- Leon County School Board
- Linking Solutions, Inc.
- Mid-Florida Housing Partnership, Inc.
- NAACP (Florida Associations)
- Nursing Homes Administrators
- Senior Resource Alliance
- Tallahassee Memorial Hospital (TMH) and other Florida hospitals
- Tallahassee Urban League
- Three Rivers Legal Services, Inc.
- United Way of Florida
- Urban Leagues of Florida
- U.S. Department of Housing and Urban Development (HUD)
- Washington County Council on Aging

Telecommunications Companies:

Twenty-seven companies had ETC status in Florida and participated in the Lifeline Program as of June 30, 2012:

- Absolute Home Phone
- BellSouth Telecommunications, LLC, d/b/a AT&T Florida (AT&T)
- Ganoco, Inc., d/b/a American Dial Tone[33]
- Budget Prepay, Inc. d/b/a Budget Phone
- dPi Teleconnect, LLC
- Easy Telephone Services Company
- Embarq Florida, Inc. d/b/a CenturyLink
- Express Phone Service, Inc.
- GTC, Inc. d/b/a FairPoint Communications
- FLATEL, Inc.
- Global Connection Inc. of America
- Frontier Communications of the South, LLC
- ITS Telecommunications Systems, Inc.
- Knology of Florida, Inc.
- Midwestern Telecommunications, Inc.[34]
- Northeast Florida Telephone Company d/b/a NEFCOM
- Nexus Communications, Inc. d/b/a Nexus Communications TSI, Inc.
- Smart City Telecommunications LLC, d/b/a Smart City Telecom
- Sun-Tel USA, Inc.
- Quincy Telephone Company d/b/a TDS Telecom/Quincy Telephone
- T-Mobile South LLC d/b/a T-Mobile Wireless
- Tele Circuit Network Corporation
- TracFone Wireless, Inc. d/b/a SafeLink Wireless
- Verizon Florida LLC

[33] American Dial Tone, Inc. – Certificate of Authority cancelled November 3, 2011.
[34] Midwestern Telecommunications, Inc. – Certificate of Authority cancelled April 27, 2012.

- Verizon Wireless (former ALLTEL territory)[35]
- Virgin Mobile USA, L.P. d/b/a Assurance Wireless
- Windstream Florida, Inc.

IX. Effectiveness of Procedures to Promote Participation

Efforts to increase Lifeline participation can be separated into two categories, consumer outreach and enrollment process. The FPSC, in cooperation with other state and federal agencies, OPC, ETCs, and other organizations, remains engaged in extensive outreach efforts. Because most of these efforts run concurrently, measuring the impact of any single activity on Lifeline participation is difficult. Nevertheless, outreach efforts overall are having a positive outcome and should be continued. Outreach efforts are also being expanded to include more CLEC and wireless ETCs.

The Commission continues to focus on enrollment process issues as a means of increasing participation. As previously discussed in this report, specific enrollment process initiatives include the following:

- FPSC Lifeline Coordinated Online Application Process
- FPSC/DCF Initial Lifeline Enrollment Procedure
- Annual Re-Certification Procedures
- DCF Certification/Verification Web Services Interface
- Lifeline Rulemaking Workshops
- Lifeline Work Group Meetings

X. Conclusion

The overall net Lifeline growth rate was 9.7 percent during the July 2011 through June 2012 review period. As of June 30, 2012, 1,035,858 eligible customers participated in the Florida Lifeline program. The FPSC attributes the continued growth of Lifeline to the ETC designation of prepaid wireless providers, such as SafeLink Wireless and Assurance Wireless, which provide a free phone and free monthly minutes to the customer. As a result of the continued increase in Florida Lifeline participation, USAC Low Income disbursements for Florida ETCs for the 12-month period ending September 2012 was at an all time high which totaled $111,389,500, and averaged $9,282,458 per month.

FPSC Chairman Ronald A. Brisé kicked off National Lifeline Awareness Week (September 10-14, 2012) by hosting an informal workshop in Tallahassee with representatives from social service agencies whose clients benefit from the Lifeline program and state agencies that facilitate Lifeline's promotion and application process. As in past years, the FPSC's Lifeline Awareness Week aimed to increase awareness among citizens who receive assistance from public benefits programs or who are income eligible.

[35] Verizon Wireless has provided notice that it will be relinquishing its ETC status in Florida as of December 31, 2012.

The FPSC will continue to identify and find solutions to barriers that may prevent Lifeline from achieving greater success for the benefit of Florida's low-income consumers. The FPSC will also continue its work on streamlining the Lifeline enrollment process and refining the FPSC/DCF Lifeline coordinated application procedure in Florida so that applying to the Lifeline program is easier and faster than in previous years.

II. Outside Persons Who Wish to Address the Commission at Internal Affairs

OUTSIDE PERSONS WHO WISH
TO ADDRESS THE COMMISSION AT

INTERNAL AFFAIRS
November 28, 2012

Speaker	**Representing**	**Item #**
Billy Stiles	TECO	3

III. Supplemental Materials Provided During Internal Affairs

The records reflect that there were no supplemental materials provided to the Commission during this Internal Affairs meeting.

IV. Transcript

STATE OF FLORIDA
PUBLIC SERVICE COMMISSION

Internal Affairs Meeting

Wednesday, November 28, 2012

Betty Easley Conference Center, Room 140

P R O C E E D I N G S

CHAIRMAN BRISÉ: All right. Good morning. We will go ahead and call this Internal Affairs meeting to order.

I'm seeking a motion to approve the minutes.

COMMISSIONER BROWN: So moved.

COMMISSIONER EDGAR: So moved.

COMMISSIONER EDGAR: Second.

COMMISSIONER BROWN: Second.

CHAIRMAN BRISÉ: Moved and seconded twice.

(Laughter.)

CHAIRMAN BRISÉ: All in favor say aye.

(Vote taken.)

CHAIRMAN BRISÉ: All right. Let's move on to Item Number 2, which is staff's review of the 2012 Ten-Year Site Plan.

MR. ELLIS: Good morning, Commissioners. Phillip Ellis with Commission Staff.

Item 2 is the review of the 2012 Ten-Year Site Plans. This report is the same version that appeared on the last IA with a few minor corrections.

Overall, the report shows that growth continues in Florida, and along with it natural gas usage, which is projected at 62 percent of all fuel for electricity this year.

Renewable generation is also projected to grow in the state with approximately 1,000 megawatts of planned new generation, about half of which is solar PV.

On the customer side, net metering has also increased to over 4,000 participants, with a total of 29 megawatts installed, a ten-fold increase since 2008.

In the Ten-Year Site Plan, three utilities are coming in with -- sorry, three utilities plan new units that require the Commission's determination of need. TECO has already filed with Polk 2 through 5 combined-cycle conversions, Progress and Seminole. With the additions outlined in the Ten-Year Site Plans, all utilities project sufficient capacity to meet planning reserve requirements through 2021.

In the report, staff also did review the impact of the continued outage of CR3. Progress has sufficient capacity to meet its planning reserve requirements until 2016, the summer peak period. At that time, if the unit has not returned to service, the company would either need to purchase power or accelerate its next generating unit. There is projected to be sufficient capacity within the state for the company to purchase power if needed.

Recent EPA rules were also addressed in the report, but due to the timing of some of the rules and recent court actions, we expect those to be more fully addressed in next year's report. Overall, staff believes the Ten-Year Site Plans to be suitable for planning purposes.

CHAIRMAN BRISÉ: All right. Thank you very much.

Commissioners, questions?

Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Chairman.

And I want to thank the Commission for deferring this item, because I needed to spend additional time with staff looking at the information.

I primarily focused on the reserve margin as we have done in the past. But I think this year staff has provided additional information about load management and the potential retirement of not only CR3, but also CR1 and 2 and Lansing 1 and 2 which have been identified by the environmental groups. So I wanted to focus on that.

And, you know, at this time I believe that it is suitable for planning purposes and it should be submitted. But I think I should reiterate -- I believe it was Commissioner Edgar yesterday indicated that next year there's going to be a lot of decisions to be made and a lot more information. So I look forward to next year's Ten-Year Site Plan and the workshop that precedes it to see what the effects will be once the CR3 decision is made as these new environmental requirements come into play and potential retirements.

But I appreciate staff's work. I like looking closely at the without load management reserve margin, which I think is something we need to focus on. But, again, I just want to thank the Commission for the deferral of this item.

CHAIRMAN BRISÉ: All right. Any further discussion or questions?

COMMISSIONER BROWN: I move approval.

COMMISSIONER EDGAR: Second.

CHAIRMAN BRISÉ: All right. Moved and seconded. All in favor say aye.

(Vote taken.)

CHAIRMAN BRISÉ: All right. Thank you very much.

Moving on to Item Number 3, which is the draft report on Electrical Vehicle Charging Station Study.

MR. CRAWFORD: Good morning, Commissioners. I'm Ben Crawford with the Office of Industry Development and Market Analysis. I'm here today seeking approval of the draft Electric Vehicle Charging Study Report that you have in front of you.

During the last general legislative session, the Legislature passed House Bill 7117, which required the Commission to provide a report on the potential effects of public charging stations and privately owned electric vehicle charging on both energy consumption and the impact on electric grid in the state. It also required the Commission to investigate the feasibility of using off-grid solar photovoltaic power as a source of electricity for the electric vehicle charging stations.

In its review, Commission staff has found that electric vehicles are likely to result only in a very small increase in electricity consumption over the ten-year planning horizon, compared with a small decrease in the consumption of petroleum-based fuels. Staff has also found that Florida's electric utilities might have to upgrade certain distribution equipment in the event of electric vehicle substrain when you have multiple electric vehicles on a single transformer, or when the high voltage quick-charge stations come in. We don't have any of those in the state right now, but they do potentially -- they will require a lot of energy on the distribution system, and there may need to be some upgrades for those.

Additionally, staff found that off-grid solar photovoltaic charging stations are technically possible, but will come at a large economic cost compared to grid type systems. And as a result, they are probably only feasible for very remote locations within the electric grid.

I would like to point out the contributions of Robert Graves in Engineering and Judy Harlow and Lee Gilbert in Economics in preparation of this report. And staff seeks approval of the draft report, and I'm available to answer any questions or concerns you may have.

CHAIRMAN BRISÉ: All right.

Commissioners, any questions or comments?

COMMISSIONER BROWN: I just have a question.

CHAIRMAN BRISÉ: Sure.

COMMISSIONER BROWN: Thank you, Mr. Crawford, for your report.

And at the recent NARUC Conference, this seemed to generate a lot of interest among other state regulatory commissions, and it is of interest -- I was curious, does this particular statute require an annual report, or is it just this one time?

MR. CRAWFORD: No, the statute -- it did make a change in statute. This wasn't one of the things where they will just pass a law that leads to a one-time report. So it did make the statute as just a one-year report. But because it remains in the statute, if the Legislature wants us to do this again, they could simply change the due date on it and have us repeat the study.

COMMISSIONER BROWN: And could we take it upon ourselves to initiate a continuing study?

MR. CRAWFORD: If the Commission wanted to, yes, we could continue to investigate this in the future in whatever context you would like us to. The staff had discussed possibly doing some of it as part of the Ten-Year Site Plan review process, or we could do it separately, or really however y'all would like to address it.

COMMISSIONER BROWN: Sounds good.

CHAIRMAN BRISÉ: Just out of curiosity, I realize that we have about 1,400 charging stations in the state. Are there any partnerships between some of our utilities and, say, automakers, or the big stores like Wal-Mart and so forth?

MR. CRAWFORD: I'm not aware of any between automakers or between any of the stores or anything. I know Walgreens has rolled out a few charging stations in the state, and there have been a large number of -- and some of the public charging stations are at auto dealerships that sell the electric vehicles, so we have seen some of that.

The utilities might be able to answer that question a little better in terms of if they entered into new partnerships.

CHAIRMAN BRISÉ: Sure.

MR. CRAWFORD: I know there have been, like, OUC has done some partnerships to put some public charging stations up in Orlando, and I think there have been a few other programs. Off the top of my head, I'm not sure of the detail about it.

CHAIRMAN BRISÉ: Sure. If there are any utilities that could answer that or have any comment on the question that I posed?

MR. STILES: Commissioners, Billy Stiles with Tampa Electric Company.

I'm not aware that we have any such partnerships for installing charging stations in our service area.

CHAIRMAN BRISÉ: Okay. Sure.

Commissioner Balbis.

COMMISSIONER BALBIS: Thank you. And I just have a quick question.

MR. CRAWFORD: Sure.

COMMISSIONER BALBIS: I think it's good to see that even with the projected increase in electric vehicles that the infrastructure -- at least generating capacity is in place to support that. So that's a good sign.

You indicated that the quick-charge stations may require distribution system improvements. Under the current tariffs or rules, the cost of those improvements will be borne by the facility that's proposed, or would it be --

MR. CRAWFORD: My understanding, and this might end up coming up on a case-by-case basis, but my understanding is those would probably -- because we are talking about specific upgrades for specific stations, that would probably end up using contributions-in-aid-of-construction, CIAC in some context.

That's not a definite, as far as I know, but that may be one of the -- one of the economics people might be able to answer that a little bit better than I could, but my understanding is that CIAC would probably be used for that.

COMMISSIONER BALBIS: Is there an economics person here?

UNIDENTIFIED SPEAKER: What are you asking for?

MR. DEAN: I'm sorry. Generally, you're dealing with what the customer is taking voltage at. If the customer asked to take a higher level of voltage that was outside the existing tariff, the standard tariffed rate would be for that particular level of service.

I don't know specifically what voltage these would be taken, but there is a range of service boundaries that you would take service under. As long as you live within that boundary, there would be no cost, no additional cost to you. If you get outside that voltage service, then you pay the next higher tariffed level.

MR. CRAWFORD: And my understanding is that those quick-charge stations, there would be, like, the 480-volt, somewhere in that range. They'd likely require three-phase power, too, so that's a little more than just the basic.

COMMISSIONER BALBIS: Okay. Thank you.

CHAIRMAN BRISÉ: All right. I think we're ready for a motion.

MR. CRAWFORD: If I may interject?

CHAIRMAN BRISÉ: Sure.

MR. CRAWFORD: We have noticed a few just, you know, little typos, wording fixes, the usual sort of thing that you are going to find on a report of this size. If possible, I'd like to -- if we could work with the Chairman's Office just to make those changes before we send this report on.

CHAIRMAN BRISÉ: All right.

COMMISSIONER BALBIS: I move approval of the Draft Report on Electric Vehicle Charging.

CHAIRMAN BRISÉ: All right. It has been moved.

Is there a second?

COMMISSIONER EDGAR: Second.

CHAIRMAN BRISÉ: All right. Moved and seconded. All in favor say aye.

(Vote taken.)

CHAIRMAN BRISÉ: All right. Moving on to Number 4, Lifeline.

MR. POLK: Good morning, Commissioners. Jim Polk on behalf of Staff.

Item Number 4 this morning addresses the draft of the 2012 Annual Lifeline Report, which was prepared in accordance with the requirements of 364.10, Florida Statutes. By December 31st of each year the Commission is required to report to the Governor, the President of the Senate, and the Speaker of the House of Representatives on the number of customers subscribing to Lifeline Service and the effectiveness of procedures to promote participation in the program.

The number of participants in Florida's Lifeline Program grew 9.7 percent this past year, July 1 through June 30th of 2012, and currently there's over one million participants in the Lifeline Program as of June 30th.

This year's report includes descriptions of changes that have been made to Florida's Linkup and Lifeline Programs due to the release of the FCC order on Lifeline and Link-Up reform and modernization. The report also describes outreach activities made throughout the last year to enable low-income Florida households to obtain and maintain basic local telephone service.

Staff is requesting the Commissioners' approval to submit this report and is prepared to answer any questions the Commissioners may have.

CHAIRMAN BRISÉ: All right.

Are there any questions?

COMMISSIONER BALBIS: I have one.

CHAIRMAN BRISÉ: Sure. Go right ahead.

COMMISSIONER BALBIS: On Table 5, on Page 11, the Lifeline Net Participation, you see some companies, you know, with a significant decrease and others with a significant increase. Can you explain why the discrepancy between companies on net growth rate?

MR. POLK: There were some decreases in wireline companies this year. There were increases in the wireless companies. Additionally, due to the FCC controlling with -- not controlling, excuse me -- with the state and finding duplicates of customers. In some of those cases, the companies found duplicates that there may be a wireline mixed with a wireless, so their participation dropped over last year.

COMMISSIONER BALBIS: Okay. That's all I have.

CHAIRMAN BRISÉ: All right. Any further questions or comments on Lifeline?

Well, I want to thank you all for your work, especially in the outreach aspect of it, making sure that people are aware that this program exists. And the more people that are eligible to sign up, the more we may fit them into our donor status of -- as a state in this program, I mean, sitting on that USAC Board it sort of hurts every time I look at those numbers.

So I certainly appreciate your work and the work of our utilities in their outreach efforts.

COMMISSIONER BROWN: I move to approve.

CHAIRMAN BRISÉ: All right.

COMMISSIONER BALBIS: Second.

CHAIRMAN BRISÉ: Moved and seconded. All in favor say aye.

(Vote taken.)

CHAIRMAN BRISÉ: All right. Thank you very much.

Legislative updates.

MS. PENNINGTON: Good morning, Commissioners. I just wanted to provide you our first legislative update. The election is over, and things have settled, and we have final results finally from the canvassing board.

Committee meetings begin next week. Tuesday and Wednesday are the busy days. It appears on Tuesday the House Energy Committee and the Senate Communications Energy and Utilities meetings will take place. I believe on Wednesday some appropriations meeting will take place. I have not seen those agendas yet, but I just wanted to let you know everything will be gearing up.

Finally, we'll start to see some bills. Being an election year, things started slowly. We do have committee members and chairmen in the House, which I sent to you, I believe, on Monday. We are still waiting for a committee chairman from the Senate, but clearly I think any day we'll see that.

Any questions?

COMMISSIONER EDGAR: Your office will be sending out meeting notices?

MS. PENNINGTON: Yes, ma'am.

COMMISSIONER EDGAR: Great.

MS. PENNINGTON: Jade is out this week, so I'm trying to play catch-up on that one. But, yes, we will continue to do that.

CHAIRMAN BRISÉ: All right. On that note, I will be representing us over there on Tuesday at the House and the Senate, so --

COMMISSIONER BROWN: Good luck.

CHAIRMAN BRISÉ: Thanks.

(Laughter.)

CHAIRMAN BRISÉ: All right. Any further questions or comments on legislative updates?

All right. Thank you very much, Katherine.

Executive Director's update.

MR. BAEZ: Briefly, a short update on the FEECA Study. We have just received our third draft providing comments of the last -- the final report is due back to the agency on December 7th.

We will have the normal circulation for you all, and will be available to discuss it with you in some format. I'm not sure we've decided on what the best format is in order to discuss it, but it will be made available, and we'll follow-up on it; that will be December 7th, when it is due back.

CHAIRMAN BRISÉ: All right. Anything else?

MR. BAEZ: Nothing else.

CHAIRMAN BRISÉ: All right.

Any questions for the Executive Director?

All right, moving on to other matters.

COMMISSIONER BROWN: Mr. Chairman, I just wanted to provide an update on the Water and Wastewater Study Committee. We have been pretty active, as you guys have been made aware. We have had four meetings so far, we are having our fifth meeting today at 12:30 p.m. in these wonderful chambers. And then we have our customer meetings December 5th at New Port Richey at 9:00 a.m., and then in Eustis at 6:00 p.m. I do suspect that they will be well-attended events, and just can't wait for those.

I also wanted to really, really commend our staff -- Greg Shafer, JoAnn Chase, Larry Harris, Katherine Pennington, Marshall Willis, Braulio -- they have been so tremendous, above and beyond. And if there is an opportunity for me to thank them at any meeting, I will be happy to do so.

The work product that is coming out is

tremendous though. Thank you, guys, so much; you are incredible. That's all.

CHAIRMAN BRISÉ: Good deal.

Anything else on other matters?

COMMISSIONER EDGAR: That's a great note to end on.

CHAIRMAN BRISÉ: I agree.

With that, Commissioner Edgar moves we rise.

(The Internal Affairs Meeting concluded at 9:49 a.m.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Hearing Reporter Services Section, Office of Commission Clerk, do hereby certify that the foregoing proceedings were transcribed from digital recording to the best of my ability.

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

DATED THIS 3rd day of December, 2012.

JANE FAUROT, RPR
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