CHAPTER 2

2.0 TVA'S RESOURCE PLANNING PROCESS

2.1. Introduction

TVA chose to employ a scenario planning approach in the IRP. The major steps in this approach are identifying the future need for power, developing scenarios and strategies, determining potential supply-side and demand-side resource options; developing portfolios associated with the strategies, and ranking the strategies and portfolios. With the exception of determining the potential options, which is described in Chapter 4, these steps are described in this chapter.

2.2. Need for Power Analysis

In the analysis of the need for power, TVA forecasts the demand for power, identifies the current power supply resources available to meet this demand during the 2010-2029 planning period, and uses the difference in these to identify the capacity and energy gaps. The long-term energy and peak demand forecasts are developed from individual forecasts of residential, commercial, and industrial sales. These forecasts serve as the basis for the power system and financial planning activities.

Capacity is the instantaneous maximum amount of energy that can be supplied by a generator. For long-term planning purposes, capacity can be specified in several ways such as nameplate (the maximum design generation), dependable (the maximum expected during normal operation), seasonal (the maximum expected during a particular season), and firm (dependable less all known adjustments). Capacity is measured in watts; common units are kilowatts (kW, one thousand watts) and megawatts (MW, one million watts).

The term energy is used in power planning to describe the amount of power generated or used in a specified time period. Common measurement units are kilowatt-hour (kWh, one thousand watts for one hour, megawatt-hour (MWh, one million watts for one hour), and gigawatt-hour (GWh, one billion watts for one hour).

Peak demand is the maximum rate of electricity use, typically measured in MW. A related concept is peak load, the maximum amount of electric power drawn from the electric system at a given point in time.

2.2.1. Load Forecasting Methodology

TVA's load forecasting uses the best available data and both econometric and end-use models. Econometric models link electricity sales to several key factors in the market, such as the price of electricity, the price of natural gas, and growth in economic activity. These models are used to forecast sales growth in the residential and commercial sectors and in each industrial sector. Underlying trends within each sector, such as the use of various types of equipment or processes, play a major role in forecasting sales. To capture these trends, TVA uses a variety of end-use forecasting models. For example, in the residential sector, sales are forecast for space heating, air conditioning, water heating, and several other uses. In the commercial sector, categories including lighting, cooling, refrigeration, and space heating are examined. For both sectors, other factors such as changes in energy efficiency over time and appliance and equipment replacement rates are also considered.

Forecasting is inherently uncertain, so TVA supplements its modeling with industry analyses and studies of specific major issues. This is part of an effort to improve TVA's understanding of the Valley load and economy and produce accurate forecasts. TVA also produces alternative regional forecasts such as the high and low forecasts that define a range of possible loads with a 90 percent confidence that the true forecast will fall within this range.

Of the many key inputs to the load forecasts for the residential, commercial, and industrial sectors, the most important are economic activity; price of electricity; customer retention; and prices of substitute sources of energy, including natural gas.

Economic Activity - TVA produces forecasts of regional economic activity for budgeting, long range planning, and economic development purposes. These forecasts are based on national forecasts of the national economy developed by the forecasting service Moody’s Economy.Com.

The economy of the TVA service territory has historically been more dependent on manufacturing than the U.S. as a whole, with industries such as pulp and paper, aluminum, and chemicals drawn to the region because of the availability of natural resources and reliable, inexpensive electricity. Regional growth has historically outpaced national growth because manufacturing products grew at a faster pace than non-manufacturing products and services. Regional growth contracts faster and more sharply 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.

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 25 years. Although the TVA region is expected to retain its comparative advantage in the automotive industry, as exemplified by the new Volkswagen auto plant under construction in Chattanooga, reduced long-term prospects for the U.S. automotive industry will also have an impact on the regional industry.

As job growth in the manufacturing sector is declining, job opportunities are growing within the services industry. While some of this growth stems from jobs in businesses (such as retail) serving the region’s population, a growing part is services exported to areas outside the region. Healthy population growth is expected to continue as people migrate to the Valley for job opportunities. In addition, the TVA region has become attractive to retirees looking for a moderate climate in an affordable area. Thus, the rising population will result in additional growth to the services industries and demand will rise for people needed to work in them.

Price of Electricity - Forecasts of the price of electricity are based on long-term estimates of TVA’s total costs to operate and maintain the power system and the markups charged by distributors. Forecasts of these total revenue requirements are based on estimates of key costs such as fuel, operations and maintenance, capital investment, and interest. The high and low electricity price forecasts are derived from variations in these same factors.

Customer Retention - In the last 20 years, the electric utility industry has undergone a fundamental change in most parts of the country. In many states, an environment of regulated monopoly has been replaced with varying degrees of competition. Wholesale open access (the rights of wholesale customers to buy power from generating utilities other than the utility who owns the transmission and distribution lines that serve them) is largely mandated, except for TVA, by the Federal Energy Regulatory Commission (FERC).

While TVA has long-term contracts with its 155 distributors of TVA power, it is not immune to competitive pressures. These contracts allow distributors to give TVA five years' notice of contract cancellation, after which they may procure power from other sources. Many of TVA's large, directly served customers have the option to shift production from plants served by TVA to plants in service territories of other utilities if TVA's rates are not competitive with those of the utilities serving those territories.

In the spring 2010 forecast (used in Scenario 7 - Reference Case: Spring 2010, see Section 2.3), TVA's average price of electricity was expected to remain competitive with the rates of other utilities. As a result, the net impact of competition in the medium forecast is that TVA will retain its current customer base.

Price of Substitute Fuels - Electricity is a source of energy, and some of the utility derived from it can be obtained from other sources of energy. The potential for substitution between the use of electricity and fossil fuels, primarily oil and natural gas, depends on relative prices and the physical capability to change fuels. Changes in the TVA price of electricity relative to the price of natural gas and other fuels influence consumers' choices of fuels for appliances, space heating, and commercial and industrial processes. While other substitutions are possible, natural gas prices serve as the benchmark for determining substitution impacts in the load forecasts.

2.2.2. Forecast Accuracy

The accuracy of the forecasts is measured in part by error in the forecasts, whether day ahead, year ahead, or multiple years ahead. The mean annual percent error of TVA's forecast of net system energy requirements and peak load for the 2000-2009 period was 1.9 percent and 2.8 percent, respectively. These include large errors in 2009 as the 2008 financial crisis and the resulting depression continued to adversely affect the economy. The 2000-2008 error was 1.1 percent for net system energy requirements and 2.2 for peak load, which is more representative of the accuracy of TVA year-in and year-out load forecasts. Forecast accuracy is described in more detail in IRP Section 4.1.2.

2.2.3. Peak Load and Net System Energy Forecasts

To deal with the uncertainty inherent in forecasting, TVA has developed a range of forecasts, each corresponding to a different scenario (see Section 2.3).

Forecasts of peak load and net system energy for the baseline Scenario 7 - Reference Case: Spring 2020 and the scenarios with the highest and lowest demands are shown in Figure 2-1.

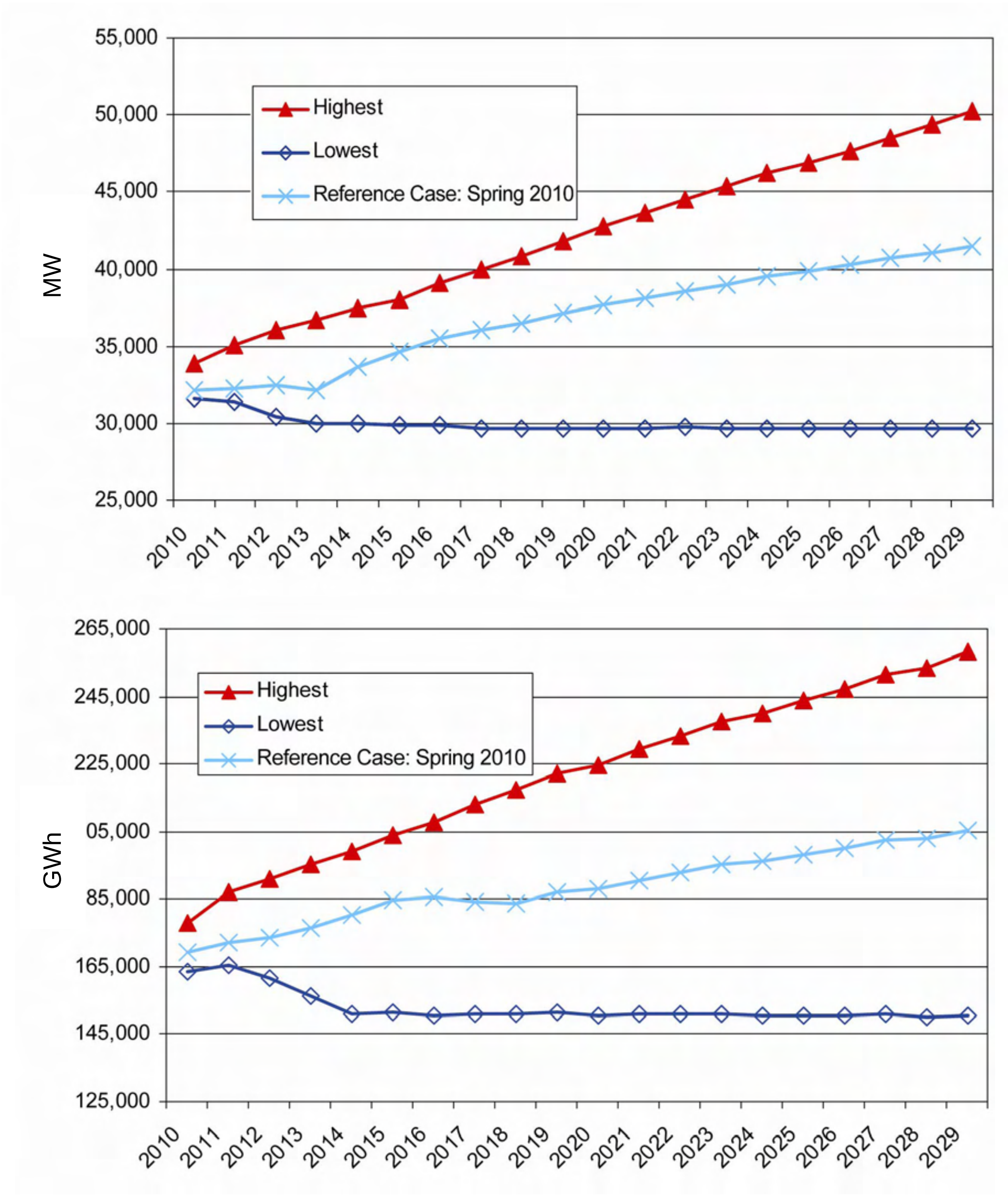

Figure 2-1. Peak load (top) and net system energy (bottom) forecasts for the baseline Scenario 7 - Reference Case: Spring 2010 and high- and low-growth scenarios**.**

Peak load grows at an average annual rate of 1.3 percent in the IRP Baseline scenario, decreases slightly and then stays flat in the lowest scenario, and grows by 2.0 percent in the highest scenario. Net system energy requirements grow at an average annual rate of 1.0 percent in the IRP Baseline scenario, decrease significantly and then stay flat in the lowest scenario, and grow by 1.9 percent per year in the highest scenario.

2.2.4. Power Supply Resources

TVA's generation supply consists of a combination of TVA-owned resources, budgeted and approved projects (such as new plant additions and uprates of existing plants), and power purchase agreements (PPAs). PPAs are contractual rights to the capacity and/or output (energy) of generating facilities not owned by TVA. The generation supply includes a diverse portfolio of coal, nuclear, hydroelectric, natural gas, oil, and renewable resources, as well as market purchases, designed to provide reliable, low-cost power and minimize the risk of disproportionate reliance on any one type of resource. Each type of generation can be categorized, based on its degree of utilization, as supplying base load, intermediate, peaking, or storage generation. Generation can also be categorized by capacity and energy.

Base Load Resources - Base load generators are primarily used to meet continuous energy needs by operating continuously at full capacity for long time periods. They have low operating costs but high capital costs, and are typically larger coal plants and nuclear plants. Some energy providers consider combined-cycle plants for incremental base load generation needs. However, historically, natural gas prices, when compared to coal and nuclear fuel prices, make combined cycle a more expensive option for large continuous generation needs.

Intermediate Resources - Intermediate resources are primarily used to fill the gap in generation between base load and peaking needs. They are required to change their output as the energy demand increases and decreases over time (usually during the course of a day). Intermediate units are more costly to operate than base load units but less costly than peaking units. This type of generation typically comes from natural gas-fired combined cycle plants and smaller coal plants. TVA's hydroelectric plants can also be operated as intermediate resources during periods of adequate precipitation. Corresponding back-up balancing supply needed for intermittent renewable generation (such as wind or solar) typically comes from intermediate resources. It is possible to use the energy generated from solar and wind as an intermediate resource with the use of energy storage.

Peaking Resources - Peaking units are only expected to operate during shorter duration high demand periods. They are essential for maintaining system reliability requirements, as they can ramp up quickly to meet sudden capacity changes. Typical peaking resources include natural gas-fired combustion turbines (CTs), conventional hydroelectric generation and pumped hydro storage, and, under some conditions, renewable resources. Storage Resources - Storage units usually serve the same power supply function as peaking units, but use low-cost off-peak electricity to store energy for later generation at peak times. TVA's Raccoon Mountain pumped storage plant is an example of a storage unit that pumps water to a reservoir during periods of low demand and releases it to generate electricity during periods of peak demand. Consequently, a storage unit is both a power supply source and an electricity user.

Figure 2-2 illustrates the uses of peaking, intermediate and base load generation. Although these categories are useful, the differences between them are not always distinct. For example, a peaking unit may be called on to run continuously for some time period like an intermediate or base load unit, although it is less economical to do so. Similarly, many base load units are capable of operating at different power levels, giving them some of the characteristics of an intermediate or peaking unit. This IRP considers strategies that take advantage of this range of operations.

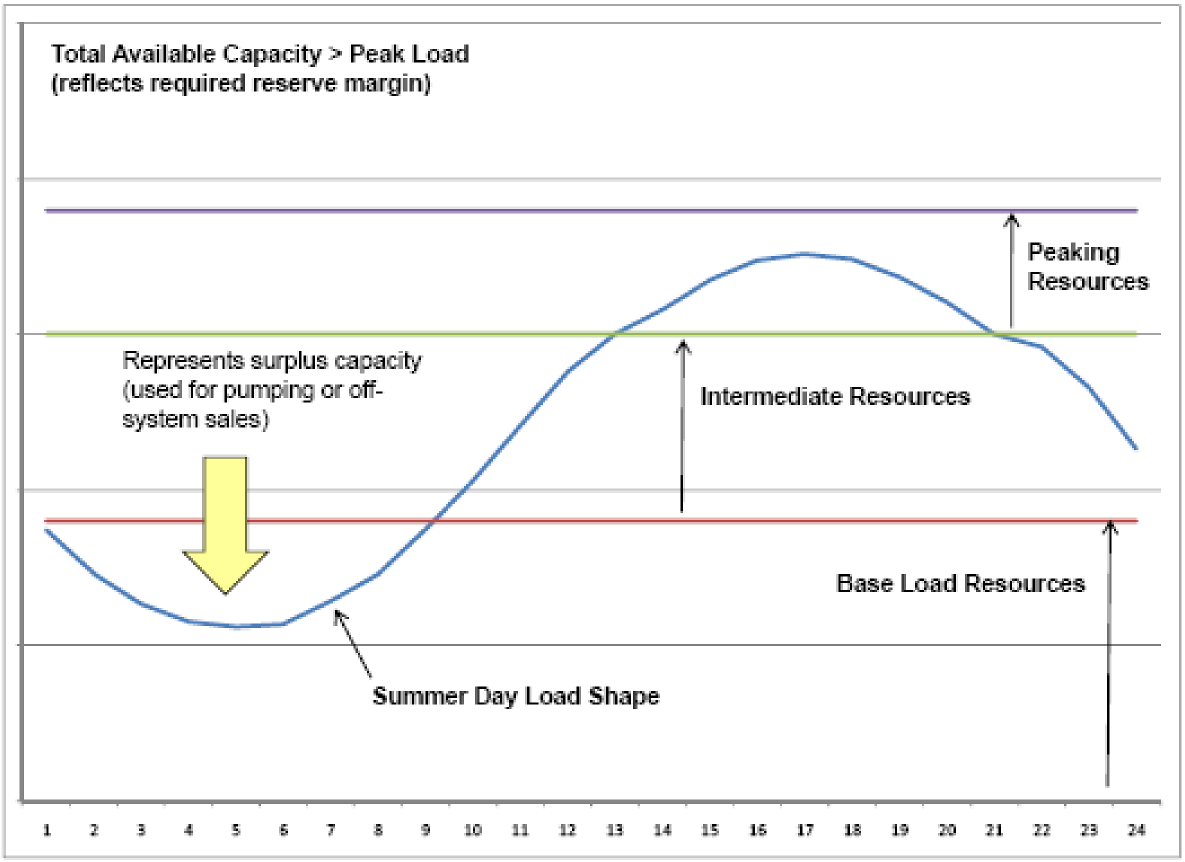

Figure 2-2. Representative summer day load shape and use of peaking, intermediate, and base load generation**.**

2.2.5. Capacity and Energy

Power system peaks are measured in terms of capacity (typically in MWs) and overall power system usage is measured in terms of energy (typically in GWhs). Capacity factor is a measure of the actual amount of energy delivered by a generator compared to the maximum amount it could have produced. Base load plants such as nuclear and large coal plants have high capacity factors and generate large amounts of energy. Plants that are used infrequently such as CTs have low capacity factors and provide relatively little energy. Because the energy they generate is often delivered at times of peak demand, CTs and other peaking resources are highly valued.

Demand-side resources (also known as energy efficiency and demand-response (EEDR) resources, see Section 3.5) can also be measured in terms of capacity and energy. Even though these resources do not generate power, their effect on the system is similar as they represent power that is not required or whose use can be shifted from high demand periods to low demand periods.

2.2.6. 2010 Resource Mix

TVA's 2010 resource mix consists of a wide range of supply-side technologies and demand-side resources to meet the needs of TVA's customers (Figure 2-3). Approximately 55 percent of TVA's electricity was expected to be produced from coal and natural gas-fired plants (51.8 percent coal; 3.5 percent gas). Nuclear plants would produce about 32 percent and hydroelectric plants approximately 12 percent. Most of the remainder is generation from renewables other than hydroelectric and avoided generation from demand-side programs. See Chapter 3 for a more detailed description of TVA’s generating facilities, power purchase agreements, and demand-side programs. Interruptibles are of power sales agreements under which TVA has the right to suspend power delivery to the purchaser.

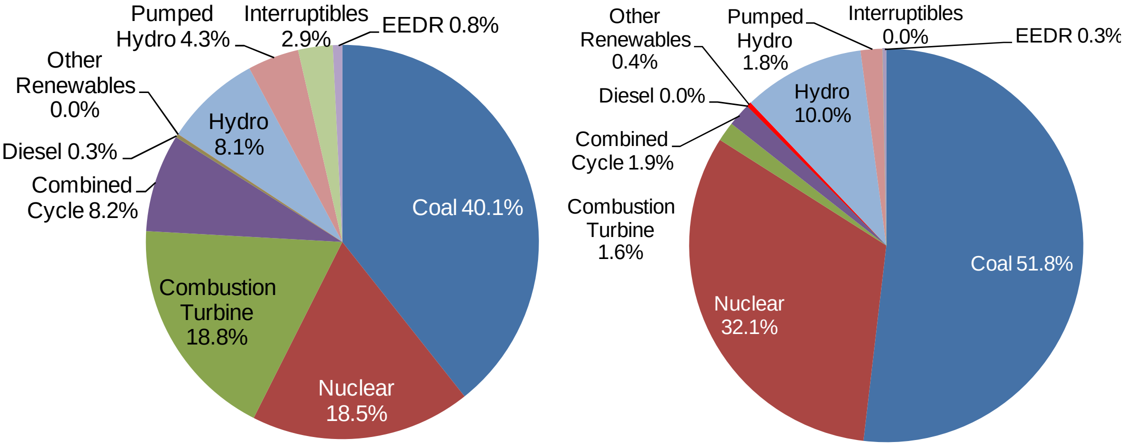

Figure 2-3. 2010 baseline portfolio firm capacity (left) and generation (right).

Figure 2-4 shows the changing composition of existing resources that currently are planned to be operated through 2029. It shows only those resources that currently exist or are under contract (such as PPAs and EEDR programs), as well as changes to existing resources and additions of new resources that are planned and approved. The total capacity of existing resources decreases through 2029 primarily because of the anticipated idling of coal-fired generating units. Total capacity also decreases when PPAs, mostly for combined-cycle generation, expire. The renewable energy component of the existing portfolio is primarily composed of wind PPAs (see Section 3.4). The current EEDR programs comprise 0.8 percent of the capacity.

2.2.7. Assessment of Need for Power

The TVA system is dual-peaking with high demand occurring in both the summer and winter months. For example, the annual peak demand in 2007 occurred in August, while in 2009, the annual peak occurred in January. Winter peaks are expected to continue for the next couple of years; thereafter, the forecasted peak load is during the summer months.

To ensure that enough capacity is available to meet peak demand, including unforeseen contingencies (e.g., forced outage of large generating units), additional generating capacity beyond that needed to meet peak demand is necessary. This additional generating capacity, known as “reserve capacity” or “operating reserves,” must be large enough to cover the loss of the largest single operating unit (contingency reserves), be able to respond to moment by moment changes in system load (regulating reserves), and replace contingency resources should they fail (replacement reserves). Total reserves must also be sufficient to cover uncertainties such as unplanned unit outages, load forecasting error including the difference between actual weather and the forecast weather, and undelivered purchased capacity.

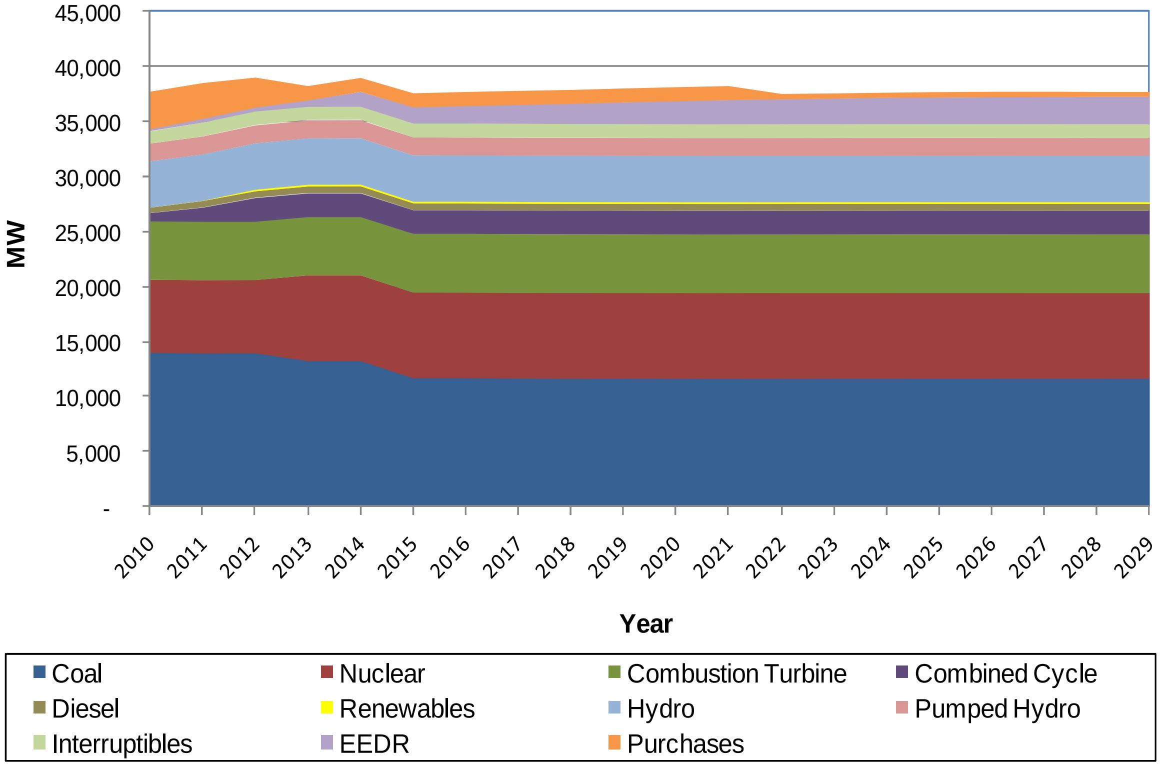

Figure 2-4. 2010 - 2029 firm capacity under the 2010 baseline portfolio.

As typical for the utility industry, TVA plans for total reserves of between 12 and 20 percent of total system load, depending on the age of current resources, as required by North American Electric Reliability Corporation (NERC) reliability standards. TVA optimizes its mix of generating assets and purchases to meet these standards. For the IRP, required total reserves were set at 15 percent.

The capacity gap is defined as the difference between the existing firm capacity (Figure 2-4) and the load forecasts (Figure 2-1) plus reserve requirements. Figure 2-5 shows the resulting capacity and generation (energy) gaps for the baseline Scenario 7 - Reference Case: Spring 2010 peak load forecast and the range corresponding to the highest and lowest planning scenarios (see Section 2.4). Under most scenarios and in most years, additional capacity and generation or EEDR is required to meet or offset forecasted capacity and energy needs. The Spring 2010 baseline need for additional generating capacity or EEDR programs is 9,617 MWs and 29,086 GWhs of additional generation in 2019, growing to 15,513 MWs and 44,988 GWhs in 2029.

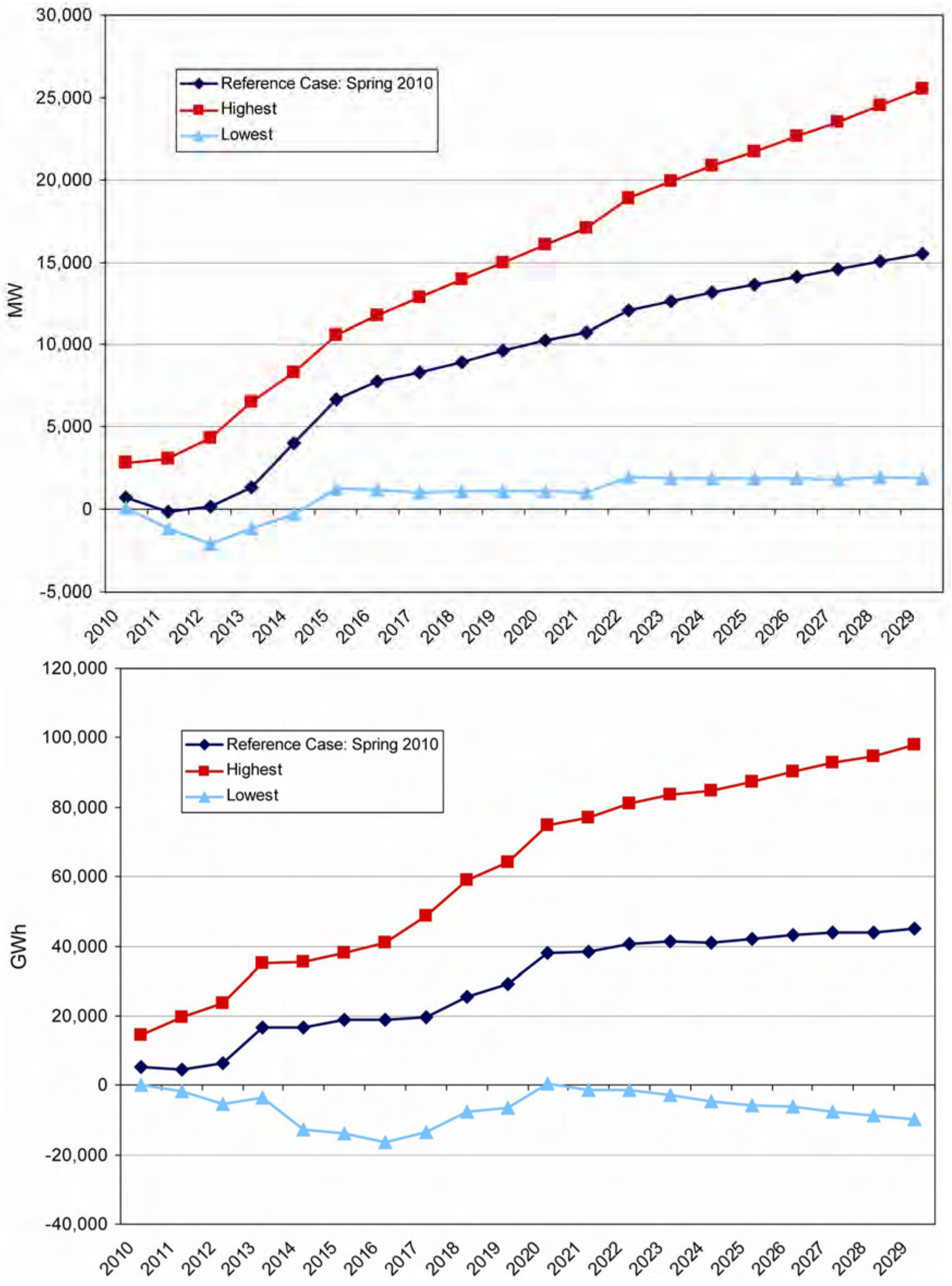

Figure 2-5. Capacity (top) and generation (bottom) gaps for the baseline Scenario 7 - Reference Case: Spring 2010 and lowest and highest scenarios.

2.3. Scenario Development

TVA chose to employ a scenario planning approach in the IRP. Scenario planning provides an understanding of how near-term and future decisions would change under different conditions ("plausible futures"). Near-term decisions that are common across different scenarios may imply that these decisions are less "risky," while major differences in near-term decisions across scenarios may imply the possibility of future problems. Scenarios provide a foundation to consider various supply and demand options in selecting a low risk, adaptable 20-year resource plan.

Scenarios are sets of potential future conditions, typically organized around different themes or narratives. As applied in the IRP, the scenarios:

- Bound key uncertainties to create a wide range of possible outcomes.
- Present sets of conditions that are plausible, but not intended to predict the future.

Major steps in scenario development are:

- Identify the uncertainties to be evaluated. These include regulations and legislation, economic and financial conditions, social trends, technological innovations, and other factors.
- For the identified key uncertainties, determine the range of variation and relative impacts to long-term plan.
- Develop the scenarios around themes and related combinations of specific conditions or values of the key uncertainties.

Uncertainties are the essential attributes that define the scenarios considered in the resource planning process. The key uncertainties used to define the scenarios are described below.

- Greenhouse gas (GHG) requirements—The levels of CO_2 and other GHG emission reductions mandated by federal legislation plus the cost of carbon emission allowances
- Environmental outlook—Changes in regulations addressing air emissions (exclusive of GHGs), water, land, and waste
- Energy efficiency and renewable energy standards (also known as renewable portfolio standards)—Consideration of mandates for minimum amounts of generation from renewable sources, the viability of renewable sources, and the percentage of renewable standards that can be met with energy efficiency
- Total load—The variance between the actual load and the forecast load, after accounting for the results of energy efficiency and demand response efforts
- Capital expansion viability and costs—For nuclear, fossil, and other generation, as well as transmission system projects, the risks associated with licensing, permitting, and the project schedule
- Financing—The cost (interest rate) of securing capital
- Commodity prices—Prices of natural gas, coal, oil, uranium, and the spot (i.e., immediate) price of electricity
- Contract purchase power cost—The demand cost, availability, and transmission constraints on purchased power

- Construction cost escalation—For generation and transmission construction, the escalation in costs of commodities, labor, and equipment
- Change in load shape—The effects of factors such as energy storage, time-of-use rates, plug-in electric vehicle charging, energy efficiency, smart grid development, distributed generation and economic effects on the customer base.

The final set of scenarios selected for use in the IRP was refined to ensure the following characteristics:

- Each scenario is distinct and reflects plausible, meaningful risks (e.g., uncertainties related to cost, regulation, environment) to TVA
- Stresses (tests) resource selection to provide a foundation for analyzing the combination of various supply and demand options (capacity plans)
- Reflects key stakeholder interests, to the extent possible.

In developing specific numerical values for each of the uncertainties within each scenario, the following design assumptions were used:

- Climate change uncertainty is based upon stringency of requirements, timeline required for compliance, and cost of CO_2 allowances
- An aggressive air quality regulatory schedule is expected to lead to additional compliance requirements (e.g., Hazardous Air Pollutants Maximum Achievable Control Technology (HAPs MACT), revised ambient air standards)
- Command and control requirements for HAPs MACT will likely drive plant-by-plant compliance instead of system-wide compliance
- Renewable energy standards (RES) will be a component of GHG reduction requirements at the federal level
- The spot price of electricity will track the price of natural gas and coal
- Total load is primarily driven by economic conditions but will also be affected by energy efficiency, demand response, and other factors
- Schedule risk is related to demand and uncertainty of permitting and licensing of generation and transmission projects
- Economic conditions and associated inflationary pressures are the primary drivers for financing costs
- Construction costs are driven by demand and availability of labor, equipment, design, and raw materials. Economic conditions are the primary driver, but the legislative / regulatory environment can apply additional pressure by introducing uncertainty related to potential schedule impacts
- Cost and availability of contract power purchases are primarily driven by economic conditions (i.e., load growth).

Six scenarios were subsequently developed (Table 2-1). A seventh baseline scenario that represented TVA's then-current longterm planning outlook was also used in the analyses. This scenario was named the IRP Baseline Case in the Draft IRP and EIS, and is here named the Reference Case: Spring 2010. Following the release of the draft plan and EIS, an eighth scenario representing summer and fall, 2010 conditions was developed; this scenario is Scenario 8 - Reference Case: "Great Recession" Impacts Recovery. Scenario 8 differs from Scenario 7 in having somewhat lower load growth.

Table 2-1. Attributes of the eight scenarios.

Uncertainty	Scenario 1 Economy Recovers Dramatically	Scenario 2 Environmental Focus is a National Priority	Scenario 3 Prolonged Economic Malaise	Scenario 4 Game-Changing Technology	Scenario 5 Energy Independence	Scenario 6 Carbon Legislation Creates Economic Downturn	Scenario 7 Reference Case: Spring 2010*	Scenario 8 Reference Case: Great Recession Impacts Recovery
Greenhouse gas requirements	CO2 price $27/ton ($30/metric ton) in 2014 and $82 ($90/metric ton) by 2030. 77% allowance allocation, 41% by 2030	CO2 price $17/ton ($19/metric ton) in 2012 and $94 ($104/metric ton) by 2030. 77% allowance allocation, 28% by 2030	No federal requirement (CO2 price = $0/ton)	CO2 price $18/ton ($20/metric ton) in 2013 and $45 ($50/metric ton) by 2030. 77% allowance allocation, 39% by 2030	CO2 price $18/ton ($20/metric ton) in 2013 and $45 ($50/metric ton) by 2030. 77% allowance allocation, 39% by 2030	CO2 price $17/ton ($19/metric ton) in 2012 and $94 ($104/metric ton) by 2030. 77% allowance allocation, 28% by 2030	CO2 price $15/ton ($17/metric ton) in 2013 and $56 ($62/metric ton) by 2030. 77% allowance allocation, 39% by 2030	Same as Spring 2010 Reference Case
Environmental outlook	Same as Spring 2010 Reference Case	SO2 controls 2017 NOX controls Dec 2016 Hg MACT 2014 HAP MACT 2015	No additional requirements (CAIR requirements, with no MACT requirements)	Same as Spring 2010 Reference Case	Same as Spring 2010 Reference Case	Same as Spring 2010 Reference Case	SCR all units by 2017 FGD all units by 2018 HAPs MACT by 2015	Same as Spring 2010 Reference Case
Energy Efficiency (EE) & Renewable Electricity Standards (RES)	RES - 3% by 2012, 20% by 2020 (adjusted total retail sales) EE can meet up to 25% of requirement	RES - 5% by 2012, 30% by 2020 (adjusted total retail sales) EE can meet up to 25% of requirement	No federal requirement	RES - 5% by 2012, 20% by 2020 (adjusted total retail sales) EE can meet up to 40% of requirement	RES - 5% by 2012, 20% by 2020 (adjusted total retail sales) EE can meet up to 40% of requirement	RES - 5% by 2012, 30% by 2020 (adjusted total retail sales) EE can meet up to 25% of requirement	RES - 3% by 2012, 15% by 2021 (adjusted total retail sales) EE can meet up to 25% or requirement	Same as Spring 2010 Reference Case

Table 2-1. Continued.

Uncertainty	Scenario 1 Economy Recovers Dramatically	Scenario 2 Environmental Focus is a National Priority	Scenario 3 Prolonged Economic Malaise	Scenario 4 Game-Changing Technology	Scenario 5 Energy Independence	Scenario 6 Carbon Legislation Creates Economic Downturn	Scenario 7 Reference Case: Spring 2010*	Scenario 8 Reference Case: Great Recession Impacts Recovery
Total load	Med grow to High by 2015; High Dist; Alcoa Returns in 2010+; USEC stays forever; Dept Dist same as 2010 Ref Case	Medium case, then 2012 40% rate increase; Low Dist; DS customer reductions (steel/paper plants); USEC stays forever; Dept Dist same as 2010 Ref Case	Low Load Case; Low Dist; Alcoa not returning, No HSC & Wacker; USEC leaves June 2013; Dept Dist same as 2010 Ref Case	Med-High load growth through 2020, then 20% decrease 2021-2022 including USEC departure, reduced dist sales & extended time of use	Medium case, then 20% rate increase in 2014; unrestricted PHEV included; time of use	Medium load case 2010-2011; 2012 low case then flat w/no growth; USEC leaves 2013; Alcoa not returning, HSC & Wacker not in; time of use	Moderate Growth	Moderate to low growth
Capital expansion viability & costs	Moderate Schedule Risk	High Schedule Risk	Low Schedule Risk	Moderate Schedule Risk	Moderate Schedule Risk	Low Schedule Risk	Moderate Schedule Risk	Moderate Schedule Risk
Financing	Higher Than 2010 Ref Case--Higher inflation due to higher economic growth	Higher Than 2010 Ref Case--Higher inflation due to looser monetary policy supporting economic growth	Lower Than 2010 Ref Case--Lower inflation due to lower economic growth	Same as 2010 Ref Case--Increased productivity due to technology leads to stronger economic, wealth, and non-inflationary money supply growth	Higher Than 2010 Ref Case--Higher inflation due to looser monetary policy supporting economic growth	Lower Than 2010 Ref Case--Lower inflation due to lower economic growth	Based on Current Borrowing Rate	Based on Current Borrowing Rate

Table 2-1. Continued.

Uncertainty	Scenario 1 Economy Recovers Dramatically	Scenario 2 Environmental Focus is a National Priority	Scenario 3 Prolonged Economic Malaise	Scenario 4 Game-Changing Technology	Scenario 5 Energy Independence	Scenario 6 Carbon Legislation Creates Economic Downturn	Scenario 7 Reference Case: Spring 2010*	Scenario 8 Reference Case: Great Recession Impacts Recovery
Commodity prices	Gas & Coal Higher than 2010 Ref Case	Gas Higher; Coal Lower than 2010 Ref Case	Gas Much Lower & Coal Much Higher than 2010 Ref Case	Gas Lower & Coal Slightly Higher than 2010 Ref Case	Gas & Coal Higher than 2010 Ref Case	Gas & Coal Much Lower than 2010 Ref Case	Gas - $6-8 / MMBTU Coal $40 / ton	Gas - $6-8 / MMBTU Coal $40 / ton
Contract Purchase Power Cost	Much Higher Cost & Lower Availability	Higher Cost & Lower Availability	Same as Base, then Much Lower Cost with High Availability	Higher Cost & Lower Availability, then Much Lower Cost with High Availability after Load Decrease	Higher Cost & Lower Availability	Lower Cost with High Availability	Moderate Cost & Availability	Moderate Cost & Availability
Construction cost escalation	Much Higher than 2010 Ref Case--High economic growth causes high demand for new plants and high escalation rate	Somewhat higher than 2010 Ref Case--due to construction costs escalating at high rate due to large volume of nuclear, renewables, and env controls projects. High regulatory scrutiny adds to project costs	Lower than 2010 Ref Case--Low load growth leads to low escalation	This scenario has two stages of escalation: 1) higher than 2010 Ref Case due to high load growth early, then 2) lower escalation when game-changing technology hits	Somewhat Higher than 2010 Ref Case--Moderately strong economy and load growth lead to somewhat higher than base escalation	Lower than 2010 Ref Case--Negative load growth, very weak economy and high renewables lead to low escalation	Moderate Escalation	Moderate Escalation

Notes on table entries: Hg MACT - Maximum Achievable Control Technology for mercury; HAP MACT - Maximum Achievable Control Technology for hazardous air pollutants; CAIR - Clean Air Interstate Rule; SCR - selective catalytic reduction (for NOx control); FGD - flue gas desulfurization; High Dist. - high sales by distributors; Low Dist. - low sales by distributors; USEC - U.S. Enrichment Corporation; HSC - Hemlock Semiconductor; Dept Dist - departure of distributors

*Named the IRP Baseline Case in the Draft IRP and EIS

2.4. Planning Strategies

Planning strategies are designed to test various business options TVA might consider in order to determine how each strategy performs in the scenarios developed. The attributes of these strategies are assumed to be within TVA's control. This is an important difference between strategies and scenarios; the attributes of scenarios are largely outside of TVA's control.

The planning strategies considered in the IRP frame alternative business plans that are tested across multiple scenarios. Each alternative business plan is described by a unique combination of strategic objectives and/or constraints. The objective in the IRP is to identify one or more strategies that provide stability and flexibility over a broad range of conditions during the next 20 years.

In developing the planning strategies, TVA identified nine categories of attributes. The choice of attributes was influenced by comments received during the public scoping and focused on those assumptions that would have the greatest impact on the options that might be included in the long-term resource plan. These attributes (Table 2-2) fall into one of two groups which vary in how they are treated in the capacity optimization model (described in more detail in Section 2.5) used to develop the resource portfolios:

- Defined model inputs—attributes that are "locked in" and assumed by the model to already exist
- Constraints—attributes that form boundary conditions within which the model will identify a resource portfolio.

Table 2-2. Attributes of planning strategies.

Attribute	Description	Type
EEDR Portfolio	The level of energy efficiency (EE) and demand response (DR) included in each strategy	Defined Model Input
Renewable Additions	The amount of renewable resources added in each strategy	Defined Model Input
Coal Capacity Idled*	A proposed schedule of coal units idled tested in each strategy	Defined Model Input
Energy Storage	Inclusion of a pumped storage hydro unit in selected strategies	Defined Model Input
Nuclear Generation	Limitations on the addition of new nuclear capacity	Constraint
Coal-Fired Generation	Limitations on technology and timing for new coal-fired plants	Constraint
Gas-Fired Generation (Self Build)	Limitations on the addition of gas-fired units	Constraint
Market Purchases	Level of reliance on purchased power allowed in each strategy	Constraint
Transmission Investment	Type and level of transmission infrastructure required to support resource options in each strategy	Constraint

*Defined in Section 5.4.1.

These nine attributes were combined to create five distinct planning strategies (Table 2-3).

Table 2-3. Attributes of the five planning strategies.

Attributes	Planning Strategy				
	A - Limited Change in Current Resource Portfolio	B - Baseline Plan Resource Portfolio	C - Diversity Focused Resource Portfolio	D - Nuclear Focused Resource Portfolio	E - EEDR and Renewables Focused Resource Portfolio
EEDR	1,940 MW & 4,725 annual GWh reductions by 2020	2,100 MW & 5,900 annual GWh reductions by 2020	3,500 MW & 11,400 annual GWh reductions by 2020	4,000 MW & 8,900 annual GWh reductions by 2020	5,900 MW & 14,400 annual reductions by 2020
Renewable Additions	1,300 & 4,500 GWh competitive renewable resources or PPAs by 2020	Same as Strategy A	2,500 MW & 8,500 GWh competitive renewable resources or PPAs by 2020	Same as Strategy C	3,500 MW & 12,000 GWh competitive renewable resources or PPAs by 2020
Coal Capacity Idled	No reductions	2,000 MW total reductions by 2017	3,000 MW total reductions by 2017	7,000 MW total reductions by 2017	5,000 MW total reductions by 2017
Energy Storage	No new additions	Same as Strategy A	Add one pumped storage unit	Same as Strategy C	Same as Strategy A
Nuclear	No new additions after WBN2	First unit online no earlier than 2018 Units at least 2 years apart	Same as Strategy B	Same as Strategy B	First unit online no earlier than 2020 Units at least 2 years apart Limited to 3 units
Coal	No new additions	New coal units are outfitted with CCS First unit online no earlier than 2025	Same as Strategy B	Same as Strategy B	No new additions
Gas-Fired Supply (Self-Build)	No new additions	Meet remaining supply needs with gas-fired units	Same as Strategy B	Same as Strategy B	Same as Strategy B
Market Purchases	No limit on market purchases beyond current contracts and contract extensions	Purchases beyond current contracts and contract extensions limited to 900 MW	Same as Strategy B	Same as Strategy B	Same as Strategy B

Table 2-3. Continued.

Attributes	Planning Strategy				
	A - Limited Change in Current Resource Portfolio	B - Baseline Plan Resource Portfolio	C - Diversity Focused Resource Portfolio	D - Nuclear Focused Resource Portfolio	E - EEDR and Renewables Focused Resource Portfolio
Transmission	Potentially higher level of transmission investment to support market purchases Transmission expansion (if needed) may have impact on resource timing and availability	Complete upgrades to support new supply resources	Increase transmission investment to support new supply resources and ensure system reliability Pursue inter-regional projects to transmit renewable energy	Same as Strategy C	Potentially higher level of transmission investment to support renewable purchases Transmission expansion (if needed) may have impact on resource timing and availability

An additional strategy, Strategy R - Recommended Planning Direction, was developed following the release of the Draft IRP and EIS. This strategy is described below in Section 6.2.

2.5. Portfolio Development

The next step in the resource planning process is the development of the potential 20-year resource plans or portfolios. A major input to the portfolio development is the definition of the supply-side and demand-side energy resource options that can become components of the portfolios. These options include existing and potential future TVA generating facilities and existing and potential future PPAs. These are described in Chapter 5. Costs, construction schedules, fuel requirements, operational characteristics, and other attributes are defined for each of these options. This resource option information and the forecast power demands are then used by the capacity planning model to develop a portfolio for each combination of a planning strategy and scenario, for a total of 35 portfolios.

The capacity planning model (System Optimizer produced by Ventyx, Inc.) found the "optimum" combination of resource options to meet projected demand/energy requirements over the 20-year planning period. An optimized portfolio has the lowest net Present Value of Revenue Requirements (PVRR) subject to the constraints of energy balance, reserve margin, generation and transmission operating limits, fuel purchase and utilization limits, and environmental compliance requirements. PVRR is the current value of the total expected future revenue requirements associated with a particular resource portfolio. The capacity planning modeling process is described in more detail in IRP Section 6.2.

Each of the 35 portfolios was then evaluated using an hourly production costing program with stochastics (the consideration of uncertainty using probability distributions). This second step computed detailed plan costs and financial indicators. This analysis was accomplished using the Strategic Planning (MIDAS) software produced by Ventyx; its operation is described in more detail in IRP Section 6.2. The results of the MIDAS analyses are the expected values of PVRR and short-term rates for each portfolio. Short-term rate is the levelized cost in dollars/MWh to serve load from 2011-2018. Portfolios were similarly developed and evaluated for the Recommended Planning Direction alternative strategy.

2.6. Portfolio and Strategy Evaluation Metrics

The portfolios and strategies are evaluated with a trade-off analysis that focuses on cost, financial risk, other risks, environmental impacts, and other aspects of TVA's overall mission. A strategy scorecard consisting of ranking metrics and strategic metrics is used to facilitate this trade-off analysis. The ranking metrics include the cost (combination of PVRR and short term rates) and financial risk metrics (combination of the risk ratio and the risk/benefit ratio). The two risk ratios are based on the potential of exceeding the expected PVRR and are explained in more detail in IRP Section 6.3.1.1.2. Each of these ranking metrics is based on a weighted formula:

Cost metric = 0.65 * PVRR + 0.35 * short-term rates

Risk metric = 0.65 * risk ratio + 0.35 * risk/benefit ratio

Ranking Metrics Score = 0.65 * cost + 0.35 * risk

The strategic indicators include environmental metrics and economic development metrics. The environmental metrics are:

Carbon footprint metric = average annual tons of direct CO_2 emissions

Water impact metric = Generation by fuel type (GWh) x heat input (mmBTU) x design factor

Waste impact metric = Fuel consumed (mmBTU) x waste factor x handling costs

The water impact metric is a measure of the amount of "leftover" heat that is released into the environment by thermal generating plants. It does not account for the type of cooling at a plant and thus is not a direct measure of potential water impacts. The design factor used in its calculation is related to the thermal efficiency of the plant, i.e., the proportion of the energy in the fuel that is converted to electricity. Among widespread generation sources, combined cycle plants have the lowest design factor (e.g., the highest proportion of heat converted to electricity) and nuclear plants have the highest design factor (see IRP Appendix A). The waste impact metric estimates the costs of managing wastes produced from coal and nuclear generation only.

The economic metrics are included to provide a general indication of the impact of each portfolio and strategy on the general economic conditions in the TVA service area. They compare the changes in total employment and personal income indicators of Strategies A, C, D, E, and R, to those of the baseline Strategy B. They are calculated with a regional economic model, developed by Regional Economic Models, Inc., of the economies of the TVA region and the surrounding area. The model maps the region's economic structure, its inter-industry linkages, and responses to TVA rate and customer cost changes, including those from energy efficiency. Inputs specific to the alternative strategies that include direct TVA expenditures on labor, equipment, fuels, and materials and the costs of electricity to customers are used to estimate the effects of the strategies on total employment and personal income. This analysis is described in more detail in Final IRP Appendix B. The economic metrics were calculated for Scenarios 1 and 6 for each strategy; these scenarios are assumed to define the upper and lower range of the economic impacts.

The ranking metrics in the scorecard are expressed on a 100-point scale for each strategy with the highest ranking ("best") value receiving 100 points and the lower ranking values receiving scores based on their relative position to the highest value.

The strategic metrics are assigned ordinal scores based on their ranking within a given scenario. These scoring methods are described in more detail in Final IRP Section 6.3.1.3.