CHAPTER 8

NEED FOR POWER

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CHAPTER 8

NEED FOR POWER

8.0 NEED FOR POWER

Tennessee Valley Authority (TVA), a non-regulated utility, is one of the nation's largest public power systems. The TVA has identified a need for baseload generation capacity within its relevant service area. In accordance with the provisions of Title 10 of the Code of Federal Regulations (CFR) Part 52, the TVA intends to submit an application for a combined license (COL) for the Bellefonte Nuclear Plant, Units 3 and 4 (BLN).

This ER chapter describes the methods utilized to assess the need for power for this proposed activity. The evaluation of need for power is described in the following sections:

- Description of Power System (Section 8.1)
- Power Demand (Section 8.2)
- Power Supply (Section 8.3)
- Assessment of Need for Power (Section 8.4)

8.1 DESCRIPTION OF POWER SYSTEM

The TVA serves an 80,000 sq. mi. region encompassing almost all of the state of Tennessee and portions of the states of Kentucky, Mississippi, Alabama, Georgia, North Carolina, and Virginia (Figure 8.1-1). The TVA service area is the relevant service area for the purposes of the need for power analysis. The major load centers are the cities of Memphis, Nashville, Chattanooga, and Knoxville, Tennessee, and Huntsville, Alabama. Figure 8.1-2 illustrates the electrical transfer capabilities between the TVA and neighboring utilities.

The population of the service area in 2006 is estimated to be 8,836,484. TVA currently serves 158 municipal and cooperative customers as their sole wholesale supplier of electricity, and 61 directly served industries as retail customers. The total number of customers in 2006 was 4,394,604. Table 8.1-1 provides the breakdown by types of customers. Table 8.2-9 provides the annual electricity usage (kWh) in 2005 for residential, commercial and industrial customers.

Sixteen of the 61 directly served customers are large electricity users and rank in the top half of TVA's wholesale customers in terms of sales; eight rank in the top quartile; and two (ALCOA and USEC) rank in the top decile. Table 8.1-2 provides the percentage of electricity that TVA supplies to each state in its service area. The TVA supplies almost all of electricity needs (99 percent) in Tennessee, 32 percent in Mississippi, 27 percent in Alabama, and 26 percent in Kentucky. Its contribution to the electricity needs in Virginia, North Carolina, and Georgia is 3 percent or less in each state.

The TVA is not a member of a power pool and has no standing arrangements for ongoing exchange of power or joint ownership of generating facilities. TVA does have interconnection agreements with its neighboring systems, and these agreements (mutual arrangements) typically provide for emergency backup power. The emergency arrangements are typically triggered in the event of a North American Electric Reliability Corporation (NERC) Energy Emergency Alert (i.e., the sudden loss of generation by one of the participants in the agreement) and provide for short-term provision of emergency power if available from the neighboring system. TVA's interconnection agreements typically also address situations involving transmission constraints (e.g., a line outage or maintenance of facilities) and the continuation of power delivery to affected customers.

As an agency of the United States, the TVA is not subject to the plenary jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Federal Power Act (FPA), and is not subject to the jurisdiction of any state public utility commission. The TVA is, however, subject to certain limited aspects of FERC jurisdiction, including the provision of open access transmission service, interconnections, and compliance with FERC-approved reliability standards. The TVA service area is one of five major sub-regions of the Southeastern Electric Reliability Corporation (SERC). SERC is divided geographically into five diverse sub-regions that are identified as Entergy, Gateway, Southern Company, TVA, and the Virginia-Carolinas Area (VACAR). Figure 8.1-3 illustrates a map of the SERC region identifying the five sub-regions. SERC Standing Committees include Engineering, Operating, and Critical Infrastructure committees that coordinate planning, standards, and compliance activities for the region.

The SERC was created to augment bulk power reliability in the southeastern United States. In performing its reliability objectives, the SERC members exchange information with one another regarding the planning and operation of their systems. This ensures the continued reliability of the interconnected systems, and facilitates periodic review of reliability-related activities within the Region. The SERC Engineering Committee (EC) was established to assist the SERC Executive Board in carrying out the purposes of the organization as they relate to the planning and engineering issues facing the members. Recognizing the need for a regional review of reliability matters on a continuing basis by knowledgeable individuals, the EC formed the Reliability Review Subcommittee (RRS). The RRS conducts seasonal and annual reliability assessments of the SERC Region by reviewing the data and studies submitted by SERC member systems, and performs a myriad of related tasks in the assessment of the reliability of the interconnected bulk power system of the SERC Region.

SERC utilizes its staff-facilitated RRS to perform assessments of future reliability and adequacy of the region and to prepare reports. Using information from the region's data collection efforts, the RRS makes an independent assessment of the ability of the region and subregions to serve their obligations given the demand growth projections, the amount of uncommitted or contracted capacity, etc. The RRS determines if the resource information submitted represents a reasonable and attainable plan. Also, the RRS annually performs a transmission assessment based on regional, interregional, and subregional reliability studies. The studies are reviewed and analyzed. If any additional study is required, the RRS requests the appropriate regional studies group to perform the study. The RRS's assessment provides a judgment on the ability of the SERC power system to operate securely under the expected range of operating conditions over the assessment period as required by the NERC Reliability Standards.

TABLE 8.1-1
TVA CUSTOMERS IN 2006 BY TYPE

Customer Type	Number
Residential	3,702,342
Small Commercial	607,647
Large Commercial	66,391
Street Lighting	7,122
Outdoor Lighting	11,041
Directly Served Industrial	61
Total	4,394,604

TABLE 8.1-2
PERCENTAGE OF ELECTRICITY SUPPLIED IN FISCAL YEAR 2006 TO EACH STATE IN THE TVA SERVICE AREA[(a)]

State	TVA Distributor Served (GWh)	TVA Directly Served (GWh)	Total TVA Served (GWh)	Est. State Usage from EIA Data (GWh)	Portion of State Usage Served by TVA (%)
TN	99,416	8,782	108,198	109,566	99
MS	11,993	3,050	15,043	46,583	32
AL	18,324	6,198	24,522	91,512	27
KY	8,082	14,677	22,759	88,912	26
GA	3,981	-	3,981	136,908	3
NC	665	6	671	129,061	1
VA	152	10	162	108,373	0.1
Total	142,613	32,722	175,335	710,914	

a) Fiscal Year begins October 1 of the preceding calendar year of the same number and ends on September 30 of the calendar year.

8.2 POWER DEMAND

Electricity is a just-in-time commodity. It cannot be stored in meaningful amounts, so the resources needed to produce the amount of electricity demanded from a system must be available when the demand is made. If demand for power cannot be met, reductions and curtailments in service, brownouts or blackouts result. One of the TVA's most important responsibilities is ensuring that it is able to meet the demand for electricity placed on its power system.

Power demand can best be analyzed by evaluating its two major components, power and energy requirements, and factors affecting growth of demand. The TVA conducted a comprehensive review of demand for power, power supply and need for power in its Integrated Resource Plan, Energy Vision 2020 EIS (TVA 1995) which evaluated a suite of options addressing these issues out through the year 2020 (Reference 1). The information presented in this section constitutes an update of those earlier analyses of need for power as they relate to the present proposal for the BLN site. Historic and projected electricity consumption and peak load demands in the relevant service areas and markets are discussed in the following sections, as well as identifying and analyzing the factors that contributed and are expected to contribute to these conditions. Unless otherwise noted, reference to particular years are to TVA fiscal years, which begin October 1 of the preceding calendar year of the same number and end on September 30 of the calendar year.

8.2.1 POWER AND ENERGY REQUIREMENTS

This section provides the analysis and evaluation of the historic and projected electricity consumption and peakload demands in the TVA service area. It addresses the methodology of the projections and the forecast assessments of the accompanying factors.

8.2.1.1 Methodology

TVA prepares near-term and long-term forecasts of demand and energy use utilizing different methods tailored to the available data and customer requirements.

The near-term forecast (up to 3 years) is developed by combining both a distributor and direct-served energy forecast, then making adjustments for losses to arrive at a system forecast. Near-term distributor energy forecasts are based on forecasts of employment (for the commercial and industrial (C&I) sector), residential customer count (for the residential sector), and trends of average use per residential customer and per employee. Each forecast is adjusted for the impacts of abnormal weather and seasonality from the monthly energy history. Near-term direct-served customer energy forecasts are based on customers' recent history, contract terms, and business outlook.

The TVA forecasts long-term electricity demand (up to 25 years) using a series of models that relate energy consumption to driving factors, particularly growth of the economy, the price of electricity, the price of natural gas as a competing fuel, as well as both growth or decline in the direct served sector:

Economic growth is the single most important driver of electricity sales. The TVA economic forecast uses a U.S. economic forecast from a national forecasting service and an econometric model that maps the relationships between the U.S. economy and the relevant service area economy. The TVA model takes into account the different mix of industries in the TVA service area and the relative competitive advantage of each. The model outputs include TVA service area forecasts for employment, production, income, and population. Population, number of households, employment, and Gross Regional Product (GRP) forecasts from the economic model are used to drive electricity sales forecasts for both the residential sector and distributor-served C&I sector by Standard Industrial Code (SIC) groupings.

Electricity use varies inversely with the retail price of electricity. For the current fiscal year, constant wholesale prices are used for firm power in accordance with TVA's published rates. For the remaining forecast years, TVA wholesale prices are based on revenue requirements, including targeted net income and debt repayment.

Natural gas competes with electricity for a number of end uses in the residential, commercial, and manufacturing sectors. Higher gas prices encourage more use of electrically powered equipment, and vice versa. The retail price of natural gas is based on TVA's internal forecast of the Henry Hub gas price. The Henry Hub price forecast is used in the demand forecasting process to determine the market share of space heating, water heating, and cooking by gas versus electricity. It is just one component of the retail gas forecast, which also includes transportation and distribution costs. Conversion to retail prices is based on recent relationships between wholesale prices and the retail prices charged by local distribution companies.

Little long-term growth is forecast for current direct-served customers. New industrial customers are assumed to be served by distributors. The most rapidly growing segments of the economy are industries for which large, single installations are not common.

For demand by distributor-served customers, several types of models are used. Econometric models and trend models use statistical methods to estimate the relationship between the drivers and electricity demand. The residential sector is modeled using the number of customers, population and income as the primary drivers and the C&I sector is modeled at the SIC North American Industry Code (NAIC) level using price, gross regional product and employment. To identify the impacts of changes in the underlying mix of usage within sectors (for instance, more widespread computer usage), a statistically adjusted end-use model approach is used. The model examines the detailed use of electricity in heating, cooling, and other categories. These models use the input forecasts summarized previously.

Transmission losses are added to sales forecasts to determine total load in the relevant service area. Load shapes, based on typical weather patterns, have been developed which reflect typical hourly usage patterns for TVA customers. These shapes are used to spread the sales forecast over the 8760 hrs. of the year. For each month, the highest hourly load becomes the peak forecast.

Uncertainty in the load forecast is quantified by evaluating the uncertainty in the future values of the input drivers and the uncertainty in the relationships between input drivers. The impact of alternative levels (high, medium, and low) of the key variables is evaluated for their impacts on future electricity consumption. This process is performed probabilistically and results in a wide range of alternative load forecasts. Several quantitative models are used to evaluate the relationship between major causal factors and their impacts on future electricity consumption.

Both econometric and economic end-use models are used. High and low forecasts are produced and a cumulative probability is developed. The 10 percent and 90 percent level loads are identified and serve as the basis for the high and low forecast.

The annual forecast error for the TVA net system requirements and summer peak load demand has been 1.0 percent and 2.4 percent, respectively, over the 10-year time period from 1997 to 2006. Figure 8.2-1 and Figure 8.2-2 compare weather-normalized annual system energy and demand observed for 1994 through 2006 with forecasts for each year prepared from July 1993 through 2006. Observed energy and demand data are weather normalized to separate weather effects from other and generally longer-term causes of load growth, such as population, and C&I economic activity, device usage, and technology and efficiency trends. Weather uncertainty is important to operational forecasts, but is addressed in long term planning forecasts through a weather normalization process. The TVA adjusts energy usage and sales to standard weather months and years based on heating and cooling degree days, and separately makes adjustments to peak demands depending on monthly extreme temperatures; i.e., highest/lowest temperatures in a month and at the time of the system peaks. Heating and cooling degree days are the departure of daily average temperature from a given base (65°F), where daily average temperature is just the average of high and low temperatures on that day. The energy and peak demand normalization adjustments are both based on statistically observed relationships between actual electricity demand and weather in the same period. The normalization adjustment is generally calculated as a weather differential multiplied by a load-to-weather relationship coefficient. Energy and demand forecasts are also based on weather-normalized input information. Figure 8.2-1 and Figure 8.2-2 illustrate reasonable accuracy of TVA energy and demand forecasts (1994 – 2006).

8.2.1.2 Forecasts of Energy, Capacity, and Load Factors

This section presents the historical energy and demand since 1990 and the forecast to 2022 for residential load, and C&I loads, net system requirements, and load factor. The forecast period is shown for five alternative load growth scenarios.

The demand and energy for the medium load forecast grow at a rate based on expected economic growth. Three relatively small distributors have served notice to TVA of their intent to terminate their contracts; however, because these customers represent less than 1.5 percent of TVA's load, the loss of these customers will not significantly affect the magnitude or timing of the need for additional baseload capacity. Therefore, for simplicity, TVA's current wholesale distributor customers are assumed to continuously renew their power supply contracts throughout the planning period. Industrial load growth is expected to be served by wholesale distributor customers. TVA continues to serve its retail customers under contract as of June 30, 2007; load growth assumptions for these customers reflect historical sales and announced plans. One customer, the United States Enrichment Corporation (USEC), has announced plans to move its nuclear fuel enrichment production from its plant in Paducah, Kentucky, to a new facility in Portsmouth, Ohio, where it is expected to be served by other suppliers.

Load forecasts for higher or lower loads are based on higher and lower economic growth. All other assumptions are the same as for the medium-load forecast. Figure 8.2-3 illustrates the actual and forecast residential load. Residential load grew at an average rate of 2.2 percent from 1990 through 2006. As shown in Table 8.2-1, residential load grows at an average rate of

2.4 percent through 2012. From 2012 to 2022, residential load grows at a rate of 2.0 percent, varying from 1.0 percent for low economic growth to 2.6 percent for high economic growth.

Figure 8.2-4 illustrates the actual and forecast C&I load for distributor-served and direct-served load. The USEC load is shown separately from the direct-served load because of its size. Regarding agricultural load, large farms are included in distributor C&I category and illustrated in Figure 8.2-4. Distributor-served C&I load grew at an average rate of 2.5 percent from 1990 through 2006. As shown in Table 8.2-2, distributor-served C&I load grows at an average rate of 2.1 percent through 2012. From 2012 to 2022, distributor-served C&I load grows at a rate of 1.9 percent, varying from 0.9 percent for low economic growth to 2.5 percent for high economic growth. Actual distributor-served C&I load grew at a high rate in the 1990s due to the expansions of the auto industry in the southeastern United States.

Direct-served industrial load grew at a rate of 0.6 percent from 1990 through 2006. Growth from 2006 through 2012 is forecast at 1.1 percent annually due to the startup of a new direct-served industrial plant in Mississippi. Direct-served industrial growth after that date is essentially flat and does not change with economic growth assumptions. Figure 8.2-4 illustrates the annual USEC load as discussed previously in the assumptions for each load growth scenario.

Figure 8.2-4a shows a breakdown of the actual and forecast direct-served industrial load in Figure 8.2-3 by category. Also shown is the USEC load from Figure 8.2-3 and direct-served Federal loads, which are not shown separately or included in the direct-served industrial load because they are primarily residential. Actual data are not available before 2002. The primary industries represented are aluminum and other metals, chemicals and fibers, and paper. The direct-served Federal category includes the Arnold Engineering Development Center, Tullahoma, TN; Redstone Arsenal, AL; Department of Energy at Oak Ridge, TN; Memphis, TN, Naval Air Support, Fort Campbell, KY, and the Columbus, MS, Air Force Base. The miscellaneous category consists of 19 smaller customers.

Figure 8.2-5 illustrates the actual and forecast net system requirements for TVA energy use, including residential, distributor-served C&I, direct-served industrial, USEC, other Federal direct-served, outdoor lighting, and losses. Large farms are included in the distributor C&I load and smaller farms (without a separate meter) are included in residential load. Municipal and cooperative loads for their own use are in distributor served C&I loads. There are no other utilities or rapid transit loads in the TVA load forecast. Agricultural and municipal loads for their own use are less than five percent of the total TVA load.

Net system requirements grew at an average rate of 2.4 percent from 1990 through 2006, driven by distributor-served residential and C&I load growth. Net system requirements are composed of sales (in MWh) to end use customers (municipal and co-ops distributors, direct-served industrial customers, federal and off-system), distributor losses, and system transmission losses. As shown in Table 8.2-3 net system requirements are projected to grow at an average rate of 2.0 percent through 2010. Net system requirements grow at an average rate of 0.3 percent annually from 2010 to 2014, reflecting the loss of production at USEC’s Paducah, Kentucky, plant. From 2014 to 2022, net system requirements grow at a rate of 1.7 percent, varying from 0.8 percent for low economic growth to 2.3 percent for high economic growth. Net system requirements are forecast to grow at a lower rate in the long term as compared to the recent past, since direct served industrial growth is assumed to be flat and the growth of the auto industry in the southeastern United States is expected to be slower than in the 1990 – 2006 period.

Figure 8.2-6 illustrates the actual and forecast peak load for the TVA service area. Forecast peak load is projected to always be in the summer months. Peak load grew at an average rate of 1.7 percent from 1990 through 2006. As shown in Table 8.2-4 summer peak load grows at an average rate of 2.0 percent through 2010. Summer peak load increases at an average rate of 2.0 percent annually from 2010 to 2014, despite the loss of demand from USEC's Paducah, Kentucky, plant. From 2014 to 2022, summer peak load grows at a rate of 1.9 percent, varying from 1.0 percent for low economic growth to 2.5 percent for high economic growth.

Comparison of Table 8.2-3 and Table 8.2-4 shows that summer peak loads are forecast to grow at a faster rate than net system energy requirements. Table 8.2-1 shows that residential loads are expected to grow at a rate of 2.0 percent in the 2012 – 2022 period, while distributor-served C&I loads grow at a rate of 1.9 percent, as shown in Table 8.2-2. Direct served industrial load growth is essentially flat as illustrated in Figure 8.2-4. The higher peak load growth rate increase, as compared to the growth rate identified for net energy system requirements, may be attributed to the loading characteristics of residential and industrial loads. Residential loads typically have greater hourly variation in electricity demand due to summer air-conditioning and winter heating and lights as compared to industrial loads. Figure 8.2-7 illustrates that the system load factor (annual energy use in MWh divided by the maximum hourly demand in MW times 8760 hrs. per year expressed as a percentage) is forecast to decrease from historical levels of 60 – 66 percent to 58 percent or less as the residential load comprises a greater portion of the TVA net system requirements. The change in composition of the TVA system load can also be seen in the load duration curve over time. Figure 8.2-8 illustrates the load duration curves for 2008, 2014, 2018, and 2022 under the medium-load forecast. Peak hourly loads increase by over 10,000 MWs from 2008 to 2022 while minimum hourly loads vary from 11,900 to 13,100 MWs over the same period.

8.2.2 FACTORS AFFECTING GROWTH OF DEMAND

This section identifies, analyzes and evaluates the factors that contribute to the rate of growth of electricity demand in the TVA relevant service area. It includes the impacts of economic and demographic trends, conservation, substitution, and the effects of price and rate structures.

8.2.2.1 Economic and Demographic Trends

Historically, the economy of the TVA service area has been more dependent on manufacturing than the United States as a whole, with industries such as pulp and paper, aluminum, and chemicals drawn to the region because of its natural resources and the availability of reliable, inexpensive electricity. Figure 8.2-9 and Table 8.2-5 show that the historical annual average real growth rate of the economy in the TVA region is 3.6 percent (1990 – 2006) versus 3.0 percent for the national economy. Regional growth has historically outpaced national growth because manufacturing product has grown at a faster pace than non-manufacturing product. Regional growth falls deeper and more quickly during an economic downturn due to its relative dependence on manufacturing; however, the regional economy also recovers more quickly and reaches a higher growth rate during an economic recovery.

Figure 8.2-9 and Table 8.2-5 also show that long-term economic growth for the region is forecast to decline to an average annual rate of 3.1 percent (2017 – 2022) while long-term growth for the nation is forecast to increase to about 3.1 percent. TVA uses the GDP deflator as the overall measure of inflation in its economic model and by inference in resource planning. Whereas the CPI only shows changes in the cost of living for U.S. workers and consumers, the GDP shows changes in prices for all U.S. goods and services, consumers and producers both, and is thus the broadest measure of U.S. inflation. Two factors explain why region growth slows compared to the national Gross Domestic Product (GDP) growth in the latter part of the forecast horizon. As more of the increase in manufactured goods purchased comes from overseas, the domestic manufacturing share of gross product shrinks in both the nation and the region. Thus, the higher productivity growth of the manufacturing sector has less impact as the sector's share of the regional economy shrinks. Also, while the region's service sector is growing, it is not expected to increase to service sector growth rates found at the national level in the forecast horizon. The industry mix within the regional service sector is more concentrated in lower productivity industries such as retail trade than the nation's industry mix. There are fewer higher productivity service sector industries such as the finance industry in Charlotte, North Carolina. As manufacturing becomes less the engine of growth than it has been historically, it is not evident that there are service industries developing in the region to drive higher product growth as is occurring in the nation.

As markets for manufacturing industries have become global in reach, production capacity has moved overseas from the TVA region for many of the same reasons that the industries first moved to the TVA region. The contraction of these industries, and the load growth associated with them, has been offset to some degree by the growth of the automobile industry in the Southeast in the last 15 years. Figure 8.2-10 illustrates that the manufacturing share of Gross Regional Product (GRP) has decreased from a high of 27 percent over the last 15 years to about 26 percent today, and is forecast to decrease to about 24 percent by 2022. Table 8.2-6 shows that the medium long-term growth in manufacturing, GDP, averages about 2.0 percent versus 3.1 percent in GRP.

Figure 8.2-11 illustrates population trends in the TVA service area. Even though jobs are declining in manufacturing, population growth is expected to be strong. Most migration to the Valley is still due to job opportunities. Part of this is to serve the existing population (such as retail), but a growing part is "export" services that are "sold" to areas outside the region. Notable examples are corporate headquarters such as Nissan in Nashville and Service Master in Memphis, but also include such industries as the still-growing music business centered in Nashville. In addition, the TVA service area has become an attractive region for retirees looking for a moderate climate and a more affordable region than traditional retirement locations. The increase in retiree population results in additional population growth in service industries and the people needed to work in them. Figure 8.2-11 and Table 8.2-7 show that the population of the TVA service area is forecast to grow at a rate of 1.0 percent annually throughout the forecast period. The number of households is currently increasing at a faster rate of 1.3 percent annually, leading to a long-term decline in the number of persons per household, as illustrated in Figure 8.2-12.

Personal income in the TVA service area is forecast to grow in concert with the expanding economy and population. Figure 8.2-13 and Table 8.2-8 show that personal income per capita grows at a rate of 2.1 percent early in the planning period to a rate of 1.6 percent later in the period. The slowing rate of income growth is associated with a gradual slowing of population increases as the attributes of the region that attract migrants, such as fewer people and lower cost of living, are not as great compared to other regions.

8.2.2.2 Energy Efficiency and Substitution

The seven states served by TVA rank among the highest in terms of electricity use per customer. Table 8.2-9 shows that electricity use per residential and industrial customer in 2005 is greater than the national average in each of the seven states served by TVA. Residential and industrial electricity use in Tennessee, Mississippi, Alabama, and Kentucky—the four states for which TVA provides a significant portion of total electricity consumed—are ranked in the top 10 of all 50 states and the District of Columbia (with the exception of industrial use in Mississippi) (Reference 2). However, electricity use per commercial customer in these four states is less than the national average. The greater use in the residential and industrial sector and the lesser use in the commercial sectors in these states are consistent with the relative importance of manufacturing versus service sectors in the economy of the region served by TVA.

Figure 8.2-14 illustrates that the real price of electricity declined for all customer classes in the TVA region and the nation during 1990 – 1999; leveled off during 2000 – 2003; and then increased in 2004 - 2006. The real price of electricity is forecast to again decline in the region through the end of the forecast period for all customer types. Declining real prices reinforce the higher-than-average use of electricity in the states making up the TVA region.

Figure 8.2-15 through Figure 8.2-17 show the percent of households in the TVA region using electricity for air conditioning, heating, and major appliances, respectively. The TVA region reached almost complete saturation in air conditioning in 2001. Room air conditioning continues to be replaced by more efficient central air conditioning and heat pump systems, decreasing from 15 percent share in 2006 to 11 percent share in 2020. Heating with electricity (whether via heat pumps, central resistance heating, or space heaters) has remained steady at just under 50 percent share historically, and is projected to stay at the same level. The biggest increases in saturation levels of appliances in the last 15 years are for dishwashers, clothes washers and dryers, and freezers. The saturation level of these appliances is not forecast to increase as much in the future.

The only items that have decreased in saturation are the electric range and water heater. Table 8.2-10 shows more detailed results from 2001 and 2004 residential saturation surveys conducted by TVA. Natural gas is the competing fuel that is most responsible for the reduction in saturation levels for electric water heaters and, most likely, for electric ranges as well. TVA expects no curtailments or restrictions in hookups for customers seeking to use natural gas or oil. Figure 8.2-18 illustrates that the real price of natural gas for both residential and C&I customers was stable and low relative to the real price of electricity through 1999, resulting in the reduction in saturation of electric water heaters and electric ranges in the same period. Since 1999, the real price of natural gas for both residential and C&I customers has increased significantly relative to the real price of electricity. For that reason, further reduction in the saturation levels of electric appliances is not anticipated.

8.2.2.3 Price and Rate Structures

As discussed in the Subsection 8.2.1.1, TVA takes into account that the price of electricity affects demand. The price of electricity is based on the End Use Wholesale (EUW) rate structure that TVA has used since 1992. EUW rates apply end-use meter reading to recover wholesale power costs. Wholesale power costs are allocated to end-use customer classes (residential, commercial, industrial) based on load profiles for these end-use classes estimated at the TVA system level. These wholesale power costs are then divided by the projected sales to end users to develop a wholesale rate for each end-use class. The wholesale rate has a structure similar to the retail rate of each end-use wholesale class. A separate charge for distribution losses is assessed based on the difference between kilowatt-hours delivered at the wholesale meter and kilowatt-hours read on retail meters.

EUW rates are applied to electricity consumed between monthly meter readings and do not vary with time of use. There is no demand charge assessed on the aggregate peak load of the distribution system. Consequently, the EUW rate minimizes many risks to the distributor by providing close tracking between retail revenues and wholesale power cost. Demand and energy volume risk is eliminated, and margin risk is minimized. However, EUW rates do not provide a direct incentive to end-use customers for load management.

TVA is currently examining and discussing with its wholesale customers, the development of a seasonal, time-differentiated rate structure that would encourage load management. No timetable has been set for adoption of a new rate structure. Load forecasts for this report are based on the existing EUW rate structure.

In lieu of price incentives in its current general rate structure for load management, TVA offers an interruptible rate program for its retail industrial customers and the industrial customers of its wholesale distributors, and conducts residential, commercial, and industrial demand-side management (DSM) programs.

The interruptible rate program includes several rate structures that provide TVA with interruptible load, which serves as supplemental reserves. The rate structures provide a mechanism to send hourly price signals to customers with larger loads within qualifying SIC codes (manufacturing, mining, universities, and pipelines). Some of the structures include market pricing, where TVA may replace hourly cost-based pricing with market-based pricing for a specified number of days each year. TVA forecasts the interruptible load and includes it as a peaking resource in its power supply plans; this forecast is summarized in Section 8.3. DSM programs are included in the forecast for net system requirements and summer peak load and are forecasted to continue at historical levels. TVA, its retail industrial customers, and its wholesale customers are discussing the interruptible rates as part of the development of seasonal, time-differentiated rate structures for industrial rates that would better reflect the underlying cost of service and improve the efficiency and effectiveness of price signals of current interruptible rate structures.

In May 2007, TVA's Board of Directors approved a new Strategic Plan. The current-day priorities for the portion of TVA's mission related to energy production focus on improving reliability, managing demand, and reducing environmental impacts. In partnership with customers and others, TVA's new strategic direction includes enhancing efforts to improve energy-efficiency, energy conservation and peak demand reduction over the next five years. Specific targets and elements to implement these efforts are under development. As the goals and program unfold over the next few years, the anticipated reduction in peak demand will be reflected in power supply planning for the TVA system. These enhanced efforts are expected to reduce some of the forecasted demand on the TVA system. These reductions should occur primarily in peak demand, but could have some affect on the demand for baseload that would be addressed by the BLN units. What can be and is actually achieved by enhanced efforts remains to be determined, but would be taken into account in future planning for the BLN units. DSM forecasts are current as of February 2007 and do not include changes that may result from TVA's 2007 Strategic Plan approved May 31, 2007.

DSM programs resulted in 50 MW of demand reduction in 2006, and a cumulative 496 MW of demand reduction since 1996. TVA and 13 of its power distributors are involved in a Direct Load Control (DLC) program. This program involves power distributors installing radio-controlled switches on their customers' air-conditioners and water heaters. During peak demand periods TVA is allowed to curtail the power to this equipment. The power distributors receive a bill credit from TVA for each operable switch. The participating power distributors are allowed to determine the type of incentive given to their customers. Currently, TVA can curtail approximately 43 MW of load upon demand.

The following sections summarize these load management programs.

Price and Rate Structures – Industrial

TVA provides end-use technical assistance to its direct-served and distributor-served industrial and institutional customers. TVA works with these clients to help them identify and solve problems related to their use of energy in areas such as manufacturing processes, environmental issues, and plant operations. The targeted industry segments, such as the automotive, machinery, forest products and food processing industries, as well as local water and wastewater treatment systems, were selected because of the large presence of such industries in the TVA service area, their high energy usage, or the availability of solutions for their existing problems. For example, TVA developed and co-chaired an in-house energy conservation team to identify and implement energy cost savings opportunities at the GM Spring Hill (Saturn) automobile assembly plant. The team achieved savings in excess of $2 million in FY 2006 and over $10.6 million since the beginning of the initiative 7 years ago. This includes electricity savings of over 42 million kWh and demand reduction of 4.8 MW in FY 2006.

Price and Rate Structures – Commercial

The TVA works with Tennessee Valley C&I customers to provide solutions to their energy-related problems and to encourage the selection of energy-efficient equipment. For example, TVA works with schools, governments, offices, retail, healthcare, and other commercial segments to provide information on the various energy options available to them. As part of that effort, TVA provides feasibility studies conducted by independent private sector professional engineers to compare different types of systems on a life-cycle-cost basis. Also, if the customer is interested in closed-loop geothermal heat pumps, TVA provides test bores and thermal conductivity tests at the proposed project site to assist with the design of the ground heat exchanger. TVA sponsors continuing education for Tennessee Valley architects and engineers on the proper design and application of geothermal heat pumps. In the TVA service area, there are approximately

278 geothermal systems installed or in design as the result of TVA's promotion of this energy efficient technology. Demand for TVA assistance to commercial customers on energy-related problems continues to grow.

Since 1997, TVA's Energy Services group has worked with customers to achieve 35,751,000 kWh of energy efficiency savings and 14 MW of cumulative peak demand reduction through performance contracting projects. More than $50 million in improvements have been made at military installations, state-owned buildings, and school systems in the Valley; at one base the energy savings now exceed $1 million per year. Under these performance contracts, the equipment cost is funded through the resulting savings on the energy bills.

Price and Rate Structures – Residential

TVA and its 158 public power distributors have implemented residential energy-efficiency programs for the Valley under the brand name Energy Right®. About 150 distributors participate in the various initiatives from the Energy Right® program:

New Homes Plan promotes all-electric, energy-efficient new homes. All homes built Energy Right® must meet a minimum rating in overall energy efficiency. Homes built at least 15 percent better than the minimum rating qualify as Energy Right® Gold, while those built 30 percent better qualify as Energy Right® Platinum.

During the summer of 2005, TVA began an ENERGY STAR® certification promotion; 754 homes have been certified to date through 26 participating distributors.

The Heat Pump Plan promotes the installation of high-efficiency heat pumps greater than the Department of Energy's minimum standard homes and small businesses. Installation, performance, and weatherization standards have been established to promote the comfort of the customer and the proper operation of the system. A Quality Contractor Network has been established for maintaining high installation standards. Through a third-party lender, TVA provides 10-year financing for residential heat pumps with repayment through the consumer's electric bill.

The Water Heater Plan promotes the installation of energy-efficient electric water heaters in homes and small businesses.

The New Manufactured Homes Plan promotes the installation of high-efficiency heat pumps in new manufactured homes.

"In Concert With The Environment" (in partnership with Nexus Energy Software) is a comprehensive environmental and energy education program directed to middle school and junior high school students. Student participants receive an energy survey to complete for their households. Results from the survey indicate the home's estimated annual and monthly energy usage by appliance and gives a number of energy, environmental, and water recommendations for the student and their family to implement.

Energy right Home e-Valuation® (in partnership with Nexus Energy Software) allows residential customers to play an active role in saving energy in their homes. After completing an energy survey, customers receive a personalized report that breaks down the home's annual and monthly energy usage by appliance, and gives a number of energy recommendations as well as information about distributor products and services.

Energy Depot for Homes (in partnership with Enercom) is a web-based home energy audit for residential customers to complete interactively. Customers complete the survey and receive a detailed analysis of their energy use based on their answers and local electric and average gas rates. Energy Depot for Homes Comparison Tool provides residential customers with a way to compare energy use, costs, and potential savings and paybacks for replacing existing heating and air conditioning systems, water heating, and lighting.

Energy Depot for Business is a web-based energy audit for small business customers to complete interactively via the internet. Customers complete the survey and receive a detailed analysis of their energy use based on their answers and local electric and average gas rates.

8.2.3 REFERENCES

1. Tennessee Valley Authority, Energy Vision 2020: Integrated Resource Plan/ Environmental Impact Statement, Volume 1, 2 and 3, December 1995.

2. Energy Information Administration, Table 2. Sales to Bundled and Unbundled Consumers by Sector, Census Division, and State, 2005.

TABLE 8.2-1
AVERAGE ANNUAL RESIDENTIAL GROWTH RATE

Load Forecast	2007-2012	2012-2022
High	3.1%	2.6%
Med High	2.8%	2.3%
Medium	2.4%	2.0%
Med Low	1.7%	1.5%
Low	1.0%	1.0%

TABLE 8.2-2
ANNUAL AVERAGE DISTRIBUTOR-SERVED C&I LOAD GROWTH

Load Forecast	2007-2012	2012-2022
High	2.7%	2.5%
Med High	2.4%	2.2%
Medium	2.1%	1.9%
Med Low	1.4%	1.4%
Low	0.6%	0.9%

TABLE 8.2-3
AVERAGE ANNUAL NET SYSTEM REQUIREMENT GROWTH RATE[a]

Load Forecast	2007-2010	2010-2014	2014-2020
High	2.4%	0.9%	2.3%
Med High	2.2%	0.6%	2.0%
Medium	2.0%	0.3%	1.7%
Med Low	1.3%	-0.2%	1.3%
Low	0.6%	-0.7%	0.8%

a) Weather - normalized input information is used in energy and demand forecasts.

TABLE 8.2-4
AVERAGE ANNUAL GROWTH RATE FOR SUMMER PEAK LOAD

Load Forecast	2007-2010	2010-2014	2014-2022
High	2.4%	2.6%	2.5%
Med High	2.2%	2.3%	2.2%
Medium	2.0%	2.0%	1.9%
Med Low	1.4%	1.5%	1.4%
Low	0.7%	1.3%	1.0%

TABLE 8.2-5
AVERAGE ANNUAL REAL GROWTH RATE

Forecast	1990-2006	2007-2012	2012-2017	2017-2022
GDP	3.0%	3.0%	3.1%	3.1%
GRP	3.6%	3.1%	3.2%	3.1%

TABLE 8.2-6
AVERAGE ANNUAL GROWTH RATE IN REGIONAL PRODUCT

Regional Manufacturing Product

Forecast	2007-2012	2012-2017	2017-2022
High	4.2%	4.2%	4.1%
Medium	3.1%	2.7%	2.0%
Low	0.7%	1.1%	0.8%

Gross Regional Product

Forecast	2007-2012	2012-2017	2017-2022
High	4.2%	4.1%	4.3%
Medium	3.2%	3.2%	3.1%
Low	1.0%	1.5%	1.2%

TABLE 8.2-7
ANNUAL AVERAGE GROWTH RATE

Number of Households

Forecast	2007-2012	2012-2017	2017-2022
High	1.5%	1.4%	1.3%
Medium	1.3%	1.1%	1.0%
Low	1.1%	0.8%	0.6%

Total Population

Forecast	2007-2012	2012-2017	2017-2022
High	1.3%	1.6%	1.5%
Medium	1.0%	1.0%	1.0%
Low	0.6%	0.6%	0.6%

TABLE 8.2-8
AVERAGE ANNUAL GROWTH RATE PER CAPITA PERSONAL INCOME

Forecast	2006-2010	2010-2015	2015-2020
High	2.6%	2.1%	1.9%
Medium	2.1%	2.0%	1.6%
Low	1.1%	1.4%	1.0%

TABLE 8.2-9
REGIONAL ELECTRICITY USE AND RANK

State	Portion of State Usage Served by TVA	Annual Use in 2005 Per Customer (kWh)			Rank among 50 States and the District of Columbia		
		Residential	Commercial	Industrial	Residential	Commercial	Industrial
TN	99%	15,988	66,198	16,829,536	1	34	2
MS	32%	14,926	59,603	1,972,363	4	43	21
AL	27%	15,370	61,351	4,159,932	2	40	9
KY	26%	14,326	67,337	6,533,972	8	32	5
GA	3%	13,777	87,059	2,252,574	10	9	19
NC	1%	13,761	72,414	2,742,463	11	22	14
VA	0.1%	14,698	116,099	3,724,081	6	2	11
East South Central[a]		15,252	64,036	5,120,328			
U.S.		11,256	75,574	1,388,757			

a) East South Central (ESC) Division, located in the central part of the southern United States, includes Alabama, Kentucky, Mississippi and Tennessee.

TABLE 8.2-10
2001 AND 2004 RESIDENTIAL SATURATION SURVEY

Response	Heating		Cooling		Water Heating		Range		Clothes Dryer	
Category	2001	2004	2001	2004	2001	2004	2001	2004	2001	2004
Electricity	48.3%	46.7%	97.1%	97.5%	70.0%	69.1%	N/A[(a)]	87.0%	N/A	94.4%
Natural Gas	36.2%	38.3%	-	-	23.9%	25.5%	N/A	9.2%	N/A	4.2%
LP Gas	2.7%	10.4%	-	-	2.8%	2.8%	N/A	3.2%	N/A	0.9%
Wood	10.6%	2.6%	-	-	-	-	N/A	-	N/A	-
Fuel oil/Kerosene	1.4%	1.0%	-	-	-	-	N/A	-	N/A	-
Don't Know	0.8%	0.5%	-	-	2.8%	1.7%	N/A	0.3%	N/A	0.5%
None/Other	-	-	2.9%	2.3%	0.5%	7.0%	N/A	0.3%	N/A	-

a) Not Available

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

8.3 POWER SUPPLY

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8.3-1 (Sheet 1 of 2)
CAPACITY PLAN FOR EXPECTED (MEDIUM) LOAD FORECAST

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8.3-1 (Sheet 2 of 2)
CAPACITY PLAN FOR EXPECTED (MEDIUM) LOAD FORECAST

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8.3-2
CHANGES IN CAPACITY TO TVA RESOURCES

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8.3-3
BASE, INTERMEDIATE, AND PEAKING CAPACITY SUMMARY OVER PLANNING PERIOD

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8.3-4
AVERAGE CAPACITY BY GENERATION AND DUTY TYPE

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8.3-5 (Sheet 1 of 2)
PRESENT AND PLANNED GENERATING CAPACITY AND PURCHASES AND SALES OF ELECTRICITY IN CONTEXT OF ELECTRICITY LOAD FORECASTS

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8.3-5 (Sheet 2 of 2)
PRESENT AND PLANNED GENERATING CAPACITY AND PURCHASES AND SALES OF ELECTRICITY IN CONTEXT OF ELECTRICITY LOAD FORECASTS

8.4 ASSESSMENT OF NEED FOR POWER

The TVA is applying for a combined license (COL) to construct and operate Bellefonte Nuclear Plant, Units 3 and 4 (BLN). These units would be operated as baseload units with a net electrical rating of 1117 MW each. Units 3 and 4 are proposed for commercial operation in 1st Quarter FY 2018 (fourth quarter of calendar year 2017), and 1st Quarter FY 2019 (fourth quarter of calendar year 2018), respectively. This section reviews the need for power in the TVA service area. The total need for power of any type (baseload, intermediate, peaking) is discussed, followed by a forecast of how much of the total need should be baseload capacity. Other considerations of need, such as diversity of energy sources, reduction in the average cost of electricity, and reduction in the reliance on fossil fuels, also are discussed.

TVA uses the loss-of-load probability method to determine the amount of planning reserves needed to provide a least-cost approach to generation reliability. The method assumes that no imports are available to the TVA service area beyond any existing or planned imports for which firm transmission has been obtained. A generation reliability model is used to determine the planning reserves needed to maintain the reliability of the power system over the forecast period. The generation reliability criterion is an Hourly Loss of Load Expectation (HLOLE) of 20 hrs. per year. An over-under study conducted for Energy Vision 2020 established that an HLOLE between 5 and 20 hrs. per year balanced the cost to customers of interrupting firm load due to insufficient generation and the cost of supplying planning reserves. TVA allocates 8 hrs. each to the winter and summer seasons (four months each season) and 2 hrs. each to spring and fall. The reliability model calculates the HLOLE for each week and iterates to adjust forecast peak loads until the resulting HLOLE matches the target. The adjusted peak load represents the load carrying ability (LCA) of existing and planned resources. The percent desired reserves are calculated as the difference between the LCA and the existing and planned resources, divided by the LCA. The desired amount of planning reserves is calculated by multiplying the percent desired reserves and the forecast peak load. Factors that are considered in determining the LCA include generating capacities, equivalent forced outage rates, hourly loads, load forecast uncertainty, planned maintenance outages, interruptible demand, availability of voluntary load curtailments, and contracts for power purchases.

TVA requires operating reserves to recover from the loss of a generating unit; to match generation to load; and to control frequency and voltage. Operating reserves include requirements for regulation, spinning reserves, and primary and secondary reserves. The overall amount of operating reserves assumed by TVA for planning studies is 1640 MW, consisting of the 1340 MW (the size of the largest unit on the system) plus 300 MW for regulation reserves.

The reserve margin is defined as the total reserves (planning and operating) divided by the peak load, as discussed in Section 8.2 and illustrated for the summer in Figure 8.2-6. TVA sets its own reserve margin requirement. In setting this requirement, TVA does not follow the guidance or requirements of any external organization, such as SERC or state pubic service commissions, but does report historical reserve margins to SERC. A desired reserve margin of 15 percent has been used in this study. The desired reserve margin over the past 5 years in TVA's plan using the loss of load probability method discussed above has been approximately 15 percent of the total TVA medium load forecasted demand. A desired reserve margin of 15 percent is in alignment with the reserve margins established by other entities in the utility industry, which range from 12 percent to 18 percent.

Figure 8.4-1 and Figure 8.4-2 illustrate the actual and desired reserve margin for the summers and winters, respectively, of 2008 - 2022. The forecast reserve margin is based on the available reserves, which is calculated as the difference between the existing and planned capacity in Table 8.3-1 (excluding TBD resources) and the peak load. Forecast reserve margins are lower than the desired reserves except in the low load forecasts of the winter peak. The relationship between reserve margin (expressed as percent) and system reliability level is approximately one-day outage in 10 years. Historical data on installed and actual reserve margins at the time of summer and winter peak hourly demand are provided for 2000 – 2002.

Need for capacity is demonstrated in Figure 8.4-1 and Figure 8.4-2 because forecast reserve margins are less than the desired reserve margin. These data illustrate the calculated reserve margins extending from the present time to the first 3 years after initial operation of all proposed units. The capacity need in total megawatts is illustrated in Figure 8.4-3 based on the summer peak loads, which are forecast to be greater than the winter peak load throughout the planning period. For reference, the sum of the resources for the summer in Table 8.3-1 is the same as the capacity need illustrated for the medium load forecast in Figure 8.4-3.

TVA determined how much of the total capacity need in Figure 8.4-3 should be baseload generation based on an assessment of energy needs. The total expected generation of existing and planned capacity resources, Table 8.3-1, is compared to the forecast net system requirements, Figure 8.2-5, to forecast the amount of energy surplus or deficit for each year of the planning period. If there is an energy deficit, then some of the additional capacity needs should be met with baseload resources. The amount of baseload capacity needed is determined by comparing the existing and planned resources (Table 8.3-1) to the average load. Figure 8.4-4 illustrates the deficit in baseload capacity by load forecast by year. In those years with a balanced energy supply or an energy surplus, the deficit is shown as zero. Figure 8.4-4 shows that baseload need under the medium load forecast begins in 2018 and grows to 1750 MWs by 2022. Except for a short term need in 2011 – 2012 under the high load forecast, baseload need begins in 2016 under the high forecast and 2017 under the medium high forecast, and is greater than 2,000 MWs by 2019 and 2020 respectively. Information in Tables 8.4-3, 8.4-4 and 8.4-5 provides data prescribed in NUREG-1555, Tables 8.4-1 and 8.4-2.

The total output of a nuclear unit with the size and expected capacity factor of the proposed AP1000 unit is needed by 2020 under the medium load forecast, 2018 under the medium-high load forecast, and 2016 under the high load forecast.

The addition of BLN was simulated using a production cost model to determine its effect on resource diversity, cost of power, and reliance on fossil fuels. TVA conducted this analysis using Global Energy Decisions’ Enterprise Planning and Risk (powered by PROSYM). The assumptions and input to the model were the same as those of the long-term power supply plan in use by TVA during the summer of 2006. The only changes in inputs were for load forecasts, which were updated to reflect customer contract decisions as of September 30, 2006. The operation of current and planned generating resources (see Table 8.3-1) was simulated for the range of load forecasts presented in Section 8.2 and compared to the operation of current and planned resources with the addition of BLN. Peaking capacity additions that have yet-to-be-determined by TVA were assumed to be simple-cycle gas-fired units. Intermediate capacity additions that have yet to be determined by TVA were assumed to be combined cycle gas-fired units. Baseload capacity additions that were not nuclear were assumed to be coal-fired units.

Figure 8.4-5, 8.4-6, and 8.4-7 illustrate the percentage of generation by fuel type for 2008, 2014, and 2020, respectively. The capacity mix that resulted in this generation was illustrated previously in Figure 8.3-1 through Figure 8.3-3 by fuel type. TVA coal resources produce 45–54 percent of the simulated generation in these years. Gas and oil resources that are using or are likely to use gas or oil produce 2 percent to 4 percent of generation, depending on the year. TBD resources grow from 1 percent of generation in 2008 to 5 percent in 2014 to 13 percent in 2020. The TBD resource mix is all gas-fired in 2008 and 2014, and a mix of gas and coal-fired in 2020. The percentage of generation produced by coal and gas resources is 59 percent in 2008, 55 percent in 2014, and 60 percent in 2020.

The effect of the additions of BLN on the generation mix is illustrated in Figure 8.4-8 for 2020, the first year of two-unit operation. The percentage of generation provided by TVA coal resources decreased from 45 percent to 44 percent and by TBD resources from 13 percent to 5 percent; the percentage of generation supplied by gas and oil and market resources was unchanged. The percentage of generation supplied by all coal and gas resources decreased from 60 percent to 51 percent while nuclear generation increased from 30 percent to 39 percent.

The effect of the additions of BLN on SO_2 emissions from all resources is illustrated in Figure 8.4-9. TVA’s plans to reduce emissions result in reductions in emissions from approximately 400,000 tons per year in 2008 (depending on the load forecast) to 150,000 to 180,000 tons per year in 2020 - 2022 when the new BLN units are projected to be in operation. Figure 8.4-9 illustrates that operation of BLN could reduce SO_2 emissions for all load forecasts in 2020 - 2022. Emissions in those years range from 130,000 tons per year to 170,000 tons per year due to the operation of BLN. Figure 8.4-10 illustrates this scenario reducing emissions between 4 and 12 percent, depending on the year and the forecast.

The effect of BLN operations on the emissions of NO_X, CO_2, and Hg in 2020 - 2022 is similar to that illustrated for SO_2 in Figure 8.4-9 and Figure 8.4-10. Table 8.4-1 summarizes the percent reduction in emissions in 2020 by load forecast and type of emission. The percentage reduction varies by load forecast and by type of emission due to the amount of coal generation, emissions rates of existing units, fuel and emissions allowance prices, electricity prices, and other factors considered in the production cost simulation.

The effect of the addition of BLN on TVA delivered cost of power in 2020 - 2022 is illustrated in Figure 8.4-11. TVA's delivered cost of power includes the following items:

- The capital costs of the new nuclear assets, which are depreciated over the license life of the plant (40 years).
- The operations and maintenance costs of TVA generating units and purchased power.
- The costs of transmission to TVA's wholesale and retail customers.
- The cost of interest, depreciation, in lieu of tax payments, and other administrative and general costs.

- The effect on the cost of fuel, variable operation and maintenance costs, and emissions allowances for other resources affected by the addition of the nuclear units.

Initial capital costs of BLN are spread over future years in the calculation of the delivered cost of power. The delivered cost of power with BLN is reduced compared to the base case because nuclear operating costs are low and increase slower than the cost of fossil fuels and purchases in the base case. Figure 8.4-11 does not portray the effects of BLN on cash flow or total TVA financial obligations for the years shown.

Table 8.4-2 summarizes the percent change in the delivered cost of power for 2020 - 2022 from Figure 8.4-11. The addition of BLN reduces the delivered cost of power an average of 3.3 percent in 2020 - 2022, ranging from a reduction of 5.1 percent for the low load forecast to a reduction of 2.6 percent for the high load forecast. The reduction is greater for lower load forecasts because the higher cost of fossil fuel generation displaced by the addition of nuclear units is greater.

TVA faces a need for power over the next decade to meet the growing demand for electricity. In light of an expected increase in demand for electricity in TVA's service area and recent purchased power price volatility and provider unreliability, TVA has taken steps to build or acquire new generation. This includes possible construction of BLN.

TABLE 8.4-1
2020 EMISSIONS REDUCTIONS

Load Forecast	SO_2	NO_x	CO_2	Hg	Average
High	-6%	-9%	-13%	-11%	-9%
Medium High	-5%	-8%	-13%	-10%	-9%
Medium	-6%	-8%	-12%	-10%	-9%
Medium Low	-9%	-9%	-9%	-9%	-9%
Low	-12%	-13%	-9%	-12%	-11%

TABLE 8.4-2
REDUCTION IN DELIVERED COST OF POWER 2020 – 2022 WITH BLN

Percent Change in Delivered Cost of Power

Load Forecast	2020	2021	2022	Average
High	-2.9%	-2.5%	-2.3%	-2.6%
Medium	-3.2%	-3.3%	-3.3%	-3.3%
Low	-6.4%	-4.7%	-4.1%	-5.1%

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8.4-3 (Sheet 1 of 2)
BASELOAD DEMAND, CAPACITY, AND CAPACITY SURPLUS (DEFICIT)

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8.4-3 (Sheet 2 of 2)
BASELOAD DEMAND, CAPACITY, AND CAPACITY SURPLUS (DEFICIT)

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8.4-4
SUMMER PEAKLOAD
RESPONSIBILITIES, GENERATING CAPACITIES, AND RESERVE MARGIN

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)

(see COL Application Part 9)

TABLE 8.4-5
WINTER PEAKLOAD
RESPONSIBILITIES, GENERATING CAPACITIES, AND RESERVE MARGIN

Exempted from Disclosure by Statute - Withheld Under 10 CFR 2.390(a)(3)
(see COL Application Part 9)

APPENDIX 8A
PRESENT AND PLANNED CAPACITY

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8A-1 (Sheet 1 of 8)
SUMMER PRESENT AND PLANNED CAPACITY (MWe)

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8A-1 (Sheet 2 of 8)
SUMMER PRESENT AND PLANNED CAPACITY (MWe)

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8A-1 (Sheet 3 of 8)
SUMMER PRESENT AND PLANNED CAPACITY (MWe)

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8A-1 (Sheet 4 of 8)
SUMMER PRESENT AND PLANNED CAPACITY (MWe)

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8A-1 (Sheet 5 of 8)
SUMMER PRESENT AND PLANNED CAPACITY (MWe)

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8A-1 (Sheet 6 of 8)
SUMMER PRESENT AND PLANNED CAPACITY (MWe)

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8A-1 (Sheet 7 of 8)
SUMMER PRESENT AND PLANNED CAPACITY (MWe)

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8A-1 (Sheet 8 of 8)
SUMMER PRESENT AND PLANNED CAPACITY (MWe)

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8A-2 (Sheet 1 of 8)
WINTER PRESENT AND PLANNED CAPACITY (MWe)

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8A-2 (Sheet 2 of 8)
WINTER PRESENT AND PLANNED CAPACITY (MWe)

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8A-2 (Sheet 3 of 8)
WINTER PRESENT AND PLANNED CAPACITY (MWe)

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8A-2 (Sheet 4 of 8)
WINTER PRESENT AND PLANNED CAPACITY (MWe)

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8A-2 (Sheet 5 of 8)
WINTER PRESENT AND PLANNED CAPACITY (MWe)

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8A-2 (Sheet 6 of 8)
WINTER PRESENT AND PLANNED CAPACITY (MWe)

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8A-2 (Sheet 7 of 8)
WINTER PRESENT AND PLANNED CAPACITY (MWe)

Proprietary Information - Withheld Under 10 CFR 2.390(a)(4)
(see COL Application Part 9)

TABLE 8A-2 (Sheet 8 of 8)
WINTER PRESENT AND PLANNED CAPACITY (MWe)