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April 4, 2012

Via Federal Express Overnight Delivery

Jeff Derouen
Cases Nos. 2011-00375
Kentucky Public Service Commission
211 Sower Blvd.
Frankfort, KY 40601

Re: Complete Hard Copy of Intergrated Resource Plans Submitted into Evidence by Environmental Intervenors During the March 20, 2012 Hearing

Dear Mr. Jeff Derouen,

Following this letter you will find a hard copy of the complete integrated resource plans (IRP) from Duke Energy Carolinas, Georgia Power, Duke Energy Ohio, Tennessee Valley Authority, and PacifiCorp as requested. Each IRP is single sided page as reqested as well. Please not that the IRP from Ameren Missouri will be coming in a different shipment due to the volume of it's size. All of the IRPs are from 2011.

Sincerely,

Kristin A. Henry

Kristin A. Henry
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215

PUBLIC VERSION

TO THE

PUBLIC UTILITIES COMMISSION OF OHIO

DUKE ENERGY OHIO, INC.

2011 ELECTRIC

LONG-TERM FORECAST REPORT

AND RESOURCE PLAN

CASE NO. 11-1439-EL-FOR

STATEMENT
OF
JULIA S. JANSON
PRESIDENT, DUKE ENERGY OHIO, INC.

I, Julia S. Janson, President of Duke Energy Ohio, Inc., hereby certify that the statement and modifications set forth in the 2011 DUKE ENERGY OHIO LONG-TERM ELECTRIC FORECAST REPORT AND RESOURCE PLAN as submitted to the Public Utilities Commission of Ohio are true and correct to the best of my knowledge and belief.

I further certify that the requirements of Ohio Administrative Code §4901:5-1-03, paragraphs (F) to (I) will be met.

Julia S. Janson
President
Duke Energy Ohio, Inc.

Libraries Receiving a Letter of Notification Regarding Duke Energy Ohio, Inc.'s 2011 Long-Term Forecast Report and Resource Plan

County	Library	Address
Adams	Manchester Branch Library	401 Pike St. Manchester, Ohio 45144
Brown	Mary P. Shelton Library	200 West Grant Avenue Georgetown, Ohio 45121
Butler	Lane Public Library	300 North Third Street Hamilton, Ohio 45011
Butler	Middletown Public Library	125 South Broad Street Middletown, Ohio 45044
Clermont	Clermont County Public Library	180 South Third Street Batavia, Ohio 45103
Clinton	Wilmington Public Library	268 North South Street Wilmington, Ohio 45117
Hamilton	Public Library of Cincinnati and Hamilton County University of Cincinnati Library Reference Division	800 Vine Street Cincinnati, Ohio 45202 2600 Clifton Avenue Cincinnati, Ohio 45221
Highland	Highland County District Library	10 Willettsville Pike Hillsboro, Ohio 45133
Montgomery	Dayton and Montgomery County Public Library	215 East Third Street Dayton, Ohio 45402
Preble	Preble County District Library	301 North Barron Street Eaton, Ohio 45320
Warren	Lebanon Public Library	101 South Broadway Lebanon, Ohio 45036

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of Duke Energy Ohio's Long-Term Forecast Report and Resource Plan was served by hand delivery, this 15th day of July, 2011 upon the following:

Office of the Ohio Consumers' Counsel

10 West Broad Street, Suite 1800

Columbus, OH 43215-3485

Furthermore, a Letter of Notification was sent by First Class U.S. Mail to each library listed in the Report.

Elizabeth H. Watts
Elizabeth H. Watts
Associate General Counsel
Duke Energy Business Services

TABLE OF CONTENTS

SECTION I – FORECAST REPORT REQUIREMENTS

A. SUMMARY OF THE LONG-TERM FORECAST REPORT

Duke Energy Ohio provides electric service to approximately 690,000 customers in an area covering some 2,500 square miles in Southwestern Ohio. Duke Energy Ohio's service territory includes the cities of Cincinnati and Middletown, Ohio. Duke Energy Kentucky provides electric service in the Northern Kentucky area contiguous to the Southwestern Ohio area served by Duke Energy Ohio. Duke Energy Kentucky serves approximately 136,000 electric customers in its 500 square mile service territory. Duke Energy Kentucky's service territory includes the cities of Covington and Newport, Kentucky. Duke Energy Ohio and Duke Energy Kentucky operate within the regional economy as defined by the Cincinnati Primary Metropolitan Statistical Area (PMSA). Therefore, the Company coordinates and prepares the forecast for the entire region encompassing both utility service areas. This consolidated forecast is then allocated to each service area. Subsequently, this report covers the forecast for Duke Energy Ohio only.

As of December 2010, the transmission system of Duke Energy Ohio consisted of approximately 403 circuit miles of 345 kV lines (including Duke Energy Ohio's share of jointly-owned transmission) and 724 circuit miles of 138 kV lines. Portions of the 345 kV transmission system are jointly owned with Columbus Southern Power Company and/or the Dayton Power & Light Company. Duke Energy Ohio is interconnected with five other transmission providers (including Duke Energy Indiana).

The electric energy and peak demand forecasts of the Duke Energy Ohio franchised service territory are prepared each year as part of the planning process.

The general framework of the Electric Energy and Peak Load Forecast involves a national economic forecast, a service area economic forecast, and the electric load forecast.

The national economic forecast provides information about the prospective growth of the national economy. This involves projections of national economic and demographic concepts such as population, employment, industrial production, inflation, wage rates, and income. The national economic forecast is obtained from Moody's Analytics, a national economic consulting firm.

Similarly, the history and forecast of key economic and demographic concepts for the service area economy is obtained from Moody's Analytics. The service area economic forecast is used along with the energy and peak models to produce the electric load forecast.

Energy sales projections are prepared for the residential, commercial, industrial, and other sectors. Those components plus electric system losses are aggregated to produce a forecast of net energy.

Table 1-1 below, provides information on the Duke Energy Ohio System projected annual growth rates in energy for the major customer classes as well as net energy and peak demand before and after implementation of any new or incremental energy efficiency programs. The growth rates are consistent with the forecast presented in the FE-D forms in Section 3 and represent the full distribution forecast regardless of who supplies the energy. The forecast incorporates impacts associated with the Energy Independence and Security Act of 2007 (EISA).

TABLE 1-1
Duke Energy Ohio System

ELECTRIC ENERGY AND PEAK LOAD

FORECAST: ANNUAL GROWTH RATES

2011 to 2021

	Before EE	**After EE**
Residential MWH	0.8%	-0.7%
Commercial MWH	1.5%	0.3%
Industrial MWH	1.6%	0.5%
Net Energy MWH	1.2%	-0.1%
Summer Peak MW	1.0%	0.2%
Winter Peak MW	0.9%	0.3%

Growth rates are computed as the compound annual rate of growth in total distribution loads for the years 2011-2021.

The forecast of energy is graphically depicted on Figure 1-1, and the summer and winter peak forecasts are shown on Figure 1-2.

Please note that the FE-T forms in Section II represent the load supplied by the regulated utility. These forecasts of energy and peak demand provide the starting point for the development of the Integrated Resource Plan. As such, the first year of the forecast reflects energy and peak reduced for current switching levels, i.e. default load supplied by the regulated utility. The remaining years of the forecast reflect the assumption that all load returns to the regulated utility at the end of the current ESP in 2011. This result follows from the assumption that the Company sets an electric generation price at a new market-based ESP price. With the establishment of an ESP price at a market level, it is assumed that the cost savings that encourages customer switching would disappear. As a result, in this event, all switched customers are expected to return to the regulated utility for generation service.

Changes In Methodology

The Company changed its approach regarding the development of its appliance stock variable to rely more completely on information from Itron, Inc. for estimates of historical appliance efficiency. The Company uses the latest historical data available and relies on recent economic data and forecasts from Moody's Analytics.

Figure 1.1: Total Energy Forecast (Before Implementation of Energy Efficiency Programs)

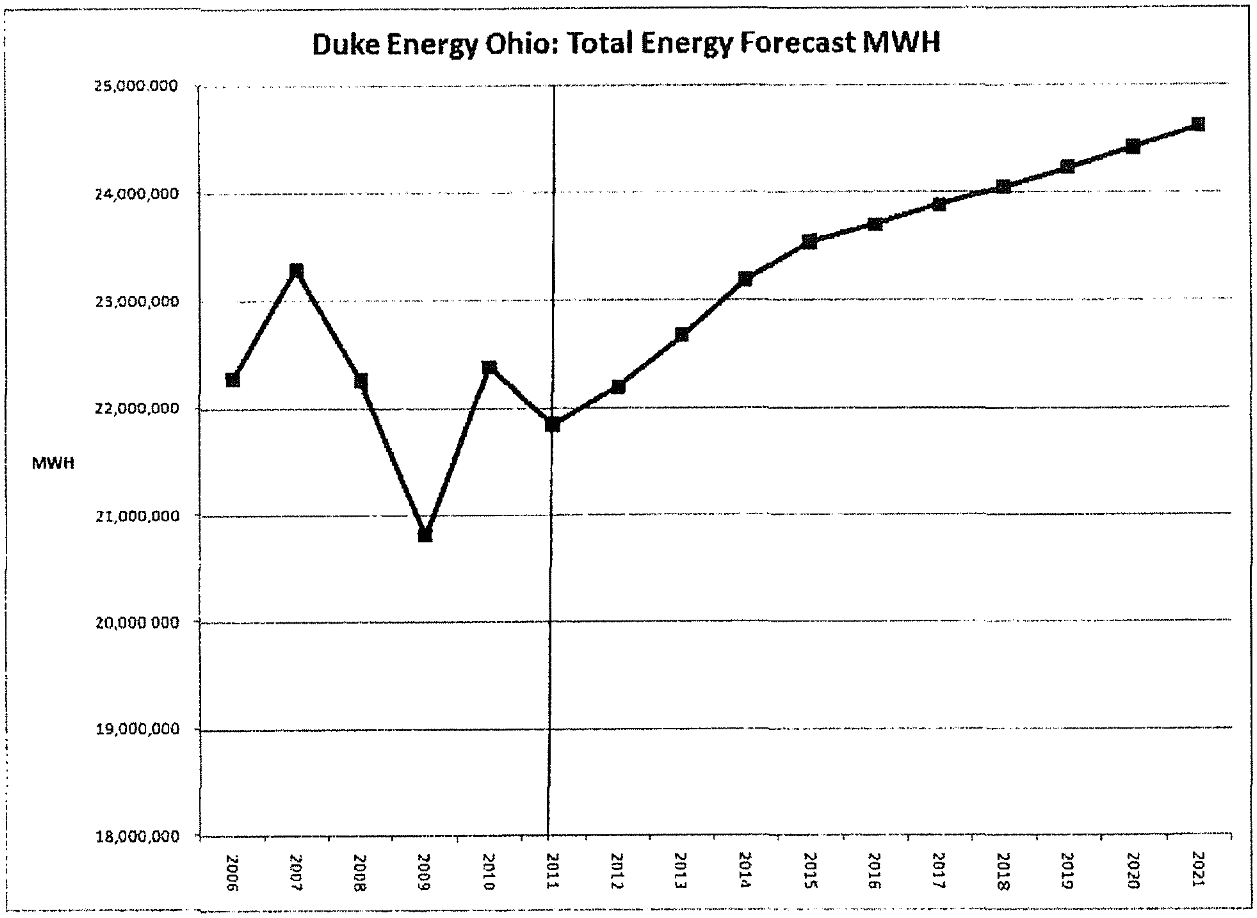
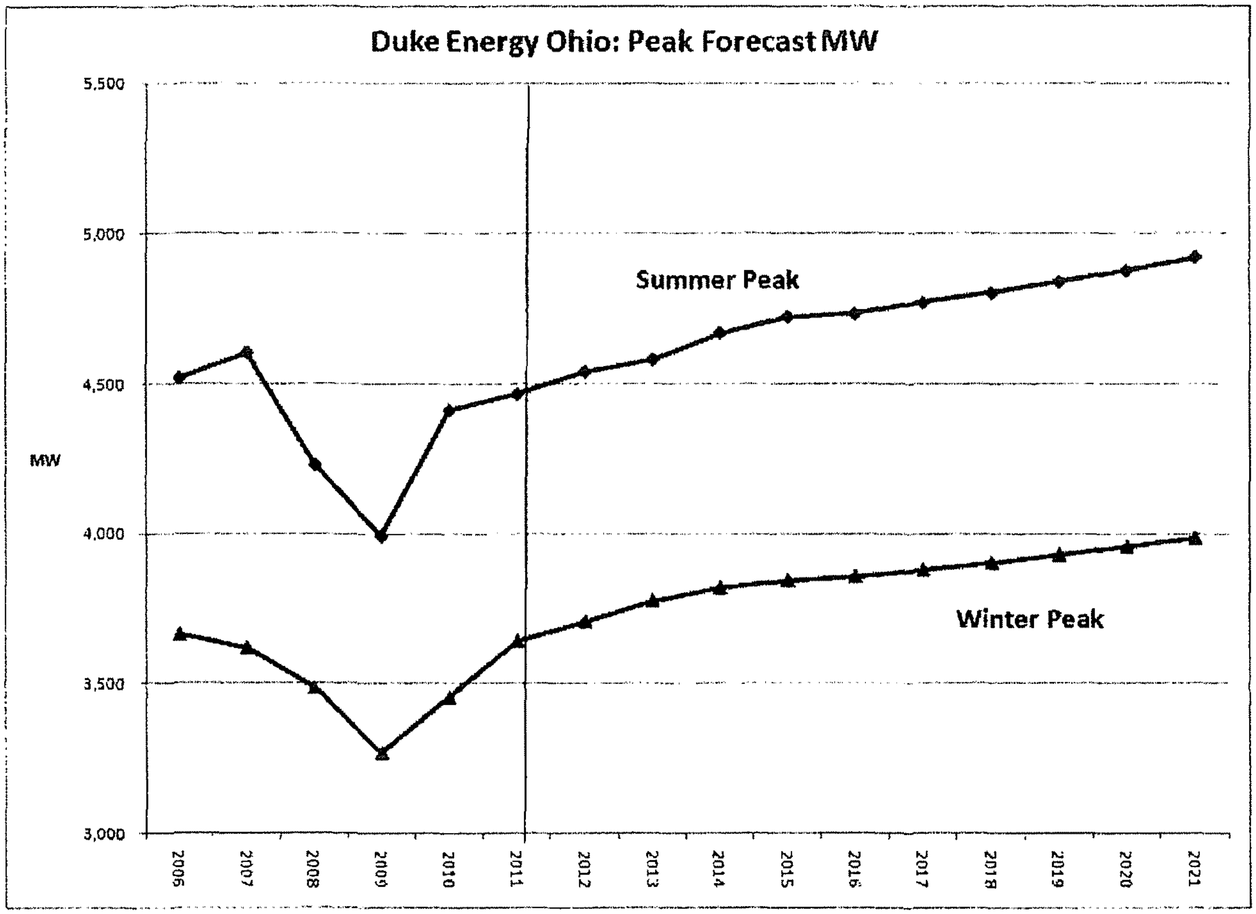


Figure 2.2: Peak Forecast (Before Implementation of Energy Efficiency Programs)



The electric energy and peak demand forecasts of the Duke Energy Ohio service territory are prepared each year as part of the planning process by a staff that is shared with the other Duke Energy affiliated utilities, using the same methodology. Duke Energy Ohio does not perform joint load forecasts with non-affiliated utility companies, and the forecast is prepared independently of the forecasting efforts of non-affiliated utilities.

B. FORECAST SUMMARY & ASSUMPTIONS

The forecast methodology is essentially the same as that presented in past Electric Long-Term Forecast Reports Plans filed with the Public Utilities Commission of Ohio (Commission). Energy is a key commodity linked to the overall level of economic activity. As residential, commercial, and industrial economic activity increases or decreases, the use of energy, or more specifically electricity, should increase or decrease, respectively. It is this linkage to economic activity that is important to the development of long-range energy forecasts. For that reason, forecasts of the national and local economies are key ingredients to energy forecasts.

The general framework of the Electric Energy and Peak Load Forecast involves a national economic forecast, a service area economic forecast, and the electric load forecast. The national economic forecast provides information about the prospective growth of the national economy. This involves projections of national economic and demographic concepts such as population, employment, industrial production, inflation, wage rates, and income. The national economic forecast is obtained from Moody's Analytics, a nationally recognized vendor of economic forecasts. In conjunction with the forecast of the national economy, the Company also obtains a forecast of the service area economy from Moody's Analytics.

The Duke Energy Ohio service area is located in southwestern Ohio adjacent to the service area of Duke Energy Kentucky. The economy of southwestern Ohio is contained within the Cincinnati Primary Metropolitan Statistical Area (PMSA) and is an integral part of the regional economy. The service area economic forecast is used along with the energy and peak models to produce the electric load forecast.

1. Service Area Economy

There are several sectors to the service area economy: employment, income, inflation, production, and population. Forecasts of employment are provided by North American Industry Classification System (NAICS) and aggregated to major sectors such as commercial and industrial. Income for the local economy is forecasted in several categories including wages, rents, proprietors' income, personal contributions for social insurance, and transfer payments. The forecasts of these items are summed to produce the forecast of income less personal contributions for social insurance. Inflation is measured by changes in the Consumer Price Index (CPI). Production is projected for each key NAICS group by multiplying the forecast of productivity (production per employee) by the forecast of employment. Population projections are aggregated from forecasts by age-cohort. This information serves as input into the energy and peak load forecast models.

2. Electric Energy Forecast

The forecast methodology follows economic theory in that the use of energy is dependent upon key economic factors such as income, production, energy prices, and the weather. The projected energy requirements for Duke Energy Ohio's retail electric customers are determined through econometric analysis. Econometric models are a means of representing economic behavior through the use of statistical methods, such as regression analysis.

The Duke Energy Ohio forecast of energy requirements is included within the overall forecast of energy requirements of the Greater Cincinnati and Northern Kentucky region. The Duke Energy Ohio sales forecast is developed by allocating percentages of the total regional forecast for each customer group. These groups include residential, commercial, industrial, governmental or other public authority (OPA), and street lighting energy sectors. In addition, forecasts are also prepared for three minor categories: interdepartmental use (Gas Department), Company use, and losses. In a similar fashion, the Duke Energy Ohio peak load forecast is developed by allocating a share from the regional total. Historical percentages and judgment are used to develop the allocations of sales and peak demands.

With respect to energy-price relationships, the forecast methodology described below includes discussion on the incorporation of energy price variables in the model specification. The price variables are explicitly included in the forecast models to account for the effect that changes in real prices can have on the level of energy usage. The econometric models presented in the report provide estimates of price elasticity for specific customer groups. Load impacts from rising real prices are also examined relative to projected load impacts from energy efficiency programs to ascertain how much of the price elasticity impacts are already reflected through impacts from energy efficiency programs.

The following sections provide the specifications of the econometric equations developed to forecast electricity sales for the franchised service territory.

Residential Sector - There are two components to the residential sector energy forecast: the number of residential customers and kWh energy usage per customer. The forecast of total residential sales is developed by multiplying the forecasts of the two components. That is:

(1) Residential Sales =

Number of Residential Customers * Use per Residential Customer.

Econometric relationships are developed for each of the component pieces of total residential sales.

Customers - The number of electric residential customers (households) is affected by real per capita income. This is represented as follows:

(2) Residential Customers =

f (Real Per Capita Income)

Where: Real Per Capita Income = (Personal Income/Population/CPI).

While changes in per capita income are expected to alter the number of residential customers, the adjustment relating to real per capita income is not immediate. The number of customers will change gradually over time as a result of a change in real per capita income. This adjustment process is modeled using a lag structure.

Residential Use per Customer - The key ingredients that impact energy use per customer are per capita income, real electricity prices and the combined impact of numerous other determinants. These include the saturation of air conditioners, electric space heating, other appliances, the efficiency of those appliances, and weather.

(3) Energy usage per Customer =

f (Real Income per Capita * Efficient Appliance Stock,

Real Electricity Price * Efficient Appliance Stock,

Saturation of Electric Heating Customers,

Saturation of Customers with Central Air Conditioning,

Saturation of Window Air Conditioning Units, Efficiency of Space Conditioning Appliances,

Billed Cooling and Heating Degree Days).

The derivation of the efficient appliance stock variable and the forecast of appliance saturations are discussed in the data section.

Commercial Sector - Commercial electricity usage changes with the level of local commercial employment, real electricity price, and the impact of weather. The model is formulated as follows:

(4) Commercial Sales =

f (Commercial Employment,

Marginal Electric Price/Consumer Price Index,

Billed Cooling and Heating Degree Days).

Industrial Sector - Duke Energy Ohio produces industrial sales forecasts by NAICS classifications. Electricity use by industrial customers is primarily dependent upon the level of industrial production and the impacts of real electricity prices, electric price relative to alternate fuels, and weather. The general model of industrial sales is formulated as follows:

(5) Industrial Sales =

f (Industrial Production,

Real Electricity Price,

Electricity Price/Alternate Fuel Price,

Billed Cooling and Heating Degree Days).

Governmental Sector - The Company uses the term Other Public Authorities (OPA) to indicate those customers involved and/or affiliated with federal, state or local government. Two categories comprise the electricity sales in the Other Public Authority (OPA) sector: sales to OPA water pumping customers and sales to OPA non-water pumping customers.

In the case of OPA water pumping, electricity sales are related to the number of residential electricity customers, real price of electricity demand, precipitation levels, and heating and cooling degree days. That is:

(6) Water Pumping Sales =

f (Residential Electricity Customers,

Real Electricity Demand Price,

Precipitation,

Cooling Degree Days).

Electricity sales to the non-water pumping component of Other Public Authority is related to governmental employment, the real price of electricity, the real price of natural gas, and heating and cooling degree days. This relationship can be represented as follows:

(7) Non-Water Pumping Sales =

f (Governmental Employment,

Marginal Electric Energy Price/Natural Gas Price, Billed Cooling and Heating Degree Days).

The total OPA electricity sales forecast is the sum of the individual forecasts of sales to water pumping and non-water pumping customers.

Street Lighting Sector - For the street lighting sector, electricity usage varies with the number of street lights and the efficiency of the lighting fixtures used. The number of street lights is associated with the population of the service area. The efficiency of the street lights is related to the saturation of mercury and sodium vapor lights. That is:

(8) Street Lighting Sales =

f (Population,

Saturation of Mercury Vapor Lights,

Saturation of Sodium Vapor Lights).

Total Electric Sales - Once these separate components have been projected - Residential sales, Commercial sales, Industrial sales, Other Public Authority sales, and Street Lighting sales - they can be summed along with Inter-department sales to produce the projection of total electric sales.

Total System Sendout - Upon completion of the total electric sales forecast, the forecast of total energy can be prepared. This requires that all the individual sector forecasts be combined along with forecasts of Company use, and system losses. After the system sendout forecast is completed, the peak load forecast can be prepared.

Peak Load - Forecasts of summer and winter peak demands are developed using econometric models.

The peak forecasting model is designed to closely represent the relationship of weather to peak loads. Only days when the temperature equaled or exceeded 90 degrees are included in the summer peak model. For the winter, only those days with a temperature at or below 10 degrees are included in the winter peak model.

Summer Peak - Summer peak loads are influenced by the current level of economic activity and the weather conditions. The primary weather factors are temperature and humidity; however, not only are the temperature and humidity at the time of the peak important, but also the morning low temperature, and high temperature from the day before. These other temperature variables are important to capture effect of thermal buildup.

The summer equation can be specified as follows:

(9) Peak = f (Weather Normalized Sendout, Weather Factors).

Winter Peak - Winter peak loads are also influenced by the current level of economic activity and the weather conditions. The selection of winter weather factors depends upon whether the peak occurs in the morning or evening. For a morning peak, the primary weather factors are morning low temperature, wind speed, and the prior evening's low temperature. For an evening peak, the primary weather factors are the evening low temperature, wind speed, and the morning low temperature.

The winter equation is specified in a similar fashion as the summer:

(10) Peak = f (Weather Normalized Sendout, Weather Factors).

The summer and winter peak equations are estimated separately for the respective seasonal periods. Peak load forecasts are produced under specific assumptions regarding the type of weather conditions typically expected to cause a peak.

Weather-Normalized Sendout - The level of peak demand is related to economic activity. The best indicator of the combined influences of economic variables on peak demand is the level of base load demand exclusive of aberrations caused by non-normal weather. Thus, the first step in developing the peak equations is to weather normalize historical monthly sendout.

The procedure used to develop historical weather normalized sendout data involves two steps. First, instead of weather normalizing sendout in the aggregate, each component is weather normalized. In other words, residential, commercial, industrial, and other public authority, are individually adjusted for the difference between actual and normal weather. Street lighting sales are not weather normalized because they are not weather sensitive. Using the equations previously discussed, the adjustment process is performed as follows:

Let: $KWH(N) = f(W(N))g(E)$

$KWH(A) = f(W(A))g(E)$

Where: KWH(N) = electric sales - normalized

W(N) = weather variables - normal

E = economic variables

KWH(A) = electric sales - actual

W(A) = weather variables - actual

Then: $KWH(N) = KWH(A) * f(W(N))g(E)/f(W(A))g(E)$

$=KWH(A) * f(W(N))/f(W(A))$

With this process, weather normalized sales are computed by scaling actual sales for each class by a factor from the forecast equation that accounts for the impact of deviation from normal weather. Industrial sales are weather normalized using a factor from an aggregate industrial equation developed for that purpose.

Second, weather normalized sendout is computed by summing the weather normalized sales with non-weather sensitive sector sales. This weather adjusted sendout is then used as a variable in the summer and winter peak equations.

Peak Forecast Procedure - *The summer peak usually occurs in July or August in the* afternoon and the winter peak occurs the following January in the morning or evening. Since the energy model produces forecasts under the assumption of normal weather, the forecast of sendout is "weather normalized" by design. Thus, the forecast of sendout drives the forecast of the peaks. In the forecast, the weather variables are set to values determined to be normal peak-producing conditions. These values are derived using historical data on the worst weather conditions in each year (summer and winter).

National Economy

It is generally assumed that the Duke Energy Ohio service area economy will tend to react much like the national economy over the forecast period. Duke Energy Ohio uses a long-term forecast of the national and service area economy prepared by Moody's Analytics.

No major wars or energy embargoes are assumed to occur during the forecast period. Even if minor conflicts and/or energy supply disruptions, such as those caused by hurricanes, occur during the forecast period, the long-range path of the overall forecast would not be dramatically altered.

A major risk to the national and regional economic forecasts and hence the electric load forecast is the continued economic growth in the U.S. economy. While the national and local economies have been experiencing the effects of a decline in economic activity since the fourth quarter of 2007, there are strong signs that the economy is recovering. The ultimate outcome in the near term is dependent upon the success of the economy moving forward out of this slow period as well as managing recent increases in energy prices.

With extensive economic diversity, the Cincinnati area economy, including Northern Kentucky, is well structured to withstand an economic slowdown and make the adjustments necessary for growth. In the manufacturing sector, its major industries are food products, paper, printing, chemicals, steel, fabricated metals, machinery, and automotive and aircraft transportation equipment. In the non-manufacturing sector, its major industries are life insurance and finance. In addition, the Cincinnati area is the headquarters for major international and national market-oriented retailing establishments.

Local Economy

Forecasts of employment, local population, industrial production, and inflation are key indicators of economic and demographic trends for the Duke Energy Ohio service area. The majority of the employment growth over the forecast period occurs in the non-manufacturing sector. This reflects a continuation of the trend toward the service industries and the fundamental change that is occurring in manufacturing and other basic industries. The rate of growth in local employment expected over the forecast will be below the national level: 0.7 percent locally versus 1.3 percent nationally (2011-2021).

Duke Energy Ohio is also affected by national population trends. The average age of the U.S. population is rising. The primary reasons for this phenomenon are stagnant birth rates and lengthening life expectancies. As a result, the portion of the population of the Duke Energy Ohio service area that is "age 65 and older" increases over the forecast period. Over the period 2011 to 2021, Duke Energy Ohio's population is expected to increase at an annual average rate of 0.6 percent. Nationally, population is expected to grow at an annual rate of 1.0 percent over the same period.

For the forecast period, local industrial production is expected to increase at a 2.0 percent annual rate, while 1.4 percent is the expected growth rate for the nation.

The residential sector is the largest in terms of total existing customers and total new customers per year. Within the Duke Energy Ohio service area, many commercial customers serve local markets. Therefore, there is a close relationship between the growth in local residential customers and the growth in commercial customers. The number of new industrial customers added per year is relatively small.

3. Specific

Commercial Fuels - Natural gas and oil prices are expected to increase over the forecast period. The projected annual growth rate 2011 to 2021, in nominal terms, is 1.6 percent for the price of electricity, 7.3 percent for the price of natural gas and 2.1 percent for the price of oil (residual fuel oils.)

Regarding availability of the conventional fuels, nothing on the horizon indicates any severe limitations in their supply, although world reserves of natural gas and oil are believed to be dwindling. There are unknown potential impacts from future changes in legislation or a change in the pricing or supply policy of oil producing countries that might affect fuel supply. However, these cannot be quantified within the forecast. The only non-utility information source relied upon is Moody's Analytics.

<u>Year End Residential Customers</u> - In the following table, historical and projected total year-end residential customers for the entire Ohio service area are provided.

NUMBER OF YEAR-END RESIDENTIAL CUSTOMERS

2006	610,648
2007	612,766
2008	610,603
2009	610,482
2010	611,494
2011	610,113
2012	614,624
2013	619,122
2014	624,127
2015	629,155
2016	633, 770
2017	638,234
2018	642,604
2019	646, 947
2020	651,337

2021	655,814

Appliance Efficiencies - Trends in appliance efficiencies, saturations, and usage patterns have an impact on the projected use per residential customer. Overall, the forecast incorporates a projection of increasing saturation for many appliances including heat pumps, air conditioners, electric space heating equipment, electric water heaters, electric clothes dryers, dish washers, and freezers. In addition, the forecast embodies trends of increasing appliance efficiency, including lighting, consistent with standards established by the federal government.

D. FORECAST DOCUMENTATION

In the following sections, information on forecast related databases is provided for Duke Energy Ohio.

The first step in the forecasting process is the collection of relevant information and data. The database discussion is broken into three parts:

a) Economic Data,

b) Energy and Peak Data, and

c) Forecast Data.

1.Economic Data

The major groups of data in the economic forecast are employment, demographics, income, production, inflation and prices. National and local values for these concepts are available from Moody's Analytics and company data.

Employment - Employment numbers are required on both a national and service area basis. Quarterly national and local employment series by industry are obtained from Moody's Analytics. Employment series are available for manufacturing and non-manufacturing sectors.

Population - National and local values for total population and population by age-cohort groups are obtained from Moody's Analytics.

Income - Local income data series are obtained from Moody's Analytics. The data is available on a county level and summed to a service area level. This includes data for personal income; dividends, interest, and rent; transfer payments; wage and salary disbursements plus other labor income; personal contributions for social insurance; and non-farm proprietors' income.

Consumer Price Index - The local CPI is equivalent to the national CPI obtained from Moody's Analytics.

Electricity and Natural Gas Prices - The average price of electricity and natural gas is available from Company financial reports. Data on marginal electricity price (including fuel cost) is collected for each customer class. This information is obtained from Company records and rate schedules.

2. Energy and Peak Models

The majority of data required to develop the electricity sales and peak forecasts is obtained from the Duke Energy Ohio service area economic data provided by Moody's Analytics, from Duke Energy Ohio financial reports and research groups, and from national sources. With regard to the national sources of information, generally all national information is obtained from Moody's Analytics. However, local weather data are obtained from the National Oceanic and Atmospheric Administration (NOAA).

The major groups of data that are used in developing the energy forecasts are: kilowatt-hour sales by customer class, number of customers, use-per-customer, electricity prices, natural gas prices, appliance saturations, and local weather data. The following are descriptions of the adjustments performed on various groups of data to develop the final data series actually used in regression analysis.

Kilowatt hour Sales and Revenue - Duke Energy Ohio collects sales and revenue data monthly by rate class. For forecast purposes this information is aggregated into the following categories: residential, commercial, industrial, OPA, and the other sales categories. In the industrial sector, sales and revenue for each manufacturing NAICS are collected. From the sales and revenue information, average electricity prices by sector can be calculated.

The other public authorities (OPA) sales category is analyzed in two parts: water pumping and OPA less water-pumping sales.

Number of Customers - The number of customers by class is obtained on a monthly basis from Company records.

Use Per Customer - Average use per customer is computed on a monthly basis by dividing residential sales by total customers.

Local Weather Data - Local climatologic data are provided by NOAA for the Cincinnati/Covington airport reporting station. Cooling degree days and heating degree days are calculated on a monthly basis using temperature data. The degree day series are required on a billing cycle basis for use in regression analysis.

Appliance Stock - To account for the impact of appliance saturations and federal efficiency standards, an appliance stock variable is created. This variable is composed of three parts: appliance efficiencies, appliance saturations, and appliance energy consumption values.

The appliance stock variable is calculated as follows:

(11) Appliance Stock_t=

$$\text{SUM}\ (K_i * SAT_{i,t} * EFF_{i,t})\ \text{for all } i$$

Where: t = time period

i = end-use appliance

K_i = fixed energy consumption value for appliance i,

$SAT_{i,t}$ = saturation of appliance i in period t, and

$EFF_{i,t}$ = efficiency of appliance i in period t.

The appliances included in the calculation of the Appliance Stock variable are: electric range, frost-free refrigerator, manual-defrost refrigerator, food freezer, dish washer, clothes washer, clothes dryer, water heater, microwave, color television, black and white television, room air conditioner, central air conditioner, electric resistance heat, electric heat pump, and miscellaneous uses including lighting.

Appliance Saturation and Efficiency - In general, information on historical appliance saturations for all appliances is obtained from Company Appliance Saturation Surveys.

Data on historical appliance efficiency are obtained from Itron, Inc., a forecast consulting firm.

The forecast of appliance saturations and efficiencies is also obtained from data provided by Itron, Inc. They have developed Regional Statistically Adjusted End-use (SAE) Models, an end-use approach to electric forecasting that provides forward looking levels of appliance saturations and efficiencies.

Peak Weather Data - The weather conditions associated with the monthly peak load are collected from the hourly and daily data recorded by NOAA. The weather variables which influence the summer peak are maximum temperature on the peak day and the day before, morning low temperature, and humidity on the peak day. The weather influence on the winter peak is measured by the low temperatures and the associated wind speed. The variables selected are dependent upon whether it is a morning or evening winter peak load.

An average of extreme weather conditions is used as the basis for the weather component in the preparation of the peak load forecast. Using historical data for the single worst summer weather occurrence and the single worst winter weather occurrence in each year, an average extreme weather condition can be computed.

3. Forecast Data

Projections of exogenous variables in Duke Energy Ohio's models are required in the following areas: national and local employment, income, industrial production, and population, as well as natural gas and electricity prices.

Employment -The forecast of employment by industry is provided by Moody's Analytics.

Income -The forecast of income is provided by Moody's Analytics.

Industrial Production - The forecast of industrial production is also provided by Moody's Analytics.

Population - Duke Energy Ohio's population forecast is derived from data provided by Moody's Analytics. Population projections for the service area are prepared by first collecting county-level population forecasts for the counties in the Company's service area and then summing.

Prices - The projected change in electricity and natural gas prices over the forecast interval is provided by the Company's Financial Planning and Analysis department and Moody's Analytics.

4. Load Research and Market Research Efforts

Duke Energy Ohio is committed to the continued development and maintenance of a substantive class load database of typical customer electricity consumption patterns and the collection of primary market research data on customers.

Load Research – Complete load profile information, or 100% sample data, is maintained on commercial and industrial customers whose average annual demand is greater than 500 kW, served at primary distribution voltage or served at transmission voltage. Additionally, the Company continues to collect whole premise or building level electricity consumption patterns on representative samples of the various customer classes and rate groups whose annual demands are less than 500 kW.

Periodically, the Company monitors selected end-uses or systems associated with energy efficiency evaluations performed in conjunction with energy efficiency programs. These studies are performed as necessary and tend to be of a shorter duration.

Market Research - Primary research projects continue to be conducted as part of the on-going efforts to gain knowledge about the Company's customers. These projects include customer satisfaction studies, appliance saturation studies, end-use studies, studies to track competition (to monitor customer switching percentages in order to forecast future utility load), and related types of marketing research projects.

E. MODELS

Specific analytical techniques have been employed for development of the forecast models.

1. Specific Analytical Techniques

Regression Analysis - Ordinary least squares is the principle regression technique employed to estimate economic/behavioral relationships among the relevant variables. This econometric technique provides a method to perform quantitative analysis of economic behavior.

Ordinary least-squares techniques were used to model electric sales. Based upon their relationship with the dependent variable, several independent variables were tested in the regression models. The final models were chosen based upon their statistical strength and logical consistency.

Logarithmic Transformations - The projection of economic relationships over time requires the use of techniques that can account for non-linear relationships. By transforming the dependent variable and independent variables into their "natural logarithm", a non-linear relationship can be transformed into a linear relationship for model estimation purposes.

Polynomial Distributed Lag Structure - One method of accounting for the lag between a change in one variable and its ultimate impact on another variable is through the use of polynomial distributed lags. This technique is also referred to as Almon lags. Polynomial Distributed Lag Structures derive their name from the fact that the lag weights follow a polynomial of specified degree. That is, the lag weights all lie on a line, parabola, or higher order polynomial as required.

This technique is employed in developing econometric models for most of the energy equations.

Serial Correlation - It is often the case in forecasting an economic time series that residual errors in one period are related to those in a previous period. This is known as serial correlation. By correcting for this serial correlation of the estimated residuals, forecast error is reduced and the estimated coefficients are more efficient. The Marquardt algorithm is employed to correct for the existence of autocorrelation.

Qualitative Variables - In several equations, qualitative variables are employed. In estimating an econometric relation using time series data, it is quite often the case that "outliers" are present in the historic data. These unusual shifts or deviations in the data can be the result of problems such as errors in the reporting of data by particular companies and agencies, labor-management disputes, severe energy shortages or restrictions, and other perturbations that do not repeat with predictability. Therefore, in order to identify the true underlying economic relationship between the dependent variable and the other independent variables, qualitative variables are employed to account for the impact of the outliers. The coefficient for the qualitative variable must be statistically significant, have a sign in the expected direction, and make an improvement to model fit statistics.

2. Relationships Between The Specific Techniques

The manner in which specific methodologies for forecasting components of the total load are related is explained in the discussion of specific analytical techniques above.

3. Alternative Methodologies

The Company continues to use the current forecasting methodology as it has for the past several years. The Company considers the forecasting methods currently utilized to be adequate.

4. Changes In Methodology

There were no significant changes to the forecast methodology. The Company uses the latest historical data available and relies on recent economic data and forecasts from Moody's Analytics.

5. Equations

Following is a display of all the relevant equations used in the forecast. Specifically, for each of the equations in the Electric Energy Forecast Model and Electric Peak Load Model the following information is included:

Equation Estimation Results - The results of the estimation of each of the stochastic equations in the models is provided. Included are the estimated coefficients and the results of appropriate statistical tests. Those equations which required a correction for serial correlation are so indicated.

The computer output for each variable lists the estimated coefficient, standard error, and the t statistic. Lagged variables are denoted with the \-N symbol, "N" being the number of periods lagged.

The use of Polynomial Distributed Lags (PDL) is indicated by the expression:

PDL followed by a number signifying the PDL variable number. The PDL is defined using the degree of the polynomial, the length of lag, and the restrictions. The restrictions may constrain the PDL such that the end values of the distributed lag are close to zero. The computer output for each PDL variable lists the estimated lag weights and their associated standard errors. There is also a plot of the distributed lag. In addition to the individual lag weights, statistics are presented on the sum and average of the lag weights.

Mnemonic Definition - Following the equation estimation results is a definition list of the mnemonics for each variable used in the equation.

Forecast Error - Following the equation mnemonics definition is the forecast error as measured by the mean of the forecast standard errors over the forecast period.

EQUATIONS USED IN FORECAST

Service Area Electric Customers – Residential

Dependent Variable: LOG(CUSRES_OH_KY)
Method: Least Squares
Date: 02/22/11 Time: 12:53
Sample: 1989M10 2010M12
Included observations: 255
Convergence achieved after 7 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
@MONTH=1	14.77528	3.476269	4.250328	0.0000
@MONTH=2	14.77606	3.476271	4.250548	0.0000
@MONTH=3	14.77619	3.476272	4.250585	0.0000
@MONTH=4	14.77461	3.476271	4.250132	0.0000
@MONTH=5	14.77171	3.476268	4.249301	0.0000
@MONTH=7	14.76918	3.476263	4.248581	0.0000
@MONTH=8	14.76796	3.476261	4.248232	0.0000
@MONTH=9	14.76739	3.476259	4.248070	0.0000
@MONTH=10	14.76912	3.476263	4.248561	0.0000
(@MONTH=6)+(@MONTH=11)	14.77052	3.476265	4.248962	0.0000
@MONTH=12	14.77363	3.476264	4.249857	0.0000
@ISPERIOD("1994M05")	-0.005035	0.001281	-3.932009	0.0001
@ISPERIOD("2001m02")	0.028551	0.001652	17.28378	0.0000
@ISPERIOD("2001m03")	0.008740	0.002084	4.193195	0.0000
@ISPERIOD("2001m04")	0.007463	0.002210	3.377294	0.0009
@ISPERIOD("2001m05")	0.028774	0.002081	13.82542	0.0000
@ISPERIOD("2001m06")	0.015467	0.001637	9.451164	0.0000
@ISPERIOD("2003m12")	-0.004948	0.001474	-3.357548	0.0009
@ISPERIOD("2004m01")	0.003394	0.001476	2.298880	0.0224
@ISPERIOD("2005m02")	-0.003342	0.001281	-2.609005	0.0097
@ISPERIOD("2006m02")	-0.002619	0.001281	-2.044769	0.0420
@ISPERIOD("2007m04")	-0.002782	0.001279	-2.174691	0.0307
@ISPERIOD("2009m05")	-0.005493	0.001281	-4.287902	0.0000
PDL01	0.006679	0.003382	1.974954	0.0495
AR(1)	0.999353	0.002004	498.7187	0.0000

R-squared	0.999392	Mean dependent var	13.42009
Adjusted R-squared	0.999329	S.D. dependent var	0.067997
S.E. of regression	0.001761	Akaike info criterion	-9.752425
Sum squared resid	0.000714	Schwarz criterion	-9.405242
Log likelihood	1268.434	Hannan-Quinn criter.	-9.612773
Durbin-Watson stat	1.993809		

Inverted AR Roots 1.00

Lag Distribution of LOG(YP_OH_KY/N_OH_KY/CPI)	i	Coefficient	Std. Error	t-Statistic
. * |	0	0.00607	0.00307	1.97495
. * |	1	0.01093	0.00553	1.97495
. * |	2	0.01457	0.00738	1.97495
. * |	3	0.01700	0.00861	1.97495
. *|	4	0.01822	0.00922	1.97495
. *|	5	0.01822	0.00922	1.97495
. * |	6	0.01700	0.00861	1.97495
. * |	7	0.01457	0.00738	1.97495
. * |	8	0.01093	0.00553	1.97495
. * |	9	0.00607	0.00307	1.97495
	Sum of Lags	0.13358	0.06764	1.97495

KWH USE PER CUSTOMER – RESIDENTIAL

Dependent Variable: LOG(KWHRES_OH_KY/CUSRES_OH_KY)
Method: Least Squares
Date: 02/22/11 Time: 17:22
Sample: 1998M01 2010M12
Included observations. 156
Convergence achieved after 11 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-0.514845	1.115202	-0.461661	0.6451
LOG(APPLSTK_EFF_OH_KY*(YP_OH_KY/N_OH_KY/CPI))	0.917152	0.143311	6.399716	0.0000
(D_DJF)*(SAT_EH_EFF)*HDDB_OH_KY_59_0_500	0.003158	0.000126	25.03541	0.0000
(1-D_DJF)*(SAT_EH_EFF)*HDDB_OH_KY_59_0_500	0.002783	0.000149	18.67755	0.0000
(D_DJF)*(SAT_EH_EFF)*HDDB_OH_KY_59_500	0.002237	9.63E-05	23.23251	0.0000
(1-D_DJF)*(SAT_EH_EFF)*HDDB_OH_KY_59_500	0.003034	0.000238	12.73487	0.0000
(D_JJA)*(SAT_CAC_EFF)*CDDB_OH_KY_65_0_100	0.005602	0.000449	12.47811	0.0000
(1-D_JJA)*(SAT_CAC_EFF)*CDDB_OH_KY_65_0_100	0.007240	0.000359	20.14954	0.0000
(D_JJA)*(SAT_CAC_EFF)*CDDB_OH_KY_65_100	0.001446	0.000319	4.532283	0.0000
(1-D_JJA)*(SAT_CAC_EFF)*CDDB_OH_KY_65_100	0.001417	0.000404	3.506665	0.0006
(D_JJA+(@MONTH=5)+(@MONTH=9))*(SAT_RAC_EFF)*CDDB_OH_KY_65	0.003962	0.000411	9.636836	0.0000
@MONTH=1	0.103920	0.006545	15.87673	0.0000
@MONTH=5	-0.047385	0.009273	-5.110109	0.0000
@MONTH=7	0.076130	0.010368	7.342619	0.0000
@MONTH=8	0.061891	0.012905	4.795728	0.0000
@MONTH=12	0.061894	0.008190	7.557223	0.0000
@ISPERIOD("2001m04")	-0.048687	0.020563	-2.367680	0.0194
@ISPERIOD("2001m05")	-0.098768	0.021593	-4.574078	0.0000
@ISPERIOD("2002m05")+@ISPERIOD("2004m05")	-0.043707	0.014726	-2.967941	0.0036
@ISPERIOD("2005m01")	0.080274	0.018672	4.299069	0.0000
@ISPERIOD("2007m05")	-0.082077	0.019906	-4.123167	0.0001
@ISPERIOD("2007m10")	0.082826	0.020268	4.086511	0.0001
@ISPERIOD("2008m10")	-0.062908	0.019367	-3.248155	0.0015
@ISPERIOD("2010m10")	-0.044210	0.019111	-2.313270	0.0223
@ISPERIOD("2004m06")	0.052896	0.019490	2.713963	0.0076
@ISPERIOD("2010m05")	-0.068642	0.019277	-3.560903	0.0005
PDL01	-0.039970	0.022929	-1.743183	0.0837
AR(1)	0.524912	0.077534	6.770093	0.0000

R-squared	0.992259	Mean dependent var	6.887594
Adjusted R-squared	0.990626	S.D. dependent var	0.206988
S.E. of regression	0.020040	*Akaike info criterion*	-4.821019
Sum squared resid	0.051405	Schwarz criterion	-4.273609
Log likelihood	404.0395	Hannan-Quinn criter.	-4.598685
F-statistic	607.6934	Durbin-Watson stat	1.843885
Prob(F-statistic)	0.000000		

Inverted AR Roots	.52

Lag Distribution of LOG(APPLSTK_EFF_OH_KY*(MP_RES_OH_KY/CPI))	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.03997	0.02293	-1.74318
* . |	1	-0.01998	0.01146	-1.74318
Sum of Lags		-0.05995	0.03439	-1.74318

KWH SALES – COMMERCIAL

Dependent Variable: LOG(KWHCOM_OH_KY)
Method: Least Squares
Date: 03/04/11 Time: 16:41
Sample: 1986M01 2010M12
Included observations: 300
Convergence achieved after 12 iterations
MA Backcast: 1985M12

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	10.03173	0.597318	16.79462	0.0000
LOG(ECOM_OH_KY)	1.472330	0.094699	15.54747	0.0000
LOG(DS_KWH_COM_OH_KY(-1)/CPI(-1))	-0.048246	0.023053	-2.092865	0.0373
(@MONTH=11)*HDDB_OH_KY_59	6.88E-05	2.64E-05	2.602332	0.0098
(@MONTH=12)*HDDB_OH_KY_59	0.000188	1.18E-05	15.85891	0.0000
(@MONTH=1)*HDDB_OH_KY_59	0.000192	8.38E-06	22.94841	0.0000
(@MONTH=2)*HDDB_OH_KY_59	0.000127	8.89E-06	14.34678	0.0000
(@MONTH=3)*HDDB_OH_KY_59	0.000108	1.09E-05	9.897655	0.0000
(@MONTH=4)*HDDB_OH_KY_59	8.00E-05	1.93E-05	4.146326	0.0000
(@MONTH=5)*CDDB_OH_KY_65	0.000975	0.000152	6.425203	0.0000
(@MONTH=6)*CDDB_OH_KY_65_0_100	0.001323	7.92E-05	16.69725	0.0000
(@MONTH=6)*CDDB_OH_KY_65_100	0.000716	7.60E-05	9.425939	0.0000
(@MONTH=7)*CDDB_OH_KY_65_0_100	0.001814	0.000153	11.82619	0.0000
(@MONTH=7)*CDDB_OH_KY_65_100	0.000467	7.42E-05	6.292792	0.0000
(@MONTH=8)*CDDB_OH_KY_65_0_100	0.001382	0.000130	10.64329	0.0000
(@MONTH=8)*CDDB_OH_KY_65_100	0.000617	4.98E-05	12.39518	0.0000
(@MONTH=9)*CDDB_OH_KY_65_0_100	0.001748	0.000106	16.44290	0.0000
(@MONTH=9)*CDDB_OH_KY_65_100	0.000457	5.68E-05	8.045500	0.0000
(@MONTH=10)*CDDB_OH_KY_65	0.000703	8.58E-05	8.195241	0.0000
@MONTH=10	0.027646	0.009710	2.847026	0.0048
@ISPERIOD("1991m04")	0.097466	0.016830	5.791198	0.0000
@ISPERIOD("1991m11")	0.058418	0.017119	3.412397	0.0007
@ISPERIOD("1993m09")	-0.120572	0.017595	-6.852518	0.0000
@ISPERIOD("1993m10")+@ISPERIOD("2004m12")+@ISPERIOD("2007m04")	0.044787	0.010405	4.304534	0.0000
@ISPERIOD("1995m04")	0.054237	0.018635	2.910520	0.0039
@ISPERIOD("1995M05")	-0.086021	0.018781	-4.580158	0.0000
@ISPERIOD("1998m05")	0.063831	0.016709	3.820089	0.0002
@ISPERIOD("1998m07")	0.053064	0.016868	3.145907	0.0018
@ISPERIOD("2000m01")+@ISPERIOD("2000m07")	-0.060989	0.012729	-4.791479	0.0000
@ISPERIOD("2000m08")	0.043076	0.018058	2.385449	0.0178
@ISPERIOD("2000m10")	0.086526	0.016861	5.131709	0.0000
@ISPERIOD("1993m11")+@ISPERIOD("2002m08")+@ISPERIOD("2004m11")+@ISPERIOD("2004m03") +@ISPERIOD("2005m02")+@ISPERIOD("2005m08")	-0.050026	0.007274	-6.877750	0.0000
@ISPERIOD("2002m04")	0.055491	0.016838	3.295599	0.0011
@ISPERIOD("2005m03")+@ISPERIOD("1999m02")	-0.028477	0.011880	-2.397000	0.0172
@ISPERIOD("2010m02")	-0.092050	0.017152	-5.366674	0.0000
AR(2)	0.797924	0.049527	16.11088	0.0000
MA(1)	0.829177	0.045827	18.09353	0.0000

R-squared	0.991621	Mean dependent var	20.05652
Adjusted R-squared	0.990474	S.D. dependent var	0.219772
S.E. of regression	0.021450	Akaike info criterion	-4.731100
Sum squared resid	0.121012	Schwarz criterion	-4.274300
Log likelihood	746.6650	Hannan-Quinn criter.	-4.548288
F-statistic	864.5352	Durbin-Watson stat	2.213320
Prob(F-statistic)	0.000000		

Inverted AR Roots	.89	-.89
Inverted MA Roots	-.83	

MWH SALES – INDUSTRIAL – FOOD, BEVERAGE AND TOBACCO

Dependent Variable: LOG(MWHN311_312_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 12:58
Sample: 1980Q1 2010Q4
Included observations: 124
Convergence achieved after 14 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	10.50195	0.424660	24.73025	0.0000
LOG(JQINDN311_312_OH_KY(-3))	0.349835	0.194308	1.800411	0.0745
LOG(DS_KWH_IND_OH_KY/CPI)	-0.114501	0.048419	-2.364800	0.0198
CDDB_OH_KY_65	0.000165	1.31E-05	12.64796	0.0000
HDDB_OH_KY_59	-3.05E-05	5.27E-06	-5.777112	0.0000
D_1965Q1_1990Q4	-0.295112	0.046512	-6.344824	0.0000
@ISPERIOD("1991q1")+@ISPERIOD("2000q3")	-0.152495	0.031910	-4.778932	0.0000
@ISPERIOD("2007q4")	0.141740	0.042345	3.347297	0.0011
@ISPERIOD("2008q4")+@ISPERIOD("2009q1")	0.149228	0.043009	3.469609	0.0007
D_1976Q1_1989Q2+D_1987Q1_1991Q3	-0.086445	0.027814	-3.107943	0.0024
@ISPERIOD("1993q2")	-0.108494	0.042446	-2.556059	0.0120
@ISPERIOD("1992q2")	-0.162981	0.042087	-3.872467	0.0002
D_1980Q1_2005Q2	-0.076237	0.032984	-2.311303	0.0227
AR(1)	0.719013	0.074756	9.618118	0.0000

R-squared	0.970883	Mean dependent var	11.31940
Adjusted R-squared	0.967441	S.D. dependent var	0.285979
S.E. of regression	0.051602	Akaike info criterion	-2.984504
Sum squared resid	0.292905	Schwarz criterion	-2.666085
Log likelihood	199.0393	Hannan-Quinn criter.	-2.855155
F-statistic	282.1387	Durbin-Watson stat	2.010146
Prob(F-statistic)	0.000000		

Inverted AR Roots	.72

MWH SALES – INDUSTRIAL – PAPER, PLASTIC AND RUBBER

Dependent Variable: LOG(MWHN322_326_OH_KY)
Method: Least Squares
Date: 02/22/11 Time: 08:40
Sample: 1979Q1 2010Q4
Included observations: 128
Convergence achieved after 13 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LOG(JQINDN322_326_OH_KY)	0.309810	0.168334	1.840453	0.0683
@ISPERIOD("1992q1")+@ISPERIOD("1993q1")	0.051513	0.016989	3.032060	0.0030
@ISPERIOD("2001q2")	-0.203553	0.024566	-8.285811	0.0000
@ISPERIOD("2003q4")+@ISPERIOD("1996q3")	-0.088605	0.016437	-5.390512	0.0000
@ISPERIOD("2005q1")	0.124963	0.023737	5.264399	0.0000
HDDB_OH_KY_59*D_1999Q1_2001Q2	-2.15E-05	8.14E-06	-2.639061	0.0095
@ISPERIOD("2000q3")	0.093176	0.023828	3.910416	0.0002
@ISPERIOD("1990q2")+@ISPERIOD("2010q2")	-0.053079	0.016964	-3.128934	0.0022
@QUARTER=1	9.894756	0.852062	11.61272	0.0000
@QUARTER=2	9.945191	0.852586	11.66474	0.0000
@QUARTER=3	9.961354	0.852341	11.68705	0.0000
@QUARTER=4	9.930137	0.852097	11.65377	0.0000
PDL01	-0.061645	0.029480	-2.091070	0.0388
PDL02	-0.024528	0.013997	-1.752412	0.0824
AR(1)	1.083638	0.097795	11.08066	0.0000
AR(2)	-0.165519	0.096048	-1.723287	0.0876

R-squared	0.957649	Mean dependent var	11.97044
Adjusted R-squared	0.951977	S.D. dependent var	0.156135
S.E. of regression	0.034216	Akaike info criterion	-3.795786
Sum squared resid	0.131121	Schwarz criterion	-3.439282
Log likelihood	258.9303	Hannan-Quinn criter.	-3.650937
Durbin-Watson stat	1.994581		

Inverted AR Roots	.90	.18

Lag Distribution of LOG(DS_KW_IND_OH_KY/CPI)	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.08219	0.03931	-2.09107
* . |	1	-0.06165	0.02948	-2.09107
* . |	2	-0.04110	0.01965	-2.09107
* . |	3	-0.02055	0.00983	-2.09107
	Sum of Lags	-0.20548	0.09827	-2.09107

Lag Distribution of LOG(DS_KWH_IND_OH_KY/CPI)	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.04292	0.02449	-1.75241
* . |	1	-0.03679	0.02099	-1.75241
* . |	2	-0.03066	0.01750	-1.75241
* . |	3	-0.02453	0.01400	-1.75241
* . |	4	-0.01840	0.01050	-1.75241
* . |	5	-0.01226	0.00700	-1.75241
* . |	6	-0.00613	0.00350	-1.75241
	Sum of Lags	-0.17169	0.09798	-1.75241

MWH SALES – INDUSTRIAL – CHEMICALS

Dependent Variable: LOG(MWHN325_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 13:04
Sample: 1978Q1 2010Q4
Included observations: 132
Convergence achieved after 20 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	10.28476	0.792054	12.98493	0.0000
LOG(JQINDN325_OH_KY)	0.486093	0.124505	3.904195	0.0002
CDDB_OH_KY_65	9.97E-05	8.17E-06	12.19917	0.0000
@ISPERIOD("1994q1")	-0.077933	0.036333	-2.144959	0.0339
@ISPERIOD("2003q4")	0.091963	0.037040	2.482807	0.0144
@ISPERIOD("2000q4")	0.080947	0.037184	2.176911	0.0314
@ISPERIOD("2009q2")	-0.131512	0.038205	-3.442319	0.0008
PDL01	-0.043777	0.017428	-2.511874	0.0133
AR(1)	0.569665	0.094034	6.058096	0.0000
AR(2)	0.352997	0.096003	3.676941	0.0004

R-squared	0.964301	Mean dependent var	12.33676
Adjusted R-squared	0.961668	S.D. dependent var	0.220981
S.E. of regression	0.043265	Akaike info criterion	-3.370200
Sum squared resid	0.228369	Schwarz criterion	-3.151806
Log likelihood	232.4332	Hannan-Quinn criter.	-3.281455
F-statistic	366.1631	Durbin-Watson stat	1.953791
Prob(F-statistic)	0.000000		

Inverted AR Roots	.94	-.37

Lag Distribution of LOG(TS_KWH_IND_OH_KY/CPI)	i	Coefficient	Std. Error	t-Statistic
* |	0	-0.06567	0.02614	-2.51187
* |	1	-0.05472	0.02179	-2.51187
* .|	2	-0.04378	0.01743	-2.51187
* .|	3	-0.03283	0.01307	-2.51187
* .|	4	-0.02189	0.00871	-2.51187
* .|	5	-0.01094	0.00436	-2.51187
	Sum of Lags	-0.22983	0.09150	-2.51187

MWH SALES – INDUSTRIAL – PRIMARY METALS – BUTLER

Dependent Variable: LOG(MWHN331_BUTLER-BASE)
Method: Least Squares
Date: 02/18/11 Time: 13:05
Sample: 1985Q1 2010Q4
Included observations: 104
Convergence achieved after 11 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	11.54289	0.475030	24.29927	0.0000
(1-D_1965Q1_1985Q4)*LOG(TS_KWH_IND_OH_KY/CPI)	-0.008049	0.004027	-1.999083	0.0487
LOG(TS_KWH_IND_OH_KY(-5)/APGIND_OH_KY(-5))	-0.070697	0.023743	-2.977573	0.0038
@ISPERIOD("2009q2")	-0.380330	0.035585	-10.68799	0.0000
@ISPERIOD("2009q1")	-0.185576	0.034136	-5.436410	0.0000
D_1965Q1_1995Q4	-0.151179	0.033208	-4.552514	0.0000
@ISPERIOD("1998q3")	-0.118403	0.028031	-4.224004	0.0001
@ISPERIOD("1990q2")	-0.083181	0.028377	-2.931266	0.0043
@ISPERIOD("2008q4")	-0.111339	0.032228	-3.454775	0.0009
@ISPERIOD("1991q3")	-0.094316	0.029815	-3.163375	0.0021
@ISPERIOD("1986q3")	-0.071409	0.028216	-2.530772	0.0132
@ISPERIOD("1991q4")	0.056292	0.029192	1.928352	0.0571
@ISPERIOD("2001q1")	-0.078628	0.028031	-2.805044	0.0062
PDL01	0.196650	0.045579	4.314501	0.0000
PDL02	-0.112835	0.064230	-1.756746	0.0825
AR(1)	0.607956	0.105443	5.765747	0.0000
AR(2)	0.361086	0.104754	3.446999	0.0009

R-squared	0.979879	Mean dependent var	12.61955
Adjusted R-squared	0.976178	S.D. dependent var	0.221847
S.E. of regression	0.034241	Akaike info criterion	-3.762375
Sum squared resid	0.102000	Schwarz criterion	-3.330118
Log likelihood	212.6435	Hannan-Quinn criter.	-3.587255
F-statistic	264.7997	Durbin-Watson stat	1.944391
Prob(F-statistic)	0.000000		

Inverted AR Roots	.98	-.37

Lag Distribution of LOG(JQINDN331_BUTLER)	i	Coefficient	Std. Error	t-Statistic
. * |	0	0.19665	0.04558	4.31450
. * |	1	0.09832	0.02279	4.31450
	Sum of Lags	0.29497	0.06837	4.31450

Lag Distribution of LOG(TS_KW_IND_OH_KY/CPI)	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.11284	0.06423	-1.75675
* . |	1	-0.05642	0.03211	-1.75675
	Sum of Lags	-0.16925	0.09634	-1.75675

MWH SALES – INDUSTRIAL – PRIMARY METALS – LESS BUTLER

Dependent Variable: LOG(MWHN331LBUTLER_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 13:07
Sample: 1987Q1 2010Q4
Included observations: 96
Convergence achieved after 9 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	7 245961	0.959964	7.548156	0.0000
@ISPERIOD("1999q1")	-0.402581	0.071569	-5.625043	0.0000
@ISPERIOD("1988q4")	-0 203375	0 071421	-2.847565	0.0055
@ISPERIOD("1996q3")+@ISPERIOD("1997q3")	-0 252081	0.050789	-4.963296	0.0000
D_1998Q3_2001Q2	0.774640	0 054284	14.27017	0.0000
D_1965Q1_1998Q2	1.097773	0.040415	27.16255	0.0000
@ISPERIOD("2002q2")	-0.326168	0.072427	-4.503412	0 0000
@ISPERIOD("2003q1")	-0.155829	0.072110	-2 160995	0.0335
PDL01	0.300736	0.073052	4.116739	0.0001
PDL02	-0.113535	0.031400	-3.615828	0.0005
AR(1)	0.611689	0.092466	6.615247	0.0000
AR(3)	-0.191377	0.079864	-2.396267	0.0186

R-squared	0.976734	Mean dependent var	11.09645
Adjusted R-squared	0 973687	S.D. dependent var	0 518957
S.E. of regression	0.084181	Akaike info criterion	-1.995227
Sum squared resid	0.595261	Schwarz criterion	-1.674683
Log likelihood	107.7709	Hannan-Quinn criter.	-1 865658
F-statistic	320.5839	Durbin-Watson stat	2.242857
Prob(F-statistic)	0 000000		

Inverted AR Roots	52- 42i	.52+.42i	-.43

Lag Distribution of LOG(JQINDN331_CMSA)	i	Coefficient	Std. Error	t-Statistic
* |	0	0.30074	0.07305	4.11674
* |	1	0.15037	0.03653	4.11674
	Sum of Lags	0.45110	0.10958	4.11674

Lag Distribution of LOG(TS_KWH_IND_OH_KY/CPI)	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.15138	0.04187	-3.61583
* . |	1	-0.11354	0.03140	-3.61583
* . |	2	-0.07569	0.02093	-3.61583
* . |	3	-0.03785	0.01047	-3.61583
	Sum of Lags	-0.37845	0.10467	-3.61583

MWH SALES – INDUSTRIAL – FABRICATED METALS

Dependent Variable: LOG(MWHN332_OH_KY)
Method: Least Squares
Date: 05/06/11 Time: 11:46
Sample: 1984Q1 2010Q4
Included observations: 108
Convergence achieved after 7 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	10.92849	0.180443	60.56472	0.0000
LOG(JQINDN332_OH_KY)	0.449144	0.149219	3.009954	0.0033
LOG(DS_KWH_IND_OH_KY/WPI0561)	-0.035225	0.014375	-2.450477	0.0160
D_2000Q3_2001Q2	0.184784	0.021119	8.749484	0.0000
@ISPERIOD("2009q1")+@ISPERIOD("2009q2")	-0.114032	0.022081	-5.164267	0.0000
CDDB_OH_KY_65	6.27E-05	5.86E-06	10.69503	0.0000
@ISPERIOD("2000q1")+@ISPERIOD("1988q3")	-0.042499	0.015110	-2.812634	0.0059
@ISPERIOD("1986q3")	-0.074790	0.021510	-3.476921	0.0008
@ISPERIOD("2001q1")	0.083925	0.021116	3.974499	0.0001
AR(1)	0.966756	0.032927	29.36071	0.0000

R-squared	0.940692	Mean dependent var	11.27337
Adjusted R-squared	*0.935245*	*S.D. dependent var*	*0.115249*
S.E. of regression	0.029328	Akaike info criterion	-4.132559
Sum squared resid	0.084290	Schwarz criterion	-3.884214
Log likelihood	233.1582	Hannan-Quinn criter.	-4.031864
F-statistic	172.7091	Durbin-Watson stat	2.009184
Prob(F-statistic)	0.000000		

Inverted AR Roots	.97

MWH SALES – INDUSTRIAL – MACHINERY

Dependent Variable: LOG(MWHN333_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 13:11
Sample: 1982Q4 2010Q4
Included observations: 113
Convergence achieved after 9 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LOG(JQINDN333_OH_KY)	0.503092	0.120403	4.178396	0.0001
LOG(DS_KW_IND_OH_KY(-8)/CPI(-8))	-0.322183	0.129203	-2.493630	0.0143
LOG(DS_KWH_IND_OH_KY/APGIND_OH_KY)	-0.047762	0.026667	-1.791068	0.0763
CDDB_OH_KY_65*(1-D_1965Q1_1986Q4)	8.27E-05	1.95E-05	4.246634	0.0000
@ISPERIOD("1998q4")	0.065967	0.030046	2.195512	0.0305
D_1965Q1_2001Q2	0.152257	0.038175	3.988430	0.0001
@ISPERIOD("2009q1")	-0.081080	0.030330	-2.673219	0.0088
@ISPERIOD("2000q2")	-0.281998	0.034988	-8.059888	0.0000
@ISPERIOD("2000q1")	-0.075197	0.034782	-2.161935	0.0330
@QUARTER=1	9.423331	0.466364	20.20596	0.0000
@QUARTER=2	9.414453	0.465468	20.22577	0.0000
@QUARTER=3	9.434672	0.462262	20.40980	0.0000
@QUARTER=4	9.414505	0.465407	20.22853	0.0000
AR(1)	0.890755	0.046713	19.06876	0.0000

R-squared	0.931419	Mean dependent var	10.82105
Adjusted R-squared	0.922414	S.D. dependent var	0.141517
S.E. of regression	0.039419	Akaike info criterion	-3.513634
Sum squared resid	0.153829	Schwarz criterion	-3.175728
Log likelihood	212.5203	Hannan-Quinn criter.	-3.376515
Durbin-Watson stat	1.869360		

Inverted AR Roots	.89

MWH SALES – INDUSTRIAL – COMPUTER AND ELECTRONICS

Dependent Variable: LOG(MWHN334_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 13.12
Sample: 1980Q1 2010Q4
Included observations: 124
Convergence achieved after 14 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	7.636820	0.785829	9.718169	0.0000
LOG(JQINDN334_OH_KY)	0.068654	0.023298	2.946718	0.0039
CDDB_OH_KY_65	0.000110	8.49E-06	12.96695	0.0000
@ISPERIOD("1986q3")	-0.075276	0.033735	-2.231351	0.0276
@ISPERIOD("1992q2")	-0.114736	0.033268	-3.448810	0.0008
@ISPERIOD("1988q4")	0.128977	0.033545	3.844941	0.0002
@ISPERIOD("2002q1")	-0.102444	0.033293	-3.077074	0.0026
@ISPERIOD("2010q2")	-0.176752	0.044545	-3.967914	0.0001
1-@ISPERIOD("2010q3")-@ISPERIOD("2010q4")	0.348847	0.059188	5.893851	0.0000
@ISPERIOD("2009Q1")	-0.110379	0.033326	-3.312139	0.0012
PDL01	-0.054523	0.015581	-3.499310	0.0007
AR(1)	0.835586	0.057735	14.47272	0.0000

R-squared	0.963975	Mean dependent var	10.76919
Adjusted R-squared	0.960437	S.D. dependent var	0.217775
S.E. of regression	0.043316	Akaike info criterion	-3.348802
Sum squared resid	0.210147	Schwarz criterion	-3.075871
Log likelihood	219.6257	Hannan-Quinn criter.	-3.237931
F-statistic	272.4499	Durbin-Watson stat	1.768787
Prob(F-statistic)	0.000000		

Inverted AR Roots	.84

Lag Distribution of LOG(DS_KWH_IND_OH_KY/CPI)	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.04544	0.01298	-3.49931
* . |	1	-0.07270	0.02077	-3.49931
* . |	2	-0.08178	0.02337	-3.49931
* . |	3	-0.07270	0.02077	-3.49931
* . |	4	-0.04544	0.01298	-3.49931
	Sum of Lags	-0.31805	0.09089	-3.49931

MWH SALES – INDUSTRIAL – ELEC. EQUIPMENT, APPLIANCE & COMPONENT

Dependent Variable: LOG(MWHN335_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 13:13
Sample: 1984Q1 2010Q4
Included observations: 108
Convergence achieved after 11 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LOG(DS_KWH_IND_OH_KY/WPI0561)	-0.045043	0.016224	-2.776292	0.0067
@ISPERIOD("1988q3")	-0.083343	0.020768	-4.013147	0.0001
@ISPERIOD("1998q3")	-0.066663	0.020910	-3.188013	0.0020
@ISPERIOD("2009q1")+@ISPERIOD("2009q2")	-0.235459	0.029168	-8.072589	0.0000
@ISPERIOD("2008q4")	-0.099709	0.026210	-3.804251	0.0003
@ISPERIOD("1986q3")+@ISPERIOD("1992q2")	-0.073565	0.014501	-5.073269	0.0000
@ISPERIOD("2002q3")	0.065103	0.020910	3.113398	0.0025
@ISPERIOD("1999q1")	-0.057785	0.020907	-2.763877	0.0069
@QUARTER=1	8.052516	1.216334	6.620316	0.0000
@QUARTER=2	8.059279	1.216439	6.625307	0.0000
@QUARTER=3	8.083518	1.216455	6.645142	0.0000
@QUARTER=4	8.062102	1.216512	6.627227	0.0000
PDL01	0.096288	0.050134	1.920602	0.0579
PDL02	-0.012352	0.006802	-1.816043	0.0726
AR(1)	1.147741	0.114382	10.03425	0.0000
AR(2)	-0.235883	0.113489	-2.078473	0.0405

R-squared	0.965821	Mean dependent var	10.54494
Adjusted R-squared	0.960248	S.D. dependent var	0.156964
S.E. of regression	0.031295	Akaike info criterion	-3.954751
Sum squared resid	0.090104	Schwarz criterion	-3.557398
Log likelihood	229.5565	Hannan-Quinn criter.	-3.793639
Durbin-Watson stat	1.904155		

Inverted AR Roots	.88	.27

Lag Distribution of LOG(JQINDN335_OH_KY)	i	Coefficient	Std. Error	t-Statistic
	0	0.12838	0.06685	1.92060
	1	0.09629	0.05013	1.92060
	2	0.06419	0.03342	1.92060
	3	0.03210	0.01671	1.92060
	Sum of Lags	0.32096	0.16711	1.92060

Lag Distribution of LOG(DS_KWH_IND_OH_KY/CPI)	i	Coefficient	Std. Error	t-Statistic
	0	-0.01123	0.00618	-1.81604
	1	-0.02021	0.01113	-1.81604
	2	-0.02695	0.01484	-1.81604
	3	-0.03144	0.01731	-1.81604
	4	-0.03369	0.01855	-1.81604
	5	-0.03369	0.01855	-1.81604
	6	-0.03144	0.01731	-1.81604
	7	-0.02695	0.01484	-1.81604
	8	-0.02021	0.01113	-1.81604
	9	-0.01123	0.00618	-1.81604
	Sum of Lags	-0.24704	0.13603	-1.81604

MWH SALES – INDUSTRIAL – MOTOR VEHICLES AND PARTS

Dependent Variable: LOG(MWHN3361_62_63_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 13:15
Sample: 1983Q1 2010Q4
Included observations: 112
Convergence achieved after 5 iterations
MA Backcast: 1982Q2 1982Q4

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	8.051917	0.520185	15.47896	0.0000
LOG(TS_KWH_IND_OH_KY(-6)/WPI0561(-6))	-0.063659	0.032882	-1.935967	0.0558
CDDB_OH_KY_65	9.43E-05	1.49E-05	6.346838	0.0000
@ISPERIOD("1999q1")	0.541207	0.058225	9.295131	0.0000
@ISPERIOD("2000q1")	0.195837	0.059601	3.285824	0.0014
@ISPERIOD("2004q4")	-0.270881	0.058810	-4.605995	0.0000
D_1965Q1_2005Q1	0.230177	0.048607	4.735464	0.0000
@ISPERIOD("2008q3")	-0.219970	0.064779	-3.395720	0.0010
@ISPERIOD("2008q4")	-0.241327	0.068775	-3.508926	0.0007
@ISPERIOD("2009q1")	*-0.296137*	*0.066781*	*-4.434421*	*0.0000*
@ISPERIOD("1991q1")	-0.131337	0.058181	-2.257392	0.0262
PDL01	0.081793	0.024827	3.294454	0.0014
PDL02	-0.174030	0.030342	-5.735555	0.0000
AR(1)	0.441387	0.097294	4.536622	0.0000
MA(3)	0.479336	0.097863	4.898011	0.0000

R-squared	0.888195	Mean dependent var	11.43920
Adjusted R-squared	0.872058	S.D. dependent var	0.197459
S.E. of regression	0.070629	Akaike info criterion	-2.338684
Sum squared resid	0.483880	Schwarz criterion	-1.974599
Log likelihood	145.9663	Hannan-Quinn criter.	-2.190963
F-statistic	55.04158	Durbin-Watson stat	2.131481
Prob(F-statistic)	0.000000		

Inverted AR Roots	.44		
Inverted MA Roots	.39-.68i	.39+.68i	-.78

Lag Distribution of LOG(JQINDN3361_62_63_OH_KY)	i	Coefficient	Std. Error	t-Statistic
. * |	0	0.12269	0.03724	3.29445
. * |	1	0.08179	0.02483	3.29445
. * |	2	0.04090	0.01241	3.29445
	Sum of Lags	0.24538	0.07448	3.29445

Lag Distribution of LOG(TS_KWH_IND_OH_KY/APGIND_OH_KY)	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.17403	0.03034	-5.73555
* . |	1	-0.08701	0.01517	-5.73555
	Sum of Lags	-0.26104	0.04551	-5.73555

MWH SALES – INDUSTRIAL – AEROSPACE PRODUCTS AND PARTS

Dependent Variable: LOG(MWHN3364_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 13:17
Sample (adjusted): 1976Q3 2010Q4
Included observations: 138 after adjustments
Convergence achieved after 9 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	10.40620	0.301787	34.48198	0.0000
LOG(TS_KWH_IND_OH_KY/CPI)	-0.077685	0.034073	-2.279933	0.0243
CDDB_OH_KY_65	0.000122	8.06E-06	15.17080	0.0000
@ISPERIOD("1986q2")+@ISPERIOD("1991q4")	0.129654	0.025078	5.170028	0.0000
@ISPERIOD("1991q1")+@ISPERIOD("1999q4")	-0.084145	0.025266	-3.330377	0.0011
@ISPERIOD("1992q1")+@ISPERIOD("2000q3")	-0.280391	0.025243	-11.10777	0.0000
@ISPERIOD("2008q2")+@ISPERIOD("2002q3")	0.164495	0.025305	6.500603	0.0000
@ISPERIOD("2001q2")	0.219082	0.036720	5.966257	0.0000
@ISPERIOD("2001q4")+@ISPERIOD("2004q1")	0.127053	0.026964	4.711866	0.0000
@ISPERIOD("2003q3")	-0.159349	0.037565	-4.241923	0.0000
@ISPERIOD("2003q4")	-0.403937	0.036510	-11.06362	0.0000
PDL01	0.159517	0.055972	2.849946	0.0051
AR(1)	0.475000	0.083613	5.680911	0.0000
AR(2)	0.458309	0.083692	5.476172	0.0000

R-squared	0.922112	Mean dependent var	11.13682
Adjusted R-squared	0.913946	S.D. dependent var	0.144033
S.E. of regression	0.042252	Akaike info criterion	-3.394411
Sum squared resid	0.221367	Schwarz criterion	-3.097443
Log likelihood	248.2144	Hannan-Quinn criter.	-3.273731
F-statistic	112.9252	Durbin-Watson stat	1.928903
Prob(F-statistic)	0.000000		

Inverted AR Roots	.95	-.48

Lag Distribution of LOG(JQINDN3364_OH_KY)	i	Coefficient	Std. Error	t-Statistic
. *|	0	0.15952	0.05597	2.84995
. * |	1	0.07976	0.02799	2.84995
	Sum of Lags	0.23928	0.08396	2.84995

MWH SALES – INDUSTRIAL – MISCELLANEOUS

Dependent Variable: LOG(MWHNAOI_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 13:16
Sample: 1979Q1 2010Q4
Included observations: 128
Convergence achieved after 8 iterations
MA Backcast: 1978Q3 1978Q4

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	11.88779	0.501920	23.68465	0.0000
LOG(JQINDNAOI_OH_KY)	0.437354	0.202024	2.164859	0.0325
CDDB_OH_KY_65	0.000152	5.82E-06	26.08549	0.0000
D_1965Q1_2001Q3	0.239000	0.034977	6.832993	0.0000
@ISPERIOD("1993q1")+@ISPERIOD("1993q2")	-0.112249	0.022882	-4.905591	0.0000
@ISPERIOD("1996q2")	-0.100633	0.024413	-4.122139	0.0001
@ISPERIOD("2003q4")	-0.064136	0.024469	-2.621110	0.0100
@ISPERIOD("2004q4")	0.131309	0.027091	4.846902	0.0000
@ISPERIOD("2005q1")	-0.166456	0.027212	-6.117062	0.0000
@ISPERIOD("2000q2")	-0.153083	0.029028	-5.273714	0.0000
@ISPERIOD("2000q3")+@ISPERIOD("2000q4")	-0.105271	0.027091	-3.885913	0.0002
@ISPERIOD("2001q2")+@ISPERIOD("2005q4")	-0.069407	0.017390	-3.991301	0.0001
@ISPERIOD("2008q3")+@ISPERIOD("2008q4")	0.133541	0.023910	5.585172	0.0000
PDL01	-0.055260	0.031283	-1.766453	0.0800
AR(1)	0.980983	0.012992	75.50632	0.0000
MA(2)	0.150976	0.000364	414.8660	0.0000

R-squared	0.986800	Mean dependent var	12.43838
Adjusted R-squared	0.985032	S.D. dependent var	0.282311
S.E. of regression	0.034539	Akaike info criterion	-3.776990
Sum squared resid	0.133609	Schwarz criterion	-3.420486
Log likelihood	257.7274	Hannan-Quinn criter.	-3.632141
F-statistic	558.1851	Durbin-Watson stat	1.906248
Prob(F-statistic)	0.000000		

Inverted AR Roots	.98

Lag Distribution of LOG(DS_KWH_IND_OH_KY(-4)/CPI(-4))	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.05526	0.03128	-1.76645
* . |	1	-0.02763	0.01564	-1.76645
	Sum of Lags	-0.08289	0.04692	-1.76645

KWH SALES – OTHER PUBLIC AUTHORITIES – WATER PUMPING

Dependent Variable: LOG(KWHOPAWP_OH_KY)
Method: Least Squares
Date: 02/22/11 Time: 17:19
Sample: 1976M01 2010M12
Included observations: 420

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	7.343583	0.815592	9.003991	0.0000
D_1965M01_2001M12*LOG(CUSRES_OH_KY)	0.666205	0.059001	11.29152	0.0000
(1-D_1965M01_2001M12)*LOG(CUSRES_OH_KY)	0.623779	0.058028	10.74957	0.0000
LOG(DS_KW_OPA_OH_KY/CPI)	-0.041952	0.020836	-2.013434	0.0448
((@MONTH=5)+(@MONTH=6)+(@MONTH=7)+(@MONTH=8))*(PRECIP_OH_KY+PRECIP_OH_KY(-1))	-0.003603	0.001357	-2.654939	0.0083
((@MONTH=4)+(@MONTH=9)+(@MONTH=10)+(@MONTH=11))*(PRECIP_OH_KY+PRECIP_OH_KY(-1))	-0.002277	0.001320	-1.725192	0.0853
((@MONTH=6)+(@MONTH=7))*CDD_OH_KY_65	0.000684	5.08E-05	13.47076	0.0000
(@MONTH=8)*CDD_OH_KY_65	0.000774	5.67E-05	13.65227	0.0000
(1-((@MONTH=6)+(@MONTH=7)+(@MONTH=8)))*CDD_OH_KY_65	0.001241	0.000101	12.33444	0.0000
@ISPERIOD("1982m06")	0.832372	0.081478	10.21594	0.0000
@ISPERIOD("1998m10")	-0.559534	0.081309	-6.881549	0.0000
@ISPERIOD("2000m01")	-0.803448	0.081575	-9.849237	0.0000
@ISPERIOD("2000m06")	0.354003	0.081863	4.324362	0.0000
@ISPERIOD("2000m05")	-0.691377	0.082285	-8.402177	0.0000
@ISPERIOD("2000m07")	-1.272906	0.081849	-15.55187	0.0000
D_2000M08_2001M12	-0.485575	0.024621	-19.72236	0.0000
@ISPERIOD("2001m07")	-0.879371	0.084491	-10.40782	0.0000
D_2001M09_2002M06	-0.144578	0.028124	-5.140731	0.0000
D_2002M07_2003M01	0.365595	0.038160	9.580551	0.0000
@ISPERIOD("2002m10")	-0.453355	0.089081	-5.089212	0.0000
@ISPERIOD("2003m01")	0.476502	0.088909	5.359416	0.0000
@ISPERIOD("2004m01")	0.424579	0.081677	5.198297	0.0000
@ISPERIOD("2004m03")	0.833829	0.081677	10.20890	0.0000
@ISPERIOD("2006m09")	-0.530826	0.081833	-6.486693	0.0000
@ISPERIOD("2006m10")	0.298049	0.082239	3.624159	0.0003
@ISPERIOD("2010m03")	0.601023	0.082044	7.325577	0.0000
D_1965M01_2007M09	0.219629	0.017147	12.80855	0.0000

R-squared	0.921765	Mean dependent var	16.43708
Adjusted R-squared	0.916589	S.D. dependent var	0.279638
S.E. of regression	0.080762	Akaike info criterion	- 2.132488
Sum squared resid	2.563358	Schwarz criterion	- 1.872757
Log likelihood	474.8225	Hannan-Quinn criter.	- 2.029831
F-statistic	178.0885	Durbin-Watson stat	1.729098
Prob(F-statistic)	0.000000		

KWH SALES – OTHER PUBLIC AUTHORITIES – LESS WATER PUMPING

Dependent Variable: LOG(KWHOPALWP_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 11:07
Sample: 1978M01 2010M12
Included observations: 396
Convergence achieved after 6 iterations
MA Backcast: 1977M01 1977M12

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	9.177343	0.464818	19.74395	0.0000
LOG(DS_KWH_OPA_OH_KY/CPI)	-0.153704	0.036853	-4.170683	0.0000
LOG(DS_KWH_OPA_OH_KY(-11)/APGOPA_OH_KY(-11))	-0.086142	0.021786	-3.953931	0.0001
CDDB_OH_KY_65*D_1976M01_1984M12	0.000266	0.000101	2.642251	0.0086
CDDB_OH_KY_65*(1-D_1976M01_1984M12)	0.000578	5.45E-05	10.59282	0.0000
HDDB_OH_KY_59*D_1976M01_1984M12	0.000107	3.18E-05	3.358502	0.0009
HDDB_OH_KY_59*(1-D_1976M01_1984M12)	8.33E-05	2.13E-05	3.912876	0.0001
@MONTH=6	0.044197	0.011728	3.768620	0.0002
@MONTH=11	-0.048075	0.011843	-4.059367	0.0001
@ISPERIOD("1994m02")	0.271680	0.053263	5.100765	0.0000
@ISPERIOD("1995m08")	-0.228265	0.053677	-4.252564	0.0000
@ISPERIOD("1999m06")	-0.239280	0.053810	-4.446751	0.0000
@ISPERIOD("1999m10")	0.263578	0.053521	4.924797	0.0000
@ISPERIOD("1999m12")	0.271471	0.054635	4.968812	0.0000
@ISPERIOD("2000m04")	-0.485594	0.054471	-8.914713	0.0000
@ISPERIOD("2000m12")	0.289804	0.060753	4.770228	0.0000
@ISPERIOD("2001m01")	-0.237152	0.059899	-3.959179	0.0001
@ISPERIOD("2001m04")	-0.280704	0.054442	-5.156055	0.0000
@ISPERIOD("2002m12")	-0.196509	0.053360	-3.682695	0.0003
PDL01	0.498819	0.045765	10.89966	0.0000
AR(1)	0.559005	0.044939	12.43909	0.0000
MA(12)	0.211711	0.052362	4.043206	0.0001

R-squared	0.941059	Mean dependent var	18.51108
Adjusted R-squared	0.937750	S.D. dependent var	0.249366
S.E. of regression	0.062217	Akaike info criterion	-2.662435
Sum squared resid	1.447722	Schwarz criterion	-2.441245
Log likelihood	549.1621	Hannan-Quinn criter.	-2.574806
F-statistic	284.3511	Durbin-Watson stat	2.160948
Prob(F-statistic)	0.000000		

Inverted AR Roots	.56			
Inverted MA Roots	.85+.23i	.85-.23i	.62+.62i	.62+.62i
	.23+.85i	.23-.85i	-.23-.85i	-.23+.85i
	-.62+.62i	-.62+.62i	-.85-.23i	-.85+.23i

Lag Distribution of LOG(E90X_OH_KY)	i	Coefficient	Std. Error	t-Statistic
. * |	0	0.74823	0.06865	10.8997
. * |	1	0.49882	0.04576	10.8997
. * |	2	0.24941	0.02288	10.8997
	Sum of Lags	1.49646	0.13729	10.8997

KWH SALES – STREET LIGHTING

Dependent Variable: LOG(KWHSL_OH_KY)
Method: Least Squares
Date: 02/18/11 Time: 11:10
Sample (adjusted): 1976M03 2010M12
Included observations: 418 after adjustments
Convergence achieved after 13 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	6.634622	0.817873	8.112046	0.0000
LOG(N_OH_KY)	1.187030	0.093199	12.73652	0.0000
D_1965M01_2002M12*@MONTH=1	0.129729	0.005804	22.34983	0.0000
D_1965M01_2002M12*@MONTH=2	-0.017364	0.005586	-3.108402	0.0020
D_1965M01_2002M12*@MONTH=4	-0.125481	0.005380	-23.32294	0.0000
D_1965M01_2002M12*@MONTH=5	-0.183103	0.005853	-31.28516	0.0000
D_1965M01_2002M12*@MONTH=6	-0.272574	0.006585	-41.39356	0.0000
D_1965M01_2002M12*@MONTH=7	-0.227443	0.006769	-33.60018	0.0000
D_1965M01_2002M12*@MONTH=8	-0.144261	0.006805	-21.19983	0.0000
D_1965M01_2002M12*@MONTH=9	-0.079487	0.006838	-11.62400	0.0000
D_1965M01_2002M12*@MONTH=10	0.026083	0.006776	3.849203	0.0001
D_1965M01_2002M12*@MONTH=11	0.080469	0.006638	12.12199	0.0000
D_1965M01_2002M12*@MONTH=12	0.143832	0.006298	22.83764	0.0000
@ISPERIOD("1980m02")	-0.163252	0.022107	-7.384568	0.0000
@ISPERIOD("1991m06")	-0.366945	0.023674	-15.49977	0.0000
@ISPERIOD("1999m06")	0.526448	0.022075	23.84800	0.0000
@ISPERIOD("1999m11")	-0.215151	0.022062	-9.752211	0.0000
@ISPERIOD("2001m02")	-0.751729	0.022988	-32.70043	0.0000
@ISPERIOD("2001m03")	0.419849	0.023222	18.08003	0.0000
@ISPERIOD("2001m05")	-0.314116	0.022717	-13.82746	0.0000
@ISPERIOD("2001m07")+@ISPERIOD("2002m07")	0.194966	0.016484	11.82759	0.0000
@ISPERIOD("2002m06")	-0.146027	0.022475	-6.497423	0.0000
@ISPERIOD("1991m03")	-0.137568	0.022208	-6.194428	0.0000
@ISPERIOD("2007m02")	-0.134596	0.021717	-6.197862	0.0000
@ISPERIOD("2007m05")	-0.106050	0.022853	-4.640490	0.0000
@ISPERIOD("2007m06")	0.054432	0.022445	2.425113	0.0158
@ISPERIOD("2002m02")	0.106135	0.022361	4.746497	0.0000
@ISPERIOD("2006m02")	0.084365	0.021746	3.879554	0.0001
D_1965M01_2007M09	0.067105	0.012236	5.484119	0.0000
PDL01	-0.148257	0.052585	-2.819371	0.0051
AR(1)	0.411845	0.055537	7.415701	0.0000
AR(2)	0.220771	0.053764	4.106317	0.0000

R-squared	0.978873	Mean dependent var	15.94102
Adjusted R-squared	0.977176	S.D. dependent var	0.157949
S.E. of regression	0.023862	Akaike info criterion	-4.559575
Sum squared resid	0.219790	Schwarz criterion	-4.250639
Log likelihood	984.9512	Hannan-Quinn criter.	-4.437446
F-statistic	576.9154	Durbin-Watson stat	2.042699
Prob(F-statistic)	0.000000		

Inverted AR Roots	.72	-.31

Lag Distribution of LOG(SAT_SL_OH_KY)	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.19768	0.07011	-2.81937
* . |	1	-0.14826	0.05259	-2.81937
* . |	2	-0.09884	0.03506	-2.81937
* . |	3	-0.04942	0.01753	-2.81937
	Sum of Lags	-0.49419	0.17528	-2.81937

SERVICE AREA – SUMMER PEAK

Dependent Variable: LOG(MWSPEAK_OH_KY)
Method: Least Squares
Date: 03/02/11 Time: 17:36
Sample: 1/01/1974 12/31/2010 IF WEEKDAY<=5
Included observations: 374

Variable	Coefficient	Std. Error	t-Statistic	Prob.
D_072180_091498*MJUN	-3.011771	0.321205	-9.376481	0.0000
(1-D_072180_091498)*MJUN	-3.124540	0.319518	-9.778925	0.0000
D_072180_091498*MJUL	-3.287855	0.290345	-11.32395	0.0000
(1-D_072180_091498)*MJUL	-3.623843	0.184254	-19.66766	0.0000
D_072180_091498*MAUG	-1.598406	0.243600	-6.561600	0.0000
(1-D_072180_091498)*MAUG	-4.460045	0.229457	-19.43742	0.0000
MSEP	-3.635690	0.260506	-13.95628	0.0000
(D_072180_091498)*(MJUN+MSEP)*LOG(KWHSEND_OH_KY_WN/1000/DAYS)	0.909660	0.018172	50.05902	0.0000
(1-D_072180_091498)*(MJUN+MSEP)*LOG(KWHSEND_OH_KY_WN/1000/DAYS)	0.920730	0.017986	51.19140	0.0000
(D_072180_091498)*(MJUL)*LOG(KWHSEND_OH_KY_WN/1000/DAYS)	0.915842	0.024645	37.16087	0.0000
(1-D_072180_091498)*(MJUL)*LOG(KWHSEND_OH_KY_WN/1000/DAYS)	0.943693	0.013466	70.08135	0.0000
(D_072180_091498)*(MAUG)*LOG(KWHSEND_OH_KY_WN/1000/DAYS)	0.749686	0.020357	36.82746	0.0000
(1-D_072180_091498)*(MAUG)*LOG(KWHSEND_OH_KY_WN/1000/DAYS)	1.007129	0.018754	53.70340	0.0000
(MJUN)*PMHIGH	0.006528	0.002595	2.516140	0.0123
(MJUL+MAUG+MSEP)*PMHIGH	0.010185	0.001090	9.341020	0.0000
(MJUN+MJUL+MAUG+MSEP)*PREVPMHIGH	0.002587	0.000596	4.339495	0.0000
(MJUN+MAUG)*AMLOW	0.005175	0.000788	6.569148	0.0000
MJUL*AMLOW	0.003140	0.000945	3.322639	0.0010
MSEP*AMLOW	0.009130	0.002129	4.288536	0.0000
(MJUN+MJUL+MAUG+MSEP)*PMHUMIDATHIGH	0.000754	0.000302	2.497370	0.0130
JULY4WEEK*PMHIGH	-0.000318	7.53E-05	-4.226065	0.0000
@ISPERIOD("6/11/1976")	-0.097349	0.036540	-2.664175	0.0081
@ISPERIOD("6/18/1976")	-0.124767	0.036541	-3.414419	0.0007
@ISPERIOD("7/5/1993")	-0.109721	0.035655	-3.077264	0.0023
@ISPERIOD("7/5/99")	-0.122669	0.035685	-3.437554	0.0007
@ISPERIOD("8/13/1999")	0.105063	0.035423	2.965939	0.0032
@ISPERIOD("8/17/1999")	0.104280	0.035654	2.924797	0.0037
D_080107_082907	-0.093970	0.010804	-8.697776	0.0000
@ISPERIOD("7/7/10")	-0.384991	0.035580	-10.82035	0.0000

R-squared	0.980720	Mean dependent var	8.264019
Adjusted R-squared	0.979155	S.D. dependent var	0.240056
S.E. of regression	0.034659	Akaike info criterion	-3.812170
Sum squared resid	0.414422	Schwarz criterion	-3.507882
Log likelihood	741.8757	Hannan-Quinn criter.	-3.691354
Durbin-Watson stat	0.689958		

SERVICE AREA – WINTER PEAK

Dependent Variable: LOG(MWWPEAK_OH_KY)
Method: Least Squares
Date: 03/03/11 Time: 12:36
Sample: 1/01/1974 12/31/2010 IF WEEKDAY<=5
Included observations: 258

Variable	Coefficient	Std. Error	t-Statistic	Prob.
AMPEAK*(MDEC+MJAN+MFEB+MMAR)	-1.609170	0.284221	-5.661692	0.0000
AMPEAK*(MDEC+MJAN+MFEB+MMAR)*LOG(KWHSEND_OH_KY_WN/1000/DAYS)	0.882089	0.025989	33.94138	0.0000
AMPEAK*(MDEC+MJAN+MFEB+MMAR)*AMLOW	-0.002167	0.001165	-1.859507	0.0641
AMPEAK*(MDEC+MJAN+MMAR)*WINDAM	0.006007	0.001457	4.122567	0.0001
AMPEAK*(MJAN+MFEB+MMAR)*PREVPMLOW	-0.002277	0.001045	-2.178155	0.0303
PMPEAK*(MDEC+MJAN+MFEB+MMAR)	-0.936795	0.372091	-2.517650	0.0125
PMPEAK*(MDEC+MMAR)*LOG(KWHSEND_OH_KY_WN/1000/DAYS)	0.826439	0.034517	23.94265	0.0000
PMPEAK*(MJAN+MFEB)*LOG(KWHSEND_OH_KY_WN/1000/DAYS)	0.822818	0.034252	24.02242	0.0000
PMPEAK*(MDEC+MJAN+MFEB+MMAR)*PMLOW	-0.003700	0.001386	-2.669020	0.0081
@ISPERIOD("1/27/1977")+@ISPERIOD("1/28/1977")	-0.253712	0.058986	-4.301214	0.0000
PMPEAK*XMAS	-0.083042	0.029656	-2.800147	0.0055
@ISPERIOD("1/23/2003")	-0.165564	0.085684	-1.932259	0.0545

R-squared	0.883007	Mean dependent var	8.026330
Adjusted R-squared	0.877776	S.D dependent var	0.235440
S.E. of regression	0.082311	Akaike info criterion	-2.111221
Sum squared resid	1.666687	Schwarz criterion	-1.945968
Log likelihood	284.3476	Hannan-Quinn criter.	-2.044772
Durbin-Watson stat	0.565187		

Mnemonics Definitions

VARIABLE	DESCRIPTION
@ISPERIOD("6/11/1976")	QUALITATIVE VARIABLE - JUNE 11, 1976
@ISPERIOD("6/18/1976")	QUALITATIVE VARIABLE - JUNE 18, 1976
@ISPERIOD("1/27/1977")	QUALITATIVE VARIABLE - JANUARY 27, 1977
@ISPERIOD("1/28/1977")	QUALITATIVE VARIABLE - JANUARY 28, 1977
@ISPERIOD("7/5/1993")	QUALITATIVE VARIABLE - JULY 5, 1993
@ISPERIOD("7/5/1999")	QUALITATIVE VARIABLE - JULY 5, 1999
@ISPERIOD("8/13/1999")	QUALITATIVE VARIABLE - AUGUST 13, 1999
@ISPERIOD("8/17/1999")	QUALITATIVE VARIABLE - AUGUST 17, 1999
@ISPERIOD("1/23/2003")	QUALITATIVE VARIABLE - JANUARY 23, 2003
@ISPERIOD("7/7/2010")	QUALITATIVE VARIABLE - JULY 7, 2010
@ISPERIOD("1980M02")	QUALITATIVE VARIABLE - FEBRUARY, 1980
@ISPERIOD("1982M06")	QUALITATIVE VARIABLE - JUNE, 1982
@ISPERIOD("1986Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 1986
@ISPERIOD("1986Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 1986
@ISPERIOD("1988Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 1988
@ISPERIOD("1988Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 1988
@ISPERIOD("1990Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 1990
@ISPERIOD("1991M03")	QUALITATIVE VARIABLE - MARCH, 1991
@ISPERIOD("1991M04")	QUALITATIVE VARIABLE - APRIL, 1991
@ISPERIOD("1991M06")	QUALITATIVE VARIABLE - JUNE, 1991
@ISPERIOD("1991M11")	QUALITATIVE VARIABLE - NOVEMBER, 1991
@ISPERIOD("1991Q1")	*QUALITATIVE VARIABLE - FIRST QUARTER, 1991*
@ISPERIOD("1991Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 1991
@ISPERIOD("1991Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 1991
@ISPERIOD("1992Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 1992
@ISPERIOD("1992Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 1992
@ISPERIOD("1993M09")	QUALITATIVE VARIABLE - SEPTEMBER, 1993
@ISPERIOD("1993M10")	QUALITATIVE VARIABLE - OCTOBER, 1993
@ISPERIOD("1993M11")	QUALITATIVE VARIABLE - NOVEMBER, 1993
@ISPERIOD("1993Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 1993
@ISPERIOD("1993Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 1993
@ISPERIOD("1994M02")	QUALITATIVE VARIABLE - FEBRUARY, 1994
@ISPERIOD("1994M05")	QUALITATIVE VARIABLE - MAY, 1994
@ISPERIOD("1994Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 1994
@ISPERIOD("1995M04")	QUALITATIVE VARIABLE - APRIL, 1995
@ISPERIOD("1995M05")	QUALITATIVE VARIABLE - MAY, 1995
@ISPERIOD("1995M08")	QUALITATIVE VARIABLE - AUGUST, 1995
@ISPERIOD("1996Q2")	QUALITATIVE VARIABLE – SECOND QUARTER, 1996
@ISPERIOD("1996Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 1996
@ISPERIOD("1997Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 1997
@ISPERIOD("1998M05")	QUALITATIVE VARIABLE - MAY, 1998
@ISPERIOD("1998M07")	QUALITATIVE VARIABLE - JULY, 1998
@ISPERIOD("1998M10")	QUALITATIVE VARIABLE - OCTOBER, 1998
@ISPERIOD("1998Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 1998
@ISPERIOD("1998Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 1998
@ISPERIOD("1999M02")	QUALITATIVE VARIABLE - FEBRUARY, 1999
@ISPERIOD("1999M06")	QUALITATIVE VARIABLE - JUNE, 1999
@ISPERIOD("1999M10")	QUALITATIVE VARIABLE - OCTOBER, 1999
@ISPERIOD("1999M11")	QUALITATIVE VARIABLE - NOVEMBER, 1999
@ISPERIOD("1999M12")	QUALITATIVE VARIABLE - DECEMBER, 1999
@ISPERIOD("1999Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 1999
@ISPERIOD("1999Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 1999
@ISPERIOD("2000M01")	QUALITATIVE VARIABLE - JANUARY, 2000
@ISPERIOD("2000M04")	QUALITATIVE VARIABLE - APRIL, 2000
@ISPERIOD("2000M05")	QUALITATIVE VARIABLE - MAY, 2000
@ISPERIOD("2000M06")	QUALITATIVE VARIABLE - JUNE, 2000
@ISPERIOD("2000M07")	QUALITATIVE VARIABLE - JULY, 2000
@ISPERIOD("2000M08")	QUALITATIVE VARIABLE - AUGUST, 2000
@ISPERIOD("2000M10")	QUALITATIVE VARIABLE - OCTOBER, 2000
@ISPERIOD("2000M12")	QUALITATIVE VARIABLE - DECEMBER, 2000
@ISPERIOD("2000Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 2000
@ISPERIOD("2000Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 2000
@ISPERIOD("2000Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 2000
@ISPERIOD("2000Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 2000
@ISPERIOD("2001M01")	QUALITATIVE VARIABLE - JANUARY, 2001
@ISPERIOD("2001M02")	QUALITATIVE VARIABLE - FEBRUARY, 2001
@ISPERIOD("2001M03")	*QUALITATIVE VARIABLE - MARCH, 2001*
@ISPERIOD("2001M04")	QUALITATIVE VARIABLE - APRIL, 2001
@ISPERIOD("2001M05")	QUALITATIVE VARIABLE - MAY, 2001
@ISPERIOD("2001M06")	QUALITATIVE VARIABLE - JUNE, 2001
@ISPERIOD("2001M07")	QUALITATIVE VARIABLE - JULY, 2001
@ISPERIOD("2001Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 2001
@ISPERIOD("2001Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 2001
@ISPERIOD("2001Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 2001
@ISPERIOD("2002M02")	QUALITATIVE VARIABLE - FEBRUARY, 2002
@ISPERIOD("2002M04")	QUALITATIVE VARIABLE - APRIL, 2002
@ISPERIOD("2002M05")	QUALITATIVE VARIABLE - MAY, 2002
@ISPERIOD("2002M06")	QUALITATIVE VARIABLE - JUNE, 2002

@ISPERIOD("2002M07")	QUALITATIVE VARIABLE - JULY, 2002
@ISPERIOD("2002M08")	QUALITATIVE VARIABLE - AUGUST, 2002
@ISPERIOD("2002M10")	QUALITATIVE VARIABLE - OCTOBER, 2002
@ISPERIOD("2002M12")	QUALITATIVE VARIABLE - DECEMBER, 2002
@ISPERIOD("2002Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 2002
@ISPERIOD("2002Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 2002
@ISPERIOD("2002Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 2002
@ISPERIOD("2003M01")	QUALITATIVE VARIABLE - JANUARY, 2003
@ISPERIOD("2003M12")	QUALITATIVE VARIABLE - DECEMBER, 2003
@ISPERIOD("2003Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 2003
@ISPERIOD("2003Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 2003
@ISPERIOD("2003Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 2003
@ISPERIOD("2004M01")	QUALITATIVE VARIABLE - JANUARY, 2004
@ISPERIOD("2004M03")	QUALITATIVE VARIABLE - MARCH, 2004
@ISPERIOD("2004M05")	QUALITATIVE VARIABLE - MAY, 2004
@ISPERIOD("2004M06")	QUALITATIVE VARIABLE - JUNE, 2004
@ISPERIOD("2004M11")	QUALITATIVE VARIABLE - NOVEMBER, 2004
@ISPERIOD("2004M12")	QUALITATIVE VARIABLE - DECEMBER, 2004
@ISPERIOD("2004Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 2004
@ISPERIOD("2004Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 2004
@ISPERIOD("2005M01")	QUALITATIVE VARIABLE - JANUARY, 2005
@ISPERIOD("2005M02")	QUALITATIVE VARIABLE - FEBRUARY, 2005
@ISPERIOD("2005M03")	QUALITATIVE VARIABLE - MARCH, 2005
@ISPERIOD("2005M08")	QUALITATIVE VARIABLE - AUGUST, 2005
@ISPERIOD("2005Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 2005
@ISPERIOD("2005Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 2005
@ISPERIOD("2006M02")	QUALITATIVE VARIABLE - FEBRUARY, 2006
@ISPERIOD("2006M09")	QUALITATIVE VARIABLE - SEPTEMBER, 2006
@ISPERIOD("2006M10")	QUALITATIVE VARIABLE - OCTOBER, 2006
@ISPERIOD("2007M02")	QUALITATIVE VARIABLE - FEBRUARY, 2007
@ISPERIOD("2007M04")	QUALITATIVE VARIABLE - APRIL, 2007
@ISPERIOD("2007M05")	QUALITATIVE VARIABLE - MAY, 2007
@ISPERIOD("2007M06")	QUALITATIVE VARIABLE - JUNE, 2007
@ISPERIOD("2007M10")	QUALITATIVE VARIABLE - OCTOBER, 2007
@ISPERIOD("2007Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 2007
@ISPERIOD("2008M10")	QUALITATIVE VARIABLE - OCTOBER, 2008
@ISPERIOD("2008Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 2008
@ISPERIOD("2008Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 2008
@ISPERIOD("2008Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 2008
@ISPERIOD("2009M05")	QUALITATIVE VARIABLE - MAY, 2009
@ISPERIOD("2009Q1")	QUALITATIVE VARIABLE - FIRST QUARTER, 2009
@ISPERIOD("2009Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 2009
@ISPERIOD("2010M02")	QUALITATIVE VARIABLE - FEBRUARY, 2010
@ISPERIOD("2010M03")	QUALITATIVE VARIABLE - MARCH, 2010
@ISPERIOD("2010M05")	QUALITATIVE VARIABLE - MAY, 2010
@ISPERIOD("2010M10")	QUALITATIVE VARIABLE - OCTOBER, 2010
@ISPERIOD("2010Q2")	QUALITATIVE VARIABLE - SECOND QUARTER, 2010
@ISPERIOD("2010Q3")	QUALITATIVE VARIABLE - THIRD QUARTER, 2010
@ISPERIOD("2010Q4")	QUALITATIVE VARIABLE - FOURTH QUARTER, 2010
@MONTH=1	QUALITATIVE VARIABLE - JANUARY
@MONTH=10	QUALITATIVE VARIABLE - OCTOBER
@MONTH=11	QUALITATIVE VARIABLE - NOVEMBER
@MONTH=12	QUALITATIVE VARIABLE - DECEMBER
@MONTH=2	QUALITATIVE VARIABLE - FEBRUARY
@MONTH=3	QUALITATIVE VARIABLE - MARCH
@MONTH=4	QUALITATIVE VARIABLE - APRIL
@MONTH=5	QUALITATIVE VARIABLE - MAY
@MONTH=6	QUALITATIVE VARIABLE - JUNE
@MONTH=7	QUALITATIVE VARIABLE - JULY
@MONTH=8	QUALITATIVE VARIABLE - AUGUST
@MONTH=9	QUALITATIVE VARIABLE – SEPTEMBER
@QUARTER=1	QUALITATIVE VARIABLE - FIRST QUARTER
@QUARTER=2	QUALITATIVE VARIABLE - SECOND QUARTER
@QUARTER=3	QUALITATIVE VARIABLE - THIRD QUARTER
@QUARTER=4	QUALITATIVE VARIABLE - FOURTH QUARTER
AMLOW	MINIMUM HOURLY TEMPERATURE - MORNING
AMPEAK	QUALITATIVE VARIABLE - MORNING PEAK
APGIND_OH_KY	SERVICE AREA AVERAGE PRICE OF GAS FOR INDUSTRIAL CUSTOMERS
APGOPA_OH_KY	SERVICE AREA AVERAGE PRICE OF GAS FOR OPA CUSTOMERS
APPLSTK_EFF_OH_KY	EFFICIENT APPLIANCE STOCK
BASE	BUTLER COUNTY BASE AMOUNT OF MWH SALES - INDUSTRIAL - PRIMARY METAL INDUSTRIES
CDD_OH_KY_65	COOLING DEGREE DAYS
CDDB_OH_KY_65	BILLING COOLING DEGREE DAYS
CDDB_OH_KY_65_0_100	=MINIMUM(CDDB_OH_KY,100)
CDDB_OH_KY_65_100	=MAXIMUM(CDDB_OH_KY-100,0)
CPI	CONSUMER PRICE INDEX (ALL URBAN) - ALL ITEMS
CUSRES_OH_KY	SERVICE AREA ELECTRIC CUSTOMERS - RESIDENTIAL
D_072180_091498	QUALITATIVE VARIABLE - JULY 21, 1980 TO SEPTEMBER 14, 1998
D_080107_082907	QUALITATIVE VARIABLE - AUGUST 1, 2007 TO AUGUST 29, 2007
D_1965M01_2001M12	QUALITATIVE VARIABLE - JANUARY, 1965 THRU DECEMBER, 2001
D_1965M01_2002M12	QUALITATIVE VARIABLE - JANUARY, 1965 THRU DECEMBER, 2002
D_1965M01_2007M09	QUALITATIVE VARIABLE - JANUARY, 1965 THRU SEPTEMBER, 2007
D_1965Q1_1985Q4	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO FOURTH QUARTER, 1985

D_1965Q1_1986Q4	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 THRU FOURTH QUARTER, 1986
D_1965Q1_1990Q4	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 THRU FOURTH QUARTER, 1990
D_1965Q1_1995Q4	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO FOURTH QUARTER, 1995
D_1965Q1_1998Q2	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO SECOND QUARTER, 1998
D_1965Q1_2001Q2	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO SECOND QUARTER, 2001
D_1965Q1_2001Q3	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 THRU THIRD QUARTER, 2001
D_1965Q1_2005Q1	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 THRU FIRST QUARTER, 2005
D_1976M01_1984M12	QUALITATIVE VARIABLE - JANUARY, 1976 THRU DECEMBER, 1984
D_1976Q1_1989Q2	QUALITATIVE VARIABLE - FIRST QUARTER, 1976 TO SECOND QUARTER, 1989
D_1980Q1_2005Q2	QUALITATIVE VARIABLE - FIRST QUARTER, 1980 TO SECOND QUARTER, 2005
D_1987Q1_1991Q3	QUALITATIVE VARIABLE - FIRST QUARTER, 1987 THRU THIRD QUARTER, 1991
D_1998Q3_2001Q2	QUALITATIVE VARIABLE - THIRD QUARTER, 1998 THRU SECOND QUARTER, 2001
D_1999Q1_2001Q2	QUALITATIVE VARIABLE - FIRST QUARTER, 1999 THRU SECOND QUARTER, 2001
D_2000M08_2001M12	QUALITATIVE VARIABLE - AUGUST, 2000 THRU DECEMBER, 2001
D_2000Q3_2001Q2	QUALITATIVE VARIABLE - THIRD QUARTER, 2000 THRU SECOND QUARTER, 2001
D_2001M09_2002M06	QUALITATIVE VARIABLE - SEPTEMBER, 2001 THRU JUNE, 2002
D_2002M07_2003M01	QUALITATIVE VARIABLE - JULY, 2002 THRU JANUARY, 2003
D_DJF	=(@MONTH=12+@MONTH=1+@MONTH=2)
D_JJA	=(@MONTH=6+@MONTH=7+@MONTH=8)
DAYS	NUMBER OF DAYS IN THE MONTH
DS_KW_IND_OH_KY	SERVICE AREA DS RATE FOR DEMAND FOR INDUSTRIAL CUSTOMERS
DS_KW_OPA_OH_KY	SERVICE AREA DS RATE FOR DEMAND FOR OTHER PUBLIC AUTHORITIES CUSTOMERS
DS_KWH_COM_OH_KY	SERVICE AREA DS RATE FOR USAGE FOR COMMERCIAL CUSTOMERS
DS_KWH_IND_OH_KY	SERVICE AREA DS RATE FOR USAGE FOR INDUSTRIAL CUSTOMERS
DS_KWH_OPA_OH_KY	SERVICE AREA DS RATE FOR USAGE FOR OTHER PUBLIC AUTHORITIES CUSTOMERS
E90X_OH_KY	SERVICE AREA EMPLOYMENT - STATE AND LOCAL GOVERNMENT
ECOM_OH_KY	SERVICE AREA EMPLOYMENT - COMMERCIAL
EFF_CAC_OH_KY	EFFICIENCY OF CENTRAL AIR CONDITIONING UNITS IN SERVICE AREA
EFF_EHP_OH_KY	EFFICIENCY OF ELECTRIC HEAT PUMP UNITS IN SERVICE AREA
EFF_RAC_OH_KY	EFFICIENCY OF WINDOW AIR CONDITIONING UNITS IN SERVICE AREA
HDDB_OH_KY_59	BILLING HEATING DEGREE DAYS
HDDB_OH_KY_59_0_500	=MINIMUM(HDDB_OH_KY,500)
HDDB_OH_KY_59_500	=MAXIMUM(HDDB_OH_KY-500,0)
JQINDN311_312_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - FOOD AND PRODUCTS
JQINDN322_326_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - PAPER AND PRODUCTS
JQINDN325_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - CHEMICALS AND PRODUCTS
JQINDN331_BUTLER	BUTLER COUNTY INDUSTRIAL PRODUCTION INDEX - PRIMARY METAL INDUSTRIES
JQINDN331_CMSA	CINCINNATI CMSA INDUSTRIAL PRODUCTION INDEX - PRIMARY METAL INDUSTRIES
JQINDN332_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - FABRICATED METALS
JQINDN333_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - INDUSTRIAL MACHINERY & EQUIPMENT
JQINDN334_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - COMPUTER AND ELECTRONICS
JQINDN335_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - ELECTRICAL EQUIPMENT
JQINDN3364_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - AIRCRAFT AND PARTS
JQINDN361_62_63_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - MOTOR VEHICLES AND PARTS
JQINDNAOI_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION - ALL OTHER INDUSTRIES
JULY4WEEK	QUALITATIVE VARIABLE FOR THE WEEK OF JULY 4TH
KWHCOM_OH_KY	SERVICEA KWH SALES - COMMERCIAL
KWHOPALWP_OH_KY	SERVICE AREA KWH SALES - OPA LESS WATER PUMPING
KWHOPAWP_OH_KY	SERVICE AREA KWH SALES - OPA WATER PUMPING
KWHRES_OH_KY	SERVICE AREA KWH SALES - RESIDENTIAL
KWHSEND_OH_KY_WN	SERVICE AREA KWH SENDOUT – WEATHER NORMALIZED
KWHSL_OH_KY	SERVICE AREA KWH SALES – STREET LIGHTING
MAUG	QUALITATIVE VARIABLE - AUGUST
MDEC	QUALITATIVE VARIABLE - DECEMBER
MFEB	QUALITATIVE VARIABLE - FEBRUARY
MJAN	QUALITATIVE VARIABLE - JANUARY
MJUL	QUALITATIVE VARIABLE - JULY
MJUN	QUALITATIVE VARIABLE - JUNE
MMAR	QUALITATIVE VARIABLE - MARCH
MP_RES_OH_KY	MARGINAL PRICE OF ELECTRICITY - RESIDENTIAL
MSEP	QUALITATIVE VARIABLE - SEPTEMBER
MWHN311_312_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - FOOD AND PRODUCTS
MWHN322_326_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - PAPER AND PRODUCTS
MWHN325_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - CHEMICALS AND PRODUCTS
MWHN331_BUTLER	BUTLER COUNTY MWH SALES - INDUSTRIAL - PRIMARY METAL INDUSTRIES
MWHN331LBUTLER_OH_KY	SERVICE AREA MWH SALES LESS BUTLER COUNTY - INDUSTRIAL - PRIMARY METAL INDUSTRIES
MWHN332_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - FABRICATED METALS
MWHN333_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - INDUSTRIAL MACHINERY AND EQUIPMENT
MWHN334_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - COMPUTER AND ELECTRONICS
MWHN335_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - ELECTRICAL EQUIPMENT
MWHN3361_62_63_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - MOTOR VEHICLES AND PARTS
MWHN3364_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - TRANSPORTATION EQUIPMENT OTHER THAN MOTOR VEHICLES AND PARTS
MWHNAOI_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - ALL OTHER INDUSTRIES
MWSPEAK_OH_KY	SERVICE AREA MW PEAK - SUMMER
MWWPEAK_OH_KY	SERVICE AREA MW PEAK - WINTER
N_OH_KY	SERVICE AREA TOTAL POPULATION
PMHIGH	MAXIMUM HOURLY TEMPERATURE - AFTERNOON
PMHUMIDATHIGH	HUMIDITY - AFTERNOON
PMLOW	MINIMUM HOURLY TEMPERATURE - EVENING
PMPEAK	QUALITATIVE VARIABLE - EVENING PEAK
PRECIP_OH_KY	SERVICE AREA PRECIPITATION
PREVPMHIGH	MAXIMUM HOURLY TEMPERATURE - PREVIOUS AFTERNOON

PREVPMLOW	MINIMUM HOURLY TEMPERATURE - PREVIOUS AFTERNOON
SAT_CAC_EFF	=EFF_CAC_OH_KY*(SAT_EHP_OH_KY+SAT_CACNHP_OH_KY)
SAT_CACNHP_OH_KY	SERVICE AREA SATURATION OF CENTRAL AIR CONDITIONING WITHOUT HEAT PUMP
SAT_EH_EFF	=(SAT_ER_OH_KY+(SAT_EHP_OH_KY*EFF_EHP_OH_KY))
SAT_EHP_OH_KY	SERVICE AREA SATURATION OF ELECTRIC HEAT PUMPS - RESIDENTIAL
SAT_ER_OH_KY	SATURATION RATE OF ELECTRIC RESISTANCE HEATERS IN SERVICE AREA
SAT_RAC_EFF	=EFF_RAC_OH_KY*SAT_RAC_OH_KY
SAT_RAC_OH_KY	SERVICE AREA SATURATION OF WINDOW AIR CONDITIONING SERVICE AREA
SAT_SL_OH_KY	=(0.5*SATMERC_OH_KY)+(0.5*SATSODVAP_OH_KY)
SATMERC_OH_KY	SERVICE AREA SATURATION OF MERCURY VAPOR STREET LIGHTING
SATSODVAP_OH_KY	SERVICE AREA SATURATION OF SODIUM VAPOR STREET LIGHTING
TS_KW_IND_OH_KY	SERVICE AREA TS RATE FOR DEMAND FOR INDUSTRIAL CUSTOMERS
TS_KWH_IND_OH_KY	SERVICE AREA TS RATE FOR USAGE FOR INDUSTRIAL CUSTOMERS
WINDAM	WIND SPEED - MORNING
WPI0561	WHOLESALE PRICE INDEX FOR CRUDE PETROLEUM
XMAS	QUALITATIVE VARIABLE - CHRISTMAS WEEK
YP_OH_KY	SERVICE AREA PERSONAL INCOME

EQUATION FORECAST ERROR
MEASURED BY
MEAN OF THE STANDARD ERRORS

	SERVICE AREA ELECTRIC CUSTOMERS – RESIDENTIAL	10,162	
	KWH USE PER CUSTOMER – RESIDENTIAL	22	KWH
	KWH SALES – COMMERCIAL	21,040,448	KWH
	MWH SALES – INDUSTRIAL – FOOD, BEVERAGE AND TOBACCO	8,780	MWH
	MWH SALES – INDUSTRIAL – PAPER, PLASTIC AND RUBBER	15,261	MWH
	MWH SALES – INDUSTRIAL – CHEMICALS	25,310	MWH
	MWH SALES – INDUSTRIAL – PRIMARY METALS - BUTLER	12,205	MWH
	MWH SALES – INDUSTRIAL – PRIMARY METALS – LESS BUTLER	3,204	MWH
	MWH SALES – INDUSTRIAL – FABRICATED METALS	7,725	MWH
	MWH SALES – INDUSTRIAL – MACHINERY	4,475	MWH
	MWH SALES – INDUSTRIAL – COMPUTER AND ELECTRONICS	4,159	MWH
	MWH SALES – INDUSTRIAL – ELEC. EQUIPMENT, APPLIANCE & COMPONENT	3,149	MWH
	MWH SALES – INDUSTRIAL – MOTOR VEHICLES AND PARTS	8,695	MWH
	MWH SALES – INDUSTRIAL – AEROSPACE PRODUCTS AND PARTS	6,614	MWH
	MWH SALES – INDUSTRIAL – MISCELLANEOUS	41,644	MWH
	KWH SALES – OTHER PUBLIC AUTHORITIES – WATER PUMPING	713,775	KWH
	KWH SALES – OTHER PUBLIC AUTHORITIES – LESS WATER PUMPING	10,029,656	KWH
	KWH SALES – STREET LIGHT	283,225	KWH
	SERVICE AREA – SUMMER PEAK	197	MW
Forecast Error	SERVICE AREA – WINTER PEAK	366	MW

6. Computer Software

All of the equations in the Electric Energy Forecast Model and Electric Peak Load Model were estimated and forecasted on personal computers using the Eviews software from Quantitative Micro Software, LLC.

SECTION II FORECASTS FOR ELECTRIC TRANSMISSION OWNERS

A. GENERAL GUIDELINES

No Response Required.

B. ELECTRIC TRANSMISSION FORECAST

This section of the 2011 Electric Long-Term Forecast Report contains the transmission forecast forms FE-T1 through FE-T10 as required by OAC 4901:5-5-04. The forecast is developed using the methodology previously described.

FORM FE-T1: TRANSMISSION ENERGY DELIVERY FORECAST

(Megawatt Hours/Year) (a)

	YEAR	(1) ENERGY RECEIPTS FROM GENERATION SOURCES CONNECTED TO THE OWNER'S SYSTEM INSIDE OHIO	(2) ENERGY RECEIPTS FROM GENERATION SOURCES CONNECTED TO THE SYSTEM OUTSIDE OHIO	(3) TOTAL ENERGY RECEIPTS FROM GENERATION SOURCES 1 + 2	(4) ENERGY RECEIPTS AT INTERCONNECTIONS WITH OTHER TRANSMISSION COMPANIES INSIDE OHIO	(5) ENERGY RECEIPTS AT INTERCONNECTIONS WITH OTHER TRANSMISSION COMPANIES OUTSIDE OHIO	(6) TOTAL ENERGY RECEIPTS AT INTERCONNECTIONS 4 + 5	(7) TOTAL ENERGY RECEIPTS 3 + 6	(8) ENERGY DELIVERIES AT INTERCONNECTIONS WITH OTHER TRANSMISSION COMPANIES INSIDE OHIO	(9) ENERGY DELIVERIES AT INTERCONNECTIONS WITH OTHER TRANSMISSION COMPANIES OUTSIDE OHIO	(10) TOTAL ENERGY DELIVERIES AT INTERCONNECTIONS 8+9	(11) TOTAL ENERGY DELIVERIES FOR LOAD CONNECTED TO THE SYSTEM 7-10	(12) ENERGY DELIVERIES FOR LOADS CONNECTED TO THE SYSTEM INSIDE OHIO	(13) ENERGY DELIVERIES FOR LOADS CONNECTED TO THE SYSTEM OUTSIDE OHIO 11-12
-5	2006	23,491,130	4,972,870	28,464,000	14,156,964	581,918	14,738,882	43,202,882	15,263,738	306,588	15,570,326	27,632,556	23,573,015	4,059,541
-4	2007	21,523,069	3,794,386	25,317,455	17,109,515	926,439	18,035,954	43,353,409	13,987,699	327,267	14,314,966	29,038,443	24,535,599	4,502,844
-3	2008	20,212,738	4,241,387	24,454,125	17,184,908	1,199,563	18,384,471	42,838,596	14,712,665	184,035	18,496,700	27,941,896	23,542,249	4,399,647
-2	2009	21,060,436	4,278,054	25,338,490	15,856,020	863,773	16,719,793	42,058,283	15,523,646	235,746	15,759,392	26,298,891	22,131,394	4,167,497
-1	2010	22,300,838	4,420,174	26,721,012	12,235,391	1,081,646	13,317,037	40,038,049	15,611,793	182,132	15,793,925	16,876,556	12,824,742	4,051,814
0	2011											16,111,663	12,042,641	4,069,022
1	2012											25,772,197	21,626,010	4,146,187
2	2013											25,608,732	21,463,685	4,145,047
3	2014											25,460,704	21,311,695	4,149,009
4	2015											25,212,628	21,075,558	4,137,070
5	2016											25,013,141	20,880,930	4,132,211
6	2017											24,825,869	20,697,588	4,128,281
7	2018											24,696,335	20,562,909	4,133,426
8	2019											24,543,847	20,409,617	4,134,230
9	2020											24,434,926	20,292,894	4,142,032
10	2021											24,337,499	20,185,629	4,151,870

(a) To be filled out by electric transmission owners operating in Ohio.

PUCO Form FE-T2 : Electric Transmission Owner's System Seasonal Peak Load Demand Forecast

(Megawatts)(a)

Duke Energy Ohio After DSM (e) (f)

		Native Load (b)		Internal Load (c)	
	Year	Summer	Winter (d)	Summer	Winter (d)
-5	2006	4,366	3,551	4,366	3,551
-4	2007	4,436	3,505	4,459	3,505
-3	2008	4,074	3,526	4,074	3,526
-2	2009	3,675	2,271	3,675	2,271
-1	2010	2,317	1,459	2,328	1,459
0	2011	1,795	3,626	1,859	3,626
1	2012	4,340	3,676	4,504	3,676
2	2013	4,376	3,729	4,540	3,729
3	2014	4,439	3,740	4,603	3,740
4	2015	4,441	3,745	4,605	3,745
5	2016	4,424	3,750	4,588	3,750
6	2017	4,432	3,756	4,596	3,756
7	2018	4,436	3,745	4,600	3,745
8	2019	4,417	3,736	4,581	3,736
9	2020	4,398	3,730	4,563	3,730
10	2021	4,388	3,724	4,552	3,724

(a) To be filled out by electric transmission owners operating in Ohio.
(b) Excludes interruptible load.
(c) Includes interruptible load.
(d) Winter load reference is to peak loads which follow the summer peak load.
(e) Includes historical DSM impacts.
(f) Historical company peaks not necessarily coincident with system peak

PUCO Form FE-T3: Electric Transmission Owner's Total Monthly Energy Forecast (MWh)

Duke Energy Ohio After DSM (e)

Year 0 (d)	Ohio Portion (a)	Total Company (b)	Total System (c)
January	622,588	622 588	622,588
February	533 214	533.214	533.214
March	503 154	503.154	503.154
April	426,514	426.514	426.514
May	452,079	452.079	452.079
June	576,330	576.330	576,330
July	672.000	672.000	672.000
August	687.108	687.108	687.108
September	545.019	545.019	545.019
October	484.528	484.528	484,528
November	480.628	480.628	480,628
December	612.486	612,486	612,486
Year 1 (d)			
January	2,031,431	2,031,431	2.031,431
February	1,748.560	1,748.560	1 748 560
March	1.747.858	1,747,858	1,747,858
April	1,571,651	1,571.651	1.571,651
May	1,686,388	1,686,388	1.686.388
June	1,955,723	1,955,723	1.955,723
July	2.132,536	2.132,536	2.132,536
August	2,172,250	2,172,250	2.172.250
September	1,746,410	1,746,410	1,746,410
October	1.661,485	1,661,485	1.661,485
November	1,634,280	1.634,280	1.634,280
December	1.906,867	1.906,867	1,906.867

a. Electric transmission owner shall provide or cause to be provided data for the Ohio portion of its service area in this column.

b. Electric transmission owner operating across Ohio bounderies shall provide or cause to be provided data for the total service area in this column.

c. Electric transmission owner operating as a part of an integrated operating system shall provide for the total system in this column.

d. Actual data shall be indicated with an asterisk (*).

PUCO Form FE-T4: Electric Transmission Owner's Monthly Internal Peak Load Forecast (Megawatts)

Internal

Duke Energy Ohio After DSM (e)

Year 0 (d)	Ohio Portion[a]	Total Service Area[b]	System[c]
January	1,259	1,259	1,259
February	1,295	1,295	1,295
March	1,238	1,238	1,238
April	1,060	1,060	1,060
May	1,229	1,229	1,229
June	1,581	1,581	1,581
July	1,859	1,859	1,859
August	1,743	1,743	1,743
September	1,617	1,617	1,617
October	1,174	1,174	1,174
November	1,225	1,225	1,225
December	1,419	1,419	1,419
Year 1 (d)			
January	3,626	3,626	3,626
February	3,529	3,529	3,529
March	3,301	3,301	3,301
April	3,036	3,036	3,036
May	3,591	3,591	3,591
June	4,275	4,275	4,275
July	4,501	4,501	4,501
August	4,504	4,504	4,504
September	3,969	3,969	3,969
October	3,195	3,195	3,195
November	3,165	3,165	3,165
December	3,577	3,577	3,577

(a) Electric transmission owner shall provide or cause to be provided data for the Ohio portion of its service area in this column

(b) Electric transmission owner operating across Ohio boundaries shall provide or cause to be provided data for the total service area in this column

(c) Electric transmission owner operating as a part of an integrated operating system shall provide data for the total system in this column.

(d) Actual data shall be indicated with an asterisk (*)

(e) Includes DSM impacts.

Form FE-T5 - As of February 1, 2002 The Midwest Independent Transmission System Operator (MISO) took over functional control of the transmission system. It is Duke Energy Ohio opinion that this form is no longer pertinent to Duke Energy Ohio since Duke Energy Ohio no longer sells transmission or tracks the firmness thereof. For this reason, Duke Energy Ohio cannot guarantee the accuracy of the numbers in firm and non-firm "transmission to transmission service."

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

PART A: SOURCES OF ENERGY

Reporting Month Jan-10

1. Energy Receipts from all sources by type: (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
Energy Receipts from Power Plants directly connected to the Electric Transmission Owner's transmission system	2,470,935		2,470,935
Energy Receipts from other sources	(71,117)		(71,117)
Total Energy Receipts	2,399,818	0	2,399,818

PART B: DELIVERY OF ENERGY

Reporting Month Jan-10

1. Energy deliveries to all points connected to the Electric Transmission Owner's system (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	2,319,273,091	0	2,319,273,091
Other Investor-Owned Electric Utilities			
Cooperative-Owned Electric System	48,839		48,839
Municipal-Owned Electric Systems	57,593		57,593
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,604,179		1,604,179
Total Energy Delivery	2,320,983,702	0	2,320,983,702

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

Reporting Month Jan-10

2. Energy deliveries to all points connected to the Electric Transmission Owner's system located in Ohio (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	1,940,075,618	0	1,940,075,618
Other Investor-Owned Electric Utilities			
Cooperatively-Owned Electric System	31,168		31,168
Municipally-Owned Electric Systems	57,593		57,593
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,471,832		1,471,832
Total Energy Delivery	1,941,636,211	0	1,941,636,211

PART C: LOSSES AND UNACCOUNTED FOR (MWH)

REPORTING MONTH Jan-10

	Firm Transmission Service	Non-Firm Transmission Service	Total
Sources minus Delivery (a)	(2,318,583,884)	0	(2,318,583,884)

(a) FE-T5: Part A minus Part B (1)

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

PART A: SOURCES OF ENERGY

Reporting Month Feb-10

1. Energy Receipts from all sources by type: (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
Energy Receipts from Power Plants directly connected to the Electric Transmission Owner's transmission system	2,340,256	0	2,340,256
Energy Receipts from other sources	50,173		50,173
Total Energy Receipts	2,390,429	0	2,390,429

PART B: DELIVERY OF ENERGY

Reporting Month Feb-10

1. Energy deliveries to all points connected to the Electric Transmission Owner's system (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	2,062,228,163	0	2,062,228,163
Other Investor-Owned Electric Utilities			
Cooperative-Owned Electric System	42,689	0	42,689
Municipal-Owned Electric Systems	52,930		52,930
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,451,208		1,451,208
Total Energy Delivery	2,063,774,990	0	2,063,774,990

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

Reporting Month Feb-10

2. Energy deliveries to all points connected to the Electric Transmission Owner's system located in Ohio (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	1,727,280,010	0	1,727,280,010
Other Investor-Owned Electric Utilities			
Cooperatively-Owned Electric System	27,227		27,227
Municipally-Owned Electric Systems	52,930	0	52,930
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,351,904	0	1,351,904
Total Energy Delivery	1,728,712,071	0	1,728,712,071

PART C: LOSSES AND UNACCOUNTED FOR (MWH)

REPORTING MONTH Feb-10

	Firm Transmission Service	Non-Firm Transmission Service	Total
Sources minus Delivery (a)	(2,061,384,561)	0	(2,061,384,561)

(a) FE-T5: Part A minus Part B (1)

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

PART A: SOURCES OF ENERGY

Reporting Month Mar-10

1. Energy Receipts from all sources by type: (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
Energy Receipts from Power Plants directly connected to the Electric Transmission Owner's transmission system	2,361,567	0	2,361,567
Energy Receipts from other sources	200,057	0	200,057
Total Energy Receipts	2,561,624	0	2,561,624

PART B: DELIVERY OF ENERGY

Reporting Month Mar-10

1. Energy deliveries to all points connected to the Electric Transmission Owner's system (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	2,013,014,898	0	2,013,014,898
Other Investor-Owned Electric Utilities			
Cooperative-Owned Electric System	36,624	0	36,624
Municipal-Owned Electric Systems	49,407	0	49,407
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,507,359	0	1,507,359
Total Energy Delivery	2,014,608,288	0	2,014,608,288

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

Reporting Month Mar-10

2. Energy deliveries to all points connected to the Electric Transmission Owner's system located in Ohio (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	1,677,561,203	0	1,677,561,203
Other Investor-Owned Electric Utilities			
Cooperatively-Owned Electric System	21,767		21,767
Municipally-Owned Electric Systems	49,407	0	49,407
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,420,011	0	1,420,011
Total Energy Delivery	1,679,052,388	0	1,679,052,388

PART C: LOSSES AND UNACCOUNTED FOR (MWH)

REPORTING MONTH Mar-10

	Firm Transmission Service	Non-Firm Transmission Service	Total
Sources minus Delivery (a)	(2,012,046,664)	0	(2,012,046,664)

(a) FE-T5: Part A minus Part B (1)

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

PART A: SOURCES OF ENERGY

Reporting Month Apr-10

1. Energy Receipts from all sources by type: (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
Energy Receipts from Power Plants directly connected to the Electric Transmission Owner's transmission system	2,274,031	0	2,274,031
Energy Receipts from other sources	339,176	0	339,176
Total Energy Receipts	2,613,207	0	2,613,207

PART B: DELIVERY OF ENERGY

Reporting Month Apr-10

1. Energy deliveries to all points connected to the Electric Transmission Owner's system (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	1,781,294,466	0	1,781,294,466
Other Investor-Owned Electric Utilities			
Cooperative-Owned Electric System	30,578	0	30,578
Municipal-Owned Electric Systems	51,743	0	51,743
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,452,297	0	1,452,297
Total Energy Delivery	1,782,829,084	0	1,782,829,084

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

Reporting Month Apr-10

2. Energy deliveries to all points connected to the Electric Transmission Owner's system located in Ohio (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	1,492,007,517	0	1,492,007,517
Other Investor-Owned Electric Utilities			
Cooperatively-Owned Electric System	16,336		16,336
Municipally-Owned Electric Systems	51,743	0	51,743
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,347,745	0	1,347,745
Total Energy Delivery	1,493,423,341	0	1,493,423,341

PART C: LOSSES AND UNACCOUNTED FOR (MWH)

REPORTING MONTH Apr-10

	Firm Transmission Service	Non-Firm Transmission Service	Total
Sources minus Delivery (a)	(1,780,215,877)	0	(1,780,215,877)

(a) FE-T5: Part A minus Part B (1)

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

PART A: SOURCES OF ENERGY

Reporting Month May-10

1. Energy Receipts from all sources by type: (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
Energy Receipts from Power Plants directly connected to the Electric Transmission Owner's transmission system	1,877,304	0	1,877,304
Energy Receipts from other sources	(301,783)	0	(301,783)
Total Energy Receipts	1,575,521	0	1,575,521

PART B: DELIVERY OF ENERGY

Reporting Month May-10

1. Energy deliveries to all points connected to the Electric Transmission Owner's system (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	1,729,906,226	0	1,729,906,226
Other Investor-Owned Electric Utilities			
Cooperative-Owned Electric System	34,118	0	34,118
Municipal-Owned Electric Systems	37,130	0	37,130
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,138,648	0	1,138,648
Total Energy Delivery	1,731,116,122	0	1,731,116,122

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

Reporting Month May-10

2. Energy deliveries to all points connected to the Electric Transmission Owner's system located in Ohio (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	1,447,689,411	0	1,447,689,411
Other Investor-Owned Electric Utilities			
Cooperatively-Owned Electric System	18,402		18,402
Municipally-Owned Electric Systems	37,130	0	37,130
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,115,655	0	1,115,655
Total Energy Delivery	1,448,860,598	0	1,448,860,598

PART C: LOSSES AND UNACCOUNTED FOR (MWH)

REPORTING MONTH May-10

	Firm Transmission Service	Non-Firm Transmission Service	Total
Sources minus Delivery (a)	(1,729,540,601)	0	(1,729,540,601)

(a) FE-T5: Part A minus Part B (1)

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL *MWH/MONTH) FOR THE MOST RECENT YEAR*

PART A: SOURCES OF ENERGY

Reporting Month Jun-10

1. Energy Receipts from all sources by type: (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
Energy Receipts from Power Plants directly connected to the Electric Transmission Owner's transmission system	2,082,701	0	2,082,701
Energy Receipts from other sources	(544,907)	0	(544,907)
Total Energy Receipts	1,537,794	0	1,537,794

PART B: DELIVERY OF ENERGY

Reporting Month Jun-10

1. Energy deliveries to all points connected to the Electric Transmission Owner's system (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	2,205,546,091	0	2,205,546,091
Other Investor-Owned Electric Utilities			
Cooperative-Owned Electric System	41,128	0	41,128
Municipal-Owned Electric Systems	48,900	0	48,900
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,228,771	0	1,228,771
Total Energy Delivery	2,206,864,890	0	2,206,864,890

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

Reporting Month Jun-10

2. Energy deliveries to all points connected to the Electric Transmission Owner's system located in Ohio (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	1,845,989,090	0	1,845,989,090
Other Investor-Owned Electric Utilities			
Cooperatively-Owned Electric System	22,857		22,857
Municipally-Owned Electric Systems	48,900	0	48,900
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,136,262	0	1,136,262
Total Energy Delivery	1,847,197,109	0	1,847,197,109

PART C: LOSSES AND UNACCOUNTED FOR (MWH)

REPORTING MONTH Jun-10

	Firm Transmission Service	Non-Firm Transmission Service	Total
Sources minus Delivery (a)	(2,205,327,096)	0	(2,205,327,096)

(a) FE-T5: Part A minus Part B (1)

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

PART A: SOURCES OF ENERGY

Reporting Month Jul-10

1. Energy Receipts from all sources by type: (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
Energy Receipts from Power Plants directly connected to the Electric Transmission Owner's transmission system	2,160,085	0	2,160,085
Energy Receipts from other sources	(692,960)	0	(692,960)
Total Energy Receipts	1,467,125	0	1,467,125

PART B: DELIVERY OF ENERGY

Reporting Month Jul-10

1. Energy deliveries to all points connected to the Electric Transmission Owner's system (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	2,426,251,794	0	2,426,251,794
Other Investor-Owned Electric Utilities			
Cooperative-Owned Electric System	44,780	0	44,780
Municipal-Owned Electric Systems	52,149	0	52,149
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,337,250	0	1,337,250
Total Energy Delivery	2,427,685,973	0	2,427,685,973

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

Reporting Month Jul-10

2. Energy deliveries to all points connected to the Electric Transmission Owner's system located in Ohio (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	2,027,417,735	0	2,027,417,735
Other Investor-Owned Electric Utilities			
Cooperatively-Owned Electric System	25,901		25,901
Municipally-Owned Electric Systems	52,149	0	52,149
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,226,326	0	1,226,326
Total Energy Delivery	2,028,722,111	0	2,028,722,111

PART C: LOSSES AND UNACCOUNTED FOR (MWH)

REPORTING MONTH Jul-10

	Firm Transmission Service	Non-Firm Transmission Service	Total
Sources minus Delivery (a)	(2,426,218,848)	0	(2,426,218,848)

(a) FE-T5: Part A minus Part B (1)

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

PART A: SOURCES OF ENERGY

Reporting Month Aug-10

1. Energy Receipts from all sources by type: (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
Energy Receipts from Power Plants directly connected to the Electric Transmission Owner's transmission system	2,346,285	0	2,346,285
Energy Receipts from other sources	(478,485)	0	(478,485)
Total Energy Receipts	1,867,800	0	1,867,800

PART B: DELIVERY OF ENERGY

Reporting Month Aug-10

1. Energy deliveries to all points connected to the Electric Transmission Owner's system (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	2,481,255,279	0	2,481,255,279
Other Investor-Owned Electric Utilities			
Cooperative-Owned Electric System	46,594	0	46,594
Municipal-Owned Electric Systems	47,835	0	47,835
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,363,617	0	1,363,617
Total Energy Delivery	2,482,713,325	0	2,482,713,325

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

Reporting Month Aug-10

2. Energy deliveries to all points connected to the Electric Transmission Owner's system located in Ohio (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	2,069,587,082	0	2,069,587,082
Other Investor-Owned Electric Utilities			
Cooperatively-Owned Electric System	25,099		25,099
Municipally-Owned Electric Systems	47,835	0	47,835
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,248,469	0	1,248,469
Total Energy Delivery	2,070,908,485	0	2,070,908,485

PART C: LOSSES AND UNACCOUNTED FOR (MWH)

REPORTING MONTH Aug-10

	Firm Transmission Service	Non-Firm Transmission Service	Total
Sources minus Delivery (a)	(2,480,845,525)	0	(2,480,845,525)

(a) FE-T5: Part A minus Part B (1)

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

PART A: SOURCES OF ENERGY

Reporting Month Sep-10

1. Energy Receipts from all sources by type: (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
Energy Receipts from Power Plants directly connected to the Electric Transmission Owner's transmission system	2,346,285	0	2,346,285
Energy Receipts from other sources	(478,485)	0	(478,485)
Total Energy Receipts	1,867,800	0	1,867,800

PART B: DELIVERY OF ENERGY

Reporting Month Sep-10

1. Energy deliveries to all points connected to the Electric Transmission Owner's system (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	2,251,222,534	0	2,251,222,534
Other Investor-Owned Electric Utilities			
Cooperative-Owned Electric System	36,407	0	36,407
Municipal-Owned Electric Systems	43,224	0	43,224
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,279,617	0	1,279,617
Total Energy Delivery	2,252,581,782	0	2,252,581,782

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

Reporting Month Sep-10

2. Energy deliveries to all points connected to the Electric Transmission Owner's system located in Ohio (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	1,875,112,769	0	1,875,112,769
Other Investor-Owned Electric Utilities			
Cooperatively-Owned Electric System	18,748		18,748
Municipally-Owned Electric Systems	43,224	0	43,224
Federal and State Electric Agencies			
Other end user service			
	0		
For Non Distribution service (transmission to transmission service)	1,198,053	0	1,198,053
Total Energy Delivery	1,876,372,794	0	1,876,372,794

PART C: LOSSES AND UNACCOUNTED FOR (MWH)

REPORTING MONTH Sep-10

	Firm Transmission Service	Non-Firm Transmission Service	Total
Sources minus Delivery (a)	(2,250,713,982)	0	(2,250,713,982)

(a) FE-T5: Part A minus Part B (1)

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

PART A: SOURCES OF ENERGY

Reporting Month Oct-10

1. Energy Receipts from all sources by type: (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
Energy Receipts from Power Plants directly connected to the Electric Transmission Owner's transmission system	2,199,638	0	2,199,638
Energy Receipts from other sources	207,519	0	207,519
Total Energy Receipts	2,407,157	0	2,407,157

PART B: DELIVERY OF ENERGY

Reporting Month Oct-10

1. Energy deliveries to all points connected to the Electric Transmission Owner's system (MWH)

	Firm Transmission *Service*	Non-Firm Transmission *Service*	*Total*
For Distribution service:			
Affiliated Electric Utility Companies	1,821,205,356	0	1,821,205,356
Other Investor-Owned Electric Utilities			
Cooperative-Owned Electric System	33,367	0	33,367
Municipal-Owned Electric Systems	54,517	0	54,517
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,433,130	0	1,433,130
Total Energy Delivery	1,822,726,370	0	1,822,726,370

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

Reporting Month Oct-10

2. Energy deliveries to all points connected to the Electric Transmission Owner's system located in Ohio (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	1,517,521,233	0	1,517,521,233
Other Investor-Owned Electric Utilities			
Cooperatively-Owned Electric System	17,104		17,104
Municipally-Owned Electric Systems	54,517	0	54,517
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,345,856	0	1,345,856
Total Energy Delivery	1,518,938,710	0	1,518,938,710

PART C: LOSSES AND UNACCOUNTED FOR (MWH)

REPORTING MONTH Oct-10

	Firm Transmission Service	Non-Firm Transmission Service	Total
Sources minus Delivery (a)	(1,820,319,213)	0	(1,820,319,213)

(a) *FE-T5: Part A minus Part B (1)*

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

PART A: SOURCES OF ENERGY

Reporting Month Nov-10

1. Energy Receipts from all sources by type: (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
Energy Receipts from Power Plants directly connected to the Electric Transmission Owner's transmission system	2,105,225	0	2,105,225
Energy Receipts from other sources	73,232	0	73,232
Total Energy Receipts	2,178,457	0	2,178,457

PART B: DELIVERY OF ENERGY

Reporting Month Nov-10

1. Energy deliveries to all points connected to the Electric Transmission Owner's system (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	1,716,163,348	0	1,716,163,348
Other Investor-Owned Electric Utilities			
Cooperative-Owned Electric System	35,367	0	35,367
Municipal-Owned Electric Systems	55,904	0	55,904
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,413,806	0	1,413,806
Total Energy Delivery	1,717,668,425	0	1,717,668,425

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

Reporting Month Nov-10

2. Energy deliveries to all points connected to the Electric Transmission Owner's system located in Ohio (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	1,434,269,777	0	1,434,269,777
Other Investor-Owned Electric Utilities			
Cooperatively-Owned Electric System	21,116		21,116
Municipally-Owned Electric Systems	55,904	0	55,904
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,325,100	0	1,325,100
Total Energy Delivery	1,435,671,897	0	1,435,671,897

PART C: LOSSES AND UNACCOUNTED FOR (MWH)

REPORTING MONTH Nov-10

	Firm Transmission Service	Non-Firm Transmission Service	Total
Sources minus Delivery (a)	(1,715,489,968)	0	(1,715,489,968)

(a) FE-T5: Part A minus Part B (1)

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

PART A: SOURCES OF ENERGY

Reporting Month Dec-10

1. Energy Receipts from all sources by type: (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
Energy Receipts from Power Plants directly connected to the Electric Transmission Owner's transmission system	2,354,478	0	2,354,478
Energy Receipts from other sources	(161,920)	0	(161,920)
Total Energy Receipts	2,192,558	0	2,192,558

PART B: DELIVERY OF ENERGY

Reporting Month Dec-10

1. Energy deliveries to all points connected to the Electric Transmission Owner's system (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	2,127,758,632	0	2,127,758,632
Other Investor-Owned Electric Utilities			
Cooperative-Owned Electric System	48,460	0	48,460
Municipal-Owned Electric Systems	62,085	0	62,085
Federal and State Electric Agencies			
Other end user service			
For Non Distribution service (transmission to transmission service)	1,530,508	0	1,530,508
Total Energy Delivery	2,129,399,685	0	2,129,399,685

FORM FE-T5 MONTHLY ENERGY TRANSACTIONS (TOTAL MWH/MONTH) FOR THE MOST RECENT YEAR

Reporting Month Dec-10

2. Energy deliveries to all points connected to the Electric Transmission Owner's system located in Ohio (MWH)

	Firm Transmission Service	Non-Firm Transmission Service	Total
For Distribution service:			
Affiliated Electric Utility Companies	1,768,025,937	0	1,768,025,937
Other Investor-Owned Electric Utilities			
Cooperatively-Owned Electric System	31,109		31,109
Municipally-Owned Electric Systems	62,085	0	62,085
Federal and State Electric Agencies	0		
Other end user service			
For Non Distribution service (transmission to transmission service)	1,424,585	0	1,424,585
Total Energy Delivery	1,769,543,716	0	1,769,543,716

PART C: LOSSES AND UNACCOUNTED FOR (MWH)

REPORTING MONTH Dec-10

	Firm Transmission Service	Non-Firm Transmission Service	Total
Sources minus Delivery (a)	(2,127,207,127)	0	(2,127,207,127)

(a) FE-T5: Part A minus Part B (1)

As of February 1, 2002 the Midwest ISO took over the function of managing DEO's Transmission Service Requests. As such, the allocation of AFC is the sole responsibility of the Midwest ISO.

FORM FE-T6: CONDITIONS AT TIME OF MONTHLY PEAK

Reporting Month JANUARY

Megawatts	3,539	Day of Week	FRI	Day of Month	8	Hour of Peak	10:00
CURTAILMENT PRIORITY CLASSES				Firm Transmission Service	Non-Firm Transmission Service	Total	
Number of Requests				73	6	79	
Requests (MW)				36,457	410	36867	
Number of requests accepted				44	3	47	
Requests accepted (MW)				31,860	44	31904	
							Reason for non-delivery
Requests not accepted (MW) and reason for not accepting delivery				4,597	366	4963	Withdrawn/ Invalid/ Refused/ Declined/ Annulled/ Retracted

Reporting Month FEBRUARY

Megawatts	3,497	Day of Week	FRI	Day of Month	12	Hour of Peak	9:00
CURTAILMENT PRIORITY CLASSES				Firm Transmission Service	Non-Firm Transmission Service	Total	
Number of Requests				72	5	77	
Requests (MW)				36,157	397	36,554	
Number of requests accepted				44	1	45	
Requests accepted (MW)				31,860	29	31,889	
							Reason for non-delivery
Requests not accepted (MW) and reason for not accepting delivery				4,297	368	4,665	Withdrawn/ Invalid/ Refused/ Declined/ Annulled/ Retracted

FORM FE-T6: CONDITIONS AT TIME OF MONTHLY PEAK

Reporting Month MARCH

Megawatts	3,240	Day of Week	TUES	Day of Month	2	Hour of Peak	20:00
CURTAILMENT PRIORITY CLASSES				Firm Transmission Service	Non-Firm Transmission Service	Total	
Number of Requests				78	4	82	
Requests (MW)				36,157	378	36535	
Number of requests accepted				50	1	51	
Requests accepted (MW)				31,860	12	31872	
							Reason for non-delivery
Requests not accepted (MW) and reason for not accepting delivery				4,297	366	4663	Withdrawn/ Invalid/ Refused/ Declined/ Annulled/ Retracted

Reporting Month APRIL

Megawatts	2,888	Day of Week	THUR	Day of Month	15	Hour of Peak	15:00
CURTAILMENT PRIORITY CLASSES				Firm Transmission Service	Non-Firm Transmission Service	Total	
Number of Requests				81	4	85	
Requests (MW)				36,448	405	36,853	
Number of requests accepted				52	1	53	
Requests accepted (MW)				32,054	39	32,093	
							Reason for non-delivery
Requests not accepted (MW) and reason for not accepting delivery				4,394	366	4,760	Withdrawn/ Invalid/ Refused/ Declined/ Annulled/ Retracted

FORM FE-T6: CONDITIONS AT TIME OF MONTHLY PEAK

Reporting Month MAY

Megawatts	3,739	Day of Week	THUR	Day of Month	27	Hour of Peak	13:00

CURTAILMENT PRIORITY CLASSES	Firm Transmission Service	Non-Firm Transmission Service	Total	
Number of Requests	82	3	85	
Requests (MW)	36,448	379	36827	
Number of requests accepted	53	2	55	
Requests accepted (MW)	32,054	19	32073	
				Reason for non-delivery
Requests not accepted (MW) and reason for not accepting delivery	4,394	360	4754	Withdrawn/ Invalid/ Refused/ Declined/ Annulled/ Retracted

Reporting Month JUNE

Megawatts	4,464	Day of Week	WED	Day of Month	23	Hour of Peak	16:00

CURTAILMENT PRIORITY CLASSES	Firm Transmission Service	Non-Firm Transmission Service	Total	
Number of Requests	83	2	85	
Requests (MW)	36,126	380	36,506	
Number of requests accepted	58	1	59	
Requests accepted (MW)	32,072	20	32,092	
				Reason for non-delivery
Requests not accepted (MW) and reason for not accepting delivery	4,054	360	4,414	Withdrawn/ Invalid/ Refused/ Declined/ Annulled/ Retracted

FORM FE-T6: CONDITIONS AT TIME OF MONTHLY PEAK

Reporting Month JULY

Megawatts	4,446	Day of Week	THUR	Day of Month	8	Hour of Peak	16:00
CURTAILMENT PRIORITY CLASSES				Firm Transmission Service	Non-Firm Transmission Service	Total	
Number of Requests				85	4	89	
Requests (MW)				36,440	612	37052	
Number of requests accepted				62	3	65	
Requests accepted (MW)				32,539	252	32791	
							Reason for non-delivery
Requests not accepted (MW) and reason for not accepting delivery				3,901	360	4261	Withdrawn/ Invalid/ Refused/ Declined/ Annulled/ Retracted

Reporting Month AUGUST

Megawatts	4,669	Day of Week	WED	Day of Month	4	Hour of Peak	14:00
CURTAILMENT PRIORITY CLASSES				Firm Transmission Service	Non-Firm Transmission Service	Total	
Number of Requests				85	3	88	
Requests (MW)				36,540	400	36,940	
Number of requests accepted				58	2	60	
Requests accepted (MW)				32,539	40	32,579	
							Reason for non-delivery
Requests not accepted (MW) and reason for not accepting delivery				4,001	360	4,361	Withdrawn/ Invalid/ Refused/ Declined/ Annulled/ Retracted

FORM FE-T6: CONDITIONS AT TIME OF MONTHLY PEAK

Reporting Month SEPTEMBER

Megawatts	4,322	Day of Week	WED	Day of Month	1	Hour of Peak	17:00

CURTAILMENT PRIORITY CLASSES	Firm Transmission Service	Non-Firm Transmission Service	Total	
Number of Requests	86	3	89	
Requests (MW)	36,590	390	36980	
Number of requests accepted	58	2	60	
Requests accepted (MW)	32,539	30	32569	
				Reason for non-delivery
Requests not accepted (MW) and reason for not accepting delivery	4,051	360	4411	Withdrawn/ Invalid/ Refused/ Declined/ Annulled/ Retracted

Reporting Month OCTOBER

Megawatts	3,006	Day of Week	MON	Day of Month	11	Hour of Peak	15:00

CURTAILMENT PRIORITY CLASSES	Firm Transmission Service	Non-Firm Transmission Service	Total	
Number of Requests	85	3	88	
Requests (MW)	36,540	404	36,944	
Number of requests accepted	58	2	60	
Requests accepted (MW)	32,539	44	32,583	
				Reason for non-delivery
Requests not accepted (MW) and reason for not accepting delivery	4,001	360	4,361	Withdrawn/ Invalid/ Refused/ Declined/ Annulled/ Retracted

FORM FE-T6: CONDITIONS AT TIME OF MONTHLY PEAK

Reporting Month NOVEMBER

Megawatts	2,993	Day of Week	WED	Day of Month	24	Hour of Peak	18:00
CURTAILMENT PRIORITY CLASSES				Firm Transmission Service	Non-Firm Transmission Service	Total	
Number of Requests				86	7	93	
Requests (MW)				36,873	401	37274	
Number of requests accepted				58	6	64	
Requests accepted (MW)				32,872	41	32913	
							Reason for non-delivery
Requests not accepted (MW) and reason for not accepting delivery				4,001	360	4361	Withdrawn/ Invalid/ Refused/ Declined/ Annulled/ Retracted

Reporting Month DECEMBER

Megawatts	3,640	Day of Week	MON	Day of Month	6	Hour of Peak	19:00
CURTAILMENT PRIORITY CLASSES				Firm Transmission Service	Non-Firm Transmission Service	Total	
Number of Requests				93	3	96	
Requests (MW)				36,916	405	37,321	
Number of requests accepted				66	2	68	
Requests accepted (MW)				32,915	45	32,960	
							Reason for non-delivery
Requests not accepted (MW) and reason for not accepting delivery				4,001	360	4,361	Withdrawn/ Invalid/ Refused/ Declined/ Annulled/ Retracted

C. THE EXISTING TRANSMISSION SYSTEM

(1) General Description - The Duke Energy-Ohio (DEO) transmission system above 125 kV consists of 138 kV and 345 kV systems. The 345 kV system generally serves to distribute power from the larger, base load generating units which are connected to the Duke Energy Ohio transmission system, and to interconnect the Duke Energy Ohio system with other systems. These interconnections enable the transmission of power between systems as required to meet the service area load requirements and they provide capacity for economy and emergency power transfers. The 345 kV system is connected to the 138 kV system through large transformers at a number of substations across the system. The 138 kV system distributes power received through the transformers and also from several smaller generating units which are connected directly at this voltage level. This power is distributed to substations which supply lower voltage sub-transmission systems, distribution circuits, or serve a number of large customer loads directly.

As of December 2010, the transmission system of Duke Energy Ohio and its subsidiary companies consisted of approximately 403 circuit miles of 345 kV lines (including Duke Energy Ohio's share of jointly owned transmission) and 725 circuit miles of 138 kV lines. Portions of the 345 kV transmission system are jointly owned with American Electric Power (AEP) and/or Dayton Power & Light (DP&L).

(a) A summary of the characteristics of existing transmission lines are shown on the following forms FE-T7, Characteristics of existing Transmission lines. The forms are separated into several groups. The first group is of lines designed to operate at 138 kV. The second group is of wholly owned lines designed to operate at 345 kV. The remaining groups are of lines designed to operate at 345 kV which are jointly owned with other utilities. The line numbers correspond to those shown on the schematic diagrams and geographic maps of section 4901:5-5-04 (C)(2).

DUKE ENERGY OHI
4901:5-5-04(C)(1)(a)
FORM FE-T7: CHARACTERISTICS OF EXISTING TRANSMISSION LINES
WHOLLY OWNED TRANSMISSION LINES DESIGNED FOR 138 KV OPERATIONS

CIRCUIT NO. DEO-A	LINE NAME	ORIGIN	TERMINUS	SUMMER CAPABILITY (MVA) NORMAL RATING	EMERGENCY RATING	WINTER CAPABILITY (MVA) NORMAL RATING	EMERGENCY RATING	VOLTAGE (KV) OPER. LEVEL	R-O-W DESIGN LEVEL	LENGTH (MILES)	WIDTH (FEET)	NUMBER SUPPORTING STRUCTURES	OF CIRCUITS	SUBSTATIONS ON THE LINE
GE4	Evendale-GE Ram Jct	Evendale	Tower No.	170	206	227	252	138	138	0.17	100	Steel Tower	1	
684	Elmwood-Lateral	Elmwood	Lateral											
	Section 1			226	275	302	336	138	138	1.34	100	Wood Pole	1	
	Section 2			226	275	302	336	138	138	2.37	100	Steel Tower	2	
689	Elmwood-Terminal	Elmwood	Terminal	261	318	349	389	138	138	1.40	100	Wood Pole	1	
885	Oakley-Red Bank	Oakley	Red Bank	282	343	377	421	138	138	1.09	100	Steel Tower	2	
886	Oakley-Beckjord	Oakley	Beckjord	282	343	377	421	138	138	16.45	100	Steel Tower	2	
1263	Mitchell-Brighton	Mitchell	Brighton	92	111	123	136	69	138	4.20	100	Steel Tower	2	
1269	Central-Ashland	Tower No. 37	Tower No. 58	98	98	122	122	69	138	3.43	100	Steel Tower	2	
1284	Mitchell-Terminal	Mitchell	Terminal	234	284	312	343	138	138	3.61	100	Steel Tower	2	Henkel Corp.
1286	Mitchell-West End	Mitchell	West End	230	280	308	343	138	138	8.18	100	Steel Tower	2	Cumminsville, Queensgate, Metro Sewer Dist.
1288	Mitchell-Ashland-Oakley	Mitchell	Oakley, Ashland											
	Section 1			230	280	308	343	138	138	1.30	100	Steel Tower	1	
	Section 2			230	280	308	343	138	138	7.33	100	Steel Tower	2	
1385	Charles-West End	Charles	West End	234	245	267	277	138	138	1.11	100	Underground	1	
1389	Charles-West End	Charles	West End	234	245	267	277	138	138	1.12	100	Underground	1	
1587	West End-Crescent	West End	Ohio/Ky. St. Line	226	275	302	336	138	138	0.30	100	Steel Tower	1	
1666	Miami Fort-Monsanto	Miami Fort	Tower No. 30	83	101	111	123	69	138	6.39	100	Steel Tower	2	
1681	Miami Fort-Greendale	Miami Fort	Ohio/Ind. St. Line	500	500	679	679	138	138	0.86	100	Steel Tower & Wood Pole	1	
1682	Miami Fort-Clifty Creek	Miami Fort	Ohio/Ky. St. Line	136	136	181	181	138	138	0.30	100	Wood H-Frame	1	
1688	Miami Fort-MFGT	Miami Fort	Miami Fort GT	226	275	302	336	138	138	0.34	100	Wood Pole	1	
1689	Miami Fort-Morgan	Miami Fort	Morgan	226	275	302	336	138	138	8.16	100	Steel Tower	2	
1762	Trenton-Terminal	Trenton	Terminal											
	Section 1			77	92	102	113	69	138	0.45	100	Steel Tower	1	
	Section 2			77	92	102	113	69	138	1.20	100	Wood Pole	1	
1782	Terminal-Glenview	Terminal	Glenview											
	Section 1			230	280	308	343	138	138	5.03	100	Steel Tower	2	
	Section 2			230	280	308	343	138	138	0.60	100	Wood H-Frame	1	
1783	Terminal-Ebenezer	Terminal	Ebenezer											
	Section 1			234	284	312	349	138	138	9.98	100	Steel Tower	2	
	Section 2			234	284	312	349	138	138	3.64	100	Wood Pole	1	
	Section 3			234	284	312	349	138	138	0.13	100	Wood H-Frame	1	Midway
1880	Beckjord-Silver Grove	Beckjord	Ohio/Ky. St. Line											
	Section 1			253	308	339	377	138	138	1.00	100	Wood Pole	1	
	Section 2			253	308	339	377	138	138	0.25	100	Steel Tower	2	
1881	Beckjord-Wilder	Beckjord	Ohio/Ky. St. Line	166	201	221	245	138	138	0.32	100	Steel Tower	2	
1885	Beckjord-Tobasco	Beckjord	Tobasco	282	343	377	421	138	138	5.84	100	Steel Tower	2	
1887	Beckjord-Pierce	Beckjord	Pierce	478	478	478	478	138	138	0.38	50	Wood Pole & Steel Tower	1	
1889	Beckjord-Pierce	Beckjord	Pierce	478	478	478	478	138	138	0.22	100	Steel Tower	1	
2166	Brighton-Wilder	Brighton	Ohio/Ky. St. Line	83	101	111	123	69	138	3.65	100	Steel Tower	2	
2381	Warren-Clinton County	Warren	Clinton County	170	206	227	252	138	138	16.32	100	Wood H-Frame	1	
2862	Miami Fort GT-Villa	Miami Fort GT	Ohio/Ky. St. Line	83	101	111	123	69	138	0.14	100	Steel Tower	2	
2865	Miami Fort GT-Monsanto	Miami Fort GT	Tower No. 30	113	137	151	168	69	138	6.39	100	Steel Tower	2	
2986	Cedarville-Ford	Cedarville	Ford											
	Section 1			253	308	339	378	138	138	5.02	100	Wood Pole	1	
	Section 2			253	308	339	378	138	138	4.86	100	Wood Pole	1	
3263	Trenton-Middletown Oxygen	Tower No.1	Tower No. 17	83	101	111	123	69	138	2.77	100	Steel Tower	1	
3281	Trenton-College Corner	Trenton	Ohio/Ind. St. Line	153	184	203	225	138	138	24.11	100	Steel Tower	2	Collinsville, BREC Huston
3283	N/A	Structure 696	Structure 645A	170	206	227	252	138	138	3.94	90	Wood H-Frame		
3284	Trenton-Todhunter	Trenton	Todhunter	170	206	227	252	138	138	4.9	100	Wood H-Frame	1	
3881	Port Union-Summerside	Port Union	Summerside	170	206	227	252	138	138	22.74	100	Steel Tower	2	
3885	Port Union-Fairfield	Port Union	Fairfield	310	310	310	310	138	138	6.59	100	Steel Tower	2	Hall
3886	Port Union-Willey	Port Union	Willey	170	206	227	252	138	138	14.30	100	Steel Tower	2	Mulhauser
3887	Port Union-Todhunter	Port Union	Todhunter	304	304	390	390	138	138	9.69	100	Steel Tower	2	Millikin
3888	Port Union-Todhunter	Port Union	Todhunter	304	304	390	390	138	138	9.69	100	Steel Tower	2	Beckett
3889	Port Union-City of Hamilton	Port Union	City of Hamilton	253	308	339	377	138	138	4.65	100	Wood Pole	1	
4187	Lateral-Red Bank	Lateral	Red Bank	230	280	308	343	138	138	2.90	100	Steel Tower	2	
4861	Ivorydale-Terminal	Tower No. 1	Tower No. 5	83	101	111	123	69	138	0.90	100	Steel Tower	2	

DUKE ENERGY OHIO
4901:5-5-04(C)(1)(a)
FORM FE-T7: CHARACTERISTICS OF EXISTING TRANSMISSION LINES
WHOLLY OWNED TRANSMISSION LINES DESIGNED FOR 138 KV OPERATION

CIRCUIT NO. DEO-A	LINE NAME	ORIGIN	TERMINUS	SUMMER CAPABILITY (MVA) NORMAL RATING	SUMMER CAPABILITY (MVA) EMERGENCY RATING	WINTER CAPABILITY (MVA) NORMAL RATING	WINTER CAPABILITY (MVA) EMERGENCY RATING	VOLTAGE (KV) OPER. LEVEL	VOLTAGE (KV) DESIGN LEVEL	R-O-W LENGTH (MILES)	WIDTH (FEET)	SUPPORTING STRUCTURES	NUMBER OF CIRCUITS	SUBSTATIONS ON THE LINE
5381	Shaker Run-Rockies Express													
	Section 1	Structure 69B	Rockies Express	478	478	478	478	138	138	0.67	50	Steel Pole	1	
	Section 2	Rockies Express	Carlisle	287	287	287	287	138	138	10.58	50	Wood Pole	1	Carlisle, Union
5483	Foster-Port Union	Foster	Port Union											Dimmick, Montgomery
	Section 1			226	275	302	336	138	138	9.19	100	Steel Tower	2	Twenty Mile, Cornell
	Section 2			253	308	339	378	138	138	8.39	100	Wood Pole	1	Simpson, Socialville
5487	Foster-Remington	Foster	Remington											
	Section 1			253	308	339	378	138	138	13.40	100	Steel Tower	2	Montgomery
	Section 2			170	206	227	252	138	138	4.45	100	Wood Pole	1	
5489	Foster-Cedarville	Foster	Cedarville	253	308	339	378	138	138	12.23	100	Wood Pole	1	Obannonville
5484	Foster-Warren	Foster	Warren	253	308	339	378	138	138	8.70	100	Wood pole	1	Maineville
5666	Todhunter-Manchester	Tower No. 17	Tower No. 20	113	137	151	168	69	138	0.55	100	Steel Tower	1	
5667	Todhunter-Shaker Run	Todhunter	Structure 645A	83	101	111	123	69	138	5.14	100	Wood H-Frame	1	
5680	Todhunter-Warren	Todhunter	Warren	165	202	227	252	138	138	9.55	90	Wood H-Frame	1	Nickel
5682	Todhunter-AK Steel	Todhunter	AK Steel	300	300	300	300	138	138	2.34	100	Steel Tower	2	
5686	Todhunter-AK Steel	Todhunter	AK Steel											
	Section 1			300	300	300	300	138	138	2.34	100	Steel Tower	2	
	Section 2			170	206	227	252	138	138	0.33	100	Steel Tower	1	Dicks Creek
5689	Todhunter-Rockies Express	Structure 69B	Rockies Express	478	478	478	478	138	138	0.63	50	Steel Pole	1	
5781	Fairfield-City of Hamilton	Fairfield	City of Hamilton	253	308	339	378	138	138	6.05	100	Wood Pole	1	
5783	Fairfield-Morgan	Fairfield	Morgan	166	201	221	245	138	138	16.50	100	Steel Tower	2	
5884	Brown-Eastwood	Brown	Eastwood	253	308	339	378	138	138	13.00	100	Wood H-Frame	1	
5886	Brown-Stuart	Brown	Stuart	234	285	213	349	138	138	21.16	100	Wood H-Frame	1	
5985	Wilder-West End	Ohio/Ky. St. Line	West End	253	287	339	351	138	138	0.20	100	Steel Tower	2	
5988	Wilder-Beckjord	Ohio/Ky. St. Line	Beckjord	226	275	302	336	138	138	0.37	100	Steel Tower	2	
6365	Tobasco-Markley	Pole No. 601	Markley	83	101	111	122	69	138	1.70	100	Wood Pole	1	
6885	Ebenezer-Miami Fort	Ebenezer	Miami Fort											
	Section 1			228	280	313	350	138	138	10.26	100	Steel Tower	2	
	Section 2			226	275	302	336	138	138	4.92	100	Wood Pole	1	
6984	Summerside-Beckjord	Summerside	Beckjord	310	310	310	310	138	138	10.44	100	Steel Tower	2	Clermont
7086	Crescent-Miami Fort	Ohio/Ky. St. Line	Miami Fort	204	248	273	303	138	138	0.13	100	Steel Tower	2	
7284	Glenview-Miami Fort	Glenview	Miami Fort											
	Section 1			230	248	308	342	138	138	0.60	100	Wood H-Frame	1	
	Section 2			230	280	308	342	138	138	15.07	100	Steel Tower	2	Kleeman
	Section 3			185	224	246	273	138	138	0.12	100	Wood H-Frame	1	Midway
7481	Red Bank-Terminal													
	Section 1	Tower 117	Cornell	344	423	463	518	138	138	9.10	100	Wood Pole	1	Deer Park
	Section 2	Pole 1493	Cooper	226	274	302	336	138	138	1.19	50	Wood Pole	1	
7484	Red Bank-Ashland	Red Bank	Ashland											
	Section 1			240	300	240	300	138	138	0.96	100	Steel Tower	2	
	Section 2			240	300	240	300	138	138	0.12	100	Wood Pole	1	
	Section 3			240	300	240	300	138	138	4.24	100	Underground	1	
7489	Red Bank-Tobasco	Red Bank	Tobasco											
	Section 1			282	344	378	421	138	138	9.64	100	Steel Tower	2	
	Section 2			282	344	378	421	138	138	0.07	100	Wood Pole	1	
8283	Rochelle-Charles	Rochelle	Charles	269	282	307	318	138	138	2.38	100	Underground	1	
8286	Rochelle-Terminal	Rochelle	Terminal											
	Section 1			234	287	307	318	138	138	3.56	100	Steel Tower	2	
	Section 2			234	287	307	318	138	138	1.25	100	Wood Pole	1	
	Section 3			234	282	307	318	138	138	1.32	100	Underground	1	
8481	Eastwood-Ford	Eastwood	Ford											
	Section 1			253	308	339	378	138	138	4.97	100	Wood Pole	1	
	Section 2			253	308	339	378	138	138	1.50	100	Wood Pole	1	
8887	Hillcrest-Eastwood	Hillcrest	Eastwood	306	306	382	382	138	138	9.63	50	Wood pole	1	SCP Eastwood
9482	Remington-Beckjord	Remington	Beckjord	310	310	310	310	138	138	19.08	100	Steel Tower	2	Feldman, Wards Corner
9784	Willey-Miami Fort	Willey	Miami Fort	170	206	227	252	138	138	14.95	100	Steel Tower	2	
9787	Willey-Terminal	Willey	Terminal											
	Section 1			226	275	302	336	138	138	5.68	100	Wood H-Frame	1	Mapleknoll
	Section 2			226	275	302	336	138	138	11.71	100	Wood Pole	1	Mt. Healthy, Finneytown
	Section 3			226	275	302	336	138	138	0.50	100	Steel Tower	2	
13803	Hutchings-College Corner													
	Section 1	Structure 1101	Trenton	170	206	227	252	138	138	4.91	100	Wood H-Frame	1	
	Section 2	Trenton	Tower 129	170	206	227	252	138	138	24.06	100	Steel Tower	2	

DUKE ENERGY OHIO
4901:5-5-04(C)(1)(a)
FORM FE-T7: CHARACTERISTICS OF EXISTING TRANSMISSION LINES

WHOLLY OWNED TRANSMISSION LINES DESIGNED FOR 345 KV OPERATION

CIRCUIT NO. DEO-B	LINE NAME	ORIGIN	TERMINUS	SUMMER CAPABILITY (MVA) NORMAL RATING	SUMMER CAPABILITY (MVA) EMERGENCY RATING	WINTER CAPABILITY (MVA) NORMAL RATING	WINTER CAPABILITY (MVA) EMERGENCY RATING	VOLTAGE (KV) OPER. LEVEL	VOLTAGE (KV) DESIGN LEVEL	R-O-W LENGTH (MILES)	WIDTH (FEET)	SUPPORTING STRUCTURES	NUMBER OF CIRCUITS	SUBSTATIONS ON THE LINE
04	Miami Fort-Tanners Creek	Miami Fort	Ohio/Ky. St. Line	717	824	717	824	345	345	0.32	150	Steel Tower	2	
08	Port Union-Foster	Port Union	Foster											
	Section 1			1195	1315	1195	1315	345	345	11.66	150	Steel Tower	2	
	Section 2			1195	1315	1195	1315	345	345	0.24	150	Steel Tower	1	
13	Terminal-Port Union	Terminal	Port Union											
	Section 1			1195	1315	1195	1315	345	345	0.46	150	Steel Tower	1	
	Section 2			1195	1315	1195	1315	345	345	9.65	150	Steel Tower	2	
14	Miami Fort-Terminal													
	Section 1	Terminal	Ohio/Ky. St. Line	1195	1315	1195	1315	345	345	14.84	150	Steel Tower	2	
	Section 2	Miami Fort	Ohio/Ky. St. Line	1195	1315	1195	1315	345	345	0.32	150	Steel Tower	2	
15	Foster-Todhunter	Foster	Todhunter	1195	1315	1195	1315	345	345	15.79	150	Steel Tower	2	
16	East Bend-Terminal	Ohio/Ky. St. Line	Terminal	1195	1315	1195	1315	345	345	14.84	150	Steel Tower	2	
62	Woodsdale-Todhunter	Woodsdale	Todhunter	1195	1315	1195	1315	345	345	4.68	150	Steel Tower	2	
1883	Beckjord-Red Bank	Beckjord	Red Bank											
	Section 1			262	344	378	421	138	345	0.89	150	Steel Tower	1	
	Section 2			282	344	378	421	138	345	13.82	150	Steel Tower	2	Newtown
4683	Evendale-Port Union	Evendale	Port Union											
	Section 1			344	423	463	518	138	345	0.52	150	Steel Tower	1	
	Section 2			344	423	463	518	138	345	5.48	150	Steel Tower	2	Kemper
4685	Evendale-Terminal	Evendale	Terminal											
	Section 1			382	382	382	382	138	345	0.21	150	Steel Tower	1	
	Section 2			382	382	382	382	138	345	4.02	150	Steel Tower	2	
5381	Shaker Run-Rockies Express	Structure 69A	Rockies Express	478	478	478	478	138	345	2.62	150	Steel Tower	2	
5485	Foster-Shaker Run	Foster	Shaker Run	259	314	345	385	138	345	10.29	150	Steel Tower	2	Park, Bethany
5689	Todhunter-Rockies Express	Todhunter	Structure 69B	478	478	478	478	138	345	6.44	150	Steel Tower	2	
7481	Red Bank-Terminal	Red Bank	Terminal	344	423	463	518	138	345	5.72	150	Stl Twr & Pole	2	Golf Manor

DUKE ENERGY OHIO
4901:5-5-04(C)(1)(a)
FORM FE-T7: CHARACTERISTICS OF EXISTING TRANSMISSION LINES

COMMONLY OWNED TRANSMISSION - DEO, AEP AND DP&L COMPANIES
TENANTS IN COMMON WITH UNDIVIDED OWNERSHIP, TOTAL MILEAGE GIVEN

CIRCUIT NO. CCD-B	LINE NAME	ORIGIN	TERMINUS	SUMMER CAPABILITY (MVA) NORMAL RATING	SUMMER CAPABILITY (MVA) EMERGENCY RATING	WINTER CAPABILITY (MVA) NORMAL RATING	WINTER CAPABILITY (MVA) EMERGENCY RATING	VOLTAGE (KV) OPER. LEVEL	VOLTAGE (KV) DESIGN LEVEL	R-O-W LENGTH (MILES)	WIDTH (FEET)	SUPPORTING STRUCTURES	NUMBER OF CIRCUITS	SUBSTATIONS ON THE LINE
01	Beckjord-Pierce	Beckjord	Pierce	500	500	500	500	345	345	0.32	150	Steel Tower	1	
02	Pierce-Foster	Pierce	Foster											
	Section 1			1195	1315	1195	1315	345	345	23.38	150	Steel Tower	2	
	Section 2			1195	1315	1195	1315	345	345	0.57	150	Steel Tower	1	
03	Sugarcreek-Greene	Sugarcreek	Greene	1195	1315	1195	1315	345	345	8.30	150	Steel Tower	1	
06	Greene-Beatty	Greene	Beatty											
	Section 1			1195	1315	1195	1315	345	345	3.66	150	Steel Tower	2	
	Section 2			1195	1315	1195	1315	345	345	45.34	150	Steel Tower	1	
07	Marquis-Bixby	Marquis	Bixby											
	Section 1			1195	1315	1195	1315	345	345	63.16	150	Steel Tower	1	
	Section 2			1195	1315	1195	1315	345	345	8.52	150	Steel Tower	2	
09	Stuart-Greene	Stuart	Greene	1195	1315	1195	1315	345	345	80.38	150	Steel Tower	1	
10	Stuart-Killen	Stuart	Killen Tap	1195	1315	1195	1315	345	345	13.13	150	Steel Tower	1	
11	Stuart-Hillcrest	Stuart	Hillcrest	1255	1374	1255	1374	345	345	32.61	150	Steel Tower	1	
24	Foster-Sugarcreek	Foster	Sugarcreek	1257	1554	1745	1947	345	345	27.33	150	Steel Tower	2	
31	Beatty-Bixby	Beatty	Bixby											
	Section 1			1042	1338	1042	1338	345	345	4.69	150	Steel Tower	1	
	Section 2			1042	1338	1042	1338	345	345	8.52	150	Steel Tower	2	
33	Kirk-Corridor	Kirk	Corridor	1302	1673	1302	1673	345	345	18.36	150	Wood H-Frame	1	
40	Conesville-Hyatt	Conesville	Hyatt											
	Section 1			1195	1374	1195	1374	345	345	66.07	150	Steel Tower	1	
	Section 2			1195	1374	1195	1374	345	345	1.78	150	Wood Pole	1	
	Section 3			1195	1374	1195	1374	345	345	0.48	150	Wood H-Frame	1	
41	Spurlock-Zimmer	Ohio/Ky. St. Line	Zimmer											
	Section 1			1195	1315	1195	1315	345	345	31.77	150	Steel Tower	1	
	Section 2			1195	1315	1195	1315	345	345	0.78	150	Steel Tower	2	
42	Atlanta-Beatty	Atlanta	Beatty											
	Section 1			1042	1281	1042	1281	345	345	3.68	150	Steel Tower	2	
	Section 2			1042	1281	1042	1281	345	345	25.22	150	Steel Tower	1	
43	Conesville-Bixby	Conesville	Bixby											
	Section 1			1195	1374	1195	1374	345	345	14.87	150	Steel Tower	2	
	Section 2			1195	1374	1195	1374	345	345	50.86	150	Wood H-Frame	1	
44	Zimmer-Port Union	Zimmer	Port Union											
	Section 1			1195	1315	1195	1315	345	345	35.88	150	Steel Tower	2	
	Section 2			1195	1315	1195	1315	345	345	10.03	150	Steel Tower	1	
45	Zimmer-Red Bank													
	Section 1	Zimmer	Ohio/Ky. St. Line	1264	1538	1264	1538	345	345	0.43	150	Steel Tower	1	
	Section 2	Red Bank	Tower No. 24	1195	1315	1195	1315	345	345	10.58	150	Steel Tower	2	
	Section 3	Tower No. 23	Ohio/Ky. St. Line	1195	1315	1195	1315	345	345	0.80	150	Steel Tower	1	
46	Red Bank-Terminal	Red Bank	Terminal											
	Section 1			1195	1315	1195	1315	345	345	5.75	150	Steel Pole	2	
	Section 2			1195	1315	1195	1315	345	345	0.90	150	Steel Tower	2	
47	Bixby-Kirk	Bixby	Kirk											
	Section 1			1302	1673	1302	1673	345	345	14.87	150	Steel Tower	2	
	Section 2			1302	1673	1302	1673	345	345	4.20	150	Wood H-Frame	1	
49	Killen-Marquis	Killen Tap	Marquis	1195	1315	1195	1315	345	345	32.01	150	Steel Tower	1	
52	Stuart-Atlanta	Stuart	Atlanta	1195	1315	1195	1315	345	345	65.00	150	Steel Tower	1	
69	Hillcrest-Foster	Hillcrest	Foster	1551	1551	1793	1793	345	345	26.36	150	Steel Tower	1	
93	Spurlock-Stuart	Ohio/Ky. St. Line	Stuart	1195	1315	1195	1315	345	345	10.86	150	Steel Tower	1	

DUKE ENERGY OHIO
4901:5-5-04(C)(1)(a)
FORM FE-T7: CHARACTERISTICS OF EXISTING TRANSMISSION LINES

COMMONLY OWNED TRANSMISSION - DEO AND DP&L COMPANIES
TENANTS IN COMMON WITH UNDIVIDED OWNERSHIP, TOTAL MILEAGE GIVEN

CIRCUIT NO. CCD-B	LINE NAME	ORIGIN	TERMINUS	SUMMER CAPABILITY (MVA) NORMAL RATING	SUMMER CAPABILITY (MVA) EMERGENCY RATING	WINTER CAPABILITY (MVA) NORMAL RATING	WINTER CAPABILITY (MVA) EMERGENCY RATING	VOLTAGE (KV) OPER. LEVEL	VOLTAGE (KV) DESIGN LEVEL	R-O-W LENGTH (MILES)	WIDTH (FEET)	SUPPORTING STRUCTURES	NUMBER OF CIRCUITS	SUBSTATIONS ON THE LINE
61	Woodsdale-Todhunter	Woodsdale	Todhunter	1195	1315	1195	1315	345	345	4.68	150	Steel Tower	2	
91	Miami Fort-West Milton	Miami Fort	Tower No. 173											
	Section 1			1195	1315	1195	1315	345	345	33.25	150	Steel Tower	2	
	Section 2			1195	1315	1195	1315	345	345	1.37	150	Steel Tower	1	
92	Miami Fort-Woodsdale	Miami Fort	Woodsdale											
	Section 1			1195	1315	1195	1315	345	345	33.25	150	Steel Tower	2	
	Section 2			1195	1315	1195	1315	345	345	4.82	150	Steel Tower	1	
98	Foster-Bath	Foster	Bath	1195	1315	1195	1315	345	345	40.28	150	Steel Tower	2	

(b) A separate listing of substations for each line included in form FE-T7 is shown on the following forms FE-T8, Summary of Existing Substations. The existing and proposed lines associated with each station are listed. The line numbers correspond to those shown on the schematic diagrams and geographic maps of section 4901:5-5-04 (C)(2).

DUKE ENERGY OHIO
4901:5-5-04(C)(1)(b)
FORM FE-T8: SUMMARY OF EXISTING SUBSTATIONS

SUBSTATION NAME	TYPE*	VOLTAGE(S) (KV)	LINE NAME	LINE NUMBER	EXISTING OR PROPOSED
AK Steel	T	138	Todhunter-AK Steel	5682	Existing
			Todhunter-AK Steel	5686	Existing
Ashland	D	138	Mitchell-Ashland-Oakley	1288	Existing
			Ashland-Mitchell	1269	Existing
			Red Bank-Ashland	7484	Existing
			Ashland-Whittier	1180	Proposed
Beckett	D	138	Port Union-Todhunter	3888	Existing
Beckjord	T	345 & 138	Oakley-Beckjord	886	Existing
			Beckjord-Silver Grove	1880	Existing
			Beckjord-Red Bank	1883	Existing
			Beckjord-Tabasco	1885	Existing
			Beckjord-Pierce	1887	Existing
			Beckjord-Pierce	1889	Existing
			Remington-Beckjord	9482	Existing
			Beckjord-Wilder	1881	Existing
			Wilder-Beckjord	5988	Existing
			Summerside-Beckjord	6984	Existing
			Beckjord-Pierce	4501	Existing
Bethany	D	138	Foster-Shaker Run	5485	Existing
BREC Huston	T	138	Trenton-College Corner	3281	Existing
Brighton	D	69	Mitchell-Brighton	1263	Existing
Brown	D	138	Brown-Stuart	5886	Existing
			Brown-Eastwood	5884	Existing
Carlisle	D	138	Shaker Run-Rockies Express	5381	Existing
Cedarville	D	138	Foster-Cedarville	5489	Existing
			Cedarville-Ford	2986	Existing
Central	D	69 & 138	Mitchell-Ashland	1269	Existing
		(138 proposed)	Central-Ashland	3985	Proposed
			Central-Mitchell	1288	Proposed
			Central-Oakley	3981	Proposed
Charles	D	138	Charles-West End	1385	Existing
			Charles-West End	1389	Existing
			Rochelle-Charles	8283	Existing
Cinti. M.S.D.	T	138	Mitchell-West End	1286	Existing
City of Hamilton	T	138	Port Union-City of Ham.	3889	Existing
			Fairfield-City of Hamilton	5781	Existing
Clermont	D	138	Summerside-Beckjord	6984	Existing
Clinton County	D	138	Warren-Clinton Co.	2381	Existing
Collinsville	D	138	Trenton-College Corner	3281	Existing
Cooper	D	138	Red Bank-Terminal	7481	Existing
Cornell	D	138	Red Bank-Terminal	7481	Existing
			Port Union-Foster	5483	Existing
Cumminsville	D	138	Mitchell-West End	1286	Existing
Deer Park	D	138	Red Bank-Terminal	7481	Existing
Dicks Creek	T	138	Todhunter-AK Steel	5686	Existing
Dimmick	D	138	Foster-Port Union	5483	Existing

* DISTRIBUTION(D) TRANSMISSION (T)

DUKE ENERGY OHIO
4901:5-5-04(C)(1)(b)
FORM FE-T8: SUMMARY OF EXISTING SUBSTATIONS

SUBSTATION NAME	TYPE*	VOLTAGE(S) (KV)	LINE NAME	LINE NUMBER	EXISTING OR PROPOSED
Eastwood	D	138	Brown-Eastwood	5884	Existing
			Eastwood-Ford	8481	Existing
			Hillcrest-Eastwood	8887	Existing
Ebenezer	D	138	Terminal-Ebenezer	1783	Existing
			Ebenezer-Miami Fort	6885	Existing
Elmwood	D	138	Elmwood-Lateral	684	Existing
			Elmwood-Terminal	689	Existing
Evendale	D	138	Evendale-Port Union	4683	Existing
			Evendale-Terminal	4685	Existing
			Evendale-General Electric	GE4	Existing
Fairfield	D	138	Fairfield-Morgan	5783	Existing
			Port Union-Fairfield	3885	Existing
			Fairfield-City of Hamilton	5781	Existing
Feldman	D	138	Remington-Beckjord	9482	Existing
Finneytown	D	138	Willey-Terminal	9787	Existing
Ford	D	138	Foster-Ford	5489	Existing
			Brown-Ford	5884	Existing
Foster	T & D	345 & 138	Foster-Port Union	5483	Existing
			Foster-Warren	5484	Existing
			Foster-Shaker Run	5485	Existing
			Foster-Remington	5487	Existing
			Foster-Cedarville	5489	Existing
			Pierce-Foster	4502	Existing
			Stuart-Foster	4511	Existing
			Port Union-Foster	4508	Existing
			Foster-Todhunter	4515	Existing
			Foster-Sugarcreek	4524	Existing
Glenview	D	138	Terminal-Glenview	1782	Existing
			Miami Fort-Glenview	7284	Existing
Golf Manor	D	138	Red Bank-Terminal	7481	Existing
Hall	D	138	Port Union-Fairfield	3885	Existing
Henkel Corp.	D	138	Mitchell-Terminal	1284	Existing
Hillcrest	T & D	345 & 138	Stuart-Hillcrest	4511	Existing
			Foster-Hillcrest	34569	Existing
			Hillcrest-Eastwood	8887	Existing
Kemper	D	138	Evendale-Port Union	4683	Existing
Kleeman	D	138	Glenview-Miami Fort	7284	Existing
Lateral	D	138	Elmwood-Lateral	684	Existing
			Lateral-Red Bank	4187	Existing
Maineville	D	138	Foster-Warren	5484	Existing
Mapleknoll	D	138	Willey-Terminal	9787	Existing

* DISTRIBUTION(D) TRANSMISSION (T)

DUKE ENERGY OHIO
4901:5-5-04(C)(1)(b)
FORM FE-T8: SUMMARY OF EXISTING SUBSTATIONS

SUBSTATION NAME	TYPE*	VOLTAGE(S) (KV)	LINE NAME	LINE NUMBER	EXISTING OR PROPOSED
Miami Fort	T	345 & 138	Miami Fort-Greendale	1681	Existing
			Miami Fort-Clifty Creek	1682	Existing
			Miami Fort-MFGT	1688	Existing
			Miami Fort-Morgan	1689	Existing
			Ebenezer-Miami Fort	6885	Existing
			Crescent-Miami Fort	7086	Existing
			Glenview-Miami Fort	7284	Existing
			Willey-Miami Fort	9784	Existing
			Miami Fort-Miami	4591	Existing
			Miami Fort-Woodsdale	4592	Existing
			Miami Fort-Tanners Creek	4504	Existing
			Miami Fort-Terminal	4514	Existing
Miami Fort GT	T	138	Miami Fort-MFGT	1688	Existing
			MFGT-Villa	2862	Existing
			MFGT-Ebenezer	2865	Existing
Midway	D	138	Terminal-Ebenezer	1783	Existing
			Miami Fort-Glenview	7284	Existing
Millikin	D	138	Port Union-Todhunter	3887	Existing
Mitchell	D	138	Mitchell-Brighton	1263	Existing
			Mitchell-Terminal	1284	Existing
			Mitchell-West End	1286	Existing
			Mitchell-Ashland-Oakley	1288	Existing
Montgomery	D	138	Foster-Remington	5487	Existing
			Foster-Port Union	5483	Existing
Morgan	D	138	Miami Fort-Morgan	1689	Existing
			Fairfield-Morgan	5783	Existing
Mt. Healthy	D	138	Willey-Terminal	9787	Existing
Mulhauser	D	138	Port Union-Willey	3886	Existing
Newtown	D	138	Beckjord-Red Bank	1883	Existing
Nickel	D	138	Warren-Todhunter	5680	Existing
Oakley	D	138	Oakley-Red Bank	885	Existing
			Oakley-Beckjord	886	Existing
			Mitchell-Ashland-Oakley	1288	Existing
OBannonville	D	138	Foster-Cedarville	5489	Existing
Park	D	138	Foster-Shaker Run	5485	Existing
Port Union	T & D	345 & 138	Port Union-Summerside	3881	Existing
			Foster-Port Union	5483	Existing
			Port Union-Fairfield	3885	Existing
			Port Union-Willey	3886	Existing
			Port Union-Todhunter	3887	Existing
			Port Union-Todhunter	3888	Existing
			Port Union-City of Hamilton	3889	Existing
			Evendale-Port Union	4683	Existing
			Zimmer-Port Union	4544	Existing
			Port Union-Foster	4508	Existing
			Terminal-Port Union	4513	Existing

* DISTRIBUTION(D) TRANSMISSION (T)

DUKE ENERGY OHIO
4901:5-5-04(C)(1)(b)
FORM FE-T8: SUMMARY OF EXISTING SUBSTATIONS

SUBSTATION NAME	TYPE*	VOLTAGE(S) (KV)	LINE NAME	LINE NUMBER	EXISTING OR PROPOSED
Queensgate	D	138	Mitchell-West End	1286	Existing
Red Bank	T	345 & 138	Red Bank-Terminal	7481	Existing
			Lateral-Red Bank	4187	Existing
			Beckjord-Red Bank	1883	Existing
			Red Bank-Ashland	7484	Existing
			Oakley-Red Bank	885	Existing
			Red Bank-Tobasco	7489	Existing
			Red Bank-Terminal	4546	Existing
			Zimmer-Red Bank	4545	Existing
Remington	D	138	Remington-Beckjord	9482	Existing
			Foster-Remington	5484	Existing
Rochelle	D	138	Rochelle-Charles	8283	Existing
			Rochelle-Terminal	8286	Existing
			Ridgeway-Whittier	8281	Proposed
Rockies Express	T	138	Shaker Run-Rockies Express	5381	Existing
			Todhunter-Rockies Express	5689	Existing
Seward	D	138	Port Union-Hamilton	3889	Existing
Shaker Run	D	138	Foster-Shaker Run	5485	Existing
			Shaker Run-Rockies Express	5381	Existing
Simpson	D	138	Foster-Port Union	5483	Existing
Socialville	D	138	Foster-Port Union	5483	Existing
SCP Eastwood	T	138	Hillcrest-Eastwood	8887	Existing
Summerside	D	138	Port Union-Summerside	3881	Existing
			Summerside-Beckjord	6984	Existing
Terminal	T & D	345 & 138	Elmwood-Terminal	689	Existing
			Mitchell-Terminal	1284	Existing
			Terminal-Allen	1762	Existing
			Terminal-Glenview	1782	Existing
			Terminal-Ebenezer	1783	Existing
			Evendale-Terminal	4685	Existing
			Red Bank-Terminal	7481	Existing
			Rochelle-Terminal	8286	Existing
			Willey-Terminal	9787	Existing
			Terminal-Port Union	4513	Existing
			Miami Fort-Terminal	4514	Existing
			East Bend-Terminal	4516	Existing
			Red Bank-Terminal	4546	Existing
Tobasco	D	138	Beckjord-Tobasco	1885	Existing
			Red Bank-Tobasco	7489	Existing

* DISTRIBUTION(D) TRANSMISSION (T)

DUKE ENERGY OHIO
4901:5-5-04(C)(1)(b)
FORM FE-T8: SUMMARY OF EXISTING SUBSTATIONS

SUBSTATION NAME	TYPE*	VOLTAGE(S) (KV)	LINE NAME	LINE NUMBER	EXISTING OR PROPOSED
Todhunter	T & D	345 &138	Trenton-Todhunter	3284	Existing
			Port Union-Todhunter	3887	Existing
			Port Union-Todhunter	3888	Existing
			Todhunter-Monroe	5667	Existing
			Warren-Todhunter	5680	Existing
			Todhunter-AK Steel	5682	Existing
			Todhunter-AK Steel	5686	Existing
			Todhunter-Rockies Express	5689	Existing
			Foster-Todhunter	4515	Existing
			Woodsdale-Todhunter	4561	Existing
			Woodsdale-Todhunter	4562	Existing
Trenton	D	138	Trenton-College Corner	3281	Existing
			Trenton-Todhunter	3284	Existing
			Trenton-Air Products	3263	Existing
Twenty Mile	D	138	Foster-Port Union	5483	Existing
Union	D	138	Shaker Run-Rockies Express	5381	Existing
Wards Corner	D	138	Remington-Beckjord	9482	Existing
Warren	T & D	138	Foster-Warren	5484	Existing
			Warren-Todhunter	5680	Existing
			Warren-Clinton County	2381	Existing
West End	D	138	Mitchell-West End	1286	Existing
			Charles-West End	1385	Existing
			Charles-West End	1389	Existing
			Crescent-West End	1587	Existing
			Wilder-West End	5985	Existing
Willey	D	138	Port Union-Willey	3886	Existing
			Willey-Miami Fort	9784	Existing
			Willey-Terminal	9787	Existing
Woodsdale	T	345	Woodsdale-Todhunter	4561	Existing
			Woodsdale-Todhunter	4562	Existing
			Miami Fort-Woodsdale	4592	Existing
Zimmer	T	345	Spurlock-Zimmer	4541	Existing
			Zimmer-Port Union	4544	Existing
			Zimmer-Red Bank	4545	Existing

* DISTRIBUTION(D) TRANSMISSION (T)

(2) Existing Transmission System Maps

(a) Schematic diagrams of the existing 345 kV and 138 kV transmission networks are considered by Duke Energy Ohio to be critical energy infrastructure information. The diagrams are provided under seal.

(b) A map showing the actual, physical routing of the transmission lines, geographic landmarks, major metropolitan areas, and the location of substations and generating plants, interconnects with distribution, and interconnections with other electric transmission owners is considered by Duke Energy Ohio to be critical energy infrastructure information. The map will be provided under seal.

(c) Rule Requirement - Two copies of the map described in paragraph (C)(2)(b) of this rule, for Commission use, on a 1:250,000 scale. The electric transmission owners may jointly provide one set of maps to meet this requirement. Participation in the Commission's joint mapping project will meet this requirement:

The joint mapping project coordinated by the OEUI has not been accomplished for a number of years to Duke Energy Ohio's knowledge. Duke Energy Ohio will provide a map at the requested scale to the Commission upon request.

D. THE PLANNED TRANSMISSION SYSTEM

(1) Specifications of planned transmission lines are provided on the following forms FE-T9, Specifications of Planned Electric Transmission Lines.

DUKE ENERGY OHIO
4901:5-5-04(D)(1)

FORM FE-T9: SPECIFICATIONS OF PLANNED ELECTRIC TRANSMISSION LINES

1.	Line Name: Line Number:	Ashland-Whittier DEO-A1180
2.	Point of Origin: Terminus:	Ashland Substation Whittier Substation (proposed)
3.	Right of Way, Length: Average width: Number of circuits:	3200 feet 50 ft. 1
4.	Voltage: 138 kV	
5.	Application for Certificate:	6/2011
6.	Construction to Commence: Commercial Operation:	commencement date: 9/2011 anticipated date: 6/2012
7.	Capital Investment:	$686,000
8.	Substations:	none
9.	Supporting Structures:	wood and/or steel poles
10.	Participation with other Utilities:	DEO – 100%
11.	Purpose of the Planned transmission line :	supply new substation to provide 12.47 kV distribution system capacity.
12.	Consequences of Line Construction deferment or Termination:	inability to supply 12.47 kV distribution load
13.	Miscellaneous:	area to be served is primarily north Cincinnati, OH

DUKE ENERGY OHIO

4901:5-5-04(D)(1)

FORM FE-T9: SPECIFICATIONS OF PLANNED ELECTRIC TRANSMISSION LINES

1.	Line Name: Line Number:	Foster-Warren DEO-A5484
2.	Point of Origin: Terminus:	Tap Feeder 5484 Columbia Substation (proposed)
3.	Right-of-Way, Length: Average Width: Number of Circuits:	approximately 175 feet 50 feet 1 transmission line above 125 kV
4.	Voltage:	138 kV design and operate voltage
5.	Application for Certificate:	6/1/2012
6.	Construction:	construction commencement – 9/1/12 anticipated date of commercial operation – 12/31/12
7.	Capital Investment:	$30,000
8.	Substations:	Columbia Substation, 138 kV
9.	Supporting Structures:	wood poles
10.	Participation with other Utilities:	DEO – 100%
11.	Purpose of the planned transmission line:	supply new substation to provide 12.47 kV distribution system capacity.
12.	Consequences of Line Construction deferment or Termination:	inability to supply 12.47 kV distribution load
13.	Miscellaneous:	area to be served is primarily west-central Warren County

DUKE ENERGY OHIO

4901:5-5-04(D)(1)

FORM FE-T9: SPECIFICATIONS OF PLANNED ELECTRIC TRANSMISSION LINES

1.	Line Name: Line Number:	Foster-Warren DEO-A5484
2.	Point of Origin: Terminus:	Tap Feeder 5484 Columbia Substation (proposed)
3.	Right-of-Way, Length: Average Width: Number of Circuits:	approximately 175 feet 50 feet 1 transmission line above 125 kV
4.	Voltage:	138 kV design and operate voltage
5.	Application for Certificate:	6/01/2012
6.	Construction:	construction commencement -- 9/01/12 anticipated date of commercial operation – 12/31/12
7.	Capital Investment:	$30,000
8.	Substations:	Columbia Substation, 138 kV
9.	Supporting Structures:	wood poles
10.	Participation with other Utilities:	DEO – 100%
11.	Purpose of the planned transmission line:	supply new substation to provide 12.47 kV distribution system capacity.
12.	Consequences of Line Construction deferment or Termination:	inability to supply 12.47 kV distribution load
13.	Miscellaneous:	area to be served is primarily west-central Warren County

DUKE ENERGY OHIO
4901:5-5-04(D)(1)
FORM FE-T9: SPECIFICATIONS OF PLANNED ELECTRIC TRANSMISSION LINES

1.	Line Name: Line Number:	Whittier-Rochelle DEO-A8281
2.	Point of Origin: Terminus:	Whittier Substation (proposed) Rochelle Substation
3.	Right of Way, Length: Average width: Number of circuits:	7100 feet 10 ft. 1
4.	Voltage: 138 kV	
5.	Application for Certificate:	12/2011
6.	Construction to Commence: Commercial Operation:	commencement date: 6/2012 anticipated date: 6/2013
7.	Capital Investment:	$7,700,000
8.	Substations:	none
9.	Supporting Structures:	underground
10.	Participation with other Utilities:	DEO – 100%
11.	Purpose of the Planned transmission line:	reinforce 138 kV transmission system
12.	Consequences of Line Construction deferment or Termination:	inability to supply all 138 kV transmission system load under normal and outage condition
13.	Miscellaneous:	area to be served is Cincinnati, OH

DUKE ENERGY OHIO
4901:5-5-04(D)(1)

FORM FE-T9: SPECIFICATIONS OF PLANNED ELECTRIC TRANSMISSION LINES

1.	Line Name: Line Number:	Eastwood – Ford Batavia DEO-A8481
2.	Point of Origin: Terminus:	Tap Feeder 8481 Curliss Sub (Proposed)
3.	Right-of-Way, Length: Average width: Number of circuits:	0.1 miles 50 ft. 1
4.	Voltage: 138 kV	
5.	Application for Certificate:	09/2015
6.	Construction to Commence: Commercial Operation:	01/2016 06/2016
8.	Capital Investment, Estimated Cost:	$58,117
8.	Substations:	Curliss Sub
9.	Supporting Structures:	Wood Poles
10.	Participation with other Utilities:	DEO – 100%
11.	Purpose of the Planned Transmission Line:	reinforce underlying 69 kV transmission system
12.	Consequences of Line Construction deferment or Termination:	inability to supply all 69 kV subtransmission system load under normal and outage conditions
13.	Miscellaneous:	area to be served is Central Clermont County

DUKE ENERGY OHIO
4901:5-5-04(D)(1)

FORM FE-T9: SPECIFICATIONS OF PLANNED ELECTRIC TRANSMISSION LINES

1.	Line Name: Line Number:	Eastwood-Ford Batavia DEO-A8481
2.	Point of Origin: Terminus:	Tap Feeder 8481 Curliss Sub (Proposed)
3.	Right-of-Way, Length: Average width: Number of circuits:	0.1 miles 50 ft. 1
4.	Voltage: 138 kV	
5.	Application for Certificate:	09/2015
6.	Construction to Commence: Commercial Operation:	01/2016 06/2016
9.	Capital Investment, Estimated Cost:	$58,117
8.	Substations:	Curliss Sub
9.	Supporting Structures:	Wood Poles
10.	Participation with other Utilities:	Duke Energy Ohio – 100%
11.	Purpose of the Planned Transmission Line:	reinforce underlying 69 kV transmission system
12.	Consequences of Line Construction deferment or termination:	inability to supply all 69 kV subtransmission system load under normal and outage conditions
13.	Miscellaneous:	area to be served is Central Clermont County

(2) A listing of all proposed substations is provided on the following forms FE-T10, Summary of Proposed Substations.

DUKE ENERGY OHIO

4901:5-5-04(D)(2)

FORM FE-T10: SUMMARY OF PROPOSED SUBSTATIONS

Substation Name: Columbia

Voltage(s): 138 kV, 12.47 kV

Type of Substation: Distribution (D)

Timing: 2012

Line Association(s): DEO-A5484

Minimum Substation Site Acreage: 5 acres

DUKE ENERGY OHIO

4901:5-5-04(D)(2)

FORM FE-T10: SUMMARY OF PROPOSED SUBSTATIONS

Substation Name: Whittier

Voltage(s): 138 kV, 12.47 kV

Type of Substation: Distribution (D)

Timing: 2012

Line Association(s): DEO-A1180

Minimum Substation Site Acreage: 5 acres

DUKE ENERGY OHIO

4901:5-5-04(D)(2)

FORM FE-T10: SUMMARY OF PROPOSED SUBSTATIONS

Substation Name: Curliss Substation

Voltage(s): 138 kV, 69 kV

Type of Substation: Distribution (D)

Timing: 2016

Line Association(s): DEO-A8481

Minimum Substation Site Acreage: 5 acres

(3) Planned Transmission System Maps

(a) Schematic maps and geographic maps depicting the existing and planned 345 kV and 138 kV transmission networks are considered by DEO to be critical energy infrastructure information. The maps and diagrams will be provided under seal.

(b) Rule Requirement - Two copies of the above maps, for Commission use, on a scale of 1:250,000. The electric transmission owners may jointly provide one set of overlays to meet this requirement. Participation in the Commission's joint mapping project will meet this requirement:

The joint mapping project coordinated by the OEUI has not been accomplished for a number of years to DEO's knowledge. DEO can provide a map at the requested scale to the Commission upon request.

E. SUBSTANTIATION OF THE PLANNED TRANSMISSION SYSTEM

(1) Graphic plots of the DEO 138 kV and 345 kV systems that show the MW and MVAR flows and the bus voltages have been prepared. They are considered by DEO to be critical energy infrastructure information. Plots of 138 kV system and 345 kV system for the 2011 summer base case and the most recently prepared 2016 summer base case plots will be provided separately to PUCO staff. The 2011 and 2016 summer base case power flow cases in PSS/E format are included with the CEII information.

(2) Contingency cases - Contingency cases based on the peak load base cases are studied to determine system performance for generation and transmission system outages. The results of such studies are used as bases for the determination of the need for and timing of additions to the transmission system. DEO has prepared several power flow outage cases which can be considered representative of the types of outages studied. All cases are based on the 2011 Summer Peak Load Power Flow Base Case. The outage cases, discussion and power flow transcription diagrams are considered by DEO to be critical energy infrastructure information which will be provided under seal.

(3) Analysis of proposed solutions to problems identified in paragraph (E)(2) of this rule: As discussed, a number of contingency cases, predicated on the various base cases, have been studied. These contingency cases include loss

of transformer and/or loss of transmission circuit, as well as unscheduled variation of generation dispatch. These contingency cases seek to model system performance under various conditions that are common to electric system operation. The general criteria applied to these studies are that the loss of either a major transformer or transmission circuit should not cause loading on any of the remaining transformers or circuits to exceed their emergency thermal ratings. In addition, double-contingency outages, which include at least one 345 kV system component, should likewise not cause loading on any remaining components to exceed the emergency thermal ratings. Probability of occurrence, availability of mitigating procedures, and other factors are considered when these reliability analyses are performed and evaluated. No problems are expected as a result of the contingencies identified in paragraph (E) (2) of this rule. DEO expects all electric components to operate within their limits based on DEO's planning criteria.

(4) Adequacy of the electric transmission owner's transmission system to withstand natural disasters and overload conditions: The contingency cases and reliability analyses described above indicate the performance of the transmission system subsequent to outages, which may be caused by natural disasters. As discussed above, the transmission system is designed to withstand certain outages without causing loading on the remaining system components to exceed emergency thermal load ratings. More severe outages may cause system components to overload. Such overloads, if not corrected by switching or other actions, may cause loss of life of the overloaded system components. Some outages may be of such a severity that all of the load could not be served. The transmission system could also be segmented to such a degree that all of the load could not be served.

(5) Analysis of the electric transmission owner's transmission system to permit power interchange with neighboring systems: The Duke Energy Ohio transmission system is interconnected to American Power (AEP), Dayton Power and Light (DAY), Ohio Valley Electric Company (OVEC), and Eastern Kentucky Power Cooperative (EKPC). The ability to accommodate any particular interchange, whether short term or long term is highly dependent on the actual transfer and the conditions under which it would occur. Duke Energy Ohio is a member of the Midwest Independent Transmission System Operator as such the allocation of Available Flowgate Capacity (AFC) is the sole responsibility if the Midwest ISO.

(6) Transmission Import and Export Transfer Capability: Duke Energy Ohio is a member of the Midwest Independent Transmission System Operator as such the allocation of AFC is the sole responsibility of the Midwest ISO.

(7) A description of any studies regarding transmission system improvement, including, but not limited to, any studies of the potential for reducing line losses, thermal loading, and low voltage, and for improving access to

alternative energy resources: No transmission system studies specifically addressing the above items have been performed. Line losses are considered in the evaluation of alternative projects. Thermal loading and low voltage issues are considered and addressed as a part of the transmission system evaluation and planning process. Accommodation of alternative energy sources requesting connection to the DEO transmission system are handled by the Midwest ISO interconnection procedures.

(8) Switching diagrams of the DEO 138 kV and 345 kV systems are considered by DEO to be critical energy infrastructure information which will be provided under seal.

F. REGIONAL AND BULK POWER REQUIREMENTS

Information relating to RFC and bulk power requirements is provided to the Public Utilities Commission of Ohio by RFC on behalf of Duke Energy Ohio and several Ohio electrical utilities.

G. CRITICAL ENERGY INFRASTRUCTURE INFORMATION

As discussed previously, Duke Energy Ohio considers all or portions of the information sought under the rules listed below to be critical energy infrastructure information. This information has been assembled separately and will be provided to the Commission under seal.

4901:5-5-04 (C)(2)(a)	4901:5-5-04 (C)(2)(b)	4901:5-5-04 (C)(2)(c)
4901:5-5-04 (D)(3)(a)	4901:5-5-04 (D)(3)(b)	4901:5-5-04 (E)(1)
4901:5-5-04 (E)(2)	4901:5-5-04 (E)(8)	

H. SUBSTANTIATION OF THE PLANNED DISTRIBUTION SYSTEM

A. Load flow or other system analysis by voltage class of the EDU's distribution system performance in Ohio, that identifies and considers each of the following:

(a) Any thermal overloading of distribution circuits and equipment;
(b) Any voltage variations on distribution circuits that do not comply with the current version of American National Standard Institute (ANSI) C84.1, electric power systems and equipment and equipment voltage ratings or standard as later amended.

The Duke Energy Ohio distribution system includes systems that operate at nominal voltages of 4.16 kV, 12.47 kV, 13.2 kV, 34.5 kV and 69 kV. Planning for the 4.16 kV, 12.47 kV and 34.5 kV systems utilizes a combination of peak load power flow analysis and projections of the expected future peak loads on the various system components. The load projections are based on historical loads, general load growth trends within defined load areas, and known proposed loads. The projected future loads are then compared to the assigned capacity of the components to determine if and when any components are expected to experience peak loading in excess of their assigned capacities. System reinforcement projects are then identified and planned for completion prior to the projected time that the components would be overloaded without relief. This process is repeated on an annual basis, adjusting project schedules as required due to differences between actual load growth and projected load growth and any other pertinent factors.

The distribution capacity planning process addresses voltage variation in planning for the Duke Energy 4.16 kV, 12.47 kV, 13.2 kV and 34.5 kV systems by incorporating design parameters intended to maintain the voltage at all the customer service points within ANSI C84.1 standards. These design parameters include the following:
1. application of automatic voltage regulation at the feeder source within substations
2. application of capacitor banks both within substations and distributed on the distribution feeders
3. utilization of adequately sized conductor and distribution transformers

Any voltage concerns identified by customer notification or system monitoring are addressed by insuring that the above design parameters are adhered to.

B. Analysis and consideration of proposed solutions to problems identified in paragraph (C)(1) of this rule.

As of the date of preparation of this report, the following major projects are planned to insure that adequate thermal capacity will exist on the Duke Energy 4.16 kV, 12.47 kV, 13.2 kV and 34.5 kV distribution systems:

<u>2011</u>
Seward Substation – Install an additional 22.4 MVA, 138-12.47 kV transformer and associated equipment at an existing Duke Energy Ohio Substation to serve expected increased demand in the West Chester area.

Green Secondary Network Improvements – Add transformers and conductors to relieve projected overloading to parts of downtown Cincinnati service area.

2012

Canal Substation – Install a 22.4 MVA, 69-12.47 kV transformer and associated equipment in a new Duke Energy substation to serve expected increased demand in the Hamilton area.

Columbia Substation – Install a 22.4 MVA, 138-12.47 kV transformer and associated equipment at a new Duke Energy Ohio substation to serve projected area loading and relieve existing circuits in the area.

Brown Substation – Install a 22.4 MVA, 138-12.47 kV transformer and associated equipment at an existing Duke Energy Ohio substation to serve projected winter heating demand in southeastern Brown County.

Mack Substation – Install an additional 22.4 MVA, 69-12.47 kV transformer and associated equipment at an existing Duke Energy Ohio substation to serve projected area loading and relieve existing circuits in the area.

Distribution capacity projects are typically not planned beyond a three to four year time horizon, due to the variability in area load growth patterns and the ability to react fairly quickly in the implementation of capacity projects. Smaller-scale projects to upgrade or establish distribution feeder routes to serve new load and/or allow loads to be served by existing substation capacity are typically planned and implemented in shorter time-frames as required by actual load development.

C. Adequacy of the electric utility distribution system to withstand natural disasters and overload conditions.

The Duke Energy Ohio distribution system is designed to withstand certain wind loading, ice loading, and other structural issues by recognized national standards. Natural disasters that exceed these conditions may result in damage to the distribution system and the inability to serve all customers. Duke Energy Ohio has an Emergency Plan that calls for the mobilization of personnel and resources as required by the severity of a given incident, including mutual assistance from other utilities.

The goal of the Duke Energy Ohio planning process is to insure that components are not loaded beyond their assigned ratings under normal system conditions to meet expected load. However, under outage or other abnormal conditions, Duke Energy Ohio recognizes that it may be necessary to load components beyond the ratings assigned for normal use. Certain components, such as transformers, regulators, and cables, have identifiable overload capabilities that are either allowable for intermittent use during the life of the component or can be mitigated after the overload by maintenance activities. Duke Energy Ohio will utilize such capacity when necessary and feasible to carry load if the alternative is to not serve the load. Certain other system components, such as overhead lines, do not have significant overload capacity due the necessity of maintaining adequate electrical clearance.

D. Analysis and consideration of any studies regarding distribution system improvement, including, but not limited to, any studies of the potential for reducing line losses, thermal loading and low voltage or any other problems, and for improving access to alternative resources.

The analytical process intended to alleviate thermal loading and low voltage conditions on the Duke Energy Ohio distribution system is described in response to paragraph 4901:5-5-04(C)(1)(a) and (b). No general improvement studies or studies related solely to the reduction of line losses are performed. No studies specifically related to improving access to alternative energy sources have been performed.

E. A switching diagram of circuits less than one hundred twenty-five kV that are not radial.

All Duke Energy Ohio 4.16 kV, 12.47 kV, 13.2 kV and 34.5 kV circuits are operated in a radial mode. A number of 69 kV circuits operate in non-radial mode. The switching diagram of the DEO 69 kV system is considered by DEO to be critical energy infrastructure information. This diagram will be provided separately to PUCO staff with the 138 kV and 345 kV switching diagrams requested under 4901:5-5-04 (E)(8). The non-radial operated circuits are indicated on this diagram.

SECTION III – ELECTRIC DISTRIBUTION FORECAST

On the following pages, the loads for Duke Energy Ohio are provided. Please note that FE-D forms represent the full distribution forecast regardless of who supplies the energy, whereas the FE-T forms represent the load supplied by the regulated utility. Therefore, the first two years of the forecast reflect energy and peak reduced for current switching levels. The remaining years of the forecast reflect the assumption that all load returns to the regulated utility at the end of the ESP.

1. Service Area Energy Forecasts

The following forms contain the energy forecast for Duke Energy Ohio's service area. Before implementation of any new EE programs or incremental EE impacts, Residential use for the ten-year period of the forecast from 2011 to 2021 is expected to increase at a rate of 0.8 percent per year; Commercial use increases 1.5 percent per year; and Industrial use increases 1.6 percent per year. The summation of the forecast across each sector and including losses results in a growth rate forecast of 1.2 percent for Total Energy.

The Total energy growth rate after EE impacts is (-0.1) percent.

2. System Seasonal Peak Load Forecast

The following forms also contain the forecast of summer and winter peaks before implementation of EE programs for the Duke Energy Ohio service area. The historical difference between native and internal load before EE reflects the impact of the interruptible rate tariff and other demand response programs.

The table shows the Summer and succeeding Winter Peaks, the Summer Peaks being the predominant ones historically. Projected growth in the internal summer peak demand is 1.0 percent. Projected growth in the internal winter peak demand is 0.9 percent per year.

Peak load forecasts after implementation of EE programs are shown for native and internal loads after EE. The projected growth in the internal summer peak is 0.2 percent.

3. Controllable Loads

The native peak load forecast reflects the MW impacts from the PowerShare® demand response program and controllable loads from the Power Manager program. The amount of load controlled depends upon the level of operation of the particular customers participating in the programs. The difference between the internal and native peak loads consists of the impact from these loads. See Section H in Duke Energy Ohio's Resource Plan for a complete discussion of controllable and other demand response programs.

PUCO Form FE-D1 : EDU Service Area Energy Delivery Forecast
(Megawatt Hours/Year) (a)
Duke Energy Ohio (d)

		1	2	3	4	5(a)	5(b)	6	7	8
	Year	Residential	Commercial	Industrial	Transportation (b)	Other (c)	Energy Efficiency & Demand Response (e)	Total End Use Delivery (f)	Line Losses and Company Use	Total Energy
								1+2+3+4+5(a)-5(b)		6+7
-5	2006	7 068,216	5 776 434	5.794 652	-	1 551 925	379	20 191,276	1.370.231	21 561 508
-4	2007	7.623.125	6 178 343	5 756.911	-	1,592 553	54 677	21 150.932	1 554 761	22.705 693
-3	2008	7,290 678	6,092 035	5,364 071	-	1,593,139	151 371	20 330 124	1 231 134	21 561 257
-2	2009	6,721,835	5.656 344	3.371 411	-	1 436 194	66.403	17 187 784	602.245	17.790,029
-1	2010	6 328 297	2.660.497	638,338	-	475 304	310 765	10 102 436	844 007	10 946 442
0	2011	4,133 790	1.168 895	718 164	-	153,007	30,746	6,143 110	452 537	6 595 647
1	2012	7 287,012	6 724,039	5.352 390	-	1 360 698	199 357	20 544,782	1,450,657	21 995,439
2	2013	7 290.455	6.988.870	5 487.437	-	1 436 194	359 405	20 843,612	1 472 977	22.316 589
3	2014	7,358.469	7,262 705	5.586 454	-	1,475,037	548.955	21,143 740	1.504 257	22 647.997
4	2015	7.454 619	7 397 689	5 666,504	-	1,494 652	960 114	21 053,350	1,525.911	22 579 261
5	2016	7.462.133	7.463 050	5.739 282	-	1.499.813	1.183 924	20 980,353	1.535,970	22 516 323
6	2017	7.524,400	7.502.188	5,809 615	-	1.497.130	1 409 053	20 924 280	1.547 916	22.472 196
7	2018	7 591 238	7.531 982	5 877 271	-	1.491 962	1,634 223	20 858 230	1 559.151	22 417 381
8	2019	7 571.620	7.567 893	5.945 452	-	1 486.384	2 083 474	20 577.885	1.571,064	22 148 949
9	2020	7.756.327	7,590.294	6.010 593	-	1.480.776	2 530 275	20 307.716	1.583 393	21.891 109
10	2021	7.945.045	7.623 573	6 075 950	-	1.476 590	2.973 168	20 047 990	1 596.409	21 644.399

(a) To be filled out by all EDUs. The category breakdown should refer to the Ohio portion of the EDU's total service area
(b) Transportation includes railroads & railways
(c) Other includes street & highway lighting public authorities, interdepartmental sales, and wholesale
(d) Historical class numbers include the impact of DSM programs in place at the time. Forecast numbers have not been reduced for energy efficiency impacts
(e) Historical numbers represent incremental impacts of energy efficiency programs. Forecast numbers represent cumulative impacts
(f) Historical numbers include the impact of DSM programs in place at the time. Forecast numbers include losses

PUCO Form FE-D1 : EDU Service Area Energy Delivery Forecast

(Megawatt Hours/Year) (a)

Duke Energy Ohio After DSM (d)

		1	2	3	4	5	6	7	8
	Year	Residential	Commercial	Industrial	Transportation (b)	Other (c)	Total End Use Delivery	Line Losses and Company Use	Total Energy
							1+2+3+4+5		6+7
-5	2006	7,068,216	5,776,484	5,794,652	-	1,551,925	20,191,276	1 370,231	21,561 508
-4	2007	7,623,125	6 178 343	5,756,911	-	1,592 563	21 150,932	1,554 761	22,705 693
-3	2008	7 280,878	6,092,035	5 364,071	-	1,593,139	20,330 124	1,231,134	21 561,257
-2	2009	6 721,835	5 656 344	3,371,411	-	1,438,194	17 187,784	602,245	17,790,029
-1	2010	6,328,297	2 660 497	638 338	-	475,304	10 102 436	844,007	10,946 442
0	2011	4,109,650	1,166,262	716,525	-	152,838	6,145 275	450,372	6,595,647
1	2012	7,181,563	6,683,490	5,320,313	-	1 372,382	20 557,749	1,437 690	21,995 439
2	2013	7 114 718	6,907,423	5 425,496	-	1 419 273	20,866 910	1 449,679	22,316 589
3	2014	7 118,472	7 127 019	5 486,990	-	1,446,897	21,179 378	1,468,619	22,647,997
4	2015	7,047,107	7,143,445	5,483,351	-	1 441,911	21,115,815	1,463 447	22,579 261
5	2016	7,038,238	7,107 190	5,484,986	-	1,426 626	21,057 041	1,459,282	22,516,323
6	2017	7,014,307	7 080 737	5,509 770	-	1,410 992	21,015,607	1,456,389	22,472,196
7	2018	6,992 629	7,045,899	5,532 528	-	1,393 342	20 964,399	1 452 982	22,417,381
8	2019	6,899,081	6,941 981	5,509,783	-	1,362,356	20 713,200	1,435,748	22 148,949
9	2020	6,806,605	6,846,478	5,486,266	-	1,332,282	20,471,652	1,419 457	21,891,109
10	2021	6 715,706	6,754 887	5,465,795	-	1,304,710	20,241 098	1,403,301	21 644 399

(a) To be filled out by all EDUs. The category breakdown should refer to the Ohio portion of the EDU's total service area
(b) Transportation includes railroads & railways
(c) Other includes street & highway lighting, public authorities, interdepartmental sales and wholesale
(d) Historical numbers include the impact of DSM programs in place at the time

4901 5-5-04

PUCO Form FE-D3 : EDU System Seasonal Peak Load Demand Forecast (c)

(Megawatts)(a)

Duke Energy Ohio Before DSM

		Native				Internal			
	Year	Summer	Demand Response	Net Summer	Winter (b)	Summer	Demand Response	Net Summer	Winter (b)
-5	2006	4,366	0	4,366	3,551	4,366	0	4,366	3,551
-4	2007	4,436	0	4,436	3,505	4,459	23	4,436	3,505
-3	2008	4,074	0	4,074	3,526	4,074	0	4,074	3,526
-2	2009	3,675	0	3,675	2,271	3,675	0	3,675	2,271
-1	2010	2,317	0	2,317	1,459	2,328	11	2,317	1,459
0	2011	1,800	0	1,800	3,644	1,864	64	1,800	3,644
1	2012	4,379	0	4,379	3,709	4,543	164	4,379	3,709
2	2013	4,419	0	4,419	3,777	4,583	164	4,419	3,777
3	2014	4,506	0	4,506	3,821	4,671	164	4,506	3,821
4	2015	4,560	0	4,560	3,845	4,725	164	4,560	3,845
5	2016	4,571	0	4,571	3,858	4,735	164	4,571	3,858
6	2017	4,607	0	4,607	3,881	4,771	164	4,607	3,881
7	2018	4,639	0	4,639	3,904	4,803	164	4,639	3,904
8	2019	4,676	0	4,676	3,929	4,840	164	4,676	3,929
9	2020	4,712	0	4,712	3,957	4,876	164	4,712	3,957
10	2021	4,757	0	4,757	3,984	4,921	164	4,757	3,984

(a) To be filled out by all EDUs. Data should refer to the Ohio portion of the EDU's total service area.
(b) Winter load reference is to peak loads which follow the summer peak load.
(c) Historical company peaks not necessarily coincident with the system peak.
(d) Figures reflect the impact of historical demand side programs.

PUCO Form FE-D3 : EDU System Seasonal Peak Load Demand Forecast

(Megawatts)(a)

Duke Energy Ohio After DSM

		Native (b)(c)				Internal (b)(c)			
	Year	Summer	Demand Response	Net Summer	Winter (b)	Summer	Demand Response	Net Summer	Winter (b)
-5	2006	4,366	0	4,366	3,551	4,366	0	4,366	3,551
-4	2007	4 436	0	4,436	3,505	4,459	23	4 436	3,505
-3	2008	4,074	0	4,074	3,526	4,074	0	4,074	3,526
-2	2009	3,675	0	3,675	2,271	3,675	0	3,675	2,271
-1	2010	2,317	0	2,317	1,459	2,328	11	2,317	1,459
0	2011	1,795	0	1,795	3,626	1 859	64	1,795	3,626
1	2012	4,340	0	4,340	3,676	4,504	164	4,340	3,676
2	2013	4,376	0	4,376	3,729	4,540	164	4,376	3,729
3	2014	4,439	0	4,439	3,740	4,603	164	4,439	3,740
4	2015	4,441	0	4,441	3,745	4,605	164	4,441	3,745
5	2016	4,424	0	4,424	3,750	4,588	164	4 424	3,750
6	2017	4,432	0	4,432	3,756	4,596	164	4,432	3,756
7	2018	4,436	0	4,436	3,745	4,600	164	4,436	3,745
8	2019	4,417	0	4,417	3,736	4,581	164	4,417	3,736
9	2020	4,398	0	4,398	3,730	4,563	164	4,398	3,730
10	2021	4,388	0	4,388	3,724	4,552	164	4,388	3,724

(a) To be filled out by all EDUs. Data should refer to the Ohio portion of the EDU's total service area.

(b) Winter load reference is to peak loads which follow the summer peak load.

(c) Includes DSM impacts

PUCO Form FE-D5: EDU's Total Monthly Energy Forecast (MWh)
Duke Energy Ohio Before DSM

				Ohio Service Area	System
Year 0 (d)					
				623,017	623 017
January				533,960	533,960
February				504,294	504 294
March				427,847	427,847
April				453,843	453,843
May				578,746	578,746
June				675,096	675,096
July				690,568	690,568
August				548,456	548,456
September				487,978	487,978
October				484,853	484,853
November				617 736	617,736
December					
Year 1 (d)					
				2,045,536	2,045,536
January				1,761,974	1 761,974
February				1,761,845	1,761,845
March				1,584,760	1,584,760
April				1,701,376	1,701,376
May				1,972,989	1,972,989
June				2,152,015	2,152,015
July				2,192,293	2,192 293
August				1,764,821	1,764,821
September				1,677 436	1,677 436
October				1,652,311	1,652,311
November				1,927,439	1,927 439
December					

(a) To be filled out by all EDUs. Data should refer to the Ohio portion of the EDU's total service area in this column.
(b) EDUs operating across Ohio boundaries shall provide data for the total service area in this column
(c) EDUs operating as a part of an integrated operating system shall provide data for the total system in this column.
(d) Actual data shall be indicated with an asterisk (*).

PUCO Form FE-D5: EDU's Total Monthly Energy Forecast (MWh)
Duke Energy Ohio After DSM (e)

Year 0 (d)				Ohio Service Area	System
January				622,588	622,588
February				533,214	533,214
March				503,154	503,154
April				426,514	426,514
May				452,079	452,079
June				576,330	576,330
July				672,000	672,000
August				687,108	687,108
September				545,019	545,019
October				484,528	484,528
November				480,628	480,628
December				612,486	612,486
Year 1 (d)					
January				2,031,431	2,031,431
February				1,748,560	1,748,560
March				1,747,858	1,747,858
April				1,571,651	1,571,651
May				1,686,388	1,686,388
June				1,955,723	1,955,723
July				2,132,536	2,132,536
August				2,172,250	2,172,250
September				1,746,410	1,746,410
October				1,661,485	1,661,485
November				1,634,280	1,634,280
December				1,906,867	1,906,867

(a) To be filled out by all EDUs. Data should refer to the Ohio portion of the EDU's total service area in this column.
(b) EDUs operating across Ohio boundaries shall provide data for the total service area in this column
(c) EDUs operating as a part of an integrated operating system shall provide data for the total system in this column.
(d) Actual data shall be indicated with an asterisk (*)
(e) *Includes DSM impacts*

PUCO Form FE-D6: EDU's Monthly Internal Peak Load Forecast (Megawatts)

Duke Energy Ohio Before DSM

	Native				Internal	
Year 0 (d)	Ohio Service Area	Demand Response	Net Summer	System	Ohio Service Area	System
January	1.259	0	1.259	1,259	1,259	1,259
February	1,296	0	1.296	1.296	1,296	1.296
March	1,240	0	1,240	1,240	1.240	1 240
April	1 028	35	1.028	1.028	1 063	1,063
May	1.198	35	1.198	1,198	1.232	1,232
June	1,532	54	1,532	1,532	1 586	1.586
July	1,810	54	1,810	1.810	1,864	1.864
August	1.695	54	1 695	1,695	1.749	1 749
September	1.570	54	1.570	1,570	1.624	1 624
October	1,180	0	1,180	1,180	1.180	1.180
November	1 230	0	1.230	1,230	1.230	1,230
December	1.425	0	1.425	1,425	1.425	1,425
Year 1 (d)						
January	3.644	0	3.644	3.644	3.644	3.644
February	3.547	0	3,547	3.547	3.547	3.547
March	3.326	0	3 326	3.326	3,326	3.326
April	2.956	106	2.956	2.956	3,061	3.061
May	3,514	106	3,514	3.514	3.620	3 620
June	4,145	164	4,145	4.145	4.309	4.309
July	4 379	164	4.379	4 379	4,543	4,543
August	4.379	164	4,379	4.379	4.543	4.543
September	3.841	164	3.841	3.841	4.005	4.005
October	3.226	0	3.226	3,226	3.226	3.226
November	3.185	0	3.185	3.185	3.185	3 185
December	3.600	0	3.600	3.600	3 600	3.600

(a) To be filled out by all EDUs Data should refer to the Ohio portion of the EDU's total service area in this column.
(b) EDUs operating across Ohio boundaries shall provide data for the total service area in this column.
(c) EDUs operating as a part of an integrated operating system shall provide data for the total system in this column
(d) Actual data shall be indicated with an asterisk (*).

PUCO Form FE-D6: EDU's Monthly Internal Peak Load Forecast (Megawatts) (e)

Duke Energy Ohio After DSM (e)

	Native				Internal	
Year 0 (d)	Ohio Service Area	Demand Response	Net Summer	System	Ohio Service Area	System
January	1.259	0	1.259	1 259	1.259	1.259
February	1.295	0	1 295	1.295	1 295	1.295
March	1.238	0	1.238	1.238	1.238	1.238
April	1,026	35	1.026	1,026	1,060	1.060
May	1 195	35	1 195	1.195	1.229	1 229
June	1.527	54	1 527	1 527	1.581	1.581
July	1.805	54	1 805	1 805	1.859	1.859
August	1.689	54	1 689	1.689	1.743	1.743
September	1.564	54	1.564	1.564	1 617	1.617
October	1.174	0	1.174	1.174	1.174	1.174
November	1.225	0	1.225	1.225	1.225	1 225
December	1.419	0	1.419	1,419	1.419	1.419
Year 1 (d)						
January	3 626	0	3,626	3.626	3,626	3.626
February	3,529	0	3 529	3.529	3.529	3.529
March	3.301	0	3.301	3.301	3.301	3.301
April	2.930	106	2 930	2.930	3.036	3.036
May	3.486	106	3.486	3 486	3.591	3 591
June	4,111	164	4.111	4,111	4.275	4.275
July	4.336	164	4,336	4.336	4.501	4.501
August	4.340	164	4,340	4.340	4.504	4 504
September	3 805	164	3.805	3,805	3.969	3.969
October	3.195	0	3 195	3.195	3.195	3 195
November	3.165	0	3 165	3.165	3 165	3.165
December	3 577	0	3,577	3.577	3 577	3 577

(a) To be filled out by all EDUs Data should refer to the Ohio portion of the EDU's total service area in this column.
(b) EDUs operating across Ohio boundaries shall provide data for the total service area in this column
(c) EDUs operating as a part of an integrated operating system shall provide data for the total system in this column
(d) Actual data shall be indicated with an asterisk (*)
(e) Includes DSM impacts

4. Load Factor

The numbers below represent the annual percentage load factor for the Duke Energy Ohio System before any new or incremental EE. It shows the relationship between Total Energy and the annual internal Summer Peak, before EE.

YEAR	LOAD FACTOR
2006	58.5%
2007	55.4%
2008	62.2%
2009	63.8%
2010	58.3%
2011	55.8%
2012	55.8%
2013	56.5%
2014	56.7%
2015	56.9%
2016	57.1%
2017	57.1%
2018	57.2%
2019	57.2%
2020	57.2%
2021	57.1%

SECTION IV - DUKE ENERGY OHIO 2011 RESOURCE PLAN

A. EXECUTIVE SUMMARY

1. Overview

Duke Energy Ohio, Inc., (Duke Energy Ohio or Company) has both a legal obligation and a corporate commitment to meet the electricity needs of its customers in a way that is affordable, reliable, and clean. Planning and analysis helps the Company achieve this commitment to customers. Duke Energy Ohio utilizes a resource planning process to identify the best options by which to serve customers in the future. The process incorporates both quantitative analysis and qualitative considerations. For example, quantitative analysis provides insight on future risks and uncertainties associated with energy efficiency (EE) impacts, fuel and energy and capacity costs, and renewables. Qualitative perspectives, such as the importance of fuel diversity, the Company's environmental profile, and the stage of technology deployment are also important factors to consider as long-term decisions are made regarding existing and new resources. The end result is a resource plan that serves as an important tool to guide the Company in making business decisions to meet customers' near-term and long-term electricity needs.

The overall objective of the resource planning process is to develop a robust and reliable economic strategy for meeting the needs of customers in a very dynamic and uncertain environment. Uncertainty always plays a role in the planning process and can normally be expected to be a concern when dealing with factors such as emerging environmental regulations, load growth or decline, and the pricing of fuel and market products. This Integrated Resource Plan (IRP) demonstrates a need for additional generation in the near future, but Duke Energy Ohio does not have any immediate plans to construct new generation in Ohio due to the lack of certainty under Ohio law in respect of the timely and adequate recovery of specific construction-related costs. Therefore, Duke Energy Ohio submits that, despite a need for additional generation, it is not requesting that the Public Utilities Commission of Ohio (Commission) certify that a need for newly used and useful generation exists as a disposition of this case.

The challenge in resource planning is to create an economical mix of existing and new resources that will be capable of serving uncertain capacity and energy needs while meeting Amended Substitute Senate Bill 221 (SB 221) resource requirements in the face of new and evolving environmental regulations. Two major changes in the 2011 Resource Plan from the 2010 Resource Plan are, first, the expectation of acceleration of the retirement date of all six units at the WC Beckjord Station (Beckjord) to 2015 and, second, the regulatory construct in which Duke Energy Ohio proposes to operate for the foreseeable future.

The accelerated retirement of Beckjord is driven primarily by the recently proposed United States Environmental Protection Agency (EPA) Utility Maximum Achievable Control Technology (MACT) rule. The MACT rule is expected to be finalized in November 2011, with required control technologies to be installed by January 1, 2015. Other emerging environmental regulations that also impact the retirement decision include the Coal Combustion Residuals (CCR) rule and the new Sulfur Dioxide (SO_2), Cross State Air Pollution Rule (CSAPR), Particulate Matter (PM) and Ozone National Ambient Air Quality standards. The anticipated retirement of the Beckjord units causes a significant incremental capacity need that likely will be realized in the 2015 period and thus places the emphasis of this resource plan on how to best meet this need.

This IRP also considers the proposed Electric Security Plan (ESP) regulatory construct as filed by Duke Energy Ohio in its recent Standard Service Offer (SSO) filing in Case No. 11-3549-EL-SSO. In this construct, all Duke Energy Ohio customers will have their capacity needs met with legacy Duke Energy Ohio resources, market purchases and potentially new resources, while the energy needs of those customers are supplied either by successful competitive suppliers in energy auctions or competitive retail electric service (CRES) providers. Further, under the proposed ESP framework, all Duke Energy Ohio's customers will share in the profits from the dedicated resources.

2. Planning Process Results

Given the numerous uncertainties and assumptions described above, the Company believes the most prudent approach is to create a plan that is robust under various possible future scenarios. At the same time, the Company must maintain its flexibility to adjust to evolving regulatory, economic, environmental, and operating circumstances.

The dedication of and investments in the Company's legacy generating assets, along with sharing in the profits these assets accrue from the energy market, was compared to securing the needed capacity from the market at PJM clearing prices. The ten year analysis indicates that the continued dedication and investments in the existing legacy generation, as proposed by the Company, is preferred to reliance on the PJM capacity market over the long-term. This analysis is dependent upon the ESP construct proposed by the Company which itself rests upon a non-bypassable charge for capacity.

The planning process identified two portfolios, shown below, that would ensure reliable service in an optimized manner to meet customers' needs for reliable, economic capacity and energy, as well as the alternative energy resource (AER) requirements. Both scenarios include dedication of, and investment in, the Company' existing generating assets and compliance with SB 221's requirements regarding AER and EE.

- Portfolio 1 (Combustion Turbine Portfolio (CT Portfolio)) – Meet capacity needs through market capacity purchases in the short term that will be met through the Duke Energy Ohio Fixed Resource Requirement (FRR) plan, with a longer-term option to meet capacity needs through the purchase of peaking capacity from a third party or a Duke Energy Ohio-owned peaking resource.

- Portfolio 2 (Combined Cycle/Combustion Turbine Portfolio (CC/CT Portfolio)) - Meet capacity needs through market capacity purchases in the short term that will be met through the Duke Energy Ohio FRR plan with a longer term option to meet capacity needs through the purchase of intermediate capacity or a Duke Energy Ohio-owned intermediate resource.

These portfolios were evaluated to determine which would better to meet both the capacity and energy needs of the Company's customers over the IRP planning horizon. While the two portfolios have similarities, the CC/CT Portfolio reduces reliance on peaking resources and increases the diversity in the resource mix. New CC intermediate generation is approximately 30% more efficient than new CT with the flexibility to operate over a broader range of capacity factors. It provides fuel diversity and acts as a price hedge if natural gas prices are lower than projected or if coal prices are significantly higher than projected in the future.

The IRP modeling results indicate that there is no significant difference in the results between the two portfolios analyzed under base assumptions. In other words, the model indicates that customers are indifferent between meeting future, incremental capacity needs with peaking or intermediate gas resources. However, in the higher fuel price sensitivity, the CC/CT Portfolio was more beneficial for customers. In addition, given the increased flexibility of CC generation as compared to CT generation, meeting a portion of the capacity need described in the CC/CT Portfolio with CC is preferred. As the future regulatory environment continues to unfold, it will impact how Duke Energy Ohio can best meet its future capacity needs. Monitoring the regulatory environment and evaluating the possible impacts to Duke Energy Ohio generating assets will be a primary focus for the Company in 2011, prior to making any definitive long-term plans to meet existing and incremental capacity needs.

Based on the results discussed above, the resource planning process indicates that the optimal resource plan for Ohio for the short-term consists of the ongoing operation of, and investment in, the legacy assets and securing capacity in the near-term through capacity market purchases.,. In addition to the continued operation of, and investment in, the legacy assets, longer-term options include building or purchasing intermediate generation over the next ten years. The option to build or purchase intermediate generation to offset some of the capacity need would reduce reliance on the capacity market and increase operational flexibility with consideration of construction lead times, and prevailing market prices. The IRP reflects meeting renewable resource requirements through a balanced approach of Renewable Energy Credit (REC) only purchases and securing energy/RECs through new, Company-owned renewable resources or contracts with third party renewable facilities. The Company's 2011 Resource Plan, shown in Table 4 A.1 below, reflects the addition of annual short-term capacity purchases and the option for a Duke Energy Ohio-owned or purchased intermediate facility, as well as the addition of renewable resources. The ongoing operation of, and investment in, the legacy assets, is not reflected in the table, but is an assumption.

Further details regarding the planning process, issues, uncertainties, and alternative plans are presented and discussed in the following sections to comply with Commission's Rule 4901:5-5-06, Ohio Administrative Code (O.A.C.). For further guidance on the location of information required pursuant to Rule 4901:5-5-06, O.A.C compliance, please refer to the cross-reference table in Appendix 4 B.

Table 4 A.1

(Table Redacted)

B. INTRODUCTION

Resource planning is about charting a course for the future in an uncertain world. Arguably, the planning environment is more dynamic than ever. A few of the key uncertainties include, but are not limited to:

- Load Forecasts: How elastic is the demand for electricity? Will environmental regulations such as federal carbon regulation result in higher costs of electricity and, thus, lower electricity usage? Can a highly successful energy efficiency program flatten or even reduce demand growth? At what pace will recovery from the current economic conditions affect the demand for electricity? What will Duke Energy Ohio's generation (*i.e.,* capacity and energy) obligation be from year to year? How can Duke Energy Ohio ensure that it has adequate resources to meet customer needs in this uncertain environment?
- Federal Carbon Regulation: What type of federal carbon legislation will be passed? Will it be industry-specific or economy-wide? Will it be a "cap-and-trade" system or in the form of a Clean Energy Standard? If legislation is not passed, how will the EPA regulations be implemented?
- Renewable Energy: Can Duke Energy Ohio secure sufficient renewable energy resources to meet its obligations under SB 221? Can the 25% AER requirement by 2025 be met with renewables alone? What impact would significant amounts of renewables have on system stability? Will a federal standard be set?
- Demand Side Management (DSM) and Energy Efficiency: Can DSM and EE deliver the anticipated capacity and energy savings reliably? Are customers ready to embrace EE? Will investments in DSM and EE be treated equally with investments in a generating plant?

- Gas Prices: What is the future of natural gas prices and supply? To what degree will enhanced natural gas recovery techniques open up new reserves and lower prices in the long term in the United States?
- Coal Prices: What is the future of coal prices and supply? What impact will increased regulatory pressure on the coal mining industry have on availability and price?

Duke Energy Ohio's resource planning process seeks to identify what actions the Company must take to ensure a safe, reliable, reasonably-priced supply of electricity for its customers regardless of how these uncertainties unfold. The planning process considers a wide range of assumptions and uncertainties and develops a resource plan and an action plan that preserves the options necessary to meet customers' needs. It is important to note that this resource plan has a limited life in a period of dynamic change. In essence, plans require constant adjustments to reflect the changing environment. The process and resulting conclusions for the current plan are discussed in this document.

The objective of the 2011 Duke Energy Ohio Resource Plan is to outline a strategy to supply electric services over a long-term planning horizon in a reliable, efficient, and economical manner. The proposed resource plan includes the specific AER and EE resource requirements as set forth by SB 221. Beyond the scope of the proposed plan, additional discussion is provided on the impact of AER requirements beginning in 2024. The integrated modeling approach of the resource plan incorporates forecasted electric loads, existing generating resources, potential traditional supply-side resources, renewable resources, and EE targets.

C. RESOURCE PLANNING PROCESS

The development of the resource plan is a multi-step process involving these key planning functions:

- Preparation of the electric load forecast.
- Consideration of the impacts of anticipated or pending regulations or events on existing resources.
- Identification of electric EE, renewable, and advanced energy resource options to the levels required by SB 221.
- Identification and economic screening for the cost-effectiveness of supply-side resource options.
- Integration of the EE, renewable, and supply-side options with the existing system and electric load forecast to develop potential resource portfolios to meet the desired reserve margin criteria.
- Performance of detailed modeling of potential resource portfolios to determine the resource portfolio that exhibits the lowest cost (*i.e.*, lowest net present value of costs) to customers over a wide range of alternative futures.
- Evaluation of the ability of the selected resource portfolio to minimize price and reliability risks to customers.

Many of these steps are influenced by or required because of the uncertainty factors presented in the Introduction section.

D. PLANNING ASSUMPTIONS

Preparing a resource plan that addresses the issues and uncertainties presented in the Executive Summary and Introduction requires the utility to develop planning assumptions for a variety of inputs including a forecast of future energy usage, current generation resource portfolio operating assumptions, future environmental regulation impacts and the expectations to meet future legislative requirements such as the comprehensive SB 221. The major planning assumptions used for the development of this plan are presented below, followed by further discussion detail.

- **Load Forecast** – Under the proposed ESP, Duke Energy Ohio has responsibility for meeting the capacity needs of all Duke Energy Ohio customers. Thus, the projected peak load for all Duke Energy Ohio customers will be used for the IRP analysis. In addition, a plus and minus 10% load in each hour of the forecast was developed for sensitivity analysis.
- **Reserve Margin** - To ensure an adequate and reliable source of electricity for customers, Duke Energy Ohio must plan to have sufficient resources to meet customer's need, while taking into consideration that load can be higher than forecasted or generating units may be unavailable due to scheduled or unscheduled outages. As a result, a target planning reserve margin is established as a reliability criteria in planning. Since Duke Energy Ohio will be a Fixed Resource Requirement ("FRR") entity when it transfers to PJM, PJM will establish the reliability requirement. The reliability requirement for an FRR entity for planning year 2011/2012 is 15.3
- **Retirements** - Due to the probable implementation of new environmental regulations, the development of the resource plan assumes the retirement of the six Beckjord coal-fired units (859 MW) at the end of 2014.
- **Fuel Cost** - Fuel is the largest cost component in estimating production costs. This plan is developed using a combination of observed market prices that transition to a long-term fundamental outlook as a base assumption. Lower and higher fuel pricing

impacts are investigated through sensitivity analyses using cost adjustments of -25% for a low fuel cost scenario and + 50% for coal and +30% for gas costs for a high fuel cost scenario.

- **Senate Bill 221 Energy Efficiency** - SB 221 EE and peak load reduction goals will be met over the next ten years with considerations for full implementation by 2025.
- **Renewables** - SB 221 renewable energy requirements for solar and non-solar will be met through a balanced combination of REC purchases and new wind, solar, and biomass resources.
- **Transmission** - Duke Energy Ohio will operate within PJM consistent with its intention to transfer the Duke Energy Ohio transmission assets from the MISO to the PJM regional transmission organization effective January 1, 2012.
- **Carbon** - Duke Energy Ohio has established a CO_2 price curve beginning in 2016 to represent the potential for future federal climate change legislation. The CO_2 prices that Duke Energy is utilizing are associated with proposed and debated legislation, including H.R. 2454 -- the American Clean Energy and Security Act of 2009, which passed the U.S. House of Representatives on June 26, 2009. The prices utilized in the 2011 Resource Plan represent the lower end of the range of prices that were estimated in proposed legislation.
- **Energy and Capacity Market Prices** – Duke Energy Corporation annually develops forecasts of fundamental prices for commodities, based on expectations of environmental regulations, including greenhouse gas regulation. For the purposes of the 2011 Duke Energy Ohio Resource Plan, observable market prices were used through

2015, switching to market fundamental prices in 2016. In addition, the energy prices were adjusted for the impacts of the high and low fuel cost sensitivities.

E. EXISTING RESOURCES AND ANTICIPATED CHANGES

1. Existing Generation System Description

The total installed net summer generation capability owned by Duke Energy Ohio is 3,894 Megawatts (MW). This capacity consists of 3,514 MW of coal-fired steam capacity, 136 MW of natural gas-fired peaking capacity, and 244 MW of oil-fired peaking capacity. The steam capacity consists of fifteen coal-fired units located at six stations. The peaking capacity consists of eight oil-fired CT units located at two stations, and four natural gas-fired CTs located at one station. Ten of the fifteen steam units are jointly owned. Table 4 E.1 is a listing of the jointly-owned units, ownership percentages, and summer capacity:

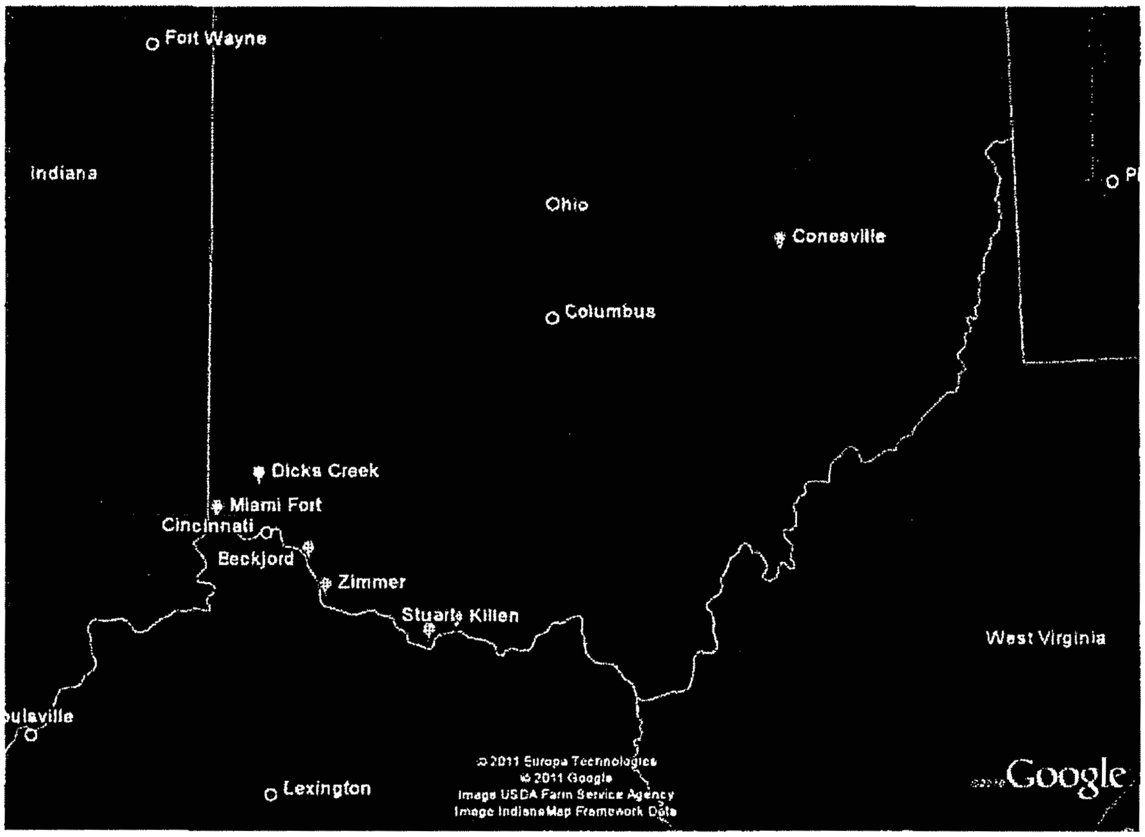
Table 4 E.1

Jointly Owned Units, Percentages, and Summer Capacity

Plant	% Ownership	MWs
Zimmer Unit 1	46.5%	605
Miami Fort Unit 7	64%	320
Miami Fort Unit 8	64%	320
Conesville Unit 4	40%	312
Stuart Unit 1	39%	225
Stuart Unit 2	39%	225
Stuart Unit 3	39%	225
Stuart Unit 4	39%	225
Killen Unit 2	33%	198
Beckjord Unit 6	37.5%	155
Total		2,810

Station locations are shown on Map 4 E.1 on the following page.

Map 4 E.1 Duke Energy Ohio Generation Station Locations



The largest coal-fired unit on the Duke Energy Ohio system is Zimmer Unit 1, rated at 1300 MW total, or 605 MW Duke Ohio ownership share. The smallest coal-fired units on the system are Beckjord Units 1 and 2, each rated at 94 MW. The CT peaking units on the Duke Energy Ohio system range in size from 14 MW (Miami Fort 3-6 and Dicks Creek 3) to 92 MW (Dicks Creek 1).

Further information on existing generating facilities is contained in PUCO Forms FE-R3 and FE-R4 as shown in Appendix A.

2. Fuel Supply and Pricing

The Duke Energy Ohio system utilizes diverse fuel sources to generate energy to serve its customers. These fuels include coal, natural gas, and oil. Furthermore, the market encompasses an even wider diversity of technology types and fuels to which the Company has access via purchased power.

Although the majority of the energy generated by Duke Energy Ohio is currently derived from coal, the actual amount of coal consumed is determined by the forward market prices for power, fuel (coal), and emission allowances. Specifically, Duke Energy Ohio uses an approach for commercial risk management, including fuel procurement, best described as active management. The benefits of active management are that Duke Energy Ohio makes rational economic decisions based upon the available market prices of fuel, power, and emission allowances and thus reduces market risk and volatility to consumers.

Electricity generated from burning coal serves approximately 98% of Duke Energy Ohio's total electric needs. The cost of coal is the most significant element in the cost of electric production. The goal of Duke Energy Ohio with respect to coal procurement is threefold. First, Duke Energy Ohio seeks to provide a reliable supply of coal in quantities sufficient to meet the generating requirements of the entire portfolio. Second, Duke Energy Ohio seeks to work closely with the stations, operations, and engineering groups to evaluate coal compatibility with environmental regulations and alternate suppliers. Finally, Duke Energy Ohio seeks to procure coal at the lowest reasonable cost. Duke Energy Ohio plans to attempt to purchase coal contemporaneously with the auction, and then actively manage the coal position as part of the portfolio.

To ensure fuel supply quality and reliability, Duke Energy Ohio purchases coal from three regions (Illinois Basin, Northern Appalachia & Central Appalachia) and ensures that potential counterparties are qualified based on coal quality and creditworthiness. Duke Energy Ohio buys and burns two types of coal (*i.e.*, low sulfur and high sulfur under various term contracts. Low sulfur coal is easily acquired via the liquid Over-The-Counter (OTC) or broker market where its price is easily discernable and its characteristics are standardized. High sulfur coal, which is purchased for units that have installed pollution control equipment, is unique given its characteristics (*e.g.*, BTU content, chlorine, ash fusion temperature, iron) and requires a greater level of negotiations with a smaller group of suppliers than does low sulfur coal. Duke Energy Ohio maintains stockpiles of coal at each station to guard against short-term supply disruptions, with a goal of having a minimum of 15 days with a target of 20 to 30 day supply (at full burn rate) on site, depending on economic and logistical conditions.

Duke Energy Ohio purchases natural gas on a day-ahead basis for the gas-fired peaking units when the units have been or are expected to be cleared in the day-ahead market. The natural gas purchased for the peaking units is a delivered product (*e.g.*, CGE City gate) and does not require the purchase of pipeline transportation capacity. Duke Energy Ohio buys fuel oil on a contractual basis. The pricing is based on the lower of the posted Oil Price Information Service (OPSI) price or the contract price. Duke Energy Ohio monitors oil pricing and makes purchases based on a combination of inventory levels and expected prices.

The fuel price assumptions utilized to develop the resource plan represent a combination of observed market prices and the long-term fundamental outlook developed for the Company by Wood McKenzie. The Company utilizes its internal subject matter experts to review and validate the assumptions and study results provided by Wood McKenzie. The Company typically uses current market prices where there is an observable market to represent the near term (first 3 to 5 years) and then transitions to the long-term fundamentals for the balance of the study period. The prices used for natural gas and fuel oil are based on a combination of the New York Mercantile Exchange (NYMEX) forward curve and the Wood McKenzie long-term fundamental outlook.

3. Maintenance and Availability

The existing generation unit unplanned outage rates used for planning purposes were derived from the historical Generating Availability Data System (GADS) data. Table 4 E.2 lists the current forced outage rates being used for modeling purposes:

Table 4 E.2

Coal Unit	Forced Outage Rate	Gas Turbine	Forced Outage Rate
Beckjord Unit 1	17%	Beckjord GT Unit 1	10%
Beckjord Unit 2	17%	Beckjord GT Unit 2	10%
Beckjord Unit 3	17%	Beckjord GT Unit 3	10%
Beckjord Unit 4	12%	Beckjord GT Unit 4	10%
Beckjord Unit 5	17%	Dicks Creek GT Unit 1	10%
Beckjord Unit 6	15%	Dicks Creek GT Unit 2	10%
Conesville Unit 4	8%	Dicks Creek GT Unit 3	10%
Killen Unit 1	7%	Dicks Creek GT Unit 4	10%
Miami Fort Unit 7	10%	Dicks Creek GT Unit 5	10%
Miami Fort Unit 8	11%	Miami Fort GT Unit 3	20%
Zimmer Unit 1	9%	Miami Fort GT Unit 4	20%
		Miami Fort GT Unit 5	20%
		Miami Fort GT Unit 6	20%

Planned outages were based on maintenance requirement projections as discussed below. This resource plan assumes that Duke Energy Ohio's existing generating units generally will continue to operate at their present availability and efficiency (heat rate) levels. A comprehensive maintenance program for generating assets is important in providing reliable, low-cost service. The following outlines the general guidelines governing the preparation of a planned outage schedule for existing units operated by Duke Energy Ohio. It is anticipated that future units will be governed by similar guidelines.

Scheduling Guidelines for Duke Energy Ohio Units:

(1) Major maintenance (turbine overhauls) on base load units 500 MWs and larger is performed at eight- to twelve-year intervals. Major boiler maintenance repairs and

replacements are performed in conjunction with major turbine overhauls. General boiler inspections, turbine valve inspections, and balance of plant repairs are performed on two or three year intervals.

(2) Major maintenance on intermediate-duty units between approximately 90 MWs and 500 MWs is performed at eight- to fifteen-year intervals. General boiler inspections, turbine valve inspections, and balance of plant repairs are performed on two-year intervals.

(3) Maintenance on simple cycle peaking units 14 MWs to approximately 90 MWs are time predictive with preventive maintenance based primarily on routine bore scope inspections. These inspections provide the opportunity to inspect the unit without disassembling the unit. The bore scope inspections provide sufficient data required for the scheduling of major maintenance.

In addition to the regularly scheduled planned outages for all unit groups "availability outages" are performed. Availability outages are unplanned, opportunistic, proactive, short-duration maintenance outages aimed at addressing peak period reliability. At appropriate times, when market conditions allow, units may be scheduled out of service for generally short periods of time to perform maintenance activities. This enhancement in maintenance philosophy reflects the focus on having generation available during peak periods.

4. Anticipated Changes to Existing Generation

In general, the existing generation system is expected to be able to maintain current operational characteristics with normal expenditures to ensure continued reliability. The exception to this statement relates to the age and condition of the Beckjord units and the anticipated impacts of environmental rulemaking.

Beckjord units 1, 2 and 3 continue to appear on the existing generation list; however, these units were suspended from operation due to operational economics on March 1, 2010, and placed in mothballed status for up to a period of three years. On November 18, 2009, Duke Energy Ohio submitted MISO Attachment Y (Notification of Potential Generation Resource/SCU Change of Status) of the MISO tariff requesting a suspension of operation for the three units effective March 1, 2010. On February 19, 2010, MISO notified Duke Energy Ohio that the units were approved to be suspended from operation after reviewing the power system reliability impacts under the MISO tariff. If the units remain mothballed after the three-year period, new interconnection and deliverability studies will be required for the units return to service. Duke Energy Ohio does not expect conditions to change the economics of this decision.

There are multiple new air, water, and waste EPA regulatory requirements with anticipated compliance requirements between 2015 and 2018. Analysis indicates that installing the necessary control equipment to meet the new rules should be economically justified for all existing units except for those at Beckjord. Given those results, it was assumed that all six of the Beckjord coal units would be retired at the end of 2014. These retirement assumptions are used for planning purposes to recognize potential new environmental regulations rather than specific unit firm commitments.

Prior to any Beckjord retirements, Duke Energy Ohio will need to submit to the appropriate transmission operator a request and receive approval to suspend the operations of these units, similar to what Duke Energy Ohio did for Beckjord units 1 through 3.

F. ENVIRONMENTAL REGULATIONS

Duke Energy Ohio is required to comply with numerous state and federal regulations. In addition to current programs and regulatory requirements, several new regulations are in various stages of implementation and development that will impact operations for Duke Energy Ohio in the coming years. Table 4 F.1 summarizes EPA's current regulatory schedule and Table 4 F.2 provides the anticipated control requirements provided at the end of this discussion. Some of the major rules include:

1. Clean Air Interstate Rule (CAIR) and Replacement CAIR – the Transport Rule

The EPA finalized its Clean Air Interstate Rule (CAIR) in May 2005. The CAIR limits total annual and summertime NO_X emissions and annual SO_2 emissions from electric generating facilities across the Eastern U.S. through a two-phased cap-and-trade program. Phase 1 began in 2009 for NO_X and in 2010 for SO_2. In December 2008, the United States District Court for the District of Columbia issued a decision remanding CAIR to the EPA, allowing CAIR to remain in effect as an interim solution until EPA develops new regulations.

In August 2010, EPA published a proposed replacement rule for CAIR, known as the Transport Rule (TR). The TR was finalized in July 2011 and is now called the Cross State Air Pollution Rule (CSAPR). In the CSAPR, EPA established state-level annual SO_2 caps and annual and ozone season NO_X caps that would take effect in 2012. Further CSAPRs are also expected that would incorporate the more stringent National Ambient Air Quality Standards (NAAQS), that are in varying stages of development and are discussed later in this document.

2. Utility Boiler Maximum Achievable Control Technology (MACT

In May 2005, the EPA issued the Clean Air Mercury Rule (CAMR). The rule established mercury emission-rate limits for new coal-fired steam generating units. It also established a nationwide mercury cap-and-trade program covering existing and new coal-fired power units.

In February 2008, the United States Court of Appeals for the District of Columbia issued its opinion, vacating the CAMR. EPA has begun the process of developing a rule to replace the CAMR. The replacement rule, the Utility Boiler MACT, will create emission limits for hazardous air pollutants (HAPs), including mercury. Duke Energy Ohio completed work in 2010 as required for EPA's Utility MACT Information Collection Request (ICR). The ICR required collection of mercury and HAPs emissions data from numerous Duke Energy Ohio facilities for use by EPA in developing the MACT rule. EPA issued a proposed MACT rule in March 2011 and expects to finalize it by the end of 2011. The MACT rule is expected to require compliance with new emission limits by 2015. [redacted]

3. National Ambient Air Quality Standards (NAAQS

a. 8 Hour Ozone Standard

In March 2008, EPA revised the 8 Hour Ozone Standard by lowering it from 84 to 75 parts per billion (ppb). In September of 2009, EPA announced a decision to reconsider the 75 ppb standard in response to a court challenge from environmental groups and their own belief that a lower standard was justified. A proposed rule was issued by the EPA in January 2010 in which EPA proposed to replace the existing 84 ppb standard with a new standard between 60 and 70 ppb. EPA must finalize the rule by the end of July 2011. State Implementation Plans (SIP) will be due by the end of 2014, with attainment dates for most areas possibly in the 2017 to 2018 timeframe. Any new controls may have to be in place prior to the 2017 ozone season. Until the states develop implementation plans, only an estimate of the potential impact to Duke Energy Ohio's generation can be developed. With a standard in the 60 to 70 ppb range, the installation of the best performing NO_X controls such as Selective Catalytic Reduction (SCR) is anticipated. All Duke Energy Ohio units, with the exception of Beckjord, currently have SCRs installed, positioning Duke Energy Ohio assets well should this standard become reality.

b. SO_2 Standard

In November 2009, the EPA proposed a rule to replace the current 24-hour and annual primary SO_2 NAAQS with a 1-hour SO_2 standard. A new 1-hour standard of 75 ppb was finalized in June 2010. States with non-attainment areas will have until January 2014 to submit their SIPs. Initial attainment dates are expected to be the summer of 2017 with any required controls in place by late-2016. EPA will base its nonattainment designations on monitored air quality data as well as on dispersion modeling. All Ohio power plants will be modeled by the state and are therefore potential targets for additional SO_2 reductions, even if there is no monitored potential to exceed the standard.

In addition, EPA is proposing to require states to relocate some existing monitors and to add new monitors. While these monitors will not be used by EPA to make the initial nonattainment designations, they will play a role in identifying possible future nonattainment areas.

All Duke Energy Ohio coal units with the exception of Beckjord currently have Flue Gas Desulfurization (FGDs) installed.

4. Global Climate Change

The EPA has been active in the regulation of greenhouse gases (GHGs). In May 2010, the EPA finalized what is commonly referred to as the Tailoring Rule. This rule sets the emission thresholds to 75,000 tons/year of CO_2 for determining when a source is potentially subject to Prevention of Significant Deterioration (PSD) permitting for greenhouse gases. The Tailoring Rule went into effect beginning January 2, 2011. Being subject to PSD permitting requirements for CO_2 will require a Best Available Control Technology (BACT) analysis and the application of BACT for GHGs. BACT will be determined by the state permitting authority. Since it is not known if, or when, a Duke Energy Ohio generating unit might undertake a modification that triggers PSD permitting requirements for GHGs and exactly what might constitute BACT, the potential implications of this regulatory requirement are unknown.

On December 23, 2010, EPA entered into a proposed settlement agreement to issue New Source Performance Standards for GHG emissions from new and modified fossil fueled electric generating units (EGUs) and emission guidelines for existing EGUs that do not undergo a modification. The agreement calls for regulations to be proposed by July 26, 2011, and to be finalized by May 26, 2012. Passage of any federal climate change legislation is not expected until 2013 or later.

5. Water Quality

a. CWA 316(b) Cooling Water Intake Structures

Federal regulations in Section 316(b) of the Clean Water Act may necessitate cooling water intake modifications for existing facilities to minimize impingement and entrainment of aquatic organisms. All Duke Energy Ohio facilities are potential affected sources under that rule. EPA issued a proposed rule in March 2011 with a final rule planned to be issued in July 2012. With an assumed timeframe for compliance of three years, implementation of selected technology is possible as early as mid-2015.

Most likely, regardless of water body type, performance standards to achieve 80% reduction of impinged fish and 80% reduction of fish entrainment will be required. Provided that performance requirements can be met, retrofits may involve intake screen modifications only. However, failure to meet these performance standards or a more stringent regulation could require use of a closed-cycle cooling system.

b. Steam Electric Effluent Guidelines

In September 2009, EPA announced plans to revise the steam electric effluent guidelines. In order to assist with development of the revised regulation, EPA issued an ICR to gather information and data from all coal-fired generating facilities. The ICR was completed by the Company and submitted to EPA in October 2010. The regulation is to be technology-based, in that limits are based on the capability of technology. The primary focus of the revised regulation is on coal-fired generation, thus the major areas likely to be impacted are FGD wastewater treatment systems and ash handling systems. The EPA may set limits that dictate certain FGD wastewater treatment technologies for the industry and may require the installation of dry ash handling systems for both fly and bottom ash. Following review of the ICR data, EPA plans to issue a draft rule in mid-2012 and a final rule around March 2014. After the final rulemaking, effluent guideline requirements will be included in a station's National Pollutant Discharge Elimination System (NPDES) permit renewals. Thus, requirements to comply with NPDES permit conditions may begin as early as 2017 for some facilities. The deadline to comply will depend upon each station's permit renewal schedule.

6. Waste Issues (Coal Combustion Byproducts)

Following Tennessee Valley Authority's Kingston ash dike failure in December 2008, EPA began to assess the integrity of ash dikes nationwide and to begin developing a rule to manage coal combustion byproducts (CCBs). CCBs include fly ash, bottom ash and FGD byproducts (gypsum). Since the 2008 dike failure, numerous ash dike inspections have been completed by EPA and an enormous amount of input has been received by EPA as it developed proposed regulations. On June 21, 2010, EPA issued its proposed rule regarding CCBs. The EPA rule refers to these as CCRs. The proposed rule offers two options: 1) a hazardous waste classification under Resource Conservation Recovery Act (RCRA) Subtitle C; and 2) a non-hazardous waste classification under RCRA Subtitle D, along with dam safety and alternative rules. Both options would require strict new requirements regarding the handling, disposal and potential re-use ability of CCRs. The proposal will likely result in more conversions to dry handling of ash, more landfills, closure of existing ash ponds and the addition of new wastewater treatment systems. Final regulations are expected in 2012. EPA's regulatory classification of CCRs as hazardous or non-hazardous will be critical in developing plans for handling CCRs in the future. Compliance with new regulations is projected to begin around 2017.

Table 4 F.1 Major Environmental Regulatory Issues Schedule

***Bold** Dates indicated in the Table are actual dates.

Regulation/Issue	Proposed Rule Date	Final Rule Date	Compliance Date	Notes
		Water		
316 (b)	**March 2011**	July 2012	Mid-Late 2015	316(b) - regulates cooling water intake requirements
Effluent Guidelines	July 2012	March 2014	Mid-2017	
		Air		
Transport Rule (TR)	**August 2, 2010**	Mid-2011	Starting 2012	
TR Phase II	Late 2011	Late 2012	2016/2017	To incl. Ozone NAAQS
Utility MACT	**March 2011**	November 2011	January 2015	
NAAQS - 8 hr. Ozone Std.	**January 6, 2010**	July 2011	Late 2017	NA Areas designated – July 2012
NAAQS PM Std.	Mid-2011	Mid-2012	Late-2018	NA Areas designated - 2014
NAAQS SO_2 Std.	**November 11, 2009**	**June 22, 2010**	Mid-2017	NA Areas designated - June 2012
		Waste		
Coal Combustion Residuals (CCRs)	**June 21, 2010**	2012	2017	
		Climate		
Greenhouse Gas Regulation – New Source Performance Standards	July 2011	May 2012	2015-2016	TR in effect **January 2, 2011** for PSD and Title V

Table 4 F.2 – Estimated Environmental Impact Summary (2012-2018)

(Table Redacted)

G. POOLING AND BULK POWER AGREEMENTS

At present, Duke Energy Ohio does not participate in any formal type of power pooling arrangement. However, Duke Energy Ohio is currently a member of the Midwest ISO. However Duke Energy Ohio will transition to the PJM Interconnection, Inc. (PJM) on 1/1/2012. Both MISO and PJM are FERC approved RTO's that administer markets for capacity, energy and ancillary services in addition to the independent provision of transmission service.

Duke Energy Ohio is directly interconnected with eight other balancing authorities: American Electric Power, Louisville Gas and Electric Energy, Ameren, Hoosier Energy, Indianapolis Power and Light, Northern Indiana Public Service Company, Vectren, and Duke Energy Indiana. PJM operate Ancillary Services Markets for their balancing authorities within the PJM, which are consolidated into a single PJM balancing authority.

Table 4 G.1 identifies Current Duke Energy Ohio full requirements contracts.

Table 4 G.1 Duke Energy Ohio Full Requirements Contracts

Wholesale Customer	Max Quantity of Energy/Capacity	Contract Expiration Date
[redacted] (OH)	[redacted] MW per hour	[redacted]

H. ENERGY EFFICIENCY/DSM PROGRAMS

In July 2008, in Case No. 08-920-EL-SSO, *et al.*, the Commission approved a Stipulation between Duke Energy Ohio and various intervenors that included a plan for

meeting EE and peak demand reduction requirements under SB 221. This plan included a portfolio that expanded existing programs and coupled them with a new regulatory mechanism called save-a-watt.

Within the ESP proposed by the Company in July 2008 was a three-year plan for supply and pricing of electric generation service. The plan requested recovery of costs for fuel used to generate electricity, wholesale electricity purchases, emission allowances, and federally mandated carbon costs. On December 17, 2008, the Commission approved the Stipulation submitted by the parties, including implementation of the proposed programs and the save-a-watt revenue recovery proposal for EE and peak demand reduction. The Company eliminated its demand side management rider and implemented a rider establishing the Company's save-a-watt program effective January 1, 2009. The Company began implementation of the programs in early January 2009. The ESP is in effect through December 31, 2011. Most of these programs were again reviewed a second time by the Commission in Case No. 09-1999-EL-POR and approved again for implementation by the Commission in an Order dated December 15, 2010.

1. Existing Programs

Under save-a-watt, the Company is reducing energy and demand on the Duke Energy Ohio system through the implementation of a broad set of EE programs. These programs fall into two categories for residential and non-residential customers: conservation EE programs and demand response programs that contain customer-specific contract curtailment options and other demand response programs such as Power Manager® and PowerShare®. The following are the current EE and Demand Response programs in place in Ohio:

a. Residential Programs

Smart $aver® Residential - Provides incentives to residential customers for installing energy efficient equipment. This program addresses the market barrier of higher upfront costs of high efficiency equipment. The program is available to residential customers served by Duke Energy Ohio. A third party is under contract to process customer applications and maintain a list of participating HVAC contractors and builders.

Residential Energy Assessment - Offers two energy assessment measures: 1) Personalized Energy Report (PER) ® and 2) Home Energy House Call. This program provides single family home customers with a customized report about their home and their energy practices. In addition, customers receive free Compact Fluorescent Light bulbs (CFLs) (both programs) and an Energy Efficiency Starter Kit (Home Energy House Call) as an incentive to participate in the program.

Energy Efficiency Education Program for Schools - Educates students about sources of energy and EE in homes and schools and provides them the ability to conduct an energy audit of their homes. This program will help homeowners identify efficiency savings, addressing the market barrier of a lack of customer recognition of savings opportunities. Energy Efficiency Starter Kits are provided free to homes where students complete a home energy survey. Additional CFL's are also provided if available sockets are identified in the survey.

Low Income Services - Provides assistance to low income customers through several measures. The upfront costs of high efficiency equipment are an especially difficult barrier for low income customers to overcome. The CFL portion of this program is available to any low income customer eligible for services provided by low income agencies who has not participated in this program within the past 36 months. The weatherization and refrigerator replacement portion of this program is available to any low income customer up to 200% of the federal poverty level who has not participated in this program within the past 10 years. For the CFL program, eligible customers will complete a survey with an assistance agency. The agency submits the report to the Company, and the customer will receive up to 12 CFLs. A third party will complete the weatherization/refrigerator replacement and will be paid by the Company.

Power Manager® - Provides financial incentives to residential customers that allow the company to cycle their outdoor A/C compressor remotely during peak energy periods between May and September when the load and/or marginal energy costs on Duke Energy Ohio's system reach peak levels. Participating customers of the Company who have a functioning outdoor A/C unit are eligible for the program.

Pilot Program – Home Energy Comparison Report - Piloted in 2010, the Home Energy Comparison Report provides a customer with a comparative usage data report for similar residences in the same geographic region. By identifying efficiency savings and educating customers, this program confronts the significant market barrier of customer awareness of potential savings. Participants receive periodic comparative usage reports along with specific recommendations to encourage energy saving behavior.

b. Non-Residential Programs

Smart $aver® Non- Residential - Provides prescriptive incentives for businesses to install high efficiency equipment. This program addresses the market barrier of higher upfront costs of high efficiency equipment. Major categories include lighting, motors, pumps, variable frequency drives (VFDs), food service and process equipment. The program is available to new or existing non-residential facilities served by Duke Energy Ohio. The incentive process is handled by a third party vendor.

Custom Rebate- Offers financial assistance to qualifying commercial, industrial and institutional customers (that have not opted out of the DSM Rider) to enhance their ability to adopt and install cost-effective electrical energy efficiency projects.

The Smart$aver®Non-Residential Custom Incentive program is designed to meet the needs of Duke Energy Ohio customers with electrical energy saving projects involving more complicated or alternative technologies, or those measures not covered by standard Prescriptive Smart$aver® incentives. The intent of the Smart$aver® Non-Residential Custom Incentive program is to encourage the implementation of energy efficiency projects that would not otherwise be completed without the Company's technical or financial assistance.

Unlike the Prescriptive Incentives, Custom Incentives do require pre-approval prior to the project implementation. Proposed energy efficiency measures may be eligible for Custom Incentives if they clearly reduce electrical consumption and/or demand.

PowerShare® - Represents Duke Energy Ohio's demand side management (or demand response) program geared toward Commercial and Industrial customers. The primary offering under PowerShare® CallOption provides customers with a variety of offers that are based on their willingness to shed load during times of peak system usage and/or high marginal energy cost conditions. These credits are received regardless of whether an event is called or not. Energy credits are also available for participation (shedding load) during curtailment events. The notice to curtail under these offers is between 6 hrs (emergency) and day-ahead (economic) and there are penalties for non-compliance during an event.

Table 4 H.1 lists information for the 2010 Save-a-watt programs.

Table 4 H.1 2010 save-a-watt Programs

Residential save-a-watt Programs		
Program	**Number of Participants/ Measures (1)**	**Annual Cost**
Residential Energy Assessments	9,617	$ 1,998,976
Smart Saver® Residential Central Air Conditioner/Heat Pump	6,531	$ 2,690,381
Smart Saver® Residential Compact Fluorescent Light	2,658,866	$ 6,875,937
Low-Income Services	3,774	$ 425,031
Energy Efficiency Education Program for Schools	3,920	$ 857,935
Power Manager	33,413	$ 2,967,675
Non Residential Save-A- Watt Programs		
Smart Saver® Non-Residential	275,531	$ 5,510,145
Custom Rebate	17,309	$ 1,441,462
PowerShare®	77	$ 309,337
Total Annual Cost		**$ 23,076,879**

(1) Participants/Measures are incremental for 2010 except for PowerShare and Power Manager which are cumulative.

Note: Table 4.H.1 does not include Participants/Measures or Annual Cost information for Pilot Program – Home Energy Comparison Report.

The annual costs for the 2010 programs, $23,076,879, are slightly less than the original projection of $24,047,482 for 2010. All energy efficiency programs are screened for cost-effectiveness. The projected incremental load impacts of existing programs, including the Save-a-watt program, were incorporated into the optimization process of the resource plan development.

The Company's measures and programs are analyzed by using DSMore, a financial analysis tool designed to evaluate the costs, benefits and risk of energy efficiency programs and measures. DSMore estimates the value of an energy efficiency measure at an hourly level across distributions of weather and/or energy costs or prices. By examining energy efficiency performance and cost effectiveness over a wide variety of weather and cost conditions, the Company is better positioned to measure the risks and benefits of employing energy efficiency measures in the same way traditional generation capacity additions are vetted, and further, to ensure that demand-side resources are compared to supply-side resources on comparable basis.

The analysis of energy efficiency cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the California Standard tests: Utility Cost Test (UCT), Rate Impact Measure (RIM) Test, Total Resource Cost (TRC) Test, and Participant Test. DSMore provides the results of these tests for any type of energy efficiency program (demand response and/or energy conservation).

- The UCT compares utility benefits (avoided energy and capacity related costs) to utility costs incurred to implement the program such as marketing, customer incentives, and measure offset costs, but does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, and the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs and load (line) losses.
- The RIM Test, or non-participants test, indicates if rates increase or decrease over the long-run as a result of implementing the program.

- The TRC test compares the total benefits to the utility and participants relative to the costs of utility program implementation and costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the Participant Test (below), however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC though some precedent exists in other jurisdictions to consider non-energy benefits in this test.
- The Participant Test compares the benefits to the participant through bill savings and incentives from the utility, relative to the costs to the participant for implementing the energy efficiency measure. The costs can include capital cost, as well as increased annual operating costs, if applicable.

The use of multiple tests can ensure the development of a reasonable set of DSM/EE programs and indicate the likelihood that customers will participate. It should also be noted that none of the tests described above include external benefits to participants and non-participants that can also offset the costs of the programs.

Table 4 H.2 summarizes the cost effectiveness results for current programs, respectively.

Table 4 H.2 Cost-Effective of Proposed Programs

Cost Effectiveness Test Results of Proposed Programs				
	Utility Test	TRC Test	RIM Test	Participant Test
RESIDENTIAL CUSTOMER PROGRAMS				
Residential Energy Assessments	2.46	2.44	1.08	210.25
Residential Smart $aver® Energy Efficiency	2.42	1.21	0.88	2.43
Low Income Services	2.19	2.19	0.79	NA
Energy Efficiency Education Program for Schools	2.69	2.69	0.94	NA
Power Manager	1.40	1.67	1.40	NA
NON-RESIDENTIAL CUSTOMER PROGRAMS				
Smart $aver® for Non-Residential Customers	3.81	2.20	1.27	2.83
Power Share ®	3.54	29.79	1.23	NA

2. Future Programs

The energy efficiency material presented thus far has been primarily focused on existing programs. However, both customer adoption rates and costs to achieve new energy efficiency measures remain uncertain over the long term. Market potential studies provide estimates of the level of energy efficiency that is realistically achievable by customers in the market place. A study of the market potential involves an assessment of the Technical Potential, the level achievable through application of all technically feasible technologies regardless of market or economic constraints, and the Economic Potential, a subset of the Technical Potential that can be acquired for less than the avoided cost of supply assuming 100% customer participation in all cost-effective energy efficiency programs. The Market Potential is a subset of the Economic Potential that reflects expected customer acceptance and adoption of energy efficiency measures.

The most recent market potential study, performed by a third party for Duke Energy Ohio in February 2009, yielded economic accomplishment potentials that indicated that the level of projected cost-effective energy efficiency accomplishments would not attain the level necessary to comply with the SB 221 requirements.

In order to achieve full compliance with SB 221 requirements, Duke Energy Ohio would need to exceed the estimated Economic Potential which, as stated above, assumes 100% customer participation in all cost-effective energy efficiency programs.

The results of the study do not impact the Company's stated goal of achieving the state mandates as long as economically achievable. However, it is important to note that even though a market potential study may indicate that a certain level of energy efficiency is economically achievable, the success of a program is ultimately driven by the adoption rate of the customers which is beyond the control of the utility.

Due to uncertainty, future programs will be guided by the experience gained through periods of testing and application. For now, EE mandates will be accomplished on an incremental basis by applying patterns of continued growth of existing programs, as well as development of new products over the next ten years. At this juncture, while the Company intends to pursue all cost-effective EE, based on the past market potential study, it is unclear whether or not there is sufficient cost-effective EE to enable the Company to fully comply with the SB 221 requirements.

Table 4 H.3 provides projected annual load impacts for an EE scenario that matches the SB 221 mandate levels.

Table 4.H.3
SB221 Scenario Load Impact Projections
Conservation and Demand-Side Management Programs

	Conservation Program Load Impacts				Demand-Side Mangement Program Impacts			Total
	MWh			Summer Peak MW	Summer Peak MW			Summer Peak MW
Year	Residential	Non-Residential	Total	Cumulative beginning 2011	Interruptible	Power Manager	Total	Total MW Impacts
2011	60,644	90,788	151,431	13	98	55	153	166
2012	140,314	182,694	323,008	39	106	59	164	203
2013	247,837	271,634	519,471	43	106	59	164	207
2014	378,627	359,909	738,536	68	106	59	164	232
2015	523,863	436,295	960,159	119	106	59	164	283
2016	645,875	538,264	1,184,139	147	106	59	164	311
2017	768,697	640,621	1,409,318	175	106	59	164	339
2018	891,533	743,009	1,634,542	203	106	59	164	367
2019	1,136,738	947,172	2,083,910	259	106	59	164	423
2020	1,380,701	1,150,126	2,530,827	314	106	59	164	478
2021	1,622,509	1,351,358	2,973,867	369	106	59	164	534

Table 4 H.4 provides projected annual energy impacts using the 2011 forecast.

Table 4.H.4
Development of SB 221 Case

Year	Spring 2011 Weather Normal Total Energy MWH	Total Energy History and Forecast MWH	Total Energy Adjusted for EE MWH	Moving Avg Prior 3 Years MWH	SB 221 Required EE Impacts %	SB 221 Required EE Impacts MWH	Cumulative EE Impacts MWH	Cumulative EE Impacts adjusted for 2011 Start MWH	Projected Cumulative Impacts MWH
2006	22,665,556	22,665,556							
2007	22,746,814	22,746,814							
2008	22,249,088	22,249,088							
2009	20,725,616	20,725,616		22,553,819	0.3%	67,661	67,661		292,830
2010	21,924,369	21,924,369		21,907,173	0.5%	109,536	177,197		603,585
2011	21,842,793	21,842,793	21,691,362	21,633,024	0.7%	151,431	328,628	151,431	755,016
2012	22,194,796	22,194,796	21,871,788	21,447,115	0.8%	171,577	500,205	323,008	926,593
2013	22,675,994	22,675,994	22,156,523	21,829,173	0.9%	196,463	696,668	519,471	1,123,056
2014	23,196,953	23,196,953	22,458,416	21,906,557	1.0%	219,066	915,734	738,536	1,342,121
2015	23,539,375	23,539,375	22,579,216	22,162,242	1.0%	221,622	1,137,356	960,159	1,563,744
2016	23,700,247	23,700,247	22,516,108	22,398,052	1.0%	223,981	1,361,336	1,184,139	1,787,724
2017	23,881,249	23,881,249	22,471,930	22,517,913	1.0%	225,179	1,586,516	1,409,318	2,012,903
2018	24,051,604	24,051,604	22,417,062	22,522,418	1.0%	225,224	1,811,740	1,634,542	2,238,127
2019	24,232,423	24,232,423	22,148,513	22,468,367	2.0%	449,367	2,261,107	2,083,910	2,687,495
2020	24,421,384	24,421,384	21,890,557	22,345,835	2.0%	446,917	2,708,024	2,530,827	3,134,412
2021	24,617,567	24,617,567	21,643,700	22,152,044	2.0%	443,041	3,151,065	2,973,867	3,577,452

Table 4.H.5 provides projected calculations of the achievement towards the peak benchmarks. It is expected that the peak load achievements will far exceed the benchmark requirements.

Table 4.H.5
Assessment of Peak Benchmark Achievements for the SB 221 Scenario

Year	Weather Normal and Forecasted Level of Peak Demand MW	Forecast Adjusted for EE and DR Impacts MW	Three Year Average MW	Benchmark Percentage %	Benchmark Requirement MW	Cumulative Requirements MW	Adjusted to 2011 Cumulative Requirements MW	Projected Cumulative Impacts MW
2006	4,591							
2007	4,328							
2008	4,462							
2009	4,478		4,460	1.00%	45	45		97
2010	4,444		4,423	0.75%	33	78		176
2011	4,467	4,434	4,461	0.75%	33	111	33	255
2012	4,543	4,476	4,452	0.75%	33	145	67	292
2013	4,583	4,483	4,462	0.75%	33	178	100	297
2014	4,671	4,537	4,498	0.75%	34	212	134	321
2015	4,725	4,556	4,554	0.75%	34	246	168	373
2016	4,735	4,532	4,603	0.75%	35	281	203	400
2017	4,771	4,534	4,642	0.75%	35	315	238	428
2018	4,803	4,531	4,664	0.75%	35	350	273	456
2019	4,840	4,567					273	
2020	4,876	4,604					273	
2021	4,921	4,648					273	

I. FUTURE RESOURCES AND REQUIREMENT

Many potential resource options are available to meet future electricity needs. These resources include conventional generation technologies, demonstrated technologies with limited acceptance, renewable technologies, EE, and demand reduction programs. All of these resources were considered in the resource planning process and are discussed in this section in relation to their applicability to this plan.

1. Generation Technologies

Generation technologies are considered at several levels. The first is a screening level where the diverse mix of technologies and fuel sources are initially screened based on the following attributes:

- Technically feasible and commercially available in the marketplace
- Compliant with all federal and state requirements
- Long-term reliability
- Reasonable cost parameters

Potential technologies that pass initial screening are moved on to a quantitative system optimization and portfolio development phase.

2. Supply Side Resources

A. Overview

An assortment of supply-side resources was considered as potential alternatives to meet future incremental capacity and energy resource needs in addition to the existing legacy assets for the Ohio Resource Plan. Supply side resources selected in this process were used as potential resource alternatives in combination with renewable generation resources to develop an integrated resource plan to meet future customer resource requirements. Specific steps for selection of potential supply side options include:

- Technical Screening - The initial step in the supply-side screening process was a technical screening of the technologies to eliminate those that have technical limitations, commercial availability issues, or are not feasible in the Duke Energy Ohio service territory.
- Economic Screening – The technologies were screened using relative dollar per kilowatt-year versus capacity factor screening curves.

As a result, supply-side technologies that were commercially available and consistently cost effective were considered "Best in Class" within each technology type, such as simple cycle CT, CC, wind, and advanced coal/nuclear units. The largest practical sizes of each technology were primarily considered to include the lowest cost due to economies of scale. A diverse range of technology choices utilizing a variety fuels was considered including advanced nuclear, wind, Integrated Coal Gasification Combined Cycle (IGCC) with carbon sequestration, CTs, and CC units. Technologies representing each category of baseload, peaking and intermediate supply side resources were included to meet all potential customer resource needs.

Duke Energy Ohio has at least two options to procure needed traditional generation capacity, beyond that supplied from its existing system: 1) own generation; or 2) purchase capacity from the market. Estimating the cost of asset ownership or capacity purchases beyond the near term is an inexact science, but the cost of both should trend toward the marginal cost of building new capacity. For the purposes of this resource plan, the Company has represented any needed peaking or intermediate capacity as purchases based on the cost of building new CT or

CC capacity, respectively. Such an assumption gives the Company flexibility to make decisions to purchase short-term market capacity or build/purchase assets at the appropriate time, taking into consideration current market prices as well as a regulatory environment that provides a reasonable assurance to mitigate risk and provide for timely cost recovery. Duke Energy Ohio will regularly assess the future, near-term resource needs and make decisions on market capacity purchases, or new build options in line with the strategic direction selected in the resource plan.

B. Selected Supply Side Technologies

Potential supply side resources selected for detailed modeling included technologies that were commercially available and consistently cost effective relative to other technologies. These resources represented new technologies to address an expected low carbon future environment. Specifically new supply side technologies that are believed to meet the AER requirements of SB 221 required by 2025 include new advanced nuclear, 90% carbon sequestered IGCC technologies and biomass for base load technologies.

The Company continues to investigate the possibility of new nuclear generation to continue to modernize its aging fleet and also to satisfy Ohio's AER requirement. Duke Energy AREVA, USEC, Inc., UniStar Nuclear Energy and the Southern Ohio Diversification Initiative (SODI), formed the Southern Ohio Clean Energy Park Alliance (SOCEPA) to identify the potential for and implications of building an advanced nuclear power plant for the region. At this time, the SOCEPA is continuing the investigation but no decision has been made on the technology, site, or timeframe for the proposed plant. Duke Energy Ohio is not proposing the construction of nuclear powered generation in the context of this resource plan.

Renewable technologies are also an integral part of the overall resource plan as mandated in SB 221. Renewable generation technologies including wind, solar, and dedicated biomass generation are included in the list of the selected supply side technologies.

Supply side resources selected for further integrated resource planning modeling based on technical and economic screening include the following:

- CT (peaking capacity annual purchases)
- CC (intermediate capacity annual purchases)
- 630 MW Class Integrated Gasified Combined Cycle Coal (IGCC)
- Advanced Nuclear Capacity (not available by 2020)
- 50 MW Wind (renewable)
- 3 MW Solar Photovoltaic (renewable)
- 50 MW Woody Biomass (renewable)

J. ADVANCED ENERGY REQUIREMENTS

SB 221 establishes a 25% AER portfolio requirement that must be met by 2025. At least one-half of the AER requirements must be satisfied by renewable energy resources. The renewable requirement also includes a specific "set-aside" for solar energy resources. The annual benchmarks for the renewable energy requirements are represented in Table 4 J.1 below:

Table 4 J.1

RENEWABLE ENERGY RESOURCE REQUIREMENTS

By end of year:	Total renewable energy resources	Solar energy resources
2009	0.25%	0.004%
2010	0.50%	0.01%
2011	1.0%	0.03%
2012	1.5%	0.06%
2013	2.0%	0.09%
2014	2.5%	0.12%
2015	3.5%	0.15%
2016	4.5%	0.18%
2017	5.5%	0.22%
2018	6.5%	0.26%
2019	7.5%	0.30%
2020	8.5%	0.34%
2021	9.5%	0.38%
2022	10.5%	0.42%
2023	11.5%	0.46%
2024 and each year thereafter	12.5%	0.50%

Demonstrated compliance with SB 221 renewable energy mandates utilizes the purchase of RECs. As defined in SB 221, a REC is measured as the environmental attributes associated with one megawatt-hour of electricity generated by a renewable energy resource.

1. Qualified Renewable Resources

The following resources or technologies, if they have a placed-in-service date of January 1, 1998, or after, are qualified resources for meeting the renewable energy resource benchmarks:

- Solar photovoltaic or solar thermal energy;
- Wind energy;
- Hydroelectric energy;
- Geothermal energy;
- Solid waste energy derived from fractionalization,
- Biological decomposition,
- Other process that does not principally involve combustion;
    - Biomass energy;

    Energy from a fuel cell;

    - Storage facility provided that a) the electricity used to pump the resource into a storage reservoir must qualify as a renewable energy resource, or the equivalent renewable energy credits are obtained; and b) the amount of energy that may qualify from a storage facility is the amount of electricity dispatched from the storage facility;
    - Distributed generation system used by a customer to generate electricity from a qualified list of resources or technologies;
- Renewable energy resource created on or after January 1, 1998, by the modification or retrofit of any facility placed in service prior to January 1, 1998.

SB 221 mandates that at least one half of the resources used to comply with the renewable energy portfolio standard must come from sources which are based in the state of Ohio. The remaining one half must come from supply sources that are deliverable into the state, or are located within one of Ohio's five contiguous states (Pennsylvania, West Virginia, Kentucky, Indiana and Michigan).

2. Qualified Advanced Energy Resources

Qualified advanced energy resources include technological improvements that increase a generating facility's output without a corresponding increase in emissions;

- Distributed generation that relies on co-generation of electricity and thermal output;
- Clean coal;
- Advanced nuclear energy;
- Fuel cell;
- Advanced solid waste or construction and demolition debris technology;
- DSM and energy efficiency.

Annual benchmarks leading up to 2025 were not established in SB 221 for advanced energy resources as they were for renewable energy resources.

In summary, by 2025, Ohio SB 221 requires that Duke Energy Ohio obtain 25% of its electricity supply from AERs, with a minimum of 12.5% coming from renewable resources.

3. Discussion of Renewable Compliance Strategy

Up until now, the compliance strategy of Duke Energy Ohio has consisted only of short-term market REC purchases. The primary reason for this decision is that longer term contracts with third parties and utility-owned renewable resources both present cost recovery uncertainties that the Company presently feels would be imprudent to assume. These uncertainties exist because the Company's renewable obligation is based on SSO sales volume, which historically has been uncertain due to customer switching. Duke Energy Ohio recognizes that efforts other than short-term REC purchases may be needed in order to ensure compliance as renewable requirements increase over time; however, over the near term, it is assumed that the current cost recovery uncertainties will continue. While these cost recovery uncertainties exist, the Company will continue to rely primarily on short-term REC purchases and will consider other long-term procurement methods as additional options if the applicable cost recovery uncertainties are adequately addressed.

An exception to the aforementioned discussion is the Company's residential solar REC purchase program, which commits the Company to enter into long-term REC purchase agreements with residential customers. However, this program is not expected to contribute to the Company's total compliance requirements on a material basis due to the relatively small size of the applicable solar installations (residential homes). More details on the necessary renewable resource additions to meet the compliance requirements follow.

4. *Renewable Energy in the Resource Planning Model*

For the purposes of the resource planning model, Duke Energy Ohio assumed that a combination of solar and wind resources would be used to satisfy renewable requirements through 2020. The Company assumed photovoltaic solar because of the specific "set-aside" and then included wind because it is a familiar and widespread renewable resource in the Midwest. In general, the need for each resource was increased in accordance with the levels proscribed in SB 221. Duke Energy Ohio considers many types of renewable resources in its compliance planning efforts, including various forms of biomass energy, biomethane (landfill gas), and hydroelectric resources. The choice of wind and solar PV resources in the resource plan is an assumption that is made for modeling purposes. It is possible that the actual resource development could be different than projected in the resource plan.

Specifically, the resource plan assumes the following:

- **Near-Term Renewable Compliance Strategy (2011):** Near-term renewable compliance for solar and non-solar will be met with market REC purchases.
- **Long-Term Renewable Compliance Strategy (2012+):** In 2012 and beyond, Duke Energy Ohio has assumed that renewable compliance will consist of approximately 50% REC purchases, and the remaining 50% of the compliance requirements coming from renewable resources that will deliver both energy and RECs. For resource planning purposes, REC purchases do not serve to meet the Company's energy or capacity requirements. This assumption is consistent with SB 221 in that contiguous state RECs may be utilized to meet up to 50% of the renewable requirement. Renewable resources that contribute both energy and RECs would contribute to the Company's energy and capacity requirements. The resources that contribute both energy and RECs could come in several variations including but not limited to local grid-tied renewable resources that are selling or self-consuming electrical energy separate from an agreement to sell RECs to the Company. For purposes of the resource planning model, it is assumed that the renewable resources that contribute energy and RECs are all solar or wind projects. Wind projects are assumed to be added in 50 MW increments beginning in 2014, and solar projects are added in 3 MW increments beginning in 2012. These resource additions are in line with the resource needs necessary to meet the renewable requirements established by SB 221. Table 4 J.2 shows the nameplate additions of wind and solar capacity in increments.

Table 4 J.2

Nameplate Capacity Additions Incremental (MW)										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Wind				50	50	50	50	50	50	50
Solar	1	3	3	3	3	3	3	3	3	3
Total	1	3	3	53	53	53	53	53	53	53
Nameplate Capacity Additions Total (MW)										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Wind	0	0	0	50	100	150	200	250	300	350
Solar	1	4	7	10	13	16	19	22	25	28
Total	1	4	7	60	113	166	219	272	325	378

The renewable resource additions identified above are included in the resource plan to meet the 12.5% SB 221 renewable requirements. These installed nameplate capacities are adjusted to reflect the intermittent capacity allocation guidelines from PJM. The adjusted wind and solar capacity resources that can be counted as firm capacity resources are shown in Table 4 J.3. PJM counts 38% of solar capacity and 13% of wind capacity for coincident peak reserve margin requirements.

Table 4 J.3

Renewable Capacity Resources at Summer Peak Incremental (MW)										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Wind	0	0	0	6.5	6.5	6.5	6.5	6.5	6.5	6.5
Solar	0.38	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14
Total	0.38	1.14	1.14	7.64	7.64	7.64	7.64	7.64	7.64	7.64
Renewable Capacity at Summer Peak Total (MW)										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Wind	0	0	0	6.5	13	19.5	26	32.5	39	45.5
Solar	0.38	1.52	2.66	3.8	4.94	6.08	7.22	8.36	9.5	10.64
Total	0.38	1.52	2.66	10.3	17.94	25.58	33.22	40.86	48.5	56.14

5. Intermittency and Capacity Factors

Both solar and wind installed capacity resources are classified as intermittent by PJM since these resources have varying generation profiles which are subject to the prevailing meteorological conditions. As such, actual energy production may not occur at the specific times when energy is most needed, such as the peak periods of each day. With this in mind, it is important to look closely at the actual amount of energy and capacity each resource contributes to the grid at any point in time. Therefore to meet SB 221 requirements, significant amounts of capacity would have to be built in order to achieve the necessary production for compliance.

Based on the Company's experience, solar resources have annual capacity factors that range from 11% to 25%, depending on the location and chosen technology. Wind in the Midwest typically has annual capacity factors that range from 25% to 40% also depending on the location and chosen technology. Cost, capacity factor values, and energy production were assigned based on results from solicited and unsolicited proposals from third party developers received by Duke Energy Ohio, as well as appropriate estimates for capital and fixed costs based on internal estimates and applicable tax credits.

6. Other Renewable Resources

As noted, Duke Energy Ohio has considered multiple forms of renewable resources in its compliance planning activities. In addition to wind and solar, the Company has utilized and/or evaluated hydroelectric, biomass and biomethane (landfill gas) resources as renewable energy options to meet the AER requirements. Duke Energy Ohio has considered biomass co-firing, which refers to blending biomass with coal fuel at existing facilities. The Company has conducted some biomass co-firing test burns at existing coal facilities, but there are presently no ongoing co-firing efforts. However, should regulations governing biomass facilities become clearer, Duke Energy Ohio may reconsider co-firing or the installation of a dedicated biomass facility for AER compliance. At this time, Duke Energy Ohio has no plans for biomass.

Duke Energy Ohio will continue to evaluate its options for satisfying its AER requirement and will make adjustments to the AER resources included in the selected resource plan based on factors such as cost recovery challenges, and the availability and prices of RECs.

K. RESOURCE PLAN

The development of the resource plan integrates the customer load forecast, energy efficiency programs, DSM programs, renewable resources, existing supply-side generation, and potential new supply-side resources into the planning process. Computer models used to perform this integration process are System Optimizer (SO) and Planning & Risk (PAR) owned by Ventyx (recently purchased by ABB).

SO is an expansion planning model that dynamically analyzes the cost-effectiveness of a multitude of combinations of resource alternatives to meet the reliability criteria of a minimum reserve margin. The model performs an economic dispatch of numerous potential combinations of resource plans to determine the lowest cost (PVRR) plan, considering capital, operations and maintenance costs, and total production costs. System Optimizer enables Duke Energy Ohio to consider various alternative planning environments such as different fuel price projections, supply side generation capital costs, and levels of future energy efficiency accomplishments. Using SO to identify the lowest cost expansion plans for alternative planning environments allows Duke Energy Ohio to examine the performance of the "best" resource plans in many possible future scenarios.

The various resource plans generated through SO are examined to identify potential alternative resource plans that will be tested in the detailed production costing simulations with the PAR model. The PAR model is similar to the detailed PROMOD production costing model (another Ventyx production costing model) in that both models perform detailed generating resource hourly dispatch to simulate total production costs of every modeled resource plan. In particular, alternative resource plans are developed to explore resource decisions that will be needed over the next 10 years. For example, plans with peaking capacity were developed for comparison with varying levels of intermediate capacity. After each alternative resource plan is modeled in PAR, the production costing results are compared along with total capital costs to compare the total cost to ratepayers for each plan. The resource plan that consistently performs cost effectively in multiple planning environments with due consideration of qualitative issues is selected as the most "robust" resource plan.

L. SYSTEM OPTIMIZER RESOURCE PORTFOLIO ALTERNATIVES

The SO capacity expansion model was used to develop alternative resource portfolios through 2020. There was not a significant difference between the EE economic potential and the requirements associated with SB 221 by 2021. Therefore, only the requirements associated with SB 221 were considered in SO portfolio development. Also, though it is the Company's belief that there will be a carbon-constrained future, the likelihood of legislation being passed prior to 2013 is unlikely. With the uncertainty of federal climate change legislation with regard to greenhouse gas reduction, Duke Energy Ohio has established a CO_2 price curve beginning in 2016 to represent the potential for future federal climate change legislation. The CO_2 prices that Duke Energy is utilizing are associated with proposed and debated legislation, including H.R. 2454 – the American Clean Energy and Security Act of 2009, which passed the U.S. House of Representatives on June 26, 2009. The prices utilized in the 2011 Resource Plan represent the lower end of the range of prices that were estimated in proposed legislation. The projected CO_2 allowance prices are less than \$20/ton by 2020 and it is not likely that prices would be higher in the short-term. For this reason, portfolios were not evaluated for variation in CO_2 prices. The primary focus of the resource plan was to determine how best to meet the capacity and energy needs in the 2015 period while positioning the Company to meet AER requirements when fully implemented by 2025.

Sensitivities in load, fuel, and the associated energy prices were evaluated to determine the basis for the different portfolios to be further evaluated in detailed production costing analysis. These portfolios are outlined in Table 4 L.1 below.

Table 4 L.1

Resource Portfolio Alternatives (2012 – 2020)		
	CT and CC Resources	RPS Renewables
CT Portfolio	1,050 – 2,100 MW Peaking PPA and/or Resources	28 MW new build Solar 350 MW new build Wind
CC/CT Portfolio	1,050 – 1,450 MW Peaking Resource 650 MW CC in 2015	28 MW new build Solar 350 MW new build Wind

The capacity need between 2012 and 2015 averages approximately 1,360 MW per year in addition to capacity that the legacy generation assets will still serve. This need will be met through the Company's FRR plan to meet the 15.3% reserve margin. The capacity need will increase in the 2015 period to 2,261 MWs primarily due to the retirement assumption of Beckjord Units 1-6 (859 MWs). The 2015 timeframe could be volatile time in the capacity market due to the significant number of coal retirements expected due to the new environmental regulatory requirements. Nationwide estimates of retirements of coal generation in the 2015 timeframe fall in the range of 40 to 80 GWs. Depending on the rate of economic recovery and the impact on load growth, adoption rates of DSM, and the number of retired coal units, there could be a capacity shortage in the 2015 timeframe. For this reason, the option of continued operation of and investment in the existing system, coupled with self- build or peaking or intermediate resource purchases is maintained to reduce the risk of exclusively relying on the capacity market to customers.

M. RESOURCE PORTFOLIO ALTERNATIVE EVALUATION RESULTS

After the development of the alternative resource portfolios in SO, the PAR model was used to perform detailed production costing analysis for the CT Portfolio and the CC/CT Portfolio under the Proposed ESP construct for future resource needs.

The analysis compared a portfolio that relies on peaking resources for future capacity needs (CT portfolio) and one that relies on a mix of peaking and intermediate resources (CT/CC portfolio). The Present Value of Revenue Requirements (PVRR) for the portfolios is calculated as shown below. The IRP rules require consideration and discussion of rate impacts associated with a selected baseline resource plan and alternative plans. Due to several factors, primarily the regulatory uncertainties involved, this document does not address explicit rate impacts. It is assumed that a minimization of PVRR will equate to a minimization of rate impact for customers.

a) Capacity Cost – PVRR associated with securing capacity to meet customers' capacity needs.

b) Duke Energy Ohio Customer Energy Cost – PVRR associated with the cost of providing energy to meet customers' energy needs from the PJM energy market (through competitive suppliers in an energy auction).

c) Duke Energy Ohio Generation Profit – PVRR of the profit associated with the dispatch of all Company Generation to the PJM energy market.

d) Customer PVRR = Capacity Cost + Duke Energy Ohio Customer Energy Cost - 80% * Duke Energy Ohio Profit

A range of sensitivities was also considered for each portfolio as shown below:

- Load Forecast - High: plus 10 %; Low: minus 10% (represent a 95% confidence interval).

- Fuel & Energy Prices

- High: Natural Gas plus 20%; Coal plus 25%; and corresponding impact on the Energy market.
- Low: Natural Gas and Coal minus 40%; and corresponding impact on the Energy market.

- AER - Evaluation of portfolios assuming meeting approximately half of the compliance obligation the AER requirements in 2024.

The results of the analysis are shown below in Table 4 M.2. Table 4 M.2 reflects a comparison of the CT Portfolio to the CC/CT Portfolio. For example, in the Reference case, the CC/CT Portfolio resulted in a $19 million higher PVRR than the CT Portfolio.

Table 4 M.2 (Proposed ESP Portfolios)

Comparison of the CT Portfolio to the CC/CT Portfolio

(PVRR Cost deltas represented in $millions)

Portfolio	Reference	High Fuel	Low Fuel	High Load	Low Load	Low EE/ Renewables
CT Portfolio	Baseline	Baseline	Baseline	Baseline	Baseline	Baseline
CC/CT Portfolio	$ 19	$ (77)	$ 192	$ 19	$ 19	$ 19

In the Proposed ESP, the PVRR of the CT Portfolio is less than 0.1% better than the CC/CT Portfolio when compared to the total system PVRR. In the High Fuel sensitivities, the CC/CT Portfolio was preferred. In the Low Fuel sensitivities, the CT Portfolio was preferred, primarily because of the difference in capital cost between a CT and CC. Profits minimally impacted the results of this sensitivity.

Peaking capacity resource options include the PJM capacity markets and short-term purchase power agreements in the near term. However, over a longer term, the option to build or purchase intermediate generation (such as CCs) to offset some of the capacity need would reduce reliance on the capacity market and increase operational flexibility with consideration of construction lead times and prevailing market prices. Duke Energy Ohio will regularly assess the future near-term resource needs and make decisions on market capacity purchases, short-term PPAs or new build/purchase options in line with the strategic direction selected in the resource plan.

The primary advantages that the CC/CT Portfolio has over the CT Portfolio are that CCs have increased flexibility to meet the energy needs of Duke Energy Ohio customers and are more competitive in the PJM energy market.

There are additional advantages associated with having some CC in the future generation mix. CC capacity provides flexibility and increased fuel diversity for operations over a broader range of capacity factors. It also serves as a price hedge if natural gas prices are lower than projected or if coal prices are significantly higher than projected in the future. If the challenging requirements associated with SB 221 cannot be met and there is more energy to be served with conventional generation, CC generation would provide the flexibility to meet the demand.

In summary, there is a significant capacity need in the 2015 period at a time when there could be increased volatility in the capacity market. Securing a portion of this need with existing resources and additional firm intermediate capacity, secured either through purchasing assets or a self-build option, would minimize this risk. But the Company must have a reasonable assurance of the timely recovery of costs. As the future regulatory environment continues to unfold, it will impact how Duke Energy Ohio can best meet the significant capacity need in the 2015 timeframe. Monitoring the regulatory environment and possible resulting impacts to Duke

Energy Ohio generating assets will be a primary focus for the Company in 2011, prior to making any definitive long-term plans to meet this capacity need.

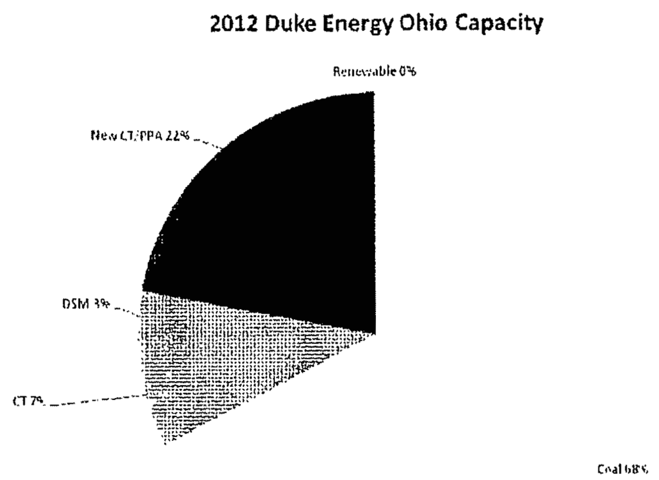
The Supply and Demand table as shown in Table 4 M.3 demonstrates that there is a 2,151 MW capacity need in 2024 with full implementation of SB 221 AER requirements, which further supports securing firm capacity in the 2015 timeframe. Chart 4 M.1 is a comparison of the capacity changes in the portfolio between 2012 and 2020 that demonstrates the increased system diversity with the increasing EE requirements, renewables, market purchases, and additional natural gas generation.

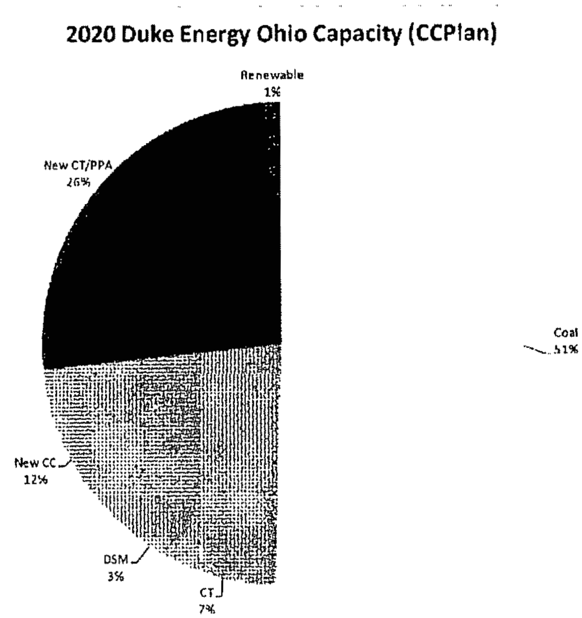
Table 4 M.3 Summer Projections of Load, Capacity and Reserves for Duke Energy Ohio 2011 Annual Plan

(Table Redacted)

Chart 4 M.1

Capacity comparison between 2012 and 2020





Appendix 4 A

PUCO Forms

PUCO Form FE-R1:
Monthly Forecast of Electric Utility's Ohio Service Area Peak Load and Resources
Dedicated to Meet Ohio Service Area Peak Load
(Megawatts)

Current Calendar Year - 2011

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Net Demonstrated Capability	4013	4013	4013	4013	4013	3894	3894	3894	3894	4013	4013	4013
Net Seasonal Capability	4013	4013	4013	4013	4013	3894	3894	3894	3894	4013	4013	4013
Purchases	0	0	0	0	0	0	0	0	0	0	0	0
Sales	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38
Available Capability[a]	4013	4013	4013	4013	4013	3894	3894	3894	3894	4013	4013	4013
Native Load	1259	1295	1238	1026	1195	1524	1795	1683	1554	1174	1225	1419
Energy Reduction Programs[c]	0	1	2	37	37	62	69	66	70	6	5	6
Available Reserve[d]	2755	2719	2776	2988	2818	2370	2099	2211	2340	2840	2788	2594
Internal Load[b]	1,259	1,296	1,240	1,063	1,232	1,586	1,864	1,749	1,624	1,180	1,230	1,425
Reserve[e]	2755	2720	2778	3025	2855	2432	2169	2277	2410	2846	2793	2600

Next Calendar Year - 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Net Demonstrated Capability	4013	4013	4013	4013	4013	3894	3894	3894	3894	4013	4013	4013
Net Seasonal Capability	4013	4013	4013	4013	4013	3894	3894	3894	3894	4013	4013	4013
Purchases	0	0	0	0	1050	1050	1050	1050	1050	1050	1050	1050
Sales	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52
Available Capability[a]	4015	4015	4015	4015	5065	4946	4946	4946	4946	5065	5065	5065
Native Load	3626	3529	3301	2930	3486	4111	4336	4340	3805	3195	3577	3577
Energy Reduction Programs[c]	18	18	26	131	134	198	207	203	200	31	20	23
Available Reserve[d]	389	486	714	1084	1579	835	609	605	1141	1869	1900	1487
Internal Load[b]	3,644	3,547	3,326	3,061	3,620	4,309	4,543	4,543	4,005	3,226	3,185	3,600
Reserve[e]	407	504	740	1215	1713	1033	816	808	1341	1900	1508	1510

a. Available Capability is equal to Net Seasonal Capability plus Purchases minus Sales plus Renewables.
b. Internal Load equals Native Load plus Energy Reduction Programs.
c. Includes both energy efficiency and demand response.
d. Available Reserve is equal to Available Capability minus Internal Load plus Energy Reduction Programs.
e. Reserve is equal to Available Capability minus Native Load plus Energy Reduction Programs.

PUCO Form FE-R2:

Monthly Forecast of System Peak Load and Resources Dedicated to Meet System Peak Load

(Megawatts)

Current Calendar Year - 2011

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Net Demonstrated Capability	4013	4013	4013	4013	4013	3894	3894	3894	3894	4013	4013	4013
Net Seasonal Capability	4013	4013	4013	4013	4013	3894	3894	3894	3894	4013	4013	4013
Purchases	0	0	0	0	0	0	0	0	0	0	0	0
Sales	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38
Available Capability[a]	4013	4013	4013	4013	4013	3894	3894	3894	3894	4013	4013	4013
Native Load	1259	1295	1238	1026	1195	1524	1795	1683	1554	1174	1225	1419
Energy Reduction Programs[c]	0	1	2	37	37	62	69	66	70	6	5	6
Available Reserve[d]	2755	2719	2776	2988	2818	2370	2099	2211	2340	2840	2788	2594
Internal Load[b]	1,259	1,296	1,240	1,063	1,232	1,586	1,864	1,749	1,624	1,180	1,230	1,425
Reserve[e]	2755	2720	2778	3025	2855	2432	2169	2277	2410	2846	2793	2600

Next Calendar Year - 2012

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Net Demonstrated Capability	4013	4013	4013	4013	4013	3894	3894	3894	3894	4013	4013	4013
Net Seasonal Capability	4013	4013	4013	4013	4013	3894	3894	3894	3894	4013	4013	4013
Purchases	0	0	0	0	1050	1050	1050	1050	1050	1050	1050	1050
Sales	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52
Available Capability[a]	4015	4015	4015	4015	5065	4946	4946	4946	4946	5065	5065	5065
Native Load	3626	3529	3301	2930	3486	4111	4336	4340	3805	3195	3577	3577
Energy Reduction Programs[c]	18	18	26	131	134	198	207	203	200	31	20	23
Available Reserve[d]	389	486	714	1084	1579	835	609	605	1141	1869	1900	1487
Internal Load[b]	3,644	3,547	3,326	3,061	3,620	4,309	4,543	4,543	4,005	3,226	3,185	3,600
Reserve[e]	407	504	740	1215	1713	1033	816	808	1341	1900	1508	1510

a. Available Capability is equal to Net Seasonal Capability plus Purchases minus Sales plus Renewables.

b. Internal Load equals Native Load plus Energy Reduction Programs.

c. Includes both energy efficiency and demand response.

d. Available Reserve is equal to Available Capability minus Internal Load plus Energy Reduction Programs.

e. Reserve is equal to Available Capability minus Native Load plus Energy Reduction Programs.

PUCO Form FE-R3:
Summary of Existing Electric Generation Facilities

STATION NAME & LOCATION	SYSTEM*	FOOT NOTES	UNIT	TYPE OF UNIT*	INSTALLATION DATE	TENTATIVE RETIREMENT YEAR	MAXIMUM GENERATING CAPABILITY (net kW) SUMMER	WINTER	ENVIRONMENTAL PROTECTION MEASURES*	MAXIMUM GENERATING CAPABILITY (net kW) Spring/Fall
W.C Beckjord	DEO		1	CF-S	6-1952	Unknown	94,000	94,000	LNB, EP & FGC	94,000
New Richmond,			2	CF-S	10-1953	Unknown	94,000	94,000	LNB, EP & FGC	94,000
Ohio			3	CF-S	11-1954	Unknown	128,000	128,000	EP, FGC, LNB & OFA	128,000
			4	CF-S	7-1958	Unknown	150,000	150,000	EP, FGC, LNB & OFA	150,000
			5	CF-S	12-1962	Unknown	238,000	238,000	EP, FGC, LNB & OFA	238,000
		A	6	CF-S	7-1969	Unknown	155,000	158,000	EP, FGC, LNB & OFA	158,000
			1-GT	OF-GT	4-1972	Unknown	47,000	61,000	None	53,000
			2-GT	OF-GT	4-1972	Unknown	47,000	61,000	None	53,000
			3-GT	OF-GT	6-1972	Unknown	47,000	61,000	None	53,000
			4-GT	OF-GT	6-1972	Unknown	47,000	61,000	None	53,000
						Station Total:	1,047,000	1,106,000		1,074,000
Conesville Conesville, OH	DEO	B	4	CF-S	6-1973	Unknown	312,000	312,000	EP, CT, LNB, SO2 Scrubber SCR	312,000
Dicks Creek	DEO		1	GF-GT	9-1965	Unknown	92,000	110,000	SC	101,000
Middletown,			3	GF-GT	6-1969	Unknown	14,000	20,000	SC	15,000
Ohio			4	GF-GT	10-1969	Unknown	15,000	21,000	None	18,000
			5	GF-GT	10-1969	Unknown	15,000	21,000	None	18,000
						Station Total:	136,000	172,000		152,000
Killen Wrightsville, OH	DEO	C	2	CF-S	6-1982	Unknown	198,000	198,000	EP, LNB, CT, SO2 Scrubber SCR	198,000
Miami Fort	DEO		3-GT	OF-GT	7-1971	Unknown	14,000	20,000	None	15,000
North Bend,			4-GT	OF-GT	8-1971	Unknown	14,000	20,000	None	15,000
Ohio			5-GT	OF-GT	9-1971	Unknown	14,000	20,000	None	15,000
			6-GT	OF-GT	10-1971	Unknown	14,000	20,000	None	15,000
		D	7	CF-S	5-1975	Unknown	320,000	320,000	EP, LNB, CT SO2 Scrubber, SCR & SBS	320,000
		D	8	CF-S	2-1978	Unknown	320,000	320,000	EP, LNB, CT SO2 Scrubber, SCR & SBS	320,000
						Station Total:	696,000	720,000		700,000
J.M.Stuart	DEO	E	1	CF-S	5-1971	Unknown	225,000	225,000	EP, LNB, SO2 Scrubber & SCR	225,000
Aberdeen,										
Ohio		E	2	CF-S	10-1970	Unknown	225,000	225,000	EP, LNB, SO2 Scrubber & SCR	225,000
		E	3	CF-S	5-1972	Unknown	225,000	225,000	EP, LNB, SO2 Scrubber & SCR	225,000
		E	4	CF-S	6-1974	Unknown	225,000	225,000	EP, LNB, CT SO2 Scrubber & SCR	225,000
						Station Total:	900,000	900,000		900,000
W.H.Zimmer Moscow, OH	DEO	F	1	CF-S	3-1991	Unknown	605,000	605,000	EP, LNB, CT, SO2 Scrubber, SCR & SBS	605,000
							3,894,000	4,013,000		3,941,000

*LEGEND:

CF = Coal Fired
OF = Oil Fired
GF = Natural Gas Fired

S = Steam
GT = Simple-Cycle Combustion Turbine

DEO = Duke Energy Ohio

EP = Electrostatic Precipitator
SC = Smokeless Combustor
CT = Cooling Tower(s)
SCR = Selective Catalytic Reduction, Nox
WI = Water Injection, NOx
SI = Steam Injection, NOx
LNB = Low NOx Burners
OFA = Overfire Air
SNCR = Selective Non-Catalytic Reduction
FGC = Flue Gas Conditioning
SBS = Sodium Bisulfite/Soda Ash Injection System

FOOT NOTES:

(A) Unit 6 is commonly owned by Duke Energy Ohio (37.5% - Operator); The Dayton Power and Light Company (50%) and Columbus Southern Power Company (12.5%).
(B) Unit 4 is commonly owned by Duke Energy Ohio (40%); The Dayton Power and Light Company (16.5%) and Columbus Southern Power Company (43.5% - Operator).
(C) Unit 2 is commonly owned by Duke Energy Ohio (33%) and The Dayton Power and Light Company (67% - Operator).
(D) Units 7 and 8 are commonly owned by Duke Energy Ohio (64% - Operator) and by The Dayton Power and Light Company (36%).
(E) This station is commonly owned by Duke Energy Ohio (39%); The Dayton Power and Light Company (35% - Operator) and Columbus Southern Power Company (26%).
(F) Unit 1 is commonly owned by Duke Energy Ohio (46.5% - Operator); The Dayton Power and Light Company (28.1%) and Columbus Southern Power Company (25.4%).

PUCO Form FE-R4:
Actual Generating Capability Dedicated to meet Ohio Peak Load (as of 12/31/20xx)

	Unit Designation			
Year/Season	Unit Name	Description	Seasonal Total (MW)	
2010/Summer	Beckjord 1	Coal - Steam	94	
2010/Summer	Beckjord 2	Coal - Steam	94	
2010/Summer	Beckjord 3	Coal - Steam	128	
2010/Summer	Beckjord 4	Coal - Steam	150	
2010/Summer	Beckjord 5	Coal - Steam	238	
2010/Summer	Beckjord 6	Coal - Steam	155	Foot Note A
2010/Summer	Conesville 4	Coal - Steam	312	Foot Note B
2010/Summer	Killen 2	Coal - Steam	198	Foot Note C
2010/Summer	Miami Fort 7	Coal - Steam	320	Foot Note D
2010/Summer	Miami Fort 8	Coal - Steam	320	Foot Note D
2010/Summer	Stuart 1	Coal - Steam	225	Foot Note E
2010/Summer	Stuart 2	Coal - Steam	225	Foot Note E
2010/Summer	Stuart 3	Coal - Steam	225	Foot Note E
2010/Summer	Stuart 4	Coal - Steam	225	Foot Note E
2010/Summer	Zimmer 1	Coal - Steam	605	Foot Note F
2010/Summer	Beckjord GT 1	Combustion Turbine/Oil-fired	47	
2010/Summer	Beckjord GT 2	Combustion Turbine/Oil-fired	47	
2010/Summer	Beckjord GT 3	Combustion Turbine/Oil-fired	47	
2010/Summer	Beckjord GT 4	Combustion Turbine/Oil-fired	47	
2010/Summer	Dicks Creek 1	Combustion Turbine/Nat Gas-fired	92	
2010/Summer	Dicks Creek 3	Combustion Turbine/Nat Gas-fired	14	
2010/Summer	Dicks Creek 4	Combustion Turbine/Nat Gas-fired	15	
2010/Summer	Dicks Creek 5	Combustion Turbine/Nat Gas-fired	15	
2010/Summer	Miami Fort 3	Combustion Turbine/Oil-fired	14	
2010/Summer	Miami Fort 4	Combustion Turbine/Oil-fired	14	
2010/Summer	Miami Fort 5	Combustion Turbine/Oil-fired	14	
2010/Summer	Miami Fort 6	Combustion Turbine/Oil-fired	14	

FOOT NOTES:

(A) Unit 6 is commonly owned by Duke Energy Ohio (37.5% - Operator); The Dayton Power and Light Company (50%) and Columbus Southern Power Company (12.5%).

(B) Unit 4 is commonly owned by Duke Energy Ohio (40%); The Dayton Power and Light Company (16.5%) and Columbus Southern Power Company (43.5% - Operator)

(C) Unit 2 is commonly owned by Duke Energy Ohio (33%) and The Dayton Power and Light Company (67% - Operator).

(D) Units 7 and 8 are commonly owned by Duke Energy Ohio (64% - Operator) and by The Dayton Power and Light Company (36%).

(E) This station is commonly owned by Duke Energy Ohio (39%); The Dayton Power and Light Company (35% - Operator) and Columbus Southern Power Company (26%).

(F) Unit 1 is commonly owned by Duke Energy Ohio (46.5% - Operator); The Dayton Power and Light Company (28.1%) and Columbus Southern Power Company (25.4%).

PUCO Form FE-R6:

Electric Utility's Actual and Forecast Ohio Peak Load and Resources

Dedicated to Meet Electric Utility's Ohio Peak Load

(Megawatts)

Summer Season

	2006	2007	2008	2009	2010	2011	2012	2013
	-5	-4	-3	-2	-1	0	1	2
Net Demonstrated Capability	3961	3906	3906	3906	3894	3894	3894	3894
Net Seasonal Capability	3961	3906	3906	3906	3894	3894	3894	3894
Purchases	1050	1058	1064	979	758	0	1050	1000
Sales				369	1035	0	0	0
Renewables[d]						0.38	1.52	2.66
Available Capability[a]	5011	4964	4970	4516	3617	3894	4946	4897
Native Load	4366	4436	4074	3675	2317	1795	4340	4376
Energy Reduction Programs[c]	0	23	0	0	11	69	203	207
Available Reserve[e]	645	528	896	841	1300	2099	605	521
Internal Load[b]	4366	4459	4074	3675	2328	1864	4543	4583
Reserve[f]	645	551	896	841	1311	2169	808	728

	2014	2015	2016	2017	2018	2019	2020	2021
	3	4	5	6	7	8	9	10
Net Demonstrated Capability	3894	3685	3685	3685	3685	3685	3685	3685
Net Seasonal Capability	3894	3685	3685	3685	3685	3685	3685	3685
Purchases	1000	1100	1100	1050	1000	950	900	850
Sales	0	0	0	0	0	0	0	0
Renewables[d]	10.3	17.94	25.58	33.22	40.86	48.5	56.14	62.64
Available Capability[a]	4904	4803	4811	4768	4726	4684	4641	4598
Native Load	4439	4441	4424	4432	4436	4417	4398	4388
Energy Reduction Programs[c]	232	283	311	339	367	423	478	534
Available Reserve[e]	466	362	387	336	290	267	243	210
Internal Load[b]	4671	4725	4735	4771	4803	4840	4876	4921
Reserve[f]	698	645	698	675	657	690	720	744

a. Available Capability is equal to Net Seasonal Capability plus Purchases minus Sales plus Renewables.
b. Internal Load equals Native Load plus Energy Reduction Programs.
c. Includes both energy efficiency and demand response.
d. Renewable Capacity on Summer Peak.
e. Available Reserve is equal to Available Capability minus Internal Load plus Energy Reduction Programs.
f. Reserve is equal to Available Capability minus Native Load plus Energy Reduction Programs.
g. Load forecast assumes wires-connected customers from 2012 forward.

PUCO Form FE-R8:
Electric Utility's Actual and Forecast Ohio Peak Load and Resources
Dedicated to Meet Electric Utility's Ohio Peak Load
(Megawatts)
Winter Season

	2006	2007	2008	2009	2010	2011	2012	2013
	-5	-4	-3	-2	-1	0	1	2
Net Demonstrated Capability	4080	4025	4025	4025	4013	4013	4013	4013
Net Seasonal Capability	4080	4025	4025	4025	4013	4013	4013	4013
Purchases	0	625	577	700		0	1050	1000
Sales						0	0	0
Renewables[d]						0.38	1.52	2.66
Available Capability[a]	4080	4650	4602	4725	4013	4013	5065	5016
Native Load	3551	3505	3526	2271	1459	3626	3676	3729
Energy Reduction Programs[c]	0	0	0	0	0	18	33	48
Available Reserve[e]	529	1145	1076	2454	2554	388	1388	1287
Internal Load[b]	3551	3505	3526	2271	1459	3644	3709	3777
Reserve[f]	529	1145	1076	2454	2554	406	1421	1335

	2014	2015	2016	2017	2018	2019	2020	2021
	3	4	5	6	7	8	9	10
Net Demonstrated Capability	4013	3804	3804	3804	3804	3804	3804	3804
Net Seasonal Capability	4013	3804	3804	3804	3804	3804	3804	3804
Purchases	1000	1100	1100	1050	1000	950	900	850
Sales	0	0	0	0	0	0	0	0
Renewables[d]	10.3	17.94	25.58	33.22	40.86	48.5	56.14	62.64
Available Capability[a]	5023	4922	4930	4887	4845	4803	4760	4717
Native Load	3740	3745	3750	3756	3745	3736	3730	3724
Energy Reduction Programs[c]	81	100	108	125	159	193	227	261
Available Reserve[e]	1283	1177	1180	1131	1100	1066	1031	993
Internal Load[b]	3821	3845	3858	3881	3904	3929	3957	3984
Reserve[f]	1364	1276	1287	1256	1259	1259	1258	1254

a. Available Capability is equal to Net Seasonal Capability plus Purchases minus Sales plus Renewables.
b. Internal Load equals Native Load plus Energy Reduction Programs.
c. Includes both energy efficiency and demand response.
d. Renewable Capacity on Summer Peak.
e. Available Reserve is equal to Available Capability minus Internal Load plus Energy Reduction Programs.
f. Reserve is equal to Available Capability minus Native Load plus Energy Reduction Programs.
g. Load forecast assumes wires-connected customers from 2012 forward.

NOTE: Plans for facilities listed on this Form are entirely speculative and consequently should not be regarded as "planned" electric generation facilities. The Company continues to monitor markets and evaluate options as appropriate.

PUCO Form FE-R10:
Specifications of Planned Electric Generation Facilities

1. Facility Name	Solar 2011
2. Facility Location	TBD
3. Facility Type	Photovoltaic
4. Anticipated Capability	1 MW
5. Anticipated Capital Cost	[redacted] [redacted]
6. Application Timing	1 year
7. Construction timing	1 year
8. Planned Pollution Control Measures	N/A
9. Fuel	Sun
10. Miscellaneous	

1. Facility Name	Solar 2012 - Solar 2019 (1 plant added per year)
2. Facility Location	TBD
3. Facility Type	Photovoltaic
4. Anticipated Capability	3 MW (per plant)
5. Anticipated Capital Cost	[redacted] [redacted]
6. Application Timing	1 year
7. Construction timing	1 year
8. Planned Pollution Control Measures	N/A
9. Fuel	Sun
10. Miscellaneous	

1. Facility Name	Wind 2014 - Wind 2021 (1 plant added per year)
2. Facility Location	TBD
3. Facility Type	Wind
4. Anticipated Capability	50 MW (per plant)
5. Anticipated Capital Cost	[redacted] [redacted]
6. Application Timing	1 year
7. Construction timing	1 year
8. Planned Pollution Control Measures	N/A
9. Fuel	Wind
10. Miscellaneous	

1. Facility Name	Woody Biomass
2. Facility Location	TBD
3. Facility Type	Biomass
4. Anticipated Capability	50 MW
5. Anticipated Capital Cost	[redacted] [redacted]
6. Application Timing	1 year
7. Construction timing	5 years
8. Planned Pollution Control Measures	NOx &Particulate
9. Fuel	Wood
10. Miscellaneous	

PUCO Form FE-R10 (continued):
Specifications of Planned Electric Generation Facilities

1. Facility Name	4 x 160 CT
2. Facility Location	TBD
3. Facility Type	Combustion Turbine
4. Anticipated Capability	632 MW
5. Anticipated Capital Cost	[redacted] [redacted]
6. Application Timing	1 year
7. Construction timing	3 year
8. Planned Pollution Control Measures	NOx
9. Fuel	Natural Gas
10. Miscellaneous	

1. Facility Name	Combined Cycle w/Duct Firing & Chilling
2. Facility Location	TBD
3. Facility Type	Combined Cycle
4. Anticipated Capability	620 MW
5. Anticipated Capital Cost	[redacted] [redacted]
6. Application Timing	1 year
7. Construction timing	4 years
8. Planned Pollution Control Measures	NOx
9. Fuel	Natural Gas
10. Miscellaneous	

Appendix 4 B

Cross-Reference Table of RP Requirements

CROSS-REFERENCE OF RESOURCE PLAN DEVELOPMENT REQUIREMENTS		
Requirement	Location	Reference
Discussion and analysis of anticipated technological changes expected to influence:		
generation mix	Sections K, L and M	4901:5-5-06 A.1
use of energy efficiency and peak-demand reduction programs	Section H	4901:5-5-06 A.1
availability of fuels	Section E, part 2	4901:5-5-06 A.1
type of generation	Sections K, L and M	4901:5-5-06 A.1
use of alternative energy resources	Section J	4901:5-5-06 A.1
Discussion and analysis of availability and potential development of alternative energy resources	Section J, all parts	4901:5-5-06 A.2
Discussion and analysis of research, development, and demonstration efforts relating to alternative energy resources	Section J, all parts	4901:5-5-06 A.3
Discussion and analysis of the impact of environmental regulations on generating capacity, cost, and reliability	Section E, part 4 and Section F, all parts	4901:5-5-06 A.4
Discussion and analysis of textual material not specifically required, but of importance to the resource forecast	Sections B, F, I and J	4901:5-5-06 A.5
Electricity resource forecast forms		4901:5-5-06 A.6.a
Form FE-R1	Appendix A	4901:5-5-06 A.6.b
Form FE-R2	Appendix A	4901:5-5-06 A.6.c
Form FE-R3	Appendix A	4901:5-5-06 A.6.d.i
Form FE-R4	Appendix A	4901:5-5-06 A.6.dii
Form FE-R5	Appendix A	4901:5-5-06 A.6.d.iii
Form FE-R6	Appendix A	4901:5-5-06 A.6.d.iv
Form FE-R7	Appendix A	4901:5-5-06 A.6.d.v
Form FE-R8	Appendix A	4901:5-5-06 A.6.d.vi
Form FE-R9	Appendix A	4901:5-5-06 A.6.e.i
Form FE-R10	Appendix A	4901:5-5-06 A.6.e.ii
Existing generation system description	Section E, part 1 and Appendix A	4901:5-5-06 B.1.a
Existing pooling, mutual assistance, and all purchase/sales agreements including costs and amounts	Section G	4901:5-5-06 B.1.b

CROSS-REFERENCE OF RESOURCE PLAN DEVELOPMENT REQUIREMENTS		
Requirement	Location	Reference
System load profile	PUCO Forms FE-D1-6	4901:5-5-06 B.2.a
Maintenance requirements of existing and planned units	Section E, part 3	4901:5-5-06 B.2.b
Number, size, and availability of existing and planned units	Section E, parts 1 & 3, Appendix A	4901:5-5-06 B.2.c
Forecast uncertainty	Section D, part 1	4901:5-5-06 B.2.d
Option uncertainty with respect to cost, availability, in-service dates, and performance	Section H, part 2 & Section I, part 2 Sections J & K	4901:5-5-06 B.2.e
Lead times for construction and implementation	Appendix A, Form FE-R10	4901:5-5-06 B.2.f
Power interchange with other electric systems	Section G	4901:5-5-06 B.2.g
Price-responsive demand and price elasticity due to the implementation of time-differentiated pricing options	Section M	4901:5-5-06 B.2.h
Regulatory climate	Sections A, B, D, F, H, J, L & M	4901:5-5-06 B.2.i
Reliability criteria and reliability measures used	Section D, part 2 & Section J, part 5	4901:5-5-06 B.2.j.i
Reliability criteria and engineering analysis performed	Section D, part 2 & Section J, part 5	4901:5-5-06 B.2.j.ii
Reliability criteria and economic analysis performed	Section D, part 2 & Section J, part 5	4901:5-5-06 B.2.j.iii
Reliability criteria and any judgments applied	Section D, part 2 & Section J, part 5	4901:5-5-06 B.2.j.iv
Resource plan description of base case projected resource mix	Sections K, L & M	4901:5-5-06 B.3.a
Resource plan discussion of projected system reliability	Section D, part 2 & Section J, part 5	4901:5-5-06 B.3.b.i
Resource plan discussion of projected adequacy of fuel supply	Section E, part 2	4901:5-5-06 B.3.b.ii
Resource plan discussion of revenue requirements and rate impacts of base and alternative plans	Sections C & M	4901:5-5-06 B.3.c
Resource plan methodology discussion of: decision-making process, criteria, and standards employed overall planning objectives (4901:5-5-03 paragraph A) key assumptions and judgments used in development	Sections C, D, I, J, K, L & M	4901:5-5-06 B.3.d.i 4901:5-5-06 B.3.d.ii 4901:5-5-06 B.3.d.iii
Discussion of adequacy, reliability, and cost-effectiveness of the plan	Sections A, C, D, E, F, H, I, J, K, L & M	4901:5-5-06 B.3.e.i
Discussion of evaluation equality among all resource options	Sections H, I, J, K & M	4901:5-5-06 B.3.e.ii
Discussion of adequate consideration of potential rate and customer bill impacts	Sections C & M	4901:5-5-06B.3.e.iii.a

CROSS-REFERENCE OF RESOURCE PLAN DEVELOPMENT REQUIREMENTS		
Requirement	Location	Reference
Discussion of adequate consideration of environmental impacts and their associated costs	Section E, part 4 & Section F	4901:5-5-06B.3.e.iii.b
Discussion of adequate consideration of other economic impacts and their associated costs	Sections C, D, I, J, K, L & M	4901:5-5-06B.3.e.iii.c
Discussion of adequate consideration of plan impact on financial status of the company	Section M	4901:5-5-06B.3.e.iii.d
Discussion of adequate consideration of plan impact on other strategic decisions (flexibility, diversity, size and lead times, and lost investment opportunities)	Sections C, D, I, J, K, L & M	4901:5-5-06B.3.e.iii.e
Discussion on adequate consideration of plan impact on equity among customer classes	Section M	4901:5-5-06B.3.e.iii.f
Discussion on adequate consideration of plan impact over time	Sections C, D, I, J, K, L & M	4901:5-5-06B.3.e.iii.g
Discussion on adequate consideration of plan impact on other matters the commission considers appropriate		4901:5-5-06B.3.e.iii.h

PUBLIC DISCLOSURE

Georgia Power Company's Application for Decertification of Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C, Application for Certification of the Power Purchase Agreements with BE Alabama LLC from the Tenaska Lindsay Hill Generating Station and with Southern Power Company from the Harris, West Georgia and Dahlberg Electric Generating Plants, and Updated Integrated Resource Plan

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Docket No. 34218

August 4, 2011

GEORGIA POWER COMPANY'S APPLICATION FOR DECERTIFICATION OF PLANT BRANCH UNITS 1 & 2 AND PLANT MITCHELL UNIT 4C, APPLICATION FOR CERTIFICATION OF THE POWER PURCHASE AGREEMENTS WITH BE ALABAMA LLC FROM THE TENASKA LINDSAY HILL GENERATING STATION AND WITH SOUTHERN POWER COMPANY FROM THE HARRIS, WEST GEORGIA AND DAHLBERG ELECTRIC GENERATING PLANTS AND UPDATED INTEGRATED RESOURCE PLAN

DOCKET NO. 34218

Applicant name, address and principle place of business:

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Basis for the Assertion That Redacted Portions of Georgia Power Company's Application for Decertification of Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C, Application for Certification of the Power Purchase Agreements with BE Alabama LLC from the Tenaska Lindsay Hill Generating Station and with Southern Power Company from the Harris, West Georgia and Dahlberg Electric Generating Plants and Updated Integrated Resource Plan

Docket No. 34218

As part of its Application For Decertification of Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C, Application for Certification of the Power Purchase Agreements with BE Alabama LLC from the Tenaska Lindsay Hill Generating Station and with Southern Power Company from the Harris, West Georgia and Dahlberg Electric Generating Plants and Updated Integrated Resource Plan in Docket No. 34218, Georgia Power Company ("Georgia Power" or the "Company") is submitting to the Georgia Public Service Commission ("Commission") copies of certain power purchase agreements ("PPAs") selected through the 2015 Request for Proposals, forecast data, cost information, financial analysis and strategy information (the "Information"). The Information (as highlighted) constitutes trade secret information of Georgia Power and its affiliates and is therefore protected from disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, certain PPA terms that have been redacted that contain pricing, heat rate factors, fuel requirements and pricing and other operational parameters that are specific to the winning bids. This information is proprietary to the Company and not generally known by the public. Revealing these terms would compromise the Company's ability to procure the best cost resources from other independent power suppliers in the future. In the event such information were released, it is quite likely that bidders in future RFPs would use this information to set the floor in constructing their own bids, thus artificially and inefficiently setting a market price and affecting other contract terms, resulting in agreements that may not be representative of the best cost or best resource that the market could offer. In addition, parties to the PPAs have agreed to maintain the confidentiality of these terms. Compromising the confidentiality of such information could also harm the Company in its attempts to negotiate PPAs in the future, as counterparties may fear compelled disclosure of key contractual terms.

In addition, revealing the redacted information in the energy and demand forecast information supplied would give competitors of Georgia Power a competitive advantage. Disclosure of such information would reveal detailed energy usage information regarding specific classes of customers. If revealed to the public, a competitor could use the information to tailor proposals with the intention of targeting certain groups of customers, thereby undermining the Company's market position. In addition, such information would reveal the Company's needs in the short-term, thereby potentially harming the Company's ability to make cost-effective sales or purchases of energy on behalf of its customers. Furthermore, the Company has expended significant resources to develop its market forecasts and such forecasts reflect the accumulated expertise of the Company. To allow competitors access to such market forecast information without similarly being required to expend resources would bestow an unfair economic advantage on such competitors. Similarly, the Company's fuel forecasts are created by the Company through the expenditure of resources and are a reflection of the Company's market knowledge. To grant access to the fuel forecasts would grant an unfair benefit on the Company and would also provide competitors with insight into the Company's future resource plans.

Disclosure of the Information could also give suppliers and vendors information related to the processes and timing of the Company's project schedules, thus granting an unfair advantage in any future negotiations. The Information also contains competitively sensitive cost information related to the prices Georgia Power has estimated for expenditures related to the Company's environmental compliance efforts and specific details related to the Company's overall environmental compliance strategy. Public dissemination of the Information would allow Georgia Power's suppliers access to such estimated costs, thereby bestowing insight into the Company's forecasted environmental cost budget and overall strategy. Such access would grant an unfair advantage to suppliers of the Company, who could use such information to artificially set bid and proposal prices during contract negotiations and would also have additional insight into the timing of future environmental expenditures. This could lead to the Company having to pay a price higher than that which it would have paid on a level playing field. Competitors of the Company may also gain an unfair advantage if they were to have access to such information. The Company has expended a significant amount of resources and developed considerable expertise in formulating its environmental compliance strategy and it would be unfair to allow competitors of the Company to have access to such plans without similarly expending resources and developing expertise. The Information also contains economic screening data performed by the Company. Disclosure of such information would harm the Company by revealing the likelihood of potential resource actions, thereby giving competitors insight in the Company's future decisions. The Information also includes data related to emissions planning on the part of the Company, which, if disclosed, would compromise the ability of the Company to obtain optimal pricing in its compliance efforts.

The Information is subject to extensive efforts to maintain its confidentiality. Only select Georgia Power and Southern Company affiliate personnel and their legal counsel are granted access to the Information. Those personnel receive access only on a "need to know" basis. If a party outside of Georgia Power and Southern Company affiliates and their legal counsel are granted access to the Information, the party is required to sign a confidentiality agreement with respect to the Information.

Volume 1: Table of Contents

Appendices

1. Executive Summary

Georgia Power Company ("Georgia Power" or the "Company") makes this filing ("Application") as part of its continuing efforts to provide a cost effective and reliable supply of electricity for its customers at a time of significant uncertainty for the electric utility industry. Georgia Power, along with the entire industry, is faced with an unprecedented confluence of new environmental regulations promulgated by the United States Environmental Protection Agency ("EPA" or "Agency"). The new and anticipated regulations are far reaching and effect a wide-range of areas including numerous air, water and waste matters. These regulations, some of which impose unrealistic timeframes for compliance, place significant uncertainty on the reliability of the electric system and will impose significant compliance costs on our customers. Because many of the regulations are still at the proposed rule stage or have yet to be proposed, the ultimate impact remains uncertain. What is certain, however, is that the Company must take steps now to prepare to deal with the challenges that these new regulations are expected to place on reliability in 2015.

The Company has undertaken a thorough analysis to determine the most cost-effective approach for providing the reliable service that its customers have come to expect. In doing so, the Company faces the challenge of developing strategies to comply not only with current environmental regulations, but also with proposed and anticipated regulations, taking into account the significant uncertainty created by those future regulations. One regulation of particular importance to this Application is the EPA's proposed regulation to set national emission standards for hazardous air pollutants from coal- and oil-fired electric utility steam generating units ("Utility MACT"). The Utility MACT rule as currently proposed would require additional emissions control equipment on the majority of the Company's generating units. The Utility MACT rule would also have one of the earliest compliance deadlines, with compliance required as early as 2015 with the possibility of a one-year extension under EPA's current schedule. The EPA is required to release a final rule by November 16, 2011. The impact that this rule will have upon reliability in 2015 and beyond is a major driver for the actions requested in the Company's Application as described in greater detail herein.

Based on its extensive analyses of these rules and the anticipated impacts, the Company has put forth in this Application a cost effective approach that provides for the decertification of certain coal- and oil-fired units. The Company also proposes to begin work on environmental controls necessary to provide for the continued operation of certain coal fired units that are cost effective to control based upon anticipated environmental regulations. As a result of the uncertainty surrounding pending environment regulations, the Company plans to defer the decision to control or fuel switch approximately 2,600 megawatts ("MW") of capacity until the Company has greater certainty regarding the final form of the pending regulations, including the Utility MACT rule. By deferring these decisions, the Company will be able to make more informed decisions at a later date to control or decertify these units in a cost effective manner for customers. The short compliance timeline under the proposed Utility MACT rule and the need for greater certainty around the pending environmental regulations is expected to render at least 2,000 MWs of capacity unavailable in 2015. To address the deficit created by the unavailability of these units and to strive to maintain reliability in 2015, the Company is proposing to certify 1,562 MW of purchase power agreements.

Specifically, Georgia Power requests that the Georgia Public Service Commission (the "Commission") do the following:

(1) Decertify Plant Branch Unit 1 and Plant Branch Unit 2 effective with the revised Georgia Multipollutant Rule compliance dates for these units, and decertify Plant Mitchell Unit 4C effective as of the date of the final order in this proceeding;

(2) Approve the reclassification of the remaining net book values of Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C as of their respective retirement dates to regulatory asset accounts and the amortization of such regulatory asset accounts ratably over a period equal to the respective unit's remaining useful life approved in Docket No. 31958;

(3) Approve the amortization of approximately **REDACTED** of Plant Branch Units 1 & 2 environmental construction work in progress ("CWIP") (which has been reclassified as a regulatory asset in accordance with the Commission's Order in Docket No. 31958) ratably over a three year period beginning January 2014;

(4) Approve the amortization of any remaining, unusable material and supplies ("M&S") inventory balance remaining at the unit retirement dates which will be reclassified to a regulatory asset as identified in accordance with the Commission's Order in Docket No. 31958 ratably over a three year period beginning January 2014;

(5) Approve the Company's decision to initiate the work necessary for the possible installation of baghouses on certain coal-fired generating units, which it expects will be necessary to help the Company strive to meet the anticipated compliance deadlines for the Utility MACT rule and approve the Company's proposed treatment for recovery of the related costs;

(6) Grant a certificate of public convenience and necessity for the four power purchase agreements ("PPAs") selected through the 2015 Request for Proposals ("RFP") and approve the Company's proposed treatment for recovery of the related costs; and

(7) Approve the 2011 Integrated Resource Plan Update ("2011 IRP Update").

The actions described in this Application are part of the Company's near term plan to help assure reliable service in an uncertain environment. In developing this plan, the Company has taken into account, to the best of its ability, the known and potential costs of complying with both existing and anticipated environmental regulations, as well as the logistical and scheduling challenges presented by the various regulations.

The Company first requests that the Commission decertify Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C. Under the Georgia Multipollutant Rule, Plant Branch Units 1 & 2, which total approximately 569 MW of capacity, will be required to have Selective Catalytic Reduction ("SCRs") and scrubbers in place by December 31, 2013 and October 1, 2013, respectively. The Company's analyses have shown that installation of such equipment on these units will not be economical for customers across a wide range of economic scenarios even if no additional controls are required by further regulations. As a result, the Company requests that the Commission grant the Company's request for decertification of Plant Branch Units 1 & 2, effective on the required compliance dates specified under the Multipollutant Rule.

Plant Mitchell Unit 4C is a 33 MW oil-fired combustion turbine ("CT"). In December 2009, the unit experienced a significant equipment failure and the Company made the economic decision to delay repairing the unit. Weighing reliability considerations, age of the unit, challenges associated with repairs, and the potential for more stringent environmental regulatory requirements, the Company requests that the Commission also approve the decertification of Plant Mitchell Unit 4C.

As a part of the request to decertify the Plant Branch Unit 1 and 2 and Mitchell Unit 4C, the Company is requesting that the Commission reclassify the remaining net book values of Plant

Branch Units 1 & 2 and Plant Mitchell Unit 4C as of their respective retirement dates to regulatory asset accounts and to amortize such regulatory asset accounts over a period equal to the respective unit's remaining useful life approved in Docket No 31958. The Company also requests that in accordance with Docket No. 31958 the Commission approve a three year recovery period (beginning January 2014) of approximately **REDACTED** of Plant Branch Units 1 & 2 environmental CWIP (which has been reclassified as a regulatory asset) and approve a three year recovery period (beginning January 2014) for any remaining, unusable M&S inventory remaining at the unit retirement dates which will be reclassified to a regulatory asset.

The Company is also requesting certification of the four PPAs identified through the 2015 RFP. As discussed above, significant uncertainty remains regarding the ultimate impact of currently pending and anticipated environmental regulations. As a result, the Company is not able to make final decisions regarding the economics of controlling approximately 2,600 MW of generating capacity and is also uncertain whether any needed controls can be installed given regulatory timelines. However, given what is currently known about such regulations and based on its analyses of potential outcomes, the Company believes it is reasonable to expect that approximately 600 MW of capacity will be controlled or switch fuels by 2015 and that the remaining capacity, approximately 2,000 MW, will be unavailable in 2015.

In light of the Company's concerns regarding resource availability in 2015, the Company initiated the 2015 RFP to help assure supplies are adequate to meet the Company's planning reserve margin target. The 2015 RFP was conducted with the oversight of Commission Staff and the Independent Evaluator ("IE") and in full compliance with the Commission's RFP rules. The RFP resulted in the selection of a portfolio of four resources, and the Company subsequently entered into PPAs in connection with these resources. The four PPAs allow for an early termination on or before March 27, 2012 in the event that the Company determines such resources are not needed in light of the final Utility MACT. As was demonstrated through the 2015 RFP, these four resources represent the best cost option for meeting the resource needs of the Company in the 2015 timeframe and should be certified by the Commission. However, it should be noted that even with the additional generation capacity obtained through the 2015 RFP, electricity reliability will be at risk in 2015 if the unrealistically short compliance timeframe associated with the Utility MACT rule is not extended.

The Company continues to pursue cost effective Demand Side Management ("DSM") and Energy Efficiency ("EE") measures that will benefit its customers. The Company's current DSM portfolio consists of 16 demand response programs, EE programs, pricing tariffs, and other activities. The Company projects that over the next 10 years these programs will reduce capacity requirements by approximately 2,600 MW.

The Company also continues to actively pursue cost effective renewable resources. For example, the Company has instituted the SP-1 tariff to procure solar resources for the Premium Green Energy Product and has instituted an additional RFP process to procure 1,000 kW of solar installed capacity to supply the Green Energy Program. Finally, the Company proposed the 2015 Large Scale Solar Proposal ("LSS") on June 24, 2011 to procure an additional 50 MW of solar resources. This proposal was approved by the Commission on July 22, 2011.

In addition to the existing qualifying facilities ("QF") and renewable resources serving the Company through the standard offer contracts approved by the Commission, the Company has also received notice through the 2015 RFP of the intention of approximately 250 MW of new QF and renewable capacity that intends to participate in meeting the needs in 2015. The Company will enter into contracts with these entities once the certification of the 2015 PPAs has concluded and the proxy price has been set.

However, despite theses significant DSM and renewable resources, the PPAs identified through the RFP remain necessary to ensure reliable service in 2015. The Company's Application also includes the 2011 IRP Update, which supports the requests made by the Company in this Application and the Company requests approval of this IRP Update. The IRP Update includes (1) an updated load and energy forecast; (2) an updated fuel forecast; (3) the 2011 Environmental Compliance Strategy ("ECS"); (4) the 2011 Unit Retirement Study; and (5) an updated Needs Assessment. The challenges posed to the Company by the pending environmental regulations discussed in this Application are significant, but the Company believes that its plan as described in this Application best addresses the challenges and uncertainty in a manner that will help provide for continued reliable and cost-effective service for its customers, and the Commission should approve the Company's requests as described in more detail below.

2. Overview of the Application

2.1 Overview of the 2011 IRP Update

In January 2010, Georgia Power filed the 2010 IRP (Docket No. 31081) and DSM Certification Application (Docket No. 31082), which described the Company's short and long term energy and demand forecast and the Company's plan for meeting the needs of its customers in an economic and reliable manner through a mix of supply-side and demand-side resources. The Commission adopted the Company's 2010 IRP and certified DSM programs, with modifications, as specified in its Final Order dated July 13, 2010 and Supplemental Order dated September 10, 2010. The Company's 2011 IRP Update provides updates to certain portions of the Company's 2010 IRP and the Company requests that the Commission approve these updates as filed.

2.1.1. Budget 2011 Load and Energy Forecast

The Budget 2011 Load and Energy Forecast (Section 3) reflects updated economic information available to the Company. The state of Georgia continues to recover from the 2008-2009 recession, though growth has been more moderate than forecasted in the 2010 IRP. Compared to Budget 2010 projections, Budget 2011 projected energy sales are slightly higher in the short term and somewhat weaker in the medium term. The Budget 2011 forecast projects that over the next ten years, total territorial retail sales will increase at a compound annual growth rate ("CAGR") of **REDACTED**% (compared with **REDACTED**% in Budget 2010). Peak demand is slightly lower in all years of the Budget 2011 forecast compared with Budget 2010. The 10-year peak demand CAGR in the Budget 2011 forecast is **REDACTED**% (compared to **REDACTED**% in Budget 2010). The updated forecast has been incorporated in the 2011 Unit Retirement Study and Needs Assessment.

2.1.2. Budget 2011 Fuel Forecast

The Budget 2011 Fuel Forecast (Section 4) is based on updated assumptions for both supply and demand for natural gas, oil, and coal resources. For natural gas, the most important updates were associated with increased North American shale gas supplies. For oil, the most important updates were associated with changes in Chinese oil consumption and new U.S.

Corporate Average Fuel Economy ("CAFE") standards. For coal, the most important updates were associated with improved coal production cost information and an updated view of environmental pressures on coal generation. In general, these changes have resulted in **REDACTED** fuel prices in the 2011 IRP Update as compared to those in the 2010 IRP.

2.1.3. 2011 Environmental Compliance Strategy

Georgia Power's 2011 ECS (Appendix B) reflects the most recent regulatory developments and subsequent corporate strategies to ensure that the Company's operations continue to meet all local, state and federal environmental laws and regulations. In previous years, the decisions and actions recommended in the ECS were based solely on current regulations and did not attempt to make recommendations based on regulations that had not been finalized (though it did attempt to identify potential future courses of action that were likely because of expected regulations). However, based on EPA's proposed Utility MACT and the impracticable compliance deadlines contemplated in the Clean Air Act of 1990, the Company is seeking approval to initiate work to install baghouses on a number of coal-fired generating units which will be necessary to help the Company strive to meet the anticipated emissions limits and compliance deadlines, as described more fully in Section 2.3.4.

2.1.4. 2011 Unit Retirement Study

In the 2011 Unit Retirement Study (Section 5), Georgia Power conducted economic evaluations of coal- and oil-fired units for which the Company has not already incurred significant expenditures for installed environmental controls. Based on these economic evaluations (along with several other key factors) that compare the costs and benefits of retiring, fuel switching, replacing or retrofitting units considering a suite of potential upcoming regulatory requirements, the Company recommends retirement of three units and the temporary deferral of decisions regarding all remaining units included in the Unit Retirement Study.

2.1.5. Needs Assessment

Based on recommendations within the Unit Retirement Study, the Company has identified through its Needs Assessment (Section 6) a 2015 capacity need of approximately 1,200 MW. The Company recommends that this need be met through a combination of supply and demand-side strategies, including the certification of new capacity selected through the 2015 RFP. The Company's recommended actions are discussed further below.

2.2 Significant Recent Regulatory Developments

As discussed in previous filings, the State of Georgia approved a "Multipollutant Rule" in 2007 that requires the installation of SCRs and scrubbers on the majority of Georgia Power's coal-fired capacity. The 2010 IRP and associated Environmental Compliance Strategy took the Multipollutant Rule into account, but since the 2010 IRP was filed, there have been numerous significant developments concerning environmental regulations that have affected, or will affect, many of Georgia Power's generating units. Regulatory actions concerning air emissions, water intake and cooling, and coal combustion residuals have added considerable uncertainty to the Company's strategy for ensuring cost-effective environmental compliance. These regulatory actions are likely to impact the availability and reliability of certain existing generating units in Georgia as early as 2015 and will increase the cost of generating power in the future. These developments are the primary factors influencing Georgia Power's current recommendations for unit retirements, retrofits, deferrals, and for the certification of new capacity needed to minimize risks to reliability. Available information on these developments has been incorporated into Georgia Power's current set of assumptions for the 2011 Unit Retirement Study, Needs Assessment, and 2011 ECS. Greater detail on each of these numerous significant developments is provided in the 2011 ECS (Appendix B). The following is a brief summary of the key regulations that will affect many of the Company's generating units.

2.2.1. National Ambient Air Quality Standards

The EPA has recently revised, and is continuing to revise, numerous National Ambient Air Quality Standards ("NAAQS"), which could lead to the requirement for additional environmental controls and result in increased electricity costs to customers. In January 2010, EPA issued a proposed rule to reduce the 8-hr ozone NAAQS from 0.075 parts per million ("ppm") to a level in the range of 0.060 to 0.070 ppm. Although EPA was to finalize reconsideration of the 2008 ozone NAAQS by August 2010, EPA was granted three separate extensions of this deadline to July 29, 2011. However, on July 26, 2011, the EPA said that the agency would not meet the end of July date, and while they expect to sign a final rule soon, they didn't set a new deadline. A lower ozone NAAQS could lead to additional nonattainment areas within the state of Georgia and the imposition of additional controls and more stringent emission limits at Georgia Power's generating units within any newly designated or existing nonattainment areas. EPA recently has also significantly lowered the NAAQS for NO_2 and SO_2, which begins a regulatory process at the state level to evaluate the need for additional controls or reduced emission limits on industrial and electric generating units to comply with these standards. EPA is continuing its review of the Particulate Matter ("PM") standards and is expected to propose another revision to the $PM_{2.5}$ NAAQS in 2012. Finally, on July 12, 2011, EPA proposed revisions to the Secondary NAAQS for NO_x and SO_2, with a proposed rule expected in March 2012. Implementation of the standards in the proposal would establish a new set of extremely stringent secondary standards. When finalized, these standards may also result in significant additional compliance and operational costs for units that require New Source permitting.

2.2.2. Hazardous Air Pollutants

On May 3, 2011, EPA proposed the Utility MACT rule, which would impose stringent emission limits on coal and oil-fired electric utility steam generating units for acid gases, mercury, and total particulate matter. According to a consent decree governing the Utility MACT rulemaking schedule, EPA must release a final rule by November 16, 2011 unless the Agency secures an extension from the court. Although meeting the proposed limits would require additional emission controls for the majority of Georgia Power's coal- and oil-fired generating units, until the final rule is issued, the full extent of additional controls needed to comply remains uncertain. The proposed rule exempts gas-fired boilers from the rule; therefore, switching fuel from coal to gas may be an option for certain units. However, EPA's proposed definition of gas-fired units significantly limits the use of coal and oil as back-up fuels, placing additional uncertainty on this option as a compliance strategy for certain units. Compliance with the Utility MACT rule will be required within three years from publication of the final rule, projected to be as early as 2015. Possibilities for extensions include an up to one-year extension granted by the state permitting agency. This compliance timeline is impracticable. It does not allow for installation of additional controls on all affected units by the anticipated compliance date, thereby creating significant uncertainty for planning purposes to prepare for operations in

2015. The Company believes the compound effect of all anticipated EPA rules applicable to coal-fired generating units should be considered in the economics of a decision of whether to control or retire a given unit and therefore has taken information available on all of the proposed rules into account in its analyses. However, because the Utility MACT rule is currently among the most stringent regulations and because it has one of the earliest anticipated compliance deadlines of numerous regulations under development, the Utility MACT rule is driving the timing of Georgia Power's actions presented in this filing, unit deferral decisions, and resulting capacity needs.

On February 21, 2011, EPA finalized the Industrial Boiler Maximum Achievable Control Technology ("IB MACT") rule, which had first been proposed on April 29, 2010. The rule establishes different emissions limits for various subcategories of boilers, including biomass utility boilers. However, EPA announced a notice of intent to reconsider a portion of the IB MACT rule on the same day it issued the final rule. EPA has subsequently agreed to stay the effectiveness of the IB MACT rule during its reconsideration and while it accepts additional public comments. As a result, it is unclear whether any changes to the final rule will be made as a result of the reconsideration process, when any such changes would become effective and whether the rule would become more or less stringent. These uncertainties make it difficult to make decisions on conversions from coal to biomass and have led Georgia Power to delay decisions on such projects.

2.2.3. Greenhouse Gases

Although the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009 with the goal of mandating reductions in greenhouse gases ("GHG"), neither this legislation nor similar measures passed the Senate before the end of the 111th Congress. Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions, renewable energy standards, and/or energy efficiency standards are expected to continue to be considered during 2011, though no particular piece of legislation yet appears to have enough support for passage.

While climate legislation has yet to be adopted, EPA is moving forward with regulation of greenhouse gases under the Clean Air Act. On April 1, 2010, EPA issued a final rule regulating greenhouse gas emissions from new motor vehicles under the Clean Air Act. EPA has taken the position that when this rule became effective on January 2, 2011, carbon dioxide and other greenhouse gases became regulated pollutants under the Prevention of Significant Deterioration ("PSD") preconstruction permit program and the Title V operating permit program, which both apply to power plants. As a result, the construction of new facilities or the major modification of existing facilities could trigger the requirement for a PSD permit for greenhouse gases. The addition of PSD permitting for greenhouse gases will extend the time it takes to obtain a PSD permit for a new or modified source and increase the likelihood of third party challenges, leading to additional uncertainty regarding the availability of any expected new fossil-fueled generation.

Finally, on December 23, 2010, EPA announced that it had reached settlement agreements with states and environmental groups that had filed suit over the New Source Performance Standards ("NSPS") for greenhouse gas emissions from fossil fuel power plants and petroleum refineries. The agreements provide timelines for the promulgation and finalization of NSPS for new, modified, and existing electric utility steam generating units and refineries. EPA is currently expected to propose standards for new and modified units by September 30, 2011, and finalize standards by May 26, 2012. EPA will propose and finalize greenhouse gas emissions guidelines, which will need to be developed into mandatory requirements by states, for existing units on the same schedule.

2.2.4. Cross-State Air Pollution Rule

On July 7, 2011, EPA released the final Cross-State Air Pollution Rule (the "Cross-State Rule", formerly known as the "Clean Air Transport Rule") to replace the Clean Air Interstate Rule ("CAIR"), which was invalidated by the U.S. Court of Appeals for the District of Columbia Circuit in 2008. The Cross-State Rule requires 27 eastern states (including Georgia) to reduce power plant emissions of SO_2 and NO_x that contribute to downwind states' nonattainment of federal ozone and/or particulate matter ambient air quality standards beginning in 2012 and becoming more stringent in 2014. Like CAIR, the final Cross-State Rule establishes an annual SO_2 and NO_X emission allowance program to help reduce fine particulate matter and a separate ozone season NO_X allowance program to help reduce ozone. Also like CAIR, it requires each plant to have allowances sufficient to cover its annual and ozone season emissions each year. However, the Cross-State Rule will require greater emission reductions than CAIR and, while the allowance markets are still developing in response to the final rule, allowance prices are expected to be higher than under CAIR. This rule may require additional environmental controls, like scrubbers and SCRs, and/or will likely require the purchase of additional emissions allowances that will result in significant additional compliance and operational costs. Like the Utility MACT rule, the Cross-State Rule establishes unrealistic deadlines for compliance. This makes installation of any required additional controls impracticable because the rule leaves the purchase of additional allowances as the only likely option to comply. Because the final rule was issued very recently, the Company is still in the process of evaluating its implications, including potential impacts on the unit retirement analyses. EPA has indicated that it intends to propose an updated version of the Cross-State Rule in the future to take into account the anticipated new ozone and PM-2.5 NAAQS, which adds additional uncertainty to Georgia Power's environmental compliance requirements.

2.2.5. Coal Combustion Residuals

On June 21, 2010, EPA issued a proposed rule regulating Coal Combustion Residuals ("CCRs"). EPA has presented two options in the proposed rule to regulate CCRs under the Resource Conservation and Recovery Act ("RCRA") as either a hazardous or solid (non-hazardous) waste for their disposal when generated from coal-fired electric generating facilities. Adoption of either option could require closure of, or significant change to, existing storage facilities, could necessitate construction of a lined landfill or off-site disposal of ash, and could result in conversion of units to dry ash handling systems. Although a final rule was initially expected to be released in late 2011, there is a significant likelihood that the final rule will not be issued until 2012.

2.2.6. Cooling Water Intake Structures

On April 20, 2011, EPA published a proposed rule for Cooling Water Intake Structures under Section 316(b) of the Clean Water Act, which proposes standards for reducing impacts to fish and other aquatic life caused by cooling water intake structures or installation of cooling towers at existing power plants and manufacturing facilities. Although the rule's proposed standards could require installation of different technologies to cooling water intake structures at many of Georgia Power's units, the extent of these required modifications cannot be determined until EPA issues a final rule, which is expected by July 27, 2012. The timeline for compliance with this rule is also uncertain.

2.2.7. Effluent Guidelines

In December 2009, EPA announced its determination that the current effluent guidelines for steam electric power plants must be revised. EPA currently plans to propose new effluent guidelines in 2012 and issue final guidelines by 2014. Although new wastewater treatment requirements are expected and may result in the installation of additional wastewater control systems on certain Georgia Power facilities, the extent of any such requirements remains unknown at this time.

2.3 Supply Side Plan for 2015

Retirement Study evaluations were performed for each Georgia Power coal unit for which the Company has not already incurred significant expenditures for installed environmental controls. The evaluations utilized various assumptions contemplating a suite of environmental controls needed to meet existing and expected federal and state environmental rules regarding air emissions, ash and gypsum handling, and water handling. The incremental costs to control the units were compared to a proxy represented by a site-specific replacement capacity cost. Details regarding the methodology, assumptions, and results of the 2011 Unit Retirement Study are further described in Section 5 of the 2011 IRP Update.

The Company utilized the economic results of these studies, along with several other key factors, to develop a resource plan designed to help ensure the most economic and reliable resources will be available to meet customers' needs. In addition to a detailed economic analysis, the Company also considered the following factors: significant uncertainty related to pending environmental regulations, fleet operational flexibility, fuel diversity, fuel price volatility, impacts to the community and employment, and the age of the units. After careful review of all the economic results of the 2011 Unit Retirement Study and the aforementioned key factors, the Company has grouped the evaluated units into two categories for purposes of further action: retire or defer decision. In other words, based on its analysis, the Company has concluded that there are certain units for which the economics clearly dictate retirement. Conversely, due to the uncertainty regarding the ultimate impacts of the pending environmental rules, there are a number of units for which it is simply too early to determine whether retirement or the installation of controls will be the most beneficial to customers. The following sections further describe which units were assigned to each category, along with an explanation of why the Company believes each unit should be assigned accordingly.

2.3.1. The Company seeks to decertify and retire Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C

2.3.1.1 Plant Branch Units 1 & 2

The Company requests decertification and retirement of Plant Branch Units 1 & 2, totaling 569 MW of coal-fired generating capacity, as of the applicable compliance dates for controls under the Georgia Multipollutant Rule. Unit 1, nominally rated at 250 MW, began operation in 1965, and Unit 2, nominally rated at 319 MW, began operation in 1967. The Multipollutant Rule requires installation of SCRs and scrubbers on all four Plant Branch units by the unit specific compliance deadlines specified in the rule. Based on the requirements specified in the Multipollutant Rule, continued operation of Units 1 & 2 is not expected to be beneficial to customers under a broad range of economic scenarios. When coupled with the environmental controls that are expected to be required under expected future federal and state environmental rules, the projected cost associated with continued operation and installation of anticipated controls at these two units is not expected to be beneficial to customers under an even broader range of economic scenarios.

The Company proposes that the timing of the retirements of Units 1 & 2 coincide with the applicable Multipollutant Rule compliance deadline for these units. On June 29, 2011, the Georgia Department of Natural Resources approved an amendment to the Multipollutant Rule establishing new compliance dates for the Plant Branch units as follows:

Unit	Compliance Deadline
Branch 1	December 31, 2013
Branch 2	October 1, 2013
Branch 3	October 1, 2015
Branch 4	December 31, 2015

Details regarding the Plant Branch Units 1 & 2 retirement decision are provided in Section 7. Along with the request for decertification, the Company also requests that the Commission approve the Company's proposed accounting treatment of costs associated with Plant Branch Units 1 & 2 as summarized in Section 2.3.1.3 and as further explained in Section 7.4.

2.3.1.2 Plant Mitchell Unit 4C

The Company requests decertification and retirement of Plant Mitchell Unit 4C as of the effective date of the Commission's order in this proceeding. Plant Mitchell Unit 4C is a Pratt & Whitney 33 MW CT installed in 1971. This unit experienced a major equipment failure in December 2009, and an economic decision was made at that time to delay repairs. Weighing reliability considerations, the age of the unit, the extensive nature of the repairs required, the limited availability of replacement parts, the lead time needed to secure parts and qualified labor, and the potential for more stringent environmental regulatory requirements against the expected economic benefits of continued operation, the Company has made the decision to seek approval to retire this unit. Additional details regarding the Plant Mitchell Unit 4C retirement decision are provided in Section 7.

2.3.1.3 Accounting for Plant Branch Units 1 & 2 and Plant Mitchell 4C decertification and retirement

The Company's proposed accounting for the decertification and retirement of Plant Branch Units 1 & 2 and Plant Mitchell 4C is designed to comply with the Commission's order in the Company's 2010 rate case, Docket No. 31958, which included guidance related to additional costs arising from environmental regulations.

When the actual retirement dates for each of the units are reached, the Company proposes to reclassify the remaining retail net book value of the units to a regulatory asset account, which would be amortized over a period equal to the respective unit's remaining useful life approved by the Commission in Docket No. 31958. The Company also proposes that **REDACTED** of the CWIP balance associated with Plant Branch Units 1 & 2 environmental controls originally certified by the Commission in Docket No. 27800 that will no longer be completed, and any remaining, unusable M&S inventory remaining at the unit retirement dates be reclassified as regulatory assets and amortized ratably over a period of three years beginning January 2014. Additional details regarding the costs associated with the Plant Branch Units 1 & 2 and Plant Mitchell 4C retirement decision, and the Company's proposed accounting treatment are provided in Section 7.

2.3.2. Decisions to control, fuel switch, or retire 2,592 MW of retail capacity should be deferred.

As described previously and in the 2011 ECS (Appendix B), considerable uncertainty exists regarding pending state and federal environmental requirements. This uncertainty affects Georgia Power's ability to determine the impacts of such requirements on the economics of its existing generating units and the availability of existing units to meet forecasted demand in 2015 and beyond. In light of this uncertainty, the Company is deferring the decision to control, fuel switch, or retire the following units:

Units	Retail MW Amount
Branch 3 & 4	**REDACTED**
Yates 1	**REDACTED**
Yates 2-5	**REDACTED**
Yates 6 & 7	**REDACTED**
Mitchell 3[1]	**REDACTED**
Kraft 1-4	**REDACTED**
McIntosh 1	**REDACTED**
McManus 1 & 2	**REDACTED**
Total: 2,592 MW	

The Company expects to be able to make more informed decisions regarding which existing generating units should be retired, switched to different fuel sources or controlled as more environmental rules are finalized. The Utility MACT rule is currently expected to be finalized in November 2011. While there are a number of other new environmental regulations being developed, the Utility MACT rule has one of the first compliance deadlines (2015 with the possibility of a one-year EPA extension) and is the key driver influencing the timing of decisions to retire, switch to different fuel sources or control units. In addition, the Utility MACT could have the largest financial and logistical impact to the Company of the rules with near-term compliance dates. As additional regulations are finalized, however, including but not limited to the NAAQS revisions, IB MACT, 316(b), CCR rule, and new effluent guidelines, the Company

[1] In Docket No. 28158, the Commission certified the Company's plan to convert Mitchell 3 into a biomass facility. In May 2011, the Company filed a proposed plan to delay the decision on proceeding with the Mitchell biomass conversion in order to gain more clarity regarding the effect certain regulations such as IB MACT may have upon the viability of the project.

will undertake further analysis to evaluate the economics of these units. Deferring decisions until these regulations are finalized also provides the Company with additional flexibility to adapt to any unforeseen or unquantifiable impacts of pending environmental requirements.

2.3.3. Approximately 2,000 MW out of the 2,592 MW of retail capacity being deferred should be considered unavailable in 2015.

While the significant uncertainty regarding the impact of pending new environmental regulations prevents the Company from making final decisions regarding the 2,592 MW of retail capacity discussed in Section 2.3.2, it is reasonable to assume that, as a result of the proposed Utility MACT compliance timeframe, approximately 600 MW of capacity will be controlled, or equipped to comply, by 2015 and approximately 2,000 MW of retail capacity will be unavailable in 2015. Based on the results of the 2011 Unit Retirement Study (Section 5), the Company believes that the following units in the "deferral" category are more likely than others to switch fuel or be controlled: Plant Kraft Units 1-4, Plant McIntosh Unit 1, and Plant McManus Units 1 & 2. The remaining units, representing approximately 2,000 MW of retail capacity, are either less likely to be controlled based on current expectations of the impacts resulting from environmental regulations, or are not likely to be controlled by the anticipated compliance deadline for the Utility MACT and thus may be unavailable. The 2011 Unit Retirement Study will be updated once the Utility MACT Rule is finalized. However, even if the updated economic evaluation shows more positive benefits associated with controlling the units, it is highly unlikely that the required environmental controls could be completed by 2015. The Company simply cannot rely on the availability of this 2,000 MW of capacity in 2015. As such, the Company proposes to procure enough capacity through the 2015 RFP to help maintain reliability in 2015 and beyond assuming that approximately 2,000 MW are unavailable.

The following sections further explain why the Company currently believes Plant Kraft Units 1-4, Plant McIntosh Unit 1, and Plant McManus Units 1 & 2 may be better candidates for a fuel switch after the final Utility MACT rule is evaluated.

2.3.3.1 Plant Kraft Units 1-4

As proposed, the Utility MACT rule would not apply to natural-gas-fired electric utility steam generating units that use very limited amounts of coal and/or oil, for example, as a limited back-up fuel. Because all of the units at Plant Kraft are already capable of burning natural gas, it may be exempt from further control requirements under the Utility MACT rule if its primary fuel is natural gas. Assuming natural gas operation and the proposed exemption from Utility MACT requirements for natural gas fired units with limited coal and/or oil use, it appears that it would be economic to continue to operate Plant Kraft Units 1-4 on natural gas and to add oil back-up capability to help assure year round unit availability. Based on the 2011 Unit Retirement Study, adding oil back-up capability and the compliance controls expected to be needed at Plant Kraft shows economic benefit associated with continued operations ranging from $**REDACTED** to $**REDACTED** (based on a range of fuel and carbon scenarios) as compared to the cost of replacement generation. While the Company is still evaluating the potential environmental permitting implications, it is currently expected that natural gas operations with oil back-up at Plant Kraft could be fully implemented by summer 2015. In later years, costs associated with 316(b) compliance were included in the analysis. As these units are not required to install controls under the Multipollutant Rule requirements, no costs for SCRs or scrubbers were included. Also, because the units are assumed to operate on natural gas, costs related to baghouses for compliance with Utility MACT and costs related to the CCR Rule were not included in the economic evaluation.

2.3.3.2 Plant McIntosh Unit 1

Similar to the proposal for Plant Kraft, the Company may be able to take advantage of the natural gas availability at Plant McIntosh. It appears that it would be economical to switch fuel for Plant McIntosh Unit 1 from coal to natural gas with oil back-up capability to help assure year round availability. Although Plant McIntosh Unit 1 is also being considered for potential biomass conversion, due to uncertainty regarding environmental regulations related to biomass units, biomass conversion is not expected to be completed in time for this unit to be available in 2015. Therefore, operation on gas appears to be an economical and achievable capacity alternative that maintains the flexibility needed for a possible future biomass conversion. Based on the 2011 Unit Retirement Study, operating Plant McIntosh on natural gas with oil back-up capability and adding the compliance controls expected to be needed shows economic benefit associated with continued operations ranging from $**REDACTED** to $**REDACTED** (based on a range of fuel and carbon scenarios) as compared to the cost of replacement generation. While the Company is still evaluating the potential environmental permitting implications of the use of natural gas as the primary fuel, it is currently expected that operation on natural gas with oil back-up at Plant McIntosh is an economic and feasible alternative starting in the summer of 2015. In later years, costs associated with 316(b) compliance were included in the analysis. As this unit is not required to install controls under the Multipollutant Rule requirements, no costs for an SCR or scrubber were included. Also, because the unit is assumed to operate on natural gas, costs related to baghouses for compliance with Utility MACT and costs related to the CCR Rule were not included in the economic evaluation.

2.3.3.3 Plant McManus Units 1 & 2

The proposed Utility MACT would place stringent emission limits on units operating on oil as a primary fuel source. While the Company continues to perform engineering evaluations to determine the controls necessary to meet the proposed Utility MACT rule limits for oil-fired units, it is possible that operating Plant McManus Units 1 & 2 on #2 oil instead of #6 oil may allow these units to comply with the proposed Utility MACT rule for oil-fired units. This option depends on the Company's continued engineering evaluation of compliance options for these oil units, and the assumption that the proposed Utility MACT emission limits for oil-fired units are not made more stringent in the final rule, which is far from certain. Based on the assumptions in the 2011 Unit Retirement Study, operating Plant McManus units on #2 oil and adding the compliance controls expected to be needed may allow Plant McManus to be in compliance with anticipated requirements and shows economic benefit associated with continued operations ranging from $**REDACTED** to $**REDACTED** (based on a range of fuel and carbon scenarios) as compared to the cost of replacement generation. While the Company is still evaluating the potential environmental permitting implications of using #2 oil at Plant McManus, it is expected that operation of Plant McManus Units 1 & 2 on #2 fuel oil will be an economic alternative starting in 2015 if allowed under the final Utility MACT rule without a significant change in required air emission controls. In later years, costs associated with 316(b) compliance were included in the analysis. As these units are not required to install controls under the Multipollutant Rule requirements, no costs for SCRs or scrubbers were included. Also, because the units are assumed to operate on #2 oil, costs related to the CCR Rule were not included in the economic evaluation.

2.3.4. The Company seeks approval to initiate work on the installation of baghouses on Plant Bowen Units 1-4, Plant Hammond Units 1-4 and Plant Wansley Units 1 & 2.

As previously indicated, Unit Retirement Study evaluations were performed for each Georgia Power coal unit for which the Company has not already incurred significant expenditures for installed environmental controls. Plant Bowen Units 1-4, Plant Wansley Units 1 & 2, Plant Scherer Units 1-3 and Plant Hammond Unit 4[2] were not included in the evaluation because significant environmental controls are already in place, and thus these units would be the most economic to control under more stringent future environmental regulations.

If the final Utility MACT requirements expected to be released in November 2011 are consistent with the proposed rule, the Company will likely be required to install baghouses on all of its coal-fired generating units as early as 2015. This potential for major baghouse installations across Georgia Power and the region make advanced planning for such large projects extremely important. Even with a possible one-year extension of the compliance deadline (to 2016), the Company will not be able to install all of the necessary controls on all units in time. However, the Company may be able to complete construction of baghouses on the proposed subset of units by the extended compliance deadline and work towards providing reliable service for its customers in this timeframe. To seek to accomplish this goal, the Company would need to begin making capital expenditures as early as January 2012. Given the Company's current expectations regarding future environmental requirements, the Company requests the

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[2] The Retirement Study did evaluate the cost of continued operations of Plant Hammond Units 1-3, with the addition of a Selective Non-Catalytic Reduction, baghouse and other environmental control technologies expected to be required by future environmental regulations, compared to a proxy cost based on replacing those units with a combined cycle unit. The economic evaluations indicate that customers are expected to benefit by controlling and continuing to operate Plant Hammond Units 1-3 (reference Tables 5.6-a and 5.6-b in Section 5 for details). The baghouse pre-work performed at Plant Hammond will thus apply to Units 1-4.

Commission approve the expenditure of approximately $**REDACTED**[3] million for the work necessary for the installation of baghouses on Plant Bowen Units 1-4, Plant Wansley Units 1 & 2 and Plant Hammond Units 1-4 to help preserve the continued operations of these units in the 2015-2017 timeframe and maintain fuel diversity for Georgia Power's customers. These costs represent the expenditures that will be necessary from January 2012 through June 2013, when the Company's next IRP is expected to be approved and potential further expenditures related to environmental controls can be addressed. The amount being requested for approval will be used for detailed engineering studies, deep foundation work, relocations of existing equipment on site, and any other work necessary to ensure the projects can be implemented in a timely manner. In the event that final Utility MACT requirements are significantly different than what is currently contemplated in the Company's evaluations, the Company will re-evaluate the decision to control these units and will only move forward with additional spending if the decision is economically beneficial for the Company's customers.

These costs associated with the installation of baghouses will be capitalized to CWIP, and if controls are completed, amounts would be closed to plant in service. If the decision is made to discontinue a project, the Company proposes to reclassify the related CWIP balance to a regulatory asset account and amortize the balance ratably over three years beginning January 2014.

2.3.5. The Company is considering advancing the retirement of Plant McDonough Unit 1 by up to sixty-one days

The Company notes that while Plant McDonough coal Units 2 and 1 are on schedule to retire no later than October 1, 2011 and April 30, 2012, respectively, the Company is currently considering advancing the retirement of coal Unit 1 up to sixty-one days to better optimize the Unit 6 cooling tower tie in work scope. Pursuant to prior Commission action in Docket No. 24506, the coal Unit 1 cooling tower will be assigned to combined cycle ("CC") Unit 6. The potential advancement of retiring Plant McDonough Unit 1 has no impact on the Company's 2015 decisions discussed in this Application.

[3] Assumes Georgia Power's 53.5% ownership share of Wansley 1 & 2 costs and assumes a common baghouse will be shared between Plant Hammond Units 1-4.

2.4 2015 Capacity Needs

Based on the analysis contained in the 2011 IRP Update, the Company has identified the need for incremental capacity in the 2015 timeframe. In order to continue to meet customers' growing electricity needs in a reliable and economic manner, the Company has secured needed capacity through the 2015 RFP in addition to pursuing cost-effective demand side management and renewable portfolios.

2.4.1. Procuring capacity through the 2015 RFP is critical to help assure reliability for Georgia Power's customers.

In determining the 2015 capacity need for Georgia Power, the Company utilized the following assumptions, which were primarily developed through the Company's economic analysis:

(1) The retail capacity for Plant Branch Units 1 & 2 as well as Plant Mitchell Unit 4C would be retired through the decertification of the units;

(2) Approximately 2,000 MW of capacity is not expected to be available for operation in 2015 due to the Utility MACT;

(3) Approximately 600 MW of capacity on which decisions to control have been deferred will be available in 2015; and

(4) All larger coal units already equipped with certain environmental controls (Plant Bowen, Plant Wansley, Plant Scherer, and Plant Hammond) will be available in 2015 either due to a possible Utility MACT compliance extension by EPA or completed construction on required controls

Incorporating these key factors along with several other modeling assumptions, the 2011 Needs Assessment (Section 6) calculated the resulting capacity deficit in 2015 to be approximately 1,200 MW. With such a deficit, the Company's reserve margin would be **REDACTED**%, well below adequate planning reserves. As described further below, four PPAs totaling 1,562 MW of capacity were identified through the 2015 RFP process as the best additions to the Company's resource plan. By adding this capacity, Georgia Power's reserve margin is projected to be **REDACTED**% in 2015.

2.4.2. The 2015 RFP Process

On May 16, 2008, the Company initiated an RFP, monitored by the IE, to solicit capacity resources for 2013-2014. The RFP documents were drafted by the Company with input from the bidders, the Commission Staff and the IE over a period of several months. On November 3, 2008, the Company filed an updated needs letter with the Commission that described a reduced need in 2013 and 2014. As a result, the RFP was suspended until early 2010, when a capacity need was identified for 2015 and the RFP process resumed. As explained in the RFP, the Company conducted the RFP in order to support a reliable and economic supply in the event pending environmental rules caused the Company to reduce its current fleet of coal-fired capacity in 2015.

The 2015 RFP, which included the pro forma PPA documents, was developed through a rigorous public process and under the oversight of the IE and the Commission Staff pursuant to Commission Rule 515-3-4-.04(3) and was widely distributed. Two bidder's conferences were also held on August 13, 2008 and February 24, 2010. On April 20, 2010, the final RFP and pro forma PPA documents (soliciting approximately 1,000 MW) were filed with the Commission and issued via the IE website. As stated in Georgia Power's 2010 IRP testimony, the Company's capacity need in 2015 was in the range of 700-1,900 MW. Announcements were made via the IE website explaining that the actual need could be significantly more or less than the 1,000 MW stated in the RFP, depending on the impact of anticipated and pending environmental rules. On May 18, 2010, the Company filed amended final documents for the 2015 RFP to reflect the Commission`s decision regarding the due diligence structure and fees for asset purchase and sale agreement bids.

The RFP explained that the Company would develop one or more dual-fuel self-build proposals in order to potentially meet some or all of the identified need. In addition to traditional PPAs the Company indicated it would also consider asset purchase and sale agreement ("APSA") bids, i.e., the purchase of an existing generating asset already in commercial operation.

The RFP did not foreclose bidders from submitting bid proposals for any type of resource (base load, intermediate, or peaking) utilizing any type of energy source including, but not limited to, coal, nuclear, oil, natural gas, biomass, wind, solar and hydro. The Company was interested in bid proposals for five, ten or fifteen year terms from a dedicated (first call) generating resource. In response to this RFP, the Company received offers for over 10,000 MW of generating capacity through forty-seven proposals from nine different bidders. The proposals received came only from companies who proposed operating plants primarily fueled by natural gas.

In accordance with the RFP documents, an evaluation method was established to evaluate the bids that included a Responsiveness Screen, an Initial Price Screen, a Detailed Evaluation, and a Portfolio Analysis. The winning resource portfolio was selected for certification because it is the most reliable and best cost supply of electricity to serve the Company's retail customers beginning in 2015. The resources selected are as follows:

(1) A twelve-year, seven month PPA with J. P. Morgan Ventures Energy Corporation through its subsidiary, BE Alabama ("BE Alabama") (the "BE Alabama PPA") that will provide a total of approximately 564 MW of capacity and associated energy beginning June 1, 2015, from a dual-fuel General Electric model 7FA 3X1 Combined Cycle, with output purchased by BE Alabama from the Tenaska Lindsay Hill facility located in Autauga County, Alabama. The BE Alabama PPA will terminate on December 31, 2027.

(2) A fifteen year PPA with Southern Power Company, ("Southern Power") (the "Harris PPA") that will provide a total of approximately 625 MW of capacity and associated energy beginning June 1, 2015, from one General Electric model 7FA 2X1 CC located in Autauga County, Alabama. Due to prior commitments at Plant Harris for 2015, a similar 625 MW interim resource from Plant Franklin will be substituted from June 1, 2015 until December 31, 2015. The Harris PPA will terminate on May 31, 2030.

(3) A fifteen year, five month PPA with Southern Power (the "West Georgia PPA") that will provide a total of approximately 298 MW of capacity and associated energy beginning January 1, 2015 from two dual-fuel General Electric model FA CTs located in Upson County, Georgia. The West Georgia PPA will terminate on May 31, 2030.

(4) A fifteen year, five month PPA with Southern Power (the "Dahlberg PPA") that will provide a total of approximately 75 MW of capacity and associated energy beginning January 1, 2015 from one dual-fuel General Electric model EA CT located in Jackson County, Georgia. The Dahlberg PPA will terminate on May 31, 2030.

2.4.3. Early Termination Option in 2015 PPAs

The 2015 RFP was conducted specifically to acquire capacity resources that might be needed due to impacts of the developing EPA rulemakings. Therefore, the pro forma PPA was designed to allow the Company to reassess these impacts after the anticipated issuance of the final Utility MACT in late 2011. If the Company's reassessment concludes that these compliance impacts are less costly than expected or if compliance by 2015 is not required and, therefore, the capacity need in 2015 is less than anticipated, then, by March 27, 2012, the Company may terminate any or all of the PPAs but will be obligated to make a $20/kW early termination payment. This provision provides another tool to help address the uncertainties resulting from the timing of the EPA rulemaking. In the event the Company utilizes the early termination option for any or all of the executed PPAs, Georgia Power proposes that any costs associated with early termination payments would be capitalized and deferred as a regulatory asset to be amortized ratably over three years beginning January 2014.

2.4.4. Demand Side Management and Renewables continue to play an important role in a balanced supply portfolio.

For decades the Company has emphasized the importance of reducing the need for new generation with cost-effective DSM and energy efficiency programs. The Company recently expanded its DSM portfolio with the certification of seven programs by the Commission in July 2010. This brings the Company's total DSM portfolio to 16 different energy efficiency programs, demand response programs, pricing tariffs, and other activities. Over the next ten years, the Company expects to invest about $600 million on these DSM efforts, with the goal of reducing capacity requirements by a total of about 2,600 MW. The energy and demand impacts of these efforts are incorporated in the Budget 2011 Load and Energy Forecast and are included in the Company's determination of capacity needs in 2015. However, DSM programs cannot by themselves eliminate the Company's need for additional power generation. Even after considering the expected impacts of customer participation in DSM programs, the Company still has a demonstrated need for new or replacement generation.

The Company is also committed to pursuing cost effective renewable resources. One potential renewable supply side resource that the Company is actively pursuing for meeting its 2015 needs is solar capacity. For about the last decade, the Company has encouraged and the

Commission has supported the development of renewable programs and the procurement of renewable sources of generation that were either cost effective or caused no rate increases on non-participants. During this same time period, the cost of renewables has declined, especially for solar technologies. Since the conclusion of the 2010 IRP, the Company proposed and the Commission approved the creation of the SP-1 tariff to facilitate the purchase of additional solar energy to supply the Company's Premium Green Energy Product. Furthermore, the Company has initiated an RFP process to procure an additional 1,000 kW of solar energy to supply the Green Energy Program. Using a cost-effective philosophy, the Company proposed the 2015 Large Scale Solar Proposal on June 24, 2011. This offer outlined the Company's proposal to purchase up to 50 MW of additional solar capacity. The Company would enter into PPAs for up to 20 years for individual solar projects of 30 MW or less. On July 22, 2011, the Commission voted to approve GPC's LSS Proposal. Over the next 30 days, Georgia Power and Commission Staff will work to finalize the process, procedures and information required for a solar supplier to provide a Notice of Intent under the LSS.

In addition, over 250 MW of renewable resources have submitted notices of intent to supply capacity need via the Qualified Facility Proxy Price contract in the 2015 RFP. Some of these resources have had to seek waivers of Commission rules in order to offer capacity over 30 MWs and others have asked for waivers for untimely notices. If agreements can be finalized with such parties, these resources would expand the Company's portfolio of renewable resources in the 2015 timeframe.

2.5 Conclusions

The Company requests that the Commission:

(1) Decertify Plant Branch Unit 1 and Plant Branch Unit 2 effective with the revised Georgia Multipollutant Rule compliance dates for these units, and decertify Plant Mitchell Unit 4C effective as of the date of the final order in this proceeding;

(2) Approve the reclassification of the remaining net book values of Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C as of their respective retirement dates to regulatory asset accounts and the amortization of such regulatory asset accounts ratably over a period equal to the respective unit's remaining useful life approved in Docket No. 31958;

(3) Approve the amortization of approximately $**REDACTED** of Plant Branch Units 1 & 2 environmental CWIP (which has been reclassified as a regulatory asset in accordance with the Commission's Order in Docket No. 31958) ratably over a three year period beginning January 2014;

(4) Approve the amortization of any remaining, unusable M&S inventory balance remaining at the unit retirement dates which will be reclassified to a regulatory asset as identified in accordance with the Commission's Order in Docket No. 31958 ratably over a three year period beginning January 2014;

(5) Approve the Company's decision to initiate the work necessary for the possible installation of baghouses and other environmental controls on certain coal-fired generating units, which it expects will be necessary to help the Company strive to meet the anticipated compliance deadlines for the Utility MACT rule and approve the Company's proposed treatment for recovery of the related costs;

(6) Grant a certificate of public convenience and necessity for the four power purchase agreements ("PPAs") selected through the 2015 Request for Proposals ("RFP") and approve the Company's proposed treatment for recovery of the related costs; and

(7) Approve the 2011 Integrated Resource Plan Update ("2011 IRP Update").

3. Budget 2011 Load and Energy Forecast

3.1 Principal Assumption Changes

Principal assumptions underlying the 2010 IRP Load and Energy Forecast ("Budget 2010") have been updated for Budget 2011. These updates include: (1) inclusion of actual Company data through the end of calendar year 2010; (2) updated historical and forecast economic data; and (3) updated electric prices to reflect the recent 2010 rate case and fuel filing. All updates are reflected in energy use and demand forecasts in Budget 2011, Georgia Power's latest budget forecast.

3.2 2010 Actual Results vs. Budget 2010

On a weather adjusted basis, territorial energy use grew 1.5% in 2010, which was slightly better than the **REDACTED**% growth rate projected in the Budget 2010 forecast. Energy use in the residential and commercial sectors was slightly worse than expected in Budget 2010, but industrial energy use was well above forecast as the manufacturing sector rebounded strongly to meet inventory replenishment needs and export demand. Residential energy use was up 1.0% in 2010 compared with an expectation of **REDACTED**% and commercial use declined 0.4% compared with an expected increase of **REDACTED**%. Industrial energy use, which was expected to grow only **REDACTED**% in the Budget 2010 forecast, grew 5.1%.

3.3 Economic Assumptions

All economic forecasts are provided by Moody's Analytics. Forecasts from other institutions such as Georgia State University, Global Insight, and various bank and other publications are used to check the reasonableness of Moody's results. Local area information provided by Georgia Power field personnel is also taken into consideration.

A comparison of actual 2010 results with the forecast underlying the Budget 2010 view shows that employment and construction-related sectors were somewhat weaker than expected while manufacturing, industrial output, and income were all stronger than expected. These results have affected the short-term economic assumptions underlying the Budget 2011 energy and demand forecasts. Although the short-term economic outlook was revised upward to reflect the effect of the extension of the Bush-era tax cuts late last year, it is generally true that the longer-term economic assumptions have changed very little from those used in the 2010 IRP.

In particular, for Budget 2011, the recovery in labor markets anticipated in 2011-2012 in Budget 2010 has been pushed out to 2012 -2013 and the level of employment, although close, never fully catches up with the Budget 2010 view. The Budget 2011 job shortfall as compared to Budget 2010 exists in both the manufacturing and nonmanufacturing sectors.

The strong improvement in industrial output that fueled the growth in industrial energy use arrived earlier than anticipated in the Budget 2010 view. As a result, both the short term and long-term industrial output assumptions in Budget 2011 are above those in the Budget 2010 view.

Demographic drivers, such as population and migration, have been very important to Georgia's economy in the past few decades. Although the recession significantly slowed both the net in-migration and the population growth rate, Moody's expects the growth rate to return to pre-recession levels fairly soon. The Budget 2010 and Budget 2011 assumptions regarding population are identical for the next ten years. The Budget 2011 forecast is slightly higher than the Budget 2010 forecast beyond year 2020.

Like employment, the outlook for recovery in the housing sector was pushed out in time in the Budget 2011 forecast compared with the Budget 2010 forecast. This revision reflects the effects of continued foreclosure activity and somewhat tighter credit conditions on home prices and home buying. Although the Budget 2011 short-term housing starts forecast has decreased compared with Budget 2010, the long-term forecast is slightly higher than the previous view and assumes housing starts return to near pre-recession levels by year 2014. The demographic outlook supports the need for new housing.

Personal income growth differs very little between the Budget 2010 and Budget 2011 forecasts, with the latter being minimally above the former in the short run and the reverse occurring in the longer run. Significant differences in the forecasts do not occur until after 2020.

3.4 Electricity and Fuel Cost Recovery

The Budget 2010 forecast assumed base rate and fuel cost recovery increases consistent with the Company's 2010 rate case and the then current fuel cost recovery filing. Based on the outcome of both of these cases, the price elasticity effects are similar in the Budget 2010 and Budget 2011 energy use forecasts.

3.5 Territorial Energy and Demand Forecasts

The Budget 2011 energy and demand forecasts for Georgia Power indicate a slight increase from the previous view in total energy use in 2011 followed by a slight decrease in later years compared with the forecast approved in the 2010 IRP. Peak demand forecasts in Budget 2011 reflect new energy efficiency programs approved in 2010 and are thus somewhat lower than in the Budget 2010 view. The ten-year territorial energy growth rate in Budget 2011 is **REDACTED**% per year; in Budget 2010, the ten-year growth rate averaged **REDACTED**%. Budget 2011 peak demand is roughly **REDACTED** in year 2020 than in the Budget 2010 view for the same year. A more detailed discussion of the revised territorial energy and demand forecasts can be found in Appendix A.

4. Budget 2011 Fuel Forecast

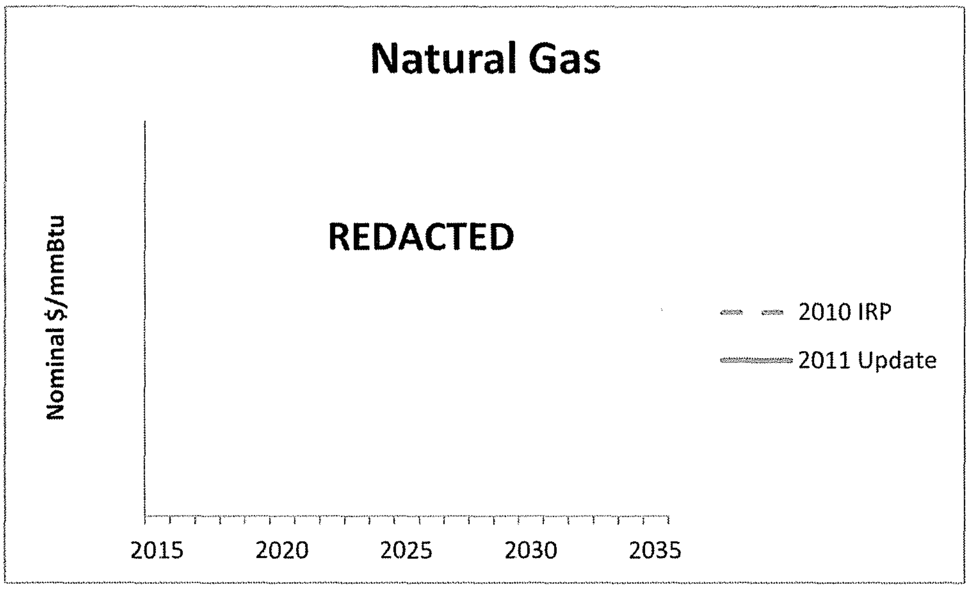
Since the adoption of the 2010 IRP, new fuel forecasts have been produced that have been utilized in the Company's most recent analyses, including the 2011 Unit Retirement Study. Fuel prices are generally lower for the 2011 IRP Update as compared to those in the 2010 IRP.

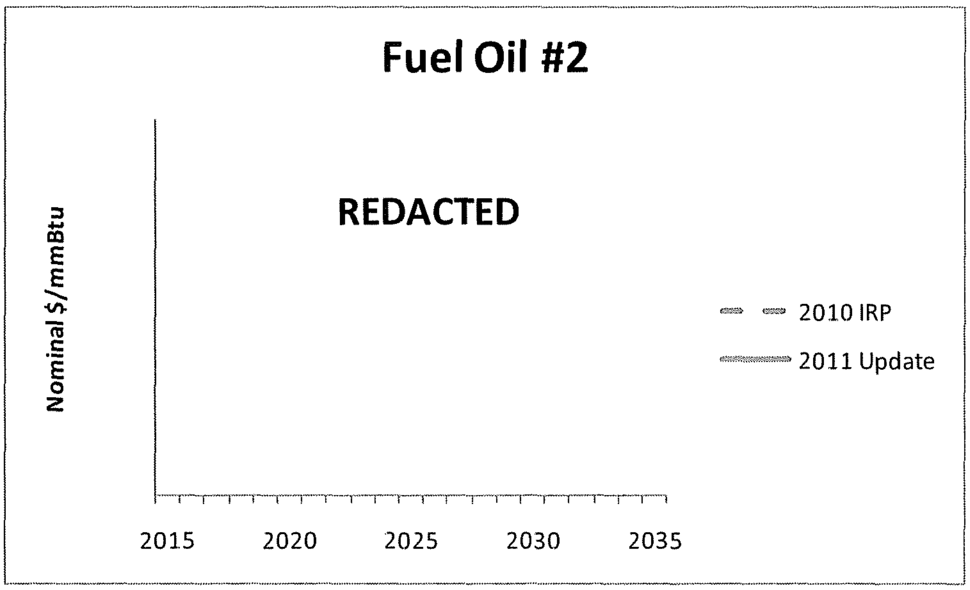
For natural gas, forecast prices are generally lower for the 2011 IRP Update than for the 2010 IRP. Increased shale resources (relative to the earlier assessment) support both lower prices and increased consumption.

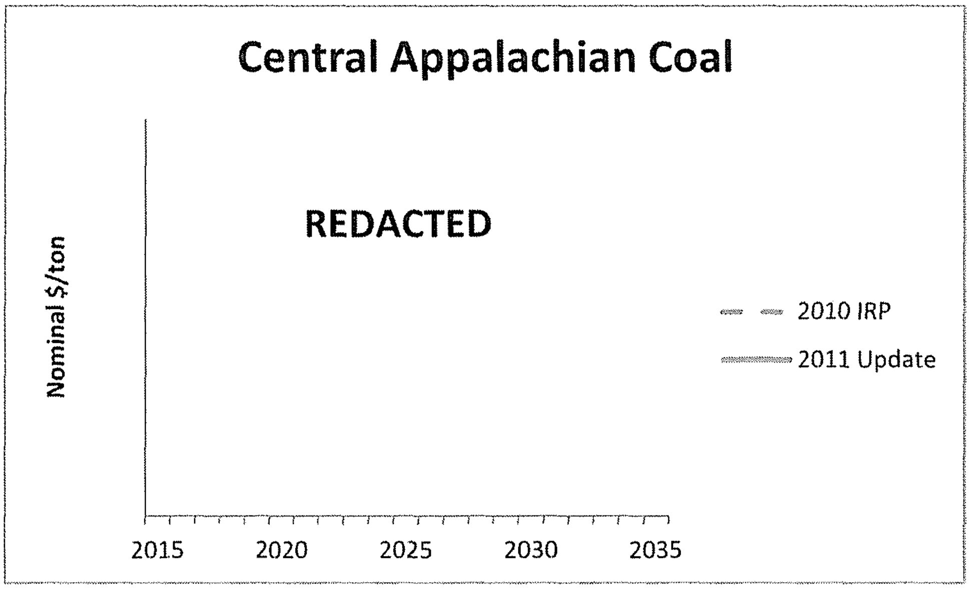
For oil, forecast prices are generally lower for the 2011 IRP Update than for the 2010 IRP. Projections of overall annual GDP growth were down about **REDACTED**% worldwide. Projections of lower oil consumption due to improvements in Chinese efficiency standards (relative to the earlier assessment) and in US auto efficiency (due to new CAFE standards) also support lower oil prices.

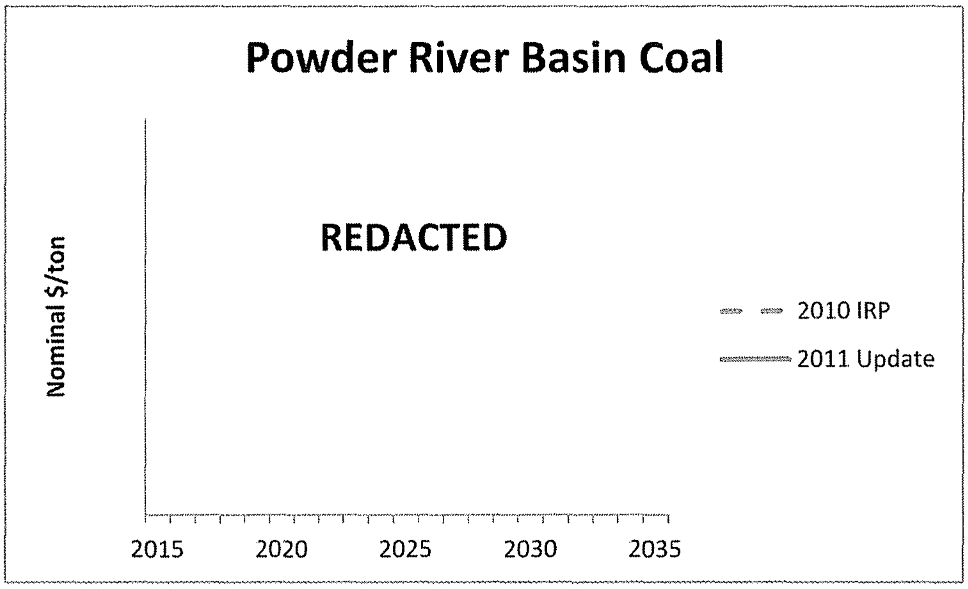
For coal, forecast prices are generally lower for the 2011 IRP Update than for the 2010 IRP. In spite of updated costs assessments that generally suggest higher costs, an updated assessment of the impact of environmental pressure on coal-fired plants suggest generally lower market demand and therefore lower prices in coal markets.

These changes are illustrated in the following fuel commodity price figures:






Central Appalachian Coal
REDACTED
Nominal $/ton
2010 IRP
2011 Update
2015
2020
2025
2030
2035


Powder River Basin Coal
REDACTED
Nominal $/ton
2010 IRP
2011 Update
2015
2020
2025
2030
2035

5. 2011 Unit Retirement Study

5.1 Introduction

Unit Retirement Study evaluations were performed for each Georgia Power coal unit that has not already incurred significant expenditures for environmental controls. For each of the analyses below (Sections 5.5.1-5.5.10), the Unit Retirement Study evaluated controlling or replacing the units in 2015 based on current expected compliance requirements and such analysis was used in the Company's decision to control, fuel switch, retire, or defer. For some of the units recommended for deferral that would not be able to be controlled in time for a 2015 Utility MACT compliance date, an additional analysis was conducted to determine the potential impacts of adding controls equipment at a later date. This additional analysis assumed that such units would be unavailable from 2015 until the projected date by which the required controls could be installed. For Plant Hammond Units 1-3, an additional analysis was conducted assuming a one year extension is granted under Utility MACT for Hammond as discussed in Section 2.3.4. The set of controls assumed for each unit varies based on what controls are currently expected to be required for compliance with current and future environmental rules and regulations. At the top of each table, there is a list of the controls included in the analysis along with the year in which the control is assumed to be applied for purposes of the analysis.

The incremental cost of the controlled coal unit was compared to a proxy represented by site-specific replacement capacity cost. The evaluation included hourly production cost modeling and cost implications to the transmission system. Changes in production cost, capital, and other fixed costs were captured in the comparison to help determine the most economical option.

5.2 Incremental Costs

Incremental costs include fuel, operation and maintenance ("O&M"), capital, and emissions costs (NO_X, SO_2, and CO_2) associated with continued operation of the facility. An economic dispatch model provided annual fuel costs and emissions costs based on the hourly operation of the unit in each scenario for the years 2011 to 2040.

O&M includes labor, materials, overhead costs, and the costs of engineering and support services requested by the plant. Five-year projections of unit incremental O&M costs were obtained from the 2011 budget process. The incremental costs for the remaining years (2015 to 2040) were calculated using a moving average of the projections for the first 5 years and escalating the resulting value at inflation. Environmental O&M for all scheduled environmental controls is also included.

The incremental capital costs for each unit for years 2011 to 2040 were based on capital expenditures projected by each generating plant. These projected capital expenditures were necessary to keep the units running through the analysis period at the current level of operation.

Environmental control capital expenditures that could be required for compliance were not included in the capital expenditures provided by individual plants. Instead, these incremental capital estimates were provided by Southern Company Services ("SCS") Engineering and Construction Services ("E&CS"). The most recently available capital estimates were used in the studies and were included as specified in the analyses below. The control requirements and dates were based on the interpretation of the combination of currently final, proposed, and/or expected environmental rulemakings and their associated compliance requirements. As these rules are finalized, some of these requirements and dates may shift; however, those included are based on the most recent knowledge and expectations at the time of the analyses.

Fixed costs associated with the continued operation for the existing generating units were based on projections of annual O&M and the net present value ("NPV") of the revenue requirements associated with incremental capital investment necessary to keep the unit operational over the 30-year evaluation period.

5.3 Replacement Costs

Replacement costs, installation capital, fixed O&M, and continue to operate capital are all site specific and developed by SCS E&CS. In addition, individual transmission cost implications of the retirement and replacement were estimated by SCS Transmission.

For the unit retirement studies, most coal units were compared to a proxy represented by the expected cost of a CC at **REDACTED**. This was judged to be the best site in Georgia and was used for comparison on the Plant Branch, Plant Yates and Plant Hammond studies. For the units where fuel was switched to gas with oil backup (Plants Kraft, McIntosh and McManus), a comparison was made to a proxy represented by the expected cost of a site-specific CT. In all comparison studies except Plant Mitchell Unit 4C, the costs of a megawatt ratio portion of the replacement unit was used. For example, if the study looked at replacing 500 MW of coal generation, the costs for a 500 MW portion of a **REDACTED** CC would be used for the comparison.

For Plant Mitchell Unit 4C, because the unit is a small CT that is used exclusively for peaking capacity, the unit was not compared to a replacement CC or CT but instead was compared to a more generic replacement capacity cost.

Replacement energy costs were estimated using the Southern Electric System marginal replacement costs for both continued coal operation and the replacement alternative. Marginal replacement costs were generated with the Pro-Sym® model over a 30-year period (2011 to 2040). The marginal replacement costs were then used to dispatch both the coal unit and the replacement units. The energy benefits (marginal replacement costs minus variable operating costs) were compared to determine the commitment and energy value to the Southern Electric System for both generating options. The net present value of the difference between replacement cost and unit operational cost was calculated to determine the overall net contribution.

In Appendix C Table C.3, the NPV of the revenue requirements for the various components of the replacement generation are provided for each set of coal units studied. These components are included in the calculations for which results are shown in Sections 5.5.1-5.5.10. The NPV of revenue requirements for the controls for each coal unit is provided in Appendix C Table C.2.

5.4 Scenarios

Uncertainty is a challenge for planning. The Company works to manage this challenge by considering multiple different future outcomes in key areas of uncertainty, including future CO_2 control requirements and future natural gas supply. The Company formally analyzes multiple scenarios, each of which adopts a particular view of future CO_2 control and a particular view of future natural gas supply.

With its modeling analysis consultant, Charles River Associates ("CRA"), the Company developed four possible CO_2 control requirement futures and three possible natural gas supply futures. The scenarios created by the combination of these CO_2 and natural gas supply price futures were developed to represent the range of plausible outcomes. Each of the twelve scenarios provides an internally-consistent view of fuel and electricity markets in the US. For each of these scenarios, the Company has performed the detailed asset valuation analysis for each unit discussed in this filing.

Four future CO_2 control scenarios were considered. Each was defined by a different future path of the price of CO_2. The four paths each start in 2015 at \$0, \$10, \$20 and \$30 per metric ton of CO_2 (2008\$). On each path (except \$0), the price increases at **REDACTED%** annually above inflation. These CO_2 price levels were chosen to span the plausible short term and long term range of CO_2 requirements when considering multiple factors, including US economic impact and likely cost-containment provisions.

Three future natural gas supply scenarios were considered. They largely reflect different views about the future supply of shale and other domestic US natural gas, from relatively plentiful to relatively scarce. Future natural gas demand scenarios were considered. They largely reflect different views about the amount of natural gas-fired generation in the U.S. and consumer and business demand for natural gas. These result in three different price futures for US natural gas, from relatively low to relatively high. These three fuel price scenarios assume long-term supply and demand market equilibrium. In recognition of the normal supply and demand imbalances that actually occur regularly in the natural gas market, the Moderate fuel case also considers volatility surrounding natural gas prices and it reflects recent historic market imbalances price impacts.

Future events related to domestic and global supply and demand may occur within the fuel markets that could result in a range of future price regimes, most importantly in the natural gas markets. These events may or may not be related to ongoing debates within the regulatory or legislative environment, but reflect potential for ranges of fuel supply such as the amount of domestic conventional and unconventional gas (primarily shale gas) available as well as the amount of imports into the U.S., including Liquified Natural Gas ("LNG") and Alaska gas. Therefore, natural gas resource assumptions have been developed describing three scenarios that result in Low, Moderate and High natural gas price forecasts. In addition, supply/demand relationships between coal, oil, and natural gas are reflected within each scenario such that a change in one of these markets impacts the others within the scenario.

The modeling system that CRA employs for the Company's analyses (MRN-NEEM) is a sophisticated, multi-sector dynamic general equilibrium model of the US economy that takes into account supplies and demands for all goods and services in the economy, focusing on the markets for energy and energy-intensive goods and services--especially electricity. The model finds price paths in all markets so that the quantity supplied is equal to the quantity demanded. All of these markets must be considered to generate a fully integrated view in each scenario.

In each scenario, the modeling captures shifts in generation investment choices through retirements of existing capacity (primarily base load coal), installation of new GHG control technologies, and the construction of new replacement capacity. Higher CO_2 and fuel costs generally increase electricity prices and reduce overall US economic activity, therefore, decreasing growth in electricity sales. All of these interrelated factors, including reductions to load growth, are considered in the Company's scenario modeling process.

The detailed asset evaluations also incorporated the twelve fully integrated scenarios in order to capture variations in the operating environments that may affect the retirement of the units. The detailed analyses included the implications of the addition of the following environmental controls where they were deemed to be required: scrubber ("FGD"), SCR, baghouse, potential SNCR, potential CCR regulation costs, scrubber wastewater treatment and compliance with proposed 316(b) regulations.

5.5 Summary of Study Results

The following tables (Sections 5.5.1-5.5.10) present the NPV customer cost results for the comparison of costs of the appropriate replacement proxy unit minus the cost to continue to operate each set of coal units with the controls listed for that particular unit. When a positive value is given for a scenario, there is a net additional cost to the customer for replacement generation and controlling the coal unit is therefore the better economic option. When there is a negative number for a scenario, there is a greater cost to the customer in controlling the coal unit and replacing the coal unit is therefore the better option. Appendix C summarizes the environmental costs applied to each of the controlled coal units. Table C.1 provides the in-service cost of the individual environmental controls. In Table C.2, the NPV of the declining revenue requirements ("DRR") for each of these controls is provided. If the analysis was to be examined without a particular environmental control that *was* included in the results given in Sections 5.5.1-5.5.10, the NPV of the DRR for that particular control could be added back to each scenario. Conversely, if there is an additional required control that was *not* included in the results in Sections 5.5.1-5.5.10, the NPV for the DRR for that control would be subtracted from each cell in the matrix.

Appendix D summarizes the costs and benefits of continued operation for each set of coal units for the \$0 CO_2 – Moderate Fuel case over the 30-year period (2011-2040).

5.5.1 Plant Branch Units 1 & 2

2015 Compliance Results

Customer Costs for Replacement CC Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the coal units:

2015 Scrubber ~ 2015 SCR ~ 2015 Baghouse ~ 2017 CCR ~ 2018 Scrubber Wastewater Treatment ~ 2018 Intake Structures

- For the purposes of this analysis, the scrubber, SCR and baghouse were online at the beginning of 2015. Note that this 2015 compliance is in accordance with the original Multipollutant Rule dates of December 31, 2014 for Branch 1 & 2.

Table 5.1

Fuel/CO_2	\$0 CO_2	\$10 CO_2	\$20 CO_2	\$30 CO_2
High	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Moderate	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Low	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

In this analysis, the assumed costs include compliance with the Georgia Multipollutant Rule (scrubber and SCR), and anticipated controls under the Utility MACT (baghouse), compliance with EPA's CCR Rule, new effluent guidelines (wastewater treatment), and 316(b) rule (intake structure). Note that a cooling tower was not included in the Plant Branch Units 1 & 2 analysis. The cost for this control is included in Appendix C. Depending on the severity of the 316(b) regulations, the upgrades to the intake structures may be sufficient or a closed cycle cooling tower may be required. Based on the proposed rule, it is expected that a cooling tower would not be required, and therefore costs have not been included. Included in the 316(b) costs is a new intake structure with 20 fine mesh screens with fish returns across the inlet from Little River. These would be required for Plant Branch Units 1 & 2 or Units 3 & 4, regardless of the operation of the other two units and have been included in the analysis.

5.5.2 Plant Branch Units 3 & 4

2015 Compliance Results

Customer Costs for Replacement CC Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the coal units:

2015 Scrubber ~ 2015 SCR ~ 2015 Baghouse ~ 2016-2017 CCR ~ 2018 Scrubber Wastewater Treatment ~ 2018 Intake Structures

- For the purposes of this analysis, the scrubber, SCR and baghouse were online at the beginning of 2015. Note that this 2015 compliance is prior to the new Multipollutant Rule dates of late 2015 for Branch 3 & 4.

Table 5.2-a

Fuel/CO_2	\$0 CO_2	\$10 CO_2	\$20 CO_2	\$30 CO_2
High	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Moderate	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Low	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

2016 Compliance Results

Customer Costs for Replacement CC Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the coal units:

2016 Scrubber ~ 2016 SCR ~ 2016 Baghouse ~ 2016-2017 CCR ~ 2018 Scrubber Wastewater Treatment ~ 2018 Intake Structures

- For the purposes of this analysis, Plant Branch Units 3 & 4 were assumed to be unavailable in 2015 due to required controls not being installed in time to meet anticipated compliance requirements.

Table 5.2-b

Fuel/CO_2	\$0 CO_2	\$10 CO_2	\$20 CO_2	\$30 CO_2
High	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Moderate	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Low	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

For both analyses, the assumed costs include compliance with the Georgia Multipollutant Rule (scrubber and SCR), and anticipated controls under the Utility MACT rule (baghouse), compliance with EPA's CCR Rule, new effluent guidelines (wastewater treatment), and 316(b) rule (intake structure). Note that a cooling tower was not included in the Plant Branch Units 3 & 4 analysis. The cost for this control is included in Appendix C. Depending on the severity of the 316(b) regulations, the upgrades to the intake structures may be sufficient or a closed cycle cooling tower may be required. At this time, it is expected that a cooling tower will not be required, and, therefore, costs have not been included. Included in the 316(b) costs is a new intake structure with 20 fine mesh screens with fish returns across the inlet from Little River.

These would be required for Plant Branch Units 1 & 2 or Units 3 & 4, regardless of the operation of the other two units and have been included in the analysis.

5.5.3 Plant Yates Units 6 & 7

2015 Compliance Results

Customer Costs for Replacement CC Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the coal units:

2015 Dry Scrubber ~ 2015 SCR ~ 2015-2017 CCR ~ 2017 316(b) Compliance

Table 5.3

Fuel/CO_2	\$0 CO_2	\$10 CO_2	\$20 CO_2	\$30 CO_2
High	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Moderate	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Low	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

Preliminary engineering studies for a dry scrubber on Plant Yates Units 6 & 7 are underway. Based on the proposed rules, it is projected that these controls could be installed in time to meet compliance requirements and would meet current and proposed emissions removal rate requirements. Based on the proposed 316(b) rule, the 316(b) compliance costs for Units 6 & 7 include fine mesh screens with a fish return system. Plant Yates already has a closed loop cooling tower. The analysis takes into account cost of compliance with EPA's anticipated CCR rule. Finally, given the assumption of dry scrubber technology, wastewater treatment controls to comply with expected effluent guidance revisions have not been included.

5.5.4 Plant Yates Unit 1

2015 Compliance Results

Customer Costs for Replacement CC Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the coal unit:

2015 SNCR ~ 2015 Baghouse ~ 2016-2017 CCR ~ 2019 Scrubber Wastewater Treatment

- For the purposes of this analysis, the a SNCR was assumed to be online in 2015 to meet potential NAAQS compliance requirements, and a baghouse was online in 2015 in order to meet Utility MACT compliance requirements.

Table 5.4-a

Fuel/CO_2	\$0 CO_2	\$10 CO_2	\$20 CO_2	\$30 CO_2
High	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Moderate	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Low	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

2016 Compliance Results

Customer Costs for Replacement CC Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the coal unit:

2017 SNCR ~ 2016 Baghouse ~ 2016-2017 CCR ~ 2019 Scrubber Waste Water Treatment

- For the purposes of this analysis, Plant Yates Unit 1 was assumed to be unavailable in 2015 because required controls could not be installed in time to meet anticipated compliance requirements.

Table 5.4-b

Fuel/CO_2	\$0 CO_2	\$10 CO_2	\$20 CO_2	\$30 CO_2
High	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Moderate	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Low	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

In both analyses, Plant Yates Unit 1 benefits from an economics perspective because of the fact that it already has a wet scrubber in place. Unlike Units 6 & 7, the smaller Plant Yates units are not required to install SCRs under the revised Multipollutant Rule. Therefore, the SCR cost was not included in this analysis. For purposes of this analysis, cost for Selective Non-Catalytic Reduction ("SNCR") was assumed to address NOx emissions to account for potential future NAAQS changes.

Based on the proposed rule, there is no additional 316(b) compliance costs assumed for Plant Yates Unit 1. The analysis takes into account cost of compliance with EPA's anticipated CCR rule and new effluent guidelines (scrubber wastewater treatment).

5.5.5 Plant Yates Units 2-5

2015 Compliance Results

Customer Costs for Replacement CC Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the coal units:

2015 Scrubber ~ 2015 SCR ~ 2015 Baghouse ~ 2016-2017 CCR ~ 2019 Scrubber Wastewater Treatment

Table 5.5-a

Fuel/CO_2	\$0 CO_2	\$10 CO_2	\$20 CO_2	\$30 CO_2
High	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Moderate	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Low	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

2018 Compliance Results

Customer Costs for Replacement CC Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the coal units:

  2017 Scrubber ~ 2017 SCR ~ 2018 Baghouse ~ 2016-2017 CCR ~ 2019 Scrubber Wastewater Treatment

- For the purposes of this analysis, Plant Yates Units 2-5 were assumed to be unavailable in 2015-2017 because required controls could not be installed in time to meet anticipated compliance requirements for Utility MACT.

Table 5.5-b

Fuel/CO_2	\$0 CO_2	\$10 CO_2	\$20 CO_2	\$30 CO_2
High	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Moderate	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Low	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

For both analyses, the assumed costs include scrubber, SCRs and baghouses to comply with Utility MACT and potential future NAAQS changes and costs for compliance with EPA's CCR rule and new effluent guidelines. Based on the proposed rule, there are no additional 316(b) compliance costs assumed for Plant Yates Units 2-5.

5.5.6 Plant Hammond Units 1-3

2015 Compliance Results

Customer Costs for Replacement CC Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the coal units:

2015 SNCR ~ 2015 Baghouse ~ 2018 Cooling Tower ~ 2015-2017 CCR ~ 2020 Scrubber Wastewater Treatment

- For the purposes of this analysis, a SNCR was assumed to be online in 2015 to meet potential NAAQS compliance requirements and a baghouse was online in 2015 in order to meet Utility MACT compliance requirements.

Table 5.6-a

Fuel/CO_2	\$0 CO_2	\$10 CO_2	\$20 CO_2	\$30 CO_2
High	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Moderate	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Low	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

2016 Compliance Results

Customer Costs for Replacement CC Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the coal units:

2017 SNCR ~ 2016 Baghouse ~ 2018 Cooling Tower ~ 2015-2017 CCR ~ 2020 Scrubber Wastewater Treatment

- For the purposes of this analysis, Plant Hammond Units 1-3 were assumed to be available beginning in 2015.

Table 5.6-b

Fuel/CO_2	\$0 CO_2	\$10 CO_2	\$20 CO_2	\$30 CO_2
High	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Moderate	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Low	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

In both analyses, Hammond Units 1-3 benefit from an economics perspective because of the fact that they already have a scrubber in place. Unlike Plant Hammond Unit 4, Units 1-3 are not required to install SCR systems under the Multipollutant Rule. Therefore, the cost for an SCR was not considered in this analysis. For purposes of this analysis, cost for an SNCR system was assumed to address NOx emissions to account for potential future NAAQS changes.

Plant Hammond Units 1-3 would share a baghouse and a cooling tower with Unit 4, which benefits the economics of Units 1-3, and there are no additional 316(b) compliance costs above the closed cycle cooling tower that are expected to be required at Units 1-3. Costs were included for wastewater treatment for compliance with expected effluent guidelines.

5.5.7 Plant Kraft Units 1-4

Customer Costs for Replacement CT Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the coal units:

2015 Fuel Switch Costs ~ 2020 316(b) Compliance Costs

Table 5.7

Fuel/CO_2	**\$0 CO_2**	**\$10 CO_2**	**\$20 CO_2**	**\$30 CO_2**
High	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Moderate	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Low	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

Results shown for Plant Kraft include operation on natural gas with incremental capital costs necessary to facilitate #2 oil backup capability at all four units as well as 316(b) compliance costs. Natural gas operations are based on **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED.** The 316(b) compliance costs for Kraft include fine mesh screens with a fish return system. Additional 316(b) compliance in the form of a closed loop cooling tower may be required but is not included in this analysis. As stated in Section 2.4.2, additional costs may be incurred to comply with Utility MACT related to backup fuel. These costs are included in Appendix C. As these units are not subject to the Multipollutant Rule requirements, no costs for SCRs and scrubbers were included. Also, because the units are assumed to operate on natural gas, neither cost for baghouses for compliance with Utility MACT nor any costs related to the CCR Rule were included. Assuming gas operations, no costs associated with wastewater treatment for compliance with effluent guidelines revisions were assumed.

5.5.8 Plant McIntosh Unit 1

Customer Costs for Replacement CT Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the coal unit:

2015 Fuel Switch Costs ~ 2020 316(b) Compliance Costs

Table 5.8

Fuel/CO_2	**\$0 CO_2**	**\$10 CO_2**	**\$20 CO_2**	**\$30 CO_2**
High	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Moderate	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Low	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

Results shown for Plant McIntosh include operation on natural gas with incremental capital costs necessary to facilitate #2 oil backup capability as well as 316(b) compliance costs. Natural gas operations are based on **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**. The 316(b) compliance costs for McIntosh include fine mesh screens with a fish return system. As stated in Section 2.4.2, additional Utility MACT compliance costs may be required as well related to backup fuel. These costs are included in Appendix C. As this unit is not subject to the Multipollutant Rule requirements, no costs for SCR and scrubber were included. Also, because the unit is assumed to operate on natural gas, neither costs for baghouse for compliance with Utility MACT nor any costs related to the CCR Rule were included. Assuming gas operations, no costs associated with wastewater treatment for compliance with effluent guidelines revisions were assumed.

5.5.9 Plant McManus Units 1-2

Customer Costs for Replacement CT Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the units:

2015 Fuel Switch Costs ~ 2020 316(b) Compliance Costs

Table 5.9

Fuel/CO_2	**\$0 CO_2**	**\$10 CO_2**	**\$20 CO_2**	**\$30 CO_2**
High	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Moderate	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Low	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

Results shown for Plant McManus include capital costs to facilitate the use of #2 oil instead of #6 oil as well as 316(b) compliance costs. The 316(b) compliance costs for Plant McManus include fine mesh screens with a fish return system. Additional 316(b) compliance in the form of a closed loop cooling tower may be required, and additional costs may be required to comply with Utility MACT compliance costs but such costs are not included in the analysis. These costs are included in Appendix C. As this unit is not subject to the Multipollutant Rule requirements, no costs for SCR and scrubber were included. Also, because the unit is assumed to operate on #2 oil, costs related to the CCR Rule were not included. No costs associated with wastewater treatment for compliance with effluent guidelines revisions were assumed.

5.5.10 Plant Mitchell Unit 4C

Customer Costs for Generic Replacement Cost Relative to the Cost of Continued Operation NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the unit:

None needed as this is an oil-fired CT unit.

Table 5.10

Fuel/CO_2	**\$0 CO_2**
Moderate	**REDACTED**

For the Plant Mitchell Unit 4C analysis, a comparison of Unit 4C Continue to Operate Capital and O&M costs were compared to the replacement capacity costs over the next 20 years (2011-2030). This analysis showed that the CT had a value of approximately $**REDACTED** in a $0 Moderate scenario.

6. Needs Assessment

6.1 Updated Needs Assessment

Based on recommendations within the Unit Retirement Study, the Company has identified a 2015 capacity need of approximately 1,200 MW in its Needs Assessment. The Company recommends that this need be met through a combination of supply and demand-side strategies, including the certification of new capacity available through the 2015 RFP.

The Needs Assessment for Georgia Power has been updated to reflect a new load forecast and the status of generation resources as discussed in the Supply Side Plan for 2015 (Section 2.3) and the 2015 Capacity Needs (Section 2.4). Tables 6.1, 6.2 and 6.3 provide further details regarding Georgia Power's capacity required to meet the Company's planning target reserve margin.

Table 6.1 reflects the capacity needs based on the 2010 IRP with updated loads, change in the status of Plant Mitchell Unit 3, and the inclusion of the Commission approved wholesale-to-retail capacity for Scherer 3 and Blocks 1-6. Table 6.2 reflects the capacity need based on the assumptions detailed in Table 6.1 adjusted for the reductions of capacity as described in the Supply Side Plan for 2015. Table 6.3 reflects the needs based on the assumptions in Table 6.2 adjusted for the addition of resources as described in the 2015 Capacity Needs.

Table 6.1 - Georgia Power Update to the 2010 IRP

Year	Peak Demand (MW)	Owned Generating Capacity (MW)	Purchased Generating Capacity (MW)	Dispatchable DSOs (MW)	Total Capacity (MW)	Capacity Required to Meet GPC Target (MW)	GPC Reserve Margin (%)
	(A)	(B)	(C)	(D)			(E)
2012	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2013	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2014	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2015	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2016	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2017	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2018	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2019	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2020	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2021	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2022	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2023	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Notes	REDACTED						
	REDACTED						
	REDACTED						
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	REDACTED						
	REDACTED						
	REDACTED						

Table 6.2 - Georgia Power 2011 IRP reflecting Supply Side Plan for 2015

Year	Peak Demand (MW)	Owned Generating Capacity (MW)	Purchased Generating Capacity (MW)	Dispatchable DSOs (MW)	Total Capacity (MW)	Capacity Required to Meet GPC Target (MW)	GPC Reserve Margin (%)
	(A)	(B)	(C)	(D)			(E)
2012	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2013	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2014	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2015	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2016	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2017	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2018	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2019	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2020	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2021	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2022	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2023	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2024	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2025	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2026	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2027	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2028	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2029	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2030	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2031	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Notes	REDACTED						
	REDACTED						
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	REDACTED						

Table 6.3 - Georgia Power 2011 IRP Update

Year	Peak Demand (MW)	Owned Generating Capacity (MW)	Purchased Generating Capacity (MW)	Dispatchable DSOs (MW)	Total Capacity (MW)	Capacity Required to Meet GPC Target (MW)	GPC Reserve Margin (%)
	(A)	(B)	(C)	(D)			(E)
2012	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2013	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2014	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2015	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2016	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2017	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2018	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2019	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2020	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2021	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2022	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2023	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Notes REDACTED
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7. Decertification of Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C

7.1 Introduction

Pursuant to O.C.G.A. § 46-3A-6, the Company requests decertification of Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C. The 2011 Unit Retirement Study, located in Section 5 of this filing, details the methodology, major assumptions and key results for the economic screening analysis conducted for Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C. The decisions to retire these units considered a number of different factors, including the uncertainty related to pending and anticipated environmental regulations, fleet operational flexibility, reliability considerations, fuel diversity, fuel price volatility, impacts to the community, employment and the age of the units.

7.2 Plant Branch Units 1 & 2

Plant Branch Units 1 & 2 are both coal-fired boilers that began commercial operation in 1965 and 1967 respectively. The Georgia Multipollutant Rule requires the installation of SCRs and scrubbers on all four units at Plant Branch by the compliance deadlines currently specified in the Rule (December 31, 2013 for Unit 1 and October 1, 2013 for Unit 2).

Based on the Multipollutant Rule requirements, the Company has determined that continued operation of Plant Branch Units 1 & 2 with the required environmental controls would not be economically beneficial to customers across a broad range of economic scenarios. When coupled with the environmental controls that are expected to be required under additional anticipated federal and state environmental rules (including those associated with coal-combustion byproducts, wastewater treatment and cooling), the projected costs associated with continued operation and installation of likely controls at these two units would further reduce the potential for customer benefits. The economic analysis shows a significant negative NPV across a wide range of the fuel and carbon scenarios contemplated with a significant positive NPV in only three of the twelve scenarios. A summary of the results of this analysis are shown below in Table 7.1 (replicated from Table 5.1 in Section 5.5.1 (Unit Retirement Study)), and information related to the in-service costs for environmental controls is contained within Appendix C Table C.1.

Table 7.1

Plant Branch Units 1 & 2

2015 Compliance Results

Customer Costs for Replacement CC Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the coal units:

2015 Scrubber ~ 2015 SCR ~ 2015 Baghouse ~ 2017 CCR ~ 2018 Scrubber Wastewater Treatment ~ 2018 Intake Structures

- For the purposes of this analysis, the scrubber, SCR and baghouse were online at the beginning of 2015. Note that this 2015 compliance is in accordance with the original Multipollutant Rule dates of December 31, 2014 for Branch 1 & 2.

Fuel/CO_2	\$0 CO_2	\$10 CO_2	\$20 CO_2	\$30 CO_2
High	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Moderate	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Low	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

Therefore, the Company requests the Commission approve the decertification and retirement of Plant Branch Units 1 & 2. The Company proposes that the timing of the retirements coincide with the applicable Multipollutant Rule compliance deadlines for Plant Branch Units 1 & 2: currently December 31, 2013 and October 1, 2013 respectively.

7.3 Plant Mitchell Unit 4C

Plant Mitchell Unit 4C is a Pratt & Whitney oil-fired CT rated at a capacity of 33 MW, and was installed in 1971 along with Units 4A and 4B. In December 2009, Unit 4C experienced a generator stator failure, and a decision was made at that time to delay repairing the unit.

While an economic evaluation of the costs for procuring replacement parts and fully repairing Plant Mitchell Unit 4C show a positive NPV for customers when taking into account reliability considerations, the age of the unit, the long lead times needed to secure the necessary replacement parts and labor, and the fact the unit may become subject to more stringent environmental requirements that could require additional capital investment prior to resuming operation, the Company is seeking approval to retire the unit. The economic evaluation associated with the repair and continued operation of Plant Mitchell Unit 4C is summarized below (replicated from Table 5.10 in Section 5.5.10 (Unit Retirement Study)).

Table 7.2

Plant Mitchell Unit 4C

Customer Costs for Generic Replacement Cost Relative to the Cost of Continued Operation
NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the unit:

None needed as this is an oil-fired CT unit

Fuel/CO_2	**\$0 CO_2**
Moderate	**REDACTED**

Therefore, Georgia Power proposes that Plant Mitchell Unit 4C be decertified and retired, effective as of the date of the Commission's final order in this proceeding.

7.4 Regulatory Accounting

On December 21, 2010, the Commission issued its order in the Company's 2010 base rate case in Docket No. 31958 adopting the Stipulation Agreement between the Company and other parties in the proceeding. The Stipulation Agreement recognized the uncertainty surrounding environmental assumptions, and addressed the potential for changes as follows:

> In the event that the Commission approves changes to the Company's environmental O&M or capital budgets, resulting from new or modified regulations or legislation that require expenditures not currently in the Company's budget as reflected in the Company's Minimum Filing Requirements Appendix Supplemental Item S-49 supporting the ECCR Levelized rate reflected in paragraph 1 above (including but not limited to retirement of units whose continued operations are deemed by the Commission to be no longer cost effective in light of any such regulations or legislation) in connection with an update to the Company's integrated resource plan, the costs associated with such Commission approved changes (including any impairment losses and any unusable materials and supplies inventories at such units) will be deferred as a regulatory asset to be recovered over a period deemed appropriate by the Commission at that time.
>
> *In Re: Georgia Power Company's 2010 Rate Case*, Docket No. 31958, Stipulation Para. 7.

Since March 2011, the retail portion of Plant Branch Units 1 & 2 as well as Plant Mitchell Unit 4C have continued to be depreciated according to the depreciation rates approved in Docket No. 31958. When the actual retirement dates are reached, the Company proposes to reclassify the remaining retail net book value of the units to a regulatory asset account, which would be amortized over a period equal to the respective unit's remaining useful life approved by the Commission in Docket No. 31958.

The Company began preliminary work on environmental controls at Plant Branch in 2009 after receiving Commission approval in Docket No. 27800. In January 2010, the Company decided to delay the ongoing physical construction of Plant Branch Units 1 and 2 controls until the proposals surrounding environmental regulations became more certain. The Company notified the Commission and received Commission approval for the delay in Docket No. 31081. As of the Company's March 14, 2011 decision to retire these units, there was a CWIP balance of $**REDACTED** directly attributable to Plant Branch Units 1 and 2 for environmental controls that will now no longer be completed (the Company ceased capitalizing Allowance for Funds Used During Construction ("AFUDC") on the CWIP balance at that time). There is no CWIP related to Plant Mitchell Unit 4C. The Company has transferred the CWIP balance to a regulatory asset account and proposes to amortize the $**REDACTED** balance ratably over three years beginning January 2014.

Because of the decision to retire the above units, the Company also performed a preliminary review of current M&S inventory to determine what items may be sold or used at another generating plant, and what items may be unusable after the units retire. Based on the preliminary review, unusable M&S inventory directly attributable to Branch Units 1 and 2 is not expected to exceed $**REDACTED** at the retirement date of the units. The Company does not expect there will be any unusable M&S inventory related to Plant Mitchell Unit 4C. The Company intends to transfer any remaining, unusable M&S inventory remaining at the unit retirement dates to a regulatory asset account and proposes to amortize the balance ratably over three years beginning January 2014.

In conclusion, the Company requests that the Commission:

(1) Approve the decertification of Plant Branch Unit 1 effective December 31, 2013, Plant Branch Unit 2 effective October 1, 2013, and Plant Mitchell Unit 4C effective as of the date of the final Order in this proceeding;

(2) Approve the reclassification of remaining net book values of Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C as of their respective retirement dates to regulatory asset accounts and the amortization of such regulatory asset accounts ratably over a period equal to the respective unit's remaining useful life approved in Docket No. 31958;

(3) Approve the amortization of approximately **REDACTED** of Plant Branch Units 1 & 2 environmental CWIP (which has been reclassified as a regulatory asset in accordance with the Commission's Order in Docket No. 31958) ratably over a three year period beginning January 2014; and

(4) Approve the amortization of any remaining, unusable M&S inventory balance remaining at the unit retirement dates which will be reclassified to a regulatory asset as identified in accordance with the Commission's Order in Docket No. 31958 ratably over a three year period beginning January 2014.

8. Certification of Replacement Capacity

8.1 Introduction

Pursuant to O.C.G.A. § 46-3A-4, Georgia Power seeks to Certify four purchase power agreements that will be utilized to support an economical and reliable supply of electric power and energy for the Company's retail customers. Specifically, the Company seeks to certify:

(1) A twelve-year, seven month PPA with J. P. Morgan Ventures Energy Corporation through its subsidiary, BE Alabama ("BE Alabama") (the "BE Alabama PPA") that will provide a total of approximately 564 MW of capacity and associated energy beginning June 1, 2015, from a dual-fuel General Electric model 7FA 3X1 Combined Cycle, with output purchased by BE Alabama from the Tenaska Lindsay Hill facility located in Autauga County, Alabama. The BE Alabama PPA will terminate on December 31, 2027.

(2) A fifteen year PPA with Southern Power Company that will provide a total of approximately 625 MW of capacity and associated energy beginning June 1, 2015, from one General Electric model 7FA 2X1 CC located in Autauga County, Alabama. Due to prior commitments at Plant Harris for 2015, a similar 625 MW interim resource from Plant Franklin will be substituted from June 1, 2015 until December 31, 2015. The Harris PPA will terminate on May 31, 2030.

(3) A fifteen year, five month PPA with Southern Power that will provide a total of approximately 298 MW of capacity and associated energy beginning January 1, 2015 from two dual-fuel General Electric model FA CTs located in Upson County, Georgia. The West Georgia PPA will terminate on May 31, 2030.

(4) A fifteen year, five month PPA with Southern Power that will provide a total of approximately 75 MW of capacity and associated energy beginning January 1, 2015 from one dual-fuel General Electric model EA CT located in Jackson County, Georgia. The Dahlberg PPA will terminate on May 31, 2030.

8.2 Issuance of the 2015 Request for Proposals

In accordance with the Commission's Rule governing RFPs, the Company drafted the 2015 RFP documents with input from the bidders, the Commission's Staff and the IE over a period of several months. Four versions of the draft RFP documents were prepared by the Company and posted on the IE web site (the first three versions were issued in connection with the initial RFP that was intended to solicit resources for 2013-2014): the initial draft on July 15, 2008; the second draft on September 25, 2008; the third draft on October 23, 2008; and the fourth draft on February 19, 2010. On April 20, 2010, the final RFP documents were issued. On April 28, 2010, the Commission issued its order approving the RFP documents but delayed a decision on the treatment of due diligence fees for APSA bids. On May 25, 2010, the Commission issued its order addressing the APSA due diligence fees. On May 18, 2010, the Company filed amended final documents for the 2015 RFP to reflect the Commission's final determination on that issue.

Interested parties were invited to review the drafts by registering to use the Commission's IE web site and, through three different methods, to comment upon or ask questions regarding the draft RFP documents. The parties could post questions or comments to suggest changes to the draft RFP documents on the web site and the parties could attend the bidders' conferences, which were held on August 13, 2008 and February 24, 2010. The Company responded to approximately 56 questions and reviewed over 50 comments submitted by interested parties. On April 9, 2010 the IE issued its first report on the 2015 RFP process.

On June 22, 2010, the Company received offers for over 10,000 MW of generating capacity through 47 proposals from nine different companies. All of the proposals came from companies that proposed operating plants primarily fueled by natural gas to generate electricity. The Company also proposed self build projects to be considered in the RFP.

8.3 Bid Evaluation

In accordance with the RFP documents, an evaluation method was established to evaluate the bids that included a Responsiveness Screen, an Initial Price Screen, a Detailed Evaluation, and a Portfolio Analysis.

The Responsiveness Screen was a quick assessment, checking the bids for compliance with the basic bid requirements defined in the RFP. This occurred at bid opening and was conducted by the IE in conjunction with the Company.

The Initial Price Screen was a ranking of the bids based on their impact on total generation cost. The evaluation considered capacity payments, fixed O&M payments, as well as variable costs and fixed fuel transportation charges. The STRATEGIST™ model was used to quantify the energy benefits of a particular offer when dispatched with Southern Company generating resources. Individual proposals were ranked on this generation-only basis. All PPA bids considered were priced on a five, ten or fifteen year basis, respective to the term submitted in each bidder's proposal. APSA bids were assumed to operate for the expected remaining life of the specific asset proposed. The Company's self build proposals reflected an expected forty year service life. The Company evaluated all proposals over the expected forty year service life of the self-build proposal by assuming that each PPA or APSA would defer the self build by the number of years of each PPA's respective term or each APSA's remaining life. The filler values used in the years after the end of a PPA or APSA represented the deferred cost of the self-build proposal.

In the Detailed Evaluation, priority was given to the best proposals. The Detailed Evaluation was a total cost ranking of all proposals, which included updated information provided by the bidders through the IE. It also included a transmission evaluation. The Detailed Evaluation examined the total cost impact of the bid as compared to an established reference case. A relative ranking table was created that ranked each proposal based on best total cost. As part of this process, proposals were analyzed using a consistent methodology that was developed prior to the receipt of bids.

The Detailed Evaluation results were used to develop a competitive tier of 5 proposals. Following this selection and notification of status to all parties per the RFP rules, the Company together with the IE and Commission Staff, met with all competitive tier bidders individually to discuss their bids and to clarify or acquire any additional information necessary that could affect the Detailed Evaluation.

8.4 Portfolio Analysis

To identify the best portfolio of supply-side options for satisfying the Company's needs, a portfolio analysis is necessary if: (1) more than one proposal is necessary to satisfy the need; and (2) there is a moderate to significant level of transmission interaction between proposals. The proposals selected for the short list were based upon the best total cost of the individual proposals. The best cost portfolio was selected as the winning portfolio and included proposals that closely matched the MW need. The remaining proposals from the short list were held as the reserve portfolio. The winning and reserve portfolio was shared with the IE and the Commission Staff. Both the IE and the Commission Staff concurred with the Company's selections.

8.5 Winning Bidders' PPAs

As stated above, the winning bidders were J. P. Morgan Ventures Energy Corporation, through its subsidiary, BE Alabama LLC, and Southern Power ("Winning Bidders"). Southern Power is a wholly owned subsidiary of Southern Company and is an affiliate of Georgia Power.

The Company negotiated with the Winning Bidders to adapt the form PPAs to the Winning Bidders' facilities. The PPAs were executed by the Company and the Winning Bidders on June 27, 2011, and the PPAs are expressly conditioned on the Commission's approval. The Winning Bidders' PPAs will provide the Company with a total of 1,562 MW of capacity and energy, with 373 MW beginning January 1, 2015 and the remainder beginning June 1, 2015. The BE Alabama PPA will terminate December 31, 2027. The Southern Power PPAs will terminate May 31, 2030. The Winning Bidders will supply capacity from existing, natural gas facilities that are in commercial operation in Jackson County and Upson County, Georgia and Lee County and Autauga County, Alabama. Appendices E, F, G and H contain copies of the Winning Bidders PPAs. No approval of any other state commission or federal entity was necessary for the parties to enter into the PPAs.

8.6 Cost Recovery

Georgia Power proposes to recover the costs associated with the Winning Bidders PPAs in its retail cost of service, including the associated assets and obligations for the PPAs that are to be treated as capital leases. The capital lease assets will be included in rate base and the capital lease obligations will be included in cost of capital. Recovery of all PPA costs is consistent with other PPAs certified by the Commission. In the event the Company utilizes the early termination option for any or all of the executed PPAs, it will be obligated to make a $20/kW early termination payment to the affected Winning Bidders. Georgia Power proposes that any costs associated with early termination payments would be capitalized and deferred as a regulatory asset to be amortized ratably over three years beginning January 2014.

8.7 Additional Sum

The IRP statute, O.C.G.A. § 46-3A-8, specifies that the Company is entitled to an "additional sum" for purchased power resources. When calculating an additional sum, the statute further requires that lost revenues, changed risks and an equitable sharing of benefits between the utility and its retail customers shall be considered. In this solicitation, as with most solicitations, the Company's self-build opportunity is competitive with the market offerings. As a Company, our shareholders may lose the opportunity to earn a return when we enter into purchase power agreements. The additional sum component of the IRP statute was intended to encourage purchases by the Company.

The Company is requesting an additional sum of $2.30/kW-year for the new 2015 PPAs, which is consistent with previous certifications.

8.8 Conclusion

The 1,562 MW from the Winning Bidders' PPAs were selected as the best cost offers and included in the best cost portfolio. The RFP process ensured fair and equal treatment of all bidders. The IE and the Commission Staff were involved throughout the process from the development of the RFP and pro forma PPAs through the evaluation of bids and negotiations between the Company and the Winning Bidders. The use of the IE web site for questions and comments regarding this RFP further ensured that the process was not only fair and equitable, but also transparent to all participants. Specifically, the April 29, 2010 IE report found the following:

> We believe the RFP draft documents are comprehensive and free of apparent bias for or against any bid type or technology sought, or any bidder anticipated to participate in this RFP. Further, we believe the RFP makes appropriate provisions to treat all bids when submitted, and the Company's expected self-build proposals, in an equivalent manner. The evaluation process also makes accommodations to treat bids of differing terms or expected useful remaining lives on an equal basis. The RFP clearly describes the preferred products sought by the Company and the minimum requirements a bid must meet in order to be considered. The RFP terms, such as pricing structure, creditworthiness, transmission access, and reliability, are equally applicable to all bidders.

The evaluation process involved a thorough analysis of the market options available in the 2015 period. The analysis was consistent and fair to all parties. The combination of the resources identified for certification represents the best cost options available for meeting Georgia Power's capacity needs in 2015. Therefore, the Company requests that the Commission certify the four PPAs identified through the 2015 RFP and grant the Company cost recovery as described above.

Appendix A
Additional Load Forecast Information

Executive Summary

A twenty-year forecast of energy sales and peak demand was developed to meet the planning needs of Georgia Power. The Budget 2011 forecast includes the retail classes of residential, commercial, industrial, MARTA, and governmental lighting and the wholesale class, the City of Hampton. The baseline forecast was begun in the spring of 2010 and completed in the winter of 2011.

Economics

Unlike previous recessions in which national economic growth significantly exceeds the long-term trend during the recovery and early expansion phases of the business cycle, the period following the recession of 2007-2009, for the most part, has been one of moderate growth in output and employment. Most economic forecasts predict that this pattern will continue for several more quarters.

Georgia's economy has also behaved atypically both during and following the recession. While Georgia had been one of the better performers in the nation in the period leading up to the recession, during the recession the state's performance was only average at best, and the recovery period, thus far, has not been strong enough to elevate the state to its pre-recession economic status.

One area where the state continued to outpace the nation through the recession, and is anticipated to continue to do so in the future, is demographics. Strong population growth, in turn, drives the demand for new homes and new business formation. Georgia's population growth rate, at 2.0% per year or better leading up to the recession, was more than double the national rate. The Census estimate released in February 2011 showed that the state's population growth rate fell to 1.0% in the twelve months ending July 2010. The assumptions underlying Budget 2011 project an annual population growth rate of **REDACTED**% over the 2010 – 2020 period in Georgia.

Additional Load Forecast Information

Forecast Assumptions and Methods

The Budget 2011 forecast for Georgia Power was developed through a joint effort of Georgia Power and Southern Company Services (SCS).

The economic forecast gives a description of the economy for the next twenty years. This description defines many elements of the economy such as population, employment, gross state product, and industrial production. Key demographic and economic variables have been demonstrated to be significant drivers of energy consumption. Price projections of alternative fuels that energy consuming devices use to support a consumer need, business purpose, or industrial process are also developed so that consumer and business choices regarding space conditioning and appliances can be modeled.

The long-term energy models used for the major classes are end-use models. Georgia Power uses the Residential End-Use Planning System (REEPS) model for the residential class, the Commercial End-Use Model (COMMEND) for the commercial class, and Industrial End-Use Forecasting Model (INFORM) for the industrial class. Governmental lighting, MARTA, and wholesale sales are forecast using econometrics, time series methods, and information from Georgia Power field personnel.

Short-term energy models are based on econometric regression models developed for the residential, commercial and industrial energy classes. The models use economic (output, income, employment, industrial production), weather (heating and cooling degree days), and other variables (binary). All models are selected on the basis of best fit to recent historical energy use.

Appendix A
Additional Load Forecast Information

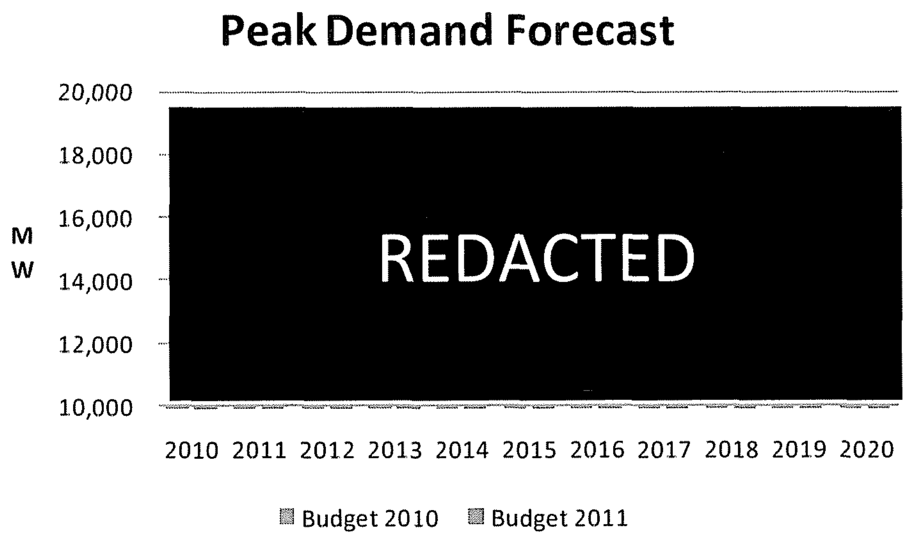
PUBLIC DISCLOSURE

Annual Summary
Georgia Power Company
Budget 2011 Load and Energy Forecast

	Retail Sales (GWh)						Wholesale Sales (GWh)	Territorial		
Year	Res	Com	Ind	Gov L	MARTA	Total Retail	Hampton	Territorial Requirements (GWh)	Territorial Supply (GWh)	Peak Demand (MW)
2011	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2012	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2013	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2014	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2015	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2016	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2017	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2018	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2019	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2020	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2021	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2022	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2023	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

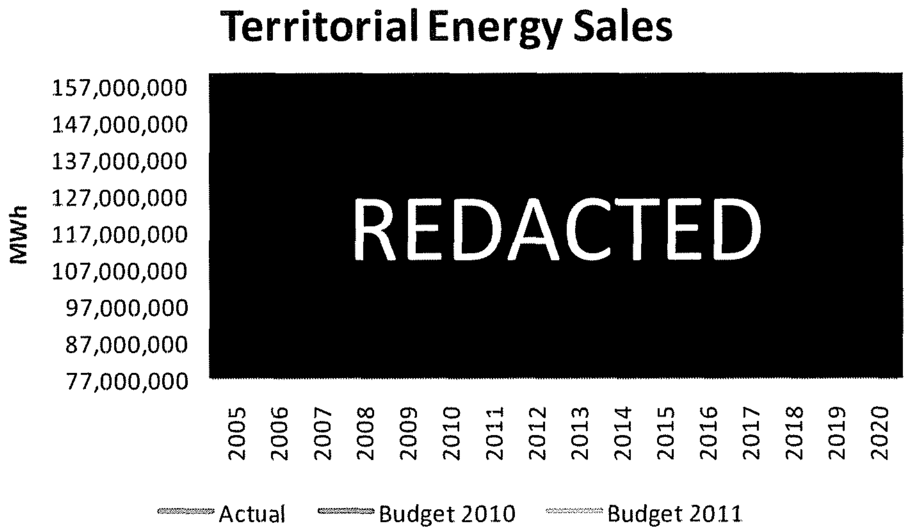
Appendix A
Additional Load Forecast Information

Peak Demand



The Budget 2011 forecast of peak demand has **REDACTED** compared with the Budget 2010 projection. The **REDACTED** reflects a **REDACTED** in commercial energy sales projections as well as **REDACTED** effects of demand side management programs. In Budget 2011, peak demand is expected to grow **REDACTED** percent per year from 2010 through 2020. Budget 2010 had peak demand growth averaging **REDACTED** percent per year.

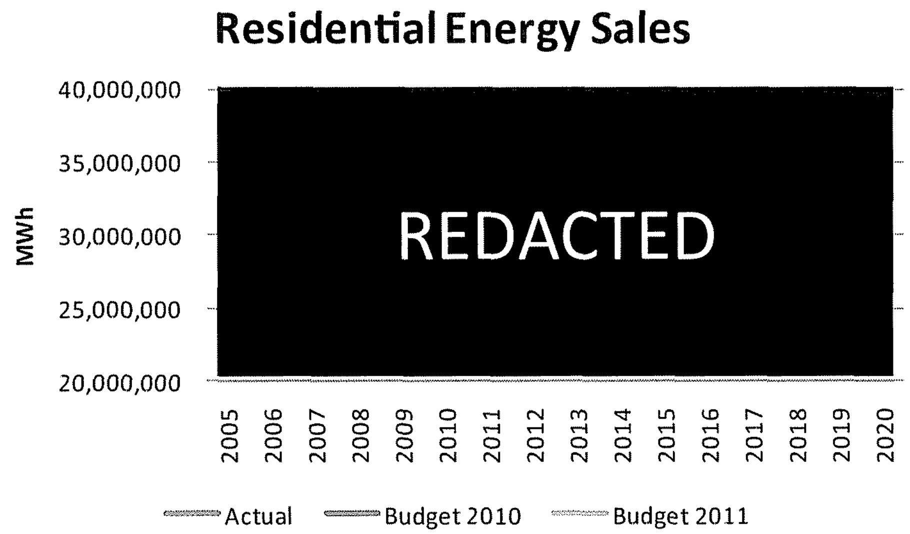
Territorial



Time Period	CAGR	AAG
Act '00 - '10	REDACTED	REDACTED
B10 '10 - '20	REDACTED	REDACTED
B11 '10 - '20	REDACTED	REDACTED

The medium-term Budget 2011 territorial energy sales forecast is, on average, very close to last year's view. In the longer run, territorial sales in Budget 2011 gradually fall below Budget 2010 as new energy efficiency programs, especially in the commercial sector, ramp up. Energy sales growth over the next ten years is expected to grow at a CAGR of **REDACTED** percent per year for an annual average growth (AAG) of **REDACTED** in Budget 2011 compared with **REDACTED** percent CAGR in Budget 2010.

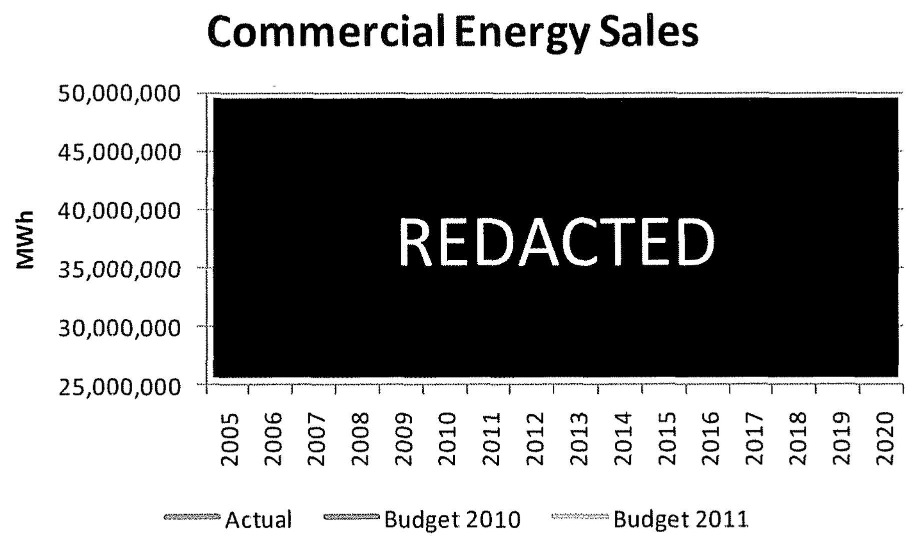
Retail – Residential



Time Period	CAGR	AAG
Act '00 - '10	REDACTED	REDACTED
B10 '10 - '20	REDACTED	REDACTED
B11 '10 - '20	REDACTED	REDACTED

The Budget 2011 residential sales forecast has increased slightly. Growth is now projected to average **REDACTED** percent per year compared with the previous view of **REDACTED** percent per year. The improvement reflects higher near-term growth in personal income, slightly lower price elasticity effects and energy efficiency programs.

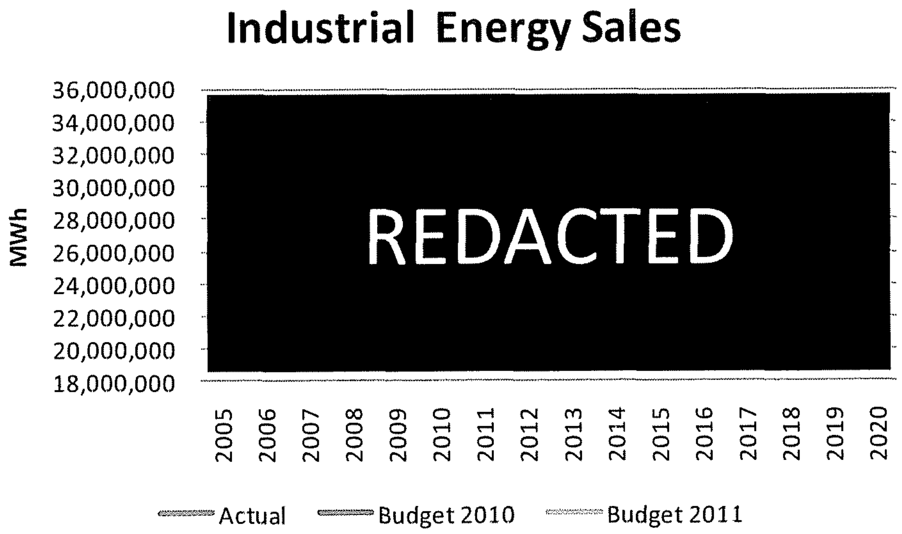
Appendix A
Additional Load Forecast Information
Retail – Commercial



Time Period	CAGR	AAG
Act '00 - '10	REDACTED	REDACTED
B10 '10 - '20	REDACTED	REDACTED
B11 '10 - '20	REDACTED	REDACTED

The Budget 2011 commercial energy sales forecast is significantly below the Budget 2010 forecast in later years. The Budget 2011 growth rate averages **REDACTED** percent per year while the Budget 2010 rate is **REDACTED** percent annually. The change reflects a weaker gross state product growth rate in the Budget 2011 forecast as well as substantially larger forecast adjustments related to the certified energy efficiency programs for commercial enterprises.

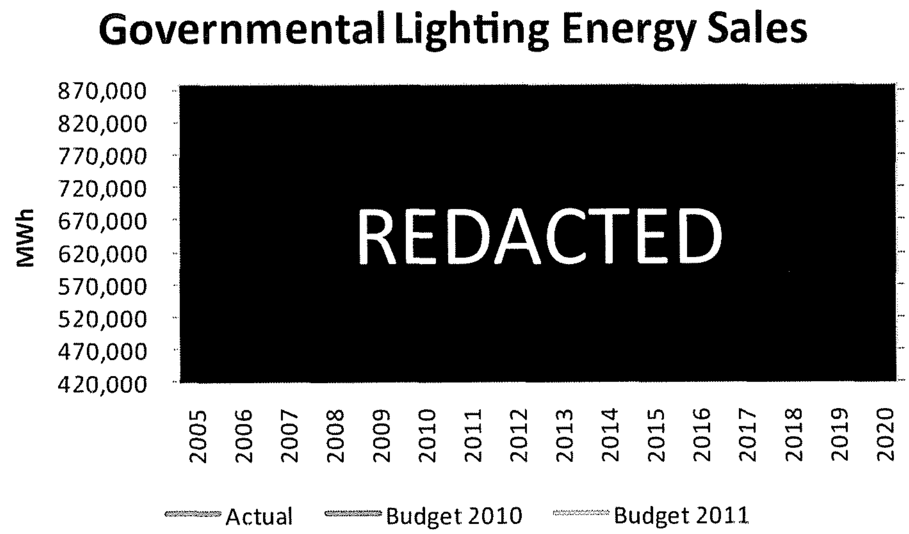
Appendix A
Additional Load Forecast Information
Retail – Industrial



Time Period	CAGR	AAG
Act '00 - '10	REDACTED	REDACTED
B10 '10 - '20	REDACTED	REDACTED
B11 '10 - '20	REDACTED	REDACTED

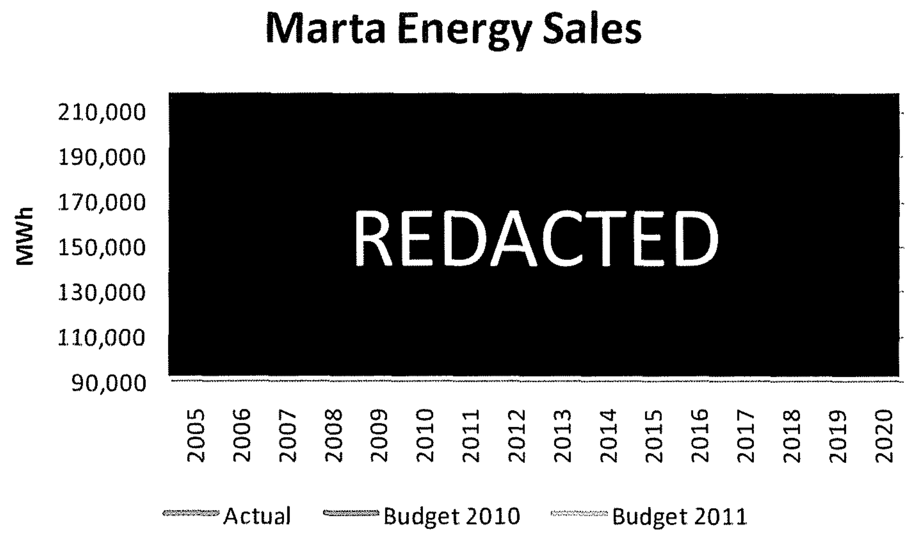
The level of industrial energy sales is higher in the Budget 2011 forecast than in Budget 2010 Actual. Industrial energy sales in 2010 were significantly higher than expected in the Budget 2010 view. As a result, the jumping off point for growth rate calculations is higher in Budget 2011, but the resulting growth rate of **REDACTED** percent per year for Budget 2011 through 2020 is lower than the growth rate in the Budget 2010 forecast, which was **REDACTED** percent per year.

Appendix A
Additional Load Forecast Information
Retail – Governmental Lighting



Time Period	CAGR	AAG
Act '00 - '10	REDACTED	REDACTED
B10 '10 - '20	REDACTED	REDACTED
B11 '10 - '20	REDACTED	REDACTED

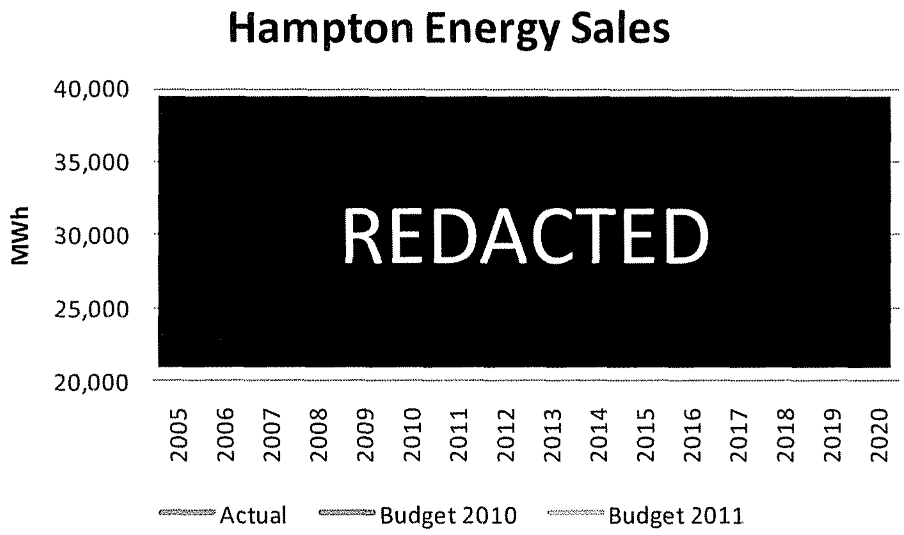
The level of governmental lighting energy sales is slightly lower in the Budget 2011 forecast than in Budget 2010. Governmental lighting energy sales in 2010 were slightly lower than expected in the Budget 2010 view and caused a lower starting point for Budget 2011. The resulting growth rate of **REDACTED** percent per year for Budget 2011 - through 2020 is higher than the growth rate in the Budget 2010 forecast, which was **REDACTED** percent per year.



Time Period	CAGR	AAG
Act '00 - '10	REDACTED	REDACTED
B10 '10 - '20	REDACTED	REDACTED
B11 '10 - '20	REDACTED	REDACTED

The level of the MARTA forecast has decreased significantly from Budget 2010 to Budget 2011. MARTA energy sales in 2010 were significantly lower than expected in Budget 2010. Due to the lower jumping off point for the growth rate calculation, the growth rate has increased slightly from **REDACTED** percent per year in Budget 2010 to **REDACTED** percent per year in Budget 2011.

Wholesale – Hampton



Time Period	CAGR	AAG
Act '00 - '10	REDACTED	REDACTED
B10 '10 - '20	REDACTED	REDACTED
B11 '10 - '20	REDACTED	REDACTED

The level of Hampton energy sales is slightly lower in the Budget 2011 forecast than in Budget 2010. Hampton energy sales in 2010 were slightly higher than expected in the Budget 2010 view. While Hampton continues to experience healthy growth, the resulting growth rate of **REDACTED** percent per year for Budget 2011 through 2020 is lower than the growth rate in the Budget 2010 forecast, which was **REDACTED** percent per year.

Environmental Compliance Strategy

Update for 2011

Georgia Power Company

August 2011

FORWARD-LOOKING STATEMENT CAUTIONARY NOTE

Much of the information contained in this report is forward-looking information based on current expectations and plans that involve risks and uncertainties. Some of the forward-looking information relates to scenarios that seek to predict future environmental rules and regulations, Georgia Power Company's (Georgia Power's) ability to address those rules and regulations in a cost-effective manner, solutions for addressing such rules and regulations, costs involved in addressing those rules and regulations, and continued economic growth in Georgia Power's service territory. Georgia Power cautions that there are certain factors that can cause actual results to differ materially from the forward-looking information that has been provided. The reader is cautioned not to put undue reliance on this forward-looking information, which is not a guarantee of future performance and is subject to a number of uncertainties and other factors, many of which are outside the control of Southern Company and its affiliates; accordingly, there can be no assurance that such suggested results will be realized.

The following factors, in addition to those discussed in Georgia Power's Annual Report on Form 10-K for the year ended December 31, 2010 and subsequent securities filings, could cause results to differ materially from management expectations as suggested by such forward-looking information: the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, and also changes in environmental, tax and other laws and regulations to which Georgia Power is subject, as well as changes in application of existing laws and regulations; current and future litigation, regulatory investigations, proceedings or inquiries, variations in demand for electricity and gas, including those relating to weather, the general economy, and population and business growth (and declines); available sources and costs of fuels; ability to control costs; advances in technology; state and federal rate regulations and the impact of pending and future rate cases and negotiations; internal restructuring or other restructuring options that may be pursued; potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Georgia Power; the ability to obtain new short and long-term contracts with neighboring utilities; the direct or indirect effect on Georgia Power's business resulting from terrorist incidents and the threat of terrorist incidents; interest rate fluctuations and financial market conditions and the results of financing efforts, including Georgia Power's credit ratings; the ability to obtain additional generating capacity at competitive prices; and catastrophic events such as fires, floods, hurricanes, earthquakes or other similar occurrences. Georgia Power expressly disclaims any obligation to update any forward-looking information.

ENVIRONMENTAL COMPLIANCE STRATEGY
CONTENTS

1.0 Southern Company Environmental Compliance Strategy and Overview

Overview

The Environmental Compliance Strategy serves as a roadmap for compliance for Georgia Power Company ("Georgia Power" or the "Company" or "GPC") and the other retail affiliates. This roadmap establishes a general direction but allows for individual decisions to be made based upon specific information available at the time. This approach is an absolute necessity in maintaining the flexibility to match a dynamic regulatory compliance environment with a variety of available compliance options. This document addresses recent environmental rulings and requirements and reflects the most recent strategy and cost estimates for incorporating these requirements.

Southern Company completed its initial Clean Air Act Amendments (CAAA) strategy in December 1990 and has produced updates or reviews in subsequent years. The information contained in this document includes the annual Environmental Compliance Strategy review for 2011 and updates for compliance with the Clean Air Act (CAA), Clean Water Act (CWA), Resource Conservation and Recovery Act (RCRA), and other environmental statutes and regulations.

Through 2010, Southern Company has invested approximately $8.1 billion (approximately $3.7 billion for GPC) in capital projects to comply with applicable environmental statutes, including the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; and the Endangered Species Act. These investments include annual totals of $500 million, $1.3 billion, and $1.6 billion for 2010, 2009, and 2008, respectively. GPC's annual totals have been $217 million, $440 million, and $689 million for 2010, 2009, and 2008, respectively. Southern Company expects that capital expenditures to assure compliance with existing environmental regulations will be an additional $341 million, $427 million, and $452 million for 2011, 2012, and 2013, respectively. For GPC, this amounts to $73 million, $79 million, and $58 million for 2011, 2012, and 2013, respectively.

In addition, Southern Company currently estimates that potential incremental investments to comply with anticipated new environmental regulations could range from $74 million to $289 million in 2011, $191 million to $670 million in 2012, and $476 million to $1.9 billion in 2013. The Company's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of any new or revised environmental statutes and regulations that are enacted, including the proposed environmental legislation and regulations described below; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix.

A summary and overview of the Southern Company environmental compliance program is provided below:

- Between 1990 and 2010, Southern Company environmental investments have reduced NO_X emissions by approximately 70 percent and have reduced SO_2 emissions by more than 72 percent. Over the same time period, GPC investments have reduced NO_X and SO_2 emissions by approximately 75 percent.

- Southern Company has installed 16 selective catalytic reduction systems (SCRs), representing more than 11,600 megawatts (about 6,000 megawatts for GPC) or approximately 50 percent of the coal generating capacity system-wide. SCRs are currently installed and operating at the following Georgia Power plants:
  - Plant Bowen, Units 1, 2, 3, and 4
  - Plant Hammond, Unit 4
  - Plant Wansley, Units 1 and 2
  - Plant Scherer, Unit 3

- Over the next few years, additional units will have SCRs installed to further reduce NO_X emissions below today's levels. The SCR projects at Branch Units 3 and 4 and Yates Units 6 and 7 have been deferred until more information is available from the on-going environmental rulemakings discussed in Section 2. The company is currently constructing or planning additional SCRs at:
  - Plant Branch, Units 3 and 4 (deferred)(GPC)
  - Plant Scherer, Units 1 and 2 (GPC)
  - Plant Yates, Units 6 and 7 (deferred)(GPC)

- Southern Company has installed flue gas desulfurization devices (scrubbers or FGDs) on 25 units, representing more than 11,000 megawatts (more than 6,000 MWs for GPC). Scrubbers are currently installed and operating at the following Georgia Power units:
  - Plant Bowen, Units 1, 2, 3 and 4
  - Plant Hammond, Units 1, 2, 3 and 4 (single scrubber vessel)
  - Plant Wansley, Units 1 and 2
  - Plant Yates, Unit 1
  - Plant Scherer, Unit 3

- Over the next few years, additional units will get scrubbers to further lower SO_2 emissions below today's levels. The scrubber projects at Branch Units 3 and 4 and Yates Units 6 and 7

have been deferred until more information is available from the on-going environmental rulemakings discussed in Section 2. The Company is currently constructing or planning additional scrubbers at:
- Plant Branch, Units 3 and 4 (single scrubber vessel; deferred)
- Plant Scherer, Units 1 and 2
- Plant Yates, Units 6 and 7 (deferred)

- Georgia Power has installed and is operating baghouses with activated carbon injection on Plant Scherer Units 1, 2, and 3. These projects represent more than 2,400 megawatts.
- These Southern Company emission controls and the associated expenditures are based on compliance requirements with rules including the Phase II of the 1990 Clean Air Act Acid Rain program (requiring SO_2 reductions); the 1-hour and 8-hour standard for ozone and accompanying state implementation plans for further NO_X reductions; the regional NO_X trading program; rules for implementing the 1997 and 2006 fine particulate matter standards, (resulting in additional SO_2 reductions); the Clean Air Interstate Rule; and the Clean Air Visibility Rule– addressing both SO_2 and NO_X reductions to improve air quality in the national parks.
- The combination of baghouses, SCRs, and scrubbers has reduced Southern Company 2010 mercury emissions by over 50% from 2005 levels.

The following graphic (Fig. 1-1) summarizes historical and projected emission reductions, generation increases and environmental capital costs.

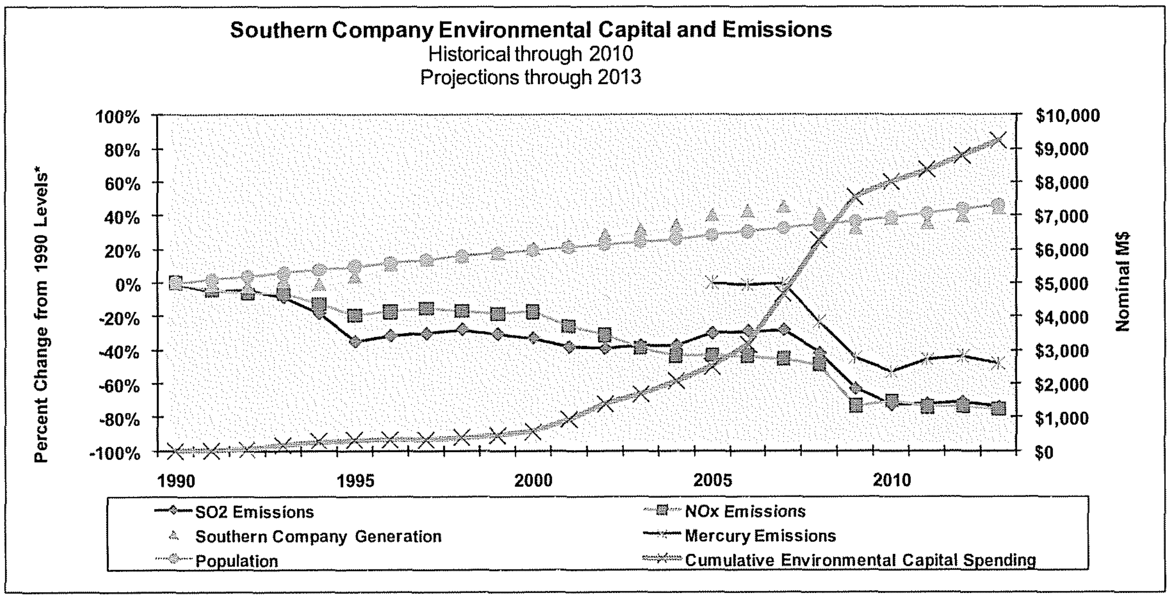


Figure 1-1 Southern Company Emissions and Environmental Capital Expenditures (Emission Estimates are based on 2011 Energy Budget Projections)

*For mercury, the percent change is from 2005, when CAMR was finalized.

- Southern Company has established a significant record of voluntary CO_2 reductions, beginning in the mid-1990s. Southern Company was a charter participant in the Department of Energy (DOE) Climate Challenge Program. Since the DOE program ended in 2005, Southern Company has continued with its voluntary CO_2 reduction programs and has reduced or avoided 268 million metric tons of CO_2 through 2010 under guidelines of that program. The company has achieved significant improvements in nuclear availability and generation, developed an extensive demand-side management program, increased natural gas generation, and reduced SF_6 emissions by approximately 85 percent through 2010.

- Southern Company is also focused on developing both advanced coal technology and the next generation of nuclear power, including Georgia Power's development of two new nuclear units at Plant Vogtle.

- Southern Company has invested $8 million over the last 5 years in renewable energy research, examining biomass, wind, and solar options.

The following graphics show Southern Company's and Georgia Power's historical and projected emissions for SO_2 (Fig. 1-2), NO_X (Fig. 1-3), mercury (Fig. 1-4), and carbon dioxide (Fig. 1-5). Note the units of measure on the vertical (y-axis) for each graphic, because they vary with the emissions.

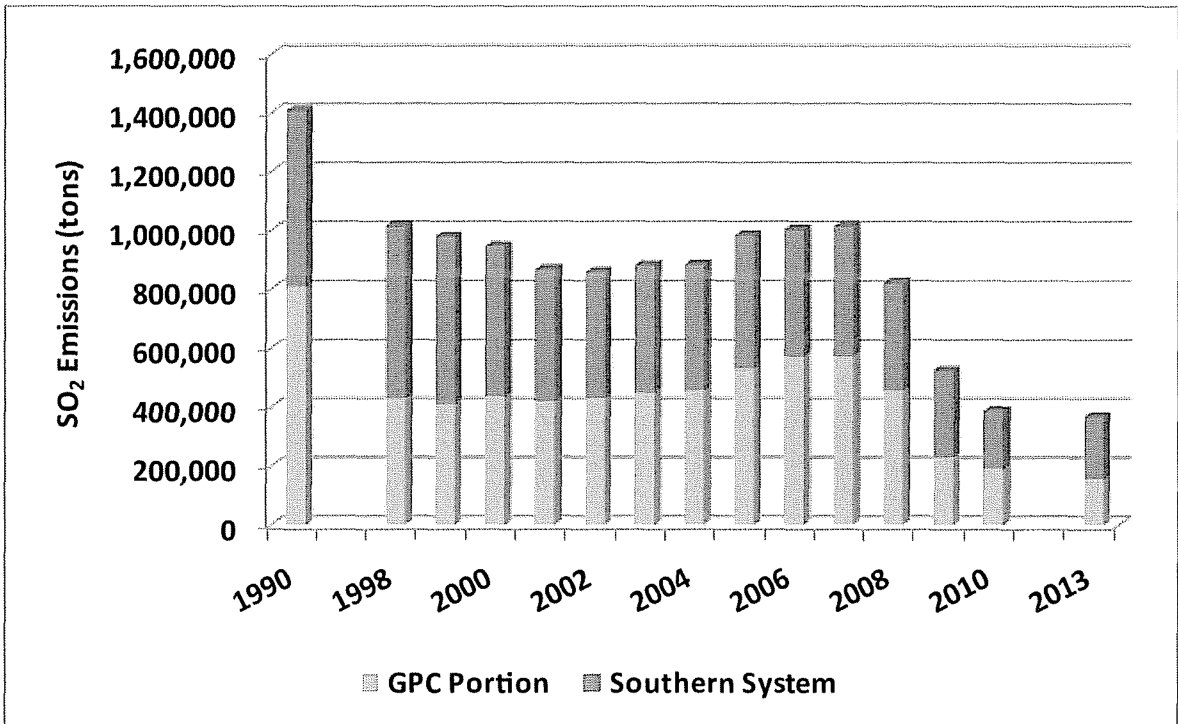


Figure 1-2 Historical and Projected SO_2 Emissions for Southern Company and GPC

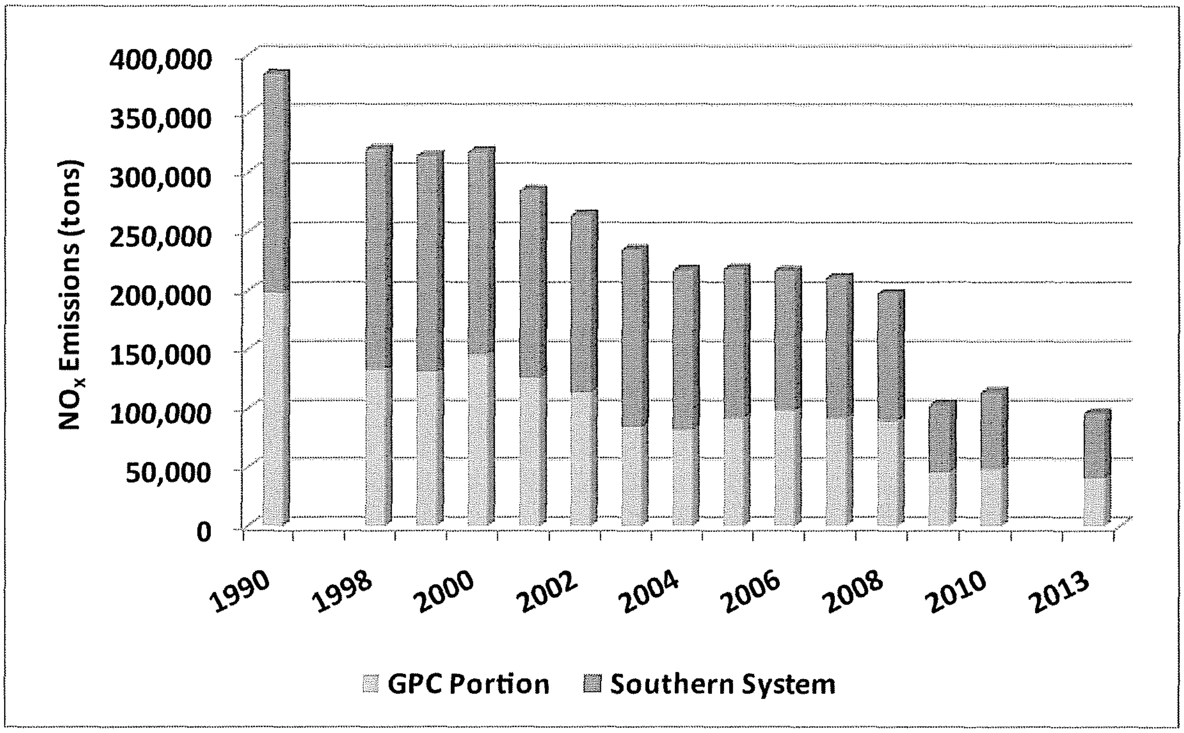


Figure 1-3 Historical and Projected NO_X Emissions for Southern Company and GPC

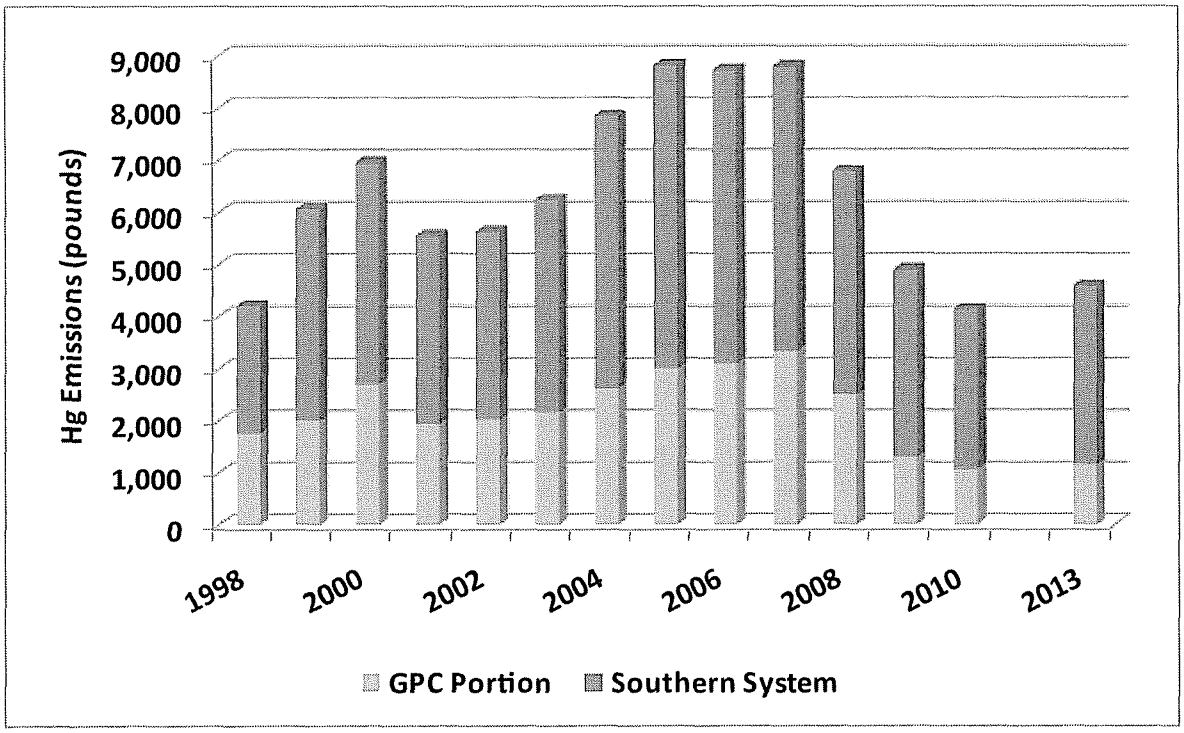


Figure 1-4 Historical and Projected Mercury Emissions for Southern Company and GPC

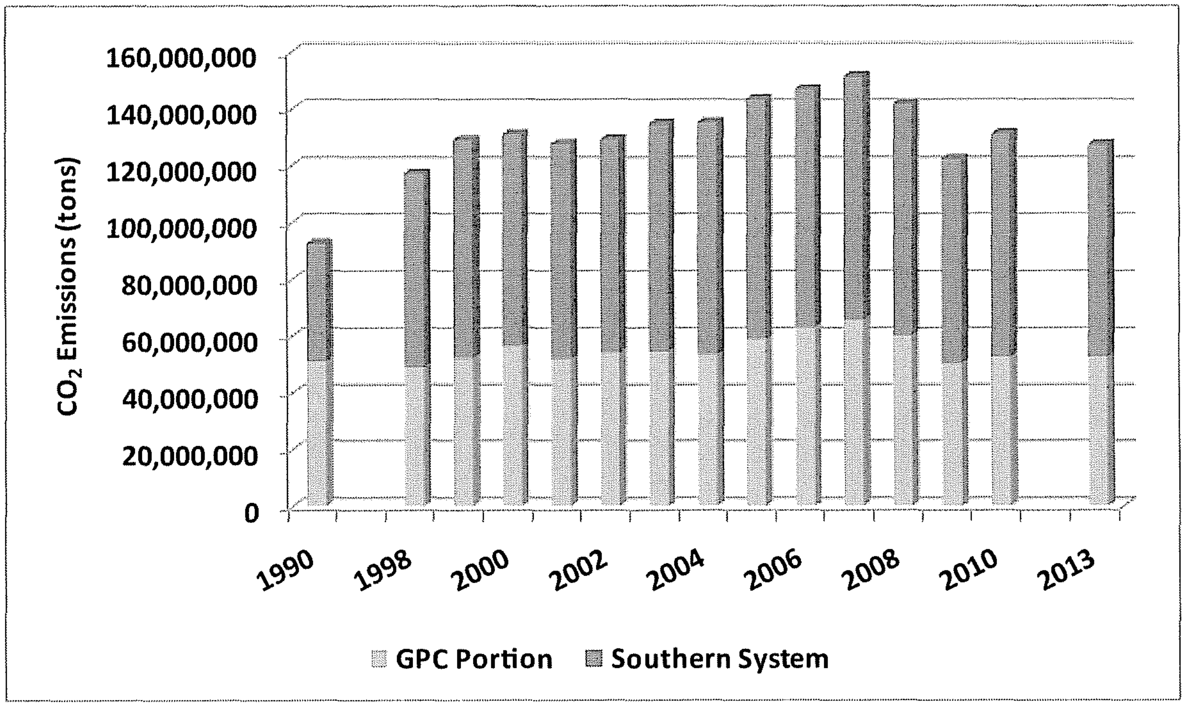


Figure 1-5 Historical and Projected CO_2 Emissions for Southern Company and GPC

Notable Regulatory Events

The following is a list of notable regulatory events over the past five years:

- **June 2007** - Georgia EPD finalizes the Georgia Rule (sss) for Multi-pollutant Control for Electric Utility Steam Generating Units (Georgia Multi-pollutant Rule)
- **July 2007** – D.C. Court of Appeals vacates the Industrial/Commercial/Institutional Boilers and Process Heaters (Industrial Boiler) Maximum Achievable Control Technology (MACT) rule.
- **February 2008** – D.C. Court of Appeals vacates Clean Air Mercury Rule (CAMR).
- **March 2008** – EPA finalizes new 8-hr ozone standard at 0.075 ppm.
- **July 2008** – D.C. Court of Appeals vacates Clean Air Interstate Rule (CAIR).

- **December 2008 –** D.C. Court of Appeals stays mandate vacating CAIR while EPA promulgates a new rule. CAIR remains in place.

- **January 2009** – NO_X compliance begins under CAIR.

- **January 2009** - Georgia EPD finalizes the Georgia Rule (uuu) for SO_2 Emissions from Electric Utility Steam Generating Units.

- **February 2009** – D.C. Court of Appeals remands 2006 Annual and Secondary fine particulate matter standards to EPA for reconsideration.

- **March 2009** – EPA issues Information Request Letter on the Structural Integrity of Coal Combustion Byproducts in Surface Impoundments to the electric utility industry.

- **March 2009** – U.S. Supreme Court rules that cost-benefit analysis can be used by EPA in a 316(b) rule.

- **September 2009** – EPA announces reconsideration of 2008 8-hr ozone standard and proposes greenhouse gas regulation for stationary sources.

- **October 2009** – EPA releases draft Information Collection Request for future Steam Electric Industry Effluent Guidelines rulemaking.

- **October 2009** – EPA finalizes nonattainment designations for 2006 24-hour fine particulate matter standard.

- **November 2009** – EPA proposes to revise the primary SO2 standard, recommending a new 1-hr standard in the range of 50-100 ppb.

- **December 2009** – EPA issues an "endangerment finding" for motor vehicles which formally determines that six greenhouse gases taken in combination endanger both the public health and public welfare.

- **January 2010** – EPA releases final Information Collection Request for future coal- and oil-fired electric utility steam generating units (EGU) MACT rulemaking.

- **January 2010** – EPA announces a proposed revision to the 8-hr ozone standard, lowering the level from 0.075 ppm to a level in the range 0.060 to 0.070 ppm.

- **January 2010 –** EPA promulgates new NO_2 1-hour 100 ppd standard
- **May 2010** – EPA announces a proposed rule regulating Coal Combustion Byproducts under RCRA.
- **May 2010** – EPA releases Tailoring Rule that applies to CO_2 and other GHGs
- **June 2010** – EPA announces the proposed Transport Rule as a successor to CAIR.
- **June 2010 –** EPA promulgates new SO2 1-hour 75 ppd standard
- **January 2, 2011** – Phase I of Tailoring Rule applying to new and modified sources
- **February 2011** – EPA finalizes MACT rule for Industrial Boilers.
- **March 2011 –** EPA signs Utility MACT Proposal
- **March 2011 –** EPA signs 316(b) Proposal
- **July 2011** – EPA releases final Cross State Air Pollution Rule

Section 2 includes a more detailed explanation of each of these events.

2.0 Regulatory, Legislative, and Judicial Review

Environmental compliance and regulation for Georgia Power Company (GPC) and all of Southern Company are principally governed by the Environmental Protection Agency (EPA), the State of Georgia Environmental Protection Division (EPD), and other state and local authorities.

2.1 Major U.S. Environmental Laws

Clean Air Act (CAA)
The portions of the 1990 Clean Air Act Amendments (CAAA) that impact the electric utility industry most directly are:

- Title I, National Ambient Air Quality Standards
- Title III, Air Toxics
- Title IV, Acid Rain
- Title V, Permits

The heart of the CAA is the National Ambient Air Quality Standards (NAAQS or "standards"). The Act requires that the U.S. EPA determine what level of six specific pollutants (ozone, particulate matter, sulfur dioxide, lead, carbon monoxide, and nitrogen dioxide) in the ambient (outside) air is protective of human health with a margin of safety. Areas of the country where levels of these pollutants exceed the NAAQS are known as "nonattainment" areas. States must develop State Implementation Plans (SIPs) with control strategies designed to bring these areas into attainment. EPA is required to review the NAAQS every five years, and update them if necessary. In addition, the CAA authorizes EPA to issue regulations necessary to prevent emissions in one or more states from contributing to nonattainment in other states. EPA has issued two sets of rules for this purpose, applicable to Southern Company units – the NO_x Budget Trading Rule (NO_x SIP Call), and the CAIR, and has recently finalized the Cross-State Air Pollution Rule (as a replacement to CAIR).

Title III of the CAAA regulates Hazardous Air Pollutants (HAPs) and requires Maximum Achievable Control Technology(MACT). EPA signed a proposed rule for Utility MACT on March 16, 2011. The proposed rule is schedule to be finalized under consent decree on November 16, 2011 and would impose stringent hazardous air pollutant (HAPs) emission limits from coal- and oil-fired electric generating units.

The 1990 Amendments added the Acid Rain Program (Title IV). This program required reductions in the emissions of sulfur dioxide and nitrogen oxides which can lead to the deposition of acid rain. The Acid Rain Program had the most immediate impact on Southern Company and the electric utility industry following the 1990 amendments.

Clean Water Act (CWA)
The CWA prohibits the discharge of pollutants into waters of the United States except in compliance with the Act. Authority to discharge pollutants under the CWA may be granted through a National Pollutant Discharge Elimination System (NPDES) permit issued by EPA or a state under a delegation of authority from EPA. The NPDES program is used as a means of achieving and enforcing technology-based and water quality-based effluent limitations.

EPA has established "effluent limitations guidelines" for the steam electric industry and other industrial source categories based on treatment technologies. EPA is responsible for periodically reviewing and updating these effluent limitations guidelines, which serve as the basis of the technology-based permit limits that appear in individual NPDES permits.
On September 15, 2009, EPA announced its intention to revise the effluent limitations guidelines after collecting additional information from the electric utility industry in 2010.

Section 316(b) of the CWA, which regulates cooling water intake structures, is implemented through NPDES permits. The Section 316(b) regulations are intended to protect fish and other aquatic species in the vicinity of utility cooling water intake structures. The focus of Section 316(b) is to ensure that the location, design, construction, operation, and capacity of cooling water intake structures reflect the best technology available to protect aquatic organisms from being impinged or entrained.

Resource Conservation and Recovery Act (RCRA)
This law governs the generation, transportation, treatment, storage and disposal of solid and hazardous waste. A major focus for electric utilities has been regulatory treatment of coal ash and other coal combustion residuals (CCRs) under RCRA, and potential regulations affecting their management and disposal. In response to a December 2008 spill at a TVA facility, Congress and EPA are currently reviewing whether CCRs and ash ponds should be subject to federal regulation under RCRA.

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Key Environmental Dates

A summary of key environmental dates is provided below.

Summary of Upcoming Environmental Regulatory Dates

- **Summer 2011** – EPA expected to propose revised $PM_{2.5}$ standard.
- **Late 2011** – EPA expected to finalize reconsidered 8-hour ozone standard.
- **November 2011** – Deadline for final Utility MACT rule.
- **Fall 2011** – EPA expected to propose performance standards and guidelines for GHGs.
- **January 2012** – Begin compliance with Cross-State Air Pollution Rule.
- **Early 2012** – EPA expected to publish proposed Cross-State Air Pollution Rule #2
- **May 2012** – EPA expected to finalize GHG performance standards and guidelines
- **July 2012** – Deadline for final 316(b) Rule
- **July 2012** – EPA expected to publish a proposed rule for Effluent Guidelines
- **Late 2012** – EPA expected to publish a final rule for the management and disposal of CCRs for the utility industry.
- **2012** – Attainment designation for criteria air pollutants: NO_2, SO_2, and Ozone

These federal rules and their impact to our operations are discussed in more detail below.

2.2 Acid Rain Program

For almost twenty years, Southern Company has been planning and implementing measures to comply with the requirements of the Title IV Acid Rain provisions of the 1990 CAAA.

Reductions in SO_2 and NO_X under the program were required in two phases – Phase I, beginning in 1995 and Phase II, beginning in 2000. Under the program, EPA issues emissions allowances for SO_2 and requires that regulated units demonstrate that they have sufficient allowances to cover their SO_2 emissions for each year. The regulations also set limitations on NO_X emissions.

GPC has reduced overall SO_2 and NO_X emissions by roughly 75 percent since 1990. Compliance actions for SO_2 have included fuel switching to lower sulfur coals, installing and operating scrubbers at certain units, and purchasing, swapping, and banking SO_2 allowances.

At the end of 2010, the GPC SO_2 allowance bank totaled **REDACTED** tons. The operating companies purchase allowances to assure compliance when, and if, their banks are depleted. Emission allowance quantities are affected by many factors including regulations, fuel, plant operation and efficiency, outages, control technology, etc., which affect the rate at which the allowances are used.

For GPC, **REDACTED** tons of SO_2 allowances included in total above have been secured or purchase commitments made to date for compliance with the requirements of the CAAA. Under current Acid Rain regulations, projections show that no additional GPC SO_2 allowance purchases should be required through 2020, but this projection could change depending on environmental regulations, the price of natural gas, and generation requirements.

Additional controls have been announced and are currently being installed at several plants throughout the Southern system to further reduce SO_2 and NO_X emissions, maintain compliance with Acid Rain regulations, and assist with compliance with new requirements.

2.3 Ambient Air Quality Standards

The cornerstone of the CAA is attainment of the NAAQS for the following six pollutants: carbon monoxide; SO_2; nitrogen dioxide (NO_2); ozone; lead; and particulate matter. While the CAA has not been significantly amended since 1990, EPA's implementation of the Act and related court determinations continue to evolve. The CAA specifically requires the EPA to review the primary health-based NAAQS every 5 years. These reviews have resulted in multiple, significant changes to the ozone and particulate matter NAAQS beginning in 1997. Implementing these standards is generally a state responsibility; however, the EPA has also issued rules, such as the NO_x SIP Call, CAIR, and the Cross-State Air Pollution Rule, that deal with the transport of pollutants on a regional or multi-state basis to facilitate attainment with the NAAQS.

Ozone

NO_X emissions from power plants and other sources combine with volatile organic compounds on hot days to form ozone. Ambient air quality standards for ozone, which are set at levels designed to protect the public health, have been in place for decades. In 1997, EPA issued the first 8-hour ozone standard and in 2004-2005, the EPA revoked the old 1-hour ozone standard that had been in place since 1979. Areas within Southern Company's service area that were designated as nonattainment under the 8-hour ozone standard included Birmingham (Alabama), Macon (Georgia), and a 20-county area within metropolitan Atlanta. Birmingham was redesignated to attainment with the 8-hour ozone standard by EPA on June 12, 2006, and EPA subsequently approved a maintenance plan for the area to address future exceedences of the standard. Macon was redesignated as attaining the standard on October 19, 2007.

The Georgia EPD issued a maintenance plan for the Macon area that set more restrictive Ozone Season NO_X emissions limits for Plant Scherer. On June 23, 2011, the EPA finalized a determination of clean data for the Atlanta nonattainment area. This action suspends the requirement for the State of Georgia to submit an attainment demonstration and associated reasonably available control measures (RACM) analyses, reasonable further progress (RFP) plans, contingency measures, and other planning State Implementation Plans (SIPs) related to attainment of the 1997 8-hour ozone NAAQS for the Atlanta Area for as long as the Area continues to meet the 1997 8-hour ozone NAAQS.

On March 12, 2008, EPA issued a final rule to establish a more stringent 8-hour ozone standard, setting the standard at 0.075 ppm. In March 2009, state agencies provided recommendations to EPA that a number of counties in the Southern Company service territory be designated nonattainment for the 2008 ozone ambient air quality standard, including several which had not previously been in nonattainment. Georgia EPD recommended the following counties for nonattainment designation:

- Atlanta Ozone Nonattainment Area (21 counties): Barrow, Bartow, Carroll, Cherokee, Clayton, Cobb, Coweta, DeKalb, Douglas, Fayette, Forsyth, Fulton, Gwinnett, Hall, Heard (partial), Henry, Newton, Paulding, Rockdale, Spalding, and Walton.
- Athens Ozone Nonattainment Area (1 county): Clarke.
- Augusta Ozone Nonattainment Area (1 county): Richmond.
- Columbus Ozone Nonattainment Area (1 county): Muscogee.
- Macon Ozone Nonattainment Area: Bibb and Monroe (partial).
- Murray County Ozone Nonattainment Area: Murray (partial).

However, on September 16, 2009 EPA announced its intent to reconsider the 2008 ozone standard. In January 2010, EPA announced it was considering a proposed revision to the 8-hour ozone standard, lowering the level from 0.075 ppm to a level in the range 0.060 to 0.070 ppm. A final reconsideration of the 2008 ozone NAAQS was expected by December 31, 2010 as agreed to by EPA under a court order. EPA received an extension of this deadline until July 2011, and EPA intended to release the final rule by July 29, 2011. However, on July 26, 2011, the EPA said that the agency would not meet the end of July date, and while they expect to sign a final rule soon, they didn't set a new deadline. The eventual outcome of a reconsidered standard and whether the D.C. Circuit Court will stay the existing rule and/or nonattainment designations is uncertain. However, a lower ozone NAAQS could lead to additional nonattainment areas within Southern Company's / GPC's service territory.

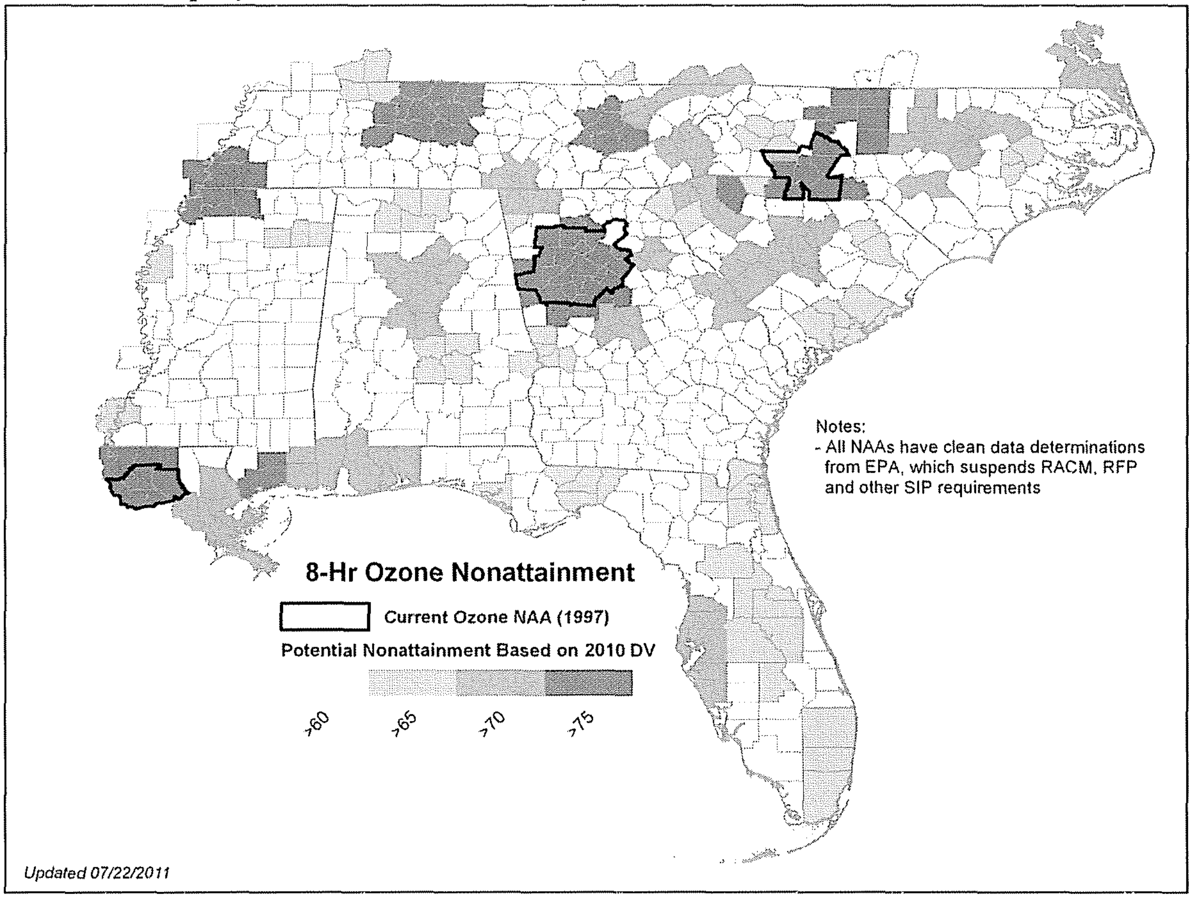

Figure 2.3-1 Potential Ozone Nonattainment Counties Under Proposed Standard

Particulate Matter

In 1997, the EPA established the first NAAQS for fine particulate matter (PM2.5), setting the annual standard at 15 µg/m3 and the 24-hour PM2.5 standard at 65 µg/m3. During 2005, the EPA's 1997 fine particulate matter nonattainment designations became effective for several areas within Southern Company's service area in Georgia and Alabama, and the EPA published its final rule for implementation of the fine particulate matter standard in April 2007. Georgia EPD's proposed attainment demonstrations for Macon, Floyd, and Chattanooga nonattainment areas rely on SO_2 reductions from power plants, as required by Georgia Rules for Air Quality Control 391-3-1-.02(2)(uuu). Rule (uuu) requires 95% removal of SO2 by Bowen Units 2, 3, and 4, Wansley Units 1 and 2, and 90% removal of SO_2 from Yates Unit 1 while these units are operating scrubbers starting by January 1, 2010. Rule (uuu) requires similar reductions from other units that are installing scrubbers at future dates. On April 5, 2011, May 31, 2011, and June 2, 2011, the EPA issued final determinations of clean data for the Floyd County, Macon and Chattanooga nonattainment areas for achieving air quality that meet the 1997 annual standard, respectively. This action suspends the requirements for these Areas to submit attainment demonstrations planning SIPs related to attainment of the 1997 annual PM2.5 NAAQS as long as this Area continues to meet the 1997 annual PM2.5 NAAQS. Attainment demonstrations for each of these Areas have been submitted by Georgia EPD to the EPA. The Atlanta Area achieved attaining air quality in 2010, but EPA has not yet proposed a clean data determination for this Area. The Atlanta attainment demonstration was submitted by Georgia EPD to the EPA in 2010. This State Implementation Plan for Atlanta PM2.5 shows that emission controls, including requirements under Georgia Rule (uuu), will assure attainment with the current standard in 2013.

In September 2006, the EPA published a final rule that retained the primary standard for annual fine particulate matter, but increased the stringency of the 24-hour standard. In December 2008, the EPA designated the Birmingham, Alabama area as nonattainment for the 24-hour standard. A State Implementation Plan for this nonattainment area is due in 2012. No areas in Georgia were found to violate the 2006 24-hour fine particulate matter standard.

EPA's decision to retain the primary standard for annual fine particulate matter in its 2006 rulemaking was challenged in the United States Court of Appeals for the D.C. Circuit by environmental groups. In February 2009, the Court ruled that EPA failed to adequately explain why the annual standard was protective of human health, and remanded the rule back to the Agency for further action, but did not vacate the current standards. EPA is continuing its next review of the PM standards and is expected to propose another revision to the $PM_{2.5}$ NAAQS in October 2011. The following graphics (Fig. 2.3-2) shows counties in nonattainment for the 24-hour and annual $PM_{2.5}$ standards.

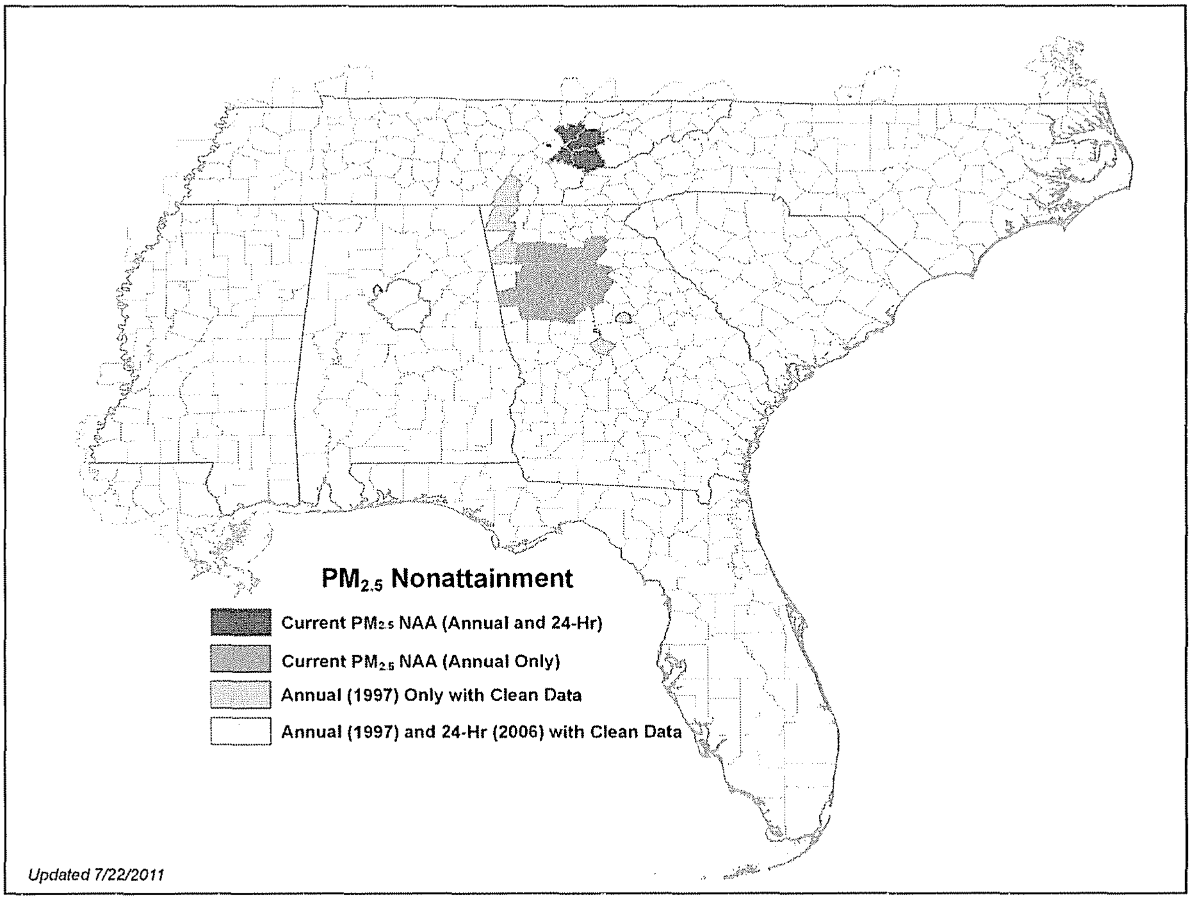

Figure 2.3-2 Nonattainment Areas for $PM_{2.5}$ NAAQS

NO_2 and SO_2

On April 12, 2010 and June 22, 2010, new short-term (1-hour) NAAQS for NO_2 and SO_2, respectively, became effective. The NO_2 standard was set at 100 ppb to be achieved at the 98th percentile level (i.e., 3-year average of the 8th highest of the daily 1-hour maximum concentrations). EPA intends to initially focus on monitoring of short-term peak concentrations which occur near major roadways and the rule imposes new roadside monitoring requirements in the urban areas with a population greater than 500,000. EPA's NO_2 nonattainment designations by EPA for this standard are expected to occur in January 2012.

The SO_2 standard was set at a level of 75 ppb. EPA has decided to implement the standard through a combination of monitoring and modeling. Initial nonattainment designations are expected to be made in June 2012 using monitoring data and any available refined modeling data for some sources. Additional nonattainment designations could follow based on additional modeling. Regardless of attainment status, EPA is requiring that all 110(a) infrastructure SIPS employ dispersion modeling of all significant SO2 sources in the state to determine whether their emissions contribute to modeled exceedances of the 1-hour standard. EPA will require that the state impose emission reductions from sources causing or contributing to exceedances of the standard to eliminate the modeled exceedances.

The impact of these standards on GPC cannot be determined at this time but will depend on the areas designated as nonattainment and the state implementation plans that follow these designations.

2.4 Regional NO_X SIP Call and Budget Trading Program

In September 1998, the EPA issued the final Regional NO_X SIP Call rule, which required 22 states and the District of Columbia (D.C.) to submit SIPs to address regional transport of the ozone precursor, NO_X. The rule requires NO_X emission reductions sufficient to meet specified emission budgets for each affected state.

The rule was challenged in the D.C. Circuit Court of Appeals but largely upheld by the Court. However, the Court vacated the rule for Georgia, Missouri, and Wisconsin. In April 2004, EPA reissued the NO_X SIP Call as applied to the northern two-thirds of Georgia and the eastern half of Missouri, in accordance with the Court's decision. Before issuance of the final rule, however, the two areas Georgia was determined to be impacting (Birmingham, Alabama and Memphis, Tennessee) came into attainment for the one-hour ozone standard. On this basis, the Georgia Coalition for Sound Environmental Policy petitioned EPA to reconsider the final rule. EPA granted that petition and stayed the 2004 NO_X SIP Call rule as applied to Georgia. Following reconsideration in April 2008, EPA issued a final rule rescinding the NO_X SIP Call as applied to Georgia. The State of North Carolina challenged this action in the D.C. Circuit, and a decision was reached by the Court on November 24, 2009. The Court found that North Carolina failed to demonstrate that including Georgia in the NO_X SIP Call would redress North Carolina's asserted injury and, therefore, North Carolina lacked standing. As a result, the Court dismissed North Carolina's petition, and the NO_x SIP call does not apply in Georgia.

2.5 CAIR/CSAPR

Clean Air Interstate Rule (CAIR)

The EPA issued the final CAIR in March 2005. CAIR was designed to reduce SO_2 and NO_X emissions that contribute to nonattainment of the ozone and fine particulate matter NAAQS in twenty-eight Eastern states. It is based on a cap-and-trade regulatory scheme for NO_x and SO_2 that requires sources to hold allowances equal to their emissions. Annual emission reductions were required in two phases, with the first phase of compliance set to begin in 2009 for NO_X (regional cap: 1.5 million tons or a reduction of approximately 50 percent from current emissions levels) and 2010 for SO_2 (regional cap: 3.6 million tons or a reduction of approximately 50 percent from current allocations). The second phase was scheduled for 2015 (regional cap: 1.3 million tons or a reduction of approximately 65 percent from current emissions levels for NO_X and 2.5 million tons or a reduction of approximately 70 percent from current allocations for SO_2). Alabama, Florida, Georgia, and Mississippi are affected for the fine particulate requirements, and power plants in these states are required to meet annual emission caps for SO_2 and NO_X. Alabama, Florida, and Mississippi, but not Georgia, are affected for the ozone season requirements, and power plants in these states are required to have allowances to meet new summer-season NO_X caps.

On July 11, 2008, in response to petitions brought by certain states and regulated industries challenging particular aspects of CAIR, the United States Court of Appeals for the District of Columbia Circuit issued a decision vacating CAIR in its entirety, and remanding it to EPA for further action consistent with its opinion. In December 2008, however, the U.S. Circuit Court amended its July decision in response to the rehearing petitions and remanded CAIR to EPA without vacatur, thereby leaving CAIR compliance requirements in place while EPA develops a revised rule.

Cross State Air Pollution Rule (CSAPR)

On July 7, 2011 EPA released the final Cross State Air Pollution Rule as a replacement to CAIR. The final rule applies to 27 states, including Georgia and the other affiliate company states. Like CAIR, the CSAPR establishes an annual allowance trading program for SO2 and NOx to reduce transport of fine particulate matter and a separate ozone season NOx allowance trading program to reduce ground-level ozone. However, the final CSAPR differs from CAIR in many ways. In a significant departure from past federal allowance trading programs, CSAPR only allows for limited interstate trading. For example, the rule divides states into two groups for purposes of SO2 allowance trading – Group 1 and Group 2. While trading is allowed within a given group, the rule prohibits trading across the two groups. For example, both Georgia and Alabama are part of Group 2; therefore, sources in those states can buy and sell SO2 allowances with each other. However, North Carolina, Virginia, West Virginia, Pennsylvania, Ohio, Indiana and Illinois are all Group 1 states; therefore sources in Alabama and Georgia cannot trade with sources in those states. In addition, like CAIR, CSAPR establishes SO2 and NOx emissions budgets for each affected state but CSAPR prohibits states from exceeding their state-wide budgets by more than a set percentage, referred to as the "variability limit." The final rule is structured as a Federal Implementation Plan (FIP). States will have the option of adopting a State Implementation Plan (SIP), but not for initial compliance.

The Cross State Air Pollution Rule will replace CAIR and all of its compliance requirements. CAIR annual and seasonal NOx allowances will have no value for compliance with the Cross State Air Pollution Rule. The Acid Rain SO2 program will continue as a separate program. Compliance with the annual reduction requirements will begin January 1, 2012 with further reductions required beginning January 1, 2014. The ozone season NOx reduction requirements begin May 1, 2012 and further reductions are required beginning May 1, 2014. Under the

CSAPR, Georgia is subject to both the annual reduction requirements and the ozone season reduction requirements.

Figure 2.5-1 shows the states affected by the final Cross-State Air Pollution Rule. The impacts of this final rule on GPC are currently being evaluated but could potentially include increased allowance purchases and/or operational restrictions.

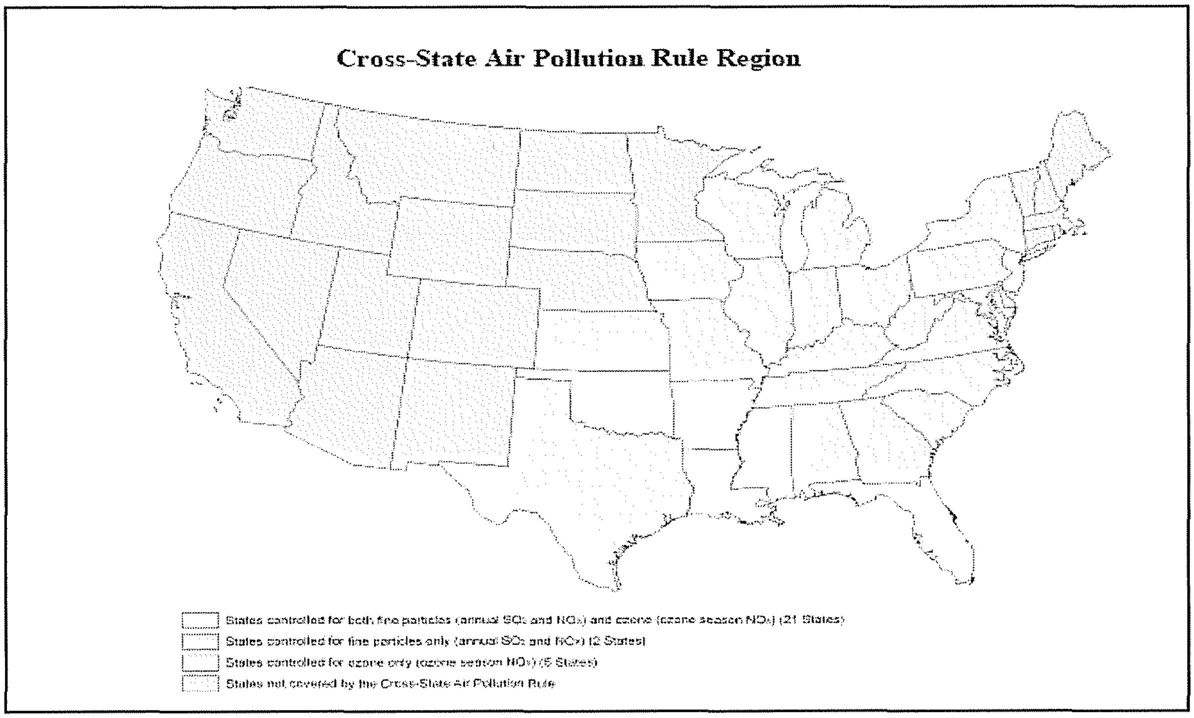

Figure 2.5-1 States Covered by the Final Cross-State Air Pollution Rule

2.6 Maximum Achievable Control Technology (MACT)

Utility MACT

On March 15, 2005, the EPA announced the final Clean Air Mercury Rule (CAMR), a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants as an alternative to maximum achievable control technology (MACT) emission limits under Section 112 of the CAA. EPA concurrently delisted coal-fired power plants from Section 112 in order to regulate them under Section 111 for CAMR. However, in February 2008, in response to a legal challenge to CAMR brought by a number of states and environmental groups, the D.C. Circuit Court of Appeals vacated the CAMR and vacated EPA's concurrent rule to "delist" power plants from the CAA provisions that require application of MACT. The vacatur became effective with the issuance of the court's mandate on March 14, 2008, nullifying CAMR mercury emission control obligations and monitoring requirements. Petitions for rehearing filed by EPA and UARG were denied on May 20, 2008, and both parties filed an appeal to the Supreme Court. EPA later withdrew its petition, and the Supreme Court denied UARG's petition on February 23, 2009.

In response to the vacatur of CAMR, EPA has proposed MACT standards for coal and oil-fired electric generating units (EGUs) under Section 112 of the CAA. Unlike CAMR, MACT is not a cap-and-trade program for mercury, rather it is a technology-based command-and-control rule that will address all hazardous air pollutants (HAPs), not just mercury. In order to gather data to support a MACT rule, EPA issued an Information Collection Request (ICR) in January 2010 in which the utility industry was obligated to submit data to support the rulemaking. All of Southern Company's coal- and oil-fired facilities were required to submit existing data on fuels, emissions, and emission controls; many were required to conduct costly emission testing for mercury, acid gases, organics, metals, and/or dioxins/furans, at the company's expense. The historical data requested by EPA was submitted in April 2010 and all of the emissions test results were submitted between July and September 2010.

EPA has entered into a consent decree governing the MACT rulemaking schedule. On March 16, 2011 EPA signed a proposed Utility MACT rule, published on May 3, 2011, which would impose HAP emission limits and other requirements on coal and oil-fired EGUs. For both coal- and oil-fired units, the proposal would require stringent emission limits for mercury, acid gases, and total particulate matter, as well as work practice standards for organic and dioxin and furan emissions. Meeting the emission limits for mercury, acid gases, and total particulate matter may require additional emission control equipment at some facilities. The proposal would also require the installation of continuous emission monitors for particulate matter and mercury. Under the court approved consent decree, EPA is required to issue a final rule by November 16, 2011. The statute requires existing sources to comply with MACT standards within 3 years after the publication of the final rule in the Federal Register with the possibility of a one-year extension. Based on the EPA's current schedule, compliance is expected to be required as early as 2015 with the possibility of a one-year extension to 2016.

Industrial Boiler (IB) HAPS MACT

In February 2004, EPA finalized the Industrial Boiler (IB) MACT rule to impose limits on hazardous air pollutants from industrial boilers, including biomass boilers and start-up boilers. Compliance with the final rule was scheduled to begin in September 2007; however, in response to challenges to the final rule, the D.C. Circuit vacated the rule in its entirety in July 2007.

In response to the court's ruling, EPA began development of a new IB MACT. On April 29, 2010, EPA issued a proposed IB MACT rule and finalized the rule on February 21, 2011. The rule establishes different emissions limits for different subcategories of boilers, including natural gas-fired boilers, oil-fired boilers, biomass stoker boilers, and biomass fluidized bed boilers among others. The limits in the new IB MACT are much more stringent than the IB MACT that was vacated in 2007. The proposal would require the use of continuous emission monitors for oxygen and particulate matter (PM). On May 16, 2011 EPA announced an administrative stay of the final rule which will delay the effectiveness of the rule during reconsideration. EPA has established a schedule for reconsideration and expects to issue a reconsidered proposed rule by October 31, 2011 and a final rule by April 30, 2012. It is unclear at this time which portions of the final rule, if any, may be changed as a result of the reconsideration process.

2.7 Clean Air Visibility Rule (CAVR)

CAVR (formerly called the Regional Haze Rule) was finalized in July 2005. The goal of this rule is to restore natural visibility conditions in specified "Class 1" areas (primarily national parks and wilderness areas) by 2064. The rule involves: (1) the application of Best Available Retrofit Technology (BART) to certain sources built between 1962 and 1977, and (2) the application of any additional emissions reductions which may be deemed necessary for each designated area to achieve reasonable progress toward the natural conditions goal by 2018. Thereafter, for each 10-year planning period, additional emissions reductions will be required to continue to demonstrate reasonable progress in each area during that period. For power plants, CAVR allowed states to determine that CAIR satisfied BART requirements for SO_2 and NO_x. Extensive studies were performed for each GPC affected units to demonstrate that additional PM controls are not necessary under BART. In 2010, the Georgia EPD submitted to EPA a regional haze SIP which includes the conclusion that CAIR was sufficient to address both SO_2 and NO_x BART as well as Reasonable Progress for GPC units, and that no additional PM controls are warranted under BART. The EPA has not acted on this SIP.

2.8 Georgia Multi-pollutant Rule and Georgia Rule (uuu)

On June 27, 2007, the State of Georgia approved a new "multi-pollutant" rule for certain existing coal-fired electric utility steam generating units in Georgia. The rule is designed to reduce emissions of mercury, sulfur dioxide, and nitrogen oxide state-wide by requiring installation of specified control technologies at each affected unit by specific dates set between December 31, 2008, and June 1, 2015. This rule will require the installation of SCRs for NO_X reduction and scrubbers for SO_2 reduction on the majority of GPC's coal-fired units. The rule also requires installation and operation of baghouses with sorbent injection at Plant Scherer for mercury control. If the emission control equipment is not installed and operating by the required date, the generating unit may not be allowed to continue operating. The following table (Table 2.8-1) illustrates the controls that are required to be installed on GPC units, in accordance with the Georgia Multipollutant Rule.

In June 2009, the State of Georgia approved a companion rule to the Georgia Multipollutant rule, Georgia Rule (uuu), "SO_2 Emissions from Electric Utility Steam Generating Units." The rule requires reduction of SO_2 emissions by 95% from all units required to install scrubbers under the

Georgia Multipollutant Rule, except Yates Unit 1 where a 90% reduction is required. The rule required compliance beginning in January 2010 for units with scrubbers in operation, and requires reductions from the remaining units at dates that align with or are close to the Multipollutant Rule compliance dates.

In June 2011, revisions to both the Georgia Multipollutant Rule and Georgia Rule (uuu) were approved by the Georgia Department of Natural Resources. These revisions, reflected in Table 2.8-1 below, incorporate changes to the SCR/FGD compliance dates of Plant Branch Units 1 and 2, Scherer Unit 3, and Branch Units 3 and 4. The revised rule will allow for additional time to install the prescribed controls on Plant Branch Units 3 & 4 and to consider new rules to be promulgated by the EPA, including the Utility MACT rule, in the near future that may impact the design and construction process for these units.

Unit	Control Equipment	Installation & Operation Deadline
Bowen 3	SCR and FGD	December 31, 2008
Bowen 4	SCR and FGD	December 31, 2008
Hammond 1	FGD	December 31, 2008
Hammond 2	FGD	December 31, 2008
Hammond 3	FGD	December 31, 2008
Hammond 4	SCR and FGD	December 31, 2008
Wansley 1	SCR and FGD	December 31, 2008
Bowen 2	SCR and FGD	June 1, 2009
Scherer 2	Sorbent injection in baghouse	June 1, 2009
Scherer 3	Sorbent injection in baghouse	June 1, 2009
Scherer 1	Sorbent injection in baghouse	December 31, 2009
Wansley 2	SCR and FGD	December 31, 2009
Scherer 4	Sorbent injection in baghouse	April 30, 2010
Bowen 1	SCR and FGD	June 1, 2010
Scherer 3	SCR and FGD	July 1, 2011
McDonough 2	SCR and FGD	December 31, 2011
McDonough 1	SCR and FGD	April 30, 2012
Branch 2	SCR and FGD	October 1, 2013
Branch 1	SCR and FGD	December 31, 2013
Scherer 2	SCR and FGD	December 31, 2013
Scherer 1	SCR and FGD	December 31, 2014
Yates 6	SCR and FGD	June 1, 2015
Yates 7	SCR and FGD	June 1, 2015
Branch 3	SCR and FGD	October 1, 2015
Branch 4	SCR and FGD	December 31, 2015

Table 2.8-1 Georgia Multipollutant Rule Requirements

2.9 Climate Change/Carbon Dioxide Emissions and Renewable Portfolio Standards

Climate Change and Renewables Legislation

Although the House passed the American Clean Energy and Security Act of 2009, neither this legislation nor similar measures passed the Senate before the end of the 111th Congress. This type of legislation is not likely to pass during 2011; however, Congress will continue consideration of federal legislative proposals that limit greenhouse gas emissions, renewable/clean energy standards, and/or energy efficiency standards.

Global Climate Change – International

International climate change negotiations under the United Nations Framework Convention on Climate Change continue. The December 2009 negotiations in Copenhagen resulted in a nonbinding agreement that included a pledge from both developed and developing countries to reduce their greenhouse gas emissions. The most recent round of negotiations took place in Cancun in December 2010. The meeting's resulting Cancun Agreements established a framework for moving forward under the two tracks of the UNFCCC and the Kyoto Protocol. The Agreements took the initial steps to implement the operational elements of the Copenhagen Accord which includes: a process to include the mitigation pledges by developed and developing countries; the creation of the Cancun Adaptation Framework to manage the development and implementation of adaptation strategies; the monitoring, reporting and verification of actions to achieve mitigation pledges; establishing a long-term financing mechanism and the creation of a Green Climate Fund; the creation of a technology mechanism for the development and transfer of technology to support mitigation and adaptation efforts; and a suite of forest sector activities (e.g., conservation of forest carbon stocks). However, resolution of many key issues – such as whether there will be a second commitment period under the Kyoto Protocol – was left to be handled through a series of workshops and expert group meetings leading up to COP-17 and CMP 7 in Durban, South Africa at the end of 2011. The outcome and impact of the international negotiations cannot be determined at this time.

CO_2 Regulation

In April 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles. In December 2009, the EPA published a final determination, which became effective on January 14, 2010, that certain greenhouse gas emissions from new motor vehicles endanger public health and welfare due to climate change. On April 1, 2010, the EPA issued a final rule regulating greenhouse gas emissions from new motor vehicles under the Clean Air Act. EPA has taken the position that once this rule went into effect on January 2, 2011, carbon dioxide and other greenhouse gases became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program, which both apply to power plants. As a result, the construction of new facilities or the major modification of existing facilities could trigger the requirement for a PSD permit and the installation of the best available control technology for carbon dioxide and other greenhouse gases. On May 13, 2010, the EPA issued a final rule, referred to as the Tailoring Rule, governing how these programs would be applied to stationary sources, including power plants. This rule establishes two phases for applying PSD and Title V requirements to greenhouse gas emissions sources. The first phase, that began on January 2, 2011, applies to sources and projects that would already be covered under PSD or Title V, whereas the second phase, which began July 1, 2011, applies to sources and projects that would not otherwise trigger those programs but for their greenhouse gas emissions.

These greenhouse gas regulations are being litigated. On December 10, 2010, the D.C. Circuit denied the motions for a stay of EPA's GHG rules, which had been filed by Texas and a number of industry petitioners. The court also ordered that the various petitions challenging different aspects of the greenhouse gas rules be scheduled for oral argument on the same day before the same panel. The challenges to the reconsideration of the Johnson Memo and the Tailoring Rule have been consolidated so there are three cases involving EPA's GHG rules before the U.S. Circuit Court of Appeals for the District of Columbia. In all three cases, the oral arguments have not yet been scheduled. The briefing, which began this spring, will continue through December 2011.

On December 23, 2010, EPA announced that it reached settlement agreements with states and environmental groups that had filed suit over the GHG standards for fossil fuel power plants and petroleum refineries. The agreements provide timelines for the promulgation and finalization of new source performance standards for new, modified, and existing electric utility steam generating units and refineries. According to the settlement agreement for electric utility steam generating units, EPA would propose standards for new and modified units as well as guidelines for States for existing units by July 26, 2011 and finalize them by May 26, 2012. However, on June 13, EPA announced it would delay proposing the standards and guidelines until September 30, 2011. EPA still intends to finalize them by May 26, 2012.

The ultimate outcome of these final rules cannot be determined at this time, and will depend on the outcome of pending legal challenges, however, mandatory restrictions on GPC's carbon dioxide emissions could result in significant additional compliance costs.

GHG Reporting Rule

Monitoring required by EPA's mandatory GHG reporting rule began on January 1, 2010. For the first year, GPC will be required to report metric tons of CO2, CH4, and N2O emissions. The second year will also require the reporting of SF6 emissions. Electric generating units subject to the Acid Rain Program have little additional requirements to report their CO2 emissions except that the emissions must be reported in metric tons instead of short tons. CH_4 and N_2O emissions will be estimated by using calculations specified in the reporting rule. Other units and devices that combust solid, liquid, or gaseous fuel that have not been previously required to monitor CO_2 emissions must also report using calculations provided by the reporting rule. This requirement will include units that have operated very little in recent years. The first report was originally due on March 31, 2011, but it has been delayed until September 30, 2011. This delay is to allow EPA more time to complete its electronic greenhouse gas reporting tool (e-GRRT).

2.10 Water Issues

316(b) Regulations
Section 316(b) of the CWA requires that the location, design, construction, and capacity of any cooling water intake structure (CWIS) reflect best technology available for minimizing adverse environmental impact that may be caused by CWISs. Historically NPDES permit writers have applied Section 316(b) on a case-by-case basis. In 2004, EPA published a final technology-based regulations under §316(b) of the CWA for the purpose of reducing impingement and entrainment of fish, shellfish and other forms of aquatic life at existing power plant CWISs. In January 2007, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule, including the use of cost-benefit analysis, to the EPA for revision. As a result, EPA withdrew the new rule and began developing a new proposal. In April 2009, the U.S. Supreme Court reversed the Second Circuit's decision with respect to the rule's use of cost-benefit analysis, and held that the EPA could consider costs in arriving at its standards and in providing variances from those standards for existing power plant CWISs. Other aspects of the court's decision were not appealed and remain unaffected by the ruling.

On March 28, 2011 under consent decree, EPA signed and released a new 316(b) proposal. Although the implications of this rule are different for each plant, it is certain that varying combinations of robust biological studies, intake modifications, and possibly closed-cycle-cooling towers will be required. Under court order, the final rule is scheduled to be signed on July 27, 2012.

Effluent Limitations Guidelines Revision
On September 15, 2009, EPA announced its plans to commence a rulemaking to revise the current effluent guidelines for steam electric plants. The current rule, which was promulgated in 1982, establishes technology-based effluent limitations for new and existing discharges. EPA completed a multi-year study of power plant wastewater discharges and concluded that pollutant discharges from coal-fired power plants will increase significantly in the next few years as new air pollution controls are installed. EPA's study concludes that technologies are available to significantly reduce pollutant loadings from ash transport water and FGD wastewater.

During the data collection phase of this rulemaking, EPA sent a lengthy and comprehensive Information Collection Request (ICR) to 733 facilities seeking technical and economic data about FGD wastewater, ash handling, metal cleaning wastes, surface impoundments, wastewater treatment, and landfill operations. In addition, EPA has completed a separate wastewater sampling program covering several facilities around the country. This sampling effort focused on the evaluation of several FGD wastewater treatment systems (e.g., physical, chemical, and biological processes) in the removal of nutrients, mercury, and metals. EPA also sampled wastewater from two IGCC facilities and from a pilot-scale carbon capture study.

Based on a settlement agreement with several environmental groups, EPA is scheduled to propose a rule in July 2012 and finalize it by January 2014. In the final rule, EPA will describe the applicable compliance deadlines. EPA may decide to phase in requirements as permits are renewed over the five-year NPDES permitting cycle, or it could take a more extreme position and require quicker compliance. The impact of this rulemaking could be very substantial, and could include requirements for stringent FGD wastewater treatment, a prohibition on wet sluicing of fly ash and bottom ash for all coal-fired facilities, and treatment of landfill leachate. The rule is not limited to coal-fired facilities and could potentially address wastewater limits at nuclear, gas, and combined-cycle facilities as well.

Thermal Variances
In recent years, federal and state environmental protection agencies have voiced concerns about whether §316(a) variances can be justified in light of alleged impacts to fish and wildlife. At a minimum, Georgia Power can expect to face growing scrutiny when it requests renewal of its thermal variances. This scrutiny may lead to new study requirements and modified permit conditions.

Water Quality and TMDLs
The Clean Water Act requires establishment of priority rankings for waters on the lists and develop TMDLs for these waters. A Total Maximum Daily Load, or TMDL, is a calculation of the maximum amount of a pollutant that a water body can receive and still safely meet water quality standards. Water quality criteria are then are set by state law to maintain healthy chemical and physical parameters and to limit toxics and other potential pollutants based on risk assessment. Permit limits are based on the in-stream water quality criteria and the assimilative capacity of the receiving stream. To meet these and other limits, additional wastewater treatment, such as physical/chemical and/or biological systems, may be needed due to FGD wastewater impacts.

2.11 Land Issues

Coal Combustion Byproducts (CCB)
In May 2000, EPA concluded, after nearly 20 years of study, that coal ash does not warrant hazardous waste regulation under RCRA Subtitle C and that states should continue to be the primary environmental regulators for coal ash management.

A December 2008 release of ash from TVA's Kingston coal-fired generating facility has resulted in increased scrutiny and focus on CCR management industry-wide. Southern Company has responded to an EPA request for information regarding ash ponds for several facilities.

In June 2010, EPA issued a proposed rule regulating the management and disposal of CCRs. EPA presented two separate regulatory options under the Resource Conservation and Recovery Act (RCRA) for regulating CCRs when generated from coal-fired electric generating facilities: regulation as a solid waste or regulation as if the materials were a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options. Georgia Power currently operates 11 electric generating plants with on-site coal combustion byproduct storage facilities (some with both "wet" (ash ponds) and "dry" (landfill) storage facilities). In addition to on-site storage, the Company also sells a portion of its coal combustion byproducts to third parties for beneficial reuse (in 2010 approximately **REDACTED** of coal combustion byproducts generated). Historically, individual states have regulated coal combustion byproducts and the states in Southern Company's service territory each have their own regulatory parameters. Georgia Power has a routine and robust inspection program in place to ensure the integrity of its coal combustion byproducts surface impoundments and compliance with applicable regulations.

The impact on the Company's operations will depend on the ultimate outcome of any final EPA regulation of coal combustion byproducts, which is estimated to be finalized no earlier than 2012.

GPC's coal combustion byproduct management practices are in compliance with the State of Georgia's regulatory requirements. GPC will continue to comply with all existing and future state and federal regulatory requirements and is continually seeking to increase appropriate beneficial use of coal combustion byproducts that it generates.

2.12 Major Litigation Matters

New Source Review

NSR is pre-construction permitting program under the CAA that applies to changes to an emissions source (*e.g.*, electric generating unit) that result in "significant" increases in air emissions. Any new changes to NSR regulations or new interpretations of existing regulations could impact the methods utilized by the Company to ensure compliance and could have significant impact on unit operations. The Company has been actively participating in various legislative, regulatory, and judicial proceedings addressing NSR issues.

In November 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the NSR provisions of the CAA and related state laws at certain coal-fired generating facilities. The court quickly dismissed the claims against Alabama Power and declined to add claims against Mississippi Power and Gulf

Power because the claims were improperly brought in Georgia. While the court retained jurisdiction over the claims against Georgia Power, the court administratively closed the case in 2001, and the case has not been reopened. To date, EPA has not refiled its NSR claims against Mississippi Power or Gulf Power; however it has sought additional information from both companies on their NSR compliance status.

<u>United States v. Alabama Power</u>
After Alabama Power was dismissed from the original action, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and Georgia Power, including facilities co-owned by Mississippi Power and Gulf Power. The civil actions request penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. The EPA concurrently issued notices of violation to Gulf Power and Mississippi Power relating the Gulf Power's Plant Crist and Mississippi Power's Plant Watson. In early 2000, the EPA filed a motion to amend its complaint to add Gulf Power and Mississippi Power as defendants based on the allegations in the notices of violation. However, in March 2001, the court denied the motion based on lack of jurisdiction, and the EPA has not re-filed. The original action, now solely against Georgia Power, has been administratively closed since the spring of 2001, and the case has not been reopened.

In the separate action against Alabama Power in the U.S. District Court for the Northern District of Alabama, Alabama Power settled certain claims in June 2006 to resolve the portion of the lawsuit related to Plant Miller. With respect to all other claims, Alabama Power prevailed on the merits – on March 14, 2011, the district court granted Alabama Power's motion for summary judgment on all remaining claims and dismissed the case with prejudice. The court ruled that the EPA could not prove Alabama Power should have predicted an emission increase following the projects at issue because the emissions methodology EPA had presented to the court was flawed. The EPA and the Alabama Environmental Council have now appealed the court's decision to the U.S. Court of Appeals for the Eleventh Circuit.

Carbon Dioxide Litigation

<u>Connecticut v. AEP</u>
In 2004, eight states and three environmental groups filed a nuisance suit against Southern Company and four other electric power companies seeking reductions in the companies' emissions of greenhouse gases. In September 2005, the U.S. District Court for the Southern District of New York dismissed the case on the grounds that the global warming issues of the case "present non-judiciable political questions that are consigned to the political branches, not the Judiciary." The plaintiffs appealed that decision to the U.S. Circuit Court of Appeals for the Second Circuit and, on September 21, 2009, the Second Circuit reversed the district court's ruling, vacating the dismissal of the plaintiffs' claim, and remanding the case to the district court.

After unsuccessfully requesting a rehearing en banc before the Second Circuit, defendants appealed the case to the United States Supreme Court. On June 20, 2011, in a unanimous decision, the Supreme Court overturned the Second Circuit's decision, holding that the plaintiffs' federal common law nuisance claims against the utilities were displaced by the Clean Air Act and EPA regulations addressing greenhouse gas emissions, and the Court remanded the case for consideration of whether federal law may also preempt the remaining state law claims.

Native Village of Kivalina v. Exxon Mobil Corp

In February 2008, the Native Village of Kivalina and the City of Kivalina (Alaska) filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that their village is being destroyed by erosion related to global warming caused by the defendants' emissions of greenhouse gases. The plaintiffs assert claims for public and private nuisance, under both state and federal law, and contend that the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. On September 30, 2009, the district court granted the defendants' motions to dismiss the case based on lack of jurisdiction and ruled that the claims were barred by the political question doctrine and by the plaintiffs' failure to establish the standard for determining that the defendants' conduct caused the injury alleged. The plaintiffs appealed the decision to the U.S. Court of Appeals for the Ninth Circuit, but case was stayed by the Ninth Circuit in February 2011, pending the decision of the Supreme Court in Connecticut v. AEP. As noted above, the Supreme Court decision was issued on June 20, 2011 in favor of the defendant companies, and the plaintiffs in Kivalina have moved to lift the stay on their Ninth Circuit appeal and have requested the opportunity to submit supplemental briefing regarding the effect of the Supreme Court's decision.

Comer v. Murphy Oil

On April 18, 2006, several plaintiffs sued Southern Company and a number of oil, gas, coal, and utility companies in the U.S. District Court for the Southern District of Mississippi seeking damages resulting from Hurricane Katrina. Because the plaintiffs named Southern Company instead of its individual operating companies, Southern Company was dismissed from the case, and the plaintiffs' motion to add the operating companies was not acted upon before the entire case was dismissed by the district court in 2007 based on the plaintiffs' lack of standing and the political question doctrine. Plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit, and a three-judge panel of the Fifth Circuit reversed the district court decision on October 16, 2009, holding that the plaintiffs did have standing to assert their nuisance, trespass, and negligence claims and that none of the claims were barred by the political question doctrine. On May 28, 2010, however, the Fifth Circuit dismissed the plaintiffs' appeal of the case on procedural grounds, reinstating the district court decision in favor of the defendants. On January 10, 2011, the United States Supreme Court denied the plaintiffs' petition to reinstate the appeal, ending the case.

However, on May 27, 2011, the same plaintiffs filed a new a class action complaint in the same district court involving substantially similar allegations. The current litigation names operating companies Alabama Power, Georgia Power, Gulf Power and Southern Power, and includes many of the other same defendants that were involved in the earlier case.

2.13 Other Considerations

Currently, there are no proposed regulations relating to lead that may have an effect on the installation of equipment or changes in the operation of electric generating plants. In addition, Appendix C provides an overview of existing and proposed regulations in regards to low-level and high-level nuclear waste. Southern Company will continue to monitor these issues and evaluate its strategy as changes occur.

3.0 Environmental Strategy

Based on the extensive regulatory and legislative issues described above, Southern Company, including GPC, has developed a comprehensive, flexible compliance strategy. Southern Company completed an initial environmental strategy following the passage of the 1990 Clean Air Act Amendments and established an annual, essentially on-going, process to develop, review, and update environmental compliance strategies using sophisticated, state-of-the-art analytical tools. The process has evolved and been refined over the years, but the goal of this process is to produce least-cost compliance strategies that will minimize the impact on customers while achieving environmental objectives and assuring compliance with all requirements. This strategy process is illustrated in the figure below (Fig. 3-1). The strategy is essential for internal decision making and communication, and is documented for the public service commissions.

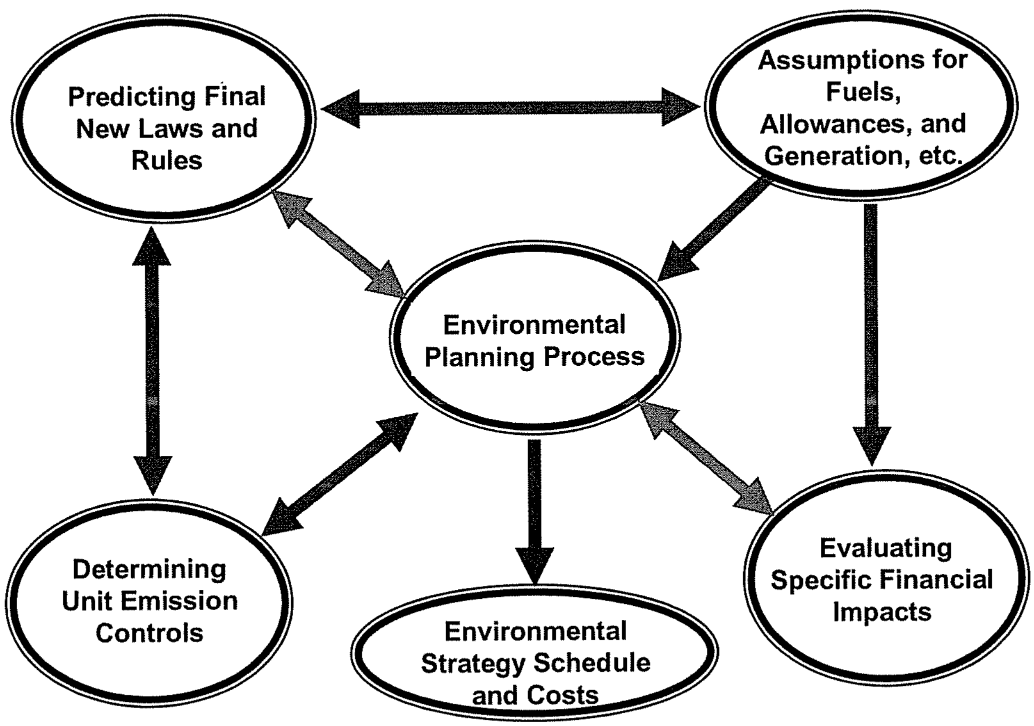

Figure 3-1 Annual Environmental Strategy Development Process for Existing Generation Retrofits

3.1 Strategy Process

The process for developing the environmental compliance plan includes the comprehensive involvement of a number of organizations within the company, including environmental, governmental affairs, planning, fuels, engineering, finance, operations, communications, generating plants, and research groups. This integrated process includes four steps as discussed below.

1. **Predicting and integrating the outcome of new environmental requirements**. The first step involves gathering all available knowledge about current and possible future local, state, regional, and national environmental requirements. The future requirements may be in the form of legislation that will need future rulemakings or in the form of draft or proposed new rules that must go through the rulemaking process to become final. Some rules may be part of an allowance-based cap and trade program over a regional or national scale and others may be local or state requirements that mandate specific requirements on specific plants. For many rules, the possibility that litigation will result in changes to the rule creates additional uncertainty.

2. **Developing assumptions on national, Southern Company, and Operating Company levels.** In order to predict the impacts of the requirements on the generating plants, the company must make assumptions to predict generating unit, Southern Company, and national electric system responses to existing and future environmental requirements (in addition to growing demands for electricity). These assumptions include:

    - Unit operating characteristics such as heat rates, capacity, and emission rates.
    - Fuel characteristics and costs, including natural gas, coal, and oil.
    - Allowance prices for cap and trade programs.
    - Control technology options and costs.
    - Future generation demand.

    To appropriately consider future legislative and market uncertainty, a scenario planning process was employed for long-term resource planning. A range of planning scenarios were developed and modeled as a part of the company's IRP Process. This range was established through the work of a coordinated planning team consisting of internal and external subject matter experts and company planning managers. The planning scenarios identify two fundamental dimensions that affect the range of potential futures for the electric utility industry – fuel market supply fundamentals and CO_2/renewables legislation. The scenario planning process is described in detail in Section 6.4 of the IRP.

3. **Application of generating unit-specific cost-effective control technology options.** The application of control technology is dictated initially by the anticipated environmental requirements for each specific generating plant and/or unit. In some cases, the plant or unit's emission control requirements are mandated, such as a plant-specific limit to meet local air quality requirements. In some cases, such as the cap and trade program for SO_2 established to address acid rain, utilities can choose the most cost-effective option: fuel switching, applying control technology, or purchasing emission allowances. The decision process reviews the cost-effectiveness of each of these options for each unit. Several of the most important emission control technologies for Southern Company compliance are described in the technology review discussion below.

   The availability of control technology options varies by pollutant, as well. For example, when complying with SO_2 reduction requirements, the choices are basically fuel switching to lower sulfur coal, installing scrubbers, or buying allowances. Scrubbers are also effective for the reduction of fine particulates. For NO_X control, there are more control technology options available, such as low-NO_X burners, selective catalytic reduction, and selective noncatalytic reduction. Mercury emissions can be reduced through co-benefits from the combined operation of an SCR and a scrubber for units burning bituminous coal. The injection of activated carbon or the introduction of other substances into the flue gas stream can also reduce mercury emissions. A fabric filter technology such as COHPAC or a baghouse may be necessary for fine particulate and/or mercury reduction at units burning sub-bituminous coal and at some older, smaller units where a scrubber is not economical. The cost, control effectiveness, and appropriateness of each technology for each generating unit must be considered. The figure below (Fig. 3.1-1) illustrates various control technologies and applications as well as typical project engineering and construction times.

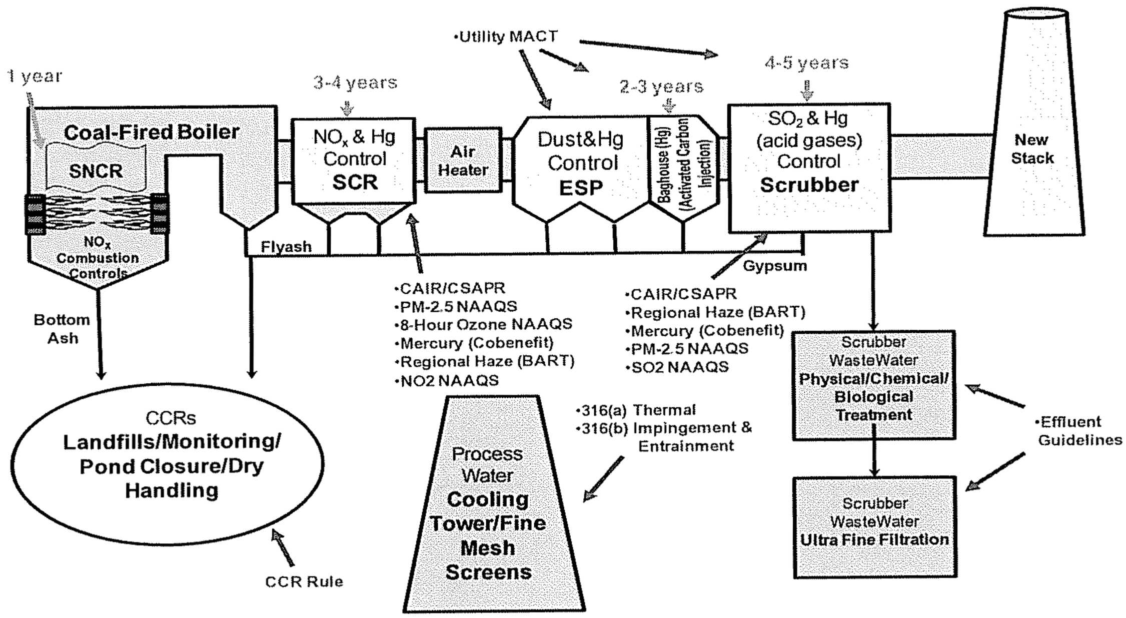

Figure 3.1-1 Emission Control Technologies for Coal-Fired Boilers

All of these considerations are taken into account in developing a unit-specific decision on the application of emissions control technologies. The figure below (Fig. 3.1-2) illustrates this decision process.

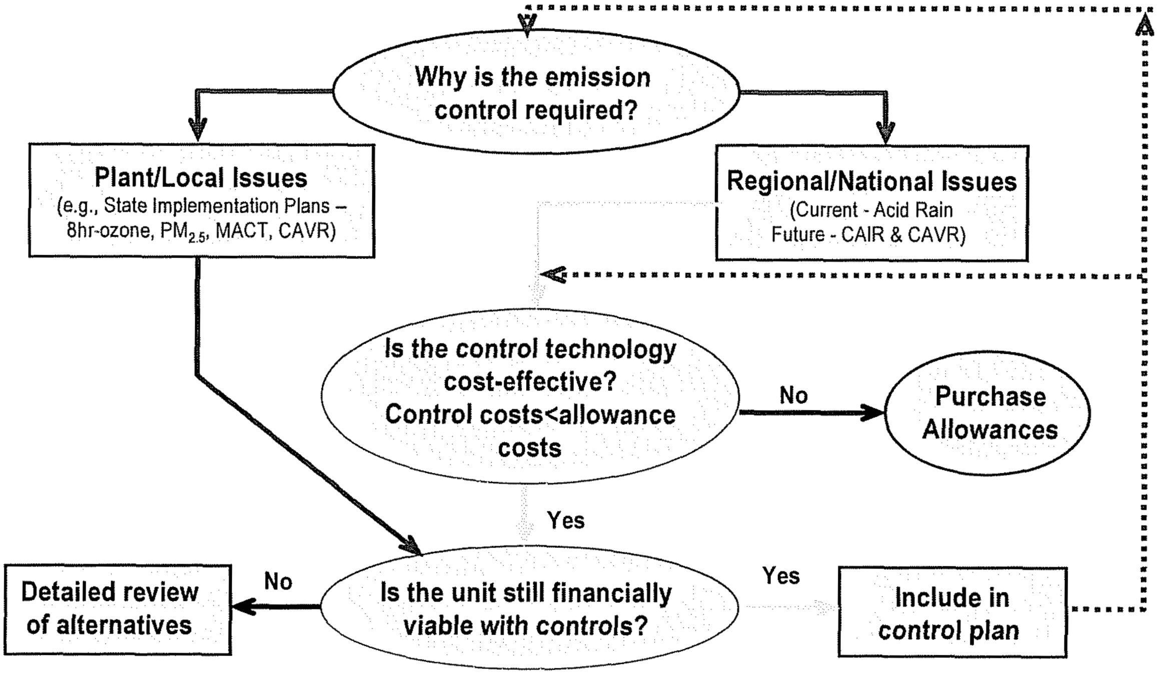

Figure 3.1-2 Visual Representation of the Decision to Control process

4. **Determining and evaluating the financial impacts of the strategy.** The final step is to make sure that the right economic decision is being made on a plant, GPC, and Southern Company basis for Georgia Power Company and its customers. Some units and plants may not be able to achieve the required emission reductions in a cost-effective manner and would need to acquire additional allowances to comply. If emission controls are mandated for a specific unit, then the economic value of the generating asset including future operating costs must be considered before application of the technology.

After the process is completed and analyzed across the various planning scenarios, a strategy is compiled on a unit level and reviewed annually based on the most current information. One major goal of the environmental strategy process is to maintain flexibility by including as much information as possible in the process before making final decisions. If allowed by the regulations, controls are applied to the most cost-effective units first.

A key advantage of this process is that it allows decision making on an incremental basis. While the strategy includes emission control plans for the next 10 years, final decisions on specific pollution control projects are not made until commitments are required so that construction can commence. That is, while controls may be "planned" on a particular unit in 2016, no firm commitment to that plan will be made until necessary to assure that the emission control equipment is in place and operational when needed. This flexibility allows the company to adapt to changing requirements and reduce costs to the customer.

Future regulatory and legislative requirements that could significantly impact both the scope and the cost of compliance over the next decade are being incorporated into the strategy. Southern Company will continue its involvement in emerging regulations, and these requirements will be incorporated into future strategy updates, as appropriate.

Many of the potential future regulatory requirements, especially those needed to attain ozone and fine-particulate ambient standards are aimed at further NO_X and SO_2 reductions. Even mercury requirements will potentially rely upon SO_2 and NO_X control technologies for emission reductions. All of this uncertainty reinforces the need for a flexible, robust compliance plan. Accordingly, as decision dates for fuel and equipment purchases approach, or as better information relative to regulatory and economic drivers becomes available, the analysis will be updated to determine the most cost-effective compliance decisions while maintaining future flexibility in the strategy. Additional expenses associated with these regulations are anticipated to be incurred each year to maintain current and future compliance. Because the Company's compliance strategy is impacted by factors such as new regulations, changes to existing environmental laws and regulations, the cost of emissions allowances, and changes in fuel use, future environmental compliance costs will continue to be incurred.

3.2 Strategy Assumptions

Based on this extensive strategy process and the regulatory and legislative requirements discussed in Section 2.0, the Southern Company environmental strategy, which includes the strategy for GPC, is reviewed and updated each year.

The current requirements underlying the current system strategy include:

- Compliance with Acid Rain Program requirements through fuel switching to lower SO_2 emissions and the installation of low-NO_X combustion controls, by using the SO_2 allowance bank and purchasing allowances, and by averaging NO_X emissions on a system basis to better assure compliance and lower costs.
- Assuring ozone compliance through the installation of SCR systems and other NO_X controls at units in the Southern Company system.
- Compliance with CAIR/CSAPR Annual and Seasonal Trading Program through 1-hour ozone controls, allowance purchases, and additional emission controls.
- Additional NO_X controls to address local concerns as appropriate.

- Assuring integration with expected state plans to achieve the 8-hour ozone and $PM_{2.5}$ standards.
- Compliance with the Georgia Multi-Pollutant Rule and the Clean Air Visibility Rule requirements.
- Permitting to assure compliance with Title V and Compliance Assurance Monitoring.
- Cooling towers, intake structures, waste management programs, and other controls and measures to assure land and water compliance.
- Preparing for Utility MACT compliance with addition of emission controls.

As outlined in Section 2.0, in addition to the current requirements, there are several anticipated future clean air requirements that will further restrict SO_2, NO_X, mercury, HAPS, and CO_2. At the same time, more stringent clean water and solid waste requirements are expected to replace and/or supplement the current rules surrounding water intake, thermal discharge, waster water, and coal combustion byproduct management. While there is uncertainty surrounding the stringency and timing of these requirements, they must also be considered in the development of the environmental strategy.

The strategy combines the assumptions surrounding the regulatory requirements with the environmental control technology that is commercially available and results in specific emission control applications across Southern Company. The current strategy also anticipates active participation in the SO_2 and NO_X allowance markets to achieve compliance.

3.3 Emission Control Technologies

Research and development are an integral part of the overall Southern Company environmental strategy and compliance plan. Through research, technologies are considered, evaluated, developed, and selected for possible implementation to meet compliance with federal and state regulatory requirements. Technology-related decisions are made based on compliance alternatives, technical review (often following actual testing), schedules, equipment-vendor price quotes, total costs over the useful life, specific unit issues, and performance guarantees. Operational, maintenance, and economic feasibility are an important part of the decision-making process.

Since the Clean Air Act Amendments of 1990 were implemented, research and development have been crucial for Southern Company in assuring that the best possible strategies are selected for implementation. Appendix B provides a list of technologies considered in an ongoing effort to lower emissions, meet mandated requirements in a timely manner, maintain system reliability, and assure low-cost energy for customers.

Research programs are conducted at GPC plants, at other Southern Company plants across the Southeast, and through industry affiliations at plants across the U.S. and around the world. To minimize cost and risk, only proven technologies should be implemented commercially. Past programs to test low-NO_X burners, precipitators, catalyst materials for Selective Catalytic Reduction (SCR) systems, flue gas desulfurization systems and other equipment have contributed to Southern Company's ability to meet stringent requirements while enabling GPC to remain a low-cost energy provider for Georgia.

3.4 Other Environmental Issues

Southern Company is actively involved in the research, evaluation, and development of renewable resources and energy efficiency initiatives. The testing of switchgrass, wood waste, and other biomass has been ongoing for a number of years and research into the feasibility of converting selected coal units to fire biomass as the primary fuel is well underway. In 2008, Southern Company and GPC completed a Plant Mitchell biomass conversion study with positive results, prompting GPC to file with the Georgia Public Service Commission an application for Certification to convert Plant Mitchell to a 96-MW biomass plant. The Georgia Public Service Commission approved the certification of the conversion to biomass fuel in a vote on March 17, 2009. However, Georgia Power has decided to delay capital spending for the Plant Mitchell biomass project to evaluate recently finalized rules regarding industrial boiler emissions discussed in Section 2.6
(IB MACT). Southern Company continues to study the potential for wind power and the sale of power from landfill gas sources and other certified "green" sources.

Southern Company operating companies plan to increase investment in energy efficiency and demand control programs. Existing programs significantly reduce the peak demand for electricity.

Efforts across Southern Company are focused on developing and deploying technologies to reduce greenhouse gases while making sure that electricity remains reliable and affordable.

4.0 Strategy Results and Financial Summary

This section summarizes Southern Company's compliance strategy for environmental requirements. Since the Clean Air Act Amendments were passed in 1990, Southern Company and its operating companies have been challenged by a host of new environmental regulations and requirements as described in Section 2.0. The company has consistently responded with a timely, cost-effective strategy that has either met or exceeded the new clean air requirements, as well as other existing and new environmental regulations.

To date, the applicable regulations and the Southern Company compliance plan have focused largely on reduction of SO_2 and NO_x emissions. Since 1990, Southern Company has reduced its emissions of SO_2 by approximately 72 percent and NO_X by more than 70 percent from 1990 levels, while electricity generation has increased by more than 40 percent. These reductions were achieved by fuel switching to lower sulfur coals and the application of low-NO_X burners and, more recently, the installation of selective catalytic reduction (SCR) systems and flue gas desulfurization (FGD or scrubbers) at plants across the Southern Company system.

Numerous additional federal and state regulations are requiring further reductions in power plant air emissions. At the same time, EPA is developing significant new regulations governing water resources and waste management at power plants. The new rules will require reductions in pollutants not regulated to date and will present new challenges. This section reviews the company's clean air strategy and provides a brief overview of the evaluations underway to address upcoming water and waste management regulations.

4.1 Clean Air Strategy Review

The Acid Rain Program required significant reductions in the emissions of SO_2 and NO_x beginning in 1995 (Phase I of the program), and also required the installation of continuous emission monitoring equipment. In 2000 (Phase II), the emission limits were reduced again. As a predominately coal- and fossil-based utility, Southern Company was greatly impacted by the Acid Rain Program requirements. There is no better example of Southern Company's effective response to a major technical challenge than the Acid Rain compliance plan. Southern Company has reduced emissions and increased generation in an efficient and cost-effective manner.

Since implementation of the Acid Rain program, Southern Company has developed cost-effective plans to ensure compliance with many other CAA regulations designed to achieve additional reductions in SO_2 and NO_X emissions from power plants, including the Clean Air Interstate Rule and state regulations designed to achieve attainment with the ozone and PM NAAQS. The company is now in the process of developing a compliance strategy for EPA's final Cross-State Air Pollution Rule (CSAPR), which was released on July 7, 2011. The company is also evaluating potential compliance options for the EPA's final Utility MACT rule, which is scheduled for release in November and will regulate mercury and other hazardous air pollutants.

The discussion below reviews Southern Company and GPC's SO_2 and NO_X compliance strategy and provides a brief overview of potential compliance options for the pending Utility MACT rule.

4.1.1 SO_2 Compliance

With respect to the Acid Rain Program, Southern Company's and GPC's SO_2 compliance strategy involved the creation of a bank of allowances during Phase I (1995-1999) to be carried over into Phase II, which began in 2000. The strategy has always relied heavily upon use of low-sulfur coals at affected units but is increasingly incorporating FGD (scrubber) systems for SO_2 control at the larger affected units. Both the overall strategy and consistent environmental compliance have been achieved in a cost effective manner.

The SO_2 strategy for compliance with CAIR continues to incorporate the use of low-sulfur coal , installation of scrubbers, and the use of banked and purchased allowances. However, further fuel switching is limited due to the large amount of low sulfur coal that Southern's generating fleet currently burns. In addition, increasingly tight fuel markets have introduced more moderate sulfur coals, which accelerate depletion of the SO_2 allowance banks. These factors combined with the Georgia Multipollutant Rule requirement to install scrubbers on certain units by specified dates and Georgia Rule (uuu), which requires a 95% reduction in SO_2 emissions at the scrubbed units, have increased GPC's reliance on scrubber installations and reduced reliance on low sulfur coal.

The table below (Table 4.1.1-1) provides an update on GPC SO_2 bank withdrawals and the SO_2 allowance banks being carried forward into 2011. For purposes of Acid Rain compliance, GPC is expected to continue to draw down from its SO_2 allowance bank and secure allowance purchases, as needed, to maintain compliance until scrubbers are installed on additional coal-fired generating units.

Company	**2010 Emissions in Excess of Allocations (tons)**	**SO_2 Bank Balance Carried Forward into 2011 (tons)**
Georgia Power	**REDACTED**	**REDACTED**

Table 4.1.1-1 Georgia Power Company's SO_2 Bank Status

In 2010, Phase I of the CAIR SO_2 program began. This CAIR SO_2 program augments the Acid Rain Program by requiring affected sources in CAIR states to retire two Acid Rain Program SO_2 allowances for every one ton of SO_2 emitted in Phase I, as opposed to a one-for-one retirement required under the Acid Rain Program from the program start through 2009. For 2011, the alternatives available for compliance with the SO_2 reduction requirements of the Acid Rain Program remain the same: fuel switching to lower-sulfur coals or natural gas, purchase of SO_2 emission allowances, scrubbing, and unit repowering or retirement.

From the time CAIR was finalized in 2005, through the litigation process, the SO_2 allowance market has been marked by volatility. As shown in the next figure (Fig. 4.1.1-1), the price for SO_2 allowances has decreased substantially from historically high prices in 2005 and 2006. The market also responded to the July 2008 vacatur of CAIR with a decrease in price and trading. Prices continued to fall in 2010 due to recession-driven electricity demand reductions and continued uncertainty over a CAIR replacement.

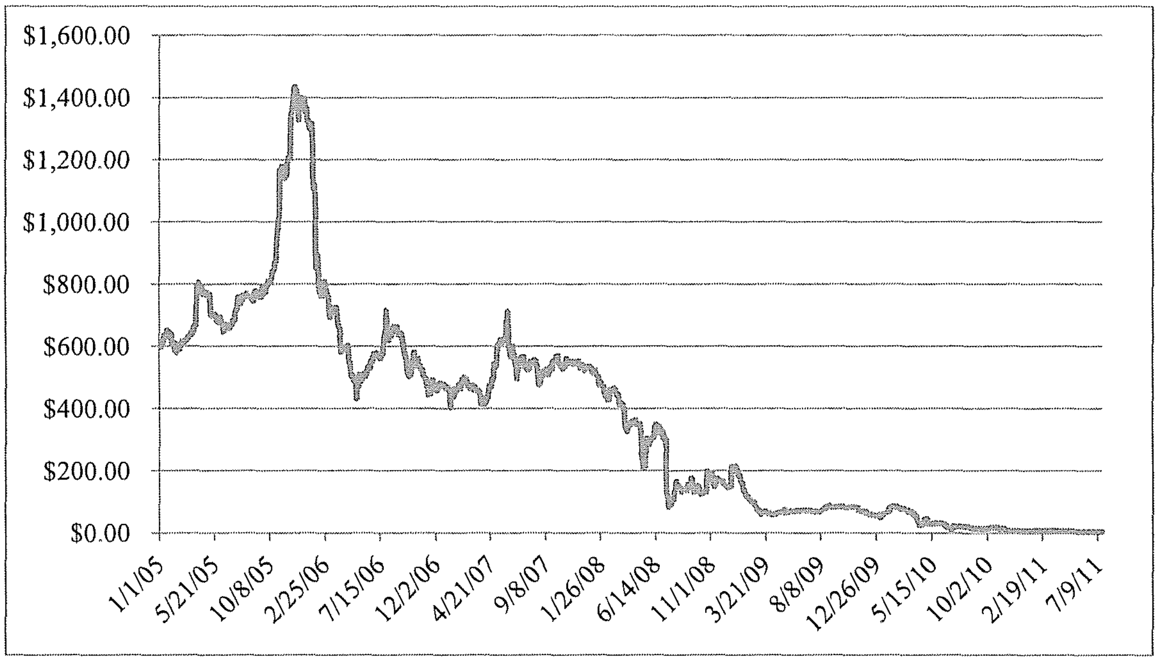

Figure 4.1.1-1 Historic SO_2 Price Summary

A review of the SO_2 compliance strategy confirmed the strategy was not significantly impacted by new fuel and/or SO_2 allowance-price forecasts. The strategy has always been to burn lower-sulfur coal, use allowances from the bank for as long as possible, and then purchase allowances and install FGD emission control equipment when necessary. Fuel switching is limited, the allowance bank has been and is continuing to be depleted, and new rules will force the next phase of the long-term strategy to be implemented. The eventual requirement for FGD equipment has been understood since the first strategy was implemented following passage of the CAAA. The timing of the requirement has been a function of fuel burn, sulfur content, energy demand, availability and price for allowance purchases, natural gas prices, and other variables. A number of scrubbers have been installed in the Southern Company system, and others will follow.

The CSAPR, issued on July 7, 2011, will replace CAIR beginning January 1, 2012, and the CAIR program will be discontinued. New annual SO_2, allowances will be allocated under CSAPR to existing affected sources, including all of Georgia Power's fossil-fuel-fired electric generating units for the 2012 compliance year and beyond. Existing banked allowances will not be useful for compliance with the CSAPR. There will be two SO_2 allowance programs running in parallel: the new CSAPR SO_2 program and the legacy Acid Rain SO_2 program. Existing SO_2 allowances will still be useful for compliance with Acid Rain program requirements, but the value of the allowances will be negligible since the CSAPR is much more stringent. Future allowance prices for SO_2 under CSAPR are uncertain at this time but are expected to be higher than what current Acid Rain / CAIR allowances have been predicted to be in the future. While the compliance plan for CSAPR SO_2 requirements is still under development, it is expected to include a combination of low sulfur fuel use, allowance purchases, and operational changes. The need for additional controls related to CSAPR is unknown at this time. Additional rulemakings underway at EPA and the state level, such as the Utility MACT, state implementation of the SO_2 NAAQS, and the new PM-2.5 NAAQS could require further reductions in SO2 emissions and impact the compliance strategy over the next few years.

4.1.2. NO_X Compliance

The Southern Company and GPC NO_X compliance strategy for Acid Rain compliance consisted of installing low-NO_X burners, over-fired air (OFA) systems, burner tips, and associated controls. Acid Rain Program NO_X compliance is demonstrated under a single-system NO_X averaging plan for Southern Company filed with each State agency and the EPA. System averaging of NO_X emissions lowers system cost and further ensures compliance with Acid Rain regulations. While NO_X compliance for Acid Rain has been achievable, subsequent regulations, including ozone nonattainment area requirements, CAIR, and the Georgia Multipollutant Rule, have required further NOx reductions which provide significant additional margin for Acid Rain Program NO_X compliance. Controls installed under these regulations, as discussed below, reduce the system average NO_X emissions well below Acid Rain Program requirements.

The table on the next page (Table 4.1.2-1) summarizes the Georgia Power NO_x control strategy and provides an up-to-date equipment installation status on the affected units, including low-NO_X equipment beyond the original Acid Rain requirements. In addition to NO_X controls, details relative to the flue gas desulfurization devices and particulate control changes are provided in this table. Appendix A provides a reference list of the acronyms/abbreviations used in the table for both controls and vendor names. See Appendix B for additional technical summaries on emission control technologies.

Table 4.1.2-1 Equipment Installation Status

Unit	Unit Type	NO_X Control	SO_2 Control
Bowen 1	T	LNCFS II (ICL) / SCR	FGD
Bowen 2	T	LNCFS II (ICL) / SCR	FGD
Bowen 3	T	LNCFS II (ICL) / SCR	FGD
Bowen 4	T	LNCFS II (ICL) / SCR	FGD
Branch 1	C	LNB (B&W) / SCR** – 2013	FGD** – 2013
Branch 2	W	LNB (B&W) / SCR** – 2013	FGD** – 2013
Branch 3	C	LNB (BBP) / SCR* – 2015	FGD* – 2015
Branch 4	C	LNB (BBP) / SCR* – 2015	FGD* – 2015
Hammond 1	W	LNB	FGD
Hammond 2	W	LNB	FGD
Hammond 3	W	LNB	FGD
Hammond 4	W	LNB / OFA (FW) / SCR (MHI)	FGD
Kraft 1	T	-	
Kraft 2	T	-	
Kraft 3	T	-	
McDonough 1	T	LNB / OFA	
McDonough 2	T	LNB / OFA	
McIntosh 1	W	OFA	
Mitchell 3	T	-	
Gaston 1	W	LNB (B&W)	
Gaston 2	W	LNB (B&W)	
Gaston 3	W	LNB (B&W)	
Gaston 4	W	LNB (B&W)	
Scherer 1+	T	OFA / SCR – 2013	FGD – 2014
Scherer 2+	T	OFA / SCR – 2013	FGD – 2013
Scherer 3+	T	OFA / SCR	FGD
Wansley 1	T	LNCFS II (ABB-CE) / SCR	FGD
Wansley 2	T	LNCFS II / SCR	FGD
Yates 1	T	LNB / Gas Cofire Capability	Chiyoda Scrubber

Yates 2	T	NR / Gas Cofire Capability	
Yates 3	T	NR / Gas Cofire Capability	
Yates 4	T	FAN / CCOFA (ICL) / Gas Cofire Capability	
Yates 5	T	FAN / CCOFA (ICL) / Gas Cofire Capability	
Yates 6	T	LNCFS II (ICL) / Gas Cofire Capability / SCR* - 2014	FGD* – 2015
Yates 7	T	FAN / SOFA (ICL) / Gas Cofire Capability / SCR* - 2014	FGD* – 2015

Legend: T – tangentially fired, W – wall fired, C – cell burner, + – Baghouse to be installed.
* Projects with an asterisk have been suspended until more information is available from the on-going environmental rulemaking and legislative processes.
** The Company has requested decertification and retirement approval from the PSC. Projects are suspended.

Ozone Nonattainment Review
To meet the NO_X reduction requirements for the 1-hour and 8-hour Atlanta ozone SIPs, additional controls beyond those necessary for the Acid Rain Program were required.

Alternatives considered technologically, operationally, and economically feasible (for at least certain units) for controlling NO_X to meet the ozone requirements included:

- SCR.
- Upper furnace gas injection (10 percent).
- Overfire air (OFA).
- LNBs.
- Selective non-catalytic reduction (SNCR).
- Generic NO_X Control Intelligent System (GNOCIS).
- Low-NO_X Concentric Firing System (LNCFS) I - III.
- Asea Brown Boveri (ABB) P2 burner tips.
- Cofire natural gas.
- Natural gas reburn.
- Deep-staging low-NO_X burners (ABB TFS 2000R).
- Separated overfire air (SOFA).
- Natural gas conversion.

- Close-coupled overfire air (CCOFA).
- Switch to PRB coal.

Analysis of the best solution for NO_X reduction at affected units considers the capital and operating cost of the controls, as well as their performance and resulting production cost savings. In the case of meeting the 1-hour SIP for the Atlanta area, Plants McDonough, Yates, Bowen, Wansley, and Hammond met specific source NO_X targets or an average 0.13-lb/mmBTU rate during the ozone season. Plants Scherer and Branch are also affected and met specific NO_X targets or comply as part of the seven-plant, 0.18-lb/mmBTU rate during the ozone season. In addition, Plant Scherer is required to comply with a site-average emission rate of 0.17-lb/mmBTU rate during the ozone season. The seven plant rate and the Scherer site-average rate were revised by the Georgia EPD effective May 1, 2007 to help address 8-hour ozone attainment in Macon, Georgia. Actual compliance implementation decisions were made based on a technical review of the compliance alternatives, equipment-vendor price quotes, specific unit issues, and performance guarantees.

Plant Scherer Units 1, 2, and 3 have been switched to PRB coal to lower NO_X emissions. In addition to controls required to comply with ozone nonattainment area requirements, the Georgia Multipollutant Rule, issued in June 2007, requires the installation and operation of SCR systems at certain additional units by specified dates between 2008 and 2015.

CAIR Annual NO_X Compliance
The Southern Company and GPC CAIR Annual NO_X compliance strategy involves purchasing allowances for CAIR Phase I (2009-2014) to supplement reductions from NO_X controls. The Annual NO_X strategy can include fuel switching from coal to natural gas, low NO_X burners, selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), the use of banked and purchased Annual NO_X allowances, and unit retirement. The strategy for the purchase of allowances is included later in this section.

Like the SO_2 market, the Annual NO_X allowance market has been marked by volatility following the vacatur of CAIR. The market for NO_X allowances dropped in price and trading volume in July 2008 and rose in December 2008 following the remand. Prices continued to fall in 2010 due to recession-driven electricity demand reductions and continued uncertainty over a CAIR replacement. Figure 4.1.2-1 shows historic Annual NO_X prices since 2008. Future allowance prices for NO_X under CSAPR are uncertain at this time but could possibly be higher than what current Acid Rain / CAIR allowances have been predicted to be in the future. The Georgia Power fuel budget calls for the continued reliance upon coal-fired generation over the next few years.

Annual NO_X allowance purchases and the use of NO_X controls across the Southern Company system have been instrumental in achieving CAIR Annual NO_X compliance. SCR emission control equipment will play a large role in current and future NO_X compliance, and, as discussed above, SCR equipment is currently being planned for additional units in Georgia and is being installed on other units across the Southern Company system. In addition to CAIR compliance, SCR equipment will likely be required on the Southern system to achieve attainment with the EPA's revised 8-hour ozone standard, which is expected to be finalized later in 2011. Any additional SCR equipment installations beyond those already required cannot be determined at this time and will be a function of individual unit economic efficiencies, energy demand, availability and price for allowance purchases, natural gas prices, and other variables.

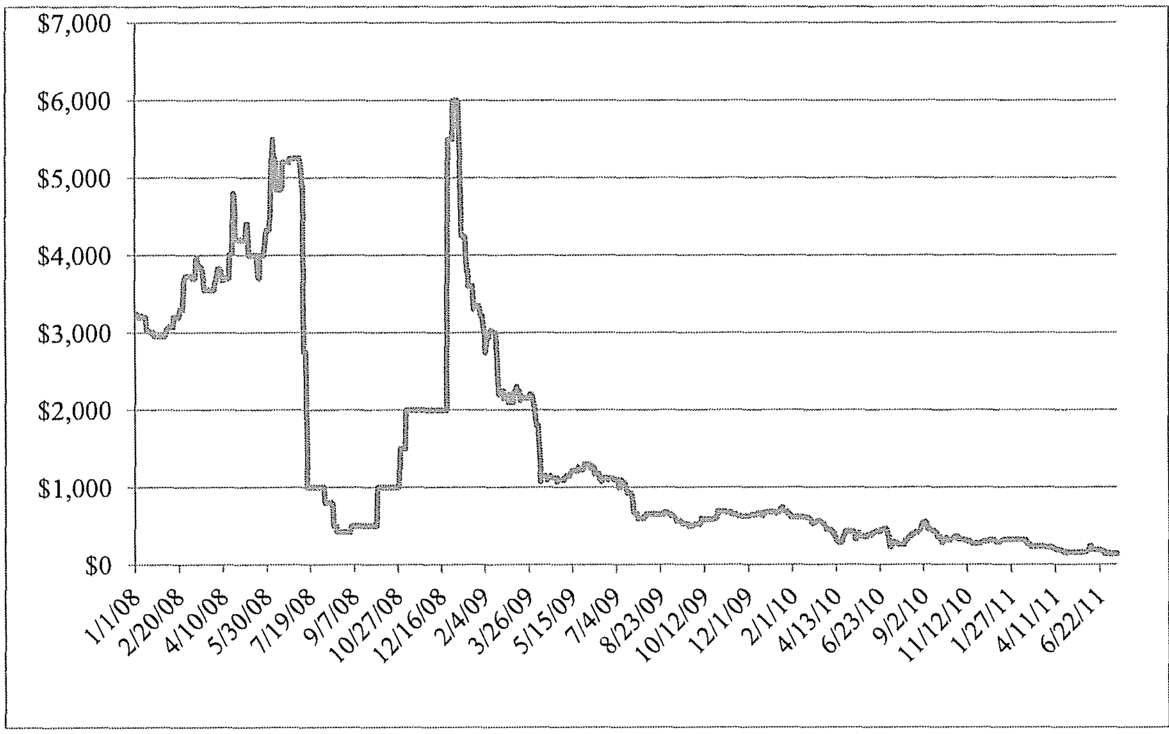

Figure 4.1.2-1 Historic Annual NO_X Price Summary

CAIR Seasonal NO_X Compliance

The Southern Company and GPC CAIR Seasonal NO_X compliance strategy is functionally identical to the Annual NO_X compliance strategy. Compliance is assured through a mix of Seasonal NO_X allowance purchases and NO_X emission controls. Emissions control decisions are driven by Annual NO_X compliance.

In past years, Southern Company's only exposure to a Seasonal NO_X program was through the NO_X Budget Trading Program (the Regional NO_X SIP Call Rule), and only for units above the 32^{nd} parallel in the State of Alabama. All of the Southern Company states, with the exception of Georgia, are subject to the CAIR Seasonal NO_X program. Thus, in 2011, GPC's exposure to the

CAIR Seasonal NO_X program is still isolated to its ownership interest in Plant Gaston Units 1 – 4 in Alabama. In 2012, however, when CSAPR goes into effect, all of the GPC's facilities will be included in the CSAPR seasonal NO_x program. While the CSAPR compliance strategy is still under development, it will likely include purchasing allowances to meet the compliance need for emissions beyond those that are controlled and covered by allocated allowances.

The needs and the costs for purchasing Seasonal NO_x allowances vary on a year-by-year basis. The current Seasonal NO_X market is depressed along with Annual NO_X for the same reasons. Figure 4.1.2-3 shows historic Seasonal NO_X prices. The market transition from the end of the NO_X Budget Trading Program to the start of the CAIR Seasonal NO_X Program was seamless. However, as with the SO_2 program, EPA is discontinuing the CAIR NOx allowance programs and is establishing new NOx trading programs with new allowances under CSAPR beginning in 2012. CAIR NOx allowances cannot be used for CSAPR compliance. Future allowance prices for NO_X under CSAPR are uncertain at this time but could possibly be higher than what current Acid Rain / CAIR allowances have been predicted to be in the future.

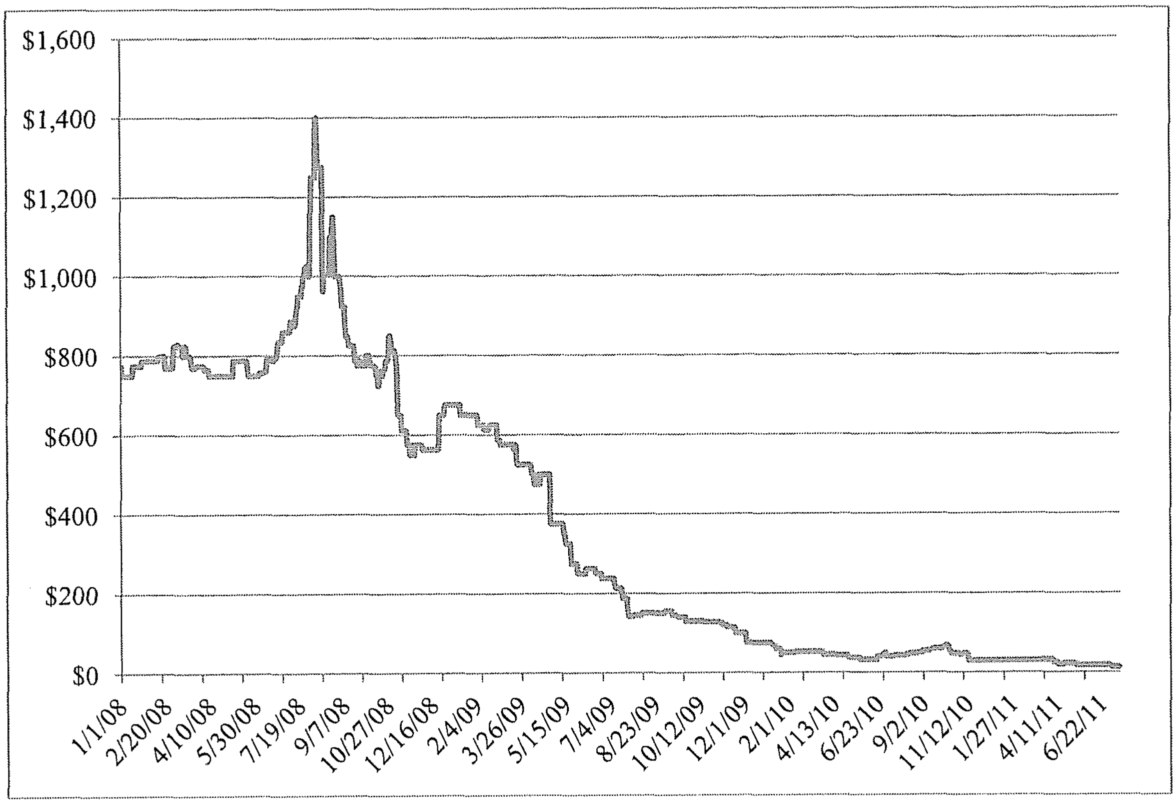

Figure 4.1.2-3 Historic Seasonal NO_X Price Summary

4.1.3 Utility MACT Standards

As the EPA proceeds in developing a new Utility MACT Rule, the company has been assessing whether the installed technologies will be sufficient to comply with the MACT standards and evaluating what additional controls may be necessary. Based on the company's analysis of the proposed rule and performance of the controls installed to date, additional controls may be required, even at plants already equipped with SCRs and scrubbers. Specifically, it appears that baghouse systems and scrubbers may be required in order to meet the proposed standards at all coal-fired units. On EPA's current schedule, the rule would require compliance within three years of publication of the final rule in the Federal Register (expected as early as 2015) with the possibility of a one-year extension (expected 2016).

Even with a possible 1-year extension of the compliance deadline, the Company has determined that it would need to begin making capital expenditures as early as January 2012 in order to strive to complete construction of the required baghouse controls on a subset of units by the extended compliance deadline. Work necessary to begin could include detailed engineering studies, deep foundation work, relocations of existing equipment on site, and any other work necessary to strive to meet the schedule for the expected compliance deadline of the Utility MACT. At the same time, while the company is projecting that baghouses may be required for MACT compliance, these analyses are based on the proposed rule, and no determination can be made regarding the ultimate compliance strategy until after EPA issues a final Utility MACT Rule.

4.2 Clean Water Strategy Review

For a discussion of the current water initiatives under consideration at EPA under the Clean Water Act as it applies to new and existing facilities, see section 2.10. The general impact on Southern Company and Georgia Power is included in the discussion.

Water Intake Structures
Georgia Power is currently evaluating compliance alternatives for the proposed Section 316(b) rules, which may include the addition of fine-mesh screens and/or other technologies such as cooling towers at certain facilities. Although the implications of this rule may be different for each plant, it is expected that varying combinations of robust biological studies, intake structure modifications, and cooling towers will be required. Exact compliance requirements are uncertain at this time and final regulations are expected in 2012.

Wastewater Treatment Facilities
As GPC brings a number of FGD systems online, wastewater at plants with these systems will possibly be impacted. Additional treatment facilities may be required to meet existing state water quality criteria or to comply with future federal effluent guidelines revisions.

4.3 Coal Combustion Byproducts (CCBs)

Southern Company and GPC are currently evaluating compliance alternatives and requirements under the proposed CCR rule The financial and operational impacts of this rule will depend on numerous factors, including: whether coal combustion byproducts will be regulated as hazardous waste or non-hazardous waste; whether the EPA will require early closure of existing wet storage facilities; whether beneficial reuse will be limited or eliminated through a hazardous waste designation; whether the construction of lined landfills is required; whether hazardous waste landfill permitting will be required for on-site storage; whether additional wastewater treatment will be required; the extent of any additional groundwater monitoring requirements; whether any equipment modifications will be required; the extent of any changes to site safety practices under a hazardous waste designation; and the time period over which compliance will be required.

Because the rule is not final, exact compliance requirements are uncertain at this time and will be determined in the final rule which is not expected before 2012.

GPC will continue to comply with all existing and future state and federal regulatory requirements and is continually seeking to increase appropriate beneficial use of coal combustion byproducts that it generates.

4.4 Strategy and Schedule

The environmental strategy and schedule continues to evolve, even as state and federal requirements are being proposed and finalized. The current 2011 GPC environmental strategy and schedule for both Air (Fig. 4.4-1) and Land and Water (Fig. 4.4-2) are provided in the following figures. Projects shown in red are either under construction or committed projects. In general, certain aspects of the strategy are constantly under reevaluation and the schedule remains dynamic.

REDACTED

Figure 4.4-1 Environmental Compliance Schedule (Air Only)
2011 Financial Plan for GPC

Scrubber requirements were assessed first to meet Acid Rain and CAIR requirements and expected $PM_{2.5}$ state implementation plans. The need for SCRs was assessed for 8-hour ozone state implementation plans and future reductions to the ozone standard. The scrubbers and SCRs will also be a major consideration for compliance with CAVR. GPC has been notified that all facilities are in compliance with CAVR through at least 2015. Mercury emissions are also reduced at units with both scrubbers and SCRs. GPC has included possible additional baghouses in its current schedule above and intends to initiate work in 2012 necessary to strive to meet the expected compliance deadline of the Utility MACT, as discussed above in Section 4.1.3. These are shown in the 2015 to 2017 time frame as an illustration of possible project completion dates. Exact completion dates will depend upon the result of the final rule and the issuance of available compliance extensions.

REDACTED

Figure 4.4-2 Environmental Compliance Schedule (Land and Water)
2011 Financial Plan for GPC

In addition to those projects included above in the current land and water schedule, additional compliance obligations are possible as a result of new or revised future rules. Intake structure upgrades, fine mesh screens, and/or cooling towers could be required for anticipated 316(b) requirements. Wastewater treatment is planned at units with scrubbers to comply with anticipated revisions to the Steam Electric Effluent Guidelines or to meet existing state water quality criteria. The State of Georgia's dissolved oxygen TMDL (Total Maximum Daily Load) requirements for the Coosa River may be issued in 2012 and will likely include a requirement to reduce Plant Hammond's thermal discharge which could require cooling towers. EPA's final CCR rules may require activities such as groundwater monitoring, dry handling of ash, landfill construction, and closure of existing ponds.

4.5 Financial Summary

The previous sections of this document describe in detail the requirements, concepts, and activities that comprise the environmental strategy of Southern Company, including GPC. The capital costs for meeting these requirements and for performing these activities are discussed in this section. Through 2010, GPC invested approximately $3.7 billion in capital projects to comply with these requirements, with annual totals of $217 million, $440 million, and $689 million for 2010, 2009, and 2008, respectively. GPC expects capital expenditures to ensure compliance with existing statutes and regulations will be an additional $73 million, $79 million, and $58 million for 2011, 2012, and 2013, respectively. In addition, the Company currently estimates that potential incremental investments to comply with anticipated new environmental regulations could range from $74 million to $289 million in 2011, $191 million to $670 million in 2012, and $476 million to $1.9 billion in 2013. The Company's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of any new or revised environmental statutes and regulations that are enacted, including the proposed environmental legislation and regulations described below; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix.

For example, the Utility MACT rulemaking, discussed in Section 2.6, is expected to be finalized by the end of 2011. Based on the proposed rule, it appears that baghouse systems may be required for continued operation of our larger coal-fired units in order to meet the proposed standards. Because the compliance schedule will likely be very short, GPC plans to include costs in the 2012 and 2013 budget to initiate the work necessary for the possible installation of baghouses.

Title IV of the 1990 Clean Air Act required reductions in SO_2 and NO_X emissions from fossil-fired generating plants in two phases. As the Company has complied under the Phase II SO_2 limits for several years, the emission allowance bank is being depleted and emission controls or additional allowance purchases will be necessary to maintain compliance. The company's allowance purchase strategy is discussed below.

Additionally, equipment to control NO_X emissions was installed on additional system fossil-fired units as necessary to meet Phase II limits and initial ozone nonattainment requirements for metropolitan Atlanta. The capital costs for GPC totaled about $123 million through 2000.

4.5.1 Allowance Strategy

Southern Company and GPC manage allowance resources by balancing compliance with value. It is imperative to ensure sufficient allowances are available and allocated to the correct generating unit accounts to satisfy the requirements of the CAAA and CAIR. The planning process outputs projected allowance needs over time for GPC. However, the volume of allowances surrendered for compliance will depend upon the individual unit operations realized within that compliance year. Southern Company, functioning as a centrally dispatched system, has a mechanism in place to track unit operations. At the end of a compliance period, any reallocation of allowances between or among units only takes place at the operating company level.

Value management focuses on optimizing the use of the allowances available to GPC. The goal of value management is to plan for the ultimate disposition of allowances in a manner that will serve in the best interest of GPC's customers.

4.6 Strategy Summary

The assumptions detailed in this Environmental Compliance Strategy and the results of the evaluation of control and compliance options herein have been used in the Company's 2011 Unit Retirement Study included in this August 4th 2011 IRP Update filing.

APPENDIX B-1

ACRONYMS/ABBREVIATIONS AND TERMINOLOGY

ABB	Asea Brown Boveri (LNB vendor).
ABBCE	Asea Brown Boveri Combustion Engineering.
B&W	Babcock & Wilcox (LNB vendor).
BACT	Best Available Control Technology.
BART	Best Available Retrofit Technology.
BBP	Babcock Borsig Power
BOOS	Burners Out-of-Service.
CAA	Clean Air Act.
CAAA	Clean Air Act Amendments (of 1990).
CAIR	Clean Air Interstate Rule.
CAM	Compliance Assurance Monitoring.
CAVR	Clean Air Visibility Rule.
CCOFA	Close-Coupled Overfire Air. (Refer to Appendix B-2 for description.)
CEM	Continuous Emissions Monitoring System.
CFS	Concentric Firing System.
CO	Carbon Monoxide.
CO_2	Carbon Dioxide.

COHPAC	Compact Hybrid Particulate Collector.
COP	Conference of Parties.
CWA	Clean Water Act.
DOE	Department of Energy.
DSM	Demand Side Management.
EAV	Equivalent Allowance Value.
EEI	Edison Electric Institute.
EPA	Environmental Protection Agency.
EGU	Electric Generating Unit.
EPRI	Electric Power Research Institute.
EPCRA	Emergency Planning and Community Right-to-Know Act.
ERC	Early Reduction Credits.
ESP	Electrostatic Precipitator.
FAN	Flame Attachment Nozzle - A low-NO_X burner tip design by ICL.
FCCC	Framework Convention on Climate Change.
FGC	Flue Gas Conditioning.
FGCS	Flue Gas Conditioning System. (Refer to Appendix B-2 for description.)
FGD	Flue Gas Desulfurization.
FW	Foster Wheeler (LNB vendor).
GEPD	Georgia Environmental Protection Division.

GNOCIS	Generic NO_X Control Intelligent System.
GPC	Georgia Power Company.
HAP	Hazardous Air Pollutant.
HCN	Hydrogen, Carbon, and Nitrogen.
HDPE	High-Density Polyethylene.
Hg	Mercury.
IAQR	Interstate Air Quality Rule.
LAER	Lowest Achievable Emission Rate.
LNB	Low-NO_X Burner.
LNCFS	Low-NO_X Concentric Firing System. (Refer to Appendix B-2 for description.)
LNCFS I	LNCFS + CCOFA.
LNCFS II	LNCFS + SOFA.
LNCFS III	LNCFS + CCOFA + SOFA.
MACT	Maximum Achievable Control Technology.
NAAQS	National Ambient Air Quality Standards.
NH_3	Ammonia.
NO_2	Nitrogen Dioxide.
NO_X	Nitrogen Oxide.
NPDES	National Pollution Discharge Elimination System.
NR	Not required for compliance under current averaging plans.

NSR	New Source Review.
OFA	Overfire Air. (Refer to Appendix B-2 for description.)
PAC	Polycyclic Aromatic Compound.
PJFF	Pulse-Jet Fabric Filter.
PM	Particulate Matter.
PM-2.5	Particulate Matter less than 2.5 micrometers in size.
PM-10	Particulate Matter less than 10 micrometers in size.
PRB	Powder River Basin.
PROMOD	Computer simulation model for evaluating production cost.
PROVIEW	Computer simulation model for evaluating production cost.
PROVAL	Cost analysis and financial computer software application.
RACT	Reasonably Available Control Technology.
RCRA	Resource Conservation and Recovery Act.
ROFA	Rotating Overfire Air.
SCR	Selective Catalytic Reduction. (Refer to Appendix B-2 for description.)
SIP	State Implementation Plan.
SNCR	Selective Noncatalytic Reduction. (Refer to Appendix B-2 for description.)
SO_2	Sulfur Dioxide.
SO_3	Sulfur Trioxide.

SOFA	Separated Overfire Air. (Refer to Appendix B-2 for description.)
T-Fired	Tangential or tangentially fired.
TMDL	Total Maximum Daily Load.
TRI	Toxics Release Inventory.
UFGI	Upper Furnace Gas Injection.
UPS	Unit Power Sales.
UVB	Ultraviolet-B.
USWAG	Utility Solid Waste Activities Group.
UWAG	Utility Water Act Group.
VCCOFA	Vane Closed-Coupled Overfire Air.
VOC	Volatile Organic Compounds.
ZECA	Zero Emission Coal Allowance.

APPENDIX B-2

EMISSION CONTROL ALTERNATIVES

INDEX

XVIII.	Activated Carbon Injection
XIX.	Chemical Injection for Mercury Removal
XX.	Mercury Research Center
XXI.	FGDexpert™
XXII.	High Temperature Sorbent Injection
XXIII.	Plasma Enhanced Electrostatic Precipitator
XXIV.	Containment and Control Technologies for Ash Storage Areas
XXV.	Cooling Water Intake Screen Technology
XXVI.	Water Cooling Technologies

EMISSION CONTROL ALTERNATIVES

I. Selective Catalytic Reduction (SCR)

SCR technology involves the catalytic reaction of ammonia (NH_3), which is injected into the flue gas, with NO_X to produce molecular nitrogen (N_2) and water vapor. These reactions take place across multiple layers of catalyst in the SCR reactor and generally result in a NO_X reduction capability of 85 to 90 percent depending upon the particular application. Theoretically, the NO_X and ammonia react in the presence of SCR catalysts. However, side reactions that produce undesirable byproducts can occur between ammonia and sulfur trioxide (SO_3) in the flue gas.

The SCR operating temperature ranges from 550 to 750°F. As a result, the SCR system normally is located in a high-dust configuration between the boiler economizer flue gas outlet and the air preheater flue gas inlet where the above temperature range normally occurs. Prior to entering the reactor, ammonia is injected into the flue gas at a sufficient distance upstream of the reactor to provide for adequate mixing of the ammonia and flue gas. The quantity of ammonia injected is adjusted to maintain the desired NO_X reduction level (within design limits). NO_X emissions are reduced in direct proportion to the quantity of ammonia injected up to an ammonia-to-NO_X ratio (NH_3/NO_X) of approximately 0.80. Above this value (and as the activity of the catalyst declines with age), some of the ammonia can escape the SCR reactor as ammonia slip. This ammonia can react with small quantities of SO_3 present in the flue gas to form ammonium bisulfate, which can foul and/or increase the corrosion potential for downstream equipment.

II. Selective Noncatalytic Reduction (SNCR)

SNCR employs chemical injection of ammonia or urea directly into the boiler at a flue gas temperature between 1,600 and 2,100°F. In this temperature range, which is typically near the top of the boiler close to the furnace exit or in the convective pass, the reagent reacts with NO_X to form nitrogen and water without the use of a catalyst to promote the reaction.

As with SCR, the ammonia slip constraint imposes a limit on the maximum amount of NO_X that can be removed with the SNCR process. Because the process is so temperature sensitive, the ability to follow boiler load becomes critical when constrained by ammonia slip limits. Advanced SNCR systems use retractable injection lances that improve load-following control for the process. These lances use a "jet curtain" to provide better cross-sectional coverage and rotation of the lance allows for better response to process signals such as boiler load or furnace temperature.

Application of SNCR to utility-scale boilers is highly site specific. Generally, SNCR is capable of 15- to 40-percent NO_X removal, consistent with a 5-ppm ammonia slip constraint. Removal levels above 40 to 50 percent are difficult to achieve due to the high-ammonia slip that is produced, the stringent requirements placed on the distributions for injected reagents, and the narrow temperature window required for the reaction.

One particular benefit of SNCR as compared to SCR is that capital cost is limited due to the absence of catalyst and the associated reactor vessel. However, potentially much higher ammonia slip levels cause increased downstream problems. In addition, the difficulty in meeting temperature and distribution requirements makes implementation of the technology difficult on many boilers, especially on a large scale boiler (typically greater than 300 MW). SNCR systems also generally require more reducing agent for a given NO_X reduction than do SCR systems since part of the reducing agent can be oxidized at the higher injection temperature, representing an initial loss of reagent. Furthermore, the oxidation product is often NO_X, requiring additional reagent to remove the NO_X formed via oxidation.

III. HERT SNCR Technology

HERT (High Energy Reagent Technology) is a novel type of SNCR system, owned by ACT (Advanced Combustion Technology). The HERT technology still incorporates the injection of urea into the appropriate temperature window in the furnace in order to achieve the desired reaction between NO_X and ammonia to produce nitrogen and water. However, certain aspects of the HERT system may allow for the use of fewer injectors and less chemical while achieving greater NO_X reductions at the same ammonia slip (<5ppm). HERT uses high velocity carrier air and specially-designed nozzles to allow the urea to penetrate further into the boiler. The carrier air flows around the urea, protecting it upon its initial entrance into the furnace and allowing it to travel further inside, and a mechanical atomizer controls the depth and droplet sizes of the urea spray. Smaller droplets are desired for instant vaporization and immediate reaction with NO_X. Larger droplet sizes are desired where delay of the vaporization of urea is necessary to hit the targeted temperature window. With better penetration, better removals are achieved, and with fewer injectors and less chemical required, capital and O&M costs are potentially lower for this system than for conventional SNCR systems.

HERT systems can be installed as high- or low-momentum systems, or as a combination of both. The high-momentum system involves injection of urea into existing OFA ports, and can achieve up to 55 percent NO_X reduction, while the low-momentum system uses a small blower to provide carrier air for urea injection into the upper furnace. Commercial demonstrations of the low-momentum system have shown approximately 30 percent or greater NO_X reductions.

IV. Cofiring Natural Gas

Cofiring natural gas involves the simultaneous firing of natural gas and pulverized coal in a boiler's primary combustion zone. The cofiring rate, or percentage of heat input from natural gas, is typically 10 to 20 percent, but it may be more or less depending on boiler design requirements, gas prices, and availability of natural gas. The advantage of cofiring natural gas with coal is to reduce NO_X emissions with low-capital cost. NO_X reductions come as a result of the lower nitrogen content of natural gas. The disadvantage of cofiring natural gas includes increased flue gas moisture content that results from combustion of the higher hydrogen content of natural gas.

V. Upper Furnace Gas Injection (UFGI)

UFGI involves the injection of a small percentage (3 to 7 percent) of natural gas (on a Btu input basis) into the upper furnace of a boiler. To reduce NO_X emissions, the gas is combusted in a low-oxygen environment at temperatures ranging from 2,000 to 2,400°F. Simply put, methane in the natural gas reacts with NO_X to form hydrogen, carbon, and nitrogen (HCN) and oxygen. The HCN product further reacts with other NO_X to form nitrogen, water, and carbon dioxide. This process is typically carried out without the use of "burn-out" air above the gas injection zone. The limiting parameter of the performance of UFGI is primarily carbon monoxide (CO) emissions resulting from overall fuel-lean furnace conditions.

Amine-Enhanced Fuel Lean Gas Reburn (AEFLGR™) Process

The AEFLGR™ Process is a combination of the Fuel Lean Gas Reburn (FLGR™), developed by Energy Systems Associates and the Gas Research Institute, with the NOxOUT™ SNCR Process, commercialized by Fuel Tech, Inc. In AEFLGR™, natural gas is introduced into the boiler above the primary combustion zone using high velocity gas jets. NOxOUT™ reagent (urea-based) is injected as a liquid within the gas jets. The flow rate of gas is controlled in order to maintain an overall fuel-lean stoichiometry in the upper furnace. Selective chemical reactions between the nitrogen oxides and the decomposition products of the gas and urea reduce the level of NO_X emissions.

The NOxOUT™ SNCR Process operates most effectively when the flue gas temperatures are between 1,700-2,000°F. Above this temperature range a portion of the amine species oxidizes to NO. Below these temperatures, the reaction rates are much slower and intermediate species (such as ammonia compounds) do not have time to fully react. Addition of natural gas in the AEFLGR™ Process widens this temperature range, so NO_X reduction can be achieved from 1,700-2,300°F.

Reduction of NO using gas reburning is most effective when oxygen levels are low. However, under conditions of very low oxygen, the hydrocarbon species do not completely combust, resulting in high levels of CO and LOI (i.e., unburned carbon in ash). High CO levels can interfere with SNCR reactions, and can exceed emissions limits. Consequently, there is a practical limit to the operating levels of O_2 – too low results in operations and emissions problems; too high results in less than optimal NO_X reduction.

FLGR™ and AEFLGR™ differ from traditional gas reburning in that the amount of reburning fuel introduced is less than the amount required to consume all the excess air. The flue gas remains "fuel lean" in the reburn zone, and no additional air is required to complete combustion. Traditional reburning processes usually require combustion modifications and air supply modifications to create a burnout zone above the gas injection. Typically, in the FLGR™ and AEFLGR™ processes the reburn fuel accounts for up to 8 percent of the gross heat input of the unit, compared with 10 to 20 percent for traditional reburning and advanced reburning.

The AEFLGR™ process uses high velocity turbulent jets for dispersing gas into the furnace. As the jets mix with the flue gas, the combustion process consumes the excess oxygen. Often, the fuel and air are not evenly distributed in the boiler and regions of flue gas will have different compositions, including zones of high CO or high O_2. Adjustment of individual nozzles is often necessary to optimize performance.

Capital expenses for AEFLGR™ average $7-30/kW, depending on the size of the boiler. NO_X reductions from this technology have approached 60 percent; however, actual sustained performance is dependent on boiler size. Substantial NO_X reductions are challenging on large boilers due to load following constraints, reagent mixing, and temperature distribution. As with other furnace injection ammonia technologies, maintaining ammonia slip at tolerable limits is also a challenge for AEFLGR™. Ammonia slip excursions (>5-10ppm) result in balance of plant impacts such as air preheater pluggage and contaminated fly ash rendering it unsellable. As in the discussion of gas reburn technology, AEFLGR™ alone cannot achieve adequate NO_X reductions to meet regulatory requirements; therefore, this technology was not considered a viable option for this large boiler application.

VI. Low-NO_X Burners (LNBs)

Low-NO_X burner is a generic term for a burner designed to combust the fuel while reducing the amount of NO_X that is formed. Since there are several different firing arrangements for oil- and coal-fired boilers, there are several different types of LNBs.

NO_X is formed during combustion from either the nitrogen in the fuel or the air. NO_X formed from nitrogen in air requires high-flame temperatures and because of this, is usually referred to as thermal NO_X. Some fuels, particularly coal and oil, contain small amounts (2 percent or less) of nitrogen as a chemical constituent. When these fuels are burned, this fuel nitrogen can be oxidized in the flame-producing NO_X, which is referred to as fuel NO_X. Thus coal and oil can form NO_X from the thermal NO_X and the fuel NO_X mechanisms, but the fuel-nitrogen pathway is by far the predominant one. Since natural gas contains no fuel nitrogen, thermal NO_X *only* is formed, explaining why natural gas flames have much lower NO_X levels than coal.

LNBs for coal and heavy oil are designed to reduce NO_X by allowing the fuel nitrogen to be released from the fuel in a region with low-oxygen concentration. Most of the fuel nitrogen can then react to molecular nitrogen (N_2, which is present in the air). High temperatures are needed to extract most of the nitrogen from the fuel and low-oxygen concentrations are also necessary to prevent the fuel nitrogen from being oxidized. This approach is known as air staging because a portion of the combustion air must be introduced later in the combustion process to form this low-oxygen reduction zone. Wall-fired LNBs achieve this end by an aerodynamic trick in each burner's flame while, in a tangentially fired furnace, a portion of the secondary air is diverted above the flame (overfire air), producing a low-oxygen zone in the entire lower furnace.

LNBs for wall-fired units are typically dual-register burners. By using two separate registers for the secondary air, some of the secondary air is used to initiate and stabilize the flame (with inner-register air), while most of the secondary air is directed by the outer register to bypass the initial flame and then mix with the flame after the fuel nitrogen is released and converted to N_2. Different manufacturers use different hardware implementations for this process, but the general technical concept is much the same. Most also use some means of ensuring the flame stays attached to the tip of the burner. A stable, attached flame is a lower NO_X producer than either an unstable flame or a detached flame.

LNBs for tangentially fired boilers serve to assist in NO_X reduction by supporting the air staging used for the major NO_X reduction technique. The details of these different approaches are described below in items VIII, IX, and X.

VII. Overfire Air (OFA)

The most general approach to lowering NO_X produced in oil or coal combustion is to create a main flame zone that is deficient in oxygen and is known as a reducing atmosphere. If the temperature can be held high in this reducing zone, the majority of the fuel nitrogen can be driven from the fuel. Since little oxygen would be present, this fuel nitrogen then reacts to form molecular nitrogen (N_2), which is the main constituent of air. OFA is the air that is added to finish the combustion process started in the combustion zone. In a vertical flow typical of boilers, the reducing zone is the main combustion zone. OFA is added above this flame zone, thus the name "overfire" air.

Up to approximately 30 percent of the total air needed for combustion may be supplied as OFA. As the amount of OFA increases, the NO_X emissions of the combustion process decrease, up to a point. Any further increase in the amount of OFA above this point will cause the NO_X emissions to increase. The practical limitations on the amount of OFA that can be used are:

- Stability of the main flame.
- Corrosion of the metal steam tubes.
- Production of carbon monoxide.
- Increases in the amount of unburned carbon that escapes the furnace and is collected with the fly ash.

OFA is a part of most of the tangentially fired NO_X control systems described below items VIII, IX, and X. Generally, in these systems, the two types of OFA are:

- Separated overfire air (SOFA)
- Close-coupled overfire air (CCOFA)

As the names suggest, any OFA close to the main combustion zone is classified as close-coupled. When OFA is injected some distance above the main combustion zone, it is classified as SOFA. As the distance from the flame zone increases, the effectiveness of the OFA for NO_X control increases; however, the installation costs also increase.

OFA can be used in wall-fired configurations but has not been widely used due to the creation of excessive amounts of unburned carbon in fly ash.

VIII. Burners Out of Service (BOOS)

BOOS can be applied to the top row of burners to further reduce NO_X emissions at some units not equipped with OFA ducts. This NO_X reduction is usually accompanied by a lower maximum unit output.

IX. Low-NO_X Concentric Firing System (LNCFS)

The LNCFS is an invention of Asea Brown Boveri Combustion Engineering (ABBCE) intended to reduce NO_X emissions from a tangentially fired boiler. The LNCFS family of systems, including Levels I, II, and III, was developed to provide a stepwise reduction in NO_X emissions, with LNCFS Level III providing the greatest reduction. System descriptions are as follows:

A. Level I — In LNCFS Level I, a CCOFA system is integrated directly into the windbox. Compared to the baseline configuration, LNCFS, LNCFS Level I is arranged by exchanging the highest coal nozzle with the air nozzle immediately below it. This configuration provides the NO_X reduction advantages of an OFA system without pressure part changes to the boiler.

B. Level II — In LNCFS Level II, a SOFA system is used. This is an advanced OFA system having back-pressuring and flow-measurement capabilities. The air supply ductwork for the SOFA is taken from the secondary-air duct and routed to the corners of the furnace above the existing windbox. The inlet pressure to the SOFA system can be increased above windbox pressure using dampers downstream of the takeoff in the secondary-air duct. The intent of operating at a higher pressure is to increase the quantity and injection velocity of the OFA into the furnace. A multicell venturi is used to measures the amount of air flow through the SOFA system.

C. Level III — LNCFS Level III uses both CCOFA and SOFA.

In addition to OFA, LNCFS incorporates other NO_X-reducing techniques into the combustion process. Using offset air, two concentric circular combustion regions are formed. The inner region contains the majority of the coal, thereby being fuel rich. This region is surrounded by a fuel-lean zone containing combustion air. For this purpose, the size of this outer circle of combustion air will be varied using adjustable offset air nozzles. The separation of air and coal at the burner level further reduces the production of NO_X.

X. Deep-Staging Low-NO_X Burners (ABB TFS 2000R)

Asea Brown Boveri Combustion Engineering's (ABBCE) TFS 2000R system was a major evolution of the ABBCE LNCFS family of low-NO_X products. The four major components of this system are:

- Precise furnace stoichiometry history control.
- Initial combustion process control.
- Concentric firing.
- Dynamic classifiers installed on the pulverizers.

The control of furnace stoichiometry uses multiple levels of OFA to stage the combustion process and pushes the stoichiometry of the flame zone to more severe reducing conditions than any of the other LNCFS systems. Thus, the TFS 2000R system achieves deeper staging of the combustion air.

The initial combustion process control is achieved by the use of coal nozzle tips to control the flame front. If the flame front is held on the nozzle tip, mixing of air and coal is delayed and helps the de-volatilization of the coal to proceed under low-oxygen conditions. The concentric firing system is utilized in all of ABBCE's low-NO_X products described above. Finally, dynamic classifiers are added to the coal pulverizers to reduce the initial coal-particle size that is fed to the combustion process, which should help reduce the amount of unburned carbon that escapes the radiant furnace.

The TFS 2000 system is available for new plant construction and has been used at a facility located near Richmond, Virginia. The "R" designation at the end of the TFS 2000 trademark is to identify it as a retrofit option for existing power plants. Given an existing plant, design compromises due to furnace size, access, location of air ducting, etc., mean that a retrofit installation will rarely meet the projections for a new plant TFS 2000 system and normally will have a less impressive NO_X performance.

XI. Low-NO_X Burner Tips (ABB P2)

ABBCE's P2 system is a standard offering for smaller T-fired boilers. This arrangement, offered as a retrofit to the conventional, higher NO_X original burner system, consists of new coal burner tips, the concentric firing system (CFS) nozzle tips, and conversion of the top-air compartments to vaned close-coupled overfire air (VCCOFA) nozzles. These burner tips cause the flame to stay attached to the nozzle and limit the mixing of the air and burning coal near the nozzle exit. The CFS is identical to that described above for the LNCFS levels. These first two changes do help lower NO_X, but most of the NO_X reduction is achieved through the installation of the VCCOFA nozzles. In the burner retrofit, the top-air nozzle is removed and replaced with the VCCOFA nozzles. These nozzles point the air upward at a fixed angle and have low drag to air flow, which serves to increase the amount of air going through the nozzles. The VCCOFA is an invention that ads OFA capability without windbox, duct, or pressure-part changes.

Overall, the P2 firing system is a relatively modest low-NO_X firing system that also has a moderate NO_X performance. In the first installation at Duke Energy's Cliffside Unit 3, NO_X was reduced approximately 47 percent with an increase in LOI from 10.3 to 13.4 percent.

XII. Generic NO_X Control Intelligent System (GNOCIS)

GNOCIS is an on-line enhancement to digital control systems and plant information systems targeted at improving unit performance parameters such as heat rate, boiler efficiency, NO_X emissions, and fly ash carbon levels. The GNOCIS methodology utilizes a neural network model of the boiler combustion process and when applicable, other plant processes. The software applies an optimizing procedure to identify the best set points for the plant, which are implemented automatically without operator intervention (closed loop), or, at the plant's discretion, conveyed to the plant operators for implementation (open loop). GNOCIS development was funded by the Electric Power Research Institute, PowerGen, Radian International, Southern Company, UK Department of Trade and Industry, and the U.S. Department of Energy.

As of January 1999, over 50 active or planned GNOCIS installations represent greater than 25,000 MW of generation. The installations include both Southern Company and external sites, and both wall- and corner-fired units. The NO_X reduction potential of GNOCIS is dependent upon many factors, including boiler type, fuel characteristics, goal definition, and the range permitted for recommended set points; however, to date, reductions of 10 to 20 percent have been observed on the majority of installations. In many of these, boiler efficiency/heat rate improvements have also been observed. Given the relative-low cost of the technology, GNOCIS is a cost-effective NO_X control option for many plants.

XIII. Rotating Overfire Air (ROFA) and Rotamix

ROFA is a second generation OFA system. Combustion is enhanced by creating upper boiler turbulence with high velocity air injection through asymmetrically located injection boxes in the boiler walls. Typically, this high velocity air is provided by additional booster fans and is introduced through injection boxes tangentially in the upper furnace region to disturb the otherwise stratified flow. This increased turbulence also increases retention time allowing more complete burnout of the flue gas constituents like NO_X, unburned carbon, and CO. Each ROFA installation is unit-specific to optimize efficiency.

Rotamix is a second generation SNCR system designed to work along with the basic ROFA system or without ROFA through injectors located in the upper furnace. One difference between the Rotamix technology and conventional SNCR systems is the introduction of the urea reagent with high velocity carrier air through the use of large fans. The amount of reagent added into the furnace is governed by the furnace temperature, fuel flow and steam production.

XIV. Powder River Basin (PRB) Coal

PRB coal is a subbituminous coal mined primarily from seams in the PRB located in the western United States. Reasons for broadening the use of PRB coal include favorable economics and the added benefits of lower fuel-bound nitrogen and sulfur components that enhance the ability of generating units to minimize NO_X, as well as SO_2 emissions. Additional NO_X reductions are realized because of the lower combustion flame temperature brought about by the higher moisture content in PRB coal. With this increase in moisture content come lower heat contents (heating values), suppression of mill outlet temperatures below design minimums, possible loss of generation due to unit-load deratings, and potential increased forced outage rates during the peak season. Increased heat rate and higher operating and maintenance costs are also usually associated with a switch to PRB coal from bituminous coal. Compacting the stockout piles and increased housekeeping around transfer points are considerations to alleviate potential problems with self-heating of the higher-reactivity PRB coal. Soot blower maintenance and increased boiler inspection may be required to maintain/sustain boiler operation. ESP capacity may also be affected and additional fields or flue gas conditioning may be required to adequately collect the PRB fly ash. The impact on SCR catalyst activity of elevated levels of alkali earth metals in PRB fly ash is also a concern.

XV. Flue Gas Desulfurization (FGD)

Flue gas from coal- and oil-fired boilers will contain sulfur oxides produced from any sulfur in the fuel. FGD is any process that removes these sulfur oxides, primarily sulfur dioxide (SO_2) with a small amount of sulfur trioxide (SO_3). These sulfur oxides, or SO_X, can range from 0.3 percent of the flue gas by volume down to several hundred parts per million. The two main types of processes are characterized by either wet- or dry-process chemistry.

As implied by the category, wet processes collect the SO_X by treating the flue gas with a water-based solution or slurry. One typical design the utility industry uses is a spray tower module where the flue gas flows up the tower and a series of nozzles spray an alkaline solution into the flue gas. The common chemical used in wet scrubbers is limestone ($CaCO_3$) and the solids produced by modern designs are predominantly calcium sulfate ($CaSO_4$), or gypsum. This gypsum can either be sold as a pre-cursor to wallboard, used for agricultural purposes or be disposed of in a landfill or pond. The wet processes are very efficient and remove 80 to 99 percent of the SO_2 in flue gas with 95 percent removal typical.

Dry processes inject an alkaline slurry into the flue gas stream in a spray dryer followed by a particulate control device. The spray dryer is a unit where the hot flue gases are contacted with the wet alkaline spray that absorbs the SO_2. The hot flue gas evaporates the water and leaves a dry residue that can then be captured with the fly ash, typically in a baghouse. ESPs are normally not used behind a spray dryer because of the high resistivity of the calcium residues that are added to the fly ash. The residue also contains a mixture of calcium sulfite/sulfate, along with the fly ash from the fuel. This waste is not suitable for other uses and must be disposed of in a landfill or pond. Dry scrubbing can remove 75 to 90 percent of the SO_2 in flue gas.

XVI. Flue Gas Conditioning (FGC)

FGC is a technique for improving the ability of an electrostatic precipitator (ESP) to collect fly ash from a coal-fired boiler. The inherent ability of fly ash particles to allow electric current to flow through a dust layer is known as resistivity. The electrical resistivity of the fly ash on the collecting plates of a precipitator in good mechanical condition has by far the greatest influence on precipitator performance. As the ash resistivity increases, the layer of fly ash collected on the plates of an ESP will conduct less current, which in turn degrades the ability to efficiently collect the fly ash. The most important use of FGC is to reduce fly ash resistivity.

FGC describes the injection of chemicals into the flue gas that subsequently collect with the fly ash and decrease the resistivity. The major chemical in use today for FGC is sulfur trioxide (SO_3). When SO_3 is injected into the flue gas, either upstream or just downstream of the air preheater, it immediately reacts with water in the flue gas to form sulfuric acid. The sulfuric acid either adsorbs or condenses on the surface of the fly ash and provides an ionic current path around the outside skin of the individual particle, thus lowering the apparent resistivity.

A twist on the SO_3 injection process is known as dual-conditioning, where ammonia and SO_3 are both added to the flue gas. The ammonia and SO_3 react and deposit on the fly ash surfaces, also providing a low-resistance-current path on the surface of the fly ash particles. The major product of this reaction is ammonium bisulfate. Ammonium bisulfate is a sticky particle that helps the fly ash layer captured on the ESP plates to adhere together. When the dust layer is physically shaken off the collection plates (called rapping), this added cohesivity of the fly-ash layer prevents small ash particles from becoming re-entrained in the flue gas stream and subsequently escaping the ESP (called rapping puffs). Two operational issues can result from dual conditioning:

- Possibility of creating deposits on the ESP internals that cannot be removed.
- Difficulty in selling ash containing ammonia salts.

Other commercial, proprietary compounds are available for flue gas conditioning but are not in widespread use.

XVII. Compact Hybrid Particulate Collector (COHPAC)

COHPAC is a novel, low-cost, retrofit particulate concept developed by EPRI to improve the performance of ESPs. The basic concept is to place a pulse-jet fabric filter (PJFF) downstream of an existing ESP to serve as a "polishing" or performance-upgrading unit. The flue gas enters the PJFF and passes through the fabric where the fly ash particles are filtered from the gas. The particles are collected on the outside of the fabric and the resulting dust layer is cleaned by air pulses (that is, the nomenclature pulse-jet fabric filters). Since the ESP removes a significant amount of the particles from the gas stream the flue gas reaching the baghouse has a significantly reduced dust load. The residual electrical charge from particle charging in the ESP and low-dust loading enables the COHPAC PJFF to operate at an air-to-cloth ratio (A/C) in the 8 to 12 range. (A/C is a ratio of the amount of gas to the amount of fabric present.) A typical full-scale PJFF must operate at A/C ratios of 4 or below, allowing the physical size of a COHPAC PJFF to be up to one-fourth the size of a normal PJFF, which reduces the cost significantly.

Currently, COPHAC can be deployed in two distinct configurations:

- COHPAC I, which a stand-alone casing to house the PJFF.
- COHPAC II, which uses the last field of the precipitator to house the PJFF.

XVIII. Activated Carbon Injection

Activated carbon injection (ACI) for Hg control involves the addition of powdered activated carbon to flue gas streams where it adsorbs vapor phase mercury. This powdered material is made by "cooking" low rank coals with steam and temperature to activate the surface, generating a highly reactive product that acts like a chemical sponge. Once injected into the flue gas, the activated carbon (and adsorbed mercury) must be collected in a particulate collection device. To date, the most common applications of this technology have either been 1) ahead of an electrostatic precipitator (ESP) or 2) downstream of an existing ESP but upstream of a high ratio (COHPAC) baghouse.

The first configuration mentioned above has been tested under various conditions with wide ranging results depending on contact time, fuel type, ESP size, and process conditions. Typically, due to rapid removal of the carbon in the ESP and limited contact time with the flue gas, these applications are limited to ~50-percent control of vapor phase mercury. A significant concern in this application is the co-mingling of activated carbon and fly ash, which typically renders the fly ash unsuitable for secondary use in building materials and forces the operator to dispose of this stream.

The second application, injection into a COHPAC baghouse, is an EPRI patented technology known as TOXECON^{TM}. This process attempts to limit the co-mingling of fly ash and activated carbon by collecting a high fraction of fly ash in the ESP before injecting the activated carbon. Furthermore, because the activated carbon is collected on bag surfaces (where it can stay up to several minutes), the TOXECON^{TM} process can typically achieve much higher removal rates than ESP injection (up to 90 percent), again depending on fuel type and process conditions. The primary drawback to this process is the added financial requirement in building a COHPAC baghouse, which will significantly affect the overall cost of mercury removal.

XIX. Chemical Injection for Mercury Removal

One relatively inexpensive way to capture and remove mercury from a flue gas stream is through the injection of chemical additives. Combustion of PRB coal produces primarily elemental mercury, which is insoluble in a wet flue gas desulfurization (scrubber) system. The presence of relatively high levels of elemental mercury in PRB flue gas is due to low levels of chlorine in the PRB coal, relative to other coals. High chlorine concentrations in many coals contribute to higher levels of oxidized mercury at the FGD inlet. Chlorine and bromine can be injected to oxidize mercury in PRB, and other low chlorine coals, so that the mercury can be captured in a flue gas desulfurization scrubber. This technology is currently being tested and if halogen injection proves to oxidize a high percentage of the elemental mercury, a costly baghouse, which can be used to capture elemental mercury, will not be needed. There may be other considerations needed for implementing this technology, including water treatment issues.

XX. Mercury Research Center

Construction of Southern Company's $5 million Mercury Research Center located at Gulf Power's Plant Crist in Pensacola, Florida, was completed in late 2005. This is the first mercury research facility of its kind in the world. The research facility houses major advanced control technology systems: a selective catalytic reduction system, a rotary air preheater, a cold-side electrostatic precipitator, a baghouse, and a wet limestone scrubber. Over the next few years, mercury capture performance will be evaluated with these advanced systems on a portion of the plant's emissions using different combinations of these devices.

The first phase of research, which began in early 2006, evaluated combinations of the five different advanced control devices. The research facility will further verify which known technologies and methods work best and could facilitate the development of new methods and technologies. As research continues, still other methods may be discovered and added for further investigation. DOE- and EPRI-sponsored test programs are under development. Programs will be sponsored by other utilities, chemical suppliers, system manufacturers, and others, and Southern Company will benefit from the work and the knowledge gained.

XXI. FGDexpert™

There is an emerging need for technology to monitor conditions and potential problems in flue gas desulfurization (scrubber) systems. FGDexpert™ is a developing neural network control system that can monitor scrubber conditions and performance. FGDexpert™ technology can also be helpful in compiling scrubber operating data for reference during testing and for future SO_X simulation models.

Significantly, FGDexpert™ can serve as a troubleshooting program for a scrubber unit. It draws and logs real-time data from the utility computer server. If any data point is out or off its operating parameters, the data point is tagged and recorded into an event log. The operator monitoring the system can see the tags and can to initiate action to correct problems. Data records may also be used for predicting scrubber outputs and for determining factors that influence scrubber efficiency.

If FGDexpert™ proves to be an operational asset, it can be incorporated into a plant's Operation Information System. Additional tags, such as the amount of mercury at the FGD outlet may be added to increase efficacy. If successful, similar programs which monitor other pollution abatement equipment can be developed.

XXII. Plasma Enhanced Electrostatic Precipitators

A prevalent cost-effective strategy for emission reduction involves co-control in existing pollution control devices. Specifically, oxidized mercury can be removed by electrostatic precipitators. This approach can work relatively well for bituminous coals but is less effective with subbituminous coals, such as PRB.

The high levels of difficult-to-control elemental mercury present in PRB make mercury removal much more difficult. One promising approach for controlling mercury from PRB-fired facilities involves a novel technology of plasma excitation using halogen gas injection. This system, known as a Plasma Enhanced Electrostatic Precipitator (PEESP), consists of a highly reactive gas injected into a wet ESP to oxidize and collect elemental mercury from coal-fired flue gas. When the reagent gas is introduced to the high voltage electrical field of the ESP, the formed ions bombard the elemental mercury and transform the mercury to a more water soluble form. Water injected into the wet ESP then removes the oxidized mercury. PEESPs can provide substantial mercury oxidation and removal with relatively low capital costs and low pressure drop

The limited tests showed up to a 50-percent removal of total mercury. PEESPs could potentially capture up to 70-percent of total mercury with a low pressure drop and relatively low capital costs, as compared to other mercury control devices. If the PEESP process proves to be successful in removing mercury from PRB flue gas, it may provide a more economic alternative to carbon injection and fabric filter technology for mercury control at Southern Company coal-fired plants.

XXIII. Containment and Control Technologies for Ash Storage Areas

Several technologies are available to control or prevent a release of contaminants from ash storage areas to groundwater. The most common technologies include liners, caps, slurry walls, sheet pile walls, grouting, and *in situ* solidification and stabilization. A brief description of each technology is provided below.

Liners

A liner is a layer of impermeable or low-permeability material placed at the bottom of ash storage facilities, which prevents ash leachate from entering soil and groundwater. Liners can be constructed of compacted natural material (such as clay), synthetic materials (such as high-density polyethylene, HDPE), or composite materials (combination of synthetic and natural materials). Regulations generally require liners under new ash storage areas.

Caps

A cap is a layer of impermeable or low-permeability material placed on top of ash storage areas, to prevent surface water infiltration and resulting leachate. By preventing water movement through the ash, transport of contamination from ash to groundwater is prevented or reduced. As with liners, caps can be constructed of natural materials (for example, compacted clay), synthetic materials (HDPE), or a composite. Capping may be used in conjunction with liners or barrier walls to encapsulate a material in place.

Slurry Walls

Slurry walls are subsurface walls constructed in trenches excavated down to the top of a relatively low-permeability layer, such as clay or bedrock. The trench is filled with a slurry of materials that forms an impermeable barrier to prevent contaminant migration within the area. Slurry materials can include various mixtures of soil, bentonite clay, and/or cement.

Sheet Pile Walls

Sheet piling includes interlocking wood, concrete, or steel sectors driven into the ground or forced into predug trenches, usually to the top of a relatively impermeable layer (for example, clay or bedrock). As with slurry walls, sheet pile walls form an impermeable barrier to prevent migration of contaminated water. Steel sheet pilings are the most reliable and most commonly used. Sheet piling is often used as a temporary measure of containment while dewatering or excavation, or while other containment is constructed.

Grout Curtains

A grout curtain is a method of sealing gaps in subsurface geology by injection of grout to fill voids in fractured rock, or to consolidate soil by filling the pore space. The grout material may be a Portland cement mix or any fluid material that hardens, such as a resin or sodium silicate. The grout material is injected as a pressurized fluid through holes drilled into the ground, generally in rows. Under ideal conditions, the injected fluids harden to create a relatively impermeable barrier, similar to a wall, in the subsurface.

In situ Solidification/Stabilization

Solidification/stabilization describes the technique of solidifying a contaminated soil or waste material (e.g., a sludge), to immobilize the contaminant both chemically and physically, and to reduce the leaching potential to groundwater. Solidification refers to the addition of a binder to produce a solid. Stabilization refers to the addition of a chemical agent to convert the soil or waste material to a more chemically stable form. Some additives, such as Portland cement, produce both physical and chemical changes. Large augers or equipment with rotary blades are used to mix the additives with contaminated soil or waste material.

XXIV. Cooling Water Intake Screen Technology

Inclined traveling screens will generally be the preferred water screen technology. The screens will allow debris handling and the design is also adaptable to minimize impingement and entrainment. Screen wash systems can maintain screen cleanliness to an acceptable level. If needed, continuous fish and debris handling systems can also be designed to work with inclined traveling screens. As needed, fish-return technologies are also available.

XXV. Water Cooling Technologies

The preferred mode of handling thermal issues at power plants can vary depending on the anticipated compliance period. For long-term solutions, conversion to closed-loop cooling water use with cooling towers might be preferable to installing one or more helper cooling towers. Conversion to a closed-loop cooling water system may also help reduce water flow through the intake, allowing appropriate intake technology to be installed. However, consumptive use of water will be increased from use of cooling towers. The issue of hot water blowdown from the cooling tower loop can be addressed by using blowdown from the cold side of the loop.

Conversion to a closed-loop system needs to be considered carefully, since it will mean that all the materials in the loop (e.g., condenser tubes) will be exposed to water that may be significantly more aggressive than with a once-through water system.

APPENDIX B-3

HIGH-LEVEL AND LOW-LEVEL RADIOACTIVE WASTE STORAGE PLANTS HATCH AND VOGTLE

Georgia Power's sister company, Southern Nuclear Operating Company (Southern Nuclear) safely operates and maintains Plants Hatch and Vogtle in accordance with industry standards and regulatory requirements. Southern Nuclear is dedicated to maintaining the highest standards for safely handling radioactive waste to protect the public, the environment, and its workers.

High-Level Radioactive Waste (HLRW - spent fuel)

Dry Cask Storage:
Plant Hatch – currently stores spent fuel in underwater spent fuel pools and some above ground in dry casks on concrete pads until such time that the federal government licenses and builds a permanent disposal facility which can accept this waste.

Plant Vogtle – currently stores spent fuel in underwater spent fuel pools and will not need dry cask storage for many years.

Southern Nuclear, as well as the nuclear industry, has a strong commitment to the Yucca Mountain repository as a scientifically safe and appropriate long-term solution for used nuclear fuel. The issues surrounding Yucca Mountain are political, not scientific. At the same time, the nuclear industry has adopted a used fuel management strategy that supports the research, development, and demonstration of projects to close the nuclear fuel cycle (i.e., reprocessing). It is important to note that even with reprocessing, the Yucca Mountain repository is necessary to dispose of the byproducts of nuclear fuel.

Low-Level Radioactive Waste (LLRW - trash, tools, scrap, filtering media, irradiated hardware, etc.)

Similar to the nuclear power industry, over 95 percent of the LLRW generated by Plant Hatch and Plant Vogtle continues to be buried at the Energy Solutions burial site in Clive, UT.

The remaining LLRW cannot be buried at Clive, UT. In the past it was buried at the Barnwell, SC burial facility, but that site is no longer accessible to most states including Georgia.

Hatch and Vogtle will store this remaining LLRW on the site where it was generated inside concrete shields on a concrete pad until such time as a new disposal site which can accept this waste becomes available or until some alternate means becomes available for eliminating or handling this waste. Southern Nuclear in conjunction with the nuclear industry is currently working at reducing these types of waste.

Table C.1

In-Service Dollars for Environmental Controls

Control Type	Branch 1&2 (2015 Compliance)	Branch 3&4 (2015 Compliance)	Branch 3&4	Yates 6&7 Dry FGD	Yates 1 (2015 Compliance)	Yates 1
FGD	2015 REDACTED	2015 REDACTED	2016 REDACTED	2015 REDACTED	-	-
SCR*	2015 REDACTED	2015 REDACTED	2016 REDACTED	2015 REDACTED	2015 *SNCR REDACTED	2017 *SNCR REDACTED
Baghouse+	2015 REDACTED	2015 REDACTED	2016 REDACTED	2015 REDACTED	2015 REDACTED	2016 REDACTED
Cooling Tower	2018 REDACTED	2018 REDACTED	2018 REDACTED	-	-	-
316b Compliance	2018 REDACTED	2018 REDACTED	2018 REDACTED	2017 REDACTED	-	-
FGD WWT	2018 REDACTED	2018 REDACTED	2018 REDACTED	-	2019 REDACTED	2019 REDACTED
Incremental CCR[1]	2017 REDACTED	2016-2017 REDACTED	2016-2017 REDACTED	2015-2017 REDACTED	2016-2017 REDACTED	2016-2017 REDACTED
Total In-Service (M$)	***REDACTED***	***REDACTED***	***REDACTED***	***REDACTED***	***REDACTED***	***REDACTED***

Control Type	Yates 2-5 (2015 Compliance)	Yates 2-5	Hammond 1-3 (2015 Compliance)	Hammond 1-3
FGD	2015 REDACTED	2017 REDACTED	-	-
SCR*	2015 REDACTED	2017 REDACTED	2015 *SNCR REDACTED	2017 *SNCR REDACTED
Baghouse+	2015 REDACTED	2018 REDACTED	2015 REDACTED	2016 REDACTED
Cooling Tower	-	-	2018 REDACTED	2018 REDACTED
316b Compliance	-	-	-	-
FGD WWT	2019 REDACTED	2019 REDACTED	2020 REDACTED	2020 REDACTED
Incremental CCR[1]	2016-2017 REDACTED	2016-2017 REDACTED	2015-2017 REDACTED	2015-2017 REDACTED
Total In-Service (M$)	***REDACTED***	***REDACTED***	***REDACTED***	***REDACTED***

****For Yates 1 and Hammond 1-3, the costs included in the SCR line are for SNCR.***

+Baghouse costs include continuous emissions monitors (CEMs). For the Yates 6-7 Dry FGD, the only costs in the Baghouse line are for the CEMS monitoring.

[1]Incremental CCR does NOT include ground water monitoring and pond closures. Costs for various categories within Incremental CCR are included where appropriate.

Table C.1 (Continued)

In-Service Dollars for Environmental Controls

Control Type	Kraft 1-4		McIntosh 1		McManus 1&2	
Fuel Switching Costs	2015	REDACTED	2015	REDACTED	2015	REDACTED
316(b) Compliance Costs	2020	REDACTED	2020	REDACTED	2020	REDACTED
Utility MACT Compliance Costs	2015	REDACTED	2015	REDACTED	2015	REDACTED
Closed Loop Cooling Tower	2020	REDACTED		----	2020	REDACTED
Total In-Service (M$)		***REDACTED***		***REDACTED***		***REDACTED***

Table C.2

NPV of the Revenue Requirements for Environmental Controls

Control Type	Branch 1&2 (2015 Compliance)	Branch 3&4 (2015 Compliance)	Branch 3&4	Yates 6&7 Dry FGD	Yates 1 (2015 Compliance)	Yates 1
FGD	2015 REDACTED	2015 REDACTED	2016 REDACTED	2015 REDACTED	---	---
SCR*	2015 REDACTED	2015 REDACTED	2016 REDACTED	2015 REDACTED	2015 *SNCR REDACTED	2017 *SNCR REDACTED
Baghouse+	2015 REDACTED	2015 REDACTED	2016 REDACTED	2015 REDACTED	2015 REDACTED	2016 REDACTED
Cooling Tower	2018 REDACTED	2018 REDACTED	2018 REDACTED	---	---	---
316b Compliance	2018 REDACTED	2018 REDACTED	2018 REDACTED	2017 REDACTED	---	---
FGD WWT	2018 REDACTED	2018 REDACTED	2018 REDACTED	---	2019 REDACTED	2019 REDACTED
Incremental CCR[1]	2017 REDACTED	2016-2017 REDACTED	2016-2017 REDACTED	2015-2017 REDACTED	2016-2017 REDACTED	2016-2017 REDACTED
Total In-Service (M$)	***REDACTED***	***REDACTED***	***REDACTED***	***REDACTED***	***REDACTED***	***REDACTED***

Control Type	Yates 2-5 (2015 Compliance)	Yates 2-5	Hammond 1-3 (2015 Compliance)	Hammond 1-3
FGD	2015 REDACTED	2017 REDACTED	---	---
SCR*	2015 REDACTED	2017 REDACTED	2015 *SNCR REDACTED	2017 *SNCR REDACTED
Baghouse+	2015 REDACTED	2018 REDACTED	2015 REDACTED	2016 REDACTED
Cooling Tower	---	---	2018 REDACTED	2018 REDACTED
316b Compliance	---	---	---	---
FGD WWT	2019 REDACTED	2019 REDACTED	2020 REDACTED	2020 REDACTED
Incremental CCR[1]	2016-2017 REDACTED	2016-2017 REDACTED	2015-2017 REDACTED	2015-2017 REDACTED
Total In-Service (M$)	***REDACTED***	***REDACTED***	***REDACTED***	***REDACTED***

*For Yates 1 and Hammond 1-3, the costs included in the SCR line are for SNCR.

+Baghouse costs include CEMS monitors. For the Yates 6-7 Dry FGD, the only costs in the Baghouse line are for the CEMS monitoring.

[1]Incremental CCR does NOT include ground water monitoring and pond closures. Costs for various categories within Incremental CCR are included where appropriate.

^Note that this table includes environmental capital and O&M costs. The totals in these tables are actually the NPV of the revenue requirements for the capital dollars plus the NPV of the stream of O&M dollars over the study period.

Table C.2 (Continued)

NPV of the Revenue Requirements for Environmental Controls

Control Type	Kraft 1-4	McIntosh 1	McManus 1&2
Fuel Switching Costs	2015 REDACTED	2015 REDACTED	2015 REDACTED
316(b) Compliance Costs	2020 REDACTED	2020 REDACTED	2020 REDACTED
Utility MACT Compliance Costs	2015 REDACTED	2015 REDACTED	2015 REDACTED
Closed Loop Cooling Tower	2020 REDACTED	----	2020 REDACTED
Total In-Service (M$)	***REDACTED***	***REDACTED***	***REDACTED***

The numbers in Table C.2 can be added and subtracted from the matrices in combination to arrive at the desired environmental cost compliance scenario.

Table C.3

NPV of Revenue Requirements for Replacement Unit Components in Millions of $

M$	Replacement Capital	Replacement Continue to Operate (CTO) Capital	Replacement O&M	Replacement Gas Costs
Branch 1-2	REDACTED	REDACTED	REDACTED	REDACTED
Branch 3-4	REDACTED	REDACTED	REDACTED	REDACTED
Yates 6-7	REDACTED	REDACTED	REDACTED	REDACTED
Yates 1	REDACTED	REDACTED	REDACTED	REDACTED
Yates 2-5	REDACTED	REDACTED	REDACTED	REDACTED
Hammond 1-3	REDACTED	REDACTED	REDACTED	REDACTED
Kraft 1-4	REDACTED	REDACTED	REDACTED	REDACTED
McIntosh 1	REDACTED	REDACTED	REDACTED	REDACTED
McManus 1-2	REDACTED	REDACTED	REDACTED	REDACTED

Appendix D

$0 CO_2 – Moderate Fuel

NPV (2011-2040) in Millions of Dollars

Customer Costs for Generation Options Relative to Continued Operation NPV 2011-2040 in Millions	Branch 1-2 Retire/REDACTED Replace 2015 $0 Mod-Branch 1-2 Continue to Operate with Wet FGD $0 Mod - 2015 COMPLIANCE	Branch 3-4 Retire/REDACTED Replace 2015 $0 Mod-Branch 3-4 Continue to Operate w/ Wet FGD $0 Mod - 2015 COMPLIANCE	Branch 3-4 Retire/REDACTED Replace 2015 $0 Mod-Branch 3-4 Continue to Operate w/ Wet FGD $0 Mod - 2016 COMPLIANCE	Yates 6-7 w/ Dry FGD Retire/REDACTED Replace 2015 $0 Mod-Yates 6-7 w/ Dry FGD Continue to Operate $0 Mod - 2015 COMPLIANCE	Yates 1 w 2015 SNCR Retire/REDACTED Replace 2015 $0 Mod-Yates 1 w 2017 SNCR Continue to Operate $0 Mod - 2015 COMPLIANCE	Yates 1 w 2017 SNCR Retire/REDACTED Replace 2015 $0 Mod-Yates 1 w 2017 SNCR Continue to Operate $0 Mod - 2016 COMPLIANCE
GENERATION UNIT COSTS AND BENEFITS						
System Avoided Energy Cost	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Continue-to-Operate Capital	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Continue-to-Operate Fixed O&M	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Environmental Capital	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Environmental O&M	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Decommissioning Costs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Spot Market Capacity Cost	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Replacement Capital	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Replacement Continue-to-Operate Capital	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Replacement Fixed O&M	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
TOTAL EXCLUDING TRANSMISSION (NPV M$)	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
TRANSMISSION						
Net System Improvements & Credits	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
TOTAL WITH TRANSMISSION (NPV M$)	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Baghouse (NPV M$)	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
CCR + WWT + 316b Compliance + Cooling Tower (NPV M$)*	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

* Cooling tower costs ommitted for Branch 1-2 and 3-4 analysis. No additional cooling tower costs for the Yates units.

$0 CO_2 – Moderate Fuel

NPV (2011-2040) in Millions of Dollars

Customer Costs for Generation Options Relative to Continued Operation NPV 2011-2040 in Millions	Yates 2-5 Retire/REDACTED Replace 2015 $0 Mod-Yates 2-5 Continue to Operate $0 Mod - 2015 COMPLIANCE	Yates 2-5 Retire/REDACTED Replace 2015 $0 Mod-Yates 2-5 Continue to Operate $0 Mod - 2018 COMPLIANCE	Hammond 1-3 Retire/REDACTED Replace 2015 $0 Mod-Hammond 1-3 Continue to Operate w/ 2017 SNCR ONLY $0 Mod - 2015 COMPLIANCE	Hammond 1-3 Retire/REDACTED Replace 2015 $0 Mod-Hammond 1-3 Continue to Operate w/ 2017 SNCR ONLY $0 Mod - 2016 COMPLIANCE
GENERATION UNIT COSTS AND BENEFITS				
System Avoided Energy Cost	REDACTED	REDACTED	REDACTED	REDACTED
Continue-to-Operate Capital	REDACTED	REDACTED	REDACTED	REDACTED
Continue-to-Operate Fixed O&M	REDACTED	REDACTED	REDACTED	REDACTED
Environmental Capital	REDACTED	REDACTED	REDACTED	REDACTED
Environmental O&M	REDACTED	REDACTED	REDACTED	REDACTED
Decommissioning Costs	REDACTED	REDACTED	REDACTED	REDACTED
Spot Market Capacity Cost	REDACTED	REDACTED	REDACTED	REDACTED
Replacement Capital	REDACTED	REDACTED	REDACTED	REDACTED
Replacement Continue-to-Operate Capital	REDACTED	REDACTED	REDACTED	REDACTED
Replacement Fixed O&M	REDACTED	REDACTED	REDACTED	REDACTED
TOTAL EXCLUDING TRANSMISSION (NPV M$)	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
TRANSMISSION				
Net System Improvements & Credits	REDACTED	REDACTED	REDACTED	REDACTED
TOTAL WITH TRANSMISSION (NPV M$)	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Baghouse (NPV M$)	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
CCR + WWT + 316b Compliance + Cooling Tower (NPV M$)	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

Appendix D

$0 CO_2 – Moderate Fuel
NPV (2011-2040) in Millions of Dollars

Customer Costs for Generation Options Relative to Continued Operation NPV 2011-2040 in Millions	Kraft 1-4 Retire/CT Replace 2015 $0 Mod-Kraft 1-4 Convert to REDACT/Oil Backup REDACT $0 Mod - 2015 COMPLIANCE	McIntosh 1 Retire/CT Replace 2015 $0 Mod-McIntosh 1 Convert to REDACT w/ oil backup $0 Mod - 2015 COMPLIANCE	McManus 1 & 2 Retire/CT Replace 2015 $0 Mod-McManus 1 & 2 CTO on Oil $0 Mod - 2015 COMPLIANCE
GENERATION UNIT COSTS AND BENEFITS			
System Avoided Energy Cost	REDACTED	REDACTED	REDACTED
Continue-to-Operate Capital	REDACTED	REDACTED	REDACTED
Continue-to-Operate Fixed O&M	REDACTED	REDACTED	REDACTED
Environmental Capital	REDACTED	REDACTED	REDACTED
Environmental O&M	REDACTED	REDACTED	REDACTED
Decommissioning Costs	REDACTED	REDACTED	REDACTED
Spot Market Capacity Cost	REDACTED	REDACTED	REDACTED
Replacement Capital	REDACTED	REDACTED	REDACTED
Replacement Continue-to-Operate Capital	REDACTED	REDACTED	REDACTED
Replacement Fixed O&M	REDACTED	REDACTED	REDACTED
TOTAL EXCLUDING TRANSMISSION (NPV M$)	**REDACTED**	**REDACTED**	**REDACTED**
TRANSMISSION			
Net System Improvements & Credits	REDACTED	REDACTED	REDACTED
TOTAL WITH TRANSMISSION (NPV M$)	**REDACTED**	**REDACTED**	**REDACTED**
Baghouse (NPV M$)	**N/A**	**N/A**	**N/A**
CCR + WWT + 316b Compliance + Cooling Tower (NPV M$)	**N/A**	**N/A**	**N/A**

STATE OF SOUTH CAROLINA	)	**BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA**
(Caption of Case) **IN RE:**	)	
Duke Energy Carolinas, LLC's 2011 Integrated Resource Plan (IRP)	)	**COVER SHEET**
	)	**DOCKET NUMBER:** 2011 - 10 - E

(Please type or print)

Submitted by:	**Charles A. Castle**	**SC Bar Number:**	**79895**
Address:	**Duke Energy**	**Telephone:**	**704.382.4499**
	550 S Tryon St., DEC45A	**Fax:**	
	Charlotte, NC 28202	**Other:**	
		Email:	**alex.castle@duke-energy.com**

NOTE: The cover sheet and information contained herein neither replaces nor supplements the filing and service of pleadings or other papers as required by law. This form is required for use by the Public Service Commission of South Carolina for the purpose of docketing and must be filled out completely.

DOCKETING INFORMATION (Check all that apply)

☐ **Emergency Relief demanded in petition** ☐ **Request for item to be placed on Commission's Agenda expeditiously**

☒ **Other: Duke Energy Carolinas' 2011 Integrated Resource Plan and Motion for Confidential Treatment**

INDUSTRY (Check one)	**NATURE OF ACTION (Check all that apply)**		
☒ Electric	☐ Affidavit	☐ Letter	☐ Request
☐ Electric/Gas	☐ Agreement	☐ Memorandum	☐ Request for Certification
☐ Electric/Telecommunications	☐ Answer	☒ Motion	☐ Request for Investigation
☐ Electric/Water	☐ Appellate Review	☐ Objection	☐ Resale Agreement
☐ Electric/Water/Telecom.	☐ Application	☐ Petition	☐ Resale Amendment
☐ Electric/Water/Sewer	☐ Brief	☐ Petition for Reconsideration	☐ Reservation Letter
☐ Gas	☐ Certificate	☐ Petition for Rulemaking	☐ Response
☐ Railroad	☐ Comments	☐ Petition for Rule to Show Cause	☐ Response to Discovery
☐ Sewer	☐ Complaint	☐ Petition to Intervene	☐ Return to Petition
☐ Telecommunications	☐ Consent Order	☐ Petition to Intervene Out of Time	☐ Stipulation
☐ Transportation	☐ Discovery	☐ Prefiled Testimony	☐ Subpoena
☐ Water	☐ Exhibit	☐ Promotion	☐ Tariff
☐ Water/Sewer	☐ Expedited Consideration	☐ Proposed Order	☒ Other: 2011 Integrated Resource Plan
☐ Administrative Matter	☐ Interconnection Agreement	☐ Protest	
☐ Other:	☐ Interconnection Amendment	☐ Publisher's Affidavit	
	☐ Late-Filed Exhibit	☐ Report	

Duke Energy
Carolinas

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September 1, 2011

VIA ELECTRONIC FILING AND
HAND DELIVERED CONFIDENTIAL VERSION

Ms. Jocelyn Boyd
Chief Clerk of the Commission
Public Service Commission of South Carolina
Synergy Business Park, Saluda Building
101 Executive Center Drive
Columbia, SC 29210

Re: Duke Energy Carolinas, LLC's 2011 Integrated Resource Plan
Motion for Confidential Treatment
Docket No. 2011-10-E

Dear Ms. Boyd:

Enclosed for filing please find the CONFIDENTIAL VERSION of Duke Energy Carolinas, LLC's ("Duke Energy Carolinas" or "the Company") 2011 Integrated Resource Plan ("2011 IRP"). The Company respectfully requests that it be permitted to file the CONFIDENTIAL VERSION under seal and maintained as confidential pursuant to Order No. 2005-226, "ORDER REQUIRING DESIGNATION OF CONFIDENTIAL MATERIALS."

The 2010 IRP contains certain confidential information (portions of the tables in Appendix C (pages 139-141) and the tables in Appendix I (page 165)). The information contained therein is proprietary and commercially sensitive, and, if disclosed, could adversely affect the Company's ability to provide least cost resources for its customers. In addition, Appendix F of the 2011 IRP contains Duke Energy Carolinas' most recently-filed FERC Form 715. As FERC Form 715 contains critical energy infrastructure information that should be kept confidential and non-public, Duke Energy Carolinas is also filing it under seal and requests that the Commission treat this information as confidential and protect it from public disclosure.

Thus, Duke Energy Carolinas respectfully requests that the Commission grant its request for confidential treatment pursuant to 26 S.C. Code Ann. Regs. 103-804(S)(2)(Supp. 2010). A copy of the Public version of the 2011 IRP is being filed electronically and a copy of the CONFIDENTIAL VERSION of the 2011 IRP is being hand delivered to the Commission and the Office of Regulatory Staff under seal.

Please consider this correspondence as Duke Energy Carolinas' Motion for Confidential Treatment of the above-referenced information in Appendices C, F and I of the 2011 IRP.

Thank you for your consideration of this matter and please contact me with any questions.

Very truly yours,

Charles A. Castle

Enclosures
cc: Shannon Bowyer Hudson, Esq.

The Duke Energy Carolinas Integrated Resource Plan (Annual Report)

September 1, 2011

TABLE OF CONTENTS

Integrated Resource Plan – abbreviations

Carbon Dioxide	CO_2
Central Electric Power Cooperative, Inc.	CEPCI
Certificate of Public Convenience and Necessity	CPCN
Clean Air Interstate Rule	CAIR
Clean Air Mercury Rule	CAMR
Coal Combustion Residuals	CCR
Combined Construction and Operating License	COL
Combined Cycle	CC
Combustion Turbines	CTs
Commercial Operation Date	COD
Compact Fluorescent Light bulbs	CFL
Cross State Air Pollution Rule	CSAPR
Demand Side Management	DSM
Direct Current	DC
Duke Energy Annual Plan	The Plan
Duke Energy Carolinas	DEC
Duke Energy Carolinas	The Company
Eastern Interconnection Planning Collaborative	EIPC
Electric Membership Corporation	EMC
Electric Power Research Institute	EPRI
Energy Efficiency	EE
Environmental Protection Agency	EPA
Federal Energy Regulatory Commission	FERC
Federal Loan Guarantee	FLG
Flue Gas Desulphurization	FGD
General Electric	GE
Greenhouse Gas	GHG
Heating, Ventilation and Air Conditioning	HVAC
Information Collection Request	ICR
Integrated Gasification Combined Cycle	IGCC
Integrated Resource Plan	IRP
Interruptible Service	IS
Load, Capacity, and Reserve Margin Table	LCR Table
Maximum Achievable Control Technology	MACT
Nantahala Power & Light	NP&L
National Ambient Air Quality Standards	NAAQS
National Pollutant Discharge Elimination System	NPDES
NC Department of Environment and Natural Resources	NCDENR
NC Green Power	NCGP
New Source Performance Standard	NSPS
Nitrogen Oxide	NO_x
North American Electric Reliability Corp	NERC
North Carolina	NC
North Carolina Clean Smokestacks Act	NCCSA
North Carolina Division of Air Quality	NCDAQ
North Carolina Electric Membership Corporation	NCEMC
North Carolina Municipal Power Agency #1	NCMPA1

Integrated Resource Plan – abbreviations

North Carolina Utilities Commission	NCUC
Notice of Proposed Rulemaking	NOPR
Nuclear Regulatory Commission	NRC
Palmetto Clean Energy	PaCE
Parts Per Billion	PPB
Photovoltaic	PV
Piedmont Municipal Power Agency	PMPA
Plug-In Electric Vehicles	PEV
Power Delivery	PD
Present Value Revenue Requirements	PVRR
Prevention of Significant Deterioration	PSD
Public Service Commission of South Carolina	PSC
Purchase Power Agreement	PPA
Qualifying Facility	QF
Rate Impact Measure	RIM
Renewable Energy and Energy Efficiency Portfolio Standard	REPS
Renewable Energy Certificates	REC
Renewable Portfolio Standard	RPS
Request for Proposal	RFP
Resource Conservation Recovery Act	RCRA
Saluda River Electric Cooperative	SR
Selective Catalytic Reduction	SCR
SERC Reliability Corporation	SERC
South Carolina	SC
Southeastern Power Administration	SEPA
Standby Generation	SG
State Implementation Plan	SIP
Sulfur Dioxide	SO_2
Technology Assessment Guide	TAG
Total Resource Cost	TRC
United States Department of Energy	USDOE
Utility Cost Test	UCT
Virginia/Carolinas	VACAR
Volt Ampere Reactive	VAR
Western Carolina University	WCU

FORWARD

This Integrated Resource Plan (IRP) is Duke Energy Carolinas' biennial report under the revised North Carolina Utilities Commission (NCUC) Rule R8-60. A cross reference identifying where each regulatory requirement can be found within this IRP is provided in Appendix K.

NCUC Rule R8-60 subparagraph (h) (2) requires by September 1 of each year in which a biennial report is not required to be filed, an annual report to be filed with the NCUC containing an updated 15-year forecast of the items described in R8-60 subparagraph (c) (1), as well as significant amendments or revision to the most recently filed biennial report, including amendments or revisions to the type and size of resources identified, as applicable. The following updates to the 2010 IRP are provided in the Duke Energy Carolinas 2011 IRP Annual Report.

a) 15-year forecast
b) Short term action plan
c) Existing Generation Plants in Service
d) Renewable Energy Initiatives
e) Energy Efficiency and Demand Side Management peak and energy impacts
f) Wholesale Power Sales Commitments
g) Legislative and Regulatory Issues
h) Fundamental fuel, energy, and emission allowance prices
i) Generating units projected to be retired
j) Load and Resource Balance
k) Changes to existing and future resources
l) Overall planning process conclusions incorporating a) through l) above
m) Detailed information pertaining to the requirement that Duke Energy Carolinas implement a Greenhouse Gas Reduction Plan (Greenhouse Plan) as a stipulation to the North Carolina Department of Air Quality (NCDAQ) Air Permit for Cliffside Unit 6. This information can be found in Appendix J.

1. EXECUTIVE SUMMARY

Duke Energy Carolinas, LLC (Duke Energy Carolinas or the Company), a subsidiary of Duke Energy Corporation, utilizes an integrated resource planning approach to ensure that it can reliably and economically meet the electric energy needs of its customers well into the future. Duke Energy Carolinas considers a diverse range of resources including renewable, nuclear, coal, gas, energy efficiency (EE), and demand-side management (DSM)[1] resources. The end result is the Company's IRP.

Consistent with its responsibility to meet customer energy needs in a way that is affordable, reliable, and clean, the Company's resource planning approach includes both quantitative analysis and qualitative considerations. Quantitative analysis provides insights on future risks and uncertainties associated with fuel prices, load growth rates, capital and operating costs, and other variables. Qualitative perspectives, such as the importance of fuel diversity, the Company's environmental profile, the emergence and development of new technologies, and regional economic development considerations are also important factors to consider as long-term decisions are made regarding new resources.

Company management uses all of these qualitative perspectives in conjunction with its quantitative analyses to ensure that Duke Energy Carolinas will meet near-term and long-term customer needs, while maintaining the operational flexibility to adjust to evolving economic, environmental, and operating circumstances in the future. As a result, the Company's plan is designed to be robust under many possible future scenarios.

The notable changes from the 2010 IRP to the 2011 IRP are the projected increase in peak generation need in 2015 due to increased load projections, updated assumptions regarding the energy impacts of Compact Fluorescent Lights (CFLs) and lower projected capacity impacts from Demand Side Management programs, as well as changes in the projected compliance portfolio relating to the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS). The overall impact of these factors results in a resource need of 790 MWs in 2015.

The increased load projection is driven primarily by an increase in the projected demand from the industrial sector. The 2011 load forecast also incorporates a change in methodology related to the projected load impacts of CFLs in the residential and commercial sectors. These methodology changes included a change in the factors utilized for the residential sector and no incremental CFL impact, beyond what's reflected in the historical sales trends.

[1] Throughout this IRP, the term EE will denote conservation programs while the term DSM will denote Demand Response programs, consistent with the language of N.C. Gen. Stat. 62-133.8 and 133.9.

The lower projections of DSM impacts were driven primarily by the anticipated impact of the proposed Environmental Protection Agency (EPA) Reciprocating Internal Combustion Engine (RICE) rule, which limits hours of non-emergency operation of emergency generators located at commercial and industrial facilities. This rule, as proposed, is projected to significantly impact Duke Energy Carolinas' PowerShare program. The 2011 DSM projections were updated to reflect the manner in which the RICE rule will materially limit participation in the PowerShare program by our customers. The projected reduction in DSM impacts results in a corresponding increase in our customers' capacity needs.

Additionally, in the 2011 IRP, the analysis reflects a shift in the Company's strategy for NC REPS compliance over the long term. In the 2010 IRP, the long term NC REPS compliance strategy relied primarily on biomass resources during the first 10 years and then shifted to wind resources for the remainder of the planning period. Based upon recent proposals for wind purchased power agreements and the continuing federal regulatory uncertainty regarding treatment of biomass generation, for the 2011 IRP, the Company has adopted a strategy with increased reliance on wind resources during the first 10 years and a shift to biomass resources for the remainder of the planning period. This change in strategy impacts the 2015 peak resource requirement because only a small percentage of the rated capacity for wind resources can be counted toward meeting the Company's system peak, as opposed to the more reliable expected system peak contribution from biomass resources.

The 2011 IRP continues to reflect the retirement of Duke Energy Carolinas' older coal units without flue gas desulfurization (FGDs) facilities (also known as SO_2 scrubbers). These planned retirements are driven primary by the recently proposed EPA Mercury Utility Maximum Achievable Control Technology (MACT) rule. The MACT rule is expected to be finalized in November 2011, with required control technologies to be installed by January 1, 2015. Other emerging environmental regulations that also are expected to impact the retirement decisions relating to the Company's existing coal fleet include the Coal Combustion Residuals (CCR) rule, Cross State Air Pollution Rule (CSAPR), Sulfur Dioxide (SO_2) and Ozone National Ambient Air Quality standards (NAAQS). The Company has developed the 2011 IRP based on expectations of how these rules will be ultimately established.

Greenhouse gas (GHG) regulations or legislation also have the potential to impact the Company's resource plans. From 2007 to 2009, multiple GHG cap and trade bills were introduced in Congress. More recently, Clean Energy Standards (CES) have been discussed in lieu of cap and trade legislation or regulation. A CES would require that a certain percentage (e.g. 10% in 2015 escalating up to 30% in 2030) of a utility's retail sales be met with combined cycle (CC) natural gas, nuclear, EE, or renewable energy. At present, the Company does not anticipate that Congress will consider GHG legislation through the end of

2012. Beyond 2012, the prospects for possible enactment of any legislation mandating reductions in GHG emissions are highly uncertain. Although the Company continues to believe that Congress will eventually adopt some form of mandatory GHG emission reduction or Clean Energy legislation, the timing and form of any such legislation remains highly uncertain. In the absence of federal GHG or Clean Energy legislation, the EPA continues to pursue GHG regulations on new and existing units. EPA has announced its plans to issue a proposed regulation for fossil-fired generating units in 2011. The impacts of future EPA regulations are uncertain at this time; however the Company believes that it is prudent to continue to plan for a carbon-constrained future. To address this uncertainty, the Company has evaluated a range of CO_2 prices, in addition to potential Clean Energy legislation.

Planning Process Results

Duke Energy Carolinas' generation resource needs increase significantly over the 20-year planning horizon of the 2011 IRP. Cliffside Unit 6 and the Buck and Dan River natural gas CC units, along with the Company's EE and DSM programs, will fulfill these needs through 2014. Beginning in 2015, the Company has a capacity need of 790 MWs to meet its projected load requirements along with a 17% reserve margin. Even if the Company fully realizes its goals for EE and DSM, the resource need grows to approximately 7,030 MWs by 2031. This projected capacity need is higher than that reflected in the 2010 Duke Energy Carolinas IRP due primarily to higher load projections and the other reasons listed above.

The 2011 Duke Energy Carolinas IRP outlines the Company's options and plans for meeting the projected long-term needs. The factors that influence resource needs are:

- Future load growth projections;
- The amount of EE and DSM that can be achieved;
- Resources needed to meet the NC REPS requirement;
- Reductions in existing resources, for example, due to unit retirements and expiration of purchased power agreements (PPA); and
- Meeting the Company's 17% target planning reserve margin over the 20-year horizon.

A key purpose of the IRP is to provide the Company's management with information to aid in making the decisions necessary to ensure that Duke Energy Carolinas has a reliable, diverse, environmentally sound, and reasonably priced portfolio of resources over time.

In the short-term, the 2011 IRP analysis results indicate the need for peaking and intermediate resources as early as 2015 and 2016 and at various points throughout the study period. The results also show the need for new baseload facilities as early as 2018.

For Duke Energy Carolinas' longer term need, the Company's analysis continues to affirm the potential benefits of new greenhouse gas emission-free nuclear capacity in a carbon-constrained future. The Company's analysis considered a portfolio based on full ownership of the 2,234 MW Lee Nuclear Station in 2021 and 2023, as well as a portfolio that reflects regional nuclear generation equivalent to the MWs associated with Lee Nuclear Station spread over 2018 to 2028. The regional nuclear portfolio is illustrative of a potential regional nuclear portfolio and the Company developed this potential portfolio based on its recent activities to procure new nuclear generation and to sell a portion of the Lee Nuclear Station. Specifically, in February 2011, JEA (formerly Jacksonville Electric Authority), located in Jacksonville, Florida, signed an option to potentially purchase up to 20% of Lee Nuclear Station. In July 2011, the Company signed a letter of intent with Public Service Authority of South Carolina (Santee Cooper) to perform due diligence and potentially acquire an option for a minority interest (5 to 10% of the capacity of the two units) in Santee Cooper's 45 percent ownership of the planned new nuclear reactors at V.C. Summer (Summer) Nuclear Generating Station in South Carolina. The new Summer units are scheduled to be online between 2016 and 2019.

The results of the Company's analysis indicate that the regional nuclear portfolio is lower cost to customers in the base case and most scenarios, but the full nuclear portfolio was chosen for the 2011 IRP preferred plan because there are no firm commitments in place at this time for the regional nuclear portfolio. Although the regional nuclear portfolio assumes 10% of the Summer station is purchased, the Company's decision on whether and how much to purchase will be based on many factors, including the results of the due diligence related to Summer, the capacity need at the time of the decision, and the financial implications of the purchase on the Company. Duke Energy Carolinas will continue to assess opportunities to benefit from economies of scale and risk reduction in new resource decisions by considering the prospects for joint ownership and/or sales agreements for new nuclear generation resources.

Both DSM and EE programs play important roles in the Company's development of a balanced, cost-effective and environmentally responsible resource portfolio. Renewable generation options are also necessary to meet NC REPS enacted in 2007. These resources will be incorporated more broadly into the Company's resource portfolio to the extent they become more cost-effective in comparison with traditional supply-side resources and with consideration of other qualitative issues such as their intermittency and relative contribution to meeting peak capacity needs. Energy savings resulting from EE programs may also be used to meet, in part, the Company's REPS obligations. The Company's REPS Compliance Plan is being filed concurrently with the 2011 IRP, pursuant to the requirements of NCUC Rule R8-67.

The 2011 IRP also includes the Company's plan for meeting the requirements set forth in the Cliffside Unit 6 NCDAQ Air Permit (Cliffside Air Permit). The Cliffside Air Permit requires the Company take specific actions to render Cliffside Unit 6 carbon neutral by 2018. In the context of the 2011 IRP, the Company is seeking approval from the NCUC of the proposed plan as required by the Cliffside Air Permit.

In light of the Company's analyses, as well as the public policy debate relating to energy and environmental issues, Duke Energy Carolinas has developed a sustainable strategy to ensure that the Company can meet customers' energy needs reliably and economically over the near and long term. Duke Energy Carolinas' strategic action plan for long-term resources maintains prudent flexibility in the face of these dynamic circumstances.

The Company's Short Term Action Plan, which identifies accomplishments in the past year and actions to be taken over the next five years, are summarized below:

- Take actions to ensure capacity needs beginning in 2015 are met. In addition to seeking to meet the Company's DSM and EE goals and meeting the Company's REPS requirements, actions to secure additional capacity may include purchased power or generating capacity or Company-owned generation. In addition, the Company's capacity needs will be evaluated in light of the combined needs and resources of Duke Energy Carolinas and Progress Energy Carolinas upon consummation of the merger between Duke Energy and Progress Energy, Inc. (Progress Energy).

- Continue to evaluate and plan for the retirement of older coal generation. Buck Steam Station Units 3 and 4 were retired in May 2011. Cliffside Units 1 through 4 and Dan River Units 1 and 2 are required to be retired in advance of the commercial operation of new generation at those locations. The timing of the retirements of the remaining un-scrubbed coal units in the 2015 timeframe will continue to be assessed as emerging federal environmental regulations are finalized over the coming years.

- Continue to execute the Company's EE and DSM plan, which includes a diverse portfolio of DSM and EE programs, and continue on-going collaborative work to develop and implement additional cost-effective EE and DSM products and services. Approved and planned programs and pilots include:

- The Residential Retrofit program, which was approved in North Carolina in Docket E-7, Sub 952 on January 25, 2011 and in South Carolina in Docket 2010-51-E on February 24, 2010.

- The Home Energy Comparison Report pilot, which was approved by the Public Service Commission of South Carolina (PSC) in Docket 2010-50-E on March 24, 2010, and is currently only offered in South Carolina.

- The Smart Energy Now (SEN) pilot program, which was approved by the NCUC in Docket E-7, Sub 961 on February 14, 2011, and is currently only offered in North Carolina.

- Subject to approval by the NCUC and/or PSC, Duke Energy Carolinas plans to offer the following full program additions to its portfolio in the next year: Additional Smart $aver® Measures, Direct Install Low Income and Appliance Recycling.

- The Company is also considering a Home Energy Manager (HEM) Lite pilot program.

- Continue construction of the 825 MW Cliffside Unit 6, with the objective of bringing this additional capacity online by 2012 at the existing Cliffside Steam Station. As of June 2011, the project was over 80% complete.

- Continue construction of new combined-cycle natural gas generation at Buck and Dan River Steam Stations.

  - Buck CC Project: Continue construction of the 620 MW Buck CC project, with the objective of bringing this additional capacity on line by the end of 2011. As of July 2011, project was over 90% complete.

  - Dan River CC Project: Construction has begun on the 620 MW Dan River CC project is scheduled to be operational by the end of 2011. As of July 2011, the project was over 50% complete.

- Pursue the conversion of Lee Steam Station from coal to natural gas fuel. Lee Steam Station is reflected in the 2011 Duke Energy Carolinas IRP as a retired coal station in the fourth quarter of 2014 and converted to natural gas by January 1, 2015. Preliminary engineering has been completed and more detailed project development and regulatory efforts are ongoing.

- Continue to pursue the option for new nuclear generating capacity in the 2015 to 2025 timeframe.

  - The Company filed an application with the NRC for a COL in December 2007. The Company plans to continue to support the NRC evaluation of the COL.

  - The Company continues to pursue project development approvals and to evaluate the optimal time to file the Certificate of Environmental Compatibility and Public Convenience and Necessity (CPCN) in South Carolina, as well as other relevant regulatory approvals.

  - The Company will continue to pursue available federal, state and local tax incentives and favorable financing options at the federal and state level.

  - The Company will continue to assess opportunities to benefit from economies of scale and risk reduction in new resource decisions by considering the prospects for joint ownership and/or sales agreements for new nuclear generation resources.

- Continue to evaluate market options for renewable generation and enter into contracts as appropriate. PPAs have been signed with developers of solar photovoltaic (PV), landfill gas, wind, and thermal resources. Additionally, renewable energy certificate (REC) purchase agreements have been executed for purchases of unbundled RECs from wind, solar PV, solar thermal and hydroelectric facilities.

- Continue to investigate the future environmental control requirements and resulting operational impacts associated with the Mercury MACT rule, the CCR rule, the CSAPR rule and the new Ozone NAAQS and SO_2.

- Continue to pursue existing and potential opportunities with wholesale power sales agreements within the Duke Energy Balancing Authority Area.

- Continue to monitor energy-related statutory and regulatory activities.

2. SYSTEM OVERVIEW, OBJECTIVES, AND PROCESS

A. SYSTEM OVERVIEW

Duke Energy Carolinas provides electric service to an approximately 24,000-square-mile service area in central and western North Carolina and western South Carolina. In addition to retail sales to approximately 2.41 million customers, Duke Energy Carolinas also sells wholesale electricity to incorporated municipalities and to public and private utilities. Recent historical values for the number of customers and sales of electricity by customer groupings may be found in Tables 3.B and 3.C in Chapter 3.

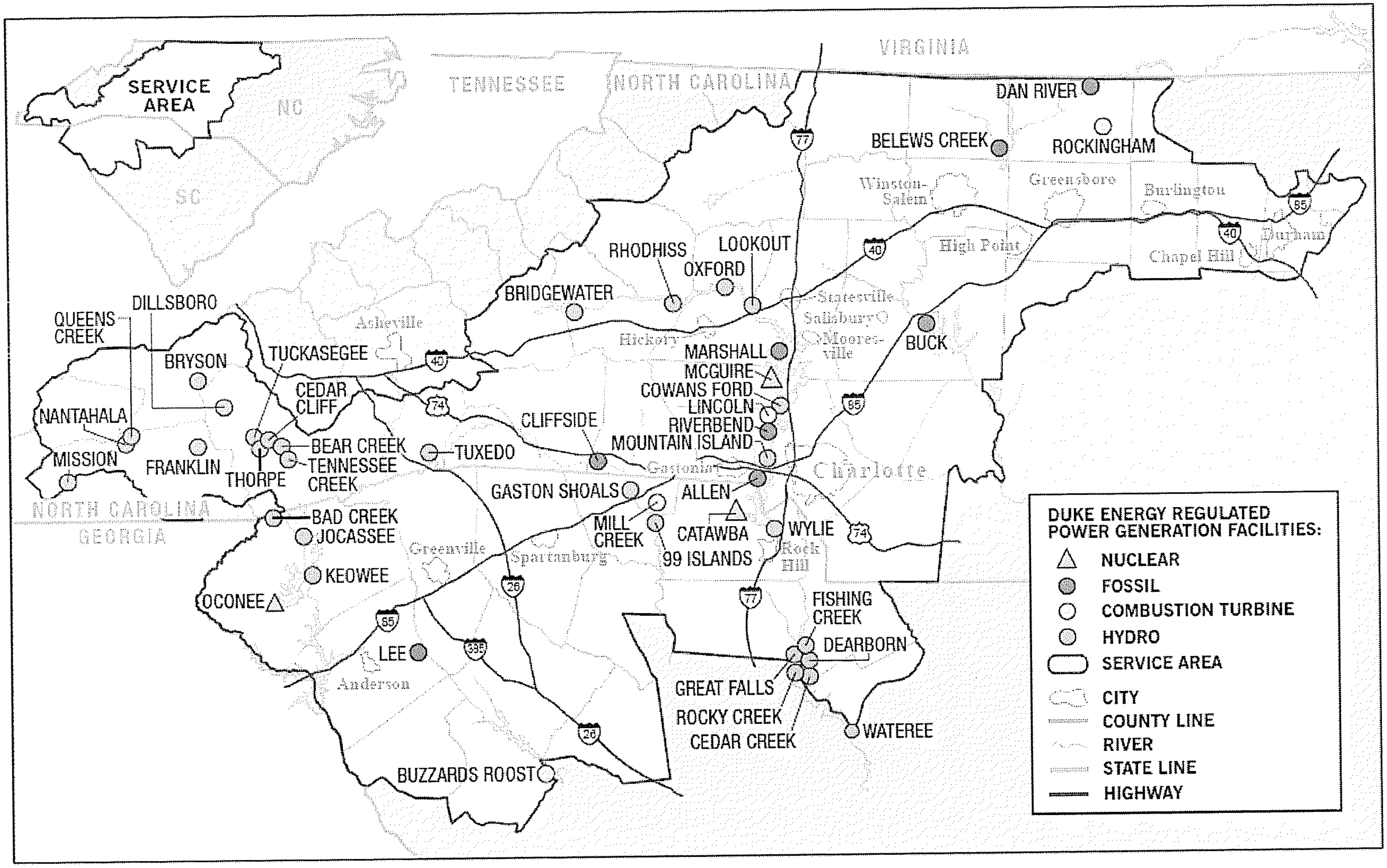
Duke Energy Carolinas currently meets energy demand, in part, by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets:

- Three nuclear generating stations with a combined net capacity of 6,996 MW (including all of Catawba Nuclear Station);
- Eight coal-fired stations with a combined capacity of 7,535 MW;
- 30 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 3,209 MW; and
- Eight combustion turbine stations with a combined capacity of 3,120 MW.

Duke Energy Carolinas' power delivery system consists of approximately 95,000 miles of distribution lines and 13,000 miles of transmission lines. The transmission system is directly connected to all of the utilities that surround the Duke Energy Carolinas service area. There are 35 circuits connecting with eight different utilities: Progress Energy Carolinas, American Electric Power, Tennessee Valley Authority, Southern Company, Yadkin, Southeastern Power Administration (SEPA), South Carolina Electric and Gas, and Santee Cooper. These interconnections allow utilities to work together to provide an additional level of reliability. The strength of the system is also reinforced through coordination with other electric service providers in the Virginia-Carolinas (VACAR) subregion, SERC Reliability Corporation (SERC) (formerly Southeastern Electric Reliability Council), and North American Electric Reliability Corporation (NERC).

The map on the following page provides a high-level view of the Duke Energy Carolinas system.

Duke Energy – Carolinas Power Generation Facilities



B. OBJECTIVES

Duke Energy Carolinas has an obligation to provide reliable and economic electric service to its customers in North Carolina and South Carolina. To meet this obligation, the Company conducted an integrated resource planning process that serves as the basis for its 2011 IRP.

The purpose of this IRP is to outline a robust strategy to furnish electric energy services to Duke Energy Carolinas customers in a reliable, efficient, and economic manner while factoring in the uncertainty of the current environment.

The planning process itself must be dynamic and constantly adaptable to changing conditions. The IRP presented herein represents the most robust and economic outcome based upon the Company's analyses under various assumptions and sensitivities. Due to the uncertainty of the current environment including regulatory, economic, environmental and operating circumstances, Duke Energy Carolinas has performed sensitivity analysis as part of this IRP to account for these uncertainties. As the environment continues to evolve, Duke Energy Carolinas will continue to monitor and make adjustments as necessary and practical to reflect improved information and changing circumstances.

Duke Energy Carolinas' long-term planning objective is to employ a flexible planning process and pursue a resource strategy that considers the costs and benefits to all stakeholders (customers, shareholders, employees, suppliers, and community). At times, this involves striking a balance between competing objectives. The major objectives of the plan presented in this filing are:

- Provide adequate, reliable, and economic service to customers in an uncertain environment.
- Maintain the flexibility and ability to alter the plan in the future as circumstances change.
- Choose a near-term plan that is robust over a wide variety of possible futures.
- Minimize risks with the development of a balanced portfolio.

C. PLANNING PROCESS

The development of the IRP is a multi-step process over the planning period of 2011-2031 involving these key planning functions:

- Develop planning objectives and assumptions.
- Consider the impacts of anticipated or pending regulations or events on existing resources (environmental, renewables, etc.).
- Consider two different regulatory constructs to assess the impact of potential CO_2 or Energy Policy legislation. The first included a CO_2 cap and trade construct with allowance prices beginning in 2016 projected at the lower end of pricing of previous proposed legislation. The second construct was based on Clean Energy Standard where an increasing percentage of retail sales starting in 2015 would come from energy efficiency, renewables, coal generation with carbon sequestration, nuclear and some allowance for combined cycle generation. Detailed descriptions of each of these constructs are available in Chapter 8.
- Prepare the electric load forecast. More details of this step may be found in Chapter 3.
- Identify EE and DSM options. More details concerning this step can be found in Chapter 4.
- Identify and economically screen for the cost-effectiveness of supply-side resource options. More details concerning this step of the process can be found in Chapter 5.
- Integrate the energy efficiency, renewable, and supply-side options with the existing system and electric load forecast to develop potential resource portfolios to meet the desired reserve margin criteria. More details concerning this step of the process can be found in Chapter 8 and Appendix A.
- Perform detailed modeling of potential resource portfolios to determine the resource portfolio that exhibits the lowest cost (lowest net present value of costs) to customers over a wide range of alternative futures. More details concerning this step of the process can be found in Chapter 8 and Appendix A.
- Evaluate the ability of the selected resource portfolio to minimize price and reliability risks to customers. More details concerning this step of the process can be found in Chapter 8 and Appendix A.

The analytical methodology includes the incorporation of sensitivity analysis of variables representing the highest risk going forward, such as the load forecast, construction costs, fuel prices, EE, carbon prices and emerging policy.

3. ELECTRIC LOAD FORECAST

The following section provides details on the Spring 2011 Load Forecast.

Duke Energy Carolinas retail sales have grown at an average annual rate of 0.9 percent from 1995 to 2010. The following table shows historical and projected major customer class growth, at a compound annual rate.

Table 3.A
Retail Load Growth (kWh sales)

Time Period	Total Retail	Residential	Commercial	Industrial Textile	Industrial Non-Textile
1995-2010	0.9%	2.7%	2.8%	-7.1%	-0.4%
1995-2005	1.2%	2.6%	3.4%	-6.0%	0.7%
2005-2010	0.4%	2.9%	1.7%	-9.4%	-2.6%
2010-2030	1.5%	1.5%	2.0%	-0.9%	1.1%

*Growth rates from 2010-2030 are derived using weather adjusted values for 2010. This differs from the Forecast Book located in Appendix B, which uses actual 2010 values.

A significant decline in the Industrial Textile class was the key contributor to the low load growth from 2005 to 2010, however, this decline was mostly offset by contributions in the Residential and Commercial classes over the same period. Over the last 5 years, an average of approximately 27,000 new residential customers per year has been added to the Duke Energy Carolinas service area.

Duke Energy Carolinas' total retail load growth over the planning horizon is driven by projected steady increases in the Residential, Commercial and Other Industrial classes. Textiles, however, are projected to experience a slow decline over the forecast horizon.

Retail load growth summaries are shown in the Duke Energy Carolinas Spring 2011 Forecast book in Appendix B.

The Residential load growth summaries shown in Table 3.A use the same history and forecast data for Residential Sales located on page 10 of the Forecast book in Appendix B. The Commercial load growth summaries use the same history and forecast data for Commercial Sales located on page 11 of the Forecast book in Appendix B. The Industrial

Textile load growth summaries use the same history and forecast data for Textile Sales located on page 13 of the Forecast book in Appendix B. The Industrial Non-Textile load growth summaries use the same history and forecast data for Other Industrial Sales located on page 14 of the Forecast book in Appendix B.

Table 3.B
Retail Customers (1000s, Annual Average)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Residential	1,814	1,840	1,872	1,901	1,935	1,972	2,016	2,052	2,059	2,072
Commercial	295	300	307	313	319	325	331	334	333	334
Industrial	8	8	8	8	7	7	7	7	7	7
Other	11	11	11	12	13	13	13	14	14	14
Total	2,128	2,159	2,198	2,234	2,275	2,317	2,368	2,407	2,413	2,427

Table 3.C
Electricity Sales (GWh Sold - Years Ended December 31)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Residential	23,272	24,466	23,947	25,150	26,108	25,816	27,459	27,335	27,273	30,049
Commercial	23,666	24,242	24,355	25,204	25,679	26,030	27,433	27,288	26,977	27,968
Industrial	26,902	26,259	24,764	25,209	25,495	24,535	23,948	22,634	19,204	20,618
Other	281	271	270	269	269	271	278	284	287	287
Total Retail	74,121	75,238	73,336	75,833	77,550	76,653	79,118	77,541	73,741	78,922
Wholesale	1,484	1,530	1,448	1,542	1,580	1,694	2,454	3,525	3,788	5,166
Total GWH	75,605	76,769	74,784	77,374	79,130	78,347	81,572	81,066	77,528	84,088

Note: Wholesale sales will vary over time due to new contract agreements.

Wholesale Power Sales Commitments

Table 3.D on the following page contains information concerning Duke Energy Carolinas' wholesale contracts.

Table 3.D

WHOLESALE CONTRACTS

Wholesale Customer	Contract Designation	Contract Term	Commitment (MW)									
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NC/SC Munis Concord, NC Dallas, NC Forest City, NC Kings Mountain, NC Lockhart Power Due West, SC Prosperity, SC Greenwood, SC Highlands, NC Western Carolina University See Note 1	 Partial Partial Partial Partial Partial Partial Partial Full Full Full	December 31,2018 with annual renewals. Can be terminated on one-year notice by either party after current contract term.	331	334	340	346	352	358	364	370	376	383
New River EMC See Note 1	Full	December 31. 2021	35	35	36	37	37	38	39	40	41	42
Blue Ridge EMC See Note 1	Full	December 31, 2021	183	187	191	196	200	205	210	215	219	224
Piedmont EMC See Note 1	Full	December 31, 2021	90	91	92	93	94	95	97	98	99	100
Rutherford EMC See Note 1	Partial	December 31, 2021	159	164	193	197	211	215	219	223	227	231
Haywood EMC See Note 1	Full	December 31, 2021	26	26	26	27	27	28	28	29	29	29
Central See Note 1	Partial incr.to Full	January 1, 2013 - December 31, 2030	0	0	121	247	377	511	650	794	898	913
NCEMC See Note 2	Contract Backstand	Through Operating Life of Catawba and McGuire Nuclear Station	586	586	586	586	586	586	586	586	586	586
NCEMC	Capacity Sale	January 1, 2009 - December 31, 2038	72	72	72	72	72	72	72	72	72	72

Note 1: The analyses in the Annual Plan assumed that the contracts will be renewed or extended through the end of the planning horizon

Note 2: The annual commitment shown is the ownership share of Catawba Nuclear Station and is included in the load forecast

The Spring 2011 Forecast includes projections of the energy needs of new and existing customers in Duke Energy Carolinas service territory. Certain wholesale customers have the option of obtaining all or a portion of their future energy requirements from other suppliers. While this may reduce Duke Energy Carolinas obligation to serve those customers, Duke Energy Carolinas assumes for planning purposes that the contracts displayed in Table 3.D will be extended through the duration of the forecast horizon.

Pursuant to NCUC Rule R8-60(i)(1), a description of the methods, models and assumptions used by the utility to prepare its peak load (MW) and energy sales (MWh) forecasts and the variables used in the models is provided on pages 4-6 of the Duke Energy Carolinas 2011 Forecast book located in Appendix B. Also, per NCUC Rule R8-60(i)(1)(A), a forecast of customers by each customer class and a forecast of energy sales (kWh) by each customer class is provided on pages 9-14 and pages 17-22 of the 2011 Forecast book located in Appendix B.

A tabulation of the utility's forecasts for a 20 year period, including peak loads for summer and winter seasons of each year and annual energy forecasts, both with and without the impact of utility-sponsored energy efficiency programs are shown below in Tables 3.E and 3.F.

Load duration curves, with and without utility-sponsored energy efficiency programs, follow Tables 3.E and 3.F, and are shown as Charts 3.A and 3.B.

These values reflect the loads that Duke Energy Carolinas is contractually obligated to provide and cover the period from 2011 to 2031.

The current 20-year forecast of the needs of the retail and wholesale customer classes, which does not include the impact of new energy efficiency programs, projects a compound annual growth rate of 1.8 percent in the summer peak demand, while winter peaks are forecasted to grow at 1.7 percent. The forecasted compound annual growth rate for energy is 1.9 percent.

If the impacts of new energy efficiency programs are included, the projected compound annual growth rate for the summer peak demand is 1.7 percent, while winter peaks are forecasted to grow at a rate of 1.6 percent. The forecasted compound annual growth rate for energy is 1.7 percent.

Table 3.E
Load Forecast without Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2011	17,596	17,121	91,750
2012	17,907	17,425	93,281
2013	18,353	17,869	95,307
2014	18,800	18,303	97,455
2015	19,273	18,746	100,044
2016	19,752	19,180	102,481
2017	20,220	19,665	104,929
2018	20,680	20,123	107,476
2019	21,122	20,539	109,865
2020	21,475	20,868	111,873
2021	21,826	21,128	113,859
2022	22,152	21,482	115,560
2023	22,469	21,782	117,366
2024	22,777	22,080	119,235
2025	23,120	22,379	121,087
2026	23,430	22,649	123,013
2027	23,777	22,922	124,979
2028	24,109	23,280	127,025
2029	24,419	23,584	129,081
2030	24,765	23,885	131,175
2031	25,121	24,186	133,281

Chart 3.A- Load Duration Curves without Energy Efficiency

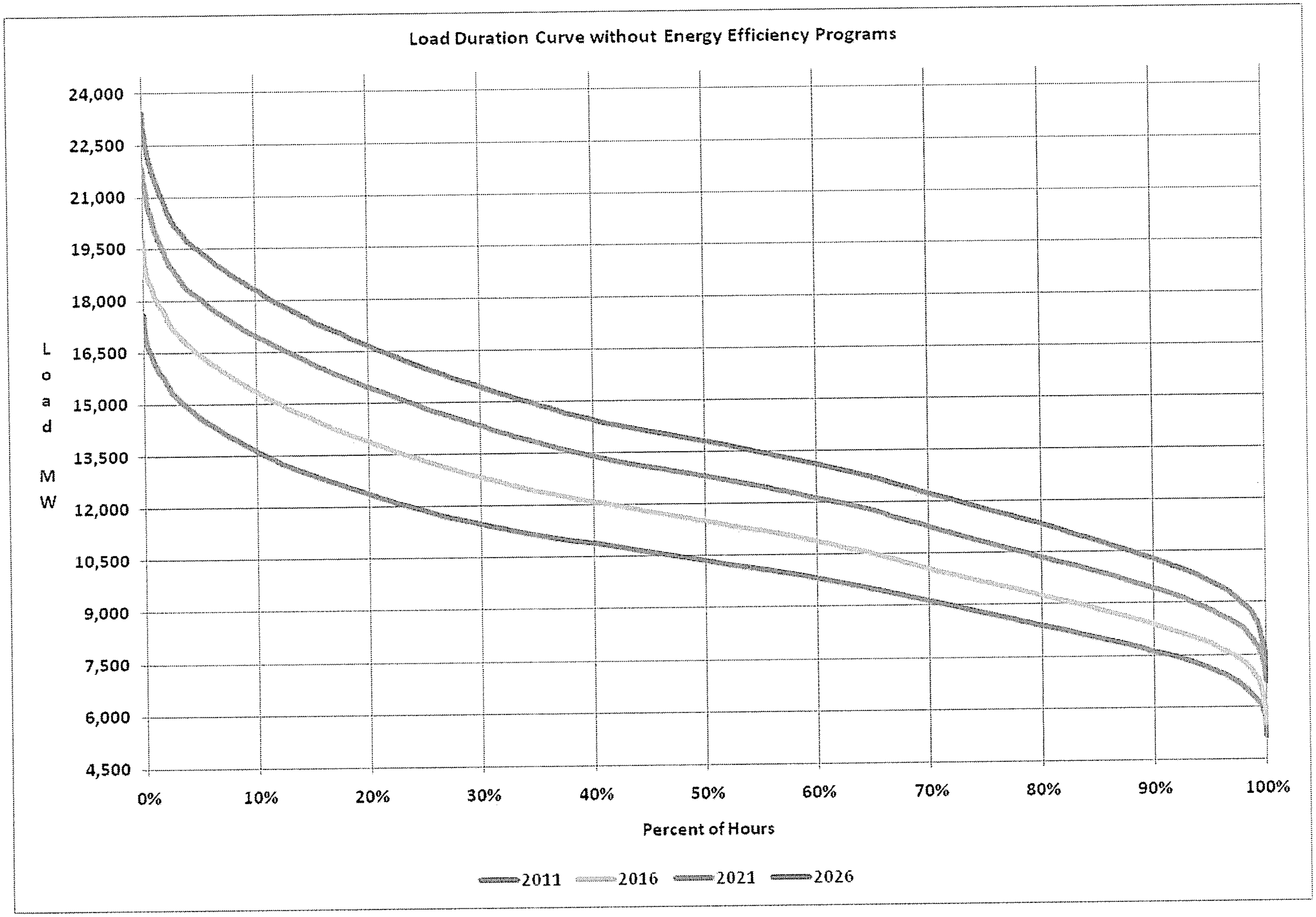
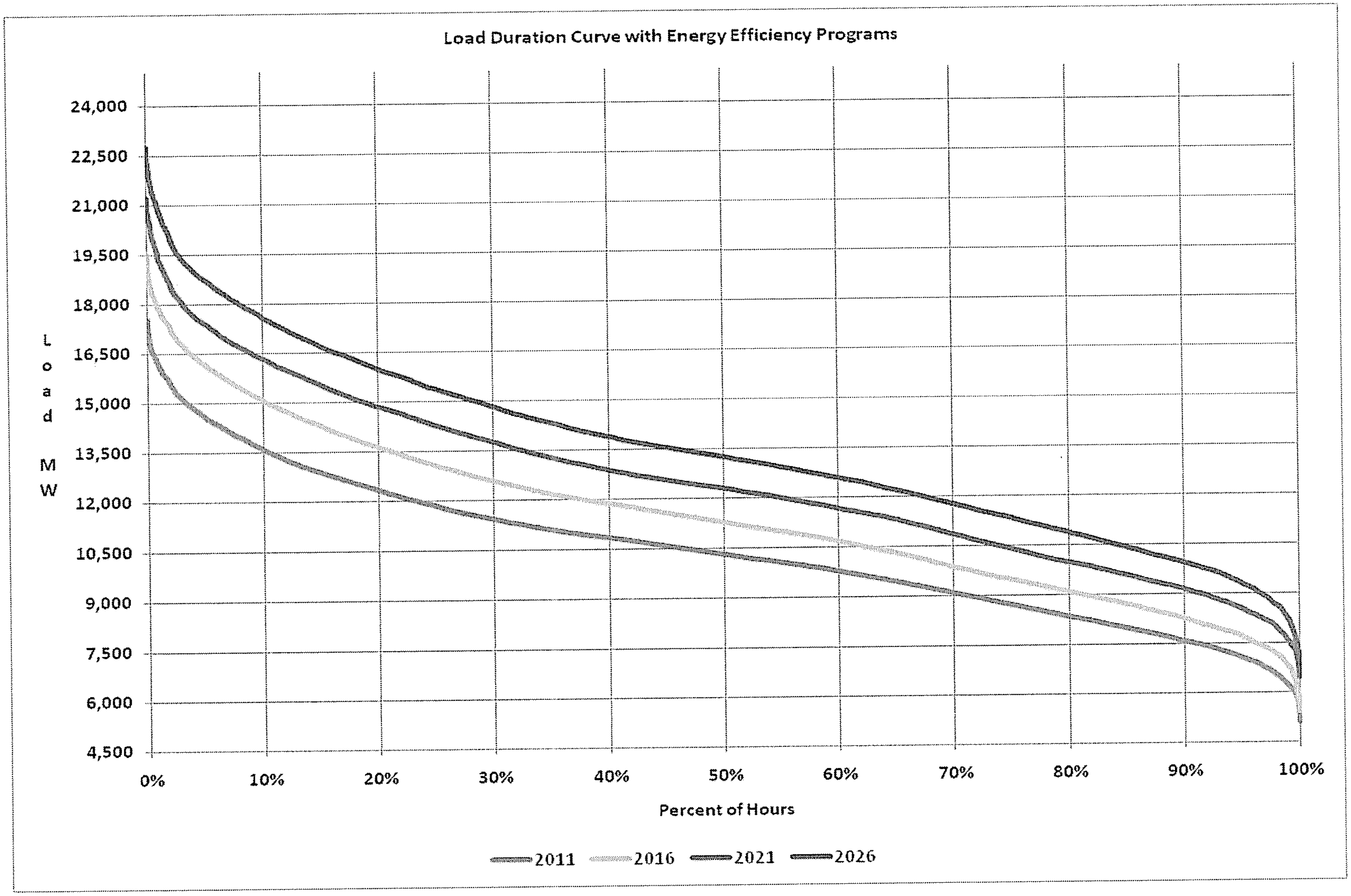


Table 3.F
Load Forecast with Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2011	17,557	17,115	91,479
2012	17,812	17,359	92,679
2013	18,245	17,773	94,518
2014	18,680	18,177	96,507
2015	19,032	18,543	98,517
2016	19,476	18,891	100,472
2017	19,877	19,305	102,438
2018	20,265	19,694	104,503
2019	20,644	20,042	106,409
2020	20,901	20,304	107,936
2021	21,214	20,492	109,440
2022	21,530	20,835	111,063
2023	21,836	21,124	112,791
2024	22,135	21,412	114,580
2025	22,465	21,697	116,350
2026	22,733	21,956	118,193
2027	23,099	22,217	120,075
2028	23,420	22,565	122,035
2029	23,715	22,853	124,003
2030	24,050	23,142	126,008
2031	24,393	23,430	128,025

Chart 3.B - Load Duration Curves with Energy Efficiency



4. ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT

Current Energy Efficiency and Demand-Side Management Programs

In May 2007, Duke Energy Carolinas filed its application for approval of EE and DSM programs under its save-a-watt initiative. The Company received the final order for approval for these programs from the NCUC in July 2010 and from the PSC in May 2009.

Duke Energy Carolinas uses EE and DSM programs to help manage customer demand in an efficient, cost-effective manner. These programs can vary greatly in their dispatch characteristics, size and duration of load response, certainty of load response, and level and frequency of customer participation. In general, programs are offered in two primary categories: EE programs that reduce energy consumption (conservation programs) and DSM programs that reduce energy demand (demand-side management or demand response programs and certain rate structure programs). The following are the current EE and DSM programs in place in the Carolinas:

Demand Response – Load Control Curtailment Programs

These programs can be dispatched by the utility and have the highest level of certainty. Once a customer agrees to participate in a demand response load control curtailment program, the Company controls the timing, frequency, and nature of the load response. Duke Energy Carolinas' current load control curtailment programs are:

- **Power Manager®** - Power Manager is a residential load control program. Participants receive billing credits during the billing months of July through October in exchange for allowing Duke Energy Carolinas the right to cycle their central air conditioning systems and, additionally, to interrupt the central air conditioning when the Company has capacity needs.

Demand Response – Interruptible and Related Rate Structures

These programs rely either on the customer's ability to respond to a utility-initiated signal requesting curtailment or on rates with price signals that provide an economic incentive to reduce or shift load. Timing, frequency and nature of the load response depend on customers' actions after notification of an event or after receiving pricing signals. Duke Energy Carolinas' current interruptible and time-of-use curtailment programs include:

- **Interruptible Power Service (IS)** (North Carolina Only) - Participants agree contractually to reduce their electrical loads to specified levels upon request by Duke Energy Carolinas. If customers fail to do so during an interruption, they receive a penalty for the increment of demand exceeding the specified level.

- **Standby Generator Control (SG)** (North Carolina Only) - Participants agree contractually to transfer electrical loads from the Duke Energy Carolinas source to their standby generators upon request by Duke Energy Carolinas. The generators in this program do not operate in parallel with the Duke Energy Carolinas system and therefore, cannot "backfeed" (i.e., export power) into the Duke Energy Carolinas system. Participating customers receive payments for capacity and/or energy, based on the amount of capacity and/or energy transferred to their generators.

- **PowerShare®** is a non-residential curtailment program consisting of four options: an emergency only option for curtailable load (PowerShare® Mandatory), an emergency only option for load curtailment using on-site generators (PowerShare® Generator), an economic based voluntary option (PowerShare® Voluntary), and a combined emergency and economic option that allows for increased notification time of events (PowerShare® CallOption).
  - PowerShare® Mandatory: Participants in this emergency only option will receive capacity credits monthly based on the amount of load they agree to curtail during utility-initiated emergency events. Participants also receive energy credits for the load curtailed during events. Customers enrolled may also be enrolled in PowerShare® Voluntary and eligible to earn additional credits.
  - PowerShare® Generator: Participants in this emergency only option will receive capacity credits monthly based on the amount of load they agree to curtail during utility-initiated emergency events and their performance during monthly test hours. Participants also receive energy credits for the load curtailed during events.
  - PowerShare® Voluntary: Enrolled customers will be notified of pending emergency or economic events and can log on to a Web site to view a posted energy price for that particular event. Customers will then have the option to participate in the event and will be paid the posted energy credit for load curtailed.
  - PowerShare® CallOption: This DSM program offers a participating customer the ability to receive credits when the customer agrees, at the Company's request, to reduce and maintain its load by a minimum of 100 kW during Emergency and/or Economic Events. Credits are paid for the load available for curtailment, and charges are applicable when the customer fails to reduce load in accordance with the participation option it has selected. Participants are obligated to curtail load during emergency events. CallOption offers four participation options to customers: PS 0/5, PS 5/5, PS 10/5 and PS 15/5. All options include a limit of five Emergency Events and set a limit for Economic

Events to 0, 5, 10 and 15 respectively.

- **Rates using price signals**

  - **Residential Time-of-Use (including a Residential Water Heating rate)**
    This category of rates for residential customers incorporates differential seasonal and time-of-day pricing that encourages customers to shift electricity usage from on-peak time periods to off-peak periods. In addition, there is a Residential Water Heating rate for off-peak water heating electricity use.

  - **General Service and Industrial Optional Time-of-Use rates**
    This category of rates for general service and industrial customers incorporates differential seasonal and time-of-day pricing that encourages customers to use less electricity during on-peak time periods and more during off-peak periods.

  - **Hourly Pricing for Incremental Load**
    This category of rates for general service and industrial customers incorporates prices that reflect Duke Energy Carolinas' estimation of hourly marginal costs. In addition, a portion of the customer's bill is calculated under their embedded-cost rate. Customers on this rate can choose to modify their usage depending on hourly prices.

Energy Efficiency Programs
These programs are typically non-dispatchable, conservation-oriented education or incentive programs. Energy and capacity savings are achieved by changing customer behavior or through the installation of more energy-efficient equipment or structures. All effects of these existing programs are reflected in the customer load forecast. Duke Energy Carolinas' existing conservation programs include:

- **Residential Energy Assessments**

  The Residential Energy Assessments program includes two separate measures: 1) Personalized Energy Report (PER) and 2) Home Energy House Call.

  The PER program is a residential energy efficiency program that provides single family home customers with a customized report about their home and family and how they use energy. In addition, the customer receives CFLs as an incentive to participate in the program.

The PER program requires customers to provide information about their home, number of occupants, equipment and energy usage and has two variations:

- A mailed offer where customers are asked to complete an included energy survey and mail it back to Duke Energy or complete the same survey online. Customers mailing the energy survey receive their PER in the mail and those completing it online receive their PER online as a printable PDF document.

- An online offer to our customers that have signed into our Online Services (OLS) bill pay and view environment. Online participants complete their energy survey online get their PER online as a printable PDF.

Home Energy House Call (HEHC) is a free in-home assessment designed to help our customers learn about home energy usage and how to save on monthly bills. The program provides personalized information unique to the customer's home and energy practices. An energy specialist visits the customer's home to analyze the total home energy usage and to pinpoint energy saving opportunities. An energy specialist will also explain how to improve the heating and cooling comfort levels, check for air leaks, examine insulation levels, review appliances, help the customer preserve the environment for the future and keep electric costs low. A customized report is prepared, explaining the steps the customer can take to increase efficiency. As a part of the Home Energy House Call program, customers receive an Energy Efficiency Starter Kit. At the request of the customer, the energy specialist can install the efficiency items to allow the customer to begin saving immediately.

- **Low Income Energy Efficiency and Weatherization Program**
  The purpose of this program is to assist low income residential customers with demand-side management measures to reduce energy usage through energy efficiency kits or through assistance in the cost of equipment or weatherization measures.

- **Energy Efficiency Education Program for Schools**
  The purpose of this program is to educate students about sources of energy and energy efficiency in homes and schools through a curriculum provided to public and private schools. This curriculum includes lesson plans, energy efficiency materials, and energy audits.

- **Residential Smart $aver® Energy Efficient Products Program**
  The Smart $aver® Program provides incentives to residential customers who

purchase energy-efficient equipment. The program has two components – CFLs and high-efficiency air conditioning equipment.

CFLs

The CFL program is designed to offer incentives to customers and increase energy efficiency by installing CFLs in high use fixtures in the home. The incentives have been offered in a variety of ways. The first deployment of this program distributed free coupons to be redeemed by the customer at a variety of retail stores. Later deployments used business reply cards and a web-based on-demand ordering tool where CFLs are shipped directly to the customer's home.

Heating Ventilation & Air Conditioning (HVAC) and Heat Pump

The residential air conditioning program provides incentives to customers, builders, and heating contractors (HVAC dealers) to promote the use of high-efficiency air conditioners and heat pumps. The program is designed to increase the efficiency of air conditioning systems in new homes and for replacements in existing homes.

- **Smart $aver® for Non-Residential Customers**

  The purpose of this program is to encourage the installation of high-efficiency equipment in new and existing non-residential establishments. The program provides incentive payments to offset a portion of the higher cost of energy-efficient equipment. The following types of equipment are eligible for incentives as part of the Prescriptive program: high-efficiency lighting, high-efficiency air conditioning equipment, high-efficiency motors, high-efficiency pumps, variable frequency drives, food services and process equipment. Customer incentives may be paid for other high-efficiency equipment as determined by the Company to be evaluated on a case-by-case basis through the Custom program.

The projected impacts from these programs are included in this year's assessment of generation needs.

Additional Programs Being Considered

In addition to our current portfolio of programs, Duke Energy Carolinas plans to add three additional concepts to our portfolio. These programs are similar to approved programs offered by Progress Energy Carolinas. The three additional programs are Additional Smart $aver® Measures, Direct Install Low Income and Appliance Recycle. A high-level overview is provided below.

- **Additional Smart $aver® Measures**

  Partnering with HVAC dealers, the program pays incentives to partially offset the cost of air conditioner and heat pump tune ups and duct sealing. This would be a new program and has not been offered in any of Duke Energy's jurisdictions. Projected impacts of this program were included in the analysis of generation needs.

- **Direct Install Low Income Program**
  Program that targets low income neighborhoods providing high impact direct install measures (CFLs, pipe and water heater wrap, low flow aerators and showerheads, HVAC filters and air infiltration sealing) and energy efficiency education. Projected impacts of this program were included in the analysis of generation needs.

- **Appliance Recycling Program**
  This is a program to incentivize households to turn in old inefficient refrigerators and freezers. Projected impacts of this program were not included in the analysis of generation needs due to the timing of approval of this concept.

The following pilot programs have been approved:

- **Residential Retrofit**
  This program was approved in North Carolina in Docket E-7, Sub 952 on January 25, 2011 and in South Carolina in Docket 2010-51-E on February 24, 2010. The Residential Retrofit program is designed to assist residential customers in assessing their energy usage, to provide recommendations for more efficient use of energy in their homes and to encourage the installation of energy efficient improvements by offsetting a portion of the cost of implementing the recommendations from the assessment. Projected impacts of this pilot program were included in the analysis of generation needs.

- **Home Energy Comparison Report**
  This pilot was approved by the Public Service Commission of South Carolina in Docket 2010-50-E on March 24, 2010 and will test the energy savings impact of providing periodic reports to targeted customers showing how their energy consumption compares to that of similar neighbors. This pilot program is currently only offered in South Carolina. Projected impacts of this pilot program were included in the analysis of generation needs.

- **Smart Energy Now (SEN)**
  The SEN pilot program was approved by the NCUC in Docket E-7, Sub 961 on February 14, 2011 and is designed to reduce energy consumption within the

commercial office space located in Charlotte City Center through community engagement leading to behavioral modification. In order to enable building managers and occupants to effectively make these behavioral modifications, they will be provided with additional energy consumption information and actionable efficiency recommendations. Projected impacts of this pilot were not included in the analysis of generation needs due to the timing of approval.

The following pilot program is being proposed:

- **Home Energy Manager (HEM) Lite**
  HEM Lite is a residential energy management solution designed for home owners with broadband internet service. The product offers energy efficiency and demand response benefits through a Wi-Fi enabled thermostat that will manage a customer's air conditioning system by providing schedules, modes (such as home/away/vacation), energy savings tips, messages, and alerts. The customer will have the tools to access and control their thermostat through any web browser or by downloading an "app" on their smart phone. In addition, it will provide customers with the opportunity to participate in demand response events. Overall, this product will provide simple, intuitive, and effective tools that will enable the customer to reduce and manage their overall energy usage.

Future EE and DSM programs

In addition to the programs and pilots listed above, Duke Energy Carolinas is actively working to add new programs to our portfolio that have not yet been developed. Estimates of the impacts of these yet-to-be-developed programs have been included in this analysis of generation needs.

EE and DSM Program Screening

The Company uses the DSMore model to evaluate the costs, benefits, and risks of DSM and EE programs and measures. DSMore is a financial analysis tool designed to estimate the value of DSM and EE measures at an hourly level across distributions of weather conditions and/or energy costs or prices. By examining projected program performance and cost effectiveness over a wide variety of weather and cost conditions, the Company is in a better position to measure the risks and benefits of employing DSM and EE measures versus traditional generation capacity additions, and further, to ensure that DSM resources are compared to supply side resources on a level playing field.

The analysis of energy efficiency cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the California Standard tests: Utility Cost Test (UCT), Rate Impact Measure (RIM) Test, Total Resource Cost (TRC) Test, and Participant Test. DSMore provides the results of those tests for any type of EE or DSM program.

- The UCT compares utility benefits (avoided costs) to incurred utility costs to implement the program, and does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, including the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs, and load (line) losses.

- The RIM Test, or non-participants test, indicates if rates increase or decrease over the long-run as a result of implementing the program.

- The TRC Test compares the total benefits to the utility and to participants relative to the costs to the utility to implement the program along with the costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the Participant Test, however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC.

- The Participant Test evaluates programs from the perspective of the program's participants. The benefits include reductions in utility bills, incentives paid by the utility and any state, federal or local tax benefits received.

The use of multiple tests can ensure the development of a reasonable set of DSM and EE programs and indicate the likelihood that customers will participate.

Energy Efficiency and Demand-Side Management Programs

Duke Energy Carolinas has made a strong commitment to EE and DSM. The Company recognizes EE and DSM as a reliable, valuable resource that is an option in the portfolio available to meet customers' growing need for electricity along with coal, nuclear, natural gas, and renewable energy. These EE and DSM programs help customers meet their energy needs with less electricity, less cost and less environmental impact. The Company will manage EE and DSM to provide customers with universal access to these services and new technology. Duke Energy Carolinas has the expertise, infrastructure, and customer relationships to produce results and make it a significant part of its resource mix. Duke Energy Carolinas accepts the challenge to develop, implement, adjust as needed, and verify the results of innovative EE programs for the benefit of its customers.

The Duke Energy Carolinas' approved EE plan is consistent with the requirement set forth in the Cliffside Unit 6 CPCN Order to invest 1% of annual retail electricity revenues in energy efficiency and demand side programs, subject to the results of ongoing collaborative workshops and appropriate regulatory treatment. For the period between the deployment of the Company's save-a-watt portfolio in 2009 and 12/31/2010, Duke Energy's conservation and demand response programs have reduced overall demand, including line losses, by approximately 500,000 net MWh and the Summer Peak has been reduced by over 700 MW. However, pursuing EE and DSM initiatives will not meet all our growing demands for electricity. The Company still envisions the need to secure additional nuclear and gas generation as well as cost-effective renewable generation, but the EE and DSM programs offered by Duke Energy Carolinas could address approximately half of the 2015 new resource need, if such programs perform as expected.

Table 4.A provides the base case projected load impacts of the EE and DSM programs through 2031. These load impacts were included in the base case IRP analysis. The Company assumes total EE savings will continue to grow on an annual basis through 2035, however the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan. The projected load impacts from the DSM programs are based upon the Company's continuing, as well as the new, demand response programs. These projections have decreased from last year in part due to incorporation of impacts from the EPA's RICE rule. This EPA rule restricts the use of customer-sited generators to a very low level for demand response purposes. EPA is currently collecting comments on this rule so it is uncertain at this time if the rule will change and what the eventual impact will be on the Company's demand response programs. Duke Energy Carolinas is considering alternatives to address the reduction in DSM capability available.

Table 4.B provides a high case load impact scenario from the Company's EE and DSM programs. For EE programs, this scenario uses the full target impacts of the Company's save-a-watt bundle of programs for the first five years and then increases the load impacts

at 1% of retail sales every year after that until 2030, beyond which point the increase in the load impacts are adjusted to match the projected growth in retail sales. For DSM programs, the load impacts are increased to match the increase between base case and high case MWH retail sales for the appropriate customer class.

Table 4.C incorporates December 31, 2010 participation levels for all demand response programs and the capability of these programs projected for the summer of 2011.

Table 4.A Load Impacts of EE and DSM Programs – Base Case

Conservation and Demand Side Management Programs

	Conservation		Demand Response Peak MW Summer Peak MW					Total Summer Peak
Year	MWh	MW	IS	SG	PowerShare	PowerManager	Total	MW Impacts
2011	271,026	39	145	48	331	249	775	814
2012	601,792	80	135	46	367	294	842	922
2013	788,832	102	128	19	364	343	854	955
2014	947,489	120	122	18	391	393	923	1,044
2015	1,526,825	208	116	17	414	436	983	1,190
2016	2,008,940	276	110	16	429	432	987	1,262
2017	2,491,055	343	110	16	429	432	986	1,329
2018	2,973,170	410	110	16	429	432	986	1,396
2019	3,455,286	478	110	16	429	432	986	1,465
2020	3,937,401	544	110	16	429	432	986	1,530
2021	4,419,513	611	110	16	429	432	986	1,598
2022	4,496,857	622	110	16	429	432	986	1,608
2023	4,575,552	633	110	16	429	432	986	1,619
2024	4,655,623	642	110	16	429	432	986	1,629
2025	4,737,095	655	110	16	429	432	986	1,642
2026	4,819,996	667	110	16	429	432	986	1,653
2027	4,904,346	679	110	16	429	432	986	1,665
2028	4,990,171	688	110	16	429	432	986	1,675
2029	5,077,501	703	110	16	429	432	986	1,689
2030	5,166,356	715	110	16	429	432	986	1,701
2031	5,256,768	727	110	16	429	432	986	1,714

Table 4.B Load Impacts of EE and DSM Programs – High Case

Conservation and Demand Side Management Programs

	Conservation		Demand Response Peak MW Summer Peak MW					Total Summer Peak
Year	MWh	MW	IS	SG	PowerShare	PowerManager	Total	MW Impacts
2011	271,026	39	163	54	373	264	855	894
2012	601,792	80	154	53	419	311	936	1,016
2013	788,832	102	147	21	418	362	947	1,049
2014	947,489	120	140	20	450	415	1,024	1,145
2015	2,070,090	283	134	19	478	460	1,091	1,374
2016	2,809,117	387	128	18	497	456	1,100	1,487
2017	3,548,145	490	128	18	500	457	1,104	1,594
2018	4,287,171	593	129	18	502	458	1,107	1,701
2019	5,026,201	698	129	19	503	460	1,111	1,809
2020	5,765,231	798	130	19	505	462	1,115	1,913
2021	6,504,259	902	130	19	507	463	1,118	2,020
2022	7,243,284	1,004	130	19	508	465	1,122	2,126
2023	7,982,312	1,107	131	19	510	467	1,126	2,233
2024	8,721,341	1,207	131	19	511	470	1,131	2,338
2025	9,460,367	1,313	132	19	513	472	1,136	2,448
2026	10,199,395	1,416	132	19	515	475	1,140	2,556
2027	10,938,425	1,519	132	19	516	477	1,145	2,663
2028	11,677,451	1,617	133	19	518	480	1,150	2,766
2029	12,416,478	1,724	133	19	520	483	1,155	2,879
2030	13,155,507	1,827	134	19	521	486	1,160	2,987
2031	13,385,729	1,859	134	19	523	489	1,165	3,024

Table 4.C

DSM Program Participation and Capability

DSM Program Name	Participation as of 12/31/10	2011 Estimated Summer IRP Capability (MW)
IS	69	145
SG	98	48
PowerShare Mandatory	115	313
PowerShare Generator	4	18
PowerShare Voluntary	4	N/A
PowerShare CallOption		
Level 0/5	-	-
Level 5/5	-	-
Level 10/5	-	-
Level 15/5	1	0
Power Manager	198,503	249
Total	198,794	775

Programs Evaluated but Rejected

Duke Energy Carolinas has not rejected any programs as a result of its EE and DSM program screening.

Looking to the Future

DSM Implementation Effectiveness – Duke Energy Carolinas has begun a review of the effectiveness of its DSM programs to reduce peak demand during reliability events. The goal of this review will be to gain insight on DSM parameters, such as duration of events and number of events and how these parameters impact the load reduction captured during a reliability event.

Grid Modernization – Duke Energy is pursuing implementation of grid modernization throughout the enterprise. The recent $200 million grant awarded to Duke Energy from the US DOE helps further that goal. Grid modernization is a mechanism to further enable adoption and market penetration of EE, DSM and plug-in electric vehicles (PEVs). In order to meet and support EE and DSM goals, the NCUC proposed a requirement to include grid modernization impacts in the IRP for North Carolina electric utilities (including Duke Energy Carolinas) in Docket E-100, Sub 126. Duke Energy Carolinas filed joint comments along with Dominion-North Carolina Power on February 26, 2010, in which the two utilities supported the inclusion of the impact of grid modernization as part of the IRP. The two utilities also advocated that grid modernization should be treated similarly to how EE and DSM resources are incorporated into the IRP. Progress Energy later joined Duke Energy Carolinas and Dominion-North Carolina Power in reply comments filed before the NCUC on March 26, 2010, further emphasizing these points.

5. SUPPLY-SIDE RESOURCES

A. EXISTING GENERATION PLANTS IN SERVICE

Duke Energy Carolinas' generation portfolio includes a balanced mix of resources with different operating and fuel characteristics. This mix is designed to provide energy at the lowest reasonable cost to meet the Company's obligation to serve its customers. Duke Energy Carolinas-owned generation, as well as purchased power, is evaluated on a real-time basis in order to select and dispatch the lowest-cost resources to meet system load requirements. In 2010, Duke Energy Carolinas' nuclear and coal-fired generating units met the vast majority of customer needs by providing 51.2% and 46.7%, respectively, of Duke Energy Carolinas' energy from generation. Hydroelectric generation, CT generation, solar generation, long term PPAs, and economical purchases from the wholesale market supplied the remainder.

Existing Resources

The tables below list the Duke Energy Carolinas plants in service in North Carolina (NC) and South Carolina (SC) with plant statistics, and the system's total generating capability.

Table 5.A

North Carolina [a,b,c,d,e]

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Allen	1	162.0	167.0	Belmont, N.C.	Conventional Coal
Allen	2	162.0	167.0	Belmont, N.C.	Conventional Coal
Allen	3	261.0	270.0	Belmont, N.C.	Conventional Coal
Allen	4	276.0	282.0	Belmont, N.C.	Conventional Coal
Allen	5	266.0	275.0	Belmont, N.C.	Conventional Coal
Allen Steam Station		**1127.0**	**1161.0**		
Belews Creek	1	1110.0	1135.0	Belews Creek, N.C.	Conventional Coal
Belews Creek	2	1110.0	1135.0	Belews Creek, N.C.	Conventional Coal
Belews Creek Steam Station		**2220.0**	**2270.0**		
Buck	5	128.0	131.0	Salisbury, N.C.	Conventional Coal
Buck	6	128.0	131.0	Salisbury, N.C.	Conventional Coal
Buck Steam Station		**256.0**	**262.0**		
Cliffside	1	38.0	39.0	Cliffside, N.C.	Conventional Coal
Cliffside	2	38.0	39.0	Cliffside, N.C.	Conventional Coal
Cliffside	3	61.0	62.0	Cliffside, N.C.	Conventional Coal
Cliffside	4	61.0	62.0	Cliffside, N.C.	Conventional Coal
Cliffside	5	556.0	562.0	Cliffside, N.C.	Conventional Coal
Cliffside Steam Station		**754.0**	**764.0**		
Dan River	1	67.0	69.0	Eden, N.C.	Conventional Coal
Dan River	2	67.0	69.0	Eden, N.C.	Conventional Coal
Dan River	3	142.0	145.0	Eden, N.C.	Conventional Coal
Dan River Steam Station		**276.0**	**283.0**		
Marshall	1	380.0	380.0	Terrell, N.C.	Conventional Coal
Marshall	2	380.0	380.0	Terrell, N.C.	Conventional Coal
Marshall	3	658.0	658.0	Terrell, N.C.	Conventional Coal
Marshall	4	660.0	660.0	Terrell, N.C.	Conventional Coal
Marshall Steam Station		**2078.0**	**2078.0**		
Riverbend	4	94.0	96.0	Mt. Holly, N.C.	Conventional Coal
Riverbend	5	94.0	96.0	Mt. Holly, N.C.	Conventional Coal
Riverbend	6	133.0	136.0	Mt. Holly, N.C.	Conventional Coal
Riverbend	7	133.0	136.0	Mt. Holly, N.C.	Conventional Coal
Riverbend Steam Station		**454.0**	**464.0**		
TOTAL N.C. CONVENTIONAL COAL		**7165.0 MW**	**7282.0 MW**		
Buck	7C	25.0	30.0	Salisbury, N.C.	Natural Gas/Oil-Fired

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
					Combustion Turbine
Buck	8C	25.0	30.0	Salisbury, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Buck	9C	12.0	15.0	Salisbury, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Buck Station CTs		**62.0**	**75.0**		
Dan River	4C	0.0	0.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Dan River	5C	24.0	31.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Dan River	6C	24.0	31.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Dan River Station CTs		**48.0**	**62.0**		
Lincoln	1	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	2	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	3	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	4	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	5	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	6	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	7	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	8	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	9	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	10	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	11	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	12	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	13	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	14	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	15	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	16	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Lincoln Station CTs		**1267.2**	**1488.0**		
Riverbend	8C	0.0	0.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	9C	22.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	10C	22.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	11C	20.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend Station CTs		**64.0**	**90.0**		
Rockingham	1	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	2	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	3	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	4	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	5	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham CTs		**825.0**	**825.0**		
TOTAL N.C. COMB. TURBINE		**2266.2 MW**	**2540.0 MW**		
McGuire	1	1100.0	1156.0	Huntersville, N.C.	Nuclear
McGuire	2	1100.0	1156.0	Huntersville, N.C.	Nuclear
McGuire Nuclear Station		**2200.0**	**2312.0**		
TOTAL N.C. NUCLEAR		**2200.0 MW**	**2312.0 MW**		
Bridgewater	1	11.5	11.5	Morganton, N.C.	Hydro
Bridgewater	2	0	0	Morganton, N.C.	Hydro
Bridgewater Hydro Station		**11.5**	**11.5**		
Bryson City	1	0.48	0.48	Whittier, N.C.	Hydro
Bryson City	2	0	0	Whittier, N.C.	Hydro
Bryson City Hydro Station		**0.48**	**0.48**		
Cowans Ford	1	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	2	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	3	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	4	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford Hydro Station		**325.2**	**325.2**		
Lookout Shoals	1	9.3	9.3	Statesville, N.C.	Hydro
Lookout Shoals	2	9.3	9.3	Statesville, N.C.	Hydro

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Lookout Shoals	3	9.3	9.3	Statesville, N.C.	Hydro
Lookout Shoals Hydro Station		**27.9**	**27.9**		
Mountain Island	1	14	14	Mount Holly, N.C.	Hydro
Mountain Island	2	14	14	Mount Holly, N.C.	Hydro
Mountain Island	3	17	17	Mount Holly, N.C.	Hydro
Mountain Island	4	17	17	Mount Holly, N.C.	
Mountain Island Hydro Station		**62.0**	**62.0**		
Oxford	1	20.0	20.0	Conover, N.C.	Hydro
Oxford	2	20.0	20.0	Conover, N.C.	Hydro
Oxford Hydro Station		**40.0**	**40.0**		
Rhodhiss	1	9.5	9.5	Rhodhiss, N.C.	Hydro
Rhodhiss	2	11.5	11.5	Rhodhiss, N.C.	Hydro
Rhodhiss	3	9.0	9.0	Rhodhiss, N.C.	Hydro
Rhodhiss Hydro Station		**30.0**	**30.0**		
Tuxedo	1	3.2	3.2	Flat Rock, N.C.	Hydro
Tuxedo	2	3.2	3.2	Flat Rock, N.C.	Hydro
Tuxedo Hydro Station		**6.4**	**6.4**		
Bear Creek	1	9.45	9.45	Tuckasegee, N.C.	Hydro
Bear Creek Hydro Station		**9.45**	**9.45**		
Cedar Cliff	1	6.4	6.4	Tuckasegee, N.C.	Hydro
Cedar Cliff Hydro Station		**6.4**	**6.4**		
Franklin	1	0	0	Franklin, N.C.	Hydro
Franklin	2	.6	.6	Franklin, N.C.	Hydro
Franklin Hydro Station		**.6**	**.6**		
Mission	1	0	0	Murphy, N.C.	Hydro
Mission	2	0	0	Murphy, N.C.	Hydro
Mission	3	0.6	0.6	Murphy, N.C.	Hydro
Mission Hydro Station		**0.6**	**0.6**		
Nantahala	1	50.0	50.0	Topton, N.C.	Hydro
Nantahala Hydro Station		**50.0**	**50.0**		
Tennessee Creek	1	9.8	9.8	Tuckasegee, N.C.	Hydro
Tennessee Creek Hydro Station		**9.8**	**9.8**		
Thorpe	1	19.7	19.7	Tuckasegee, N.C.	Hydro
Thorpe Hydro Station		**19.7**	**19.7**		
Tuckasegee	1	2.5	2.5	Tuckasegee, N.C.	Hydro
Tuckasegee Hydro Station		**2.5**	**2.5**		
Queens Creek	1	1.44	1.44	Topton, N.C.	Hydro

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Queens Creek Hydro Station		**1.44**	**1.44**		
TOTAL N.C. HYDRO		**603.97 MW**	**603.97 MW**		
TOTAL N.C. SOLAR		**8.43 MW**	**8.43 MW**	N.C.	Solar
TOTAL N.C. CAPABILITY		**12,243.60 MW**	**12,746.40 MW**		

Table 5.B

South Carolina [a,b,c,d,e]

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Lee	1	100.0	100.0	Pelzer, S.C.	Conventional Coal
Lee	2	100.0	102.0	Pelzer, S.C.	Conventional Coal
Lee	3	170.0	170.0	Pelzer, S.C.	Conventional Coal
Lee Steam Station		**370.0**	**372.0**		
TOTAL S.C. CONVENTIONAL COAL		**370.0 MW**	**372.0 MW**		
Buzzard Roost	6C	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	7C	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	8C	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	9C	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	10C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	11C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	12C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	13C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	14C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	15C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost Station CTs		**176.0**	**176.0**		
Lee	7C	41.0	41.0	Pelzer, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Lee	8C	41.0	41.0	Pelzer, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Lee Station CTs		**82.0**	**82.0**		
Mill Creek	1	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	2	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	3	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	4	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	5	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
					Combustion Turbine
Mill Creek	6	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	7	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	8	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek Station CTs		**595.4**	**739.2**		
TOTAL S.C. COMB TURBINE		**853.4 MW**	**997.2 MW**		
Catawba	1	1129.0	1163.0	York, S.C.	Nuclear
Catawba	2	1129.0	1163.0	York, S.C.	Nuclear
Catawba Nuclear Station		**2258.0**	**2326.0**		
Oconee	1	846.0	865.0	Seneca, S.C.	Nuclear
Oconee	2	846.0	865.0	Seneca, S.C.	Nuclear
Oconee	3	846.0	865.0	Seneca, S.C.	Nuclear
Oconee Nuclear Station		**2538.0**	**2595.0**		
TOTAL S.C. NUCLEAR		**4796.0 MW**	**4921.0 MW**		
Jocassee	1	195.0	195.0	Salem, S.C.	Pumped Storage
Jocassee	2	195.0	195.0	Salem, S.C.	Pumped Storage
Jocassee	3	195.0	195.0	Salem, S.C.	Pumped Storage
Jocassee	4	195.0	195.0	Salem, S.C.	Pumped Storage
Jocassee Pumped Hydro Station		**780.0**	**780.0**		
Bad Creek	1	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	2	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	3	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	4	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek Pumped Hydro Station		**1360.0**	**1360.0**		
TOTAL PUMPED STORAGE		**2140.0 MW**	**2140.0 MW**		
Cedar Creek	1	15.0	15.0	Great Falls, S.C.	Hydro
Cedar Creek	2	15.0	15.0	Great Falls, S.C.	Hydro
Cedar Creek	3	15.0	15.0	Great Falls, S.C.	Hydro
Cedar Creek Hydro Station		**45.0**	**45.0**		
Dearborn	1	14.0	14.0	Great Falls, S.C.	Hydro
Dearborn	2	14.0	14.0	Great Falls, S.C.	Hydro
Dearborn	3	14.0	14.0	Great Falls, S.C.	Hydro

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Dearborn Hydro Station		**42.0**	**42.0**		
Fishing Creek	1	11.0	11.0	Great Falls, S.C.	Hydro
Fishing Creek	2	9.5	9.5	Great Falls, S.C.	Hydro
Fishing Creek	3	9.5	9.5	Great Falls, S.C.	Hydro
Fishing Creek	4	11.0	11.0	Great Falls, S.C.	Hydro
Fishing Creek	5	8.0	8.0	Great Falls, S.C.	Hydro
Fishing Creek Hydro Station		**49.0**	**49.0**		
Gaston Shoals	3	0	0	Blacksburg, S.C.	Hydro
Gaston Shoals	4	1.0	1.0	Blacksburg, S.C.	Hydro
Gaston Shoals	5	1.0	1.0	Blacksburg, S.C.	Hydro
Gaston Shoals	6	0	0	Blacksburg, S.C.	Hydro
Gaston Shoals Hydro Station		**2.0**	**2.0**		
Great Falls	1	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	2	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	3	0	0	Great Falls, S.C.	Hydro
Great Falls	4	0	0	Great Falls, S.C.	Hydro
Great Falls	5	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	6	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	7	0	0	Great Falls, S.C.	Hydro
Great Falls	8	0	0	Great Falls, S.C.	Hydro
Great Falls Hydro Station		**12.0**	**12.0**		
Rocky Creek	1	0	0	Great Falls, S.C.	Hydro
Rocky Creek	2	0	0	Great Falls, S.C.	Hydro
Rocky Creek	3	0	0	Great Falls, S.C.	Hydro
Rocky Creek	4	0	0	Great Falls, S.C.	Hydro
Rocky Creek	5	0	0	Great Falls, S.C.	Hydro
Rocky Creek	6	0	0	Great Falls, S.C.	Hydro
Rocky Creek	7	0	0	Great Falls, S.C.	Hydro
Rocky Creek	8	0	0	Great Falls, S.C.	Hydro
Rocky Creek Hydro Station		**0**	**0**		
Wateree	1	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	2	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	3	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	4	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	5	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree Hydro Station		**85.0**	**85.0**		
Wylie	1	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie	2	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie	3	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie	4	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie Hydro Station		**72.0**	**72.0**		

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
99 Islands	1	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	2	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	3	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	4	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	5	0	0	Blacksburg, S.C.	Hydro
99 Islands	6	0	0	Blacksburg, S.C.	Hydro
99 Islands Hydro Station		**6.4**	**6.4**		
Keowee	1	76.0	76.0	Seneca, S.C.	Hydro
Keowee	2	76.0	76.0	Seneca, S.C.	Hydro
Keowee Hydro Station		**152.0**	**152.0**		
TOTAL S.C. HYDRO		**465.4 MW**	**465.4 MW**		
TOTAL S.C. CAPABILITY		**8,624.8 MW**	**8,895.6 MW**		

Table 5.C
Total Generation Capability [a,b,c,d,e]

NAME	SUMMER CAPACITY MW	WINTER CAPACITY MW
TOTAL DUKE ENERGY CAROLINAS GENERATING CAPABILITY	**20,868.4**	**21,642.0**

Note a: Unit information is provided by State, but resources are dispatched on a system-wide basis.

Note b: Summer and winter capability does not take into account reductions due to future environmental emission controls.

Note c: Summer and winter capability reflects system configuration as of June 22, 2011.

Note d: Catawba Units 1 and 2 capacity reflects 100% of the station's capability, and does not factor in the North Carolina Municipal Power Agency #1's (NCMPA#1) decision to sell or utilize its 832 MW retained ownership in Catawba.

Note e: The Catawba units' multiple owners and their effective ownership percentages are:

CATAWBA OWNER	PERCENT OF OWNERSHIP
Duke Energy Carolinas	19.246%
North Carolina Electric Membership Corporation (NCEMC)	30.754%
NCMPA#1	37.5%
Piedmont Municipal Power Agency (PMPA)	12.5%

Changes to Existing Resources

Duke Energy Carolinas will adjust the capabilities of its resource mix over the 20-year planning horizon. Retirements of generating units, system capacity uprates and derates, purchased power contract expirations, and adjustments in EE and DSM capability affect the amount of resources Duke Energy Carolinas will need to meet its load obligation. Below are the known and/or anticipated changes and their respective impacts on the resource mix.

New Cliffside Pulverized Coal Unit
In March 2007, Duke Energy Carolinas received a CPCN for the 825 MW Cliffside 6 unit, which is scheduled to be on line in 2012. As of June 2011, the project is over 80% complete.

Bridgewater Hydro Powerhouse Upgrade
The two existing 11.5 MW units at Bridgewater Hydro Station are being replaced by two 15 MW units and a small 1.5 MW unit to be used to meet continuous release requirements, which is scheduled to be available for the summer peak of 2012.

Jocassee Unit 1 and 2 Runner Upgrades
This project is completed. Capacity additions reflect a 50 MW capacity uprate at the Jocassee pumped storage facility from increased efficiency of the new runners. These uprates were included in the 2011 IRP analysis.

Buck Combined Cycle Natural Gas Unit
The Company received the CPCN for this project in June 2008 and received the corresponding air permit in October 2008. The 620 MW Buck CC unit is scheduled to be operational by the end of 2011. Construction and commissioning activities are underway and the project is currently over 90% complete.

Dan River Combined Cycle Natural Gas Unit
The Company received the CPCN for this project concurrently with the CPCN for the Buck CC project in June 2008 and received its air permit for this project in August 2009. The 620 MW Dan River CC unit is scheduled to be operational by the end of 2012. Construction is underway and the project is currently over 50% complete.

Lee Steam Station Natural Gas Conversion
Lee Steam Station was originally designed to generate with natural gas or coal as a fuel source. Switching fuel sources from coal to natural gas could prove to be an economic solution to avoid adding costly pollution control equipment or replacing the 370 MW of capacity at an alternative site. For planning purposes Lee Steam Station will be retired as

a coal station the fourth quarter of 2014 and converted to natural gas by January 1, 2015. Preliminary engineering has been completed and more detailed project development and regulatory efforts will begin in 2011.

Generating Units Projected To Be Retired

Various factors have an impact on decisions to retire existing generating units. These factors, including the investment requirements necessary to support ongoing operation of generation facilities, are continuously evaluated as future resource needs are considered. Table 5.D reflects current assessments of generating units with identified decision dates for retirement or major refurbishment.

There are two requirements related to the retirement of 800 MWs of older coal units. The first, a condition set forth in the NCUC Order in Docket No. E-7, Sub 790, granting a CPCN to build Cliffside Unit 6, requires the retirement of the existing Cliffside Units 1-4 no later than the commercial operation date of the new unit, and retirement of older coal-fired generating units (in addition to Cliffside Units 1-4) on a MW-for-MW basis, considering the impact on the reliability of the system, to account for actual load reductions realized from the new EE and DSM programs up to the MW level added by the new Cliffside unit[2]. The requirement to retire older coal is also set forth in the air permit for the new Cliffside unit, in addition to Cliffside Units 1-4, of 350 MWs of coal generation by 2015, an additional 200 MWs by 2016, and an additional 250 MWs by 2018. If the NCUC determines that the scheduled retirement of any unit identified for retirement pursuant to the Plan will have a material adverse impact of the reliability of electric generating system, Duke Energy Carolinas may seek modification of this plan.

Additionally, multiple environmental regulatory issues are presently converging as the EPA has proposed new rules to regulate multiple areas relating to generation resources. These new rules, if implemented, will increase the need for the installation of additional control technology or retirement of coal fired generation in the 2014 to 2018 timeframe. Anticipating that there will be increased control requirements, the Carolinas 2011 IRP incorporates a planning assumption that all coal-fired generation that does not have an installed SO_2 scrubber will be retired by 2015.

Table 5.D shows the assumptions used for planning purposes rather than firm commitments concerning the specific units to be retired and/or their exact retirement dates. The conditions of the units are evaluated annually and decision dates are revised as appropriate. Duke Energy Carolinas will develop orderly retirement plans that consider the implementation, evaluation, and achievement of EE goals, system reliability

[2] NCUC Docket No. E-7, Sub 790 Order Granting CPCN with Conditions, March 21, 2007.

considerations, long-term generation maintenance and capital spending plans, workforce allocations, long-term contracts including fuel supply and contractors, long-term transmission planning, and major site retirement activities.

Table 5.D
Projected Unit Retirements

STATION	CAPACITY IN MW	LOCATION	EXPECTED RETIREMENT	PLANT TYPE
Buck 4*	38	Salisbury, N.C.	RETIRED	Conventional Coal
Buck 3*	75	Salisbury, N.C.	RETIRED	Conventional Coal
Cliffside 1*	38	Cliffside, N.C.	10/01/2011	Conventional Coal
Cliffside 2*	38	Cliffside, N.C.	10/01/2011	Conventional Coal
Cliffside 3*	61	Cliffside, N.C.	10/01/2011	Conventional Coal
Cliffside 4*	61	Cliffside, N.C.	10/01/2011	Conventional Coal
Dan River 1*	67	Eden, N.C.	4/01/2012	Conventional Coal
Dan River 2*	67	Eden, N.C.	3/01/2012	Conventional Coal
Dan River 3*	142	Eden, N.C.	4/01/2012	Conventional Coal
Buzzard Roost 6C**	22	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 7C**	22	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 8C**	22	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 9C**	22	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 10C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 11C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 12C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 13C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 14C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 15C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Riverbend 8C**	0	Mt. Holly, N.C.	6/01/2012	Combustion Turbine
Riverbend 9C**	22	Mt. Holly, N.C.	6/01/2012	Combustion Turbine
Riverbend 10C**	22	Mt. Holly, N.C.	6/01/2012	Combustion Turbine
Riverbend 11C**	20	Mt. Holly, N.C.	6/01/2012	Combustion Turbine
Buck 7C**	25	Spencer, N.C.	6/01/2012	Combustion Turbine
Buck 8C**	25	Spencer, N.C.	6/01/2012	Combustion Turbine
Buck 9C**	12	Spencer, N.C.	6/01/2012	Combustion Turbine
Dan River 4C**	0	Eden, N.C.	6/01/2012	Combustion Turbine
Dan River 5C**	24	Eden, N.C.	6/01/2012	Combustion Turbine
Dan River 6C**	24	Eden, N.C.	6/01/2012	Combustion Turbine
Riverbend 4*	94	Mt. Holly, N.C.	1/01/2015	Conventional Coal
Riverbend 5*	94	Mt. Holly, N.C.	1/01/2015	Conventional Coal
Riverbend 6***	133	Mt. Holly, N.C.	1/01/2015	Conventional Coal
Riverbend 7***	133	Mt. Holly, N.C.	1/01/2015	Conventional Coal
Buck 5***	128	Spencer, N.C.	1/01/2015	Conventional Coal
Buck 6***	128	Spencer, N.C.	1/01/2015	Conventional Coal
Lee 1***	100	Pelzer, S.C.	10/01/2014	Conventional Coal
Lee 2***	100	Pelzer, S.C.	10/01/2014	Conventional Coal
Lee 3***	170	Pelzer, S.C.	10/01/2014	Conventional Coal

Notes:

* Retirement assumptions associated with the conditions in the NCUC Order in Docket No. E-7, Sub 790, granting a CPCN to build Cliffside Unit 6.

** The old fleet combustion turbines retirement dates were accelerated in 2009 based on derates, availability of replacement parts and the general condition of the remaining units.

*** For the 2011 IRP process, remaining coal units without scrubbers were assumed to be retired by 2015. Based on the continued increased regulatory scrutiny from an air, water and waste perspective, these units will likely either be required to install additional controls or retire. If final regulations or new legislation allows for latitude in the retirement date if a retirement commitment is made versus adding controls, the retirement date may be adjusted.

Fuel Supply

Duke Energy Carolinas' current fuel usage consists primarily of coal and uranium. Oil and gas are currently used for peaking generation, but natural gas usage will expand when the Buck and Dan River Combined Cycle units are brought on-line.

Coal

Until the economic downturn in 2008, Duke Energy Carolinas had burned approximately 19 million tons of coal annually. However, the burn dropped drastically in 2009 before recovering somewhat in 2010 to around 15 million tons of coal, a level that is projected to be maintained over the next few years.

The Company primarily procures coal from Central Appalachian (CAPP) coal mines and delivered by the Norfolk Southern and CSX Railroads. The Company continually assesses coal market conditions to determine the appropriate mix of contract and spot market purchases in order to reduce exposure to the risk of price fluctuations. The Company also evaluates its diversity of coal supply from sources throughout the United States and internationally.

Although CAPP coal market prices are well below the all-time highs experienced in 2008, low gas prices have displaced some of the demand for CAPP from marginal units. Projected market prices for CAPP two years out are 20-50% higher than those seen in 2010, reflecting higher production costs combined with a more balanced supply and demand picture. Increasingly strict federal safety regulations and surface mine permit requirements in Central Appalachia could result in lower production and corresponding higher prices (relative to other coal produced in other basins.) For this reason, the Company is exploring means to develop greater supply and transportation flexibility in order to minimize the Company's dependency on CAPP.

Natural Gas

Duke Energy is still feeling the effects of the supply and demand imbalance which began during the fall of 2008 as the economy stumbled and new supplies of gas from unconventional sources came on line. Gas prices tumbled in 2009 to the $4/mmbtu range and the NYMEX forward market has continued to trade within a very narrow band over the past year as new supplies from shale resources continue to outpace the demand growth from the recovering industrial sector. This imbalance should start to wane in 2012, however, as several new factors begin to weigh on the market.

The first factor is the shift in drilling capital away from dry natural gas toward oil shales or gas shales that are rich in natural gas liquids (NGLs). NGLs include ethane, butane, propane and natural gasoline, and have various uses. A shift is already being seen in the Haynesville and Barnett regions, which were the early "game changers" in this area. With oil futures holding steady near $100/barrel and gas futures down in the $4 - $6/MMBTU range, the Company has perceived a strategic shift to oil/liquids directed drilling.

The second factor which will add near-term pressure to the market is the recently promulgated CSAPR for SO_2 and NO_x, scheduled to go into effect on Jan 1, 2012. Duke Energy Carolinas anticipates that CSAPR will push uncontrolled or un-scrubbed coal units higher in the dispatch order and further extend the gas displacement of coal; this is already occurring in areas where CAPP coal is the primary coal fuel source.

The third factor is the recovery in the petro-chemical demand for gas. A weak U.S. dollar coupled with a huge advantage in feedstock price, domestic gas versus global oil priced gas contracts, will lead to sustained growth in industrial gas demand. The size of the U.S. natural gas resource base has grown immensely over the past few years, but not all of these resources will remain economic at the current market price. Improvements are expected in the drilling and completion process of shale resources, and new regulations are likely to address a host of environmental concerns like methane migration into residential wells, fugitive methane emissions during the drilling process, produced water capture, storage and recycling. These issues will lead to technical solutions, but likely at a higher cost.

Nuclear Fuel

To provide fuel for Duke Energy Carolinas' nuclear fleet, the Company maintains a diversified portfolio of natural uranium and downstream services supply contracts from around the world.

Requirements for uranium concentrates, conversion services and enrichment services are primarily met through a portfolio of long-term supply contracts. The contracts are diversified by supplier, country of origin and pricing. In addition, Duke Energy Carolinas staggers its contracting so that its portfolio of long-term contracts covers the majority of fleet fuel requirements in the near-term and decreasing portions of the fuel requirements over time thereafter. By staggering long-term contracts over time, the Company's purchase price for deliveries within a given year consists of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. Diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply.

Due to the technical complexities of changing suppliers of fuel fabrication services, Duke Energy Carolinas generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

As fuel with a low cost basis is used and lower-priced legacy contracts are replaced with contracts at higher market prices, nuclear fuel expense is expected to increase in the future. Although the costs of certain components of nuclear fuel are expected to increase in future years, nuclear fuel costs on a kWh basis will likely continue to be a fraction of the kWh cost of fossil fuel. Therefore, customers will continue to benefit from the Company's diverse generation mix and the strong performance of its nuclear fleet through lower fuel costs than would otherwise result absent the significant contribution of nuclear generation to meeting customers' demands.

B. RENEWABLE RESOURCES AND RENEWABLE ENERGY INITIATIVES

1. Overview of Planning Assumptions

Duke Energy Carolinas' plans regarding renewable energy resources within this IRP are based primarily upon the presence of existing renewable energy requirements as well as the potential introduction of additional renewable energy requirements in the future.

Regarding existing renewable requirements, the Company is committed to meeting the requirements of the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS). This is a statutory requirement enacted in 2007 mandating that Duke Energy Carolinas supply the equivalent of 12.5% of retail electricity sales in

North Carolina from eligible renewable energy resources and/or energy efficiency savings by 2021.

With respect to potential new renewable energy portfolio standard requirements, the Company's plans in this IRP account for the possibility of future requirements that will result in additional renewable resource development beyond the NC REPS requirements. Renewable requirements have been adopted in many states across the nation, and have also been contemplated as a federal measure and by members of the legislature in South Carolina. As such, the Company believes it is reasonable to plan for additional renewable requirements within the IRP beyond what presently exists with the NC REPS requirements.

Although there are many potential assumptions that could be made regarding such future renewable requirements, the Company has assumed in this IRP that a new legislative requirement (imposed by either federal or state level legislation) would be implemented in the future that would result in additional renewable resource development in South Carolina. For planning purposes, it is assumed that the requirement would be similar in many respects to the NC REPS requirement, but with a different implementation schedule. Specifically, the Company has assumed that this requirement would have an initial 3% milestone in 2016 and would gradually increase to a 12.5% level by 2030. Similar to NC REPS, this assumed legislative requirement would incorporate both renewable energy and energy efficiency, as well as a limited capability to utilize out of state unbundled purchases of Renewable Energy Certificates (REC or RECs). Further, this assumed requirement would have a solar set-aside requirement comparable to that in NC REPS, but would not contain any additional set-asides such as the poultry waste or swine waste set-aside requirements that are part of NC REPS. Finally, no assumptions related to a cost-cap feature that may limit development of renewables and ultimate cost to customers were made with this assumed legislation, whereas the Company's projections of renewable resource development for NC REPS are governed by the statutory cost caps within the law.

The Company has assessed the current and potential future costs of renewable and traditional technologies and, based on this analysis, the IRP modeling process shows that, for the most part, the amount of renewable energy resources that will be developed over the planning horizon will be defined by the existing and anticipated statutory renewable energy requirements described above. In other words, the IRP modeling does not indicate any material quantity of renewable resource development over and above the required levels due to lack of cost-effectiveness of these resources.

2. Summary of Expected Renewable Resource Capacity Additions

Based on the planning assumptions noted above regarding current and potential future renewable energy requirements, the Company projects that a total of approximately 800 MW (nameplate) of renewable energy resources will be interconnected to the Duke Energy Carolinas system by 2023, with that figure growing to approximately 884 MW by the end of the planning horizon in 2031. Actual results could vary substantially, with key drivers of different outcomes being future legislative requirements; relative costs of various renewable technologies in relation to traditional technologies; and various impediments impacting the development of various resources including permitting requirements, transmission and interconnection issues, or other matters.

It should be noted that many renewable technologies are intermittent in nature and that they therefore may not be contributing energy or capacity benefits to the Company's load requirements at any particular point in time. The details of the forecasted capacity additions, including both nameplate capacity and the expected contribution towards the Company's peak load needs, are summarized in Table 5.E below.

Table 5.E Expected Renewable Resource Capacity Additions

Renewables								
	MW Contribution to Summer Peak				MW Nameplate			
Year	Wind	Solar	Biomass	Total	Wind	Solar	Biomass	Total
2011	15.0	12	20	46	100	24	20	143
2012	0.0	12	29	41	0	24	29	53
2013	0.0	12	33	44	0	24	33	56
2014	15.0	12	89	116	100	24	89	213
2015	15.6	21	91	128	104	42	91	237
2016	47.8	22	179	249	318	45	179	542
2017	47.8	23	180	250	319	45	180	543
2018	49.7	24	230	304	332	49	230	610
2019	50.7	25	265	341	338	51	265	654
2020	53	28	296	376	352	56	296	703
2021	51	26	295	372	339	51	295	686
2022	55	28	344	427	367	57	344	767
2023	55	36	346	437	368	72	346	786
2024	55	36	347	439	369	73	347	789
2025	58	36	384	478	389	73	384	846
2026	61	41	386	488	406	81	386	874
2027	59	37	385	481	392	73	385	851
2028	59	37	388	484	393	74	388	855
2029	62	41	391	493	411	82	391	884
2030	62	41	391	493	411	82	391	884
2031	62	41	391	493	411	82	391	884

3. Changes in Renewable Planning Assumptions Since 2010

The renewable energy requirements (existing and anticipated) that are assumed in this IRP are largely similar to what was assumed in the Company's 2010 IRP. However, the Company's expectations regarding how those requirements will be met have evolved. Changes from the prior year are summarized here.

As compared to last year's IRP, the Company has assumed the development and interconnection of more wind resources over the planning horizon, along with a corresponding reduction in the development of biomass resources. The projected increase in wind resources is driven by the Company's observations that land-based wind developers are presently pursuing projects of significant size in North Carolina. The Company believes it is reasonable to expect that land-based wind will be developed in both North and South Carolina within the planning horizon to a degree that exceeds what was expected a year ago. The Company also has observed that opportunities currently exist, and may continue to exist, to transmit land-based wind energy resources into the Carolinas from other regions, which could supplement the amount of wind that could be developed within the Carolinas.

The Company's expectations regarding biomass resources are somewhat more modest, particularly in the near-term, than a year ago. This reduction in reliance upon biomass is in part due to uncertainties around the developable amount of such resources in the Carolinas, uncertainties related to the EPA's various rulemaking proceedings, and the projected availability of other forms of renewable resources to offset the needs for biomass. Because of the increased contributions from wind, which is an intermittent resource, versus biomass, which more closely mirrors a baseload resource, the Company has an additional system peak need in 2015.

In this current IRP, the Company also projects it will utilize more short term contracts than was assumed a year ago in the later years of the planning horizon. This is driven by a combination of factors, including an assumption that in the outer years of the planning horizon (e.g. beyond ~2023) there will be a more liquid market where the Company could engage in shorter term purchases of qualifying renewable energy or RECs to meet its REPS compliance needs. While the characteristics of this more distant portion of the planning horizon are difficult to ascertain with confidence, the Company projects that shorter term contracts may in fact be a necessity in order to effectively manage expenditures in accordance with the NC REPS statutory per-account cost caps, which remain fixed after 2015.

Through 2023, the Company's plans are based predominately on resources that are longer term in nature, with a gradual increase in the total amount of renewable resources over this time period. Beyond 2023, Duke Energy Carolinas forecasts that it will need additional resources to maintain compliance with NC REPS, with at least some of those resources being secured under short-term agreements. In this IRP, short-term agreements are assumed to come from a combination of unbundled in-state RECs from resources of various types, potentially including thermal RECs from Combined Heat and Power (CHP) facilities, as well as bundled energy and REC purchases of various resource types.

4. Further Details on Compliance with NC REPS

A more detailed discussion of the Company's plans to comply with the NC REPS requirements can be found in the Company's NC REPS Compliance Plan (Compliance Plan), which the Company submits to the NCUC as a separate document within the same docket as this IRP.

Details of that Compliance Plan are not duplicated here, although it is important to note that various details of the NC REPS law have impacts on the amount of energy and capacity that the Company projects to obtain from renewable resources to help meet the Company's long term resource needs. For instance, NC REPS contains several detailed parameters, including technology specific set-aside requirements for solar, swine waste, and poultry waste resources; capabilities to utilize EE savings and unbundled REC purchases from in-state or out-of-state resources, and RECs derived from thermal (non-electrical) energy; and a statutory spending limit to protect customers from cost increases stemming from renewable energy procurement or development. Each of these features of NC REPS has implications on the amount of renewable energy and capacity the Company forecasts to obtain over the planning horizon of this IRP. Additional details on NC REPS compliance can be found in the Company's Compliance Plan.

C. SUPPLY-SIDE RESOURCE SCREENING

For purposes of the 2011 IRP, the Company considered a diverse range of technology choices utilizing a variety of different fuels, including pulverized coal units with and without carbon capture sequestration, Integrated Gasification Combined Cycle (IGCC) with and without carbon capture sequestration, CTs, CC units, and nuclear units. In addition, Duke Energy Carolinas considered renewable technologies such as wind, biomass, and solar in this year's screening analysis. Landfill gas was not included in this screening process due to limited availability. However, to the extent that landfill gas is available, it is competitive from a cost perspective with conventional baseload technologies.

For the 2011 IRP screening analyses, the Company screened technology types within their own respective general categories of baseload, peaking/intermediate, and renewable, with the ultimate goal of screening being to pass the best alternatives from each of these three categories to the integration process. As in past years, the reason for performing these initial screening analyses is to determine the most viable and cost-effective resources for further evaluation. This initial screening evaluation is necessary because of the size of the problem to be solved and computer execution time limitations of the System Optimizer capacity model (described in detail in Chapter 8).

1. Process Description

Information Sources

The cost and performance data for each technology being screened is based on research and information from several sources. These sources include, but may not be limited to the following: Duke Energy's New Generation, Emerging Technologies, Duke Energy Analytical and Investment Engineering Teams, the EPRI Technology Assessment Guide (TAG®), and studies performed by and/or information gathered from external sources. In addition, fuel and operating cost estimates are developed internally by Company personnel, or from other sources such as those mentioned above, or a combination of the two. The EPRI information along with any information or estimates from external studies are not site-specific, but generally reflect the costs and operating parameters for installation in the Carolinas.

Finally, every effort is made to ensure, as much as possible, that the cost and other parameters are current and include similar scope across the technology types being screened. While this has always been important, keeping cost estimates across a variety of technology types consistent in today's construction material, manufactured equipment, and commodity markets, remains very difficult.

Technical Screening

The first step in the Company's supply-side screening process for the IRP was a technical screening of the technologies to eliminate those that have technical limitations, commercial availability issues, or are not feasible in the Duke Energy Carolinas service territory. A brief explanation of the technologies excluded at this point and the logic for their exclusion follows:

- Geothermal was eliminated because there are no suitable geothermal resources in the region to develop into a power generation project.

- Advanced Battery storage technologies (Lead acid, Li-ion, Sodium Ion, Zinc Bromide, Fly wheels, pump storage) remain relatively expensive and are generally suitable for small-scale emergency back-up and/or power quality applications with short-term duty cycles of three hours or less. In addition, the current energy storage capability is generally 100 MWh or less. Research, development, and demonstration continue within Duke Energy, but this technology is generally not commercially available on a larger utility scale. Currently Duke Energy is installing 36 MW advanced acid lead batteries at the Notrees wind farm in Texas that is scheduled for start-up in 2012. Duke Energy has other storage system test stations at the Envision Energy Center in Charlotte, which specifically include 2 Community Energy Storage (CES) systems of 24 kW.
- Compressed Air Energy Storage (CAES), although demonstrated on a utility scale and generally commercially available, is not a widely applied technology and remains relatively expensive. The high capital requirements for these resources arise from the fact that suitable sites that possess the proper geological formations and conditions necessary for the compressed air storage reservoir are relatively scarce.
- Small and medium nuclear reactors are generally limited to less than 300 MW. The NRC has not licensed any smaller nuclear reactor designs at this point in time. Several designs including those by General Electric (GE), Babcock & Wilcox (B&W) and Westinghouse may seek licensing in 2012 and 2013.
- Fuel Cells, although originally envisioned as being a competitor for combustion turbines and central power plants, are now targeted to mostly distributed power generation systems. The size of the distributed generation applications ranges from a few kW to tens of MW in the long-term. Cost and performance issues have generally limited their application to niche markets and/or subsidized installations. While a medium level of research and development continues, this technology is not commercially available for utility-scale application.
- Poultry waste and hog waste digesters remain relatively expensive and are capable of generating 500 – 600 MWh or less annually. Research, development, and demonstration continue, but these technologies are generally not commercially available on a larger utility scale. The Company's detailed quantitative analysis in this IRP included evaluation of purchased power agreements for poultry waste-to-energy facilities due to the poultry waste set-aside requirements in the NC REPS.
- Off-shore wind, although demonstrated on a utility scale and commercially available, is not a widely applied technology and not easily permittable.

This technology remains expensive and has yet to actually be constructed anywhere in the United States. Duke Energy Carolinas has collaborated with the University North Carolinas to continue studying off-shore wind on the Carolinas coastal area.

- Combined cycle G-Class technology has been demonstrated on a utility scale and is comparable to the F-Class in terms of efficiency. Its development remains limited due to lack of experience. The combined cycle G-class technology is larger in size and is designed to operate primarily as base load and not suitable for the anticipated cycling operation.

Economic Screening

In the supply-side screening analysis, the Company used the same fuel prices for coal and natural gas, and NO_x, SO_2, and CO_2 allowance prices as those utilized downstream in the System Optimizer analysis (discussed in Chapter 8). The Company derived its biomass fuel price from various vendor fuel and delivery prices. The biomass fuel price may vary in the future as more utilities begin to use biomass fuel.

The Company screened all technologies using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves. The screening within each general class, as well as the final screening across the general classes used a spreadsheet-based screening curve model developed by Duke Energy. This model is considered proprietary, confidential and competitive information by Duke Energy.

This screening curve analysis model calculates the fixed costs associated with owning and maintaining a technology type over its lifetime and computes a levelized fixed $/kW-year value. This calculated value represents the cost of operating the technology at a zero capacity factor or not at all, *i.e.*, the Y-intercept on the graph (see the General Appendix for individual graphs). The model then calculates the variable costs, such as fuel, variable O&M, and emission costs associated with operating the technology at 100% capacity factor, or at full load, over its lifetime and the present worth is computed back to the start year. This levelized operating $/kW-year is next added to the levelized fixed $/kW-year value to arrive at a total owning and operating value at 100% utilization in $/kW-year. Then a straight line is drawn connecting the two points. This line represents the technology's "screening curve".

The Company repeats this process for each supply technology to be screened resulting in a family of lines (curves). The lower envelope along the curves represents the least costly supply options for various capacity factors or unit utilizations. Some of the renewable resources that have known limited energy output, such as wind and solar, have screening curves limited to their expected operating range on the individual graphs.

Lines that never become part of the lower envelope, or those that become part of the lower envelope only at capacity factors outside of their relevant operating ranges, have a very low probability of being part of the least cost solution, and generally can be eliminated from further analysis.

2. Screening Results

The results of the screening within each category are shown in Appendix C.

The Company passes on those technologies from each of the three general categories screened (Baseload, Peaking/Intermediate, and Renewables) which were the "best," i.e., the lowest levelized busbar cost for a given capacity factor range within each of these categories, to the quantitative analysis phase for further evaluation.

Duke Energy Carolinas included CC generation in the peaking intermediate screening curves for comparison purposes. However, based on the screen results, CC generation would also be cost effective as a base load technology.

The Company's model selected the following technologies for the quantitative analysis:

- Baseload – 800MW Supercritical Pulverized Coal
- Baseload – 630 MW IGCC
- Baseload – 2 x 1,117MW Nuclear units (AP1000)
- Peaking/Intermediate – 4x204MW CTs (7FA.05)
- Base Load/Intermediate/Peaking – 480 MW Unfired + 125MW Duct Fired + 45MW Inlet Evaporative Cooler Natural Gas CC
- Base Load/Intermediate/Peaking – 480 MW Unfired + 45MW Inlet Evaporative Cooler Natural Gas CC
- Renewable – 100 MW Woody Biomass
- Renewable – 150 MW Wind - On-Shore
- Renewable – 15 MW Landfill Gas
- Renewable – 25 MW Solar PV

3. Unit Size

The unit sizes selected for planning purposes generally are the largest technologies available today because they generally offer lower $/kW installed capital costs due to economies of scale. However, the true test of whether a resource is economic depends on the economics of an overall resource plan that contains that resource (including fuel costs, O&M costs, emission costs, *etc.*), not merely on the $/kW cost. In the case of very large unit sizes such as those utilized for the nuclear and/or IGCC technology types, if these are routinely selected as part of a least cost plan, joint ownership can and may be evaluated and pursued.

4. Cost, Availability, and Performance Uncertainty

Supply-side alternative project scope and estimated costs used for planning purposes for conventional technology types, such as simple-cycle CT units and CC units, are relatively well known and are estimated in the TAG® and can be obtained from architect and engineering (A&E) firms and/or equipment vendors. The Company also uses its experience with the scope and costs for such resources to confirm the reasonableness of the estimates. The cost estimates include step-up transformers and a substation to connect with the transmission system. Since any additional transmission costs would be site-specific and specific sites requiring additional transmission are unknown at this time, typical values for additional transmission costs were also added to the alternatives. For natural gas units, gas pipeline costs were also included in the cost estimates. The unit availability and performance of conventional supply-side options is also relatively well known and the TAG®, A&E firms and/or equipment vendors are sources of estimates of these parameters.

5. Lead Time for Construction

The estimated construction lead time and the lead time used for modeling purposes for the proposed simple-cycle CT units is about two years. For the CC units, the estimated lead time is about two to three years. For coal units, the lead time is approximately five years. For nuclear units, the lead time is approximately five years. However, the time required to obtain regulatory approvals and environmental permits adds uncertainty to the process, so Company judgment is also incorporated into the analysis as necessary.

6. RD&D Efforts and Technology Advances

New energy and technology alternatives will be necessary to ensure a long-term sustainable electric future. Duke Energy Carolinas' research, development, and delivery (RD&D) activities enable Duke Energy Carolinas to track new options including modular and potentially dispersed generation systems (small and medium nuclear reactors), CTs, and advanced fossil technologies. The Company places emphasis on providing information, assessment tools, validated technology, demonstration/deployment support, and RD&D investment opportunities for planning and implementing projects utilizing new power generation technology to assure a strategic advantage in electricity supply and delivery. Duke Energy is also a member of EPRI.

Within the planning horizon of this forecast, Duke Energy Carolinas expects that significant advances will continue to be made in CT technology. Advances in stationary industrial CT technology should result from ongoing research and development efforts to improve both commercial and military aircraft engine efficiency and power density, as well as expanding research efforts to burn more hydrogen-rich fuels. The ability to burn hydrogen-rich fuels will enable very high levels of CO_2 removal and shifting in the syngas utilized in IGCC technology, thereby enabling a major portion of the advancement necessary for a significant reduction in the carbon footprint of this coal-based technology.

7. Coordination with Other Utilities

Decisions concerning coordinating the construction and operation of new units with other utilities or entities are dependent on a number of factors including the size of the unit versus each utility's capacity requirement and whether the timing of the need for facilities is the same. To the extent that units larger than Duke Energy Carolina's requirements become economically viable in a plan, co-ownership can be considered at that time. Coordination with other utilities can also be achieved through purchases and sales in the bulk power market.

D. WHOLESALE AND QF PURCHASED POWER AGREEMENTS

Duke Energy Carolinas is an active participant in the wholesale market for capacity and energy. The Company has issued RFPs for purchased power capacity over the past several years, and has entered into purchased power arrangements for over 2,000 MWs over the past 10 years. In addition, Duke Energy Carolinas has contracts with a number of Qualifying Facilities (QFs). Table 5.F shows both the purchased power capacity obtained through RFPs as well as the larger QF agreements. See Appendix I for additional information on all purchases from QFs.

Table 5.F
Wholesale Purchases & Purchased Power Agreements

SUPPLIER	CITY	STATE	SUMMER FIRM CAPACITY (MW)	WINTER FIRM CAPACITY (MW)	CONTRACT START	CONTRACT EXPIRATION
Catawba County	Newton	NC	4	4	8/23/1999	8/22/2014
Concord Energy, LLC	Concord	NC	9	9	TBD	12/31/2031
Davidson Gas Producers, LLC	Lexington	NC	2	2	12/1/2010	12/31/2030
Gas Recovery Systems, LLC	Concord	NC	3	3	2/1/2010	12/31/2030
Gaston County	Dallas	NC	4	4	TBD	12/31/2021
Greenville Gas Producers, LLC	Greer	SC	3	3	8/1/2008	Ongoing
Lockhart Power Company	Wellford	SC	2	2	4/1/2011	12/31/2020
MP Durham, LLC	Durham	NC	3	3	9/18/2009	12/31/2029
Salem Energy Systems, LLC	Winston-Salem	NC	4	4	7/10/1996	Ongoing
WMRE Energy, LLC	Kernersville	NC	2	2	3/31/2011	12/31/2026
Mayberry Solar LLC	Mt. Airy	NC	1	0	9/1/2011	8/31/2026
Solar Green Development, LLC	Charlotte	NC	1	0	10/1/2011	9/30/2026
Solar Green Development, LLC	Mint Hill	NC	1	0	12/1/2011	11/30/2026
SunEd DEC1, LLC	Lexington	NC	8	0	12/1/2009	12/31/2030
Other PV	Various	NC	1	0	Various	Ongoing
Cherokee County Cogeneration Partners, L.P.	Gaffney	SC	88	95	7/1/1996	6/30/2013
Northbrook Carolina Hydro, LLC	Various	NC & SC	6	6	12/4/2006	Ongoing
Town of Lake Lure	Lake Lure	NC	3	3	2/21/2006	2/20/2011
Misc. Small Hydro/Other	Various	Both	6	6	Various	Assumed Evergreen
Other Wholesale	Various	Both	119	119	Various	Ongoing

Notes: Solar PV Firm Capacity represents 50% contribution to peak

Summary of Wholesale and QF Purchased Power Commitments
(as of July 1, 2011)

	SUMMER 11	WINTER 10/11
Non-Utility Generation		
Traditional	102 MW	109 MW
Renewable *	47 MW	36 MW
Duke Energy Carolinas allocation		
of SEPA capacity	37.8 MW	37.8 MW
Other-Wholesale	81.3 MW	81.3 MW
Total Firm Purchases	268.1 MW	264.1 MW

* Renewable includes landfill gas and solar PV

Planning Philosophy with Regard to Purchased Power

Opportunities for the purchase of wholesale power from suppliers and marketers are an important resource option for meeting the electricity needs of Duke Energy Carolinas' retail and wholesale customers. Duke Energy Carolinas has been active in the wholesale purchased power market since 1996 and during that time has entered into contracts totaling 2500 MWs to meet customer needs. The use of supply side requests for proposal (RFPs) continues to be an essential component of Duke Energy Carolinas' resource procurement strategy. In particular, the purchased power agreements that the Company has entered into have allowed customers to enjoy the benefits of discounted market capacity prices and have provided flexibility in meeting target planning reserve margin requirements.

The Company's approach to resource selection is as follows:

The IRP process is used to identify the type, size, and timing of the resource need. In selecting the optimal resource plan, Duke Energy Carolinas begins with an optimization model that selects the resource mix that minimizes the present value of revenue requirements (PVRR) for a given set of assumptions. The levelized cost method used for generation options serves as a proxy for either self-build or long-term purchased power opportunities. From the optimization step, several diverse portfolios of resources are selected for further detailed production costing modeling and ultimate selection of a resource plan for the IRP.

Once a resource need is identified, the Company determines the options to satisfy that need and determines the near-term and long-term actions necessary to secure the resource. The options could include a self-build Duke Energy Carolinas-owned resource, a Duke Energy Carolinas-owned acquired resource (new or existing), or a purchased power resource. The Company consistently has issued RFPs for peaking and intermediate resource needs. For example, following the identification of peaking and intermediate resource needs, the Company issued a RFP in May 2007 for conventional intermediate and peaking resource proposals of up to 800 MW beginning in the 2009-2010 timeframe and up to 2000 additional MW beginning in the 2013 timeframe. Potential bidders could submit bids for purchased power or for the acquisition of existing or new facilities. Ten bidders submitted a total of forty-five bids spanning time periods of two to thirty years. The bid evaluation considered price, operational flexibility, and location benefits. Ultimately, the Company determined that none of the proposed bids provided sufficient advantages to offset the multiple benefits of the proposed Buck and Dan River CC projects. The consideration of purchased power options was described in the Company's CPCN application for these facilities and addressed in testimony. The NCUC issued the CPCNs for the Buck and Dan River CC projects in June 2008.

The Company also issued a RFP for renewable energy proposals in 2007. This RFP process produced proposals for approximately 1,900 megawatts of electricity from alternative sources from 26 different companies. The bids included wind, solar, biomass, biodiesel, landfill gas, hydro, and biogas projects. The Company entered into PPAs for a large solar project and several landfill gas facilities. In addition, the Company continues to receive unsolicited proposals for renewable purchased power resources and has entered into several PPAs as a result of unsolicited proposals.

The 2011 IRP plans included approximately 2,890 MWs of "New CT" capacity, in addition to existing and committed resources for the Cliffside Modernization project and Buck and Dan River combined cycle projects, as well as Lee Nuclear. The "New CT" resources reflect an identified need for peaking capacity that will be refined in future IRPs and could be met through new self-build capacity, purchased power, additional DSM or any combination of the three.

Although Duke Energy Carolinas evaluates the competitive wholesale market for peaking and intermediate resources, the Company's purchased power philosophy does not currently include soliciting purchased power bids for baseload capacity. Duke Energy Carolinas views baseload capacity as fundamentally different from peaking and intermediate capacity. Currently, there are two key concerns with relying upon the wholesale market for baseload capacity. First, generation outside the control area could be subject to interruption due to transmission issues more so than generation within the control area. Second, supplier default could jeopardize the ability to provide reliable service. The Company therefore believes that Duke Energy Carolinas-owned baseload resources are the most reliable means for Duke Energy Carolinas to meet its service obligations in a cost-effective and reliable manner.

In addition, the Company examines unsolicited bids for purchased power or resource acquisitions and is alert to opportunities to purchase power or resources.

6. ENVIRONMENTAL COMPLIANCE

Legislative and Regulatory Issues

Duke Energy Carolinas, which is subject to the jurisdiction of federal agencies including the Federal Energy Regulatory Commission (FERC), EPA, and the NRC, as well as state commissions and agencies, is potentially impacted by state and federal legislative and regulatory actions. This section provides a high-level description of several issues Duke Energy Carolinas is actively monitoring or engaged in that could potentially influence the existing generation and choices for new generation.

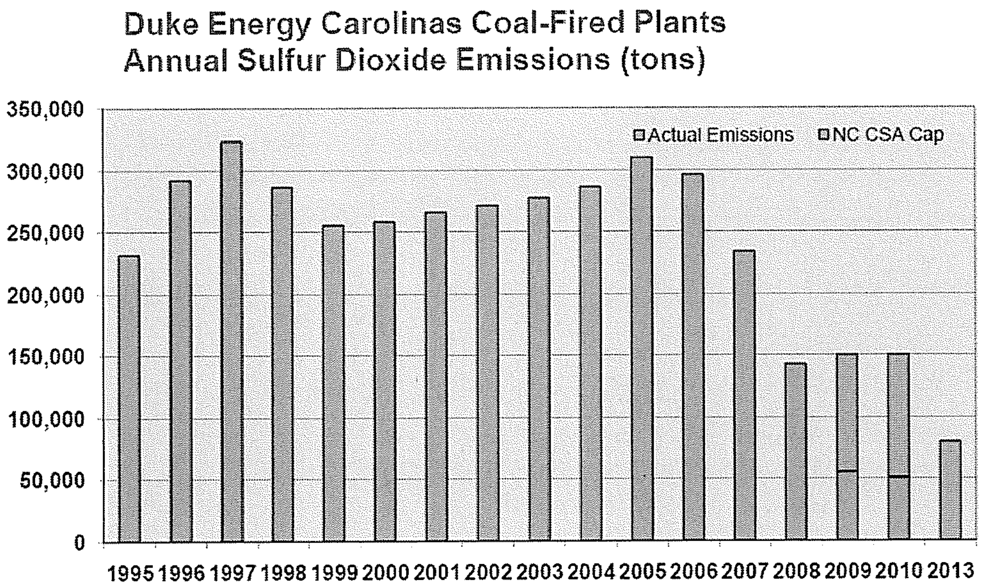
Air Quality

Duke Energy Carolinas is required to comply with numerous state and federal air emission regulations such as the current Clean Air Interstate Rule (CAIR) NO_x and SO_2 cap-and-trade program, and the 2002 North Carolina Clean Smokestacks Act (NC CSA).

As a result of complying with the NC CSA, Duke Energy Carolinas will reduce SO_2 emissions by approximately 75 percent by 2013 from 2000 levels. The law also required additional reductions in NO_x emissions in 2007 and 2009, beyond those required by the CAIR rule, which Duke Energy Carolinas has achieved. This landmark legislation, which was passed by the North Carolina General Assembly in June of 2002, calls for some of the lowest state-mandated emission levels in the nation, and was passed with Duke Energy Carolinas' input and support.

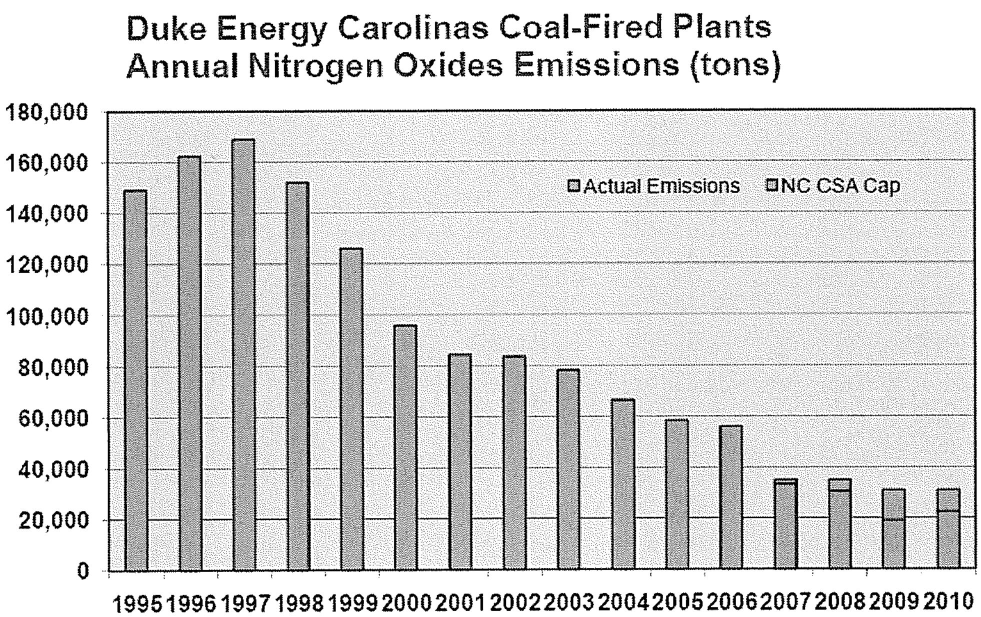
The following Charts 6.A and 6.B show Duke Energy Carolinas' NO_x and SO_2 emissions reductions to comply with the 2002 NC CSA requirements and actual emission through 2010.

Chart 6.A



75 % Reduction from 2000 to 2013 attributed to scrubbers installed to meet NC Clean Air Legislation.

Chart 6.B



Overall reduction of 80% from 1997 to 2009 attributed to controls to meet Federal Requirements and NC Clean Air Legislation.

In addition to current programs and regulatory requirements, several new regulations are in various stages of implementation and development that will impact operations for

Duke Energy Carolinas in the coming years. Some of the major rules include:

Cross-State Air Pollution Rule – Replacement for Clean Air Interstate Rule (CAIR)

The EPA finalized its CAIR in May 2005. The CAIR limits total annual and summertime NO_x emissions and annual SO_2 emissions from electric generating facilities across the Eastern U.S. through a two-phased cap-and-trade program. Phase 1 began in 2009 for NO_x and in 2010 for SO_2. In July 2008, the U.S. Court of Appeals for the District of Columbia (D.C. Circuit) issued its decision in *North Carolina v. EPA* vacating the CAIR. In December 2008, the D.C. Circuit issued a decision remanding the CAIR to the EPA, allowing CAIR to remain in effect until EPA develops new regulations.

In August 2010, EPA published its proposed Transport Rule to replace the CAIR. On July 6, 2011, EPA issued the final rule, now known as the Cross-State Air Pollution Rule (CSAPR). The CSAPR replaces the CAIR and establishes state-level annual SO_2 and NO_x caps that take effect on January 1, 2012, and state-level ozone-season NO_x caps that take effect on May 1, 2012. The cap levels decline in 2014 in North Carolina, but remain constant in South Carolina. The CSAPR allows limited interstate and unlimited intrastate allowance trading. The final rule is significantly different from the original proposal. As a result, Duke Energy Carolinas has not had adequate time to prepare for these changes. Immediate steps are planned to develop strategies to minimize impacts while complying with the CSAPR. Duke Energy Carolinas will be particularly challenged to comply with annual and ozone season NO_x allocations in North Carolina beginning in 2014, as well as for both SO_2 and NO_x in South Carolina beginning in 2012. Additional revisions to the CSAPR could be developed by EPA that would incorporate the more stringent ozone and particulate matter NAAQS, which are in varying stages of development by the EPA.

Utility Boiler Maximum Achievable Control Technology (MACT)

In May 2005, the EPA issued the Clean Air Mercury Rule (CAMR). The rule established mercury emission-rate limits for new coal-fired steam generating units, as defined in Clean Air Act (CAA) section 111(d). It also established a nationwide mercury cap-and-trade program covering existing and new coal-fired power units.

In February 2008, the D.C. Circuit Court of Appeals issued its opinion, vacating the CAMR. EPA then began the process of developing a rule to replace the CAMR. The replacement rule, the Utility Boiler MACT, will create emission limits for hazardous air pollutants (HAPs), including mercury, from coal-fired and oil-fired power plants. Duke Energy completed work in 2010 as required for EPA's Utility MACT Information Collection Request (ICR). The ICR required collection of mercury and HAPs emissions data from numerous Duke Energy Carolinas facilities for use by EPA in developing the MACT rule. EPA published a proposed MACT rule (now referred to by EPA as the "Toxics Rule") on May 3, 2011 and expects to finalize it in November 2011. As proposed, the Toxics Rule is expected to require compliance with new emission limits in early 2015, with possible one-year extensions that a permitting authority can grant on a case-by-case basis. While the implications of the MACT rule are not fully known at this time, Duke Energy Carolinas is likely to face challenges from the rule which could include consideration of retiring certain assets rather than installing controls to comply.

Reciprocating Internal Combustion Engine (RICE) Maximum Achievable Control Technology (MACT)

EPA also has finalized the Reciprocating Internal Combustion Engine MACT (RICE MACT) which had an effective date of May 3, 2010. The RICE MACT requires certain existing engines such as those used for power production to retrofit with catalyst beds. While the RICE MACT has limited direct impact on the Company's operations, it does impact customers and suppliers of Duke Energy Carolinas and impacts purchasing agreements for the overall power supply portfolio. Non-emergency sources are most likely to be required to retrofit to comply with RICE standards. Engines used for emergency purposes, such as fire pumps and generators have limitations on operations and other less stringent requirements under the RICE MACT. These emergency-use engines will mostly be impacted with additional maintenance requirements, such as inspections, record keeping and periodic maintenance requirements. All engines will have to be in compliance by May 3, 2013, with costs to comply occurring in the 2011-2012 timeframe. This has impacted the Company's expected demand response program reductions identified in this IRP.

National Ambient Air Quality Standards (NAAQS)

8 Hour Ozone Standard

In March 2008 EPA revised the 8-hour ozone standard by lowering it from 84 to 75 parts per billion (ppb). In September 2009, EPA announced a decision to reconsider the 75 ppb standard. The decision was in response to a court challenge from environmental groups and EPA's belief that a lower standard was justified.

EPA issued a proposed rule on January 7, 2010 in which EPA proposed to replace the existing standard with a new standard between 60 and 70 ppb. EPA plans to issue a final rule in the fall of 2011. The schedule for implementing a new standard is somewhat uncertain until EPA finalizes the rule as well as its plans for implementation. It is estimated, however, that State Implementation Plans (SIP) could be due by December

2014, with possible attainment dates for most areas in the 2018 timeframe. Additional controls could be required by the 2018 ozone season. Until the states develop implementation plans, only an estimate can be developed of the potential impact to Duke Energy Carolina's generation fleet. A standard in the 60 to 70 ppb range is considered very stringent and will likely result in numerous non-attainment area designations.

SO_2 Standards

In November 2009, EPA proposed a rule to replace the 24-hour and annual primary SO_2 NAAQS with a 1-hour SO_2 standard. EPA finalized its new 1-hr standard of 75 ppb in June 2010. EPA will have 2 years (June 2012) to designate areas relative to their attainment status with the new standard. States with non-attainment areas will have until the January 2014 to submit their SIPs. Initial attainment dates are expected to be the summer of 2017. EPA has not yet indicated when any required controls might need to be in place, but is expected by late-2016. EPA will base its nonattainment designations on monitored air quality data as well as on dispersion modeling. All power plants will be modeled by the NC and SC Department of Air Quality and are therefore potential targets for additional SO_2 reductions, even if there is no monitored exceedance of the standard. In addition, EPA is proposing to require states to relocate some existing monitors and to add some new monitors. Although these monitors will not be used by EPA to make the initial nonattainment designations, they will play a role in identifying possible future nonattainment areas.

Particulate Matter (PM) Standard

On September 21, 2006, the EPA announced its decision to revise the $PM_{2.5}$ NAAQS standard. The daily standard was reduced from 65 ug/m^3 (micrograms per cubic meter) to 35 ug/m^3. The annual standard remained at 15 ug/m^3.

EPA finalized designations for the 2006 daily standard in October 2009, which did not include any nonattainment areas in the Duke Energy Carolinas service territory. On February 24, 2009, the D.C Circuit unanimously remanded to EPA the Agency's decision to retain the annual 15 ug/m^3 primary $PM_{2.5}$ NAAQS and to equate the secondary $PM_{2.5}$ NAAQS with the primary NAAQS. EPA must now undertake new rulemaking to revise the standards consistent with the Court's decision. EPA's current timeline indicates that it will propose a $PM_{2.5}$ rule in fall 2011 and possibly finalize a rule around mid-2012. The likely outcome of EPA's ongoing review will be a tightening of the primary daily and annual $PM_{2.5}$ NAAQS along with the creation of a separate secondary $PM_{2.5}$ NAAQS. The current annual and daily $PM_{2.5}$ standards alone are not driving any emission reductions at Duke Energy Carolinas facilities. The reduction in SO_2 and NO_x emissions to address the current annual standard are being addressed through CAIR.

Reductions to address the current daily standard will be addressed as part of the CSAPR that EPA developed to replace CAIR (the CSAPR will continue to address reductions needed for the current annual standard).

Greenhouse Gas Regulation

The EPA has been active in the regulation of greenhouse gases (GHGs). In May 2010, the EPA finalized what is commonly referred to as the Tailoring Rule, which sets the emission thresholds to 75,000 tons/year of CO_2 for determining when a source is potentially subject to Prevention of Significant Deterioration (PSD) permitting for GHGs. The Tailoring Rule went into effect beginning January 2, 2011. Being subject to PSD permitting requirements for CO_2 will require a Best Available Control Technology (BACT) analysis and the application of BACT for GHGs. BACT will be determined by the state permitting authority. Since it is not known if, or when, a Duke Energy Carolinas generating unit might undertake a modification that triggers PSD permitting requirements for GHGs and exactly what might constitute BACT at a particular point in time, the potential implications of this regulatory requirement are presently unknown.

In early 2011, EPA entered into a settlement agreement to issue New Source Performance Standards for GHG emissions from new and modified fossil fueled electric generating units (EGUs) and emission guidelines for existing EGUs. The agreement calls for regulations to be proposed by September 30, 2011 and to be finalized by 2012.

It is currently not known if or when any federal climate change legislation limiting GHG emissions might be enacted.

Water Quality and By-product Issues

CWA 316(b) Cooling Water Intake Structures

Federal regulations in Section 316(b) of the Clean Water Act may necessitate cooling water intake modifications and/or cooling towers for existing facilities to minimize impingement and entrainment of aquatic organisms. All Duke Energy Carolina's coal and nuclear generating stations are potentially affected sources under that rule.

EPA issued a proposed rule on April 20, 2011 and expects to finalize the rule in July 2012. Depending upon a station's National Pollutant Discharge Elimination System (NPDES) permit renewal schedule, compliance with the rule could begin as early as mid-2015.

EPA's proposed rule lists four options with a preference for one option. The preferred option impacts all facilities with a design intake flow greater than 2 million gallons per day (mgd). In order to meet fish impingement standards, intake screen modifications are likely to be needed for nearly all plant intakes. EPA has not mandated the use of cooling towers as "Best Technology Available" to address entrainment requirements. However, site specific studies are proposed by the rule in order to address best technology options for complying with the entrainment requirements. These studies could begin as early as 2013.

Steam Electric Effluent Guidelines

In September 2009, EPA announced plans to revise the steam electric effluent guidelines. In order to assist with development of the revised regulation, EPA issued an Information Collection Request (ICR) to gather information and data from nearly all steam-electric generating facilities. The ICR was completed and submitted to EPA in October 2010. The regulation is to be technology-based, in that limits are based on the capability of technology. The primary focus of the revised regulation is on coal-fired generation, thus the major areas likely to be impacted are FGD wastewater treatment systems and ash handling systems. The EPA may set limits that dictate certain FGD wastewater treatment technologies for the industry and may require dry ash handling systems be installed. Following review of the ICR data, EPA plans to issue a draft rule in July 2012 and a final rule in January 2014. After the final rulemaking, effluent guideline requirements will be included in a station's NPDES permit renewals. Thus, requirements to comply with NPDES permit conditions may begin as early as 2017 for some facilities. The length of time allowed to comply will be determined through the permit renewal process.

Coal Combustion Residuals

Following Tennessee Valley Authority's Kingston ash dike failure in December 2008, EPA began an effort to assess the integrity of ash dikes nationwide and to begin developing a rule to manage coal combustion residuals (CCRs). CCRs include fly ash, bottom ash and FGD byproducts (gypsum). Since the 2008 dike failure, numerous ash dike inspections have been completed by EPA and an enormous amount of input has been received by EPA, as it developed proposed regulations.

In June 2010, EPA issued its proposed rule regarding CCRs. The proposed rule offers two options: (1) a hazardous waste classification under Resource Conservation and Recovery Act (RCRA) Subtitle C; and (2) a non-hazardous waste classification under RCRA Subtitle D, along with dam safety and alternative rules. Both options would require strict new requirements regarding the handling, disposal and potential re-use ability of CCRs. The proposal could result in more conversions to dry handling of ash, more landfills, closure of existing ash ponds and the addition of new wastewater treatment systems. Final regulations are not expected until 2012 or 2013. EPA's regulatory classification of CCRs as hazardous or non-hazardous will be critical in developing plans for handling CCRs in the future. The impact to Duke Energy Carolinas of this regulation as proposed is still being assessed. The schedule for compliance will depend upon when EPA finalizes a rule and the rule requirements.

7. TRANSMISSION AND DISTRIBUTION

A. Transmission System Adequacy

Duke Energy Carolinas monitors the adequacy and reliability of its transmission system and interconnections through internal analysis and participation in regional reliability groups. Internal transmission planning looks 10 years ahead at available generating resources and projected load to identify transmission system upgrade and expansion requirements. Corrective actions are planned and implemented in advance to ensure continued cost-effective and high-quality service. The Duke Energy Carolinas' transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability.

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with Duke Energy Carolinas' Transmission Planning Guidelines for voltage and thermal loading. The annual screening uses methods that comply with SERC policy and NERC Reliability Standards and the screening results identify the need for future transmission system expansion and upgrades and are used as inputs into the Duke Energy Carolinas – Power Delivery optimization process. The Power Delivery optimization process evaluates problem-solution alternatives and their respective priority, scope, cost, and timing. The optimization process enables Power Delivery to produce a multi-year work plan and budget to fund a portfolio of projects which provides the greatest benefit for the dollars invested.

Duke Energy Carolinas currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning Guidelines and the FERC Open Access Transmission Tariff (OATT). The Company performs studies to ensure transfer capability is acceptable to meet reliability needs and customers' expected use of the transmission system. The Power Delivery optimization process is also used to manage projects for improvement of transfer capability.

The SERC audits Duke Energy Carolinas every three years for compliance with NERC Reliability Standards. Specifically, the audit requires Duke Energy Carolinas to demonstrate that its transmission planning practices meet NERC standards and to provide data supporting the Company's annual compliance filing certifications. SERC completed a full audit in April 2008 and also completed a "spot check" audit of selected standards in August 2009. Duke Energy Carolinas was found compliant in all areas of the audit. SERC also conducted a full audit in May 2011. The 2011 audit results are not yet publically available.

Duke Energy Carolinas participates in a number of regional reliability groups to coordinate analysis of regional, sub-regional and inter-control area transfer capability and interconnection reliability. The reliability groups' purpose is to:

- Assess the interconnected system's capability to handle large firm and non-firm transactions for purposes of economic access to resources and system reliability;
- Ensure that planned future transmission system improvements do not adversely affect neighboring systems; and
- Ensure the interconnected system's compliance with NERC Reliability Standards.

Regional reliability groups evaluate transfer capability and compliance with NERC Reliability Standards for the upcoming peak season and five- and ten-year periods. The groups also perform computer simulation tests for high transfer levels to verify satisfactory transfer capability.

B. Transmission System Emerging Issues

Looking forward, several items that have the potential to impact the planning of the Duke Energy Carolinas Transmission System include:

- Industry-approved revisions to the NERC Reliability Standards for transmission planning standards that are awaiting FERC approval.

- The FERC Final Order on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, issued in July 2011 under Docket No. RM10-23-000.

- Increased interest in the integration of variable renewable resources (e.g., wind) into the grid. The North Carolina Transmission Planning Collaborative and the DOE-funded Southeastern Offshore Wind Energy Infrastructure Project are performing studies in 2011 to assess the transmission impacts of significant off-shore wind development along the Southeast coast including North Carolina.

- The Eastern Interconnection Planning Collaborative (EIPC), which is a transmission study process that began in late 2009. The EIPC provides:

1. A mechanism to aggregate existing regional transmission plans in the Eastern Interconnection and assess them on an Eastern Interconnection wide basis; and
2. A framework to be able to perform technical analyses to inform state and federal government representatives and policy makers on important issues, such as future renewable resources and their impact on transmission infrastructure.

As of late July 2011, the EIPC is awaiting determination by its Stakeholder Steering Committee (SSC) of the three future scenarios they will request receive detailed analysis by the EIPC powerflow study group. The detailed analysis will determine the future transmission infrastructure required to support each of the three resource scenarios selected by the SSC.

- Duke Energy and Progress Energy are working towards a merger of the corporations and are targeting a closing by the end of 2011. The organizational structure and processes related to transmission planning in North Carolina are being discussed and evaluated by the management of the two companies.

8. SELECTION AND IMPLEMENTATION OF THE PLAN

A. RESOURCE NEEDS ASSESSMENT (FUTURE STATE)

To meet the future needs of Duke Energy Carolinas' customers, it is necessary for the Company to adequately understand the load and resource balance. For each year of the planning horizon, Duke Energy Carolinas develops a load forecast of energy sales and peak demand. To determine total resources needed, the Company considers the load obligation plus a 17 percent target planning reserve margin (see Reserve Margin discussion below). The capability of existing resources, including generating units, energy efficiency and demand-side management programs, and purchased power contracts, is measured against the total resource need. Any deficit in future years will be met by a mix of additional resources that reliably and cost-effectively meets the load obligation.

Reserve Margin Explanation and Justification

Reserve margins are necessary to help ensure the availability of adequate resources to meet load obligations due to consideration of customer demand uncertainty, unit outages, transmission constraints, and weather extremes. Many factors have an impact on the appropriate levels of reserves, including existing generation performance, lead times needed to acquire or develop new resources, and product availability in the purchased power market.

Duke Energy Carolinas' historical experience has shown that a 17 percent target planning reserve margin is sufficient to provide reliable power supplies, based on the prevailing expectations of reasonable lead times for the development of new generation, siting of transmission facilities, and procurement of purchased capacity. As part of the Company's process for determining its target planning reserve margins, Duke Energy Carolinas reviews whether the current target planning reserve margin is adequate in the prior period. From July 2006 through June 2011, generating reserves, defined as available Duke Energy Carolinas generation capacity plus the net of firm purchases less sales, never dropped below 450 MW. However, on June 1, 2011, the Company's generating reserves dropped to approximately 500 MWs due to above-normal temperatures and forced outages on several units. Since 1997, Duke Energy Carolinas has had sufficient reserves to meet customer load reliably with limited need for activation of interruptible programs. However, on June 1, 2011, 535 MWs of DSM were activated. The DSM Activation History in Appendix D illustrates Duke Energy Carolinas' limited activation of interruptible programs through June 2011.

Duke Energy Carolinas also continually reviews its generating system capability, level of potential DSM activations, scheduled maintenance, environmental retrofit equipment and environmental compliance requirements, purchased power availability, and transmission capability to assess its capability to reliably meet customer demand. There are a number of increased risks that need to be considered with regard to Duke Energy Carolinas' reserve margin target. These risks include: (1) the increasing age of existing units on the system; (2) the inclusion of a significant amount of renewables (which are generally less available than traditional supply-side resources) in the plan due to the enactment of the NC REPS; (3) uncertainty regarding the impacts associated with significant increases in the Company's energy efficiency and demand-side management programs; (4) longer lead times for building baseload capacity such as nuclear; (5) increasing environmental pressures, which may cause additional unit derates and/or unit retirements; and (6) increases in derates of units due to extreme hot weather and drought conditions. Each of these risks would negatively impact the resources available to provide reliable service to customers. Duke Energy Carolinas will continue to monitor these risks in the future and make any necessary adjustments to the reserve margin target in future plans.

Duke Energy Carolinas also assesses its reserve margins on a short-term basis to determine whether to pursue additional capacity in the short-term power market. As each peak demand season approaches, the Company has a greater level of certainty regarding the customer load forecast and total system capability, due to greater knowledge of near-term weather conditions and generation unit availability.

Duke Energy Carolinas uses adjusted system capacity[3], along with Interruptible DSM capability to satisfy Duke Energy Carolinas' NERC Reliability Standards requirements for operating and contingency reserves. Contingencies include events such as higher than expected unavailability of generating units, increased customer load due to extreme weather conditions, and loss of generating capacity because of extreme weather conditions such as the severe drought conditions in 2007.

Upon the completion of the merger between Duke Energy and Progress Energy, the combined system reserve margin will be comprehensively reviewed to determine if the reserve margin needs to be adjusted.

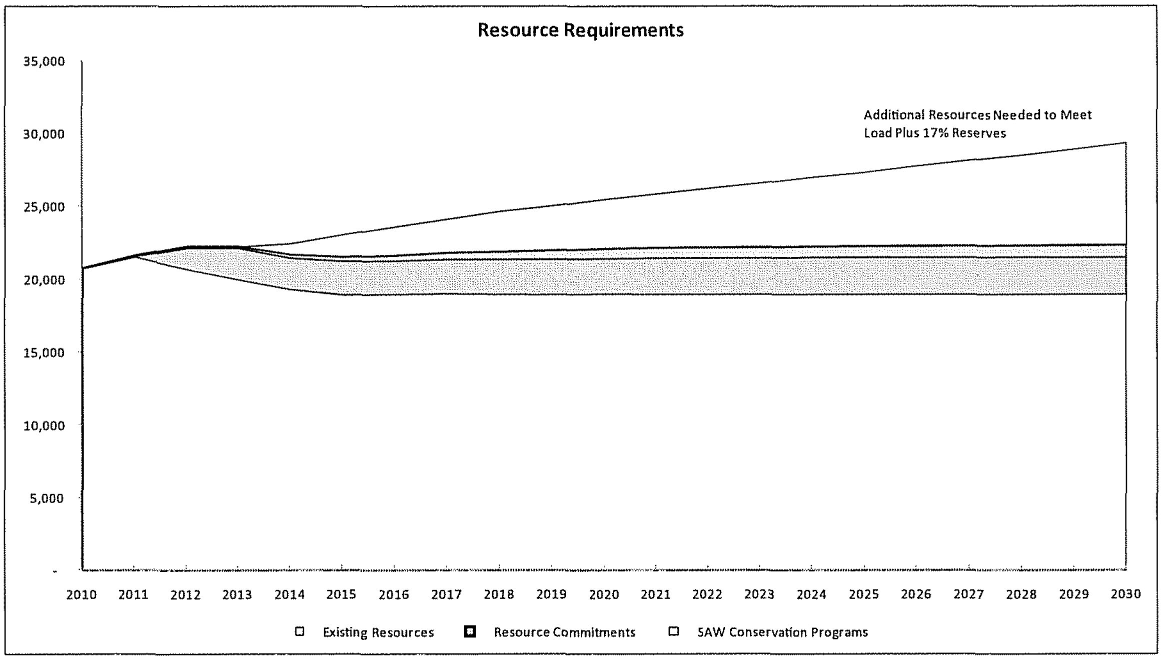
[3] Adjusted system capacity is calculated by adding the expected capacity of each generating unit plus firm purchased power capacity.

Load and Resource Balance

The following chart shows the existing resources and resource requirements needed to meet the Company's load obligation, plus the 17 percent target planning reserve margin. Beginning in 2011, existing resources, consisting of existing generation and purchased power to meet load requirements, total 20,777 MW. The load obligation plus the target planning reserve margin is 20,547 MW, indicating sufficient resources to meet Duke Energy Carolinas' obligation. The need for additional capacity grows over time due to load growth, unit capacity adjustments, unit retirements, and expirations of purchased-power contracts. The need grows to approximately 3,090 MW by 2020 and to 7,030 MW by 2031. Assumptions made in the development of this chart include:

1. Cliffside Unit 6 is built by the summer of 2012 and therefore included in Resource Commitments;
2. Coal retirements associated with the Cliffside Unit 6 CPCN and Air Permit, Buck Units 5&6, and Lee Steam Station are included;
3. Retirement of the old fleet combustion turbines;
4. Conservation programs associated with the save-a-watt program are included;
5. DSM programs associated with the save-a-watt program are included;
6. Buck/Dan River combined cycle facilities are included in Resource Commitments;
7. Renewable capacity is built or purchased to meet the NC REPS

Chart 8.A
Load and Resource Balance



Cumulative Resource Additions to Meet a 17 Percent Planning Reserve Margin (MWs)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Resource Need	0	0	0	790	1550	1990	2330	2790	3090	3410
Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Resource Need	3730	4080	4430	4780	5080	5520	5890	6220	6630	7030

B. OVERALL PLANNING PROCESS CONCLUSIONS

Duke Energy Carolinas' resource planning process provides a framework for the Company to access, analyze and implement a cost-effective approach to reliably meet customers' growing energy needs. In addition to assessing qualitative factors, the Company has also conducted a quantitative assessment using simulation models.

Duke Energy Carolinas tested a variety of sensitivities and scenarios against a base set of inputs for various resource mixes, allowing the Company to better understand how potentially different future operating environments due to fuel commodity price changes, environmental emission mandates, and structural regulatory requirements can affect resource choices, and, ultimately, the cost of electricity to customers. (Appendix A provides a detailed description and results of the quantitative analyses).

The results of the Company's quantitative analyses suggest that a combination of additional baseload, intermediate and peaking generation, renewable resources, EE, and DSM programs is required over the next twenty years to meet customer demand reliably and cost-effectively.

The new pulverized coal unit at Cliffside Steam Station (Unit 6) is assumed to be in service in 2012, annually providing 5,700 GWh of baseload energy. Project implementation is underway for the new CC facilities at Buck and Dan River, with the facilities assumed to be operational in late 2011 and late 2012, respectively. In addition, Duke Energy Carolinas has included DSM, EE and renewable resources consistent with the Company's energy efficiency plan approved in North and South Carolina and to meet the NC REPS. For planning purposes, approximately 5% of retail sales in South Carolina would come from renewable energy, in addition to the energy efficiency programs, phased in from 2015 to 2031. The Company's analysis for the 2010 IRP demonstrated that approximately 200 MWs of nuclear uprates were cost effective and specific projects are being developed to be implemented in the 2011-2019 timeframe. For planning purposes, Lee Steam Station will be retired from coal fired generation and converted to natural gas generation in 2015. The increase in the peak generation need in 2015 is primarily due to increased load projections, updated assumptions regarding the energy impacts of CFLs and lower projected capacity impacts from DSM programs, as well as changes in the projected compliance portfolio relating to the NC REPS.

The Company's analysis of new nuclear capacity contained in the 2011 IRP focuses on the impact of various uncertainties such as load variations, nuclear capital costs, greenhouse gas and clean energy legislation, EPA regulations, fuel prices, and the availability of financing options such as federal loan guarantees (FLG).

The IRP analysis included sensitivities on each of the uncertainties described below:

Load Variations: The base case load forecast incorporates the impact of the current recession, projected EE achievements, demand destruction associated with the implementation of carbon legislation, new wholesale sales opportunities, and the impact associated with future plug-in hybrid vehicles. The Company also developed high and low load forecast sensitivities to reflect a 95% confidence interval.

Nuclear Capital Costs: The Company varied the nuclear capital cost on the low end to reflect the impact of minimal project contingency and varied on the high side to reflect increased labor and material cost.

Greenhouse Gas Legislation: The 2011 fundamental CO_2 allowance price forecast was lower primarily due to uncertainty of Congress to pass legislation. For the 2011 IRP, the Company evaluated a range of CO_2 prices based on various legislative cap and trade proposals used in 2009 and 2010 IRPs, in addition to potential Clean Energy legislation that does not have a CO_2 cap and trade mechanism, but relies upon a federal RPS.

Fuel Prices: The base case natural gas and coal price projections were based on Duke Energy's fundamental price forecasts, which are updated annually. The Company also evaluated a high cost fuel scenario, which reflects the impact of increased demand on natural gas and regulatory challenges to the coal mining industry. The lower cost fuel scenario represents a larger supply of domestic natural gas than currently assumed and a lower demand on coal.

Nuclear Financing Options: The nuclear cost referenced as "traditional financing" in the 2011 IRP includes state incentives, local incentives, and the ability to recover construction financing cost prior to commercial operation. Duke Energy Carolinas continues to believe that legislation allowing for timely collection of financing cost outside a general rate case during construction (nuclear financing legislation) is critical to the development of new nuclear plants. The Company plans to pursue nuclear financing legislation in the 2012 NC legislative session. Duke Energy Carolinas believes this legislation is important to demonstrate support for new nuclear development, and to allow utilities investing in new nuclear construction to maintain the strength of their respective balance sheets during construction to the benefit of their customers.

The nuclear cost referenced as "favorable financing" includes FLGs. The Company evaluated these credits as sensitivities because Duke Energy Carolinas' proposed Lee Nuclear Station does not currently qualify for these incentives. However, it is important to continue to include these benefits as sensitivities because it demonstrates how much expansion of these programs could lower the ultimate costs to customers, should the project qualify. There is federal legislative support for expanding these programs in the future.

Results

The results of the Company's quantitative and qualitative analyses suggest that a combination of additional baseload, intermediate, and peaking generation, renewable resources, and EE and DSM programs are required over the next 20 years. The near-term resource needs can be met, in part, with new EE and DSM programs, completing construction of the Buck, Dan River, and Cliffside Projects, completion of various fossil and hydro unit uprates, as well as pursuing nuclear uprates and renewable resources. However, additional resources will be needed as early as 2015 due to increased load projections, updated assumptions regarding the energy impacts of CFLs, lower projected capacity impacts from DSM programs, and changes in the projected renewable compliance portfolio. The Company's analysis continues to affirm the potential benefits of new nuclear capacity in the 2020 timeframe in a carbon-constrained future. The Company expects to receive the COL for the Lee Nuclear Station project in early 2013 and will make a final decision on the construction of the project based on the market conditions at that time, including the status of nuclear financing legislation in North Carolina.

To demonstrate that the Company is planning adequately for customers, the Company selected a portfolio incorporating the impact of future carbon legislation for the purposes of preparing the Load, Capacity, and Reserve Margin Table (LCR Table).

This portfolio consisted of 2,890 MW[4] of new natural gas simple cycle capacity, 1,300 MW of CC capacity, 2,234 MW of new nuclear capacity, 987 MW of DSM, 727 MW of EE, and 484 MW of renewable resources. The selected portfolio specifically includes the Cliffside Unit 6, Buck CC, and Dan River CC projects.

However, the Company will likely face significant challenges relating to its resource planning in the future, such as specific challenges in (1) obtaining the necessary regulatory approvals to implement future demand-side, EE, and supply-side resources, (2) finding sufficient cost-effective, reliable renewable resources to meet the standard, (3) effectively integrating renewables into the resource mix, and (4) ensuring sufficient transmission capability for these resources. In light of the myriad of qualitative issues facing the Company relating to its fuel diversity, the Company's environmental profile, the stage of technology deployment and regional economic development, Duke Energy Carolinas has developed a strategy to ensure that the Company can meet customers'

[4] The ultimate sizes of any generating unit may change somewhat depending on the vendor selected.

energy needs reliably and economically while maintaining flexibility pertaining to long-term resource decisions.

On July 12, 2011, the NRC task force on the Japanese Fukishima Dai-ichi event noted it had not identified any issues that undermine confidence in the continued safety and emergency planning of U.S. nuclear plants. The task force review is ongoing and is likely to result in additional actions to enhance safety and preparedness of the U.S. nuclear fleet. The nuclear industry will ensure an exhaustive review of the events in Japan is completed and all possible lessons learned are applied to further improve nuclear safety. At this time, no significant impacts on new nuclear plant licensing are anticipated as a result of the events in Japan.

The Oconee Nuclear Station's (Oconee) current operating license expires in 2033, which is close to the end of our current IRP planning horizon. At this time, the Company has not made a decision concerning a second license extension for this plant. Oconee is a significant part of our generation portfolio representing over 2,500 MW of capacity and annual energy output of approximately 20,000 GWHrs. As such, it is important to start to examine the impacts of any potential retirement of Oconee to help the Company as it considers a second license extension, as well as incorporate these impacts into the resource planning process.

The planning process must be dynamic and adaptable to changing conditions. While this plan is the most appropriate resource plan at this point in time, good business practice requires Duke Energy Carolinas to continue to study the options, and make adjustments as necessary and practical to reflect improved information and changing circumstances. Consequently, a good business planning analysis is truly an evolving process that can never be considered complete.

The seasonal projections of load, capacity, and reserves of the selected plan are provided in Table 8.A.

Table 8.A

Summer Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2011 Annual Plan

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Load Forecast																				
1 Duke System Peak	17,892	18,347	18,800	19,239	19,752	20,220	20,675	21,122	21,444	21,826	22,152	22,469	22,777	23,120	23,399	23,777	24,109	24,417	24,765	25,121
Reductions to Load Forecast																				
2 New EE Programs	(80)	(102)	(120)	(208)	(276)	(343)	(410)	(478)	(544)	(611)	(622)	(633)	(642)	(655)	(667)	(679)	(688)	(703)	(715)	(727)
3 Adjusted Duke System Peak	**17,812**	**18,245**	**18,680**	**19,032**	**19,476**	**19,877**	**20,265**	**20,644**	**20,901**	**21,214**	**21,530**	**21,836**	**22,135**	**22,465**	**22,732**	**23,099**	**23,420**	**23,714**	**24,050**	**24,393**
Cumulative System Capacity																				
4 Generating Capacity	19,762	20,404	21,070	21,088	20,378	20,388	20,415	20,495	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525
5 Capacity Additions	1,465	666	18	370	10	27	81	30	0	0	0	0	0	0	0	0	0	0	0	0
6 Capacity Derates	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	(824)	0	0	(1,080)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	20,404	21,070	21,088	20,378	20,388	20,415	20,495	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525
Purchase Contracts																				
9 Cumulative Purchase Contracts	270	211	123	100	100	100	100	100	97	96	87	87	87	87	87	87	87	87	87	87
Sales Contracts																				
10 Catawba Owner Backstand	0	0	(47)	(47)	(47)	(47)	(47)	(47)	(47)	0	0	0	0	0	0	0	0	0	0	0
11 Catawba Owner Load Following Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 Cumulative Future Resource Additions																				
Base Load	0	0	0	0	0	0	0	0	0	1,117	1,117	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234
Peaking/Intermediate	0	0	0	740	1,480	1,480	2,130	2,130	2,870	2,870	2,870	2,870	2,870	2,870	2,870	2,870	2,870	3,520	3,520	4,190
Renewables	41	44	116	128	249	250	304	341	376	372	427	437	439	478	488	481	484	493	484	484
13 Cumulative Production Capacity	**20,715**	**21,326**	**21,281**	**21,300**	**22,171**	**22,198**	**22,983**	**23,050**	**23,822**	**24,980**	**25,027**	**26,154**	**26,156**	**26,195**	**26,205**	**26,198**	**26,201**	**26,860**	**26,851**	**27,521**
Reserves w/o Demand-Side Management																				
14 Generating Reserves	2,903	3,081	2,600	2,268	2,694	2,321	2,718	2,406	2,921	3,766	3,497	4,318	4,021	3,731	3,473	3,099	2,780	3,146	2,801	3,128
15 % Reserve Margin	**16.3%**	**16.9%**	**13.9%**	**11.9%**	**13.8%**	**11.7%**	**13.4%**	**11.7%**	**14.0%**	**17.8%**	**16.2%**	**19.8%**	**18.2%**	**16.6%**	**15.3%**	**13.4%**	**11.9%**	**13.3%**	**11.6%**	**12.8%**
16 % Capacity Margin	14.0%	14.4%	12.2%	10.6%	12.2%	10.5%	11.8%	10.4%	12.3%	15.1%	14.0%	16.5%	15.4%	14.2%	13.3%	11.8%	10.6%	11.7%	10.4%	11.4%
Demand-Side Management																				
17 Cumulative DSM Capacity	838	850	919	983	987	986	986	986	986	986	986	986	986	986	986	986	986	986	986	986
IS / SG	181	147	140	133	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126
Power Share / Power Manager	657	703	780	851	861	861	861	861	861	861	861	861	861	861	861	861	861	861	861	861
18 Cumulative Equivalent Capacity	21,553	22,175	22,200	22,283	23,157	23,184	23,969	24,036	24,808	25,967	26,013	27,140	27,142	27,182	27,191	27,184	27,187	27,847	27,837	28,507
Reserves w/ DSM																				
19 Generating Reserves	3,741	3,930	3,520	3,251	3,681	3,307	3,705	3,392	3,908	4,753	4,484	5,304	5,008	4,717	4,459	4,085	3,767	4,132	3,787	4,114
20 % Reserve Margin	**21.0%**	**21.5%**	**18.8%**	**17.1%**	**18.9%**	**16.6%**	**18.3%**	**16.4%**	**18.7%**	**22.4%**	**20.8%**	**24.3%**	**22.6%**	**21.0%**	**19.6%**	**17.7%**	**16.1%**	**17.4%**	**15.7%**	**16.9%**
21 % Capacity Margin	17.4%	17.7%	15.9%	14.6%	15.9%	14.3%	15.5%	14.1%	15.8%	18.3%	17.2%	19.5%	18.4%	17.4%	16.4%	15.0%	13.9%	14.8%	13.6%	14.4%

Winter Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2011 Annual Plan

	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
Load Forecast																				
1 Duke System Peak	17,425	17,869	18,303	18,746	19,180	19,665	20,123	20,539	20,868	21,128	21,482	21,782	22,080	22,379	22,649	22,922	23,280	23,584	23,885	24,186
Reductions to Load Forecast																				
2 New EE Programs	(67)	(96)	(126)	(204)	(289)	(360)	(429)	(497)	(564)	(636)	(647)	(658)	(668)	(681)	(693)	(706)	(716)	(730)	(743)	(756)
3 Adjusted Duke System Peak	**17,359**	**17,773**	**18,177**	**18,543**	**18,891**	**19,305**	**19,694**	**20,042**	**20,304**	**20,492**	**20,835**	**21,124**	**21,412**	**21,697**	**21,956**	**22,217**	**22,565**	**22,853**	**23,142**	**23,430**
Cumulative System Capacity																				
4 Generating Capacity	20,567	20,934	21,773	21,820	21,468	21,128	21,137	21,164	21,245	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275
5 Capacity Additions	684	1,465	46	18	370	10	27	81	30	0	0	0	0	0	0	0	0	0	0	0
6 Capacity Derates	(6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	(311)	(626)	0	(370)	(710)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	20,934	21,773	21,820	21,468	21,128	21,137	21,164	21,245	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275
Purchase Contracts																				
9 Cumulative Purchase Contracts	277	218	123	100	100	100	100	100	97	96	87	87	87	87	87	87	87	87	87	87
Sales Contracts																				
10 Catawba Owner Backstand	0	0	(47)	(47)	(47)	(47)	(47)	(47)	(47)	0	0	0	0	0	0	0	0	0	0	0
11 Catawba Owner Load Following Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 Cumulative Future Resource Additions																				
Base Load	0	0	0	0	0	0	0	0	0	0	1,117	1,117	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234
Peaking/Intermediate	0	0	0	0	740	1,480	1,480	2,130	2,130	2,870	2,870	2,870	2,870	2,870	2,870	2,870	2,870	2,870	3,520	3,520
Renewables	46	41	44	116	128	249	250	304	341	376	372	427	437	439	478	488	481	484	493	484
13 Cumulative Production Capacity	**21,257**	**22,032**	**21,940**	**21,638**	**22,049**	**22,920**	**22,947**	**23,732**	**23,796**	**24,618**	**25,721**	**25,776**	**26,903**	**26,906**	**26,945**	**26,954**	**26,947**	**26,950**	**27,610**	**27,601**
Reserves w/o Demand-Side Management																				
14 Generating Reserves	3,899	4,260	3,764	3,095	3,158	3,615	3,254	3,690	3,492	4,126	4,886	4,653	5,491	5,208	4,989	4,737	4,383	4,097	4,468	4,170
15 % Reserve Margin	**22.5%**	**24.0%**	**20.7%**	**16.7%**	**16.7%**	**18.7%**	**16.5%**	**18.4%**	**17.2%**	**20.1%**	**23.5%**	**22.0%**	**25.6%**	**24.0%**	**22.7%**	**21.3%**	**19.4%**	**17.9%**	**19.3%**	**17.8%**
16 % Capacity Margin	18.3%	19.3%	17.2%	14.3%	14.3%	15.8%	14.2%	15.5%	14.7%	16.8%	19.0%	18.1%	20.4%	19.4%	18.5%	17.6%	16.3%	15.2%	16.2%	15.1%
Demand-Side Management																				
17 Cumulative DSM Capacity	548	511	530	547	555	555	555	555	555	555	555	555	555	555	555	555	555	555	555	555
IS / SG	181	147	140	133	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126
Power Share / Power Manager	367	364	391	414	429	429	429	429	429	429	429	429	429	429	429	429	429	429	429	429
18 Cumulative Equivalent Capacity	21,806	22,544	22,471	22,184	22,604	23,475	23,502	24,287	24,351	25,172	26,276	26,331	27,458	27,460	27,499	27,509	27,502	27,505	28,164	28,155
Reserves w/ DSM																				
19 Generating Reserves	4,447	4,771	4,294	3,641	3,713	4,169	3,808	4,245	4,047	4,680	5,441	5,207	6,046	5,763	5,544	5,292	4,937	4,652	5,023	4,725
20 % Reserve Margin	**25.6%**	**26.8%**	**23.6%**	**19.6%**	**19.7%**	**21.6%**	**19.3%**	**21.2%**	**19.9%**	**22.8%**	**26.1%**	**24.7%**	**28.2%**	**26.6%**	**25.2%**	**23.8%**	**21.9%**	**20.4%**	**21.7%**	**20.2%**
21 % Capacity Margin	20.4%	21.2%	19.1%	16.4%	16.4%	17.8%	16.2%	17.5%	16.6%	18.6%	20.7%	19.8%	22.0%	21.0%	20.2%	19.2%	18.0%	16.9%	17.8%	16.8%

Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Summer and Winter Projections of Load, Capacity, and Reserves tables. All values are MW except where shown as a Percent.

1. Planning is done for the peak demand for the Duke System including Nantahala. Nantahala became a division of Duke Energy Carolinas in 1998.

4. Generating Capacity must be online by June 1 to be included in the available capacity for the summer peak of that year. Capacity must be online by Dec 1 to be included in the available capacity for the winter peak of that year. Includes 91 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for NCMPA1 firm capacity sale.

5. Capacity Additions reflect an 8.75 MW increase in capacity at Bridgewater Hydro by summer 2012.
   Capacity Additions include Duke Energy Carolinas projects that have been approved by the NCUC (Cliffside 6, Buck and Dan River Combined Cycle facilities).
   Capacity Additions include the conversion of Lee Steam Station from coal to natural gas in 2015.
   Capacity Additions include Duke Energy Carolinas hydro units scheduled to be repaired and returned to service. These units are returned to service in the 2011-2017 timeframe and total 34 MW.
   Also included is a 204 MW capacity increase due to nuclear uprates at Catawba, McGuire, and Oconee. Timing of these uprates is shown from 2012-2019

6. No more Capacity Derates for existing units are expected at this time.

7. Buck units 3-4 (113 MW) were retired during the summer of 2011.
   The 824 MW capacity retirement in summer 2012 represents the projected retirement date for Dan River Steam Station units 1-3 (276 MW), Cliffside Steam Station units 1-4 (198 MW), and 350 MWs of old fleet CT retirements.
   The 1080 MW capacity retirement in summer 2015 represents the projected retirement date for Lee Steam Station (370 MW), Buck Steam Station units 5 and 6 (256 MW) and Riverbend Steam Station units 4-7 (454 MW).
   The NRC has issued renewed energy facility operating licenses for all Duke Energy Carolinas' nuclear facilities.
   The Hydro facilities for which Duke has submitted an application to FERC for licence renewal are assumed to continue operation through the planning horizon.
   All retirement dates are subject to review on an ongoing basis.

9. Cumulative Purchase Contracts have several components:

   A. Piedmont Municipal Power Agency took sole responsibility for total load requirements beginning January 1, 2006. This reduces the SEPA allocation from 94 MW to 19 MW in 2006, which is attributed to certain wholesale customers who continue to be served by Duke.
   B. Purchased capacity from PURPA Qualifying Facilities includes the 88 MW Cherokee County Cogeneration Partners contract which began in June 1998 and expires June 2013 and miscellaneous other QF projects totaling 36 MW.

10-11. A firm wholesale backstand agreement up to 277 MW between Duke Energy Carolinas and PMPA starts on 1/1/2014 and continues through the end of 2020.

12. Cumulative Future Resource Additions represent a combination of new capacity resources or capability increases from the most robust plan.

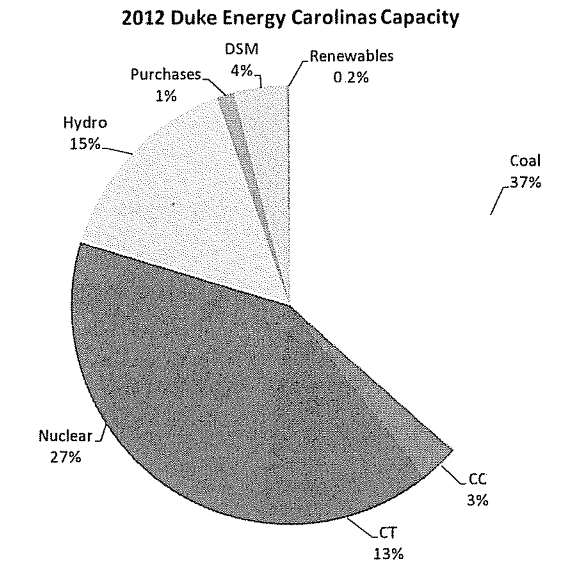
15. Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand

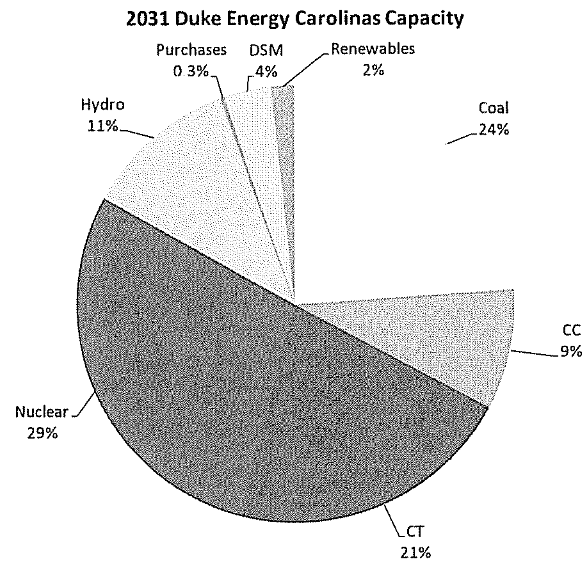
16. Capacity Margin = (Cumulative Capacity - System Peak Demand)/Cumulative Capacity

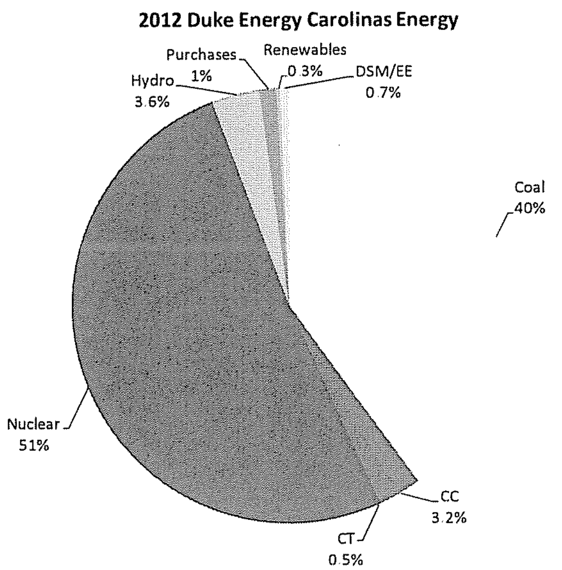
17. The Cumulative Demand Side Management capacity includes new Demand Side Management capacity representing placeholders for demand response and energy efficiency programs.

The charts in Chart 8.B and 8.C show the changes in Duke Energy Carolinas' capacity mix and energy mix between 2012 and 2031. The relative shares of renewables, energy efficiency, and gas all increase, while the relative share of coal decreases.

Chart 8.B







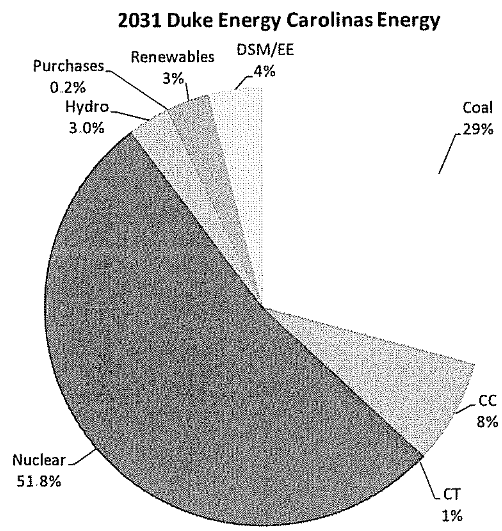
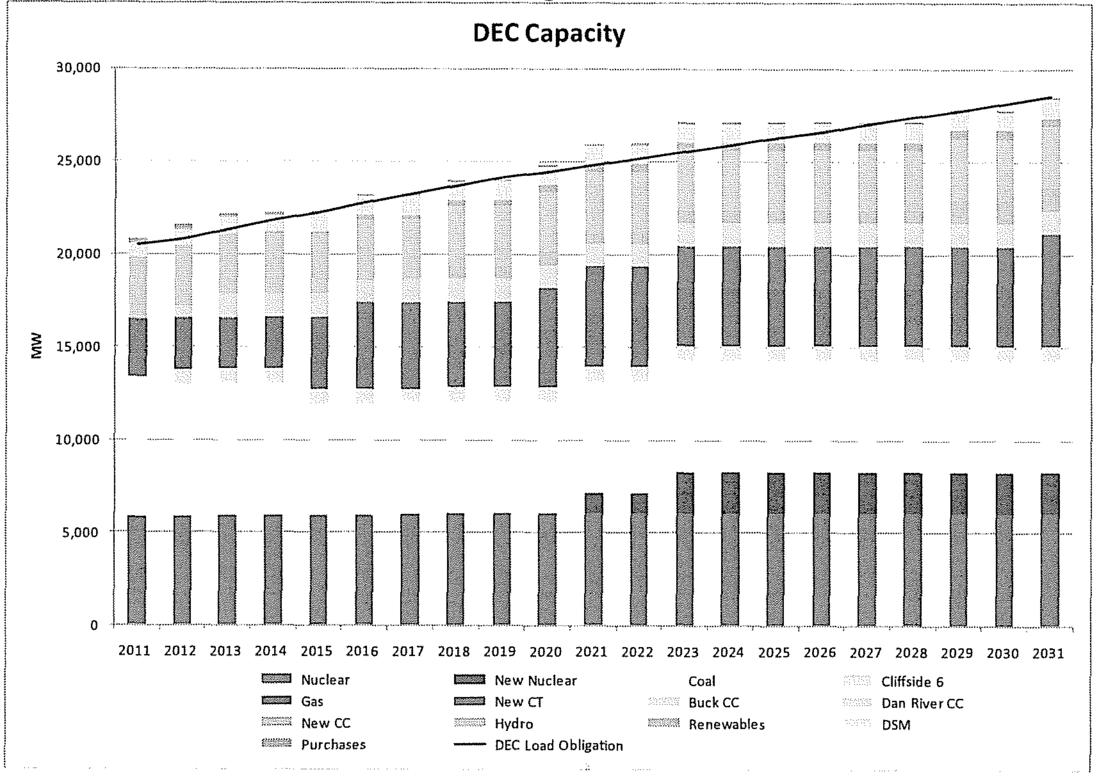


Chart 8.C
Annual Capacity Projection 2011 through 2031



Annual Energy Projection 2011 through 2031

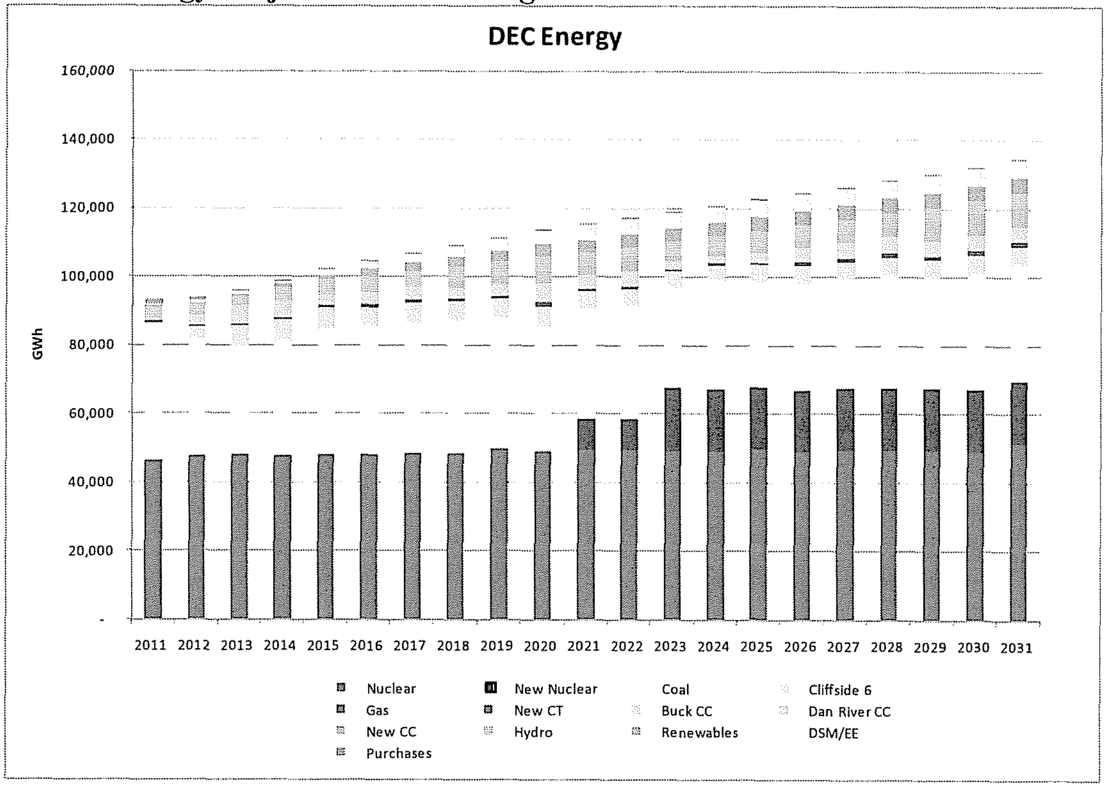


Table 8.D below represents the annual non-renewable incremental additions reflected in the LCR Table of the most robust expansion plan. The plan contains the addition of Cliffside Unit 6 in 2012, the unit retirements shown in Table 5.D and the impact of EE and DSM programs.

Table 8.D

Year	Month	Project	MW
2011	6	Jocassee Uprates	50
2011	12	Buck Combined Cycle	620
2012	6	Cliffside 6	825
2012	6	Bridgewater Hydro	8.75
2012	6	Nuclear Uprates	10
2012	12	Dan River Combined Cycle	620
2013	6	Nuclear Uprates	45
2014	6	Nuclear Uprates	18
2015	6	New CT	740
2016	6	New CT	740
2017	6	Nuclear Uprates	21
2018	6	New CC	650
2018	6	Nuclear Uprates	81
2019	6	Nuclear Uprates	30
2020	6	New CT	740
2021	6	New Nuclear	1117
2023	6	New Nuclear	1117
2029	6	New CC	650
2031	6	New CT	670

The details of the forecasted capacity additions, including both nameplate capacity and the expected contribution of renewable resources towards the Company's peak load needs, are summarized in Table 8.E below.

Table 8.E Expected Renewable Resource Capacity Additions

Renewables								
	MW Contribution to Summer Peak				MW Nameplate			
Year	Wind	Solar	Biomass	Total	Wind	Solar	Biomass	Total
2011	15.0	12	20	46	100	24	20	143
2012	0.0	12	29	41	0	24	29	53
2013	0.0	12	33	44	0	24	33	56
2014	15.0	12	89	116	100	24	89	213
2015	15.6	21	91	128	104	42	91	237
2016	47.8	22	179	249	318	45	179	542
2017	47.8	23	180	250	319	45	180	543
2018	49.7	24	230	304	332	49	230	610
2019	50.7	25	265	341	338	51	265	654
2020	53	28	296	376	352	56	296	703
2021	51	26	295	372	339	51	295	686
2022	55	28	344	427	367	57	344	767
2023	55	36	346	437	368	72	346	786
2024	55	36	347	439	369	73	347	789
2025	58	36	384	478	389	73	384	846
2026	61	41	386	488	406	81	386	874
2027	59	37	385	481	392	73	385	851
2028	59	37	388	484	393	74	388	855
2029	62	41	391	493	411	82	391	884
2030	62	41	391	493	411	82	391	884
2031	62	41	391	493	411	82	391	884

APPENDICES

APPENDIX A: QUANTITATIVE ANALYSIS

This appendix provides an overview of the Company's quantitative analysis of resource options available to meet customers' future energy needs.

Overview of Analytical Process

Assess Resource Needs

Duke Energy Carolinas estimates the required load and generation resource balance needed to meet future customer demands by assessing:

- Customer load forecast peak and energy – identifying future customer aggregate demands to identify system peak demands and developing the corresponding energy load shape
- Existing supply-side resources – summarizing each existing generation resource's operating characteristics including unit capability, potential operational constraints, and life expectancy
- Operating parameters – determining operational requirements including target planning reserve margins and other regulatory considerations.

Customer load growth coupled with the expiration of purchased power contracts, lower demand response, and renewable compliance assumptions, results in significant resource needs to meet energy and peak demands, based on the following assumptions:

- 1.8% average summer peak system demand growth over the next 20 years without impacts of new energy efficiency programs
- Generation retirements of approximately 350 MW of old fleet combustion turbines by 2012
- Generation retirements of approximately 1,040 MW of older coal units associated with the addition of Cliffside Unit 6.
- Generation retirements of approximately 630 MW of remaining coal units without scrubbers by 2015
- Approximately 70 MW of net generation reductions due to new environmental equipment
- Continued operational reliability of existing generation portfolio
- Using a 17 percent target planning reserve margin for the planning horizon

Identify and Screen Resource Options for Further Consideration

The IRP process evaluates EE, DSM and supply-side options to meet customer energy and capacity needs. The Company develops DSM/EE options for consideration within the IRP based on input from our collaborative partners and cost-effectiveness screening. Supply-side options reflect a diverse mix of technologies and fuel sources (gas, coal, nuclear and renewable). Supply-side options are initially screened based on the following attributes:

- Technically feasible and commercially available in the marketplace
- Compliant with all federal and state requirements
- Long-run reliability
- Reasonable cost parameters.

The Company compared capacity options within their respective fuel types and operational capabilities, with the most cost-effective options being selected for inclusion in the portfolio analysis phase.

Resource Options

Supply-Side

Based on the results of the screening analysis, the following technologies were included in the quantitative analysis as potential supply-side resource options to meet future capacity needs:

- Baseload – 800 MW Supercritical Pulverized Coal
- Baseload – 630 MW Integrated Gasification Combined Cycle (IGCC)
- Baseload – 2,234 MW (2x1,117 MW) Nuclear units (AP1000)
- Peaking/Intermediate – 740 MW (4x185 MW) CT
- Peaking/Intermediate – 650 MW (460 MW Unfired + 150MW Duct Fired + 40MW Inlet Chilled) Natural Gas CC
- Renewable – Existing Unit Biomass Co-Firing
- Renewable – Wind PPA On-Shore
- Renewable – Landfill Gas PPA
- Renewable – Solar Photovoltaic PPA
- Renewable – Biomass Firing PPA
- Renewable – Poultry Waste PPA

Although the supply-side screening curves showed that some of these resources would be screened out, they were included in the next step of the quantitative analysis for completeness.

Energy Efficiency and Demand-Side Management

EE and DSM programs continue to be an important part of Duke Energy Carolinas' system mix. The Company considered both demand response and conservation programs in the analysis.

The Company modeled the costs and impacts from EE and DSM programs based on the data included in Duke Energy Carolinas' approved Energy Efficiency Plan settlement in NCUC Docket No. E-7, Sub 831. For the analysis, Duke Energy Carolinas assumed these costs and impacts would continue through the duration of the planning period.

The forecasted energy efficiency savings through 2012 are consistent with Duke Energy Carolinas' North Carolina Energy Efficiency Plan for 2009 through 2012. The Company assumes for purposes of the IRP that total efficiency savings will continue to grow on an annual basis through 2031, however the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan.

Develop Theoretical Portfolio Configurations

The Company conducted a screening analysis using a simulation model to identify the most attractive capacity options under the expected load profile as well as under a range of risk cases. This analysis began with a set of basic inputs which were varied to test the system under different future conditions, such as changes in fuel prices, load levels, and construction costs. These analyses yielded many different theoretical configurations of resources required to meet an annual 17 percent target planning reserve margin while minimizing the long-run revenue requirements to customers, with differing operating (production) and capital costs.

The set of basic inputs included:

- Fuel costs and availability for coal, gas, and nuclear generation;
- Development, operation, and maintenance costs of both new and existing generation;
- Compliance with current and potential environmental regulations;
- Cost of capital;
- System operational needs for load ramping, spinning reserve (10 to 15-minute start-up)

- The projected load and generation resource need; and
- A menu of new resource options with corresponding costs and timing parameters.

Duke Energy Carolinas reviewed a number of variations to the theoretical portfolios to aid in the development of the portfolio options discussed in the following section.

Develop Various Portfolio Options

Using the insights gleaned from developing theoretical portfolios, Duke Energy Carolinas created a representative range of generation plans reflecting plant designs, lead times and environmental emissions limits. Recognizing that different generation plans expose customers to different sources and levels of risk, the Company developed a variety of portfolios to assess the impact of various risk factors on the costs to serve customers. The portfolios analyzed for the development of this IRP were chosen in order to focus on the optimal timing of CT, CC, and nuclear additions in the 2016 – 2031 timeframe.

The information as shown on the following pages outlines the planning options that the Company considered in the portfolio analysis phase. Each portfolio contains demand response and conservation identified in the base EE and DSM case and renewable portfolio standard requirements modeled after the NC REPS in NC and applied to SC. In addition, each portfolio contains the addition of Cliffside Unit 6 in 2012, Buck CC in 2012 and Dan River CC in 2013 and the unit retirements shown in Table 5 D.

The RPS assumptions are based on NC REPS in North Carolina. The assumptions for planning purposes are as follows:

<u>Overall Requirements/Timing</u>

- 3% of 2011 load by 2012
- 6% of 2014 load by 2015
- 10% of 2017 load by 2018
- 12.5% of 2020 load by 2021

<u>Additional Requirements</u>

- Up to 25% from EE through 2020
- Up to 40% from EE starting in 2021
- Up to 25% of the requirements can be met with out-of-state, unbundled RECs
- Solar requirement
    - 0.02% by 2010
    - 0.07% by 2012

  - 0.14% by 2015
  - 0.20% by 2018
- Hog waste requirement (NC only – using Duke Energy Carolinas' share of total North Carolina load which is approximately 42%)
  - 0.07% by 2012
  - 0.14% by 2015
  - 0.20% by 2018
- Poultry waste requirement (NC only - using Duke Energy Carolinas' share of total North Carolina load which is approximately 42%)
  - 71,400 MWh by 2012
  - 294,000 MWh by 2013
  - 378,000 MWh by 2014

The overall requirements were applied to all retail load and to wholesale customers who have contracted with Duke Energy Carolinas to meet their REPS requirement. The requirement that a certain percentage must come from Hog and Poultry waste was not applied to the South Carolina portion.

Conduct Portfolio Analysis

Duke Energy Carolinas tested the portfolio options under the nominal set of inputs, as well as a variety of risk sensitivities and scenarios, in order to understand the strengths and weaknesses of various resource configurations and evaluate the long-term costs to customers under various potential outcomes.

For this IRP analysis, the Company selected six main scenarios to illustrate the impacts of key risks and decisions. Three of these scenarios fall into the Reference CO_2 Case and three fall into the Clean Energy Legislation Case.

- Reference Case: Cap and trade program with CO_2 prices based on Duke Energy's 2011 fundamental prices.
- Clean Energy Legislation: In addition to evaluating potential CO_2 cap and trade options, the impact of proposed Clean Energy legislation without a price on CO_2 emissions was also evaluated. Assumptions used in this analysis include:
  - 10% of retail sales by 2015 must be clean energy, increasing to 30% by 2030.
  - Alternative Compliance Payment (ACP) of 50$/MWhr.
  - "Clean Energy" includes renewable resources, EE, nuclear, natural gas CC, or alternative compliance payment.
  - Portfolios based on this legislation include the increased EE to meet 25

percent of the total clean energy target.

The six analyzed portfolios are shown below:

Reference CO_2 Case Scenarios:

1. Natural Gas – Combustion turbine/combined cycle portfolio (CT/CC)
2. Lee Nuclear – Two Lee Nuclear unit portfolio with units on-line in 2021 and 2023 (2N 2021-2023)
3. Regional Nuclear – Co-ownership of nuclear units in the region. The portfolio consists of 215 MW of nuclear in 2018, 730 MW in 2021 and 2023, and 559 MW in 2028 (Reg Nuclear)

Clean Energy Legislation Scenarios:

4. Clean Energy CC – CC portfolio with the Clean Energy Legislation assumptions
5. Clean Energy 2N – Two Lee Nuclear unit portfolio with the Clean Energy Legislation assumptions
6. Clean Energy Regional Nuclear – Regional co-ownership of nuclear with the Clean Energy Legislation assumptions

An overview of the specifics of each portfolio is shown in Table A.1 below.

The sensitivities chosen to be performed for these scenarios were those representing the highest risks going forward.

The Company evaluated the following sensitivities in the Reference CO_2 Case scenarios:

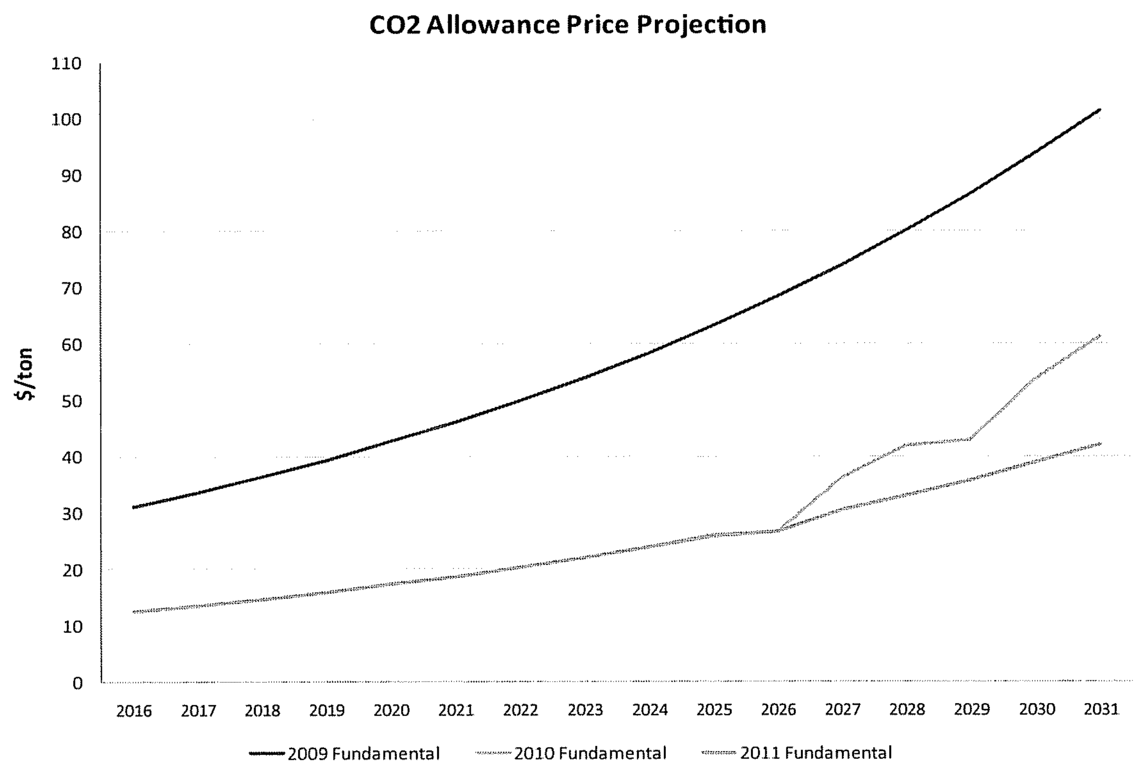
- Load forecast variations
  - Increase relative to base forecast (+15% for peak demand and +16% for energy by 2031)
  - Decrease relative to base forecast (-8% for peak demand and energy by 2031)
- Construction cost sensitivity[5]
  - Costs to construct a new nuclear plant (+20/- 10% higher than base case)
- Fuel price variability
  - Higher Fuel Prices (coal prices 25% higher, natural gas prices 25% higher)
  - Lower Fuel Prices (coal prices 40% lower, natural gas prices 40% lower)

[5] These sensitivities test the risks from increases in construction costs of one type of supply-side resource at a time. In reality, cost increases of many construction component inputs such as labor, concrete and steel would affect all supply-side resources to varying degrees rather than affecting one technology in isolation.

- Nuclear Financing
  - Federal loan guarantees for the Lee nuclear station
- The Carbon reference case had CO_2 emission prices ranging from $12/ton starting in 2016 to $42/ton in 2031. The Company performed sensitivities based on the 2009 and 2010 fundamental CO_2 prices.
- High Energy Efficiency – This sensitivity includes the full target impacts of the Company's save-a-watt bundle of programs for the first five years and then increases the load impacts at 1% of retail sales every year after that until the load impacts reach the economic potential identified by the 2007 market potential study. When fully implemented, this increased EE impacts resulted in approximately a 13% decrease in retail sales over the planning period.

Chart A.1 shows the CO_2 prices utilized in the analysis.

Chart A.1



For the Clean Energy Legislation, the Company also performed a sensitivity by lowering the ACP to $30/MWhr and increasing the renewable energy assumptions to lower the Company's need to purchase ACPs.

An overview of the specifics of each portfolio is shown in Table A.1 below.

Table A.1 – Portfolios Evaluated

Year	Portfolios					
	CT/CC	2N 2021/2023	Regional Nuclear	Clean Energy Std - Gas	Clean Energy Std - Nuc	Clean Energy Std - Reg Nuc
2011						
2012						
2013						
2014						
2015	CT	CT	CT	CC	CT	CT
2016	CT	CT	CT	CC	CT	CT
2017						
2018	CC	CC	N	CC	CC	N
2019			CC	CC		CC
2020	CT	CT			CC	
2021		N	N		N	N
2022				CC		
2023	CC	N	N		N	N
2024				CC		
2025	CC		CT			
2026	CT			CC		CC
2027			CC			
2028	CC		N	CC		N
2029		CC				
2030	CC			CC	CT	CT
2031	CT	CT	CT	CC	CT	CT
Total CT	3,180 MW	2,890 MW	2,890 MW		2,450 MW	2,450 MW
Total CC	3,250 MW	1,300 MW	1,300 MW	6,000 MW	1,300 MW	1,300 MW
Total Nuclear		2,234 MW	2,234 MW		2,234 MW	2,234 MW
Total Nuclear Uprate	204 MW	204 MW	204 MW	204 MW	204 MW	204 MW
Total Retire	2,017 MW	2,017 MW	2,017 MW	2,017 MW	2,017 MW	2,017 MW

Quantitative Analysis Results

The quantitative analysis focused on critical variables that impact the need for and timing of new nuclear generation. Three potential resource planning strategies were tested under base assumption and variations in CO_2 price, fuel costs, load/energy efficiency, and nuclear capital costs. These three potential resource planning strategies are:

- No new nuclear capacity (the CT/CC portfolio)

- Full ownership of new nuclear capacity (the 2 Nuclear Units portfolio)
- Regional co-ownership of new nuclear capacity (the Regional Nuclear portfolio)

For the base case and sensitivities, the Company calculated the PVRR for each portfolio. The revenue requirement calculation estimates the costs to customers for the Company to recover system production costs and new capital incurred. Duke Energy Carolinas used a 50-year analysis time frame to fully capture the long-term impact of nuclear generation added late in the 20 year planning horizon. Table A2 below represents a comparison of the Natural Gas (CT/CC) portfolio with a full ownership nuclear portfolio (1st unit in 2021 & 2nd unit in 2023) and the regional nuclear portfolio over a range of sensitivities. The green block represents the lowest PVRRs between the Natural Gas and the two nuclear portfolios. The value contained within the block is the PVRR savings in $billions between the cases.

Table A.2

Comparison of Nuclear Portfolios to the CT/CC Portfolio

(Cost are represented in $billions)

	Reference Case	**CO2 Price Sensitivity**		**Fuel Sensitivity**	
Portfolio		2009 Fundamental	2010 Fundamental	High Fuel Cost	Low Fuel Cost
2 Nuclear Units (2021-2023)	(0.6)	(5.9)	(2.0)	(2.8)	
Regional Nuclear	(1.1)	(6.1)	(2.4)	(3.2)	
Natural Gas					(3.0) 2N / (2.4) Reg

	Load Sensitivity			**Nuclear Capital Cost Sensitivity**	
	High Load	Low Load	High DSM	20% Increase	10% Decrease
2 Nuclear Units (2021-2023)	(1.0)	(0.6)	(0.4)		(1.8)
Regional Nuclear	(1.3)	(0.9)	(0.7)		(2.2)
Natural Gas				(1.8) 2N / (1.2) Reg	

	Nuclear Financing		**Clean Energy Bill**	
Portfolio	FLG	Portfolio	$50 ACP	$30 ACP
2 Nuclear Units (2021-2023)	(1.0)	2 Nuclear Units (2021-2023)	(2.6)	(1.2)
Regional Nuclear	(1.3)	Regional Nuclear	(2.9)	(1.6)
Natural Gas		Natural Gas		

Based on the quantitative analysis, the optimal plan includes two new nuclear units in the 2020 timeframe. The nuclear portfolios resulted in a lower cost to customers in every case with the exception of increased nuclear capital cost and lower fuel cost. In a Clean Energy Standard regulatory construct, the advantages of adding additional nuclear are greater than in a CO_2 Cap and Trade construct.

The Company's proposed portfolio including full ownership of two nuclear units in 2021 and 2023 continues to be cost effective, but the Company recognizes the potential benefits to customers of securing new nuclear generation in smaller capacity increments through regional nuclear development. The analysis indicates that the regional nuclear portfolio is lower cost to customers in the base case and most scenarios, but the full nuclear portfolio was chosen for the 2011 IRP preferred plan because there are no firm commitments in place at this time for the regional nuclear portfolio. Regional nuclear is where two or more partners plan collaboratively to stage multiple nuclear stations over a period of years and each partner would own a portion of each station. Several advantages to a regional nuclear approach are:

- Load Growth: Smaller blocks of base load generation brought on-line over a period of years would more closely match projected load growth.
- Financial: The substantial capital cost would be phased in over a longer period of time and would spread the risk if there were cost increases.
- Regulatory Uncertainty: The optimal amount and timing of additional nuclear generation will depend on the outcome of final legislation. Using a regional approach would allow utilities to better optimize their portfolios as legislation or regulation change over time.

Duke Energy Carolinas strongly supports this concept and continues to explore regional nuclear opportunities. The Company will continue to assess opportunities to benefit from economies of scale and risk reduction in new resource decisions by considering the prospects for joint ownership and/or sales agreements for new nuclear generation resources. Recent efforts in support of regional nuclear include:

- In February 2011, JEA (formerly Jacksonville Electric Authority), located in Jacksonville, Florida, signed an option to potentially purchase up to 20% of Lee Nuclear Station.

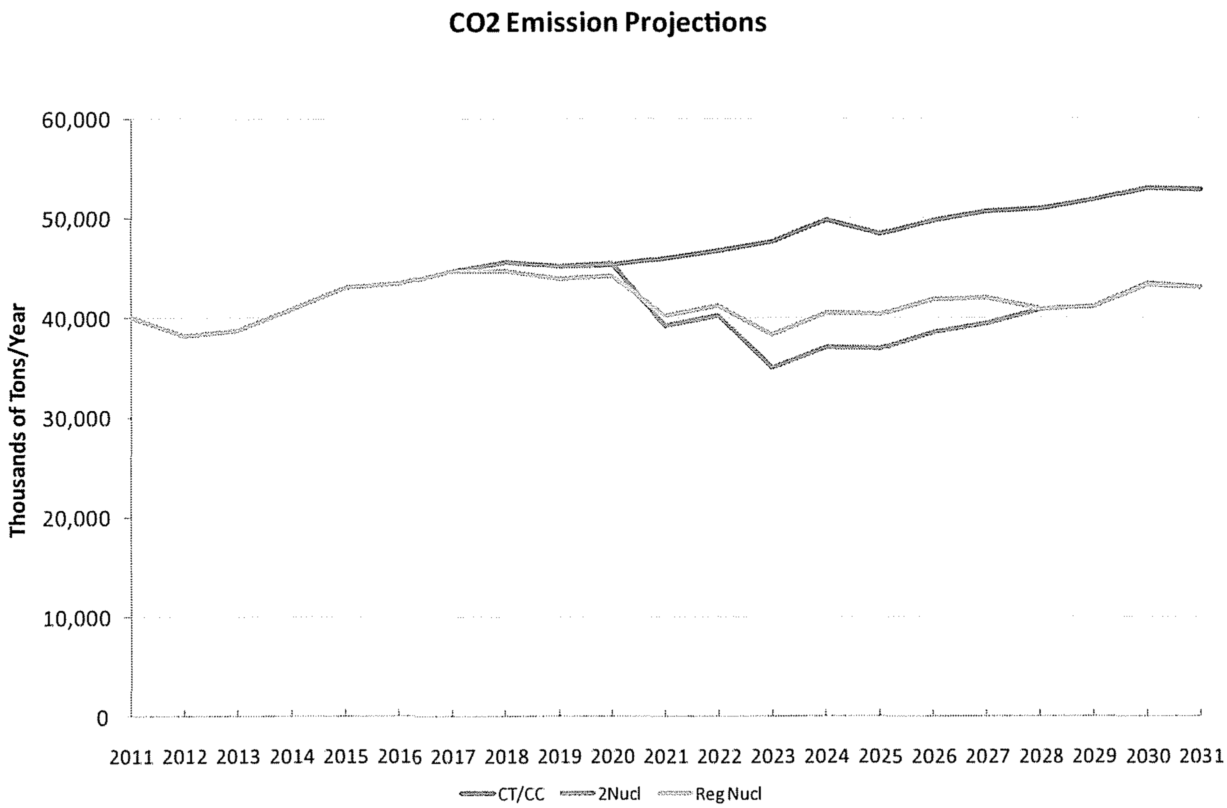
- In July 2011, the Company signed a letter of intent with Santee Cooper to perform due diligence and potentially acquire an option for a minority interest (5 to 10 percent of the capacity of the two units) in Santee Cooper's 45 percent ownership of the planned new nuclear reactors at V.C. Summer Nuclear Generating Station in South Carolina. The new units are scheduled to be online between 2016 and

2019.

Quantitative Analysis Summary

One of the major benefits of having additional nuclear generation is the lower system CO_2 footprint and the associated economic benefit. The projected CO_2 emissions under the CT/CC, 2 Nuclear, and Regional Nuclear scenarios are shown in Chart A.4 below. A review of these projections illustrates that for the Company to achieve material system reductions in CO_2 emissions, it must add new nuclear generation to the future resource portfolio.

Chart A.3



The biggest risks to the proposed nuclear portfolios are the time required to license and construct a nuclear unit, uncertainty regarding GHG regulation/legislation, potential for lower demand than currently estimated, capital cost to build, and the ability to secure favorable financing. However, in a carbon constrained future, new nuclear generation must be in the generation mix to reduce the Company's carbon footprint.

In summary, the results of the quantitative analyses indicate that it is prudent for Duke Energy Carolinas to continue to preserve the option to build new nuclear capacity in the 2020 timeframe. The Company's analysis re-affirms the advantages of favorable financing and co-ownership in future nuclear generation. Duke Energy Carolinas is aggressively pursuing favorable financing options and continues to seek potential co-owners for this generation.

The overall conclusions of the quantitative analysis are that significant additions of baseload, intermediate, peaking, EE, DSM, and renewable resources to the Duke Energy Carolinas portfolio are required over the planning horizon. Conclusions based on these analyses are:

- The new levels of EE and DSM are cost-effective for customers.
  - ➢ The screening analysis shows that portfolios with the new EE and DSM were lower cost than those without and EE and DSM.
  - ➢ The high EE sensitivity assumes 100% participation of cost effective EE programs identified in the market potential study. The high EE sensitivity is cost effective if there is an equal participation between residential and non-residential customers. If a significant number of non-residential customers opt out, then the high EE case may no longer be cost effective.
- Significant renewable resources will be needed to meet the new NC REPS (and potentially a federal standard).
- There is a capacity need in 2015 to 2020 timeframe to maintain the 17% reserve margin.
- The analysis demonstrates that the nuclear option is an attractive option for the Company's customers.
  - ➢ Continuing to preserve the option to secure new nuclear generation is prudent under the circumstances.
  - ➢ Favorable financing is very important to the project cost when compared to other generation options.
  - ➢ Co-ownership is beneficial from a generation and risk perspective.

For the purpose of demonstrating that there will be sufficient resources to meet customers' needs, Duke Energy Carolinas has selected a portfolio which, over the 20-year planning horizon provides for the following:

- 987 MW equivalent of incremental capacity under the new save-a-watt DSM programs
- 727 MW of new EE (reduction to system peak load)

- 2,234 MW of new nuclear capacity
- 1,300 MW of new CC capacity
- 2,890 MW of new CT capacity
- 204 MW of nuclear uprates
- 484 MW of renewables (858 MWs nameplate)

Significant challenges remain with respect to the Company's portfolio, such as obtaining the necessary regulatory approvals to implement the EE and DSM programs and supply side resources, finding sufficient cost-effective, reliable renewable resources to meet the NC REPS standard, effectively integrating renewables into the resource mix, and ensuring sufficient transmission capability for these resources.

APPENDIX B

Duke Energy Carolinas Spring 2011 Forecast

Duke Energy.

Sales

Rates Billed

Peaks

2011-2026

August 17, 2011

Table of Contents

Regular Sales and System Peak Summer (2010 Forecast vs. 2011 Forecast)

Regular sales include total Retail and Full/Partial Requirements Wholesale sales. The system peak summer demand includes all MW demands associated with the IRP loads. The table below shows values after the effects of utility sponsored energy efficiency have been reflected.

Growth Statistics from 2011 to 2012				
	Forecasted 2011	Forecasted 2012	Growth	
Item	Amount	Amount	Amount	%
Regular Sales	81,008 GWH	82,273 GWH	1,266 GWH	1.6%
System Peak Summer	17,557 MW	17,812 MW	255 MW	1.5%

Regular Sales Outlook for the Forecast Horizon (2010 – 2026)

Total Regular sales for the Spring 2011 Forecast are projected to grow at an average annual rate of 1.5% from 2010 through 2026, the same rate as the Fall 2010 Forecast. The Spring 2011 Forecast for Residential and Commercial is higher in the short and mid-term due to higher economic growth and a smaller reduction in the expected impacts of CFL's. In the long-run, however, the Residential and Commercial forecasts are slightly lower due to higher energy efficiency impacts The Industrial Forecast is higher throughout due to stronger economic projections in industries such autos and steel, and a surprisingly improved textile outlook. Adjustments were made to the energy forecasts for the Spring 2011 Forecast and the Fall 2010 Forecast to account for utility sponsored efficiency programs. The expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007 was reflected differently in the Spring 2011 Forecast. Its impacts were reflected directly in the residential model rather than an ex-post adjustment. Additional adjustments to the Spring 2011 Forecast include sales additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) beginning in 2011.

The Full/Partial Requirements Wholesale class forecast will increase due to new sales contracts with Central Electric Power Cooperative, Inc. (CEPCI) starting in 2013.

(Load Forecast Pg 1)

Comparison of Regular Sales Growth Statistics Spring 2011 Forecast vs. Fall 2010 Forecast					
	Spring 2011 Forecast Annual Growth (2010-2026)		Fall 2010 Forecast Annual Growth (2010-2026)		Average Annual Difference [1]
Item	**Amount**	**%**	**Amount**	**%**	
Regular Sales:					
Residential	272 GWH	0.9%	289 GWH	0.9%	-16 GWH
Commercial	569 GWH	1.8%	595 GWH	1.8%	-26 GWH
Industrial (total)	158 GWH	0.7%	96 GWH	0.5%	62 GWH
Textile	-35 GWH	-0.9%	-64 GWH	-1.8%	29 GWH
Other Industrial	193 GWH	1.1%	160 GWH	0.9%	33 GWH
Other [2]	5 GWH	1.5%	5 GWH	1.6%	0 GWH
Full/Partial Wholesale [3]	377 GWH	5.0%	390 GWH	5.1%	-13 GWH
Total Regular	1,381 GWH	1.5%	1,375 GWH	1.5%	6 GWH

[1] *Average annual differences may not match due to rounding*
[2] *Other sales consist of Street and Public Lighting and Traffic Signal GWH sales.*
[3] *For List of Full/Partial Wholesale customers see page 6.*

System Peak Outlook for the Forecast Horizon (2010 – 2026)

System peak demands are forecasted on a summer and winter basis. Additional adjustments have been made to the Spring 2011 Forecast for the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) and utility sponsored enery efficiency programs. The system peak summer demand on the Duke Energy Carolinas is expected to grow at an average annual rate of 1.8% from 2010 through 2026. The system peak winter demand is expected to grow at an average annual rate of 1.7% from 2010 through 2026.

Comparison of System Peak Demand Growth Statistics Spring 2011 Forecast vs. Fall 2010 Forecast					
	Spring 2011 Forecast Annual Growth (2010-2026)		Fall 2010 Forecast Annual Growth (2010-2026)		Average Annual Difference [1]
Item	**Amount**	**%**	**Amount**	**%**	
System Peaks					
Summer	353 MW	1.8%	333 MW	1.7%	19 MW
Winter	316 MW	1.7%	296 MW	1.6%	20 MW

(Load Forecast pg 2)

Other Forecasts

- The number of rates billed is forecasted for the Residential, Commercial and Industrial classes of Duke Energy Carolinas. The total number of rates billed is expected to grow at 1.3% annually over the forecast horizon.

(Load Forecast pg 3)

General forecasting methodology for Duke Energy Carolinas energy and demand forecasts for Spring 2010

Duke Energy Carolinas' Spring 2011 forecasts represent projections of the energy and peak demand needs for its service area, which is located within the states of North and South Carolina, including the major urban areas of Charlotte, Greensboro and Winston-Salem in North Carolina and Spartanburg and Greenville in South Carolina. The forecasts cover the time period of 2011 – 2026 and represent the energy and peak demand needs for the Duke Energy Carolinas system comprised of the following customer classes and other utility/wholesale entities:

- Residential
- Commercial
- Textiles
- Other Industrial
- Other Retail
- Duke Energy Carolinas full /partial requirements wholesale

Energy use is dependent upon key economic factors such as income, energy prices and employment along with weather. The general framework of the Company's forecast methodology begins with projections of regional economic activity, demographic trends and expected long-term weather. The economic projections used in the Spring 2011 forecasts are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the Duke Carolinas service area region. These economic forecasts represent long-term projections of numerous economic concepts including the following:

- Total real gross regional product (GRP)
- Non-manufacturing real GRP
- Non-manufacturing employment
- Manufacturing real GRP industry group, e.g., textiles
- Manufacturing Employment by industry group
- Total real personal income

Total population forecasts are obtained from the two states' demographic offices for each county in each state which are then used to derive the total population forecast for the 51 counties that the Company serves in the Carolinas.

General forecasting methodology (continued)

A projection of weather variables, cooling degree days (CDD) and heating degree days (HDD), are made for the forecast period by examining long-term historical weather. For the Spring 2011 forecasts, a 10 year simple average of CDD and HDD from 2001-2010 was used.

Other factors influencing the forecasts are identified and quantified such as changes in wholesale power contracts and housing trends, which reflects the Energy Information Administration's outlook for appliance saturations and efficiency trends.

The price of electricity is also an important input to the energy and peak models. The projected price of electricity is developed by the company's Financial Model group, and incorporates expected future costs of captial additions, fuel price increases, as well as enviromental costs, such as tighter Carbon standards.

Energy forecasts for all of the Company's retail customers are developed at a customer class level, i.e., residential, commercial, textile, other industrial and street lighting along with forecasts for its wholesale customers. Econometric models incorporating the use of industry-standard linear regression techniques were developed utilizing a number of key drivers of energy usage as outlined above. The following provides information about the models.

Residential Class:
The Company's residential class sales forecast is comprised of two separate and independent forecasts. The first is the number of residential rates billed which is driven by population projections of the counties in which the Company provides electric service. The second forecast is energy usage per rate billed which is driven primarily by weather, regional economic trends, electric price and appliance efficiencies. The total residential sales forecast is derived by multiplying the two forecasts together.

Commercial Class:
Commercial electricity usage changes with the level of regional economic activity and the impact of weather.

Textile Class:
The level of electricity consumption by Duke Energy Carolinas' textile group is impacted by the level of textile manufacturing output, exchange rates, electric prices and weather.

Other Industrial Class:
Electricity usage for Duke's other industrial customers was forecasted by 14 groups according to the 3 digit NAICS classification and then aggregated to provide the overall other industrial sales forecast. Usage is driven primarily by regional manufacturing output at a 3 digit NAICS level, electric prices and weather.

Other Retail Class:
This class in comprised of public street lighting and traffic signals within the Company's service area. The level of electricity usage is impacted not only by economic growth but

General forecasting methodology (continued)

Wholesale:
Duke Energy Carolnas serves the follwing wholesale customers on a full or partial basis:

Concord, Prosperity, Dallas, Lockhart, Forest City, Greenwood, Kings Mountain, Highlands, Due West, Western Carolina, Blue Ridge EMC, Piedmont EMC, New River, Rutherford EMC, Central, and NCEMC Fixed Load Shape.

The larger wholesale entities, Blue Ridge, Rutherford, and Piedmont, are forecasted by econometric models. The smaller whoelsale customers, however, are projected by using an assumed growth rate, comparable to Duke Carolinas Retail growth.

Peaks:
Adjustments were made to the energy and peak projections for the Spring 2011 Forecast to reflect additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011. The expected ban on incandescent lighting mandated by the Energy Independence and Security Act of 2007 is reflected in the residential sales model by adjusting the appliance efficiency variable.

Similarly, Duke Energy Carolinas' forecasts of its annual summer and winter peak demand forecasts uses econometric linear regression models that relate historical annual summer/winter peak demands to key drivers including daily temperature variables (such as daily sum of heating degree hours from 7 to 8AM in the winter with a base of 60 degrees and the daily sum of cooling degree hours from 1 to 5PM in the summer with a base of 69 degrees) and the monthly electricity usage of the entity to be forecasted.

Billed Sales and Other Energy Requirements

(Load Forecast Pg 7)

Regular Sales, which includes billed sales to Retail and Full/Partial Requirements Wholesale classes, are expected to grow at 1381 GWH per year or 1.5% over the forecast horizon. Retail sales include GWH sales billed to the Residential, Commercial, Industrial, Street and Public Lighting, and Traffic Signal Service classes. Wholesale sales are to resale customers that Duke provides either full or partial service.

Adjustments were made to the energy and peak projections for the Spring 2011 Forecast to reflect additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011. The expected ban on incandescent lighting mandated by the Energy Independence and Security Act of 2007 is reflected in the residential sales model by adjusting the appliance efficiency variable.

Points of Interest

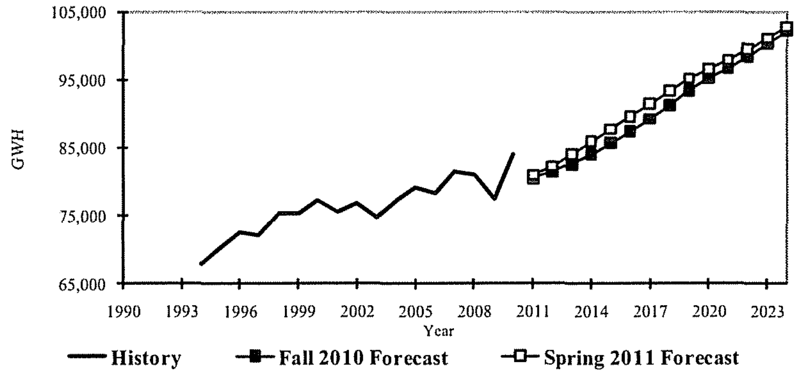
• The **Residential** class continues to show positive growth, driven by steady gains in population within the Duke Energy Carolinas service area. The resulting annual growth in Residential billed sales is expected to average 1.4% over the forecast horizon on a temperature corrected basis..

• The **Commercial** class is projected to be the fastest growing retail class, with billed sales growing at 1.8% per year over the next fifteen years. The three largest sectors in the Commercial Class are Offices, which includes banking, Retail and Education.

• The **Industrial** class rebounded strongly in 2010 after struggling for several years. The long term structural decline that has occurred in the Textile industry is expected to moderate significantly in the forecast horizon, with an overall projected decline of 0.9%. In the Other Industrial sector, several industries such as Autos, Rubber & Plastics and Primary Metals, are projected to show strong growth. Overall, Other Industrial sales are expected to grow 1.1% over the forecast horizon.

• The **Full/Partial Requirements Wholesale** class is expected to grow at 5.0% annually over the forecast horizon, primarily due to the forecasted supplemental sales to specified EMCs in North Carolina and sales to CEPCI in South Carolina.

Regular Billed Sales *(Sum of Retail and Full/Partial Wholesale classes)*



HISTORY | **AVERAGE ANNUAL GROWTH**

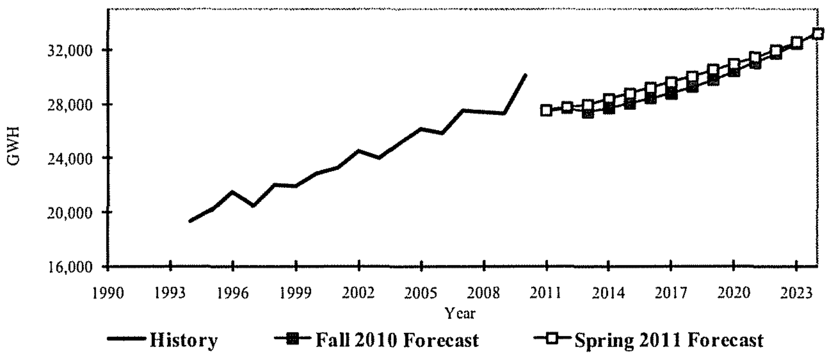
Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
2001	75,605	-1,692	-2.2			
2002	76,769	1,164	1.5			
2003	74,784	-1,984	-2.6			
2004	77,374	2,590	3.5			
2005	79,130	1,756	2.3			
2006	78,347	-784	-1.0	History (2005 to 2010)	992	1.2
2007	81,572	3,225	4.1	History (1995 to 2010)	918	1.2
2008	81,066	-505	-0.6			
2009	77,528	-3,538	-4.4	Spring 2011 Forecast (2010 to 2026)	1381	1.5
2010	84,088	6,560	8.5	Fall 2010 Forecast (2010 to 2026)	1375	1.5

SPRING 2011 FORECAST | **Fall 2010 FORECAST**

Year	GWH	Growth GWH	Growth %	GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	81,008	-3,081	-3.7	80,519	489	0.6	-3,570
2012	82,273	1,266	1.6	81,543	730	0.9	1,025
2013	84,039	1,766	2.1	82,577	1,462	1.8	1,034
2014	85,930	1,891	2.2	84,041	1,890	2.2	1,463
2015	87,752	1,821	2.1	85,715	2,037	2.4	1,674
2016	89,570	1,819	2.1	87,393	2,178	2.5	1,678
2017	91,427	1,857	2.1	89,235	2,192	2.5	1,843
2018	93,364	1,937	2.1	91,248	2,115	2.3	2,013
2019	95,146	1,782	1.9	93,415	1,731	1.9	2,167
2020	96,546	1,399	1.5	95,166	1,380	1.4	1,751
2021	97,950	1,405	1.5	96,687	1,263	1.3	1,521
2022	99,479	1,529	1.6	98,432	1,047	1.1	1,745
2023	101,104	1,625	1.6	100,294	810	0.8	1,862
2024	102,775	1,670	1.7	102,224	551	0.5	1,930
2025	104,454	1,679	1.6	104,107	347	0.3	1,883
2026	106,189	1,734	1.7	106,094	94	0.1	1,987

(Load Forecast Pg 9)

Residential Billed Sales



HISTORY / AVERAGE ANNUAL GROWTH

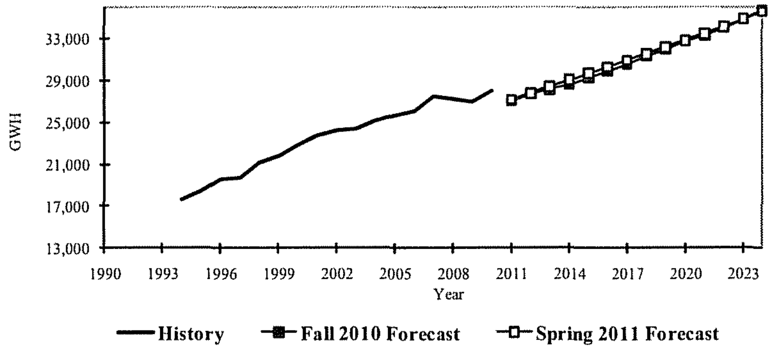
Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
2001	23,272	388	1 7			
2002	24,466	1,194	5 1			
2003	23,947	-519	-2.1			
2004	25,150	1,203	5.0			
2005	26,108	958	3 8			
2006	25,816	-292	-1.1	History (2005 to 2010)	788	2.9
2007	27,459	1,643	6 4	History (1995 to 2010)	662	2.7
2008	27,335	-124	-0.5			
2009	27,273	-62	-0 2	Spring 2011 Forecast (2010 to 2026)	272	0 9
2010	30,049	2,777	10.2	Fall 2010 Forecast (2010 to 2026)	289	0.9

SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	GWH	Growth GWH	Growth %	Fall 2010 GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	27,517	-2,532	-8 4	27,464	53	0 2	-2,585
2012	27,749	232	0 8	27,656	93	0 3	192
2013	27,914	165	0 6	27,400	514	1 9	-255
2014	28,350	436	1.6	27,663	687	2 5	262
2015	28,760	410	1 4	28,036	724	2 6	373
2016	29,154	394	1 4	28,367	787	2 8	331
2017	29,554	400	1 4	28,743	811	2 8	376
2018	29,995	441	1 5	29,201	794	2 7	458
2019	30,454	459	1 5	29,732	722	2.4	531
2020	30,926	472	1 5	30,315	612	2 0	582
2021	31,387	461	1.5	31,008	379	1 2	693
2022	31,946	559	1 8	31,698	248	0 8	691
2023	32,535	589	1 8	32,434	101	0 3	736
2024	33,154	619	1 9	33,204	-50	-0.1	770
2025	33,774	620	1 9	33,896	-122	-0 4	692
2026	34,408	634	1 9	34,668	-260	-0 7	772

(Load Forecast Pg 10)

Commercial Billed Sales



HISTORY

Year	Actual GWH	Growth GWH	Growth %
2001	23,666	821	3.6
2002	24,242	576	2.4
2003	24,355	113	0.5
2004	25,204	849	3.5
2005	25,679	475	1.9
2006	26,030	352	1.4
2007	27,433	1,402	5.4
2008	27,288	-145	-0.5
2009	26,977	-311	-1.1
2010	27,968	991	3.7

AVERAGE ANNUAL GROWTH

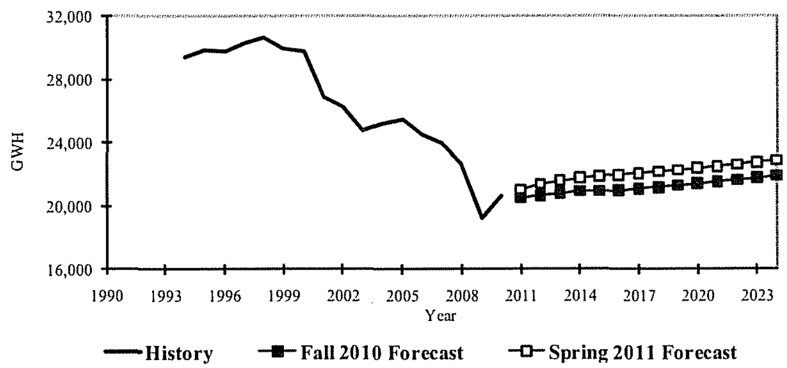
	GWH Per Year	% Per Year
History (2005 to 2010)	458	1.7
History (1995 to 2010)	634	2.8
Spring 2011 Forecast (2010 to 2026)	569	1.8
Fall 2010 Forecast (2010 to 2026)	595	1.8

SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	Spring 2011 GWH	Growth GWH	Growth %	Fall 2010 GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	27,148	-820	-2.9	27,076	72	0.3	-892
2012	27,759	611	2.3	27,688	72	0.3	612
2013	28,399	640	2.3	28,146	253	0.9	458
2014	29,031	631	2.2	28,588	443	1.5	442
2015	29,658	627	2.2	29,229	429	1.5	641
2016	30,281	623	2.1	29,903	378	1.3	674
2017	30,907	626	2.1	30,571	336	1.1	668
2018	31,537	630	2.0	31,301	236	0.8	730
2019	32,173	636	2.0	32,020	153	0.5	719
2020	32,815	642	2.0	32,760	54	0.2	741
2021	33,468	653	2.0	33,295	173	0.5	535
2022	34,129	662	2.0	34,040	89	0.3	745
2023	34,847	718	2.1	34,862	-15	0.0	822
2024	35,577	729	2.1	35,710	-133	-0.4	847
2025	36,319	742	2.1	36,598	-279	-0.8	888
2026	37,074	756	2.1	37,494	-420	-1.1	896

(Load Forecast Pg 11)

Total Industrial Billed Sales *(includes Textile and Other Industrial)*



HISTORY

Year	Actual GWH	Growth GWH	Growth %
2001	26,902	-2,869	-9.6
2002	26,259	-643	-2.4
2003	24,764	-1,496	-5.7
2004	25,209	445	1.8
2005	25,495	286	1.1
2006	24,535	-960	-3.8
2007	23,948	-587	-2.4
2008	22,634	-1,314	-5.5
2009	19,204	-3,430	-15.2
2010	20,618	1,414	7.4

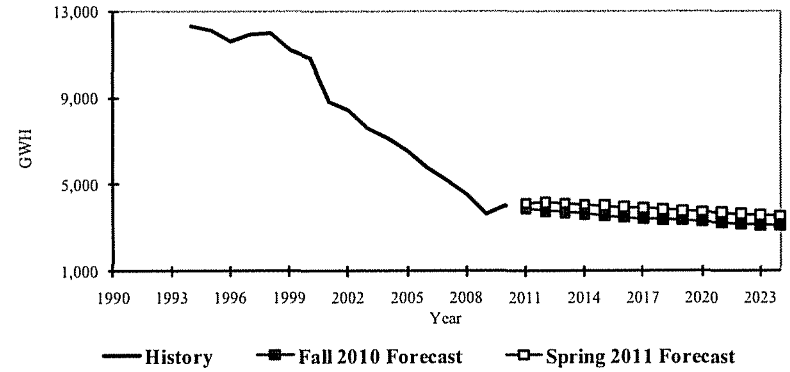
AVERAGE ANNUAL GROWTH

	GWH Per Year	% Per Year
History (2005 to 2010)	-975	-4.2
History (1995 to 2010)	-618	-2.4
Spring 2011 Forecast (2010 to 2026)	158	0.7
Fall 2010 Forecast (2010 to 2026)	96	0.5

SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	GWH	Growth GWH	Growth %	Fall 2010 GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	21,026	408	2.0	20,515	511	2.5	-103
2012	21,374	348	1.7	20,664	711	3.4	149
2013	21,600	225	1.1	20,812	787	3.8	149
2014	21,770	171	0.8	20,951	819	3.9	139
2015	21,871	100	0.5	20,944	927	4.4	-7
2016	21,963	93	0.4	20,982	981	4.7	38
2017	22,059	96	0.4	21,082	977	4.6	100
2018	22,159	100	0.5	21,178	981	4.6	96
2019	22,263	104	0.5	21,294	969	4.6	116
2020	22,375	112	0.5	21,404	970	4.5	111
2021	22,493	119	0.5	21,525	969	4.5	120
2022	22,618	125	0.6	21,653	966	4.5	128
2023	22,748	130	0.6	21,777	972	4.5	124
2024	22,876	128	0.6	21,901	975	4.5	124
2025	23,001	125	0.5	22,025	976	4.4	124
2026	23,147	146	0.6	22,161	987	4.5	136

Textile Billed Sales



HISTORY **AVERAGE ANNUAL GROWTH**

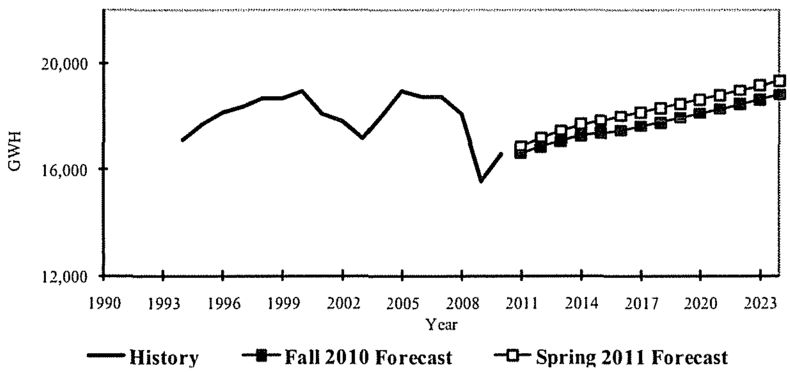
Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
2001	8,825	-1,989	-18.4			
2002	8,443	-382	-4.3			
2003	7,562	-881	-10.4			
2004	7,147	-415	-5.5			
2005	6,561	-586	-8.2			
2006	5,791	-770	-11.7	History (2005 to 2010)	-512	-9.4
2007	5,224	-567	-9.8	History (1995 to 2010)	-543	-7.1
2008	4,524	-700	-13.4			
2009	3,616	-908	-20.1	Spring 2011 Forecast (2010 to 2026)	-35	-0.9
2010	4,003	387	10.7	Fall 2010 Forecast (2010 to 2026)	-64	-1.8

SPRING 2011 FORECAST **Fall 2010 FORECAST**

Year	GWH	Growth GWH	Growth %	GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	4,134	131	3.3	3,872	261	6.8	-130
2012	4,159	25	0.6	3,788	371	9.8	-84
2013	4,125	-33	-0.8	3,723	403	10.8	-66
2014	4,068	-57	-1.4	3,656	412	11.3	-66
2015	4,011	-57	-1.4	3,560	451	12.7	-96
2016	3,953	-57	-1.4	3,499	454	13.0	-60
2017	3,900	-54	-1.4	3,445	455	13.2	-55
2018	3,845	-54	-1.4	3,390	455	13.4	-55
2019	3,790	-55	-1.4	3,339	451	13.5	-51
2020	3,739	-51	-1.3	3,286	453	13.8	-53
2021	3,689	-51	-1.4	3,235	453	14.0	-51
2022	3,638	-51	-1.4	3,184	454	14.2	-51
2023	3,588	-50	-1.4	3,131	457	14.6	-53
2024	3,539	-49	-1.4	3,078	460	15.0	-52
2025	3,491	-48	-1.4	3,028	463	15.3	-50
2026	3,445	-45	-1.3	2,979	466	15.7	-49

(Load Forecast Pg 13)

Other Industrial Billed Sales



HISTORY

Year	Actual GWH	Growth GWH	Growth %
2001	18,077	-880	-4.6
2002	17,816	-261	-1.4
2003	17,202	-614	-3.4
2004	18,063	861	5.0
2005	18,934	872	4.8
2006	18,744	-191	-1.0
2007	18,724	-20	-0.1
2008	18,110	-614	-3.3
2009	15,588	-2,522	-13.9
2010	16,616	1,028	6.6

AVERAGE ANNUAL GROWTH

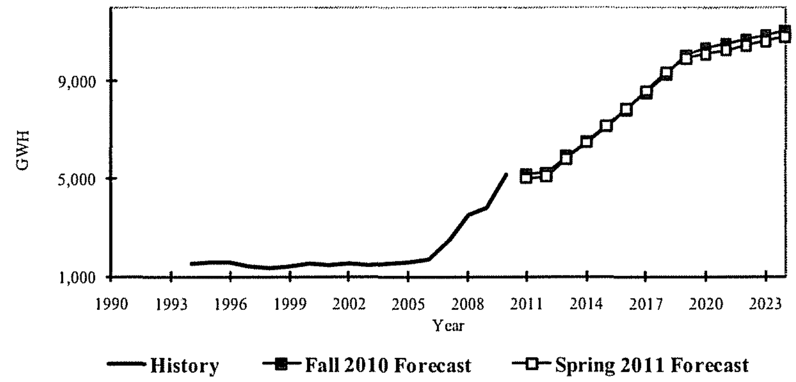
	GWH Per Year	% Per Year
History (2005 to 2010)	-464	-2.6
History (1995 to 2010)	-75	-0.4
Spring 2011 Forecast (2010 to 2026)	193	1.1
Fall 2010 Forecast (2010 to 2026)	160	0.9

SPRING 2011 FORECAST / **Fall 2010 FORECAST**

Year	GWH	Growth GWH	Growth %	GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	*Fall 2010* Growth Per Year
2011	16,893	277	1.7	16,643	250	1.5	27
2012	17,216	323	1.9	16,876	340	2.0	233
2013	17,474	259	1.5	17,090	385	2.3	214
2014	17,702	228	1.3	17,295	407	2.4	205
2015	17,860	158	0.9	17,384	476	2.7	89
2016	18,010	150	0.8	17,483	527	3.0	99
2017	18,159	150	0.8	17,637	522	3.0	154
2018	18,314	154	0.8	17,788	526	3.0	151
2019	18,473	159	0.9	17,955	518	2.9	167
2020	18,635	162	0.9	18,118	517	2.9	163
2021	18,805	169	0.9	18,289	515	2.8	171
2022	18,981	176	0.9	18,469	512	2.8	179
2023	19,160	180	0.9	18,646	515	2.8	177
2024	19,337	177	0.9	18,822	515	2.7	177
2025	19,510	173	0.9	18,997	514	2.7	174
2026	19,702	192	1.0	19,182	520	2.7	185

(Load Forecast Pg 14)

Full / Partial Requirements Wholesale Billed Sales [1]



HISTORY

Year	Actual GWH	Growth GWH	Growth %
2001	1,484	-16	-1.1
2002	1,530	47	3.1
2003	1,448	-82	-5.4
2004	1,542	93	6.4
2005	1,580	38	2.5
2006	1,694	114	7.2
2007	2,454	760	44.8
2008	3,525	1,072	43.7
2009	3,788	262	7.4
2010	5,166	1,379	36.4

AVERAGE ANNUAL GROWTH

	GWH Per Year	% Per Year
History (2005 to 2010)	717	26.7
History (1995 to 2010)	238	8.1
Spring 2011 Forecast (2010 to 2026)	377	5.0
Fall 2010 Forecast (2010 to 2026)	390	5.1

SPRING 2011 FORECAST / **Fall 2010 FORECAST**

Year	GWH	Growth GWH	Growth %	Fall 2010 GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	*Fall 2010* Growth Per Year
2011	5,027	-139	-2.7	5,172	-145	-2.8	6
2012	5,098	71	1.4	5,239	-141	-2.7	67
2013	5,829	731	14.3	5,917	-88	-1.5	678
2014	6,478	648	11.1	6,532	-55	-0.8	615
2015	7,157	679	10.5	7,194	-37	-0.5	662
2016	7,862	705	9.8	7,823	38	0.5	629
2017	8,592	730	9.3	8,518	74	0.9	694
2018	9,353	761	8.9	9,241	112	1.2	724
2019	9,932	579	6.2	10,037	-106	-1.1	796
2020	10,101	169	1.7	10,349	-248	-2.4	311
2021	10,268	168	1.7	10,517	-249	-2.4	168
2022	10,446	177	1.7	10,693	-247	-2.3	176
2023	10,628	182	1.7	10,868	-240	-2.2	175
2024	10,816	188	1.8	11,051	-235	-2.1	183
2025	11,002	186	1.7	11,224	-222	-2.0	173
2026	11,195	192	1.7	11,402	-208	-1.8	178

1 Schedule 10A Resale Sales does not include SEPA allocation.

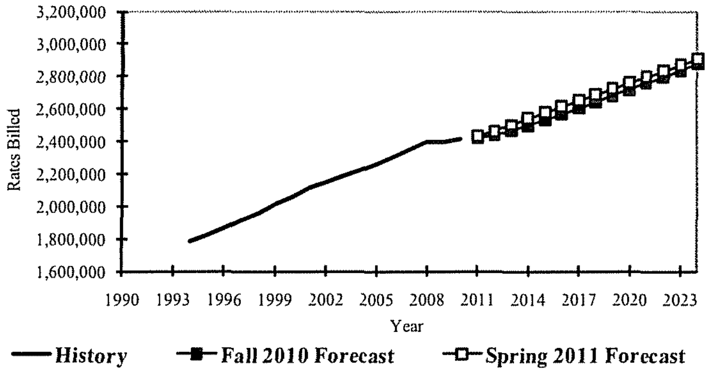
(Load Forecast Pg 15)

Number of Rates Billed

(Load Forecast Pg 16)

Total Rates Billed

(Sum of Major Retail Classes: Residential, Commercial and Industrial)



HISTORY | **AVERAGE ANNUAL GROWTH**

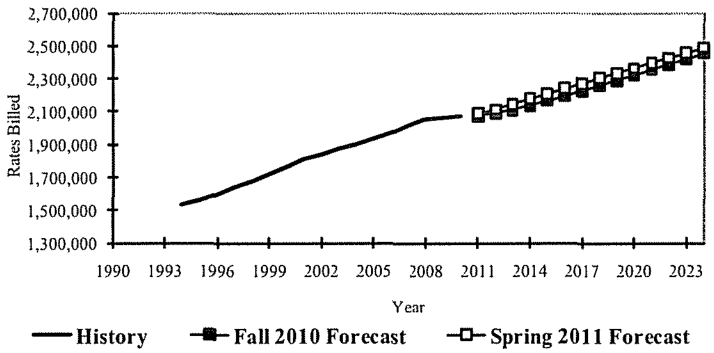
Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
2001	2,117,432	58,280	2.8			
2002	2,148,117	30,685	1.4			
2003	2,186,825	38,708	1.8			
2004	2,221,590	34,766	1.6			
2005	2,261,639	40,049	1.8			
2006	2,304,050	42,411	1.9	History (2005 to 2010)	30,289	1.3
2007	2,354,078	50,028	2.2	History (1995 to 2010)	39,573	1.9
2008	2,393,426	39,348	1.7			
2009	2,399,359	5,933	0.2	Spring 2011 Forecast (2010 to 2026)	35,490	1.3
2010	2,413,085	13,727	0.6	Fall 2010 Forecast (2010 to 2026)	34,098	1.3

SPRING 2011 FORECAST | **Fall 2010 FORECAST**

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	SPRING 2011 vs. FALL 2010 Rates Billed	%	Fall 2010 Growth Per Year
2011	2,432,796	19,711	0.8	2,419,493	13,303	0.5	6,408
2012	2,461,853	29,057	1.2	2,441,122	20,731	0.8	21,629
2013	2,500,751	38,899	1.6	2,467,355	33,396	1.4	26,233
2014	2,539,624	38,872	1.6	2,498,353	41,271	1.7	30,997
2015	2,577,453	37,829	1.5	2,532,562	44,891	1.8	34,210
2016	2,614,490	37,037	1.4	2,567,517	46,973	1.8	34,955
2017	2,651,397	36,907	1.4	2,605,027	46,370	1.8	37,510
2018	2,688,220	36,823	1.4	2,642,592	45,629	1.7	37,565
2019	2,724,824	36,604	1.4	2,680,067	44,757	1.7	37,475
2020	2,761,410	36,586	1.3	2,718,487	42,923	1.6	38,420
2021	2,798,003	36,593	1.3	2,757,932	40,070	1.5	39,445
2022	2,834,602	36,599	1.3	2,797,858	36,743	1.3	39,926
2023	2,871,206	36,604	1.3	2,837,010	34,196	1.2	39,151
2024	2,907,812	36,606	1.3	2,876,261	31,551	1.1	39,251
2025	2,944,418	36,606	1.3	2,917,108	27,310	0.9	40,847
2026	2,980,922	36,504	1.2	2,958,661	22,261	0.8	41,553

(Load Forecast Pg 17)

Residential Rates Billed



HISTORY / **AVERAGE ANNUAL GROWTH**

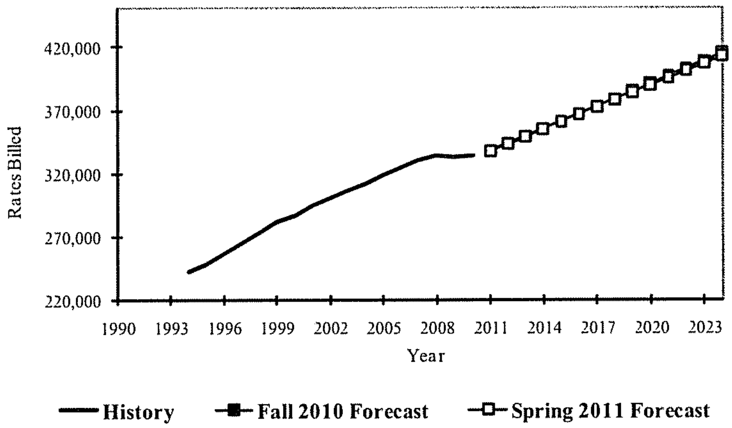
Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
2001	1,813,867	49,684	2.8			
2002	1,839,689	25,822	1.4			
2003	1,872,484	32,795	1.8			
2004	1,901,335	28,851	1.5			
2005	1,935,320	33,985	1.8			
2006	1,971,673	36,353	1.9	History (2005 to 2010)	27,311	1.4
2007	2,016,104	44,431	2.3	History (1995 to 2010)	33,990	1.9
2008	2,052,252	36,149	1.8			
2009	2,059,394	7,142	0.3	Spring 2011 Forecast (2010 to 2026)	29,890	1.3
2010	2,071,877	12,484	0.6	Fall 2010 Forecast (2010 to 2026)	28,311	1.2

SPRING 2011 FORECAST / **Fall 2010 FORECAST**

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	SPRING 2011 vs. FALL 2010 Rates Billed	%		Fall 2010 Growth Per Year
2011	2,087,805	15,928	0.8	2,074,790	13,016	0.6		2,913
2012	2,111,339	23,534	1.1	2,090,384	20,955	1.0	0.8%	15,594
2013	2,144,532	33,193	1.6	2,110,803	33,729	1.6	1.0%	20,419
2014	2,177,288	32,756	1.5	2,136,238	41,051	1.9	1.2%	25,434
2015	2,209,204	31,915	1.5	2,164,770	44,433	2.1	1.3%	28,533
2016	2,240,467	31,263	1.4	2,193,961	46,505	2.1	1.3%	29,191
2017	2,271,658	31,192	1.4	2,225,590	46,068	2.1	1.4%	31,628
2018	2,302,781	31,122	1.4	2,257,247	45,533	2.0	1.4%	31,658
2019	2,333,700	30,919	1.3	2,288,808	44,892	2.0	1.4%	31,560
2020	2,364,617	30,918	1.3	2,321,292	43,325	1.9	1.4%	32,484
2021	2,395,539	30,922	1.3	2,354,751	40,788	1.7	1.4%	33,459
2022	2,426,465	30,925	1.3	2,388,605	37,860	1.6	1.4%	33,854
2023	2,457,395	30,931	1.3	2,421,649	35,747	1.5	1.4%	33,044
2024	2,488,332	30,937	1.3	2,454,772	33,559	1.4	1.4%	33,124
2025	2,519,270	30,939	1.2	2,489,476	29,794	1.2	1.4%	34,704
2026	2,550,110	30,840	1.2	2,524,854	25,256	1.0	1.4%	35,378

(Load Forecast Pg 18)

Commercial Rates Billed



HISTORY / AVERAGE ANNUAL GROWTH

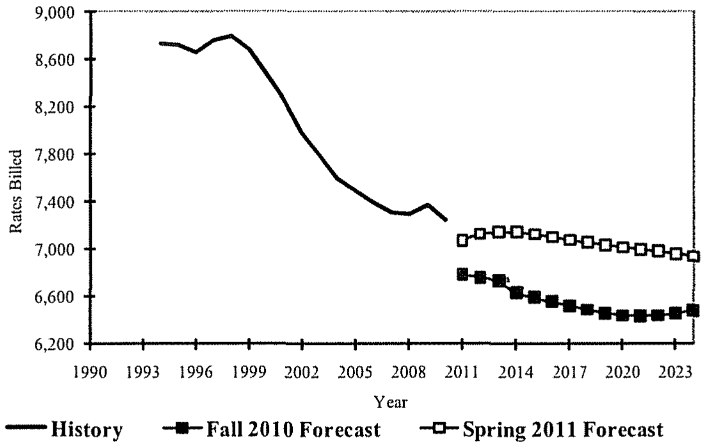
Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
2001	295,300	8,805	3.1			
2002	300,440	5,140	1.7			
2003	306,540	6,101	2.0			
2004	312,665	6,125	2.0			
2005	318,827	6,162	2.0			
2006	324,977	6,150	1.9	History (2005 to 2010)	3,027	0.9
2007	330,666	5,689	1.8	History (1995 to 2010)	5,681	2.0
2008	333,873	3,208	1.0			
2009	332,593	-1,280	-0.4	Spring 2011 Forecast (2010 to 2026)	5,622	1.5
2010	333,960	1,367	0.4	Fall 2010 Forecast (2010 to 2026)	5,831	1.6

SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	SPRING 2011 vs. FALL 2010 Rates Billed	%	Fall 2010 Growth Per Year
2011	337,918	3,958	1.2	337,920	-2	0.0	3,960
2012	343,384	5,466	1.6	343,977	-593	-0.2	6,057
2013	349,077	5,693	1.7	349,819	-742	-0.2	5,842
2014	355,189	6,112	1.8	355,484	-295	-0.1	5,666
2015	361,123	5,934	1.7	361,197	-73	0.0	5,713
2016	366,919	5,795	1.6	366,998	-80	0.0	5,801
2017	372,660	5,741	1.6	372,916	-256	-0.1	5,917
2018	378,382	5,722	1.5	378,856	-474	-0.1	5,941
2019	384,087	5,705	1.5	384,800	-713	-0.2	5,944
2020	389,777	5,690	1.5	390,755	-979	-0.3	5,955
2021	395,466	5,690	1.5	396,748	-1,281	-0.3	5,992
2022	401,157	5,690	1.4	402,814	-1,657	-0.4	6,066
2023	406,848	5,691	1.4	408,904	-2,057	-0.5	6,090
2024	412,539	5,692	1.4	415,002	-2,463	-0.6	6,098
2025	418,232	5,693	1.4	421,113	-2,881	-0.7	6,111
2026	423,917	5,685	1.4	427,255	-3,338	-0.8	6,142

(Load Forecast Pg 19)

Total Industrial Rates Billed *(Includes Textile and Other Industrial)*



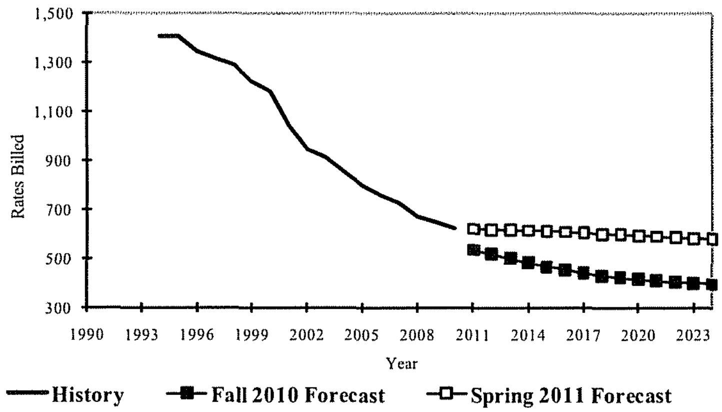
HISTORY / AVERAGE ANNUAL GROWTH

Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
2001	8,265	-210	-2.5			
2002	7,989	-276	-3.3			
2003	7,801	-188	-2.3			
2004	7,591	-210	-2.7			
2005	7,492	-99	-1.3			
2006	7,401	-91	-1.2	History (2005 to 2010)	-49	-0.7
2007	7,309	-92	-1.2	History (1995 to 2010)	-98	-1.2
2008	7,301	-8	-0.1			
2009	7,372	71	1.0	Spring 2011 Forecast (2010 to 2026)	-22	-0.3
2010	7,248	-124	-1.7	Fall 2010 Forecast (2010 to 2026)	-44	-0.6

SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	SPRING 2011 vs. FALL 2010 Rates Billed	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	7,073	-175	-2.4	6,783	289	4.3	-465
2012	7,130	57	0.8	6,761	368	5.4	-22
2013	7,143	13	0.2	6,733	409	6.1	-28
2014	7,146	3	0.0	6,631	515	7.8	-102
2015	7,126	-20	-0.3	6,595	531	8.0	-36
2016	7,104	-22	-0.3	6,557	547	8.3	-38
2017	7,079	-26	-0.4	6,522	557	8.5	-36
2018	7,057	-21	-0.3	6,488	569	8.8	-34
2019	7,037	-20	-0.3	6,459	578	8.9	-29
2020	7,016	-21	-0.3	6,440	576	8.9	-19
2021	6,997	-19	-0.3	6,434	564	8.8	-6
2022	6,981	-17	-0.2	6,440	541	8.4	6
2023	6,963	-18	-0.3	6,457	506	7.8	17
2024	6,941	-22	-0.3	6,486	455	7.0	29
2025	6,915	-26	-0.4	6,519	397	6.1	33
2026	6,894	-22	-0.3	6,551	343	5.2	32

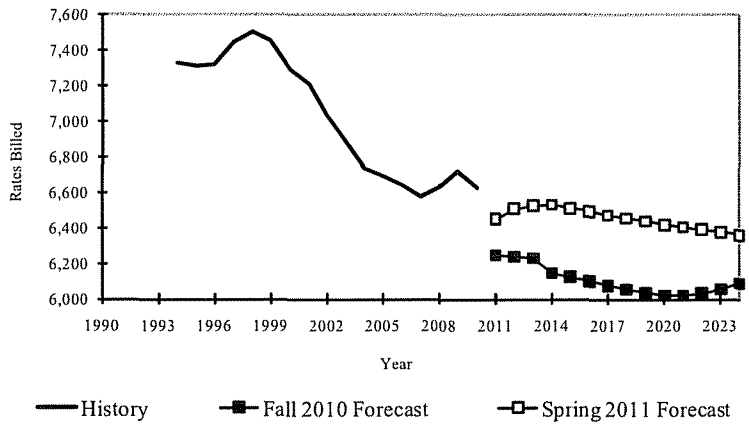
Textile Rates Billed



HISTORY				AVERAGE ANNUAL GROWTH		
Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
2001	1,052	-129	-10.9			
2002	949	-103	-9.8			
2003	914	-35	-3.6			
2004	857	-57	-6.2			
2005	802	-56	-6.5			
2006	757	-45	-5.6	History (2005 to 2010)	-36	-4.9
2007	728	-29	-3.8	History (1995 to 2010)	-52	-5.3
2008	675	-53	-7.3			
2009	649	-26	-3.9	Spring 2011 Forecast (2010 to 2026)	-3	-0.5
2010	622	-27	-4.2	Fall 2010 Forecast (2010 to 2026)	-14	-2.9

SPRING 2011 FORECAST				Fall 2010 FORECAST			
		Growth			SPRING 2011 vs. FALL 2010		Fall 2010 Growth
Year	Rates Billed	Rates Billed	%	Rates Billed	Rates Billed	%	Per Year
2011	623	1	0.1	536	86	16.1	-86
2012	621	-2	-0.3	522	99	19.0	-15
2013	618	-2	-0.4	503	115	22.8	-18
2014	616	-2	-0.4	485	131	27.1	-19
2015	613	-3	-0.5	469	144	30.7	-16
2016	609	-4	-0.6	455	154	33.8	-14
2017	606	-3	-0.6	443	163	36.8	-12
2018	602	-3	-0.6	432	170	39.3	-11
2019	599	-4	-0.6	424	175	41.4	-9
2020	595	-3	-0.6	417	178	42.7	-7
2021	592	-3	-0.6	412	180	43.8	-5
2022	588	-4	-0.6	407	182	44.7	-5
2023	585	-4	-0.7	402	183	45.5	-5
2024	581	-4	-0.7	398	182	45.8	-3
2025	576	-5	-0.8	395	181	45.9	-3
2026	573	-3	-0.6	391	182	46.5	-4

Other Industrial Rates Billed



HISTORY

Year	Actual Rates Billed	Growth Rates Billed	%
2001	7,213	-81	-1.1
2002	7,040	-173	-2.4
2003	6,887	-153	-2.2
2004	6,733	-154	-2.2
2005	6,690	-43	-0.6
2006	6,644	-47	-0.7
2007	6,581	-63	-0.9
2008	6,626	45	0.7
2009	6,723	97	1.5
2010	6,626	-97	-1.4

AVERAGE ANNUAL GROWTH

	Rates Billed Per Year	% Per Year
History (2005 to 2010)	-13	-0.2
History (1995 to 2010)	-46	-0.7
Spring 2011 Forecast (2010 to 2026)	-19	-0.3
Fall 2010 Forecast (2010 to 2026)	-29	-0.5

SPRING 2011 FORECAST | **Fall 2010 FORECAST**

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	SPRING 2011 vs. FALL 2010 Rates Billed	%	*Fall 2010* Growth Per Year
2011	6,450	-176	-2.7	6,247	203	3.2	-379
2012	6,509	59	0.9	6,240	269	4.3	-8
2013	6,524	15	0.2	6,230	294	4.7	-10
2014	6,530	6	0.1	6,146	384	6.2	-84
2015	6,513	-17	-0.3	6,126	387	6.3	-20
2016	6,495	-18	-0.3	6,102	393	6.4	-24
2017	6,473	-22	-0.3	6,079	394	6.5	-23
2018	6,455	-18	-0.3	6,056	399	6.6	-23
2019	6,438	-17	-0.3	6,036	403	6.7	-20
2020	6,420	-18	-0.3	6,023	398	6.6	-13
2021	6,405	-15	-0.2	6,022	383	6.4	-1
2022	6,392	-13	-0.2	6,033	359	5.9	11
2023	6,378	-14	-0.2	6,055	323	5.3	22
2024	6,360	-18	-0.3	6,088	273	4.5	32
2025	6,339	-21	-0.3	6,124	216	3.5	36
2026	6,321	-18	-0.3	6,160	161	2.6	36

System Peaks

(Load Forecast Pg 23)

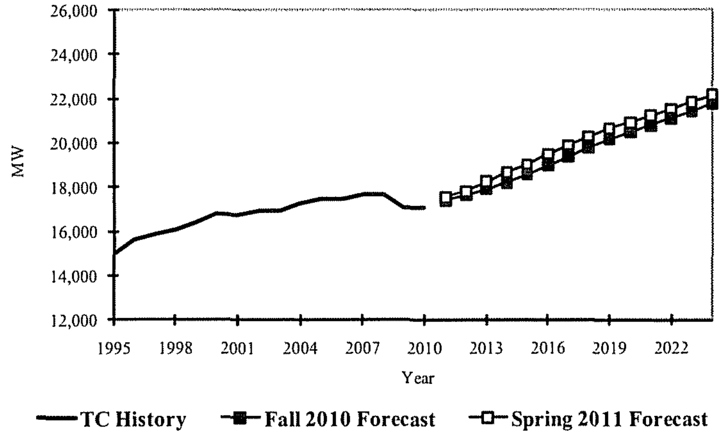
The Summer peak forecast represents the maximum coincidental demand during the summer season on the Duke Energy Carolinas system. It includes all Retail classes as well as wholesale customers to whom Duke provides full or partial service. It represents the Integrated Resource Plan load that Duke is obligated to serve. It is expressed in MW at the point of generation and includes losses.

Adjustments were made to the peak forecast associated with price increases due to a Carbon Tax starting in 2015 and peak additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011. Adjustments were also made to reflect the impacts of utility sponsored energy efficiency programs.

Growth Forecasts

The new forecast projects an incremental growth of 345 MW or 1.7% per year for 2011-2026. The previous forecast growth was 334 MW or 1.7% per year for 2011-2026.

System Summer MW (IRP Load)



HISTORY

Year	Weather Normalized MW	Growth MW	Growth %
2001	16,748	-79	-0.5
2002	16,919	171	1.0
2003	16,915	-4	0.0
2004	17,285	370	2.2
2005	17,497	212	1.2
2006	17,439	-58	-0.3
2007	17,698	259	1.5
2008	17,670	-28	-0.2
2009	17,100	-570	-3.2
2010	17,088	-12	-0.1

AVERAGE ANNUAL GROWTH

	MW Per Year	% Per Year
History (2005 to 2010)	-82	-0.5
History (1995 to 2010)	140	0.9
Spring 2011 Forecast (2010 to 2026)	353	1.8
Fall 2010 Forecast (2010 to 2026)	333	1.7

SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	MW	Growth MW	Growth %	Fall 2010 MW	SPRING 2011 vs. FALL 2010 MW	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	17,557	469	2.7	17,418	139	0.8	330
2012	17,812	255	1.5	17,659	153	0.9	241
2013	18,245	433	2.4	17,893	352	2.0	234
2014	18,680	435	2.4	18,216	464	2.5	323
2015	19,032	352	1.9	18,582	450	2.4	366
2016	19,476	444	2.3	18,983	493	2.6	401
2017	19,877	401	2.1	19,372	505	2.6	389
2018	20,265	388	2.0	19,790	475	2.4	418
2019	20,644	379	1.9	20,172	472	2.3	382
2020	20,901	257	1.2	20,498	403	2.0	326
2021	21,214	313	1.5	20,788	426	2.0	290
2022	21,530	316	1.5	21,101	429	2.0	313
2023	21,836	306	1.4	21,425	411	1.9	324
2024	22,135	299	1.4	21,759	376	1.7	334
2025	22,465	330	1.5	22,085	380	1.7	326
2026	22,733	268	1.2	22,423	310	1.4	338

(Load Forecast Pg 25)

Winter Peak

The Summer peak forecast represents the maximum coincidental demand during the summer season on the Duke Energy Carolinas system. It includes all Retail classes as well as wholesale customers to whom Duke provides full or partial service. It represents the Integrated Resource Plan load that Duke is obligated to serve. It is expressed in MW at the point of generation and includes losses.

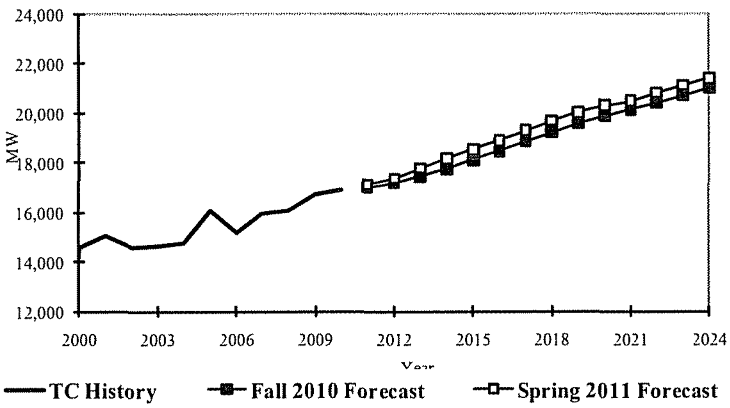
Adjustments were made to the peak forecast associated with price increases due to a Carbon Tax starting in 2015 and peak additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011. Adjustments were also made to reflect the impacts of utility sponsored energy efficiency programs.

Growth Forecasts

The new Forecast projects an incremental growth of 323 MW or 1.7% per year from 2011-2026. The previous forecast growth was 308 MW or 1.6% per year from 2011-2026.

(Load Forecast Pg 26)

System Winter MW



HISTORY

Year	Weather Normalized MW	Growth MW	Growth %
2001	15,071	486	3.3
2002	14,565	-506	-3.4
2003	14,626	61	0.4
2004	14,770	144	1.0
2005	16,054	1,285	8.7
2006	15,193	-861	-5.4
2007	15,936	742	4.9
2008	16,065	130	0.8
2009	16,723	657	4.1
2010	16,893	170	1.0

AVERAGE ANNUAL GROWTH

	MW Per Year	% Per Year
History (2005 to 2010)	168	1.0
History (2000 to 2010)	231	1.5
Spring 2011 Forecast (2010 to 2026)	316	1.7
Fall 2010 Forecast (2010 to 2026)	296	1.6

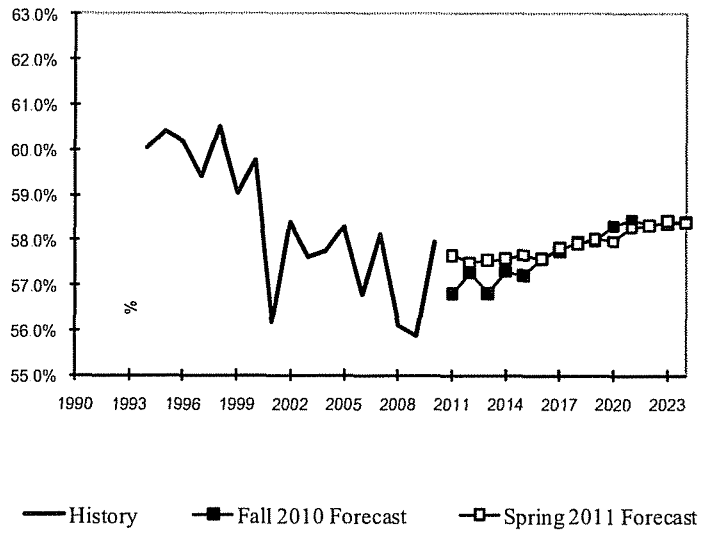
SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	MW	Growth MW	Growth %	Fall 2010 MW	SPRING 2011 vs. FALL 2010 MW	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	17,115	222	1.3	17,004	111	0.7	111
2012	17,359	243	1.4	17,204	155	0.9	200
2013	17,773	414	2.4	17,455	318	1.8	251
2014	18,177	404	2.3	17,767	410	2.3	312
2015	18,543	366	2.0	18,111	432	2.4	344
2016	18,891	348	1.9	18,485	406	2.2	374
2017	19,305	414	2.2	18,848	457	2.4	363
2018	19,694	388	2.0	19,234	460	2.4	386
2019	20,042	348	1.8	19,582	460	2.4	348
2020	20,304	262	1.3	19,873	431	2.2	291
2021	20,492	188	0.9	20,150	342	1.7	277
2022	20,835	343	1.7	20,434	401	2.0	284
2023	21,124	288	1.4	20,729	395	1.9	295
2024	21,412	288	1.4	21,028	384	1.8	299
2025	21,697	285	1.3	21,326	371	1.7	298
2026	21,956	259	1.2	21,631	325	1.5	305

(Load Forecast Pg 27)

The system load factor represents the relationship between annual energy and the maximum demand for the Duke Energy Carolinas' system. It is measured at generation level and excludes off-system sales and peaks.

Load Factor



(Load Forecast Pg 28)

APPENDIX C: SUPPLY-SIDE SCREENING

The following sets of estimated Levelized Busbar Cost[6] charts provide an economic comparison of the technologies in their respective categories. Busbar charts comparisons involving some renewable resources, particularly wind and solar resources, can be somewhat misleading because these resources do not contribute their full installed capacity at the time of the system peak[7]. Since busbar charts attempt to levelize and compare costs on an installed kW basis, wind and solar resources appear to be more economic than they would be if the comparison was performed on a peak kW basis. The Renewables Busbar Chart shows a single point for each type of resource at the particular capacity factor specified. Also, the capacity (MW size) of the Baseload and Peak/Intermediate technology categories are listed in the chart legends, and tabular listings below. The expected energy (MWh) at any given capacity factor (whether along a continuous line, or a specific point) may be determined by the following formula: Expected Energy (MWh) = 8,760 x Capacity (MW size) x Capacity Factor (%/100).

Busbar Charts by Technology Category – Base 2011 Fundamentals Carbon Scenario

Baseload

The following technologies are found on the baseload technologies screening chart:

1) 2 x 1,117 MW Nuclear
2) 800 MW Supercritical Coal
3) 800 MW Supercritical Coal with Carbon Capture and Storage at 90%
4) 630 MW IGCC Coal
5) 630 MW IGCC with Carbon Capture and Storage at 90%

[6] While these estimated levelized busbar costs provide a reasonable basis for initial screening of technologies, simple busbar cost information has limitations. In isolation, busbar cost information has limited applicability in decision-making because it is highly dependent on the circumstances being considered. A complete analysis of feasible technologies must include consideration of the interdependence of the technologies within the context of Duke Energy Carolinas' existing generation portfolio.

[7] For purposes of this IRP, wind resources are assumed to contribute 15% of installed capacity at the time of peak and solar resources are assumed to contribute 50% of installed capacity at the time of peak.

C O N F I D E N T I A L

Baseload Technologies Screening 2011-2031

[redacted]

2 x 1117 MW Nuclear w/o Sunk Costs (AP1000) | 600 MW Supercritical Coal Greenfield | 630 MW Class IGCC Greenfield
630 MW w/CCS 90% IGCC | 800 MW w/CCS 90% SCPC

New un-sequestered coal generation is the lowest cost baseload option. However, baseload coal was not considered in the detailed portfolio evaluation due to EPA's pursuit of GHG regulation on new and existing coal units.

Nuclear becomes economic compared to IGCC at about 60% capacity factor. It is important to note that the capital and operating costs for carbon capture technology are still the subjects of ongoing industry studies and research, along with the feasibility and costs of geological sequestration of CO_2 once it is captured. The sequestration geology is not favorable in the Carolinas.

Intermediate and Peaking

The following technologies are found on the peak/intermediate technologies screening chart:

1) 4x204 MW Simple-Cycle CT
2) 460 MW Unfired + 150 MW Duct Fired + 40 MW Inlet Evaporative Cooler Combined Cycle (650MW total)
3) 460 MW Unfired + 40 MW Inlet Evaporative Cooler Combined Cycle (500 MW total)

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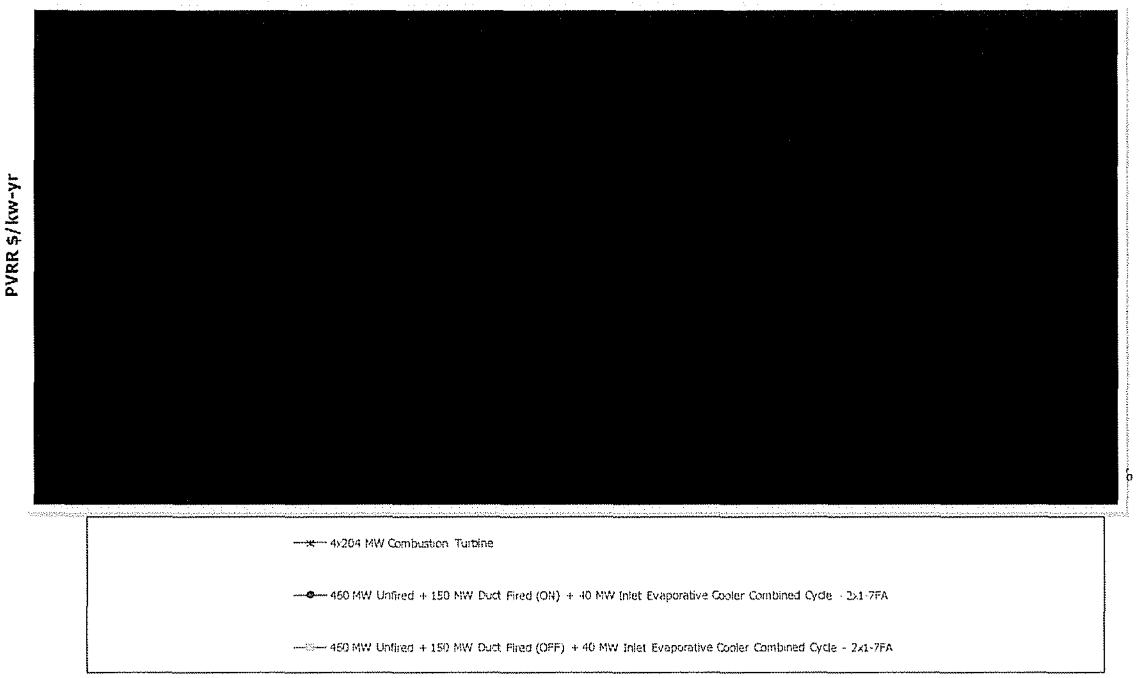
Peak / Intermediate Technologies Screening 2011-2031



The simple-cycle CT unit makes up the lower envelope of the curves up to about 35% capacity factor, where the unfired option is the most economic over the rest of the capacity factor range.

Duct firing in a CC unit is a process to introduce more fuel (heat) directly into the combustion turbine exhaust (waste heat) stream, by way of a duct burner, to increase the temperature of the exhaust gases entering the Heat Recovery Steam Generator (HRSG). This additional heat allows the production of additional steam to produce more electricity in the steam (bottoming) cycle of a CC unit. It is a low cost ($/kW installed cost) way to increase power (MW) output during times of very high electrical demands and/or system emergencies. However, it adversely impacts the efficiency (raises the heat rate) and thereby dramatically increases the operating cost of a CC unit (notice the much steeper slope of the duct firing "On" cases in the screening curve charts). Duct firing also increases emissions, generally resulting in a very limited number of hours per year that duct firing is allowed within operating permits.

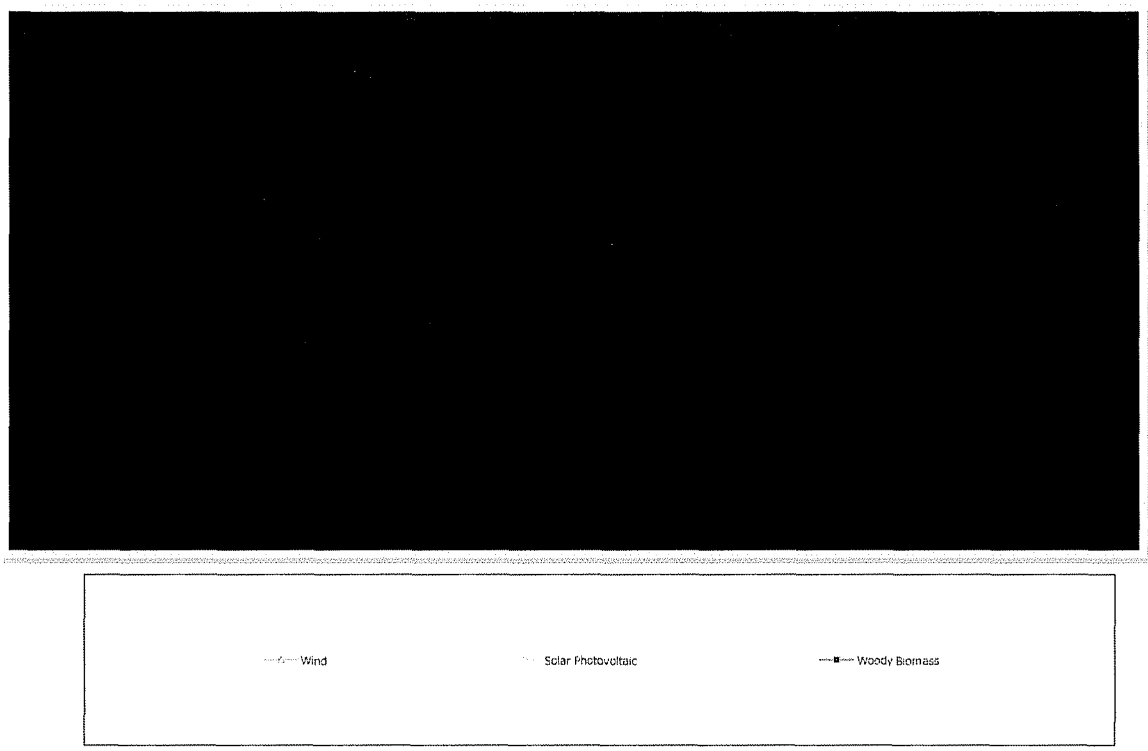
Within the screening curves, the estimated capital cost for a combined cycle unit always includes the duct burner and related equipment. The two curves, one "On," and one "Off," are intended to show the efficiency loss (steeper slope) when the duct burner is "On", but also show that even with the duct burner "On" the efficiency (slope) is still better than a simple-cycle CT unit (much steeper slope). The duct burner "Off" curve is where the combined cycle unit will operate most of the time, and this is the one best compared with all other candidate technologies

Renewables

The following technologies are found on the renewable technologies screening chart:

1) 150 MW Wind
2) 25 MW Solar Photovoltaic
3) 100 MW Woody Biomass

[redacted]



One must remember that busbar charts comparisons involving some renewable resources, particularly wind and solar resources can be somewhat misleading because these resources do not contribute their full installed capacity at the time of the system peak[8]. Since busbar charts attempt to levelize and compare costs on an installed kW basis, wind and solar resources appear to be more economic than they would be if the comparison was performed on a peak kW basis.

Since these renewable technologies either have no CO_2 emissions or are deemed to be carbon neutral, the cost of CO_2 emissions does not impact their operating cost. Wind appears to be the least cost renewable alternative through its maximum practical capacity

[8] For purposes of this IRP, wind resources are assumed to contribute 15% of installed capacity at the time of peak and solar resources are assumed to contribute 50% of installed capacity at the time of peak.

factor range. Woody biomass is next throughout its entire capacity range. The Solar Photovoltaic is the most costly renewable within the renewable category.

APPENDIX D: DEMAND SIDE MANAGEMENT ACTIVATION HISTORY

DEMAND-SIDE MANAGEMENT ACTIVATION HISTORY

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
09/10-06/11	Air Conditioners	Economic Event	113 MW	Verifying	06/21/2011
	Standby Generator	Emergency Event	48 MW	54 MW	06/01/2011
		Monthly Tests			
	Interruptible Service	Emergency Event	145 MW	147 MW	06/01/2011
		Communication Test	N/A	N/A	05/12/2011
	PowerShare Generator	Emergency Event	11 MW	8 MW	06/01/2011
	PowerShare Mandatory	Emergency Event	280 MW	325 MW	06/01/2011
	PowerShare Voluntary	Economic Event	N/A	14 MW	12/15/2010
		Economic Event	N/A	1 MW	06/01/2011
		Economic Event	N/A	16 MW	06/02/2011
	PowerShare CallOption	Economic Event	0.2 MW	0.2 MW	12/14/2010
		Economic Event	0.2 MW	0.2 MW	12/15/2010
		Economic Event	0.2 MW	0.2 MW	01/13/2011
9/09 – 9/10*	Air Conditioners	Economic Event	46 MW**	50 MW	6/14/2010
		Economic Event	50 MW	45 MW	6/15/2010
		Economic Event	103 MW**	102 MW	6/23/2010
		Economic Event	90 MW	81 MW	07/07/2010
		Economic Event	90 MW	87 MW	07/08/2010
		Economic Event	99 MW	103 MW	07/22/2010
		Economic Event	114 MW	114 MW	07/23/2010
		Economic Event	107 MW	107 MW	08/05/2010
	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	6/8/2010
	PowerShare Voluntary	Economic Event	N/A	13 MW	6/15/2010
		Economic Event	N/A	17 MW	6/23/2010
		Economic Event	N/A	9 MW	7/7/2010
		Economic Event	N/A	7 MW	7/8/2010
		Economic Event	N/A	7 MW	7/23/2010
		Economic Event	N/A	28 MW	7/29/2010
		Economic Event	N/A	5 MW	8/4/2010
		Economic Event	N/A	7 MW	8/5/2010
	PowerShareCallOption	Economic Event	0.2 MW	0.2 MW	07/07/2010
		Economic Event	0.2 MW	0.2 MW	07/08/2010
		Economic Event	0.2 MW	0.2 MW	08/05/2010
9/08 -9/09	Air Conditioners	Cycling Event		30 MW	8/10/2009
		SOC Full Shed Test	N/A	N/A	8/11/2009
	Water Heaters				
	Standby Generators				
	Interruptible Service	Communication Test	N/A	N/A	5/6/2009

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
9/07 – 9/08	Air Conditioners				
	Water Heaters				
	Standby Generators				
	Interruptible Service	Communication Test	N/A	N/A	5/6/2008
8/06 – 8/07	Air Conditioners	Cycling Test	N/A	N/A	8/30/2007
		Load Test (PLC only)	N/A	N/A	8/7/2007
		Load Test	120 MW	88 MW	8/2/2007
	Water Heaters	Cycling Test	N/A	N/A	8/30/2007
		Load Test (PLC only)	N/A	N/A	8/7/2007
		Load Test	2 MW	Included in Air Conditioners.	8/2/2007
	Standby Generators	Capacity Need	82 MW	88 MW	8/10/2007
		Capacity Need	82 MW	90 MW	8/9/2007
		Capacity Need	82 MW	79 MW	8/8/2007
		Capacity Need	82 MW	85 MW	8/1/2006
		Monthly Test			
	Interruptible Service	Capacity Need	306 MW	301 MW	8/10/2007
		Capacity Need	306 MW	323 MW	8/9/2007
		Capacity Need	341 MW	391 MW	8/1/2006
		Communication Test	N/A	N/A	4/24/2007
8/05 – 7/06	Air Conditioners	Load Test	110 MW	107 MW	6/21/2006
		Cycling Test	N/A	N/A	9/21/2005
		Cycling Test	N/A	N/A	9/20/2005
	Water Heaters	Load Test	2 MW	Included in Air Conditioners.	6/21/2006
		Cycling Test	N/A	N/A	9/21/2005
		Cycling Test	N/A	N/A	9/20/2005
	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	4/25/2006
8/04 – 7/05	Air Conditioners	Load Test	140 MW	148 MW	7/21/2005
		Cycling Test	N/A	N/A	8/19/2004
		Cycling Test	N/A	N/A	8/18/2004
	Water Heaters	Load Test	2 MW	Included in Air Conditioners.	7/21/2005
		Cycling Test	N/A	N/A	8/19/2004
		Cycling Test	N/A	N/A	8/18/2004
	Standby Generators	Monthly Test			
8/03 – 7/04	Air Conditioners	Load Test	110 MW	170 MW	7/14/2004
		Cycling Test	N/A	N/A	8/20/2003
	Water Heaters	Cycling Test	N/A	N/A	8/20/2003
	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	4/28/2004

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
8/02 – 7/03	Air Conditioners	Load Test	120 MW	195 MW	7/16/2003
		Cycling Test	N/A	N/A	6/18/2003
		Cycling Test	N/A	N/A	9/18/2002
		Load Test	82 MW	122 MW	8/21/2002
	Water Heaters	Load Test	5 MW	Included in Air Conditioners.	7/16/2003
		Cycling Test	N/A	N/A	6/18/2003
		Cycling Test	N/A	N/A	9/18/2002
		Load Test	6 MW	Included in Air Conditioners.	8/21/2002
	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	5/7/2003
		Communication Test	N/A	N/A	11/19/2002
8/01 – 7/02	Air Conditioners	Cycling Test	N/A	N/A	7/17/2002
		Cycling Test	N/A	N/A	6/19/2002
		Cycling Test	N/A	N/A	8/31/2001
		Load Test	150 MW	151 MW	8/17/2001
	Water Heaters	Cycling Test	N/A	N/A	7/17/2002
		Cycling Test	N/A	N/A	6/19/2002
		Cycling Test	N/A	N/A	8/31/2001
		Load Test	6 MW	Included in Air Conditioners.	8/17/2001
	Standby Generators	Capacity Need	80 MW	20 MW Estimation due to communication problems.	6/13/2002
		Monthly Test			
	Interruptible Service	Capacity Need	403 MW	370 MW	6/13/2002
		Communication Test	N/A	N/A	4/17/2002
8/00 – 7/01	Air Conditioners	Communication Test	N/A	N/A	9/14/2000
	Water Heaters	Communication Test	N/A	N/A	9/14/2000
	Standby Generators	Capacity Need	70 MW	70 MW	8/7/2000
		Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	5/8/2001
7/99 – 8/00	Air Conditioners	Load Test	170-200 MW	175-200 MW	6/15/2000
	Water Heaters	Load Test	6 MW	Included in Air Conditioners.	6/15/2000
	Standby Generators	Capacity Need	70 MW	70 MW	7/2/2000
		Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	5/17/2000
		Communication Test	N/A	N/A	10/20/1999

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
9/98 – 7/99	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	5/11/1999
		Communication Test	N/A	N/A	10/27/1998
9/97 – 9/98	Air Conditioners	Load Test	180 MW	170 MW	8/18/1998
	Water Heaters	Load Test	7 MW	7 MW	8/18/1998
		Communication Test	N/A	N/A	5/29/1998
	Standby Generators	Capacity Need	68 MW	58 MW	8/31/1998
		Capacity Need	68 MW	58 MW	6/12/1998
		Monthly Test			
	Interruptible Service	Capacity Need	570 MW	500 MW	8/31/1998
		Communication Test	N/A	N/A	5/29/1998
9/96 – 9/97	Air Conditioners	Communication Test	N/A	N/A	6/17/1997
	Standby Generators	Capacity Need	62 MW	50 MW	7/28/1997
		Capacity Need	62 MW	50 MW	7/15/1997
		Capacity Need	62 MW	50 MW	7/14/1997
		Capacity Need	62 MW	50 MW	12/20/1996
		Monthly Test			
	Interruptible Service	Capacity Need	650 MW	550 MW	7/28/1997
		Communication Tests	N/A	N/A	6/17/1997
		Communication Tests	N/A	N/A	10/16/1996

*Starting in 2010, a new category of event called an Economic Event has been added to the table.
**Corrected numbers from previous table filed.

APPENDIX E: PROPOSED GENERATING UNITS AT LOCATIONS NOT KNOWN

A list of proposed generating units at locations not known with capacity, plant type, and date of operation included to the extent known:

Line 12 of the LCR Table for Duke Energy Carolinas identifies cumulative future resource additions needed to meet customer load reliably. Resource additions may be a combination of short/long-term capacity purchases from the wholesale market, capacity purchase options, and building or contracting of new generation

APPENDIX F: TRANSMISSION LINES AND OTHER ASSOCIATED FACILITIES PLANNED OR UNDER CONSTRUCTION

There are no significant planned construction projects on the Duke Energy Carolinas' transmission system.

In addition, NCUC Rule R8-62(p) requires the following information.

1. For existing lines, the information required on FERC Form 1, pages 422, 423, 424 and 425: (Please see Appendix J for Duke Energy Carolinas' current FERC Form 1 pages 422, 423, 422.1, 423.1, 422.2, 423.2, 423.3, 424, 425, and 450.1.)

2. For lines under construction:
    - Commission docket number
    - Location of end point(s)
    - Length
    - Range of right-of-way width
    - Range of tower heights
    - Number of circuits
    - Operating voltage
    - Design capacity
    - Date construction started
    - Projected in-service date

3. For all other proposed lines, as the information becomes available:

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	07/25/2011	End of 2010/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	Antioch Tie	Appalachian Power	525.00	525.00	Tower	27.57		1
2	Jocassee Tie	Bad Creek Hydro	525.00	525.00	Tower	9.25		1
3	Jocassee Tie	McGuire Switching	525.00	525.00	Tower	119.86		1
4	McGuire Switching	Antioch Tie	525.00	525.00	Tower	54.40		1
5	McGuire Switching	Woodleaf Switching	525.00	525.00	Tower	29.96		1
6	Newport Tie	Progress Energy Rockingham	525.00	525.00	Tower	48.62		1
7	Newport Tie	McGuire Switching	525.00	525.00	Tower & Pole	32.34		1
8	Oconee Nuclear	Newport Tie	525.00	525.00	Tower	108.12		1
9	Oconee Nuclear	South Hall	525.00	525.00	Tower & Pole	22.50		1
10	Oconee Nuclear	Jocassee Tie	525.00	525.00	Tower	20.90		1
11	Pleasant Garden Tie	Parkwood Tie	525.00	525.00	Tower	48.65		1
12	Woodleaf Switching	Pleasant Garden Tie	525.00	525.00	Tower	52.07		1
13								
14	TOTAL 525 KV LINES					576.27		12
15								
16	Allen Steam	Catawba Nuclear	230.00	230.00	Tower	10.88		2
17	Allen Steam	Riverbend Steam	230.00	230.00	Tower	12.49		2
18	Allen Steam	Winecoff Tie	230.00	230.00	Tower	32.22		2
19	Allen Steam	Woodlawn Tie	230.00	230.00	Tower & Pole	8.63		2
20	Anderson Tie	Hodges Tie	230.00	230.00	Tower	25.79		2
21	Antioch Tie	Wilkes Tie	230.00	230.00	Tower	4.39		2
22	Beckerdite Tie	Belews Creek Steam	230.00	230.00	Tower	24.60		2
23	Beckerdite Tie	Pleasant Garden Tie	230.00	230.00	Tower	28.46		2
24	Belews Creek Steam	Ernest Switching Station	230.00	230.00	Tower	13.71		2
25	Belews Creek Steam	North Greensboro Tie	230.00	230.00	Tower	21.65		2
26	Belews Creek Steam	Pleasant Garden Tie	230.00	230.00	Tower & Pole	38.72		2
27	Belews Creek Steam	Rural Hall Tie	230.00	230.00	Tower	18.32		2
28	Bobwhite Switching	North Greensboro Tie	230.00	230.00	Tower	3.83		2
29	Buck Tie	Beckerdite Tie	230.00	230.00	Tower	23.63		2
30	Catawba Nuclear	Newport Tie	230.00	230.00	Tower & Pole	10.36		2
31	Catawba Nuclear	Pacolet Tie	230.00	230.00	Tower	41.25		2
32	Catawba Nuclear	Peacock Tie	230.00	230.00	Tower	14.88		2
33	Catawba Nuclear	Ripp Switching Station	230.00	230.00	Tower	24.44		2
34	Central Tie	Anderson Tie	230.00	230.00	Tower	22.12		2
35	Cliffside Steam	Pacolet Tie	230.00	230.00	Tower	23.01		2
36					TOTAL	8,259.59		162

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	07/20/2011	End of 2010/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Cliffside Steam	Shelby Tie	230.00	230.00	Tower	14.16		2
2	Cowans Ford Hydro	McGuire Switching	230.00	230.00	Tower	1.57		2
3	East Durham Tie	Parkwood Tie	230.00	230.00	Tower	19.25		2
4	Eno Tap Bent	Progress Energy (Roxboro)	230.00	230.00	Tower	13.74		2
5	Eno Tap Bent	East Durham Tie	230.00	230.00	Tower	15.76		2
6	Ernest Switching Station	Sadler Tie	230.00	230.00	Tower	12.61		2
7	Harrisburg Tie	Oakboro Tie	230.00	230.00	Tower	21.52		2
8	Hartwell Hydro	Anderson Tie	230.00	230.00	Tower	11.16		2
9	Jocassee Switching	Shiloh Switching	230.00	230.00	Tower	22.53		2
10	Jocassee Switching	Tuckasegee Tie	230.00	230.00	Tower	26.62		2
11	Lakewood Tie	Riverbend Steam	230.00	230.00	Tower	10.64		2
12	Lincoln CT	Longview Tie	230.00	230.00	Tower	30.95		2
13	Longview Tie	McDowell Tie	230.00	230.00	Tower	31.93		2
14	Marshall Steam	Beckerdite Tie	230.00	230.00	Tower	52.61		2
15	Marshall Steam	Longview Tie	230.00	230.00	Tower	29.04		2
16	Marshall Steam	McGuire Switching	230.00	230.00	Tower	13.75		2
17	Marshall Steam	Stamey Tie	230.00	230.00	Tower	13.44		2
18	Marshall Steam	Winecoff Tie	230.00	230.00	Tower	24.35		2
19	McGuire Switching	Harrisburg Tie	230.00	230.00	Tower	36.27		2
20	Mitchell River Tie	Antioch Tie	230.00	230.00	Tower & Pole	10.90		2
21	Mitchell River Tie	Rural Hall Tie	230.00	230.00	Tower	26.85		2
22	Morningstar Tie	Oakboro Tie	230.00	230.00	Tower	32.55		1
23	North Greenville Tie	Central Tie	230.00	230.00	Tower & Pole	26.22		2
24	North Greenville Tie	Shiloh Switching	230.00	230.00	Tower	8.95		2
25	Newport Tie	Morningstar Tie	230.00	230.00	Tower & Pole	33.59		1
26	Newport Tie	SCE&G (Parr)	230.00	230.00	Tower	45.36		1
27	Oakboro Tie	Progress Energy Rockingham	230.00	230.00	Tower	5.13		2
28	Oconee Nuclear	Central Tie	230.00	230.00	Tower	17.82		2
29	Oconee Nuclear	Jocassee Switching	230.00	230.00	Tower & Pole	12.26		2
30	Oconee Nuclear	North Greenville Tie	230.00	230.00	Tower & Pole	29.25		2
31	Pacolet Tie	Tiger Tie	230.00	230.00	Tower	27.93		2
32	Peach Valley Tie	Tiger Tie	230.00	230.00	Tower	15.69		2
33	Pisgah Tie	Progress Energy Skyland Stm	230.00	230.00	Tower	14.41		2
34	Pleasant GardenTie	Eno Tie	230.00	230.00	Tower	42.85		2
35	Ripp Switching	Riverview Switching	230.00	230.00	Tower	9.70		2
36					TOTAL	8,259.59		162

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	07/20/2011	End of 2010/Q4

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Ripp Switching	Shelby Tie	230.00	230.00	Tower	9.95		2
2	Riverbend Steam	Lincoln CT	230.00	230.00	Tower & Pole	11.59		2
3	Riverbend Steam	McGuire Switching	230.00	230.00	Tower	5.61		2
4	Riverbend Steam	Ripp Switching	230.00	230.00	Tower	30.12		2
5	Riverview Switching	Peach Valley Tie	230.00	230.00	Tower	19.33		2
6	SCE&G (Parr)	Bush River Tie	230.00	230.00	Tower	17.63		1
7	Shady Grove Tap	Shady Grove Tie	230.00	230.00	Tower	7.80		2
8	Shiloh Switching	Pisgah Tie	230.00	230.00	Tower	31.83		2
9	Shiloh Switching	Tiger Tie	230.00	230.00	Tower	21.46		2
10	Stamey Tie	Mitchell River Tie	230.00	230.00	Tower	35.93		2
11	Tiger Tie	North Greenville Tie	230.00	230.00	Tower	18.36		2
12	Winecoff Tie	Buck Tie	230.00	230.00	Tower	24.05		2
13								
14	TOTAL 230 KV LINES					1,395.31		130
15								
16	Nantahala Hydro	Webster Tie	161.00	161.00	Tower	12.69		1
17	Nantahala Tie	Marble Tie	161.00	161.00	Tower	16.55		2
18	Nantahala Hydro	Santeetlah Plt Robbinsville	161.00	161.00	Tower	16.88		2
19	Tuckaseegee Tie	West Mill Tie	161.00	161.00	Tower & Pole	10.43		2
20	Tuckasegee Tie	Thorpe Hydro	161.00	161.00	Tower & Pole	3.25		1
21	Wesbter Tie	Lake Emory S. S.	161.00	161.00	Tower	11.33		1
22	West Mill Tie	Lake Emory S. S.	161.00	161.00	Tower	6.78		1
23	West Mill Tie	Nantahala Tie	161.00	161.00	Tower	13.08		1
24	West Mill Tie	East Bryson	161.00	161.00	Tower & Pole	13.30		3
25								
26	TOTAL 161 KV LINES					107.15		14
27								
28	Dan River Steam	Appalachian Power	138.00	138.00	Tower & Pole	6.54		1
29	115 KV Lines		115.00	115.00	Tower & Pole	54.88		1
30	100 KV Lines		100.00	100.00	Tower	2,884.35		
31	100 KV Lines		100.00	100.00	Pole	640.25		
32	100 KV Lines		100.00	100.00	Underground	2.08		
33								
34	TOTAL 100 - 138 KV LINES					3,588.10		2
35								
36					TOTAL	5,259.59		182

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	66 KV Lines		66.00	66.00	Pole	104.88		1
2								
3	TOTAL 66 KV LINES					104.88		1
4								
5	44 KV Lines		44.00	44.00	Tower	183.29		
6	44 KV Lines		44.00	44.00	Pole	2,178.66		
7	44 KV Lines		44.00	44.00	Underground	0.34		1
8								
9	TOTAL 44 KV LINES					2,362.29		1
10								
11	33 KV Lines		33.00	33.00	Pole	14.65		
12	24 KV Lines		24.00	24.00	Pole	84.54		
13	24 KV Lines		24.00	24.00	Underground	0.44		1
14	12 KV Lines		12.00	12.00	Tower & Pole	25.67		
15	12 KV Lines		12.00	12.00	Underground	0.22		1
16								
17	TOTAL 12-33 KV LINES					125.52		2
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	8,259.59		152

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	07/20/2011	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2515								1
2515								2
2515								3
2515								4
2515								5
2515								6
2515								7
2515								8
2515								9
2515								10
2515								11
2515								12
	20,355,903	99,736,822	120,092,725					13
	20,355,903	99,736,822	120,092,725					14
								15
1272								16
1272								17
954 & 1272								18
2156								19
954								20
954								21
2156								22
954								23
1272								24
2156								25
2156								26
2156								27
2156								28
954								29
1272								30
954								31
1272								32
1272								33
954								34
954								35
	161,478,509	1,228,987,846	1,390,466,355	715,074	15,727,295		16,442,369	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954								1
795								2
1272								3
1272								4
1272								5
1272								6
954								7
954								8
2156								9
1272								10
954								11
795								12
954								13
954								14
1272								15
1272								16
954								17
1272								18
1272								19
954								20
954								21
954								22
954								23
954								24
954								25
954								26
954								27
1272								28
2156								29
1272								30
954								31
795								32
954								33
954								34
795								35
	161,478,508	1,228,987,845	1,390,466,353	716,074	15,727,295		16,443,369	36

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 07/20/2011	Year/Period of Report End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. *Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line.* Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954								1
795								2
1272								3
795								4
795								5
954								6
2515								7
954								8
1272								9
954								10
954								11
954								12
	41,217,981	220,619,462	261,837,443					13
	41,217,981	220,619,462	261,837,443					14
								15
795								16
795								17
636								18
795								19
397.5								20
636								21
795								22
795								23
954								24
	3,422,657	73,995,073	77,417,730					25
	3,422,657	73,995,073	77,417,730					26
								27
477								28
								29
								30
								31
								32
	68,746,288	567,900,634	636,646,922					33
	68,746,288	567,900,634	636,646,922					34
								35
	161,478,506	1,228,987,846	1,390,466,352	715,074	15,727,295		16,442,369	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	07/20/2011	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
	4,464,582	21,632,669	26,097,251					2
	4,464,582	21,632,669	26,097,251					3
								4
								5
								6
								7
	22,606,882	240,793,751	263,400,633					8
	22,606,882	240,793,751	263,400,633					9
								10
								11
								12
								13
								14
								15
	564,217	4,409,434	4,973,651					16
	564,217	4,409,434	4,973,651					17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
				715,074	15,727,295		16,442,369	35
	161,478,509	1,228,987,846	1,390,466,355	715,074	15,727,295		16,442,369	36

Name of Respondent Duke Energy Carolinas, LLC	This Report is: (1) _ An Original (2) X A Resubmission	Date of Report (Mo, Da, Yr) 07/20/2011	Year/Period of Report 2010/Q4

FOOTNOTE DATA

Schedule Page: 422 Line No.: 1 Column: h

For column (h) the number of circuits - 1 & 2

Schedule Page: 422 Line No.: 1 Column: i

All Conductors in column (i) are ACSR shown in MCM.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	07/20/2011	End of 2010/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Overhead: New Lines						
2	Beatles Ford Ret Tap		1.70	Pole	6.00	1	
3	Parkwood Ret Tap		0.11	Pole	9.00	1	
4	Cleveland County School Tap		0.84	Towers	20.00	2	
5	Cathey Rd Tap		0.90	Pole	11.00	1	
6	Institute for B & H Safety Tap		0.19			1	
7	Piercetown to Plainview Tap		5.30		9.00	2	
8	Indian land & Charlotte #2 Tap		0.04	Pole	75.00	1	
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23	Overhead: Major Rebuild						
24	Ebert Rd Tap	Buck Tie - Winston Tie	2.53		9.00	2	
25	Buzzard Roost Hydro	International Paper Tap	5.46		8.00	2	
26	Central Tie	Greenlawn Switching Station	0.28		93.00	2	
27	Kent Line	Hillside Line to Shoal Line	0.02	Pole	55.00	1	
28	Armory Bent	N Greenwood Retail	0.75		17.00	2	
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		18.12		327.00	18	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	07/20/2011	End of 2010/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
556.5	ACSR		100	461,933	1,114,037	682,796		2,258,766	2
1272.0	ACSR		100		24,013	46,764		70,777	3
556.0	ACSR		44	15,393	356,495	218,497		590,385	4
336.0	ACSR		100	748,190	286,710	175,725		1,210,625	5
556.0	ACSR		100		83,646	51,268		134,914	6
954.0	ACSR		100		3,070,606	1,882,106		4,952,916	7
336.0	ACSR		44		33,050	20,256		53,306	8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
954.0	ACSR		100		1,114,259	682,933		1,797,192	24
556.0	ACSR		100		1,535,851	941,328		2,477,179	25
477.0	ACSR		100		3,473,523	2,128,935		5,602,462	26
556.0	ACSR		44		247,741	151,840		399,581	27
556.0	ACSR		100		549,952	337,068		887,020	28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				1,225,516	11,890,088	7,319,521		20,435,125	44

Name of Respondent Duke Energy Carolinas, LLC	This Report is: (1) _ An Original (2) X A Resubmission	Date of Report (Mo, Da, Yr) 07/20/2011	Year/Period of Report 2010/Q4

FOOTNOTE DATA

Schedule Page: 424 Line No.: 1 Column: l

For all of column "l", "m" and "n" all or portion of the cost is in account 106

Schedule Page: 424 Line No.: 6 Column: d

No structures used in the new line

Schedule Page: 424 Line No.: 7 Column: d

Towers & Poles used in the new line

Schedule Page: 424 Line No.: 24 Column: d

Towers & Poles used in the new line

Schedule Page: 424 Line No.: 25 Column: d

Towers & Poles used in the new line

Schedule Page: 424 Line No.: 26 Column: d

Towers & Poles used in the new line

Schedule Page: 424 Line No.: 28 Column: d

Towers & Poles used in the new line

GENERATION AND ASSOCIATED TRANSMISSION FACILITIES SUBJECT TO CONSTRUCTION DELAYS

A list of any generation and associated transmission facilities under construction which have delays of over six months in the previously reported in-service dates and the major causes of such delays. Upon request from the NCUC Staff, the reporting utility shall supply a statement of the economic impact of such delays:

There are no delays over six months in the stated in-service dates.

2011 FERC Form 715

The 2011 FERC Form 715 filed April 2011, is confidential and filed under seal.

APPENDIX G: OTHER INFORMATION (ECONOMIC DEVELOPMENT)

Customers Served Under Economic Development:

In the NCUC Order issued in Docket No. E-100, Sub 97, dated November 15, 2002, the NCUC ordered North Carolina utilities to review the combined effects of existing economic development rates within the approved IRP process and file the results in its short-term action plan. There are no significant changes to the incremental load (demand) for which customers are receiving credits under economic development rates and/or self-generation deferral rates (Rider EC), as well as economic redevelopment rates (Rider ER) since the 2010 Carolinas IRP.

APPENDIX H: NON-UTILITY GENERATION/CUSTOMER-OWNED GENERATION/STAND-BY GENERATION:

In NCUC Order in Docket No. E-100, Sub 111, dated July 11, 2007, the NCUC required North Carolina utilities to provide a separate list of all non-utility electric generating facilities in the North Carolina portion of their control areas, including customer-owned and standby generating facilities, to the extent possible. Duke Energy Carolinas' response to that Order was based on the best available information, and the Company has not attempted to independently validate it. In addition, some of that information duplicates data that Duke Energy Carolinas supplies elsewhere in this IRP.

The Company has continued to add small non-utility electric generation in 2011. A separate list is not included in the 2011 IRP, however the total additions are reflected in Tables 5.E and 5.F, and the Company has included a full list in its annual status report filed in Docket No. E-100, Sub 41B.

APPENDIX I: WHOLESALE PROJECTIONS FROM EXISTING AND POTENTIAL CUSTOMERS

Table I.1 below provides the historical and projected growth in peak loads for the Company's wholesale customers. The values are summer peaks at generation. The wholesale customer growth rates vary and none are the same as the historical growth rate in Duke Energy Carolinas' retail load. With respect to wholesale sales contracts, the Company has developed econometric forecasting models for the larger wholesale customer in a process similar to that used for retail to produce MWH sales forecasts. For smaller wholesale customers, however, their forecasted growth is assumed to be the same as Duke Energy Carolinas' retail growth.

It is important to note that the growth rates for Central and NCEMC Supplemental Requirements) are primarily driven by terms of the contract. The Central Sale provides for a seven year "step-in" to Central's full load requirement such that the Company will provide 15% of Central's total member cooperative load in Duke's Balancing Authority Area requirement in 2013. This initial load requirement will be followed by subsequent 15% annual increases in load over the following six years up to a total of 100% of Central's load requirements. The NCEMC Supplemental Requirements sale is essentially a fixed quantity of capacity and energy specified by the contract

The wholesale sales contracts, shown in Table 3.D, are net of resources provided by the customer.

TABLE I.1 (CONFIDENTIAL)

[redacted]

APPENDIX J: CARBON NEUTRALITY PLAN

Greenhouse Gas Reduction Compliance Plan – Cliffside Unit 6

On January 29, 2008, the NCDAQ issued the Air Quality Permit to Duke Energy Carolinas for the Cliffside Unit 6. The Permit specifically requires that Duke Energy Carolinas implement a Greenhouse Gas Reduction Plan (Greenhouse Plan), and specifically obligates Duke Energy Carolinas to take the following actions in recognition of NCDAQ's issuance of the Permit for Cliffside Unit 6: (1) retire 800 MWs of coal capacity in North Carolina in accordance with the schedule set forth in Table J.1, which is in addition to the retirement of Cliffside Units 1 – 4; (2) accommodate, to the extent practicable, the installation and operations of future carbon control technology; and (3) take additional actions to make Cliffside Unit 6 carbon neutral by 2018.

With regard to obligation (1) identified above, as shown in Table J.1 below, Duke Energy Carolinas proposes to retire up to the following generating units to satisfy the required retirement schedule set forth in the Greenhouse Plan.

Table J.1 - Cumulative Coal Plant Retirements

	Greenhouse Plan Retirement Schedule Capacity in MW	**IRP Retirement Schedule Capacity in MW (per Table 5.D)[1]**	**Description for IRP Retirement Schedule**
by end of 2011		113	Buck 3 & 4
by end of 2012		389	Dan River 1-3
by end of 2015	350	1159	Riverbend 4 - 7, Buck 5 & 6
by end of 2016	550	1159	Note [2]
by end of 2018	**800**	**1159**	

[1] In the 2011 IRP, this data appears in Table 5.D, page 50. Plant retirements that were applicable to the first obligation were put in this table. References will be updated with the 2011 IRP.

[2] The IRP Retirement Schedule indicates that the retirements would exceed the Greenhouse Plan by close to 50%.

With respect to obligation (2) listed above, the requirement to build Cliffside Unit 6 to accommodate future carbon technologies has been met by allocating space at the 1100 acre site for this equipment and incorporating practical energy efficiency designs into the plant.

With respect to obligation (3) to render Cliffside Unit 6 carbon neutral by 2018, the proposed plan to achieve this requirement is set forth below. The Greenhouse Gas

Reduction Plan states that the plan for carbon neutrality:

may include energy efficiency, carbon free tariffs, purchase of credits, domestic and international offsets, additional retirements or reduction in fossil fuel usage as carbon free generation becomes available, and carbon reduction through the development of smart grid, plug in hybrid electric vehicles or other carbon mitigation projects. Such actions will be included in plans to be filed with the NCUC and will be subject to NCUC approval, including appropriate cost recovery of such actions. In addition, the plans shall be submitted to the Division of Air Quality, which will evaluate the effect of the plans on carbon, and provide its conclusions to the NCUC.

Duke Energy Carolinas is including the plan for carbon neutrality in this 2011 IRP in order to satisfy the requirement to file and seek approval of the plan from the NCUC as required by the NCDAQ Air Permit.

The estimated emissions reductions required to render Cliffside Unit 6 carbon neutral in 2018 is approximately 5.3 million tons of carbon dioxide (the Emission Reduction Requirement). The Company calculated the estimated emission reductions by estimating the actual tons of carbon dioxide emissions that will be released per year from Cliffside Unit 6 less 681,954 tons of carbon dioxide emissions that was historically generated from Cliffside Units 1 – 4 and will be eliminated by the retirement of these units. (See Table J.2 below.)

Table J.2 - Emission Reduction Requirement

Actions	**Tons of CO_2 Equivalent Emissions**	**Notes**
Cliffside Unit 6	6,000,000	Expected Annual Emissions (based on an approximate 90% capacity factor)
Less Cliffside Units 1 – 4	(681,954)	Average of emissions in 2007 & 2008[1]
Total Increase	**5,318,055**	**Emissions Reduction Requirement**

[1]The emissions attributable to coal plant retirements are identified as the highest two year average CO_2 emissions for the five years prior to the operations of Unit 6 in 2012, consistent with the methodology for calculating emissions for major modification under the Clean Air Act Prevention of Significant Deterioration regulations.

The Company's plan for meeting the Emissions Reductions Requirements includes actions from multiple categories and associated methodologies for determining the offset value known as "Qualifying Actions" (defined below and as further indicated in Table J.3). The Company requests approval from the NCUC of the method of calculating the Emission Reduction Requirements and emissions offset values of the Qualifying Actions during the 2011 IRP review process.

For 2018, the Company has identified approximately 9.9 million annual tons of carbon dioxide emissions reductions and a life-time credit of 600,000 tons of carbon dioxide bio-sequestration as eligible Qualifying Actions. (See Table J.3) The Qualifying Actions include the avoidance of carbon dioxide emission releases from coal plant retirements, addition of renewable resources, implementation of energy efficiency measures, nuclear and hydropower capacity upgrades. This also includes the expected retirement of coal-fired operations at Lee Units 1, 2 and 3 in South Carolina in 2015. In addition, carbon dioxide bio-sequestration offsets from the Greentrees program, which sequesters carbon as trees grow, is identified as a Qualifying Action.

While the reductions associated for retirements for each of the coal plants shall be the same each year, the reductions for the remaining Qualifying Actions will vary based on actual results for each of the categories and the then current system carbon intensity factor. The system carbon intensity factor shall be equal to the actual carbon dioxide emissions of all Company-owned generation dedicated for Duke Energy Carolina customers divided by the megawatt hours generated by those same resources (the "Conversion Factor").

Table J.3 - Qualifying Actions for carbon dioxide emission reductions

Categories	Tons of CO_2 Equivalent Emissions	Methodology Description
Buck 3	216,202	Average of emissions in 2007 & 2008[1]
Buck 4	139,429	Average of emissions in 2007 & 2008[1]
Buck 5	606,837	Average of emissions in 2007 & 2008[1]
Buck 6	653,860	Average of emissions in 2007 & 2008[1]
Riverbend 4	462,314	Average of emissions in 2007 & 2008[1]
Riverbend 5	435,895	Average of emissions in 2007 & 2008[1]
Riverbend 6	684,010	Average of emissions in 2007 & 2008[1]
Riverbend 7	710,023	Average of emissions in 2007 & 2008[1]
Dan River 1	249,900	Average of emissions in 2007 & 2008[1]
Dan River 2	282,944	Average of emissions in 2007 & 2008[1]
Dan River 3	677,334	Average of emissions in 2007 & 2008[1]
Lee 1 [5]	335,583	Average of emissions in 2007 & 2008[1]
Lee 2 [5]	390,965	Average of emissions in 2007 & 2008[1]
Lee 3 [5]	783,658	Average of emissions in 2007 & 2008[1]
Conservation	1,189,268	In 2018, 2,973,170 MWH "Conservation and Demand Side Management Programs"[2] is multiplied by a Conversion Factor of 0.40.
Renewable Energy	1,068,370	In 2018, 610 MW per the Table 8.E "MW Nameplate Capacity".[3] Is multiplied by an assumed 30% (wind), 20% (solar), and 85% (biomass) capacity factor and a Conversion Factor of 0.40.
Bridgewater Hydro	7,997	See Note 5 in the "Assumptions of Load, Capacity, and Reserve Table" indicates 8.75 MW increase in capacity. This is multiplied by a 26% capacity factor and a Conversion Factor of 0.40.
Nuclear Uprates	560,920	Assumed 174 MW of nuclear uprates by June of 2018.[4] Assumed a 92% capacity factor and a Conversion Factor of 0.40.
Total Annual	9,455,509	

[1] The emissions attributable to coal plant retirements are identified as the highest two year average CO_2 emissions for the five years prior to the operations of Unit 6 in 2012, consistent with the methodology for calculating emissions for major modifications under the Clean Air Act Prevention of Significant Deterioration regulations. Company reserves the right to use any credits for reduction of nitrogen oxide, sulfur dioxide and carbon dioxide emissions generated by retirement of units retired under the plan consistent with provisions of State and federal law.

[2] Data is from Table 4.A, page 34 of the 2011 IRP.

[3] Data is from the Table 8.E on page 93 of the 2011 IRP. Actual nameplate capacity is 610 MW. The contribution to peak is 304 MW.

[4] Data is a portion of the total capacity addition on page 87 of 2011 IRP prior to June 2018.

[5] Lee Units 1, 2 and 3 are planned for retirement by January 1, 2015. Alternatively, Duke Energy is considering converting one or more of these units to natural gas to allow continued operation for peak

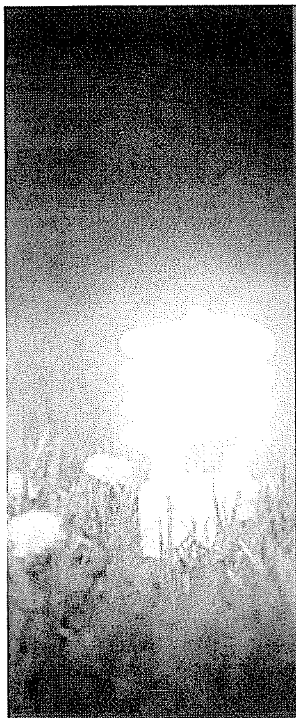
generation demand only (at a low annual capacity factor). Any CO_2 from operating with natural gas would be subtracted from the reductions shown in the table.

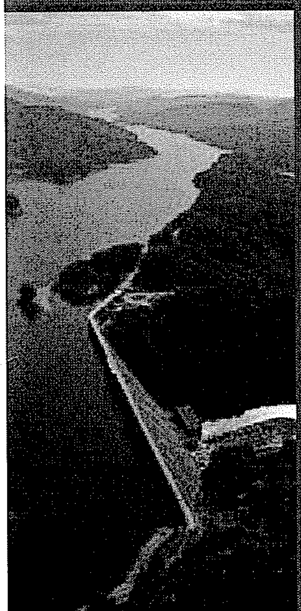
If the method described above is approved, Duke Energy Carolinas shall provide a compliance report (Compliance Reports) in the 2019 IRP filing indicating what Qualifying Actions were used to meet the Emission Reduction Requirement in 2018. The expected Qualifying Actions total of 9.9 million tons of emission reductions by 2018. The Company's proposed Qualifying Actions clearly demonstrate that identified reductions can more than exceed the Required Emissions Reduction estimate of 5.3 million tons. The Company therefore requests the ability to alter the mix of actions undertaken, and even to eliminate some completely, in its discretion so long as the annual emissions reductions achieved total at least 5.3 million tons in accordance with the NCDAQ Air Permit.

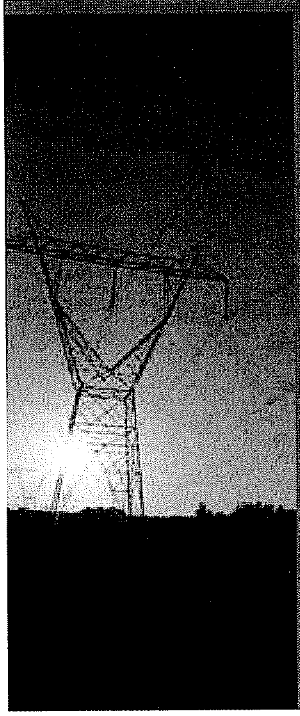
APPENDIX K: CROSS-REFERENCE OF IRP REQUIREMENTS

The following table cross-references IRP regulatory requirements for North Carolina and South Carolina, and identifies where those requirements are discussed in the IRP.

Requirement	Location	Reference	Updated
Forecast of Load, Supply-side Resources, and Demand-Side Resources. • 10 year history of customers & energy sales • 15 year forecast w & w/o energy efficiency • Description of supply-side resources	 Ch 3 Ch 3 Ch 5 & App C	 NC R8-60 h (i) 1(i) NC R8-60 h(i) 1(ii) NC R8-60 h(i) 1(iii)	 Yes Yes Yes
Generating Facilities • Existing Generation • Planned Generation • Non Utility Generation • Proposed Generation Units at Locations not known • Generating Units Projected to be Retired • Generating Units with plan for life extension	 Ch 5 A Ch 8 & App A Ch 5 D Ch 8 & App A Ch 5 A N/A	 NC R8-60 h (i) 2(i)(a-f) NC R8-60 h (i) 2(ii)(a-d) NC R8-60 h (i) 2(iii)	 Yes Yes Yes Yes Yes
Reserve Margin	Ch 8	NC R8-60 h (i) 3	Yes
Wholesale Contract for the Purchase and Sale of Power • Wholesale Purchase Power Contract • Request for Proposal • Wholesale power sales contracts • Wholesale projections (existing and undesignated)	 Ch 5 D Ch 5 D Ch 3 & App I App I	 NC R8-60 h (i) 4(i) NC R8-60 h (i) 4(ii) NC R8-60 h (i) 4(iii) NCUC 09 IRP req (6)	 Yes Yes Yes Yes
Transmission Facilities , planned & under construction Transmissions System Adequacy FERC Form 1 (pages 422-425) FERC Form 715	App F Ch 7 App F App F	NC R8-60 h (i) 5	Yes Yes Yes Yes
Energy Efficiency and Demand Side Management • Existing Programs • Future Programs • Rejected Programs • Consumer Education Programs • DSM projected reliance	 Ch 4 Ch 4 Ch 4 Ch 4 App D	 NC R8-60 h (i) 6(i) NC R8-60 h (i) 6(ii) NC R8-60 h (i) 6(iii) NC R8-60 h (i) 6(iv) NCUC 09 IRP req (7)	 Yes Yes Yes Yes Yes
Assessment of Alternative Supply-Side Energy Resource • Current and Future Alternative Supply-Side • Rejected Alternative Supply-Side Energy Resource	 Ch5C & App C Ch5C & App C	 NC R8-60 h (i) 7(i) NC R8-60 h (i) 7(ii)	 Yes Yes
Evaluation of Resource Options (Quantitative Analysis)	 App A	NC R8-60 h (i) 8	Yes
Cost benefit analysis of each option Levelized Bus-bar Costs	 App C	 NC R8-60 h (i) 9	 Yes
Other Information (economic development)	App G		No
Legislative and Regulatory Issues	Ch 6		Yes
Supplier's Program for Meeting the Requirements Shown in its Forecast in an Economic and Reliable Manner, including EE and DSM and Supply-Side Options	Ch 1, Ch 8 & App A		Yes
Supplier's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy service, and a description of the external, environmental and economic consequences of the plan to the extent practicable	Ch 8, App A		Yes
Greenhouse Gas Reduction Compliance Plan	App J		Yes







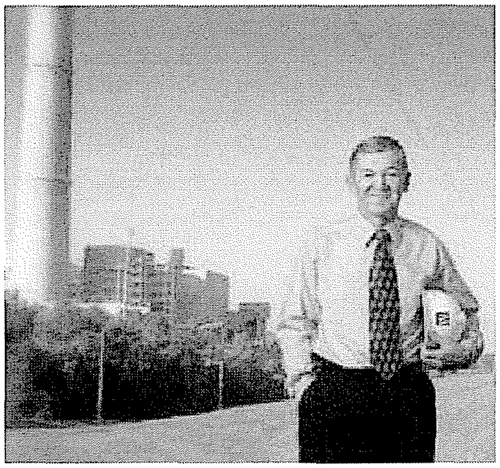
Integrated Resource Plan

TVA's Environmental & Energy Future

March 2011

Message from the CEO

TVA operates one of the largest power systems in the United States. With a generating capacity of more than 34,000 megawatts, we meet the daily electricity needs for an 80,000-square-mile region where more than 9 million people live, work and go to school. That's an enormous responsibility, and one we take very seriously.



A power system large and reliable enough to handle that responsibility doesn't come about by accident. It's the culmination of work by thousands of skilled professionals, and it all starts with focused and detailed planning.

Planning a power system is complex work that involves hundreds of variables, such as consumer trends, fuel and material costs, regulations, technology advancements and the weather. It's complicated even further by the need to forecast needs and conditions decades into the future.

TVA's new integrated resource plan is a critical part of our overall planning effort. It is a comprehensive study of options and strategies and their potential economic and environmental outcomes. The plan was shaped by input from the businesses, industries and regional leaders, as well as ordinary people, whose lives and livelihoods depend on the electricity supplied by TVA. The result of this two-year exercise gives us a sound basis for making better long-term decisions.

In addition, our integrated resource plan will help us fulfill TVA's renewed vision to become one of the nation's leading providers of low-cost and cleaner energy by 2020. The options that have been identified from this process involve reducing TVA's reliance on coal, increasing our supply of nuclear and renewable energy, and working in partnership with local utilities and the people they serve to use energy more efficiently.

Like most things, the cost of electricity is not likely to stay flat in the years ahead. Our challenge will be to keep power affordable while carrying out our vital work with the least impact on the environment today and for future generations.

Tom Kilgore

Tom Kilgore

Table of Contents

Table of Contents

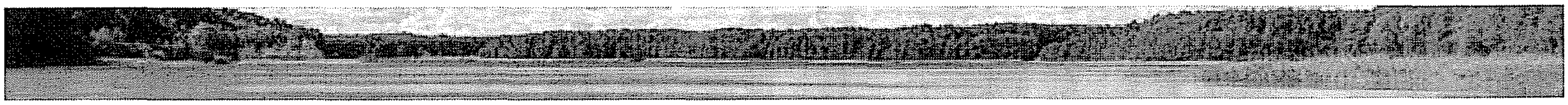
List of Figures

List of Figures (continued)

List of Figures (continued)

List of Figures (continued)

Appendix E



EXECUTIVE SUMMARY

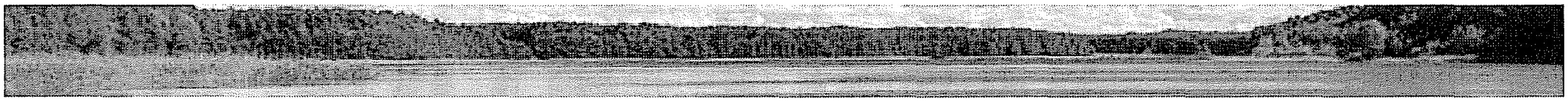
Contents

Overview

The Tennessee Valley Authority's (TVA) Integrated Resource Plan (IRP), entitled TVA's Environmental and Energy Future, serves as a roadmap for identifying the resources that are acceptable and available to meet the energy needs of the Tennessee Valley region over the next 20 years. It addresses the demand for power in the region, the options available for meeting that demand and the potential environmental, economic and operating impacts of each.

This endeavor aligns with TVA's Environmental Policy and will serve as a guide for TVA to fulfill its renewed vision—to become one of the nation's leading providers of low-cost and cleaner energy by 2020. TVA is committed to lead the nation in improved air quality and increased nuclear production and to lead the Southeast in increased energy efficiency. This vision will be accomplished as TVA continues to carry out the mission established by Congress in 1933.

The current planning environment that confronts TVA is one of the most challenging in TVA's history. Therefore, TVA must ensure that its strategy is robust, regardless of future conditions, and enables TVA to navigate through these challenges in a way that best supports its multiple responsibilities. This IRP establishes a strategic direction for TVA and provides it with the flexibility to make the best decisions in a dynamic, ever-changing regulatory and economic environment.



Public Participation

Public participation was a significant component of the IRP process. In an effort to develop the plan in a transparent manner, TVA offered multiple opportunities for the public to contribute to and influence the development of this IRP. These opportunities included two series of public meetings, written comments, webinars, briefings, a web-based questionnaire, and a phone survey. The goal for all public participation opportunities was to encourage others to share their views on issues they believe TVA should focus on as it plans for the region's future energy needs.

In addition to public participation, TVA also formed a Stakeholder Review Group (SRG). This group consisted of 16 individuals representing a wide range of interests. Members of the group were asked to provide TVA with their viewpoints on the IRP process, assumptions, analyses and results. TVA met approximately every month with the SRG throughout the IRP process to discuss strategic findings.

Need for Power Analysis

As a part of the IRP analysis, TVA developed a forecast of the need for power, referred to in the electric utility industry as "demand." To develop this forecast, the following four basic steps were taken:

1. Demand for electricity (peak demand and energy sales) was forecasted for a 20-year planning horizon (Figure 1)
2. Firm requirements were calculated to determine generation capacity required by adding forecasted demand to a planning contingency. The planning contingency allowed for unforeseen events, inaccuracies or unplanned unit outages and other resource limitations
3. Existing generation resources available to meet the forecasted demand were identified
4. The need for power was calculated by comparing the firm requirements to the existing viable generation resources. The difference between the two defines the need for additional resources over the planning period. This is referred to as "the capacity gap" (Figure 2)

TVA expects the need for power to continue to grow due to economic recovery, population growth and other factors. However, this growth is expected to occur at a lower rate than historical average.

Figure 1 shows the Reference Case: Spring 2010 forecast of peak demand over the 20-year planning horizon. The figure also illustrates the range of load forecasts considered within this IRP, with the highest and lowest forecasts representing the upper and lower bounds.

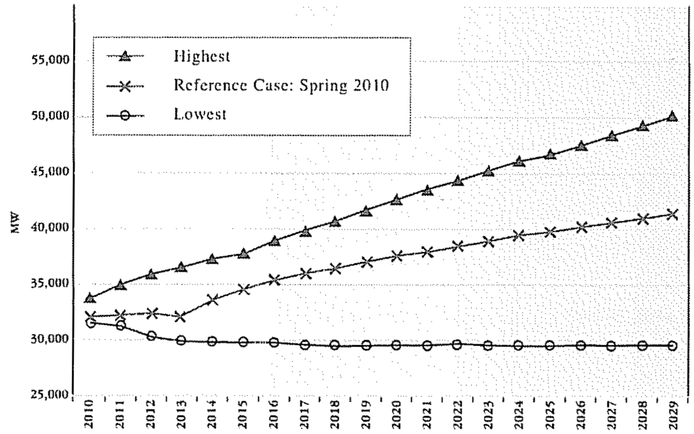


Figure 1 – Peak Load Forecast

Figure 2 shows the capacity gap for the Reference Case: Spring 2010 forecast over the 20-year planning horizon. The figure also illustrates the capacity gap based on the range of peak loads considered in this IRP. The capacity gaps were developed by adding a planning reserve margin to the peak load forecast and subtracting existing resources. Additional detail on the need for power analysis is included in Chapter 4 – Need for Power Analysis.

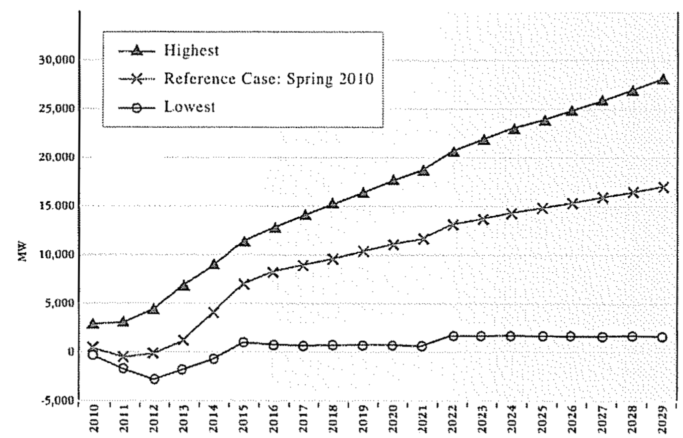


Figure 2 – Capacity Gap

Approach

Scenario Planning

A scenario planning approach was utilized for the development of this IRP. TVA carried out its analysis in a "no-regrets" framework. This framework defined a process in which all relevant and available information was analyzed in a careful and considered fashion, with significant attention paid to what would happen if the future unfolds in an unexpected way.

In other words, strategic options were analyzed not only from the perspective of what was expected to occur in the future, but also from the perspective of what was possible to occur in the future. Using this framework, decisions made today and in the near future are not overly dependent on the future unfolding exactly as expected. Therefore, this IRP should provide benefit and value to stakeholders even if the future turns out to be different than predicted.

Scenarios and planning strategies form the basic building blocks of the IRP analysis. Scenarios do not predict the future, but rather portray the range of possible "worlds" that TVA may encounter in the future based on a number of uncertainties outside of TVA's control. Scenarios were also used to test resource selection and reflect key stakeholder interests.

Factors that differed between scenarios included economic growth, inflation, fuel prices, demand growth and regulatory environments. Uncertainties varied among scenarios to highlight how decisions would change under different conditions.

Six unique scenarios were developed for this IRP along with two iterations of a reference forecast. Scenario 7 – Reference Case: Spring 2010 was used in the Draft IRP analysis and was refreshed with Scenario 8 – Reference Case: Great Recession Impacts Recovery between the Draft and final IRP. The following eight scenarios were used:

- Scenario 1 – Economy Recovers Dramatically
- Scenario 2 – Environmental Focus is National Priority
- Scenario 3 – Prolonged Economic Malaise
- Scenario 4 – Game-Changing Technology
- Scenario 5 – Energy Independence
- Scenario 6 – Carbon Regulation Creates Economic Downturn

- Scenario 7 – Reference Case: Spring 2010
- Scenario 8 – Reference Case: Great Recession Impacts Recovery

Additional details on the scenarios are included in Chapter 6 – Resource Plan Development and Analysis.

Recommended Planning Direction Development

The Draft IRP evaluated five specific planning strategies. These planning strategies described a broad range of business options that TVA could adopt and were built upon key decisions within TVA's control. Components such as renewable generation additions, nuclear expansion and market purchases varied among planning strategies. The following planning strategies were considered in the Draft IRP:

- Strategy A – Limited Change in Current Resource Portfolio
- Strategy B – Baseline Plan Resource Portfolio
- Strategy C – Diversity Focused Resource Portfolio
- Strategy D – Nuclear Focused Resource Portfolio
- Strategy E – EEDR and Renewables Focused Resource Portfolio

Each planning strategy was evaluated across the first seven scenarios. The results were summarized using a scorecard designed to identify financial, risk and strategic factors to consider when selecting a Recommended Planning Direction.

Based on the preliminary results, TVA focused on the top three ranked planning strategies (Strategies B, C and E) for further evaluation. Additional detail on the Draft IRP results is included in Chapter 7 – Draft Study Results.

A high-level summary of the process used for developing the final IRP is shown in Figure 3.

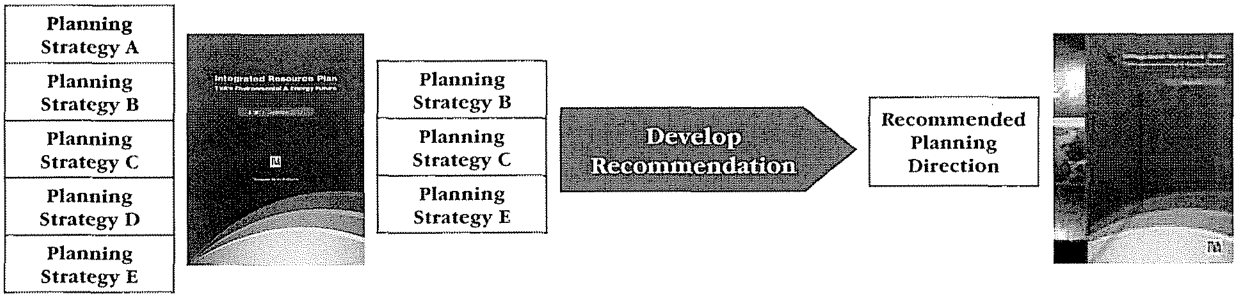


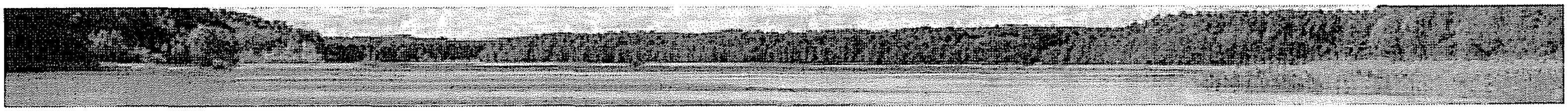
Figure 3 – Final IRP Development

A key objective in transitioning from the Draft to the final IRP was to identify a Recommended Planning Direction. The preliminary results and findings of the Draft IRP were used to establish boundaries for evaluating new combinations of planning strategy components through an optimization framework. In addition, input received during the public comment period was reviewed in detail and appropriately incorporated into the analysis. This approach produced more comprehensive results by allowing unique combinations of resources to be tested in addition to those directly considered in the Draft IRP. A summary of the options considered for the final IRP is shown in Figure 4.

Components	Range of Options Tested				
EEDR	2,100 MW & 5,900 annual GWh reductions by 2020	3,600 MW & 11,400 annual GWh reductions by 2020	5,100 MW & 14,400 annual GWh reductions by 2020		
Renewable additions	1,500 MW competitive resources or PPAs by 2020	2,500 MW competitive resources or PPAs by 2020	2,500 MW competitive resources or PPAs by 2029	3,500 MW competitive resources or PPAs by 2020	3,500 MW competitive resources or PPAs by 2029
Coal-fired capacity idled	2,400 MW total fleet reductions by 2017	3,200 MW total fleet reductions by 2017	4,000 MW total fleet reductions by 2017	4,700 MW total fleet reductions by 2017	

Figure 4 – Optimization Framework for the final IRP Analysis

The Recommended Planning Direction was evaluated in all eight scenarios. The results were used to build a fully populated scorecard with ranking and strategic metrics. The completed scorecard was compared with the Draft IRP results to evaluate improvements between previously considered planning strategies. Additional detail on the Recommended Planning Direction results is included in Chapter 8 – Final Study Results and Recommended Planning Direction.



Strategic Findings

The following strategic findings emerged from the IRP analysis:

- Expanded EEDR portfolios perform well; the mid level portfolio provided the best balance of cost and implementation risk
- Renewable generation above existing wind contracts played a role in future resource portfolios, assuming certain costs
- Some increased idling of coal-fired capacity was favorable compared to adding environmental controls to the existing fleet
- Coal-fired capacity was only added in scenarios with high load growth
- Pumped-storage added needed operational flexibility
- Nuclear expansion was selected in most cases, except scenarios with no load growth
- Natural gas-fired capacity was selected in most cases after 2020, except when needed earlier to meet high load growth or to provide grid reliability

Recommended Planning Direction

This IRP provides TVA with a strategic direction and the flexibility to make sound choices in a dynamic, ever-changing regulatory and economic environment. The Recommended Planning Direction is the most balanced in terms of cost, financial risk and other strategic considerations and provides direction by articulating a 20-year roadmap.

Components of the Recommended Planning Direction are based upon extensive modeling, in-depth stakeholder input and the assessment of quantified and non-quantified risks. They also allow for flexibility to adapt to future conditions by providing guideline ranges and timeframes for each component of the planning strategy. A summary of the Recommended Planning Direction is shown in Figure 5.

Component	Guideline MW Range	Window of Time	Recommendations
EEDR	3,600-5,100 (11,400-14,400 GWh)	By 2020[1]	Expand contribution of EEDR in the portfolio
Renewable additions	1,500-2,500[2]	By 2020[1]	Pursue cost effective renewable energy
Coal-fired capacity idled	2,400-4,700[3]	By 2017	Consider increasing amount of coal-fired capacity idled
Energy storage	850[4]	2020-2024	Add pumped-storage capacity
Nuclear additions	1,150-5,900[5]	2013-2029	Increase contribution of nuclear generation
Coal additions	0-900[6]	2025-2029	Preserve option of generation with carbon capture
Natural gas additions	900-9,300[7]	2012-2029	Utilize natural gas as an intermediate supply source

1 – This range includes EEDR savings achieved through 2010. The 2020 range for EEDR and renewable energy does not preclude further investment in these resources during the following decade

2 – TVA's existing wind contracts that total more than 1,600 MW are included in this range. Values are nameplate capacity. Net dependable capacity would be lower

3 – TVA has previously announced plans to idle 1,000 MW of coal-fired capacity, which is included in this range. MW values based on maximum net dependable capacity

4 – This is the expected size of a new pumped-storage hydro facility

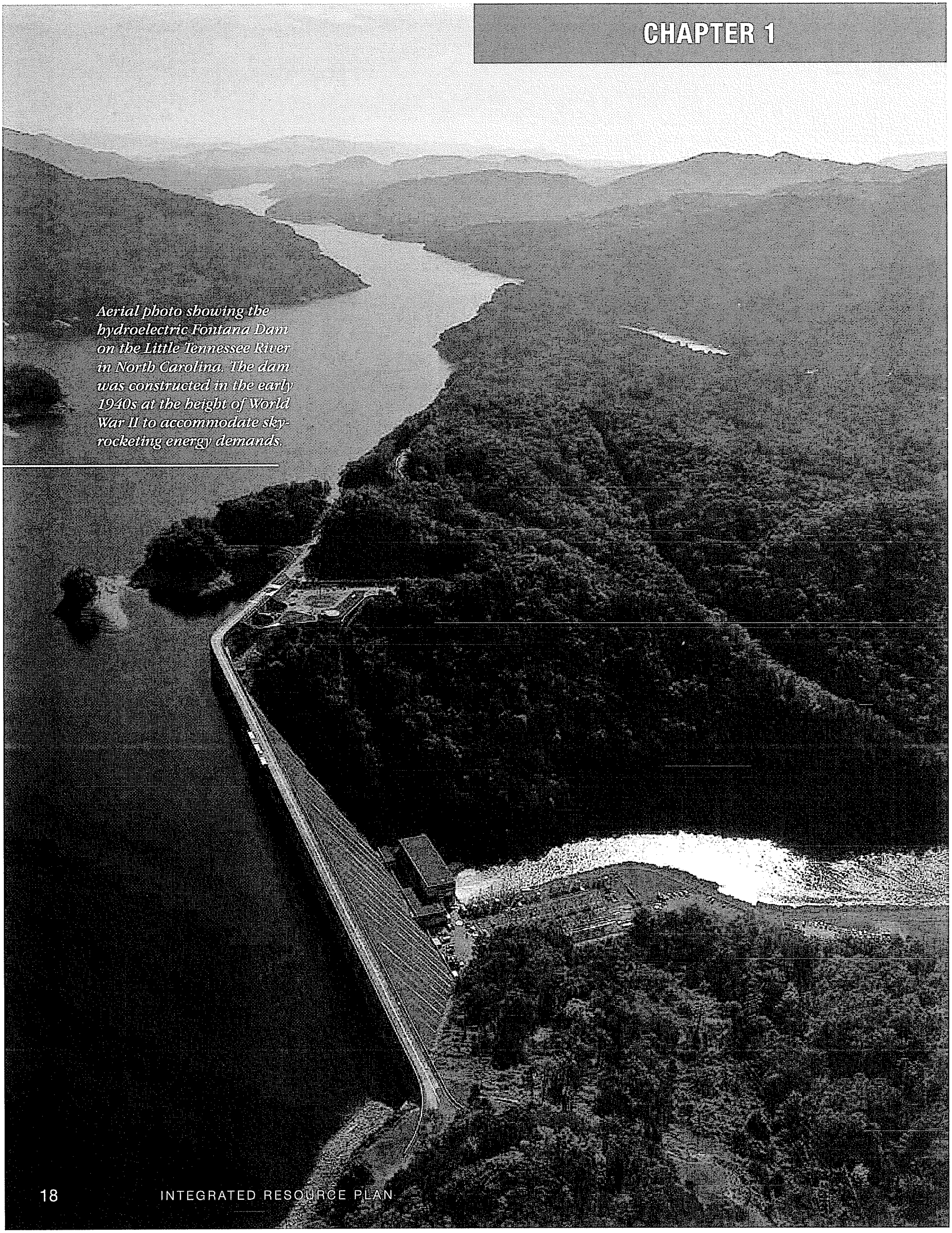
5 – The completion of Watts Bar Unit 2 represents the lower end of this range

6 – Up to 900 MW of new coal-fired capacity is recommended between 2025 and 2029

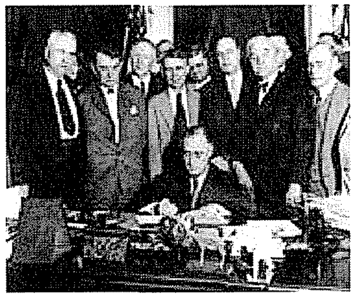
7 – The completion of John Sevier combined cycle plant represents the lower end of this range

Figure 5 – The Recommended Planning Direction

CHAPTER 1



Aerial photo showing the hydroelectric Fontana Dam on the Little Tennessee River in North Carolina. The dam was constructed in the early 1940s at the height of World War II to accommodate sky-rocketing energy demands.

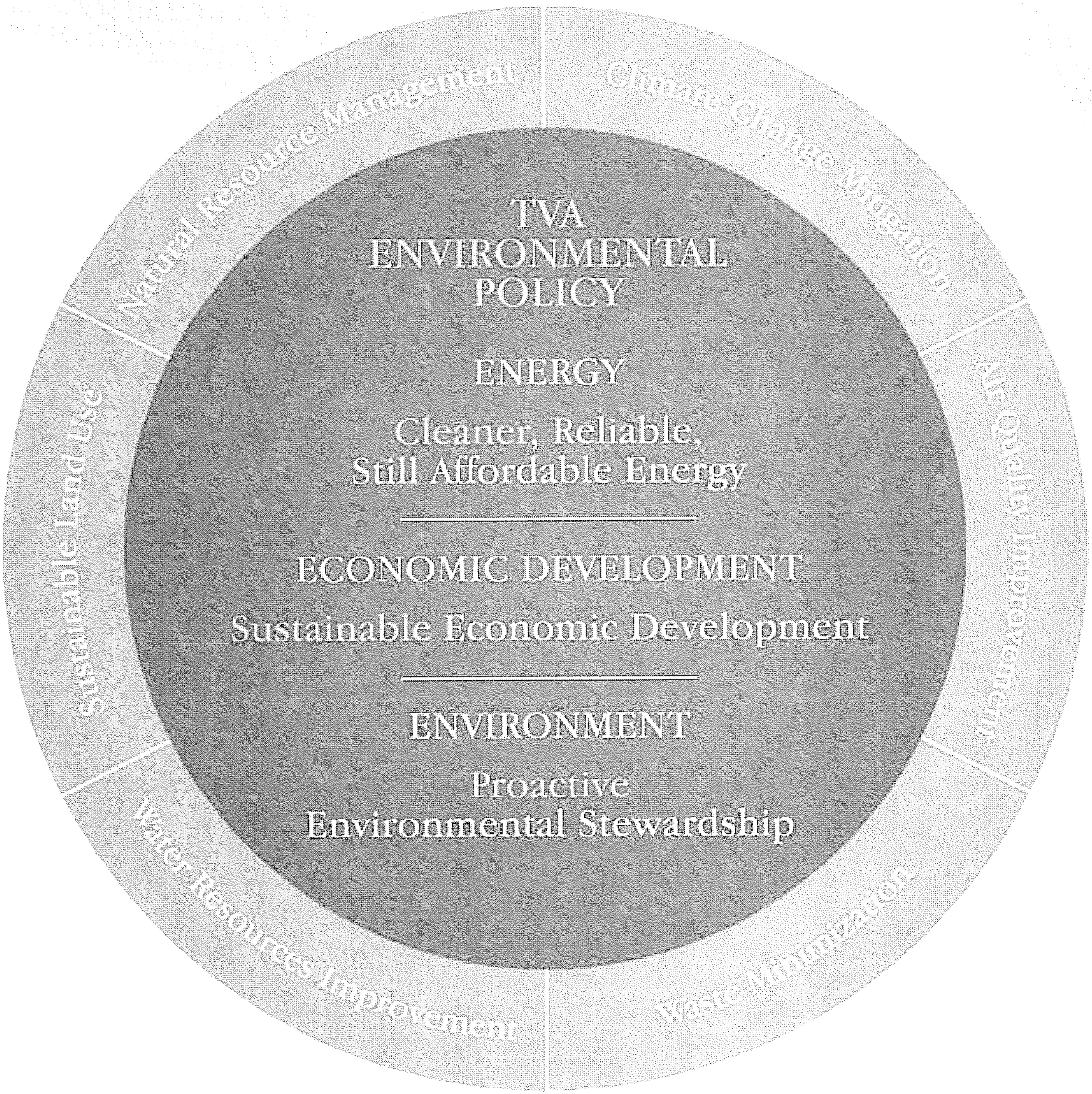


President Franklin D. Roosevelt (seated) signs the Tennessee Valley Authority Act, creating TVA on May 18, 1933.

Trout fishing in the Clinch River near Norris Dam is just one of the many recreational amenities available to the people of the Tennessee Valley.

Construction overlook of the Norris Dam located in Anderson and Campbell Counties in Tennessee, c. mid-1930s.

TVA's Environmental Policy



1 TVA's Environmental and Energy Future

After more than two years of development, the Tennessee Valley Authority (TVA) has completed its Integrated Resource Plan (IRP), entitled TVA's Energy and Environmental Future. This IRP is the product of extensive analysis and collaboration with many of TVA's partners and stakeholders.

Many electric utilities use the integrated resource planning process as a decision tool to help define both near- and long-term challenges. For TVA, the process was expanded to consider impacts on the environment and the economy. The IRP provides guidance in choosing the best resource options to meet future energy demand by considering future uncertainties, power reliability, financial, economic and environmental impacts associated with those options.

TVA's IRP has been developed to support TVA's mission for meeting the electric power needs of the Tennessee Valley region in a sustainable manner. The 20-year strategy recommended by the IRP provides direction for decisions that require a long lead time. It is consistent with TVA's Environmental Policy and its renewed vision – to become one of the nation's leading providers of low-cost and cleaner energy by 2020. The renewed vision and this IRP will better equip TVA to meet the substantial challenges facing the electric utility industry for the benefit of TVA stakeholders.

1.1 TVA Overview

1.1.1 Yesterday – An Innovative Solution

TVA stands as one of President Franklin D. Roosevelt's most innovative ideas. He envisioned TVA as "a corporation clothed with the power of government but possessed with the flexibility and initiative of a private enterprise."

TVA is a federal agency and corporation, wholly owned by the people of the United States and tasked by Congress to:

- Improve the quality of life for the residents of the Tennessee Valley region
- Foster economic development
- Promote conservation and wise use of the region's natural resources

Since its inception, TVA has worked to improve the quality of life for the people who live in the TVA service area. For more than 75 years, TVA has succeeded in its unique mission of serving the region through energy, environment and economic development. TVA established integrated resource management as the means for solving the competing and often conflicting interests of its mission, such as managing the Tennessee River system for navigation, flood control, recreation and power production. While the challenges evolved and new ones developed, TVA has relied on its strategy of devising integrated solutions.

1.1.2 Today – The Mission Continues

TVA's multi-faceted mission of providing low-cost, reliable power; serving as a catalyst for economic development; protecting the environment; stimulating technological innovation and managing an integrated river system in the Tennessee Valley region is the same today as it was 78 years ago.

TVA operates the nation's largest public power system. It provides power to more than nine million people, through 155 distributors of TVA power and 56 directly served customers, in an area encompassing 80,000-square-miles, including most of Tennessee and parts of Alabama, Georgia, Kentucky, Mississippi, North Carolina and Virginia.

Low-Cost Power

Maintaining a diverse portfolio of generation resources helps TVA keep power rates in the Tennessee Valley competitive regionally and nationally. TVA operates 56 active coal-fired units, six nuclear units, 109 conventional hydroelectric units, four pumped-storage units, 87 simple-cycle combustion turbine units, eight combined cycle units, nine diesel generator units, one digester gas site, one wind energy site and 14 solar energy sites.[1]

[1]As of Sept. 30, 2010

A portion of TVA's electrical supply is purchased from third-party operators under long-term purchased power agreements (PPAs). This diverse supply portfolio has enabled TVA to meet the region's energy demands, reliably and at competitive prices.

While keeping prices low, TVA has maintained world-class transmission reliability. TVA's transmission system is one of the largest in North America. It efficiently delivered more than 177 billion kilowatt-hours to customers in 2010. For the past 12 years, the system has achieved 99.999 percent reliability.

Economic Development

A benefit of TVA's large power system is the ability to produce power at prices below the national average, thus attracting industry to the region and making TVA a national leader in economic development. During the past five years, TVA has helped attract or retain 265,000 jobs in its service territory and has secured more than $27 billion in capital investment for the region through its Valley Investment Initiative program.

The Watts Bar Nuclear Plant's Unit 2 project created 3,200 construction jobs.

After completion in 2013, it will provide 300 permanent jobs.

In 2010, TVA worked in partnership with state and local officials in the recruitment and/or expansion of 150 companies in the TVA service area. One of TVA's most recent economic development initiatives has been the Megasites program. Through the Megasites program, five large industrial sites were sold to Dow Corning/Hemlock Semiconductor, Volkswagen, Paccar, Toyota and SeverCorr.

Environmental Stewardship

TVA's environmental stewardship (non power) programs include managing the Tennessee River and approximately 293,000 acres of reservoir lands to protect natural resources, to enhance economic development, and to provide recreational opportunities, adequate water supply and improved water quality within the Tennessee Valley watershed.

TVA's Environmental Policy provides objectives for an integrated approach related to providing cleaner, reliable and affordable energy, supporting sustainable economic growth, and engaging in proactive environmental stewardship. The Environmental Policy provides additional direction in several environmental stewardship areas, including air quality improvement, climate change mitigation, water resource protection and improvements, sustainable land use and natural resource management.

Aligning with the objectives of the Environmental Policy and TVA's renewed vision, TVA is committed to continue minimizing the environmental impacts of its operations. In 1995, TVA was the first utility in the nation to participate in a voluntary greenhouse gas reduction program sponsored by the U.S. Department of Energy. As a result, TVA has reduced or avoided more than 305 million tons of carbon dioxide (CO_2) from being emitted into the atmosphere.

Today, air quality across the region is the best it has been in more than 30 years. Since 1977, TVA has spent more than $5 billion on clean air controls. The controls have reduced sulfur dioxide (SO_2) emissions by 82 percent and nitrogen oxide (NO_x) emissions by nearly 86 percent from 1990 levels.

Technological Innovation

TVA is also committed to technological innovation. In 2000, TVA developed the first wind farm in the Southeast, and five of today's 14 solar photovoltaic sites were constructed for its green power pricing program, Green Power Switch®. In 2001, the program was expanded to include methane co-firing at Allen Fossil Plant in Memphis, Tenn.

Recently, TVA partnered with Nissan North America, the State of Tennessee, the Electric Transportation Engineering Corporation and local distributors to develop a plan to deploy electric vehicle charging stations. In January 2011, TVA and the Electric Power Research Institute unveiled an electric vehicle charging station that can make electricity from sunlight, store it and put it back in the power grid when needed.

Integrated River Management

TVA has remained focused on its mission to manage the nation's seventh-largest river system. TVA works constantly to balance energy production, navigation, flood control, recreation and water supply to provide multiple benefits from its management of the river system and associated public lands. In an average year, TVA prevents about $240 million in flood damage in the Tennessee Valley region and along the Ohio and Mississippi rivers.

TVA Customers

TVA delivers electricity to three main customer groups–local utilities (distributors of TVA power), directly served customers and off-system customers. A priority for TVA is to serve customers by meeting their needs in a reliable, responsible manner. Partnership with the distributors of TVA power is crucial in the delivery of low-cost, reliable power to end-use customers.

Distributors of TVA power comprise the bulk of TVA's customer base and are the backbone of the region's power distribution system. Accounting for roughly 81 percent of total

TVA sales and 87 percent of total TVA revenue, the distributors consist of municipally-owned and consumer-owned utilities. TVA generates and delivers electricity to the local utilities, which deliver electricity to their residential, commercial and industrial end-use customers. Municipal distributors comprise the largest block of TVA customers. Many of the consumer-owned cooperative utilities were formed to bring electricity to then-sparsely populated rural, remote areas of the Tennessee Valley region.

Large industries and federal installations, such as Oak Ridge National Laboratory, that buy electricity directly from TVA, account for 19 percent of total sales and 13 percent of TVA's total revenue. The remainder of TVA's sales and revenue comes from off-system customers that buy power from TVA on the interchange market.

TVA power contracts govern the relationships between TVA and the distributors of TVA power, including the pricing structure under which power is sold. These contracts provide for distributors' total power requirements, meaning TVA agrees to generate and deliver enough electricity to meet the distributors' full electric load, including reserves, both now and in the future.

1.1.3 Future – A New Era

In the face of challenging economic conditions, tougher emissions standards, an aging generating fleet and emerging customer needs, TVA needed to examine its strategic direction. In August 2010, TVA President and Chief Executive Officer, Tom Kilgore, announced a renewed TVA vision. The renewed vision is the first step toward establishing a new strategic direction for TVA.

TVA's renewed vision – to become one of the nation's leading providers of low-cost and cleaner energy by 2020 – will help the region and the nation achieve a cleaner energy future. The vision has three components:

1. To be the nation's leader in improved air quality
2. To be the nation's leader in increased nuclear production
3. To be the Southeast's leader in increased energy efficiency

> In support of the renewed vision, TVA plans to idle nine coal-fired units (1,000 MW) over the next five years.

TVA will work to achieve this vision while being dedicated to improving its core business of low rates, high reliability and responsibility.

1.2 Looking Ahead

1.2.1 Bridging the Gap

TVA undertook the IRP process at a critical time. Nationally, there is a consensus that energy should be produced in cleaner ways—a direction that TVA has embraced in specific goals set forth in its environmental policy and renewed vision. Achieving these goals and keeping electricity affordable is a significant challenge. Analyses of stakeholder concerns, operational constraints and the trade-offs necessary to develop an acceptable long-term solution make the challenge particularly difficult, especially when coupled with the recovering economy and regulatory uncertainty facing the utility industry.

TVA last completed an Integrated Resource Plan, entitled *Energy Vision 2020* (EV2020), in 1995. EV2020 was a comprehensive assessment of alternative strategies developed for meeting future electricity needs through 2020 based on projected future conditions in the Tennessee Valley region.

While EV2020 accurately reflected the challenges, forecasts and opportunities at the time of publication, significant changes in the industry and changing customer demand called for a fresh analysis and plan.

This IRP was built from the foundation established in EV2020, incorporates changes that have transpired and will ensure the best possible solutions are implemented for TVA and its stakeholders.

1.2.2 Challenges Facing TVA

The size of TVA's power system and its influence on the region's economy, environment and resources make integrated resource planning significant to the public it serves. The competitive success of businesses and industries, as well as the ability to sustain and improve the quality of life for the millions served by TVA electricity, are significantly impacted by the decisions that will be guided by the results of the IRP process.

Electricity cannot yet be stored economically in meaningful quantities, so the supply of electricity must constantly be balanced with the demand. Therefore, electricity providers such as TVA must project the future demand and take the necessary steps to meet the forecasted demand. This involves the construction of generating capacity and the procurement of purchased power. Given the long lead times required to plan, permit and build generating facilities, demand forecasts involve 10- to 20-year outlooks.

Effective transmission is usually a cost-effective means of providing power system flexibility and reliability. However, potential effects on water, vegetation, wildlife and other environmental concerns make this an option that must be carefully evaluated.

Transmission expansion also requires long lead times and is a vital component in meeting forecasted demand. It is particularly necessary to acquire renewable energy, which tends to be located outside TVA's service area and is intermittent in nature.

In addition to building generating facilities and purchasing power from independently owned facilities through long-term contracts, TVA and distributors of TVA power can meet demand by deploying programs that encourage energy efficiency and reduce demand during daily periods of peak power use. These activities entail associated uncertainty and risk that must be managed to ensure reliability.

Designing and executing an effective strategy is a major planning challenge for all electric utilities. TVA meets the challenge by working with stakeholders to design a long-term resource plan that recognizes the choices that must be made to achieve a common goal of an affordable, clean and reliable supply of electricity.

1.3 Integrated Resource Planning

1.3.1 Role of the Integrated Resource Plan

Integrated resource planning is a crucial element for success in a constantly changing business and regulatory environment and is based on comprehensive, holistic and risk-aware analysis. The integrated approach considers a broad spectrum of feasible supply- and demand-side options and assesses them against a common set of planning objectives and criteria, including environmental impact.

The IRP objective is to help meet future customer demand by identifying the need for generating capacity and determining the best mix of resources to fill the need. The capacity gap is the difference between the projected firm (or known) requirements and existing firm supply.

The following strategic principles guided development of this IRP:

- Mitigate risk at a reasonable cost
- Balance generation resources to reduce supply and price risk
- Balance production and load
- Minimize environmental impacts of the portfolios
- Provide incentives to customers to optimize the load factor
- Provide flexibility to adapt to changing market conditions and future uncertainty

- Improve credibility and image through a comprehensive, balanced and transparent approach
- Integrate perspectives of internal and external stakeholders throughout the process

1.3.2 Integrated Resource Planning Process

Instead of one correct answer, this IRP entails a robust, "no-regrets" plan that balances competing objectives while reducing costs and risks and retaining the flexibility to respond to future risks and opportunities.

This IRP was framed to assess future demand and the cost and quantity of future supply options. Therefore, forecasts of various inputs (e.g., inflation, commodity prices and environmental regulations) were simultaneously evaluated. Constraints (e.g., corporate strategic and environmental objectives) were considered as different combinations of strategies and futures were analyzed and evaluated. Afterward, additional extensive computer modeling, analyses, public input, reviews and dialogue with TVA's leadership led to the consideration of strategic alternatives.

"No-regrets" is a plan that best balances competing objectives while reducing costs and risk and retaining the flexibility to respond to future risk and opportunities as they unfold.

TVA recognizes that the future is uncertain and that forecasts and stakeholder concerns can change. To take advantage of updated information and encourage ongoing public involvement in defining the region's future energy needs, TVA is committed to begin the next IRP effort by 2015.

1.4 IRP Deliverables

1.4.1 Draft and Final IRP Documents

The Draft IRP was released Sept. 15, 2010, for public review and comment. It provided a broad look at all options considered by TVA and the long-term implications of various business strategies.

The final IRP recommends a robust, flexible strategy that supports TVA's renewed vision. The Recommended Planning Direction entails an outcome that balances costs, efficiency in electricity generation, reliability, energy efficiency, environmental responsibility and competitive prices for customers.

1.4.2 Natural Resource Plan

Since the June 15, 2009, publication of the IRP Notice of Intent, TVA determined that planning processes for the Environmental Policy goals that are not closely tied to energy production and consumption would be better addressed in a separate study.

Therefore, a Natural Resource Plan will evaluate the implementation of TVA's reservoir lands planning, natural resource management, water resources management and recreation processes and strategies. The content of the accompanying environmental impact statement will be consistent with TVA's Environmental Policy, TVA's Land Policy, the previous Shoreline Management Initiative Environmental Impact Statement and the Reservoir Operations Study Environmental Impact Statement.

1.4.3 Draft and Final Environmental Impact Statement

As a federal agency, TVA must comply with the National Environmental Policy Act of 1992 (NEPA). The act requires all federal agencies to consider the impact of its proposed actions and alternatives on the environment before making decisions with potential environmental impacts. The NEPA process provides a structured means for analyzing competing options and for involving the public in TVA's decision-making process. The primary product from the NEPA process is an environmental impact statement (EIS).

Even though the IRP and the associated EIS were combined into one document for EV2020, they are published as two separate documents for this IRP. The components of the associated EIS were incorporated into the overall integrated resource planning process. This provided a preferred resource plan that focuses on reducing costs and risk while improving TVA's environmental performance.

TVA chose to develop a programmatic level EIS as opposed to a project- or site-specific document because of the broad nature of integrated resource planning.

As part of the final IRP, TVA prepared an associated EIS in accordance with the NEPA 42 USC §§ et seq., Council on Environmental Quality regulations for implementing NEPA.

1.5 IRP Outline

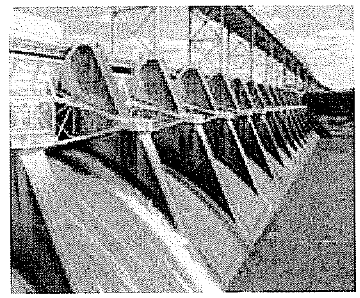
This IRP consists of nine chapters and six appendices.

Chapter 1	TVA's Environmental and Energy Future – history of TVA, TVA overview, looking ahead, the IRP's role and purpose, the goals and objectives of this IRP, the overall process, release of the Draft IRP and the associated EIS, incorporation of public input and IRP deliverables
Chapter 2	IRP Process – seven distinct steps of the IRP process and how public participation was incorporated in each step
Chapter 3	Public Participation – public participation components during this IRP process and summary of the valuable input received
Chapter 4	Need for Power Analysis – TVA's need for power analysis, TVA power supply, base-load, intermediate, peaking, storage resources and TVA's generation mix
Chapter 5	Energy Resource Options – potential supply- and demand-side options for future TVA power portfolios
Chapter 6	Resource Plan Development and Analysis – overview of scenario and strategy development, key uncertainties that defined the scenarios, planning strategies, portfolio development, planning strategy scorecard (including ranking and strategic metrics), scorecard calculation and planning strategy evaluation
Chapter 7	Draft Study Results – results from the Draft IRP analysis which includes the identification of the preferred planning strategies
Chapter 8	Final Study Results and Recommended Planning Direction – results from the final IRP study which includes the identification of the Recommended Planning Direction
Chapter 9	Next Steps – identifies next steps and recommendations
Appendix A	Method for Computing Environmental Metrics – process and results from the analysis used to determine the impact of the Recommended Planning Direction on the TVA environment
Appendix B	Method for Computing Economic Impact Metrics – process and results from the analysis used to determine the impact of the Recommended Planning Direction on the TVA economy
Appendix C	Energy Efficiency and Demand Response – process used to develop EEDR portfolio used in the Draft IRP and final analysis for the Recommended Planning Direction
Appendix D	Development of Renewable Energy Portfolios – process used to develop the renewables portfolio used in the Draft IRP and the final analysis for the Recommended Planning Direction
Appendix E	Draft IRP Phase Expansion Plan Listing – 20-year expansion plans for each strategy evaluated during the Draft IRP analysis
Appendix F	Stakeholder Input Considered and Incorporated – comments were reviewed in detail and input was incorporated

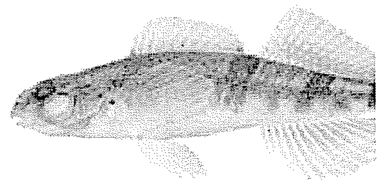
TVA's Environmental and Energy Future

CHAPTER 2

TVA was created to be a model of benefits of integrated resource management. To fulfill its mission requires a delicate balance of energy, environmental and economic development.



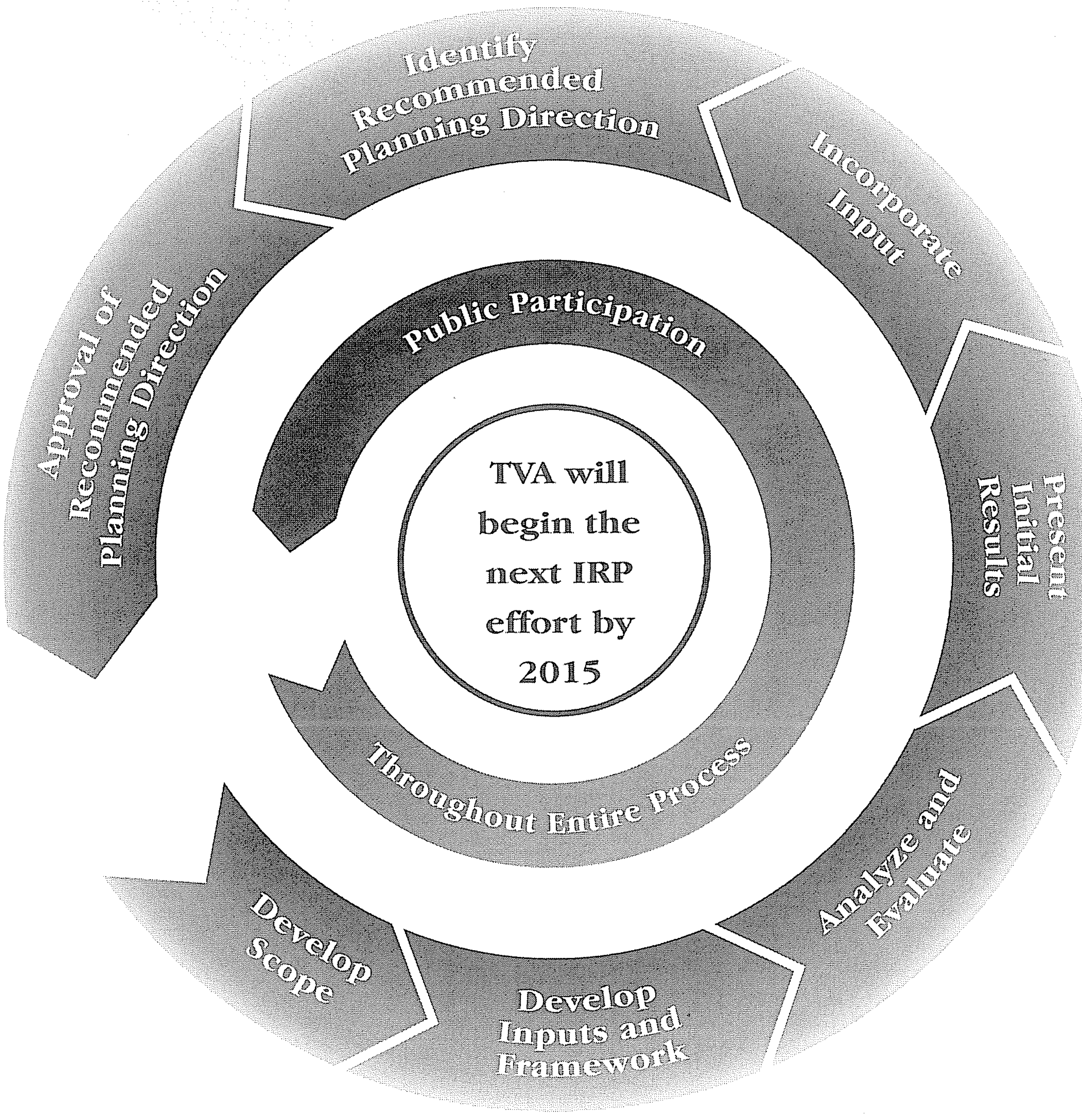
Water spills over the Fort Loudon Dam in Loudon County, Tennessee.



The once-endangered Snail Darter, native to rivers of the Tennessee Valley, is now thriving due in large part to the conservation efforts of TVA.

Enthusiasts enjoy white-water rafting down the Ocoee River in Polk County, Tennessee.

The IRP Process



2 IRP Process

The IRP process to develop the Recommended Planning Direction was extensive. More than two years were dedicated to discuss needs, wants, advantages, challenges, constraints, trade-offs and compromises required to develop a plan of this magnitude. A wide range of stakeholders were involved in this process, representing the general public, distributors of TVA power, industry groups, academia and research professionals and TVA leadership.

This IRP represents a significant investment by TVA to understand the needs of the people it serves and how to address those needs in a cost-effective, reliable manner. TVA believes in this process and has committed to begin the next IRP effort by 2015.

To fully appreciate the scope of TVA's IRP process, the road to producing the final IRP must be understood. TVA's IRP process consisted of the following seven distinct steps:

1. Develop scope
2. Develop inputs and framework
3. Analyze and evaluate
4. Present initial results
5. Incorporate input
6. Identify Recommended Planning Direction
7. Approval of Recommended Planning Direction

Public participation was included in each step of the process and is explained in more detail in Chapter 3 – Public Participation. The process for steps two through six are described in more detail in Chapter 6 – Resource Plan Development and Analysis. Step seven, approval of Recommended Planning Direction, is described in Chapter 8 – Final Study Results and Recommended Planning Direction.

2.1 Develop Scope

In June 2009, TVA began a public scoping period. Public scoping comments addressed a wide range of issues, including the nature of the integrated resource planning process, preferences for various types of power generation, increased energy efficiency and demand response (EEDR) and the environmental impacts of TVA's power generation. The comments received helped TVA identify issues that were important to the public.

2.2 Develop Inputs and Framework

When faced with a challenge like planning the power system for the next 20 years, a "no-regrets" decision-making framework is generally the best approach. A "no-regrets" framework is one in which decision makers utilize the best possible information available to them. This allows them to weigh the likelihood and consequence of the risks and challenges that could surface so that decisions have a high likelihood of being sound in many possible states of the world. In order to facilitate a "no-regrets" decision-making framework, TVA employed a scenario planning approach in the development of this IRP.

Scenario planning provides an understanding of how near-term and future decisions would change under different conditions. This allows for impacts on different courses of action to be effectively analyzed. These actions are then assessed to determine their performance in each and every scenario as well as their relative performance in all scenarios.

Future decisions that produce similar results across different conditions may imply that these decisions provide more predictable outcomes, whereas decisions that result in major differences are less predictable and therefore more "risky."

TVA began this process in collaboration with the Stakeholder Review Group (SRG) and developed a set of resource planning strategies that would be analyzed within the framework of this IRP.

These resource strategies represent decisions that TVA has control over (e.g., asset additions, idling coal-fired capacity, integration of more flexible resource options), whereas the scenarios, which are described in more detail below, represent aspects that TVA has no control over (e.g., more stringent regulations, fuel prices, construction costs).

Different mixes of resource options (i.e., supply-side generating technologies and demand-side programs) formed the framework for distinct resource planning strategies and were designed to allow for flexible resource selection over the intended duration of the IRP planning horizon. Significant expert input was incorporated to ensure the feasibility of the elements of each planning strategy.

Strategies represent future business decisions that TVA can make and has full control over.

Scenarios represent future conditions that TVA cannot control.

A portfolio is the intersection of a strategy and a scenario and represents a multiyear resource plan detailing how TVA intends to meet future load growth.

To facilitate a "no-regrets" analysis of the strategies developed above, TVA developed a series of scenarios to analyze the various outcomes of the resource planning strategies.

These scenarios differed from each other in several key areas, such as projected customer demand, future economic conditions, fuel prices, regulatory frameworks and numerous other key drivers. Like the strategies, these scenarios were also developed in collaboration with the SRG.

The goal of defining scenarios was to identify sets of potential events, forecasts and other important drivers that TVA cannot directly control, but that would have a direct impact on TVA's ability to achieve the goals of this IRP.

One way to think of scenarios is as miniature models of the future. In one model, the economy might stagnate, prices drop and electricity demand remains flat. In another, strong economic recovery could pressure fuel prices, drive interest rates higher, lead to rapid recovery in electricity sales and long-term demand growth and put pressure on the cost of building generating assets. Both scenarios present dramatically different challenges to any one resource strategy.

Therefore, the key to sound resource planning is designing a strategy that performs reasonably well in all scenarios, regardless of which scenario best captures the actual state of the world in the future.

Seven scenarios were initially developed. Each resource planning strategy was tested within the seven scenarios for performance. The seven scenarios and five strategies are explained in detail in Chapter 6 – Resource Plan Development and Analysis.

2.3 Analyze and Evaluate

After the scenarios and strategies were developed, detailed analysis was undertaken for each planning strategy within each of the scenarios. This phase of the IRP employed industry standard capacity expansion planning and production cost modeling software to develop total cost estimates of each planning strategy in each scenario. Other metrics, including near-term rate impacts, risks and environmental footprint, were also developed using model outputs.

TVA analyzed the hypothetical performance on the cost, risk and environmental footprint of each strategy based on the assumption that the future unfolds in a manner that resembles the specifics of each scenario.

A total of 35 unique capacity expansion plans or "portfolios" were developed for each of the seven scenarios specific to each of the five strategies. Each portfolio represented a long-term, least-cost plan of different asset mixes (both supply- and demand-side assets) that can be deployed to meet the power needs of the region.

Each portfolio was ranked using selected metrics within the framework of a consistent, standard scorecard. Special care was also taken to note not only those portfolios that performed best overall, but also those portfolios that performed well in most states of the future (a key requirement for a "no-regrets" portfolio development). The metrics used were chosen based on their importance and centrality to TVA's mission and included measures for capturing financial (e.g., cost and risk), economical and environmental impacts.

The ranking was not intended to identify any single portfolio as "the best" in recognition of the fact that a portfolio with the highest overall score may not have performed as well as other portfolios across multiple scenarios. In other words, portfolios were analyzed for their robustness under stress across multiple scenarios, as opposed to overall performance in total. This was an important step since metrics alone could signify good performance in one or two future states of the "world," but average or poor performance in all others.

The process of a consistent analytical ranking exercise provided TVA's Board of Directors and leadership team with information that was used to help conduct evaluations of decisions pertaining to TVA's existing generation fleet and available generation options. It also facilitates TVA's ultimate adoption of a long-term resource planning strategy that will serve as a foundation for TVA's near-term business and financial plans.

2.4 Present Initial Results

For this phase of the IRP process, TVA presented the results of the Draft IRP and the associated EIS to both internal TVA management and the general public. The Draft IRP outlined alternative strategies that TVA considered, but did not include an exhaustive list of all strategies that were analyzed. However, it did include a sampling of unique strategies that represent a broad spectrum of viable options for implementation.

As in the scoping period, TVA encouraged public comments on the Draft IRP and the associated EIS. The comments received enabled TVA staff to identify public concerns and recommendations concerning the future operation of the TVA power system.

The public comment period began in October 2010 with the EPA's publication of the Notice of Availability of the Draft IRP and associated EIS in the Federal Register.

During the public comment period, TVA held five public meetings to provide information about this IRP as well as the opportunity to provide input to TVA staff.

TVA addressed all substantive comments received during the public comment period in the final IRP and the associated EIS.

2.5 Incorporate Input

The public comment period ended Nov. 15, 2010. TVA received approximately 500 comments. All comments were reviewed in detail and synthesized into key points that required a response. Comments were logged into a comment management database for tracking purposes and assigned to an appropriate subject-matter expert. An extensive inventory of responses is included in the associated EIS.

2.6 Identify Recommended Planning Direction

After review of the public comments received and additional analysis, TVA staff identified a Recommended Planning Direction to present to TVA's Board of Directors. The Recommended Planning Direction is based on a number of key criteria, as mentioned above, and is intended to serve as a guide for implementation of TVA's planning objectives.

2.7 Approval of Recommended Planning Direction

No sooner than 30 days after the Notice of Availability of the associated EIS is published in the Federal Register, the TVA Board of Directors will be asked to approve the Recommended Planning Direction. The TVA Board of Directors' decision will be described and explained in a Record of Decision.