Energy Vision 2020

VOLUME TWO, TECHNICAL DOCUMENTS

Integrated Resource Plan
Environmental Impact Statement

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TVA

Energy Vision 2020

VOLUME TWO, TECHNICAL DOCUMENTS

Integrated Resource Plan Environmental Impact Statement

Tennessee Valley Authority
December 1995

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These technical documents support Volume 1 of TVA's Energy Vision 2020 Integrated Resource Plan/Environmental Impact Statement:

- Chapter One: Overview and Objectives
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Responses to public comments on the draft Energy Vision 2020 published on July 26. 1995, are found in Volume 3 of this set.

Energy Vision

2020

Volume 2, Technical Document

Comprehensive Affected Environment

Summary

This document provides detailed information about the natural and socioeconomic resources in the region that may be influenced by TVA's Energy Vision 2020 decisions about future energy resources. It helps provide a baseline for assessing the potential environmental consequences of alternative energy strategies for the future.

The Energy Vision 2020 assessment is made at a macro, or regional, scale rather than at a micro, or site-specific, scale.

The primary study area for Energy Vision 2020 includes the TVA power service area and the Tennessee River watershed. This area contains 201 counties within a 58- million acre area. It also covers appropriate areas of the Green and Ohio Rivers in Kentucky and the Cumberland and Mississippi Rivers in Tennessee because they contain TVA coal-fired plants and, in the case of the Cumberland River, one hydro-electric power plant.

Similarly, there are potential effects on other resources outside the primary study area. As appropriate, the study contains information about them.

Volume 2, Technical Document 1

Comprehensive Affected Environment

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Comprehensive Affected Environment

SECTION 1: OVERVIEW

Energy Vision 2020 evaluates the affected environment to help provide a baseline for assessing the environmental consequences of alternative energy strategies. Because Energy Vision 2020 is also an environmental impact statement, special emphasis is being given to the environment. A regional perspective takes in both natural conditions and those resulting from human development. It considers socioeconomic, air, water, and land resources.

The Study Area

The primary study area for Energy Vision 2020, shown in the maps in *Figures T1-1* and *T1-2*, includes the TVA power service area and the Tennessee River watershed. This area contains 201 counties within a 58-million acre area. This study also covers appropriate areas of the Green and Ohio Rivers in Kentucky and the Cumberland and Mississippi Rivers in Tennessee because they contain TVA coal-fired plants and, in the case of the Cumberland River, one hydroelectric power plant. Similarly, there are potential effects on other resources outside the primary study area. As appropriate, the study contains information about them. For example, the assessment region for air quality is not limited to the TVA service area because of pollutant emissions originating outside the region, pollutants leaving the region, and because of some air pollution effects such as haze and ozone. These are recognized as regional issues.

Fuel Cycles

Fuel cycles have a wide range of impacts in the environment. They include mining, drilling, fuel transportation, power generation and waste assimilation or disposal impacts that involve air, land, and water resources. As a result, the affected environment also encompasses potentially impacted areas that may be remote from power plants. A fuel cycle consists of all the actions and outcomes of using any fuel for energy conversion, including both direct and indirect effects of the fuel cycle.

Figure T1-3 shows the relationships between fuel cycles and their resulting environmental impacts. Fuel energy choices, conversion technology, and environmental controls determine potential environmental impacts. For most impacts, site selection determines to what degree potential impacts are realized.

Environmental Quality and Trends

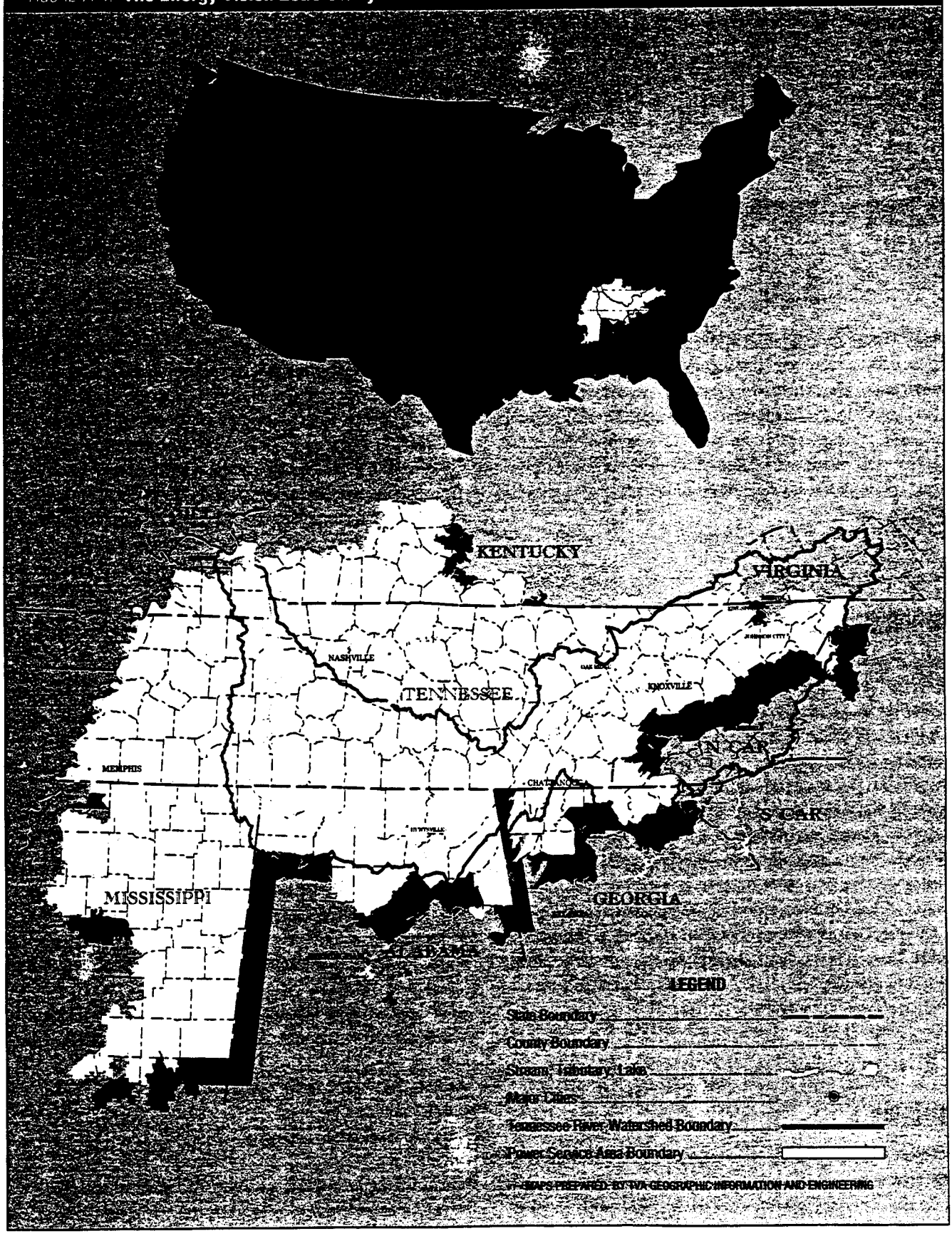
Natural resources include the air, water, and land resources of the region. This document, Technical Document 1, discusses the present quality of these resources, as well as recent and current trends in environmental quality. The socioeconomic environment, also discussed here, encompasses both the regional economy and the TVA power system.

Most direct land, water, and socioeconomic impacts are localized and depend on site selection. Proper environmental screening and selection can avoid many potentially significant impacts such as:

- Loss of wetlands, habitats, prime farmland, and cultural and historic resources
- Alteration of sensitive aquatic habitats due to heat releases, wastewater discharge, water withdrawal, or stream flow alteration
- Danger to threatened or endangered species
- Aesthetics and noise
- Socioeconomic implications

Although some air quality impacts are localized, such as plume impacts on elevated terrain, most are not. Air pollutant transport

FIGURE T1-1. **The Energy Vision 2020 Study Area is in the Southeastern United States**



and conversion processes are complex and depend greatly on meteorological conditions. TVA considers air quality impacts distant from the site when selecting plant locations. Considerations include the "down wind" spatial distribution of sensitive receptors (humans, natural resources), prevailing ambient air quality, dominant meteorological conditions, and characteristics of the air pollutant emissions. Some air quality conditions, however, are regional in scale, and some level of direct impacts may occur regardless of the location of emissions in the TVA region. Visibility impairment due to haze, ozone formation, and acid deposition are examples of potential regional effects.

Some indirect impacts, such as those from fuel sourcing and transportation, function independently of site selection. For example, coal mining impacts are generally unaffected by a power plant's location. Most potential land and water impacts depend on site selection. These are assessed in a general manner, with emphasis on the range of impacts that may be encountered. Some strategies are inherently more likely than others to result in significant environmental impacts because of an emphasis on a particular fuel or energy conversion technology. These inherent differences are discussed. Detailed environmental reviews will be conducted under National Environmental Policy Act guidelines as specific sites are selected.

SOCIOECONOMIC ENVIRONMENT

The socioeconomic environment is an integral portion of the region's total environment. Potential socioeconomic effects include impacts to social services and the local or regional economies. Energy Vision 2020 focuses on the region's economy and its components, since social services impacts are largely site-specific.

AIR RESOURCES

Air quality is important to the protection of human health and natural resources. Regional compliance with the Federal National Ambient Air Quality Standards (NAAQS) serves as a key indicator of how well human health is protected. This document presents trends in regional compliance and analyzes present air quality. Federal standards are reviewed periodically by the U.S. Environmental Protection Agency to determine if changes in standards are necessary to ensure continued adequate protection for human health and natural resources. Section 3, Air Resources, in this document examines the implications of stricter standards on compliance.

Natural resources such as soils, forests, crops, other vegetation, surface waters, aquatic ecosystems, and aquatic life may be sensitive to air quality impacts of acidic deposition (including acid rain), ozone exposure, and heavy metals deposition. Concerns in these areas are discussed in terms of present air quality and regional emissions, including those emissions contributed by TVA.

WATER RESOURCES

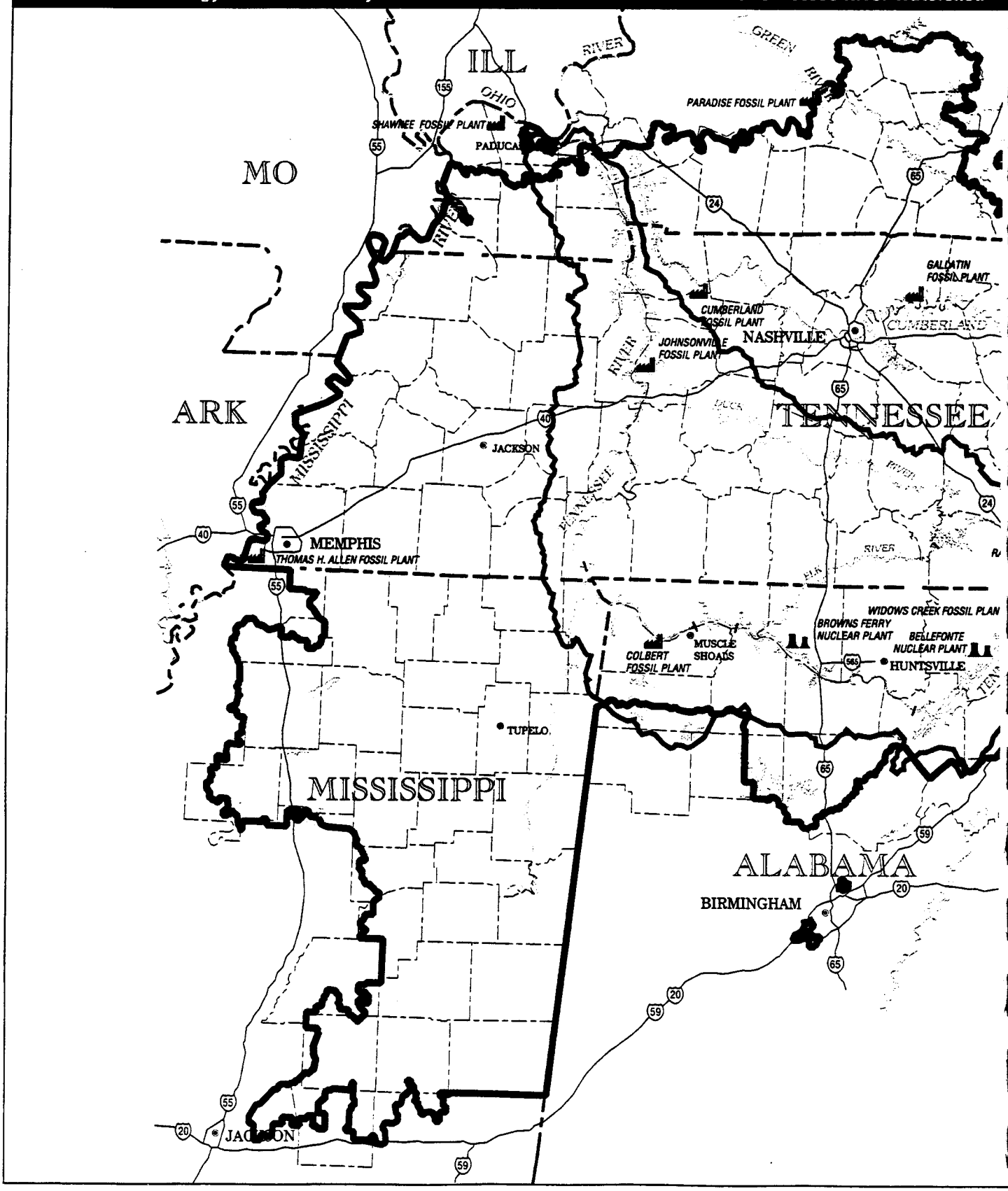
Water quality is critical to protecting, preserving, and restoring finite water resources. These resources include aquatic ecosystems and aquatic life, recreation, and domestic and industrial water supplies. Section 4, Water Resources, in this document discusses in detail the water quality necessary to support these uses. The sources and reasons for impaired water quality are presented, including TVA operations.

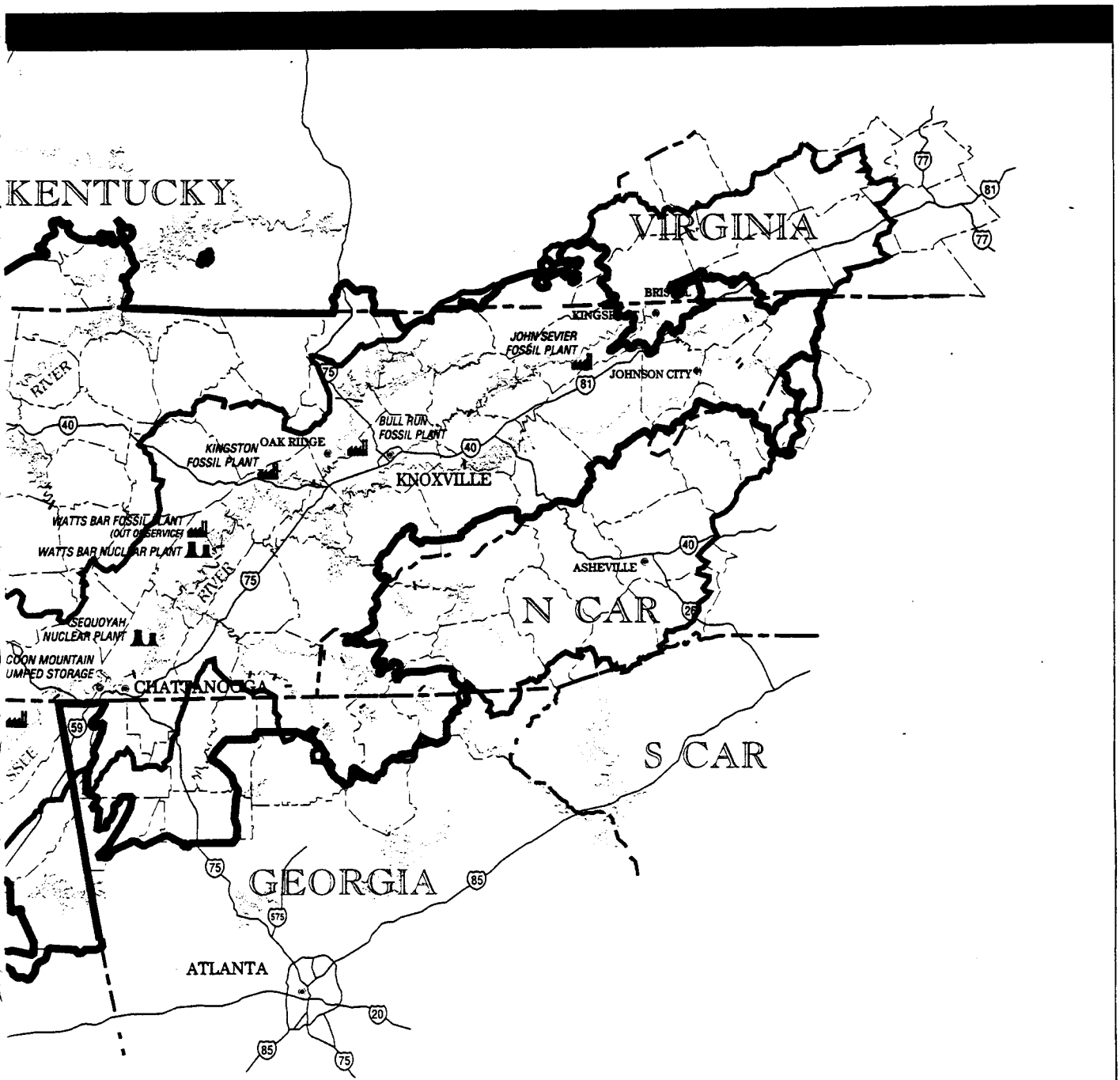
LAND RESOURCES

A broad range of land uses takes in management of the natural ecosystem, agriculture, forestry, urban and industrial use, and recreational use. Factors such as soils, groundwater, wildlife, sensitive or threatened ecosystems, threatened and endangered species, cultural resources, and terrestrial environments, such as wetlands and forests, are critically important in supporting and preserving these uses.

TVA affects land resources through site selection for power plants, reservoirs, and transmission lines; fuel procurement; air emissions; radioactive waste management; and solid waste management. Most land resource impacts are site-specific in nature and thus are not addressed in detail in this document because Energy Vision 2020 is intended to serve as a broader program-level review. Appropriate National Environmental Policy Act environmental reviews will evaluate site-specific effects associated with the actual deployment of future energy resource options.

FIGURE T1-2: **The Energy Vision 2020 Study Area Includes the TVA Service Area and the Tennessee River Watershed**





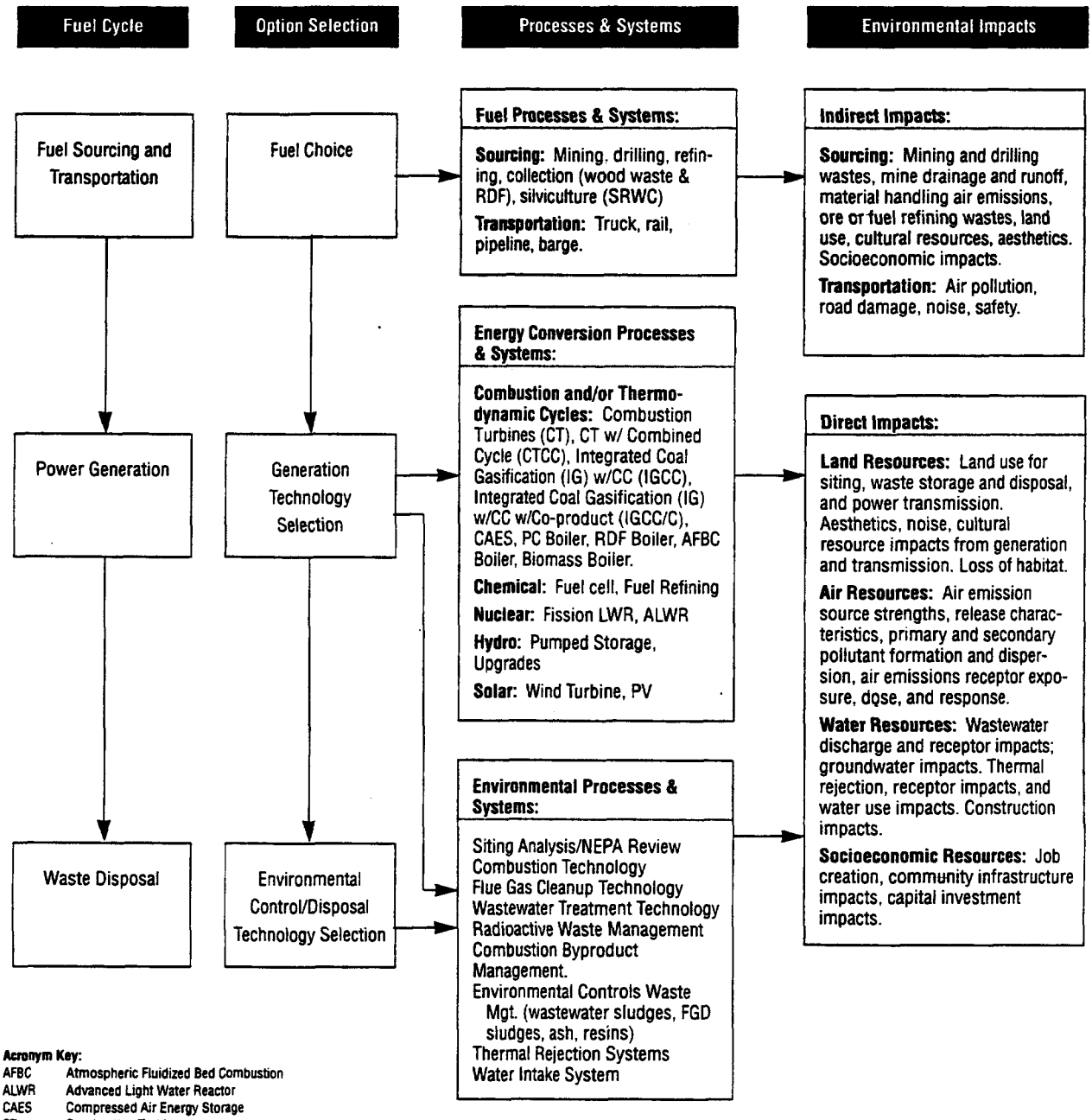
LEGEND

Tennessee Watershed Boundary.....

Power Service Boundary .....

MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

FIGURE T1-3. Relationships Between Fuel Cycles and Their Resultant Environmental Impacts



Acronym Key:

AFBC	Atmospheric Fluidized Bed Combustion
ALWR	Advanced Light Water Reactor
CAES	Compressed Air Energy Storage
CT	Combustion Turbine
FGD	Flue Gas Desulfurization
IG	Integrated Gasification
IGCC	Integrated Gasification Combined Cycle
LWR	Light Water Reactor
NEPA	National Environmental Policy Act
RDF	Refuse Derived Fuel
PV	Photovoltiacs
SRWC	Short Rotation Woody Crops

SECTION 2: SOCIOECONOMIC ENVIRONMENT

Introduction

The TVA region consists of the 170 counties in which TVA provides electric power. It also includes 31 additional counties that are within the Tennessee River watershed, most of Tennessee, and parts of the surrounding states of Alabama, Georgia, Kentucky, Mississippi, North Carolina, and Virginia, to comprise a 201-county area. In terms of economic development impacts, the study area is the power service area, since this is the area that is directly affected by TVA plant locations, electric rates, and bills. In 1994, the power service area had an economy of $146 billion in total personal income, 3.6 million people in total non-farm payroll employment, and $175 billion in gross product. The population was 7.7 million in 1994. Per capita income in the power service area was about $19 thousand the same year, or about 86 percent of the national average.

The 201-county area constitutes an economy that is about 13 percent larger than the power service area. In 1994, the 201-county region had an economy of $165 billion in total personal income and 4 million non-farm jobs. (Gross product is not available for this area.) The population was 8.7 million, and per capita income was about the same as for the power service area. The general economic situation and trends are identical for the power service area and the 201-county region.

The region is considerably more rural and the economy depends much more on manufacturing than the nation as a whole. Close to half of the region's population lives in non-metropolitan counties, compared to less than one-fourth in the nation. In 1994, about 26 percent of total non-farm payroll employment in the region was in manufacturing. This compares to 16 percent for the entire United States Manufacturing's predominance in the region is due to several advantages that have previously benefited the area and should continue to do so in the future. They include:

- A location in the South, with good access to the markets of the Northeast, the Midwest, the Southwest, and Florida
- Good transportation for shipping commodities via interstate highway, rail, and barge
- A low-wage (for the U.S.) workforce with good work habits
- Abundant, relatively low-cost resources including water, electricity, and land.

Economy

A large manufacturing base has helped this area outperform the U.S. economy and is expected to continue to do so. Strong manufacturing gains since 1985, as evidenced in manufacturing employment shown in *Figure T1-4*, have stimulated the region's growth. Three critical factors hampered manufacturing in the early to mid-1980s: exceptionally high oil and energy prices, high interest rates, and high foreign exchange rates. These have returned to relatively lower levels and are expected to remain there, setting up favorable conditions for growth in the region's manufacturing.

FIGURE T1-4. **Manufacturing Employment**

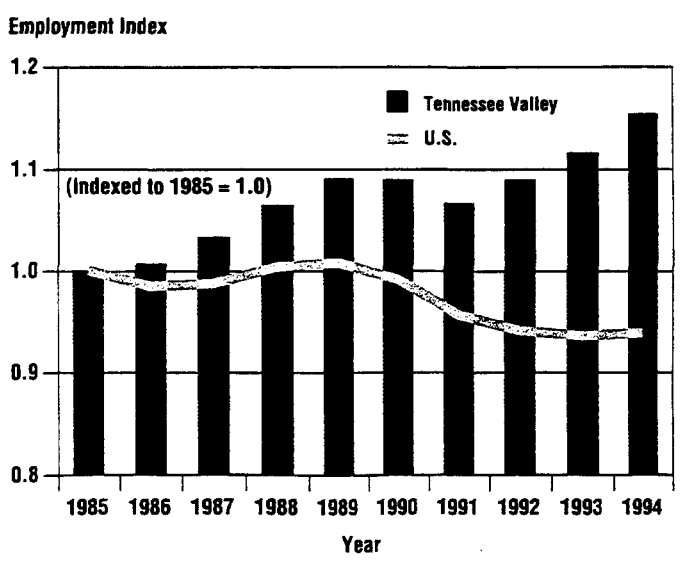


FIGURE T1-5. Earnings, Employment, and Product in the Tennessee Valley

	AVERAGE ANNUAL GROWTH RATES	
Earnings (1994 dollars)	**1979-1985**	**1985-1994**
Total	1.0%	3.4%
Manufacturing	0.3%	2.5%
Durables	1.1%	3.0%
Non-Durables	-0.6%	2.0%
Service Sector	2.5%	4.4%
Employment		
Total	0.9%	3.0%
Manufacturing	-0.4%	1.6%
Durables	0.1%	2.2%
Non-Durables	-0.9%	1.1%
Service Sector	2.8%	4.2%
Product (1987 dollars)		
Total	2.1%	3.9%
Manufacturing	2.4%	5.3%
Durables	3.4%	6.5%
Non-Durables	1.7%	4.2%
Service Sector	3.1%	4.0%

The cost of electricity significantly affects production costs for many of the region's manufacturing industries. Manufacturing has been helped by relatively low, stable TVA electric rates since 1988. In the future, TVA rates are expected to become even more competitive with the U.S. average. This will aid the region in maintaining manufacturing's competitive edge.

The region's manufacturing industry mix has been changing. The manufacture of durable goods, those which generally last three or more years, has expanded rapidly in the region. This has been due to newer durables industries. such as motor vehicles, coming to the region. At the same time, non-durable goods industries, such as textiles and apparel. have been losing jobs to foreign markets despite outperforming the national market.

Although manufacturing is the core of the region's economic base, non-manufacturing industries accounted for some two-thirds of total regional product in 1994. The service sector, which makes up the bulk of the non-manufacturing side of the economy, has provided, and is expected to continue to provide, the great majority of all new jobs created in the region. This follows the national trend. However, the region does not have particular comparative advantages in the service sector, as it does in manufacturing. Thus, compared with the national service sector, the service sector in the Energy Vision 2020 study area remains highly dependent on the income generated in manufacturing.

Figure T1-5 shows these historical trends for earnings, employment, and product in the manufacturing and service sectors of the TVA power service area.

Future Trends

For the balance of the decade, the region's performance is expected to continue the trend of the 1985 to 1994 period. Relatively favorable national conditions and TVA's favorable electric rates for regional manufacturing are both expected to continue. TVA expects the region's newer manufacturing industries to continue further expansion. However, worldwide economic competition is likely to become more intense as some trade barriers are removed and regions of the world favor trading blocs. For this reason, businesses will continue to hold down labor costs as much as possible; downsizing and relatively slow wage growth in the TVA region will persist. Overall, manufacturing growth in the region is expected to exceed the national rate significantly. The strength in the region's service sector is expected to continue, following the growth in manufacturing.

After the year 2000, Energy Vision 2020 expects the region's growth will slow considerably as the area's newer manufacturing industries reach maturity. Nevertheless, manufacturing's intensiveness is expected to continue to provide enough impetus for the region to expand somewhat faster than the national rate. The region's service sector is expected to remain somewhat underdeveloped relative to the nation's. Thus, with the slowing of manufacturing growth, the whole regional economy is expected to proceed at a slower tempo.

The TVA region is not a uniform economic area, however. Manufacturing accounts for about twice the share of non-farm employment in the region's non-metropolitan areas compared to the metropolitan areas (42 percent compared to only 20 percent). Further, the region's non-metropolitan areas have shown faster growth in manufacturing during expansionary periods than its metropolitan areas. Thus, the non-metropolitan areas have been, and are more likely to continue to be, more affected by the fortunes of manufacturing.

Additional information on the economic forecast is available in Volume 2, Technical Document 5, "Load Forecast." Detailed information on the regional economic situation and trends is available from TVA in a report titled "Economic Outlook" (TVA 1994).

The Agricultural Sector

Agriculture directly represents a very small percentage of the Valley's economy. The terms "agriculture" and "agricultural" refer to industries grouped in Division A of the Office of Management and Budget's (OMB) Standard Industrial Classification of Establishments. Division A industries include those involved in crop and livestock production, agricultural services, forestry, fishing, hunting, and trapping.

In 1989, only 2.7 percent of the area's population lived on farms. These farms generated only 1.8 percent of the region's total earnings, produced only 1.6 percent of its total product, and employed only 5.1 percent of its labor force. These small percentages belie the importance of agriculture to the area, however, since they do not account for the strong linkages between the agricultural sector and most other Valley industrial sectors. Once the economy's most important sector, agriculture has been declining in importance in terms of earnings, product, and employment, as shown in *Figure T1-6*. It is expected to continue to wane in the future.

The table in *Figure T1-6* shows that the Valley's farm population in 1969 was almost three times larger than in 1989. Earnings, employment, and production also fell steeply over the period, both absolutely and relative to regional totals. By 2020, the Valley's agricultural sector is expected to account for only 0.5 percent of regional earnings, 0.9 percent of regional product, and 3.1 percent of regional employment.

FIGURE T1-6. **Population, Earnings, Employment, and Product in the Agricultural Sector in 1969, 1979, and 1989**

	1969	1979	1989
Farm Population	636,090	337,008	219,503
Earnings (millions of 1994 dollars)	$2,675	$2,176	$1,656
Employment	250,876	224,901	201,401
Product (millions of 1987 dollars)	$1,936	$1,769	$1,865
SHARE OF REGIONAL TOTAL:			
Farm Population	9.5%	4.3%	2.7%
Earnings	5.0%	2.9%	1.8%
Employment	9.7%	6.8%	5.1%
Product	3.3%	2.1%	1.6%

1 Population for the 201-County Valley Region from the 1970, 1980, and 1990 U.S. Censuses of Population.

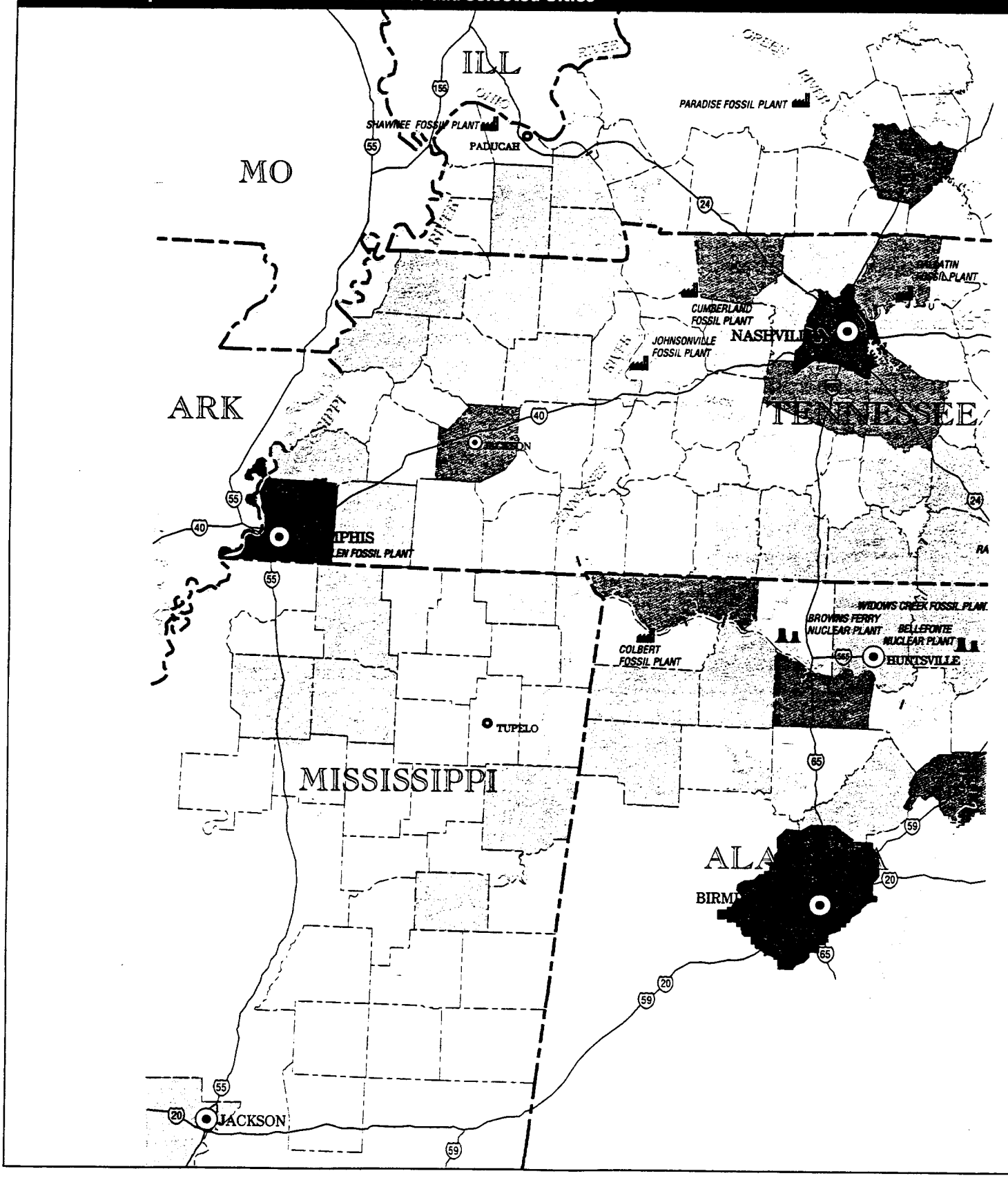
2 Earnings, employment, and product data are for the 170-County Power Service Area.

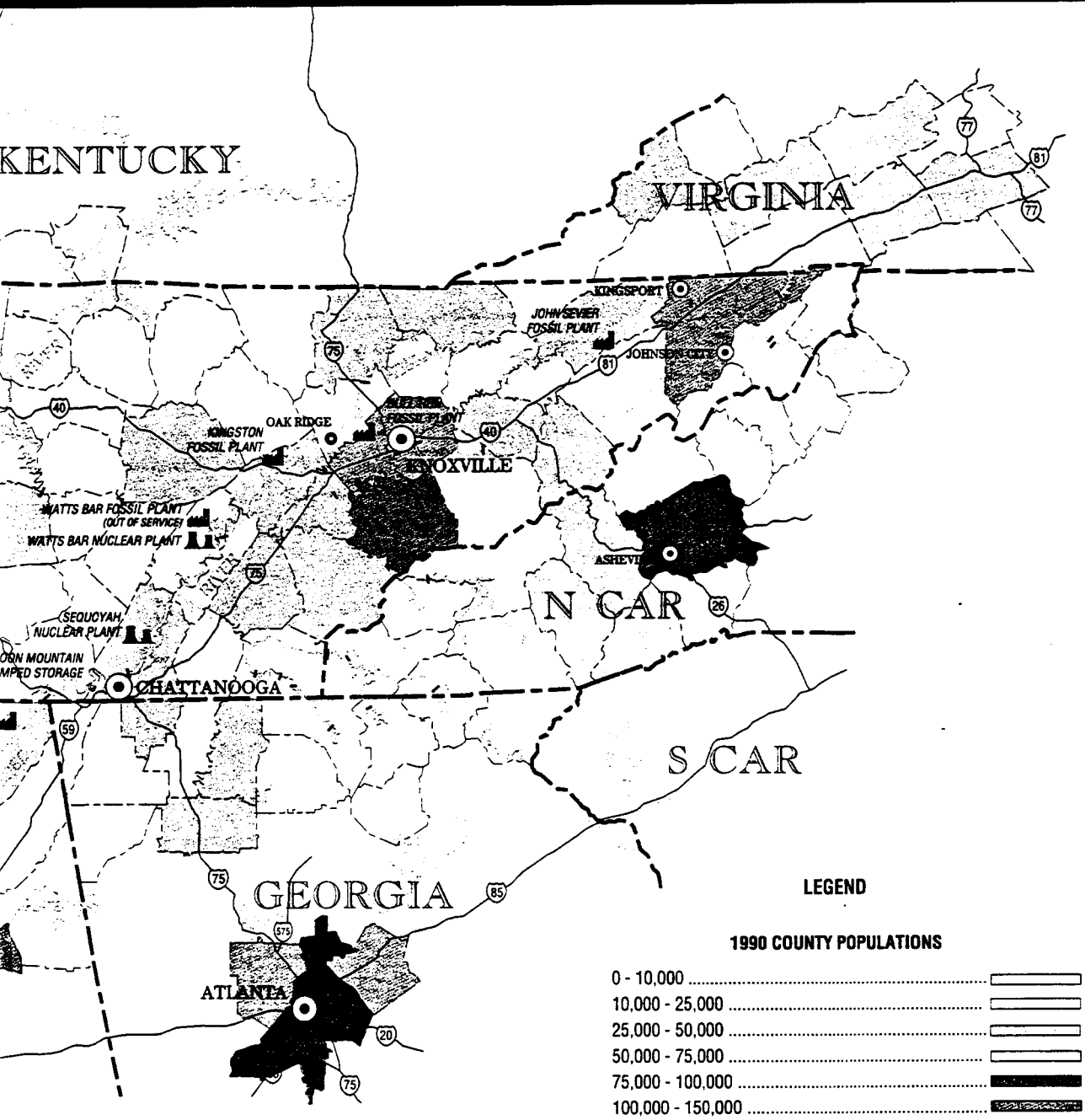
Population

About 8.7 million people live in the 201-county TVA region (about 7.7 million of these within the TVA power service area), with almost half residing in the major metropolitan areas of Nashville, Memphis, Knoxville, Chattanooga, and Tri-Cities, Tennessee, and Huntsville, Alabama. These metropolitan areas are all mid-sized, without any one large dominating area in the region, and are distributed fairly evenly throughout the region. Surrounding these metropolitan areas are a few smaller metropolitan areas and numerous satellite cities, along with the surrounding rural communities connected by both economic and transportation links. *Figure T1-7* shows the distribution of population in the TVA region. Thus, the region, while largely rural, is generally well served by centers of commerce and government, and the workforce is evenly distributed across the region, rather than focused in any particular central area.

Although only about 15 percent of the population is non-white, the distribution of the non-white population is very uneven across the region. There are greater concentrations in the central counties of metropolitan areas and in an area including most of the region's Mississippi counties, Memphis, and the counties north and east of Memphis. The region's African American households had a median income of $15,705 in 1990, about two-thirds of the region's median. Most of the region's non-metropolitan counties also had low median income levels. Similarly, regional poverty rates are generally much higher among the non-white population and in both rural and inner city areas. (Poverty rates are 34 percent for African American persons compared with 16 percent of the total population.)

FIGURE T1-7. **Population Distribution for Counties and Selected Cities**





LEGEND

1990 COUNTY POPULATIONS

- 0 - 10,000
- 10,000 - 25,000
- 25,000 - 50,000
- 50,000 - 75,000
- 75,000 - 100,000
- 100,000 - 150,000
- 150,000 - 200,000
- 200,000 - 300,000
- 300,000 - 500,000
- Over 500,000
- State Boundary
- County Boundary

1991 CITY POPULATIONS

- 25,000 - 35,000
- 35,000 - 75,000
- 75,000 - 150,000
- 150,000 or more

MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

SECTION 3: AIR RESOURCES

Introduction

This section describes the ambient (surrounding) air quality of the TVA region, discusses TVA emission contributions to ambient air quality, and identifies air quality impacts to human health and welfare. Volume 2, Technical Document 2, Environmental Consequences, describes how changes in TVA emissions could affect regional air quality, human health, environmental resources, and materials.

The primary region of the affected environment is broadly defined as the state of Tennessee, as well as southwestern Kentucky, southwestern Virginia, western North Carolina, and northern Georgia, Alabama, and Mississippi. This area represents the watershed of the Tennessee River and the 201 counties of the greater TVA service area, as shown in *Figure T1-2*. Emissions from outside the Tennessee Valley region contribute to air quality in the Valley. Also, TVA emissions are transported outside the Valley and have some impact on air quality beyond the primary study area. Although the study area experiences a number of air quality problems, overall air quality is good.

Weather and Climate Patterns

Weather and climate patterns of the Tennessee Valley affect several aspects of TVA's energy strategy. Strategy considerations include:

- Ability to meet permitted thermal limits for cooling water discharges and nuclear safety intakes
- Available energy supply from hydroelectric power generation (a function of reservoir water levels)
- Energy demand for heating and air conditioning
- Dispersion of air emissions from TVA facilities and their impact on regional air quality

Much of the year the western extension of the Azores-Bermuda high pressure ridge dominates the TVA region. This circulation results in extended periods of fair weather and, at times, atmospheric stagnation. Its greatest influence is in the summer and fall. Warm, humid air masses dominate in the summer with occasional tropical disturbances from the Gulf or cold fronts from the northwest, north, or northeast. Light winds and considerable sunshine typify summer weather, often with afternoon cumulus clouds and scattered thunderstorms. The Bermuda high is much weaker in winter and spring. Stronger westerly flows dominate the weather pattern, bringing alternately low and high pressure systems. Storms come primarily from the Southwest and the Gulf Coast or from the Plains and the Midwest.

FIGURE T1-8. **Climatic Averages of Eight First-Order National Weather Service Stations in the TVA Region[1]**

	MEAN TEMPERATURE [2]		MEAN DEWPOINT [3]		PRECIPITATION [2]		Percent of Possible Sunshine [4]	WIND SPEED [3]	
	Celsius	Fahrenheit	Celsius	Fahrenheit	Millimeters	Inches		Meters Per Second	Miles Per Hour
Annual	14.9	58.9	8.9	48.0	1,270	50.01	59	3.3	7.3
Winter	4.5	40.1	-0.8	30.5	334	13.13	47	3.8	8.4
Spring	14.9	58.8	7.9	46.2	360	14.19	61	3.7	8.3
Summer	24.7	76.5	18.8	65.9	301	11.87	64	2.6	5.8
Fall	15.7	60.3	9.6	49.3	275	10.82	61	2.9	6.5
Maximums and Month of Occurrence									
Month	JULY		JULY		MARCH		JUNE	MARCH	
Maximum	25.5	77.9	19.7	67.4	135	5.32	66	4.2	9.3
Minimums and Month of Occurrence									
Month	JANUARY		JANUARY		OCTOBER		JANUARY	AUGUST	
Minimum	3.0	37.4	-1.6	29.1	76	2.99	44	2.5	5.5

[1] Cities include Asheville, North Carolina; Tri-Cities Airport, Knoxville Airport, Chattanooga, Nashville and Memphis, Tennessee; Birmingham and Huntsville, Alabama.

[2] 1961 – 1990 normals.

[3] 1951-1980 hourly data bases.

[4] Excluding Tri-Cities Airport and Huntsville; data periods for the other six varying, but generally including 1951-1980.

FIGURE T1-9. Annual Average Temperatures and Precipitation Averaged for 1961-1990 Across the TVA Region

	TEMPERATURE Celsius	TEMPERATURE Fahrenheit	PRECIPITATION Millimeters	PRECIPITATION Inches
Southwest Virginia, Western North Carolina	12.0	53.6	1,268	49.9
Eastern Tennessee	13.7	56.7	1,271	50.0
Central Tennessee & Kentucky	13.7	56.7	1,358	53.5
Western Tennessee & Kentucky	14.5	58.0	1,302	51.3
North Georgia & Northeast Alabama	15.5	59.8	1,431	56.3
Northwest Alabama & North Mississippi	16.3	61.3	1,435	56.5

Two charts paint a picture of climate conditions in the TVA region. *Figure T1-8* gives 30-year average temperatures for the Tennessee Valley. Average summer temperatures are 24.7° C (76.5° F) and winter temperatures, 4.5° C (40.1° F). Heat waves with daily maximum temperatures above 35° C (95° F) occur in some summers, and cold waves with temperatures falling below -15° C (5° F), in some winters. The southern and western parts of the region are warmer than the northern and eastern parts *(Figure T1-9). Figure T1-10* contrasts summer temperatures during 1988 and 1989. These are examples of temperatures for unusually dry and wet years. Summer 1988 was warmer than normal; summer 1989, cooler than normal.

Figure T1-8 indicates that precipitation is abundant and normally well distributed throughout the year, although winter and spring are somewhat wetter than summer and fall. Averages in this table are representative of lower elevations in the Tennessee Valley. Patterns of precipitation across the TVA region are indicated in *Figure T1-9. Figure T1-11* indicates regional patterns during the abnormally dry summer of 1988 and wet summer of 1989. The last in a series of five drier than normal years was 1988. The period from 1985 to 1988 marked the four driest consecutive years during the last 100 years in the Tennessee River Basin. This pattern is important in interpreting regional air quality impacts during the decade of the 1980s.

Wind speed and direction significantly determine weather patterns and dispersion of emissions. *Figure T1-8* shows that surface wind speeds are relatively light, with higher winds in winter and spring and lower winds in summer and fall. Wind speeds at higher elevations are generally stronger than averages shown in the table. The most frequent surface wind directions are from the south or southeast and from the north or northeast sectors. *Figure T1-12* gives the surface wind roses (direction patterns) for airports in the TVA region. At higher levels in the atmosphere, winds generally blow from the southwest, west, or northwest, as shown on the same map by the Nashville winds-aloft wind rose for an altitude of 1,500 meters above ground level. A windrose is a diagram with spokes representing the sixteen cardinal directions (i.e., N, NNE, NE, etc.). The frequency with which the measured wind blows from a given direction is illustrated by the distance between the point where a heavy line, or edge of the rose, crosses a spoke and the center of the diagram. In *Figure T1-12*, the wind direction frequencies in all windroses have been normalized (i.e., divided by a common factor) using the frequency of the most frequent wind direction. Thus, the heavy line in each windrose crosses the outer end of the spoke representing the most frequent wind direction (a normalized frequency of one). A direction only half as frequent as the most frequent direction has a normalized frequency of 0.5, and the heavy line crosses the midpoint of the spoke.

Figure T1-8 indicates that solar radiation (shown as percent of possible sunshine) and dewpoint are higher in the summer than other seasons.

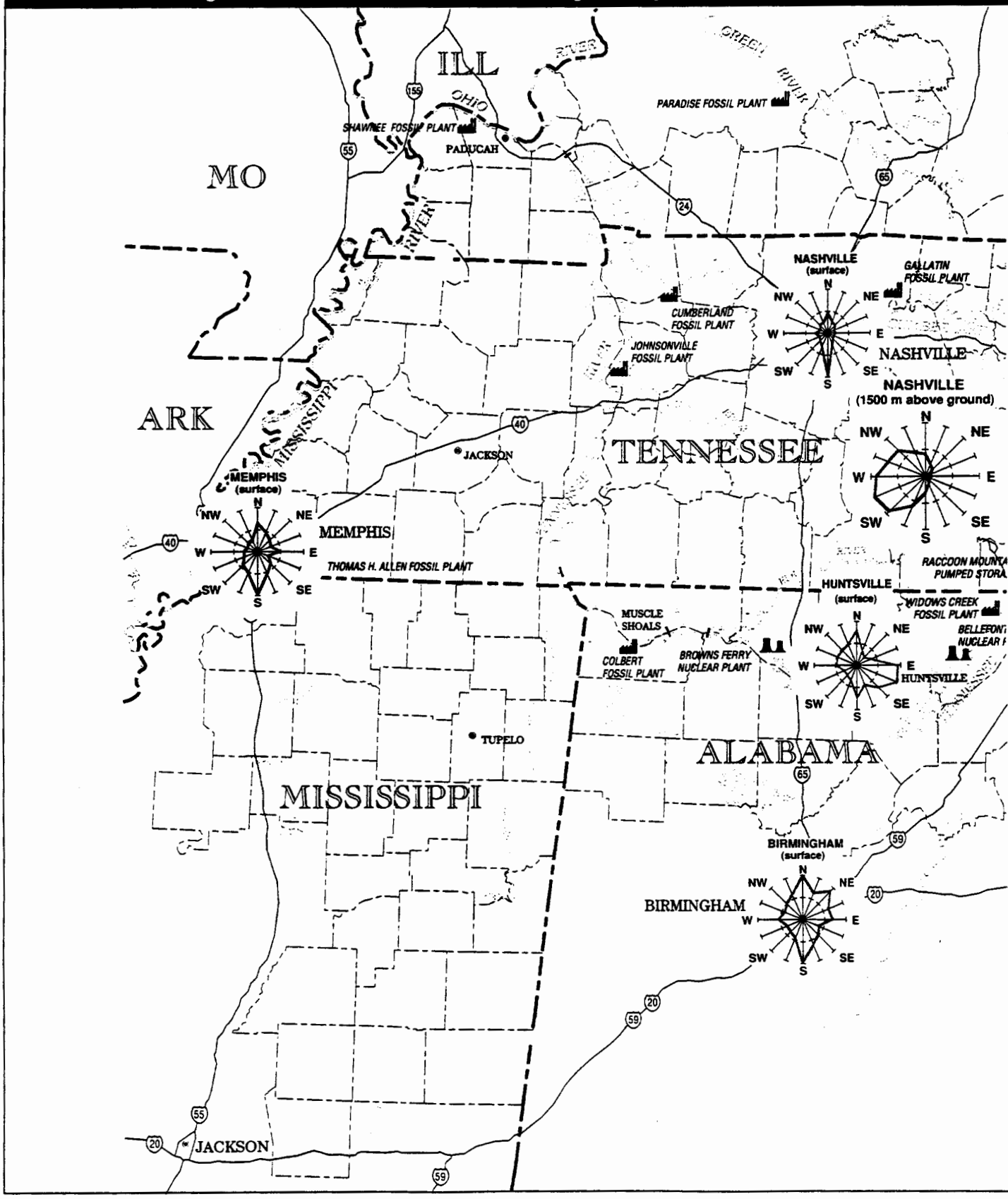
FIGURE T1-10. Summer Temperature Across the TVA Region for 1988 and 1989

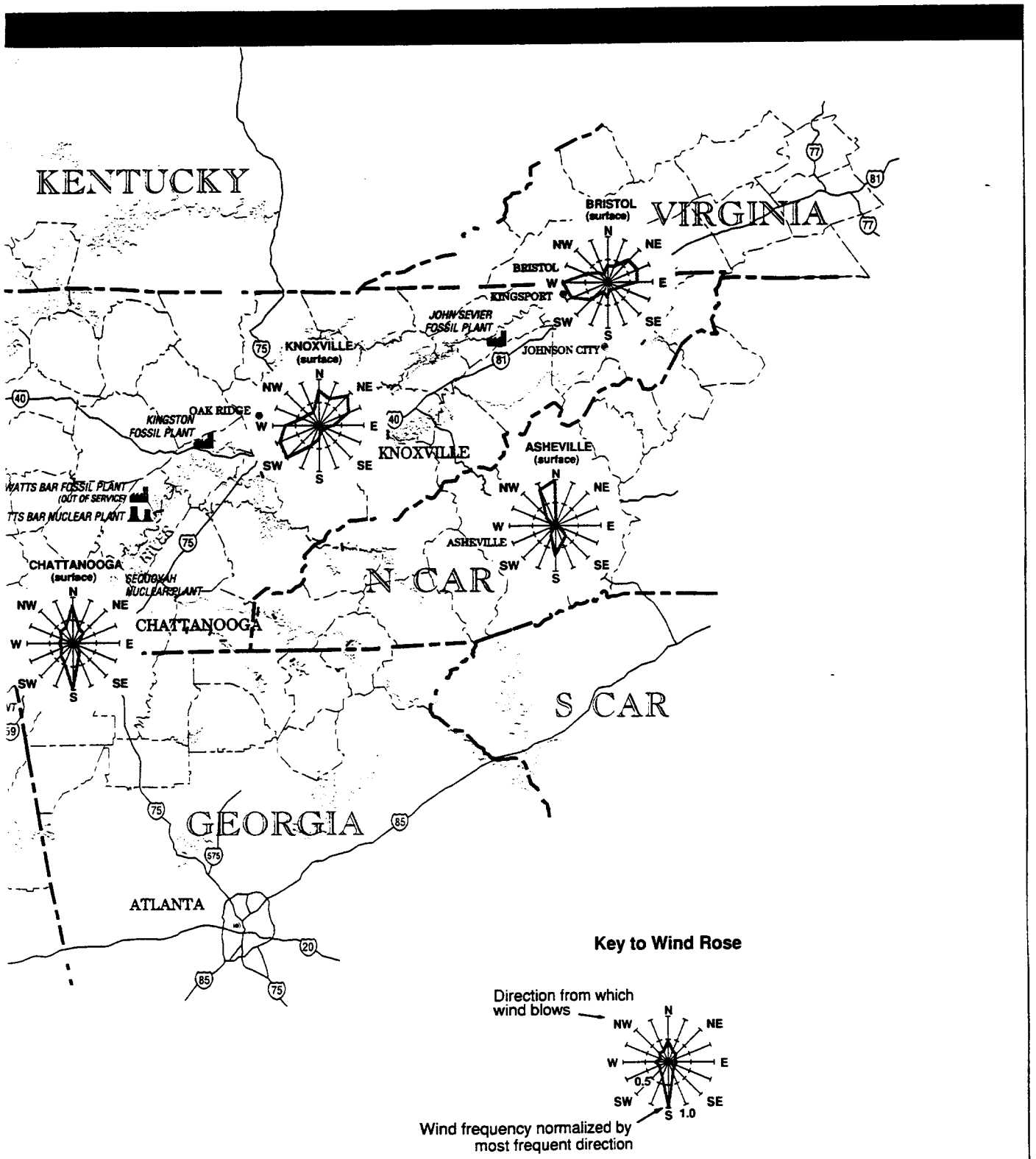
	Summer 1988 Fahrenheit	Summer 1989 Fahrenheit
Southwest Virginia, Western North Carolina	71.1	70.3
Eastern Tennessee	74.8	73.6
Central Tennessee & Kentucky	76.8	74.2
Western Tennessee & Kentucky	78.5	76.3
North Georgia & Northeast Alabama	77.5	75.8
Northwest Alabama & North Mississippi	79.3	77.5

FIGURE T1-11. Summer Precipitation Across the TVA Region for 1988 and 1989

	Summer 1988 Inches	Summer 1989 Inches
Southwest Virginia, Western North Carolina	10.5	20.5
Eastern Tennessee	10.0	17.9
Central Tennessee & Kentucky	10.1	18.3
Western Tennessee & Kentucky	9.3	15.9
North Georgia & Northeast Alabama	9.5	21.2
Northwest Alabama & North Mississippi	7.8	21.2

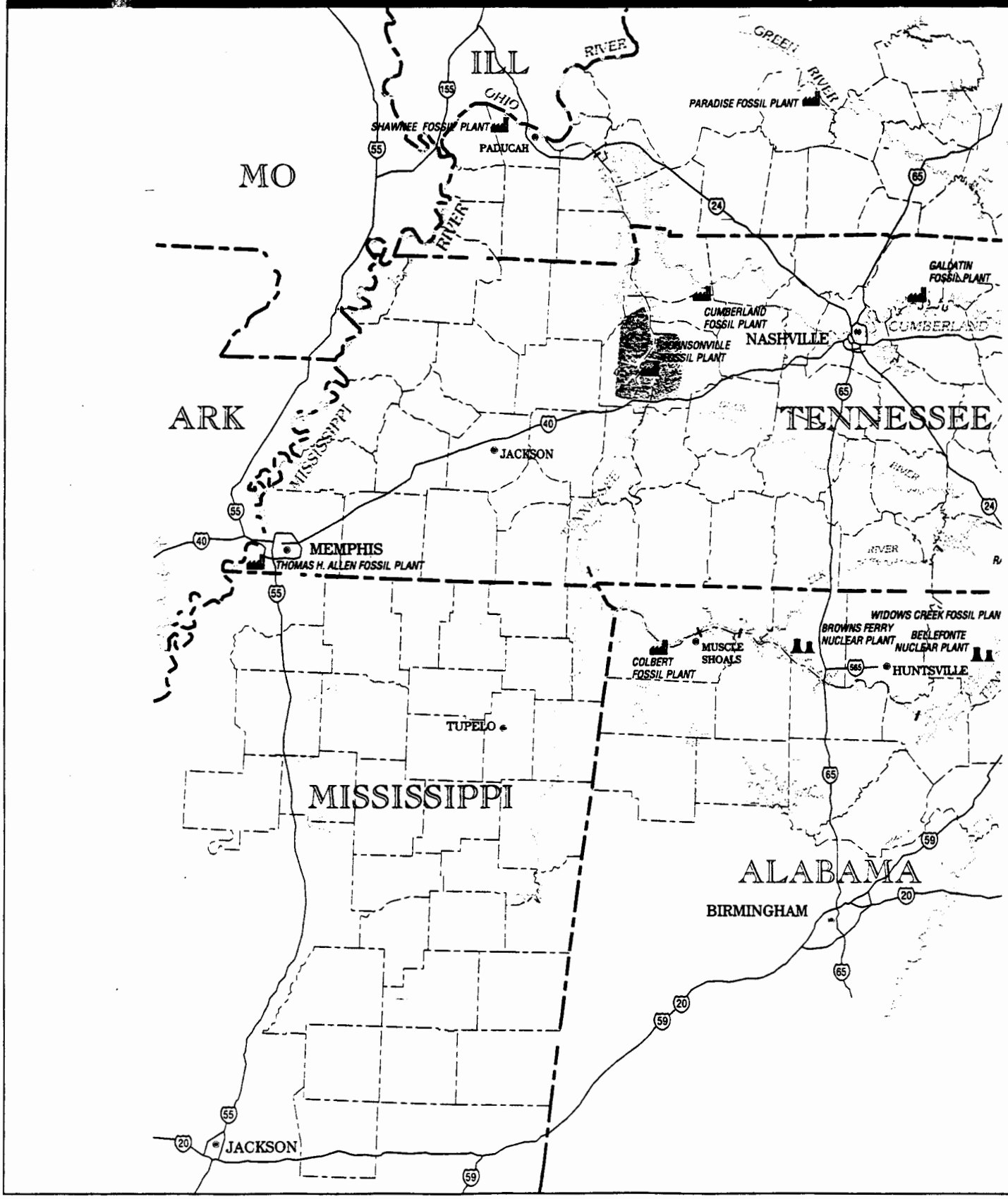
FIGURE T1-12. **Prevailing Wind Direction for Surface Winds at 8 Regional Airports and Winds Aloft at Nashville**

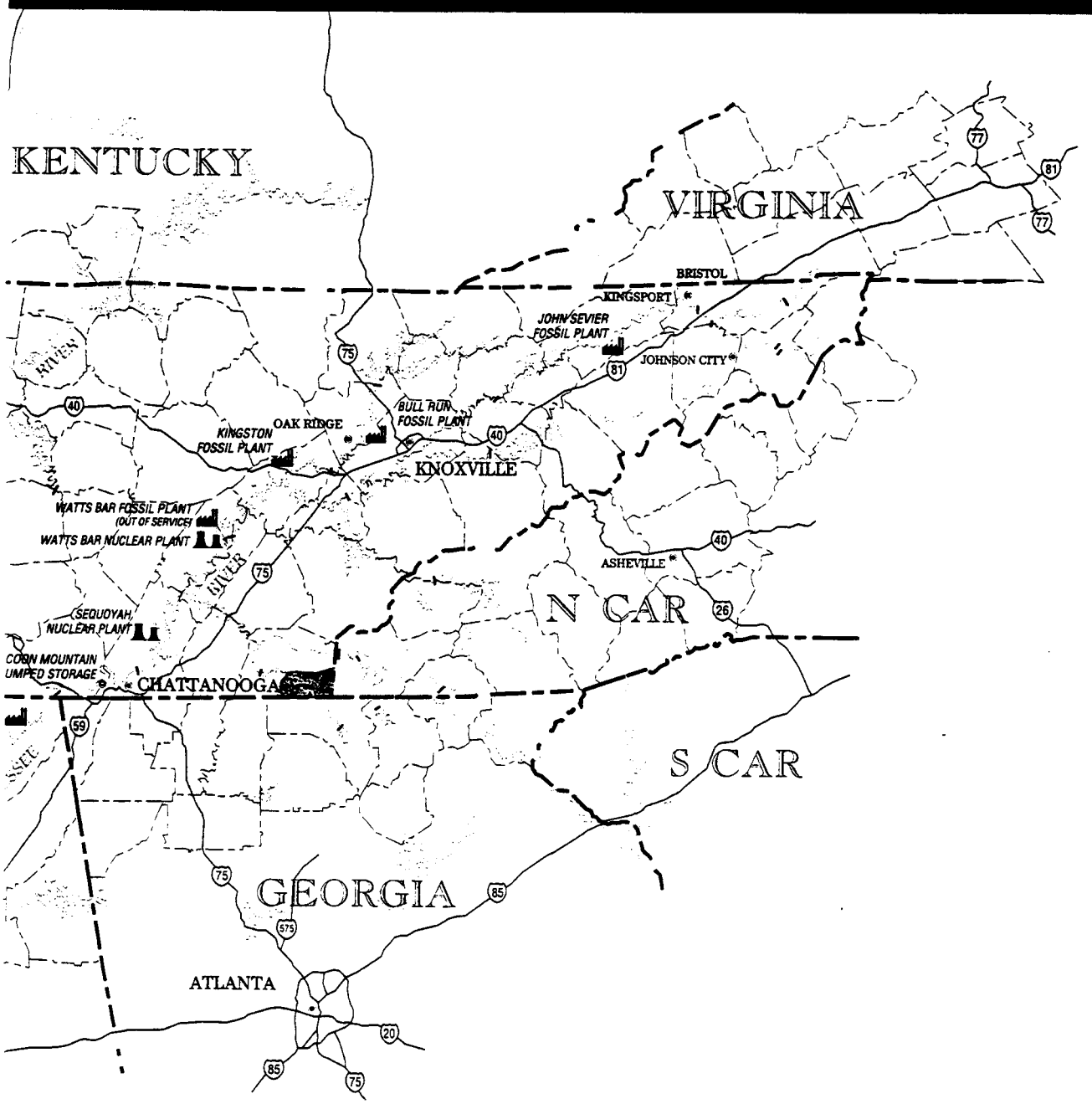




MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

FIGURE T1-14 **Areas in Nonattainment for Sulfur Dioxide Under the National Ambient Air Quality Standards**



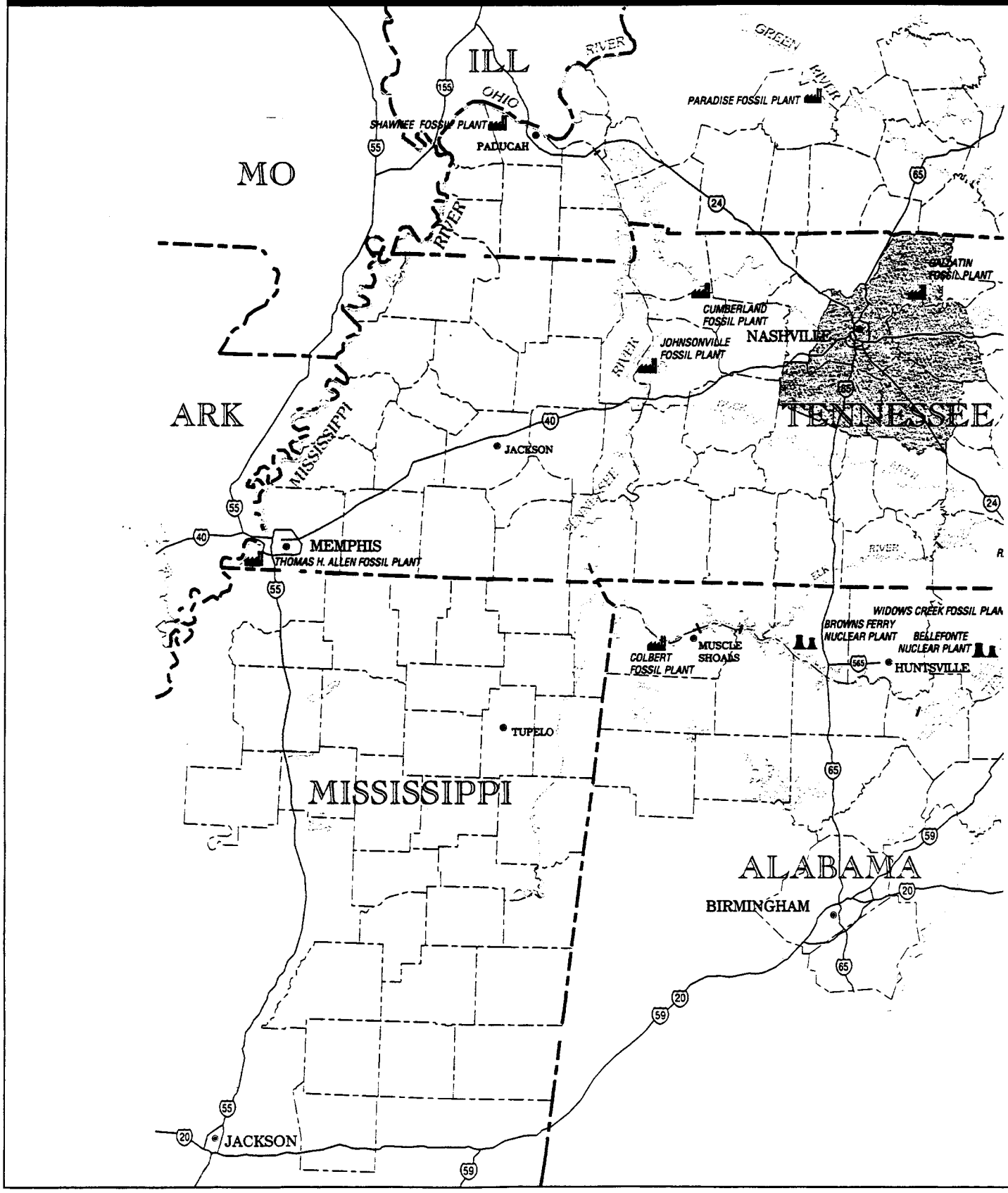


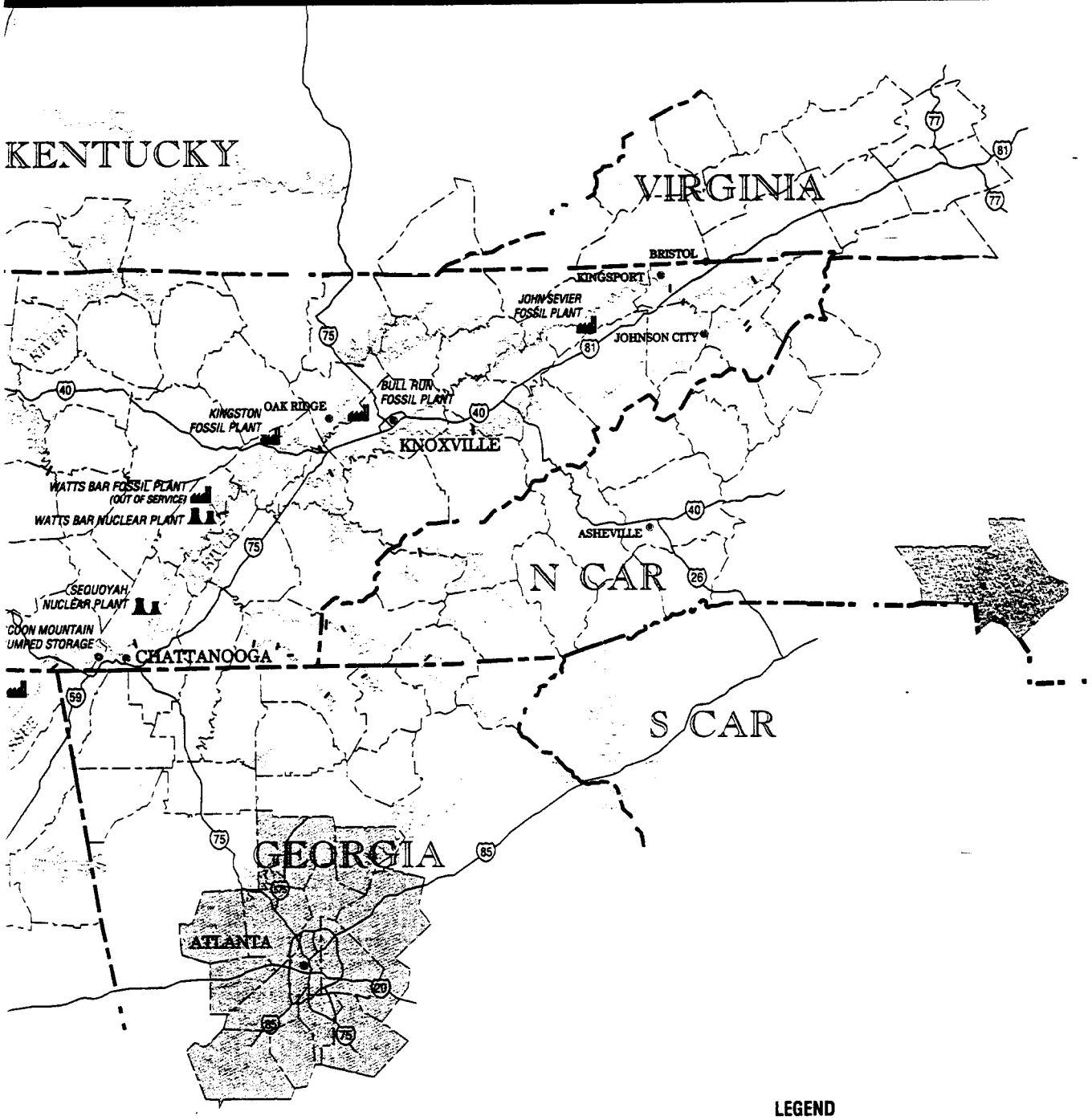
LEGEND

Does not meet Secondary Standard .....
Does not meet Primary or Secondary Standard .....

MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

FIGURE T1-15. **Areas in Nonattainment for Ozone Under the National Ambient Air Quality Standards**



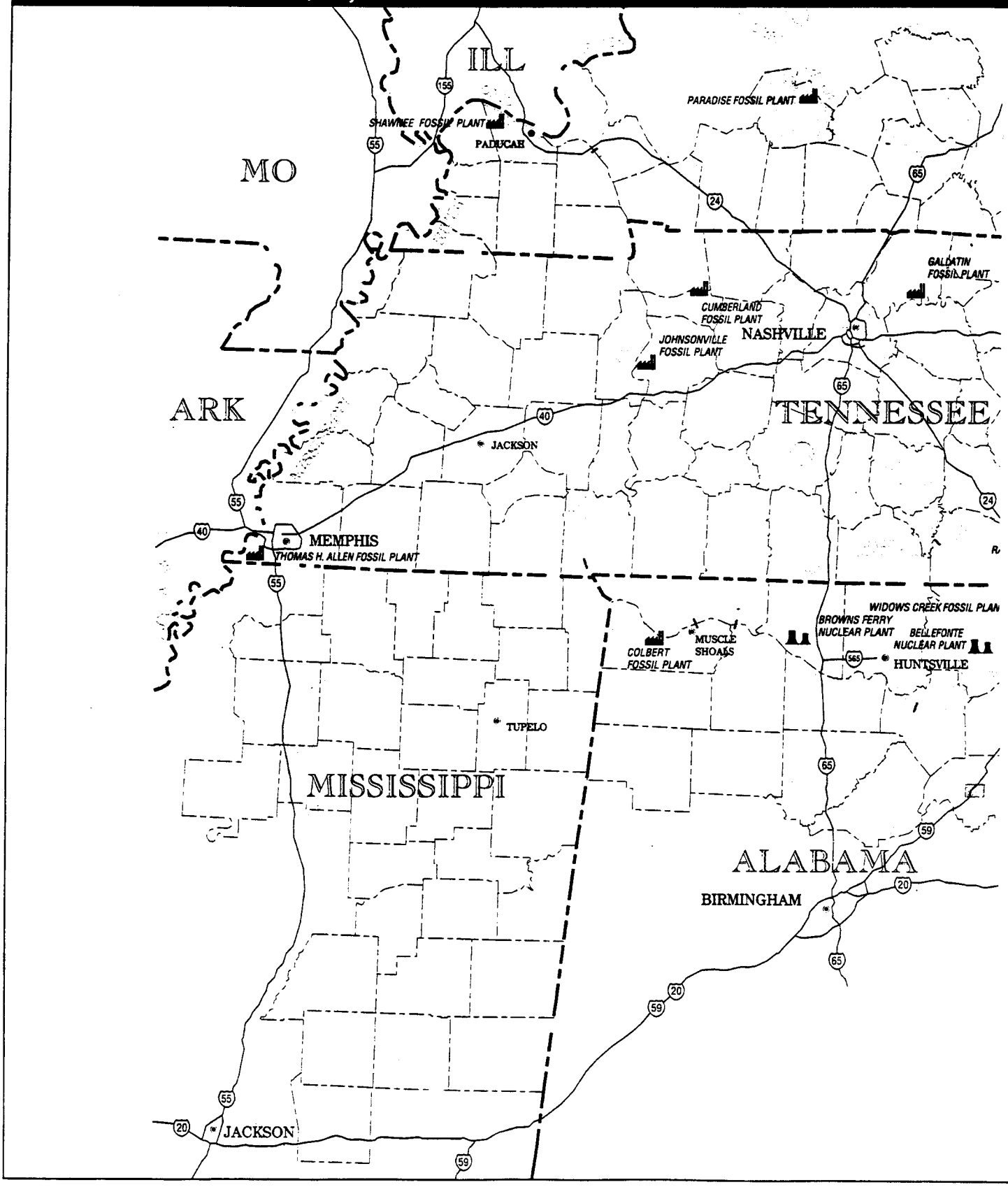


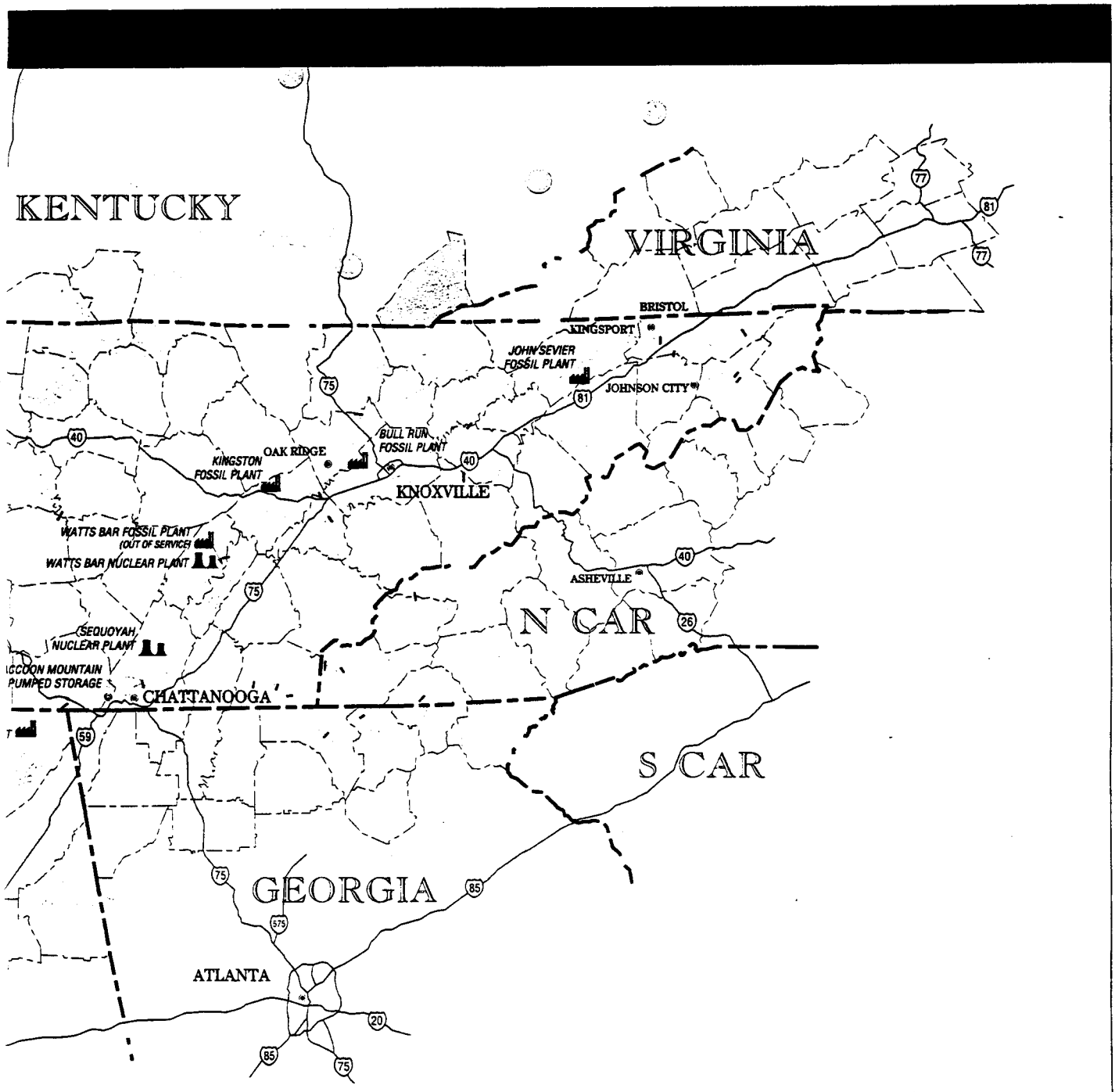
LEGEND

Does not meet Primary Standard (SERIOUS).....
Does not meet Primary Standard (MODERATE).....
Does not meet Primary Standard (MARGINAL) .....

MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

FIGURE T1-16 **Areas in Nonattainment for Total Suspended Particulate Matter Under the National Ambient Air Quality Standards**



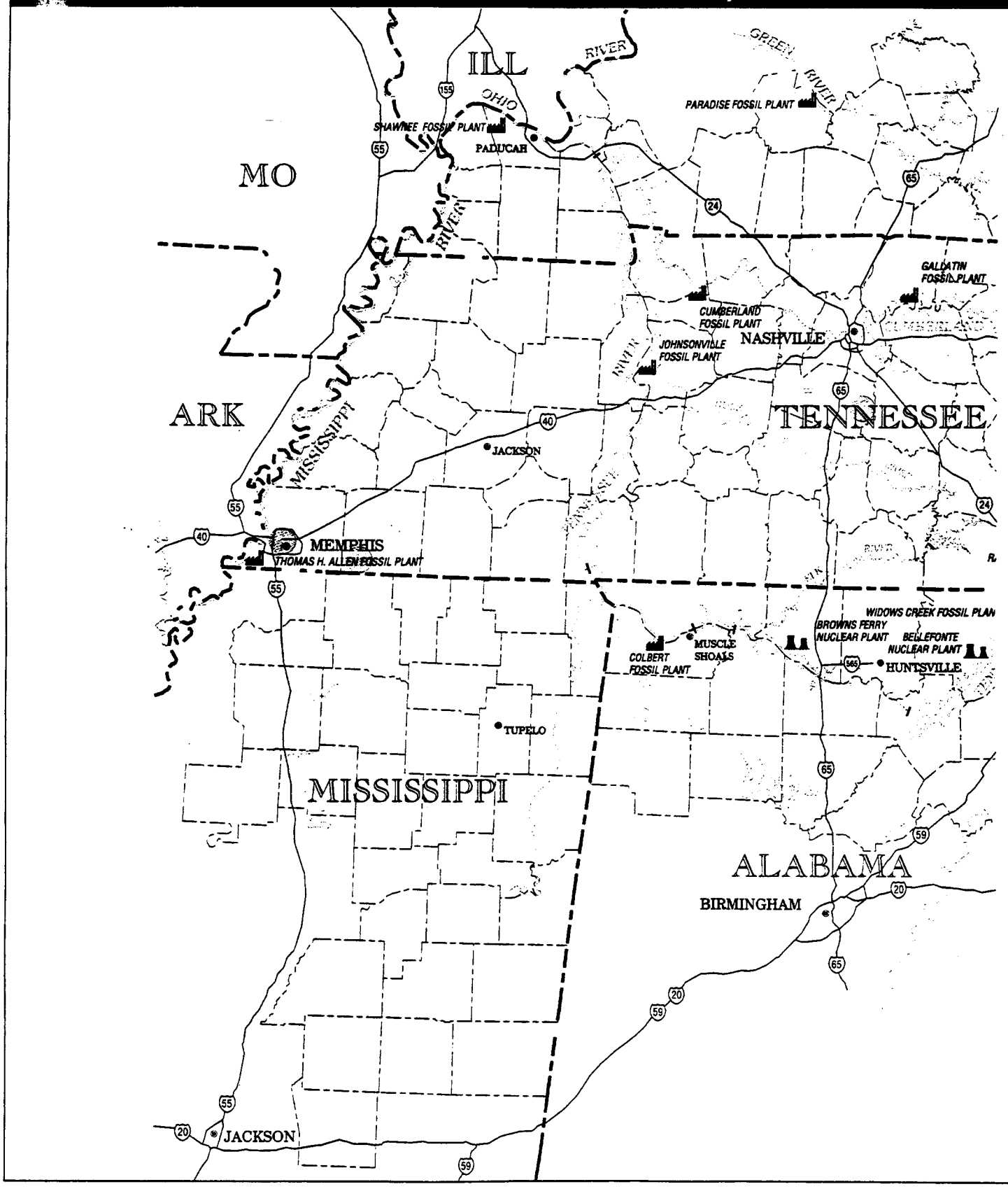


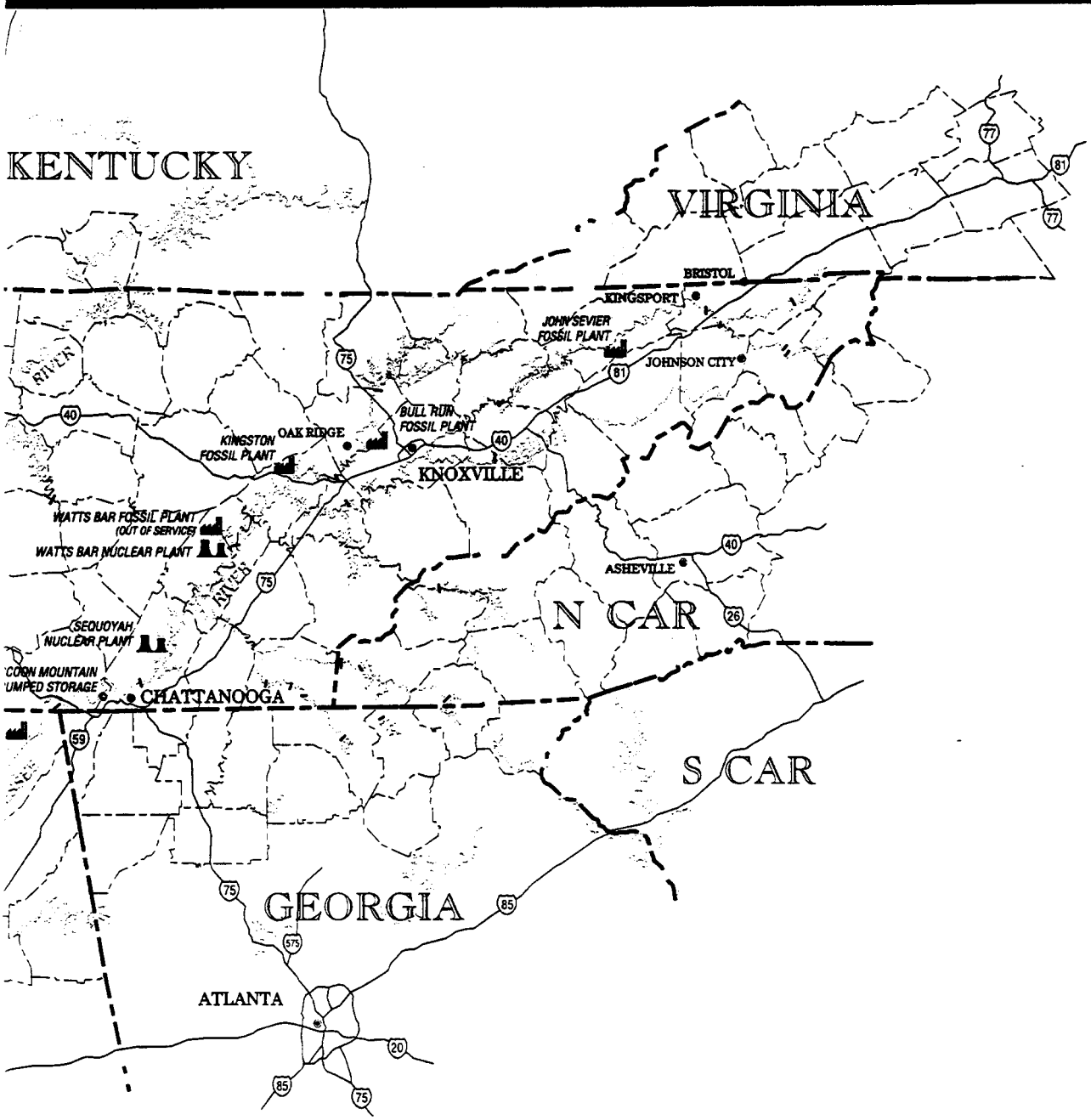
LEGEND

Does not meet Primary Standard .....
Does not meet Secondary Standard .....
Cannot be Classified .....

MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

FIGURE T1-17. Areas in Nonattainment for Lead Under the National Ambient Air Quality Standards



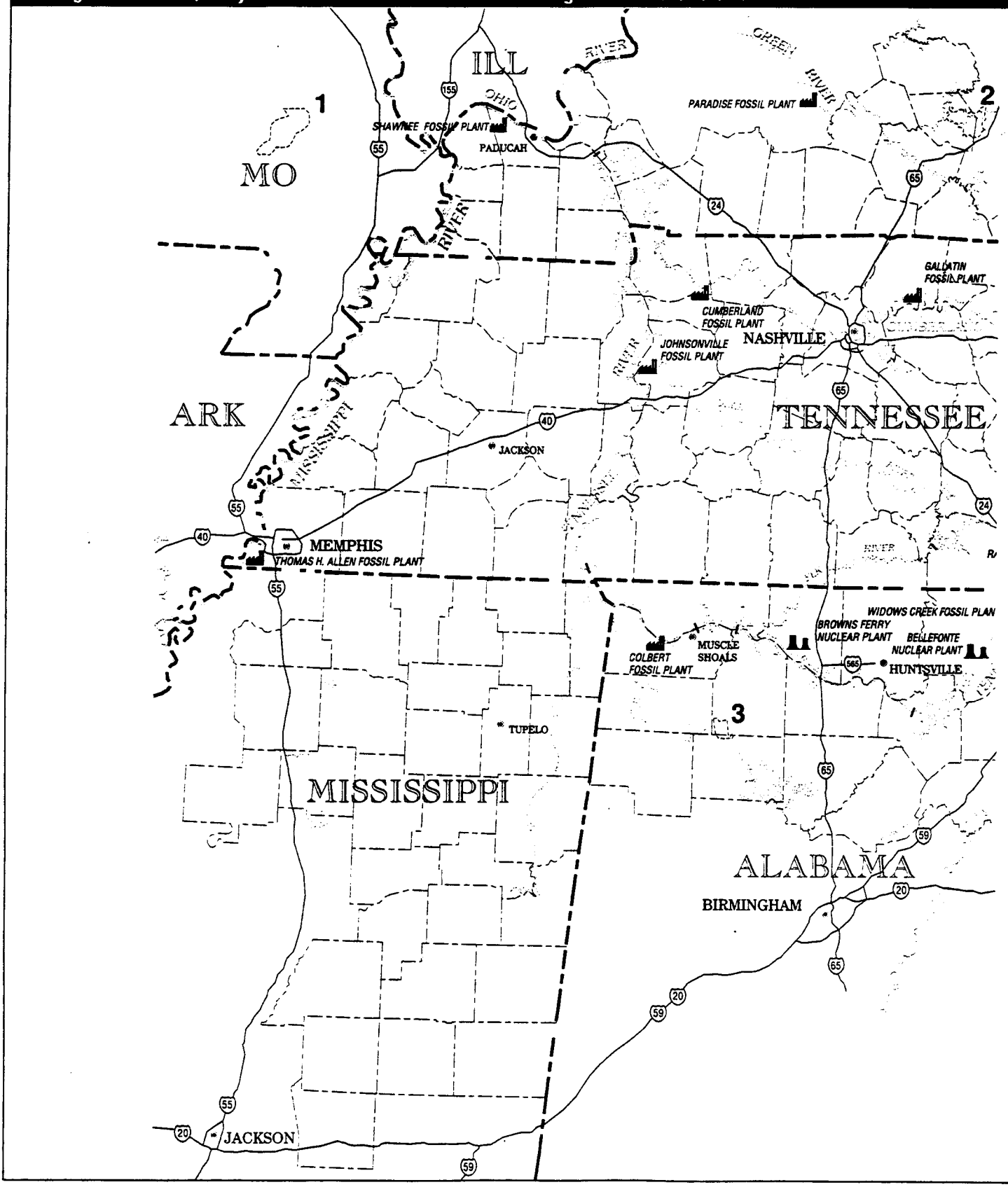


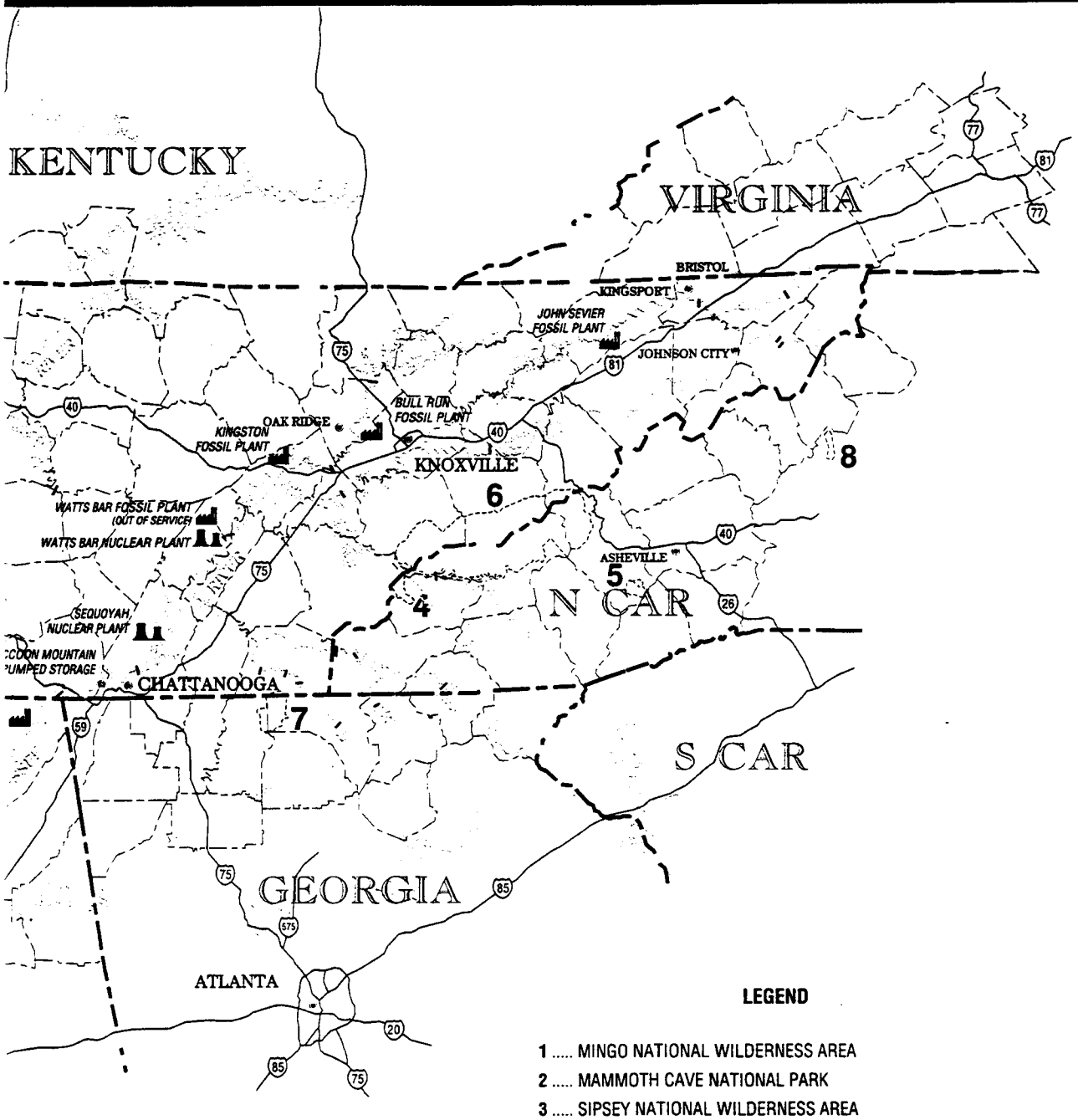
LEGEND

Does not meet Primary Standard .....

MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

FIGURE T1-18. **National Park and National Wilderness Areas in the Energy Vision 2020 Study Area Designated as Air Quality Class I Areas for the Prevention of Significant Deterioration**



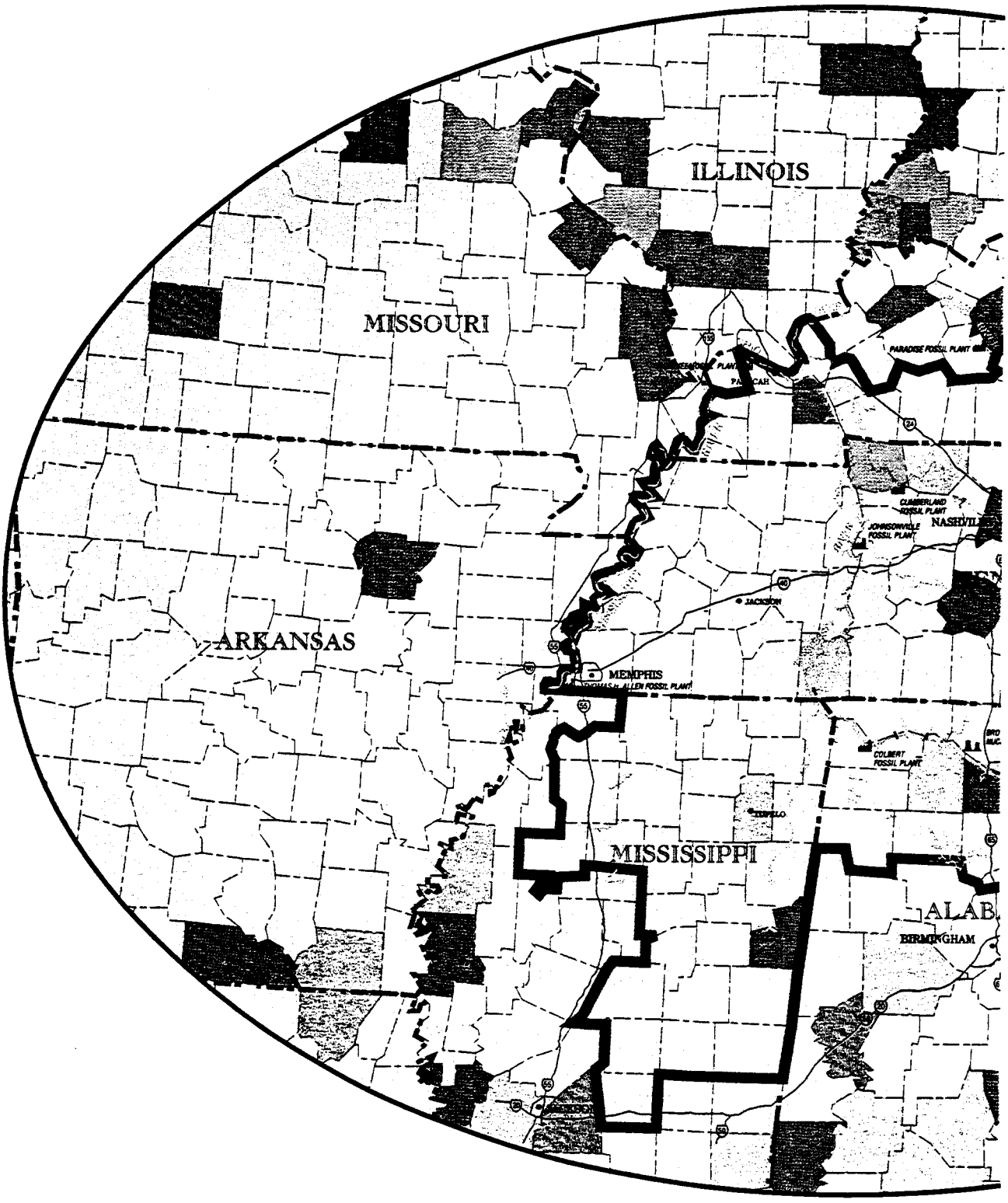


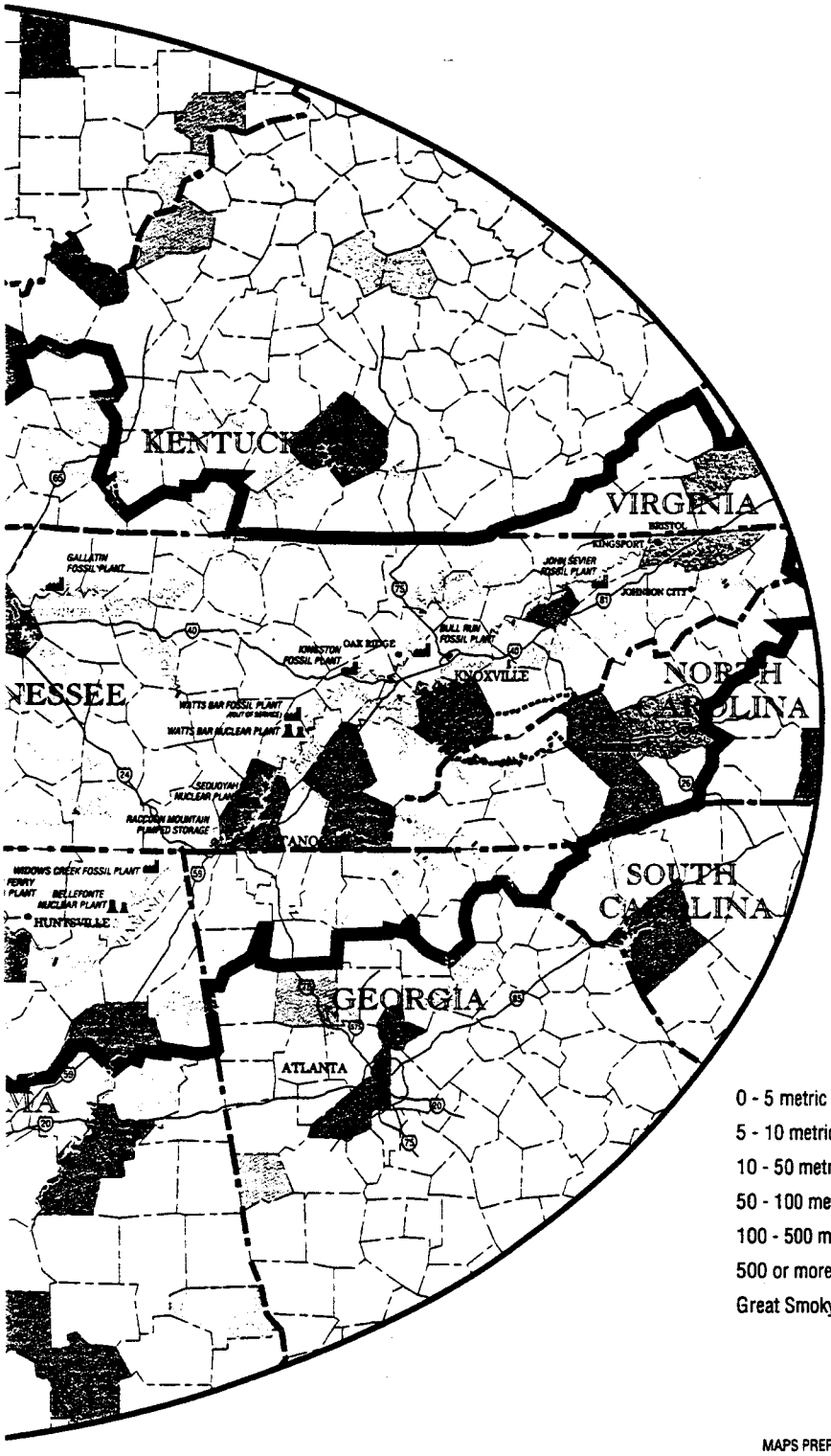
LEGEND

1 ..... MINGO NATIONAL WILDERNESS AREA
2 ..... MAMMOTH CAVE NATIONAL PARK
3 ..... SIPSEY NATIONAL WILDERNESS AREA
4 ..... JOYCE KILMER/SLICKROCK NATIONAL WILDERNESS AREA
5 ..... SHINING ROCK NATIONAL WILDERNESS AREA
6 ..... GREAT SMOKY MOUNTAINS NATIONAL PARK
7 ..... COHUTTA NATIONAL WILDERNESS AREA
8 ..... LINVILLE GORGE NATIONAL WILDERNESS AREA

MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

FIGURE T1-20. **Total Sulfur Dioxide Emissions from Point, Area, and Mobile Sources in the Greater Source Area for Energy Vision 2020**





LEGEND

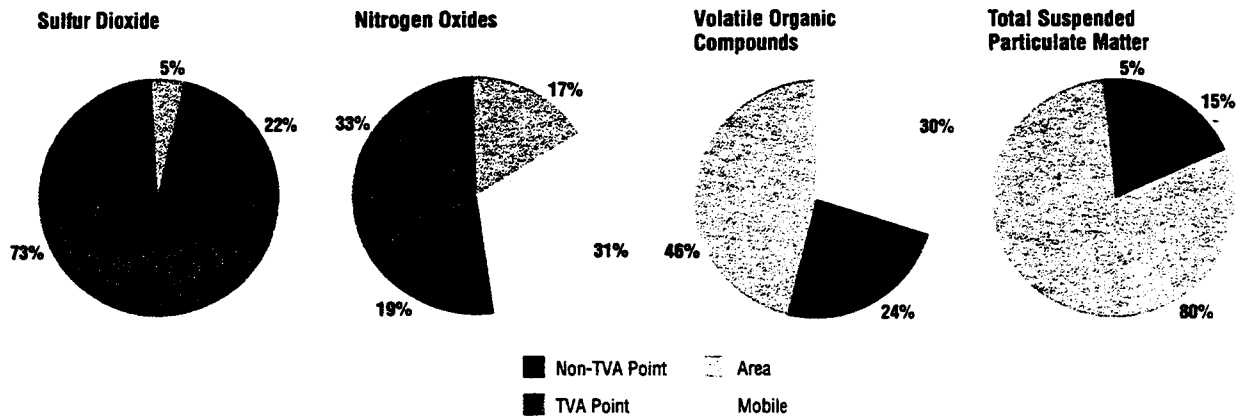
SULFUR DIOXIDE EMISSIONS

- 0 - 5 metric tons per day
- 5 - 10 metric tons per day
- 10 - 50 metric tons per day
- 50 - 100 metric tons per day
- 100 - 500 metric tons per day
- 500 or more metric tons per day
- Great Smoky Mountains National Park

Interim 1990 Emissions Inventory

MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

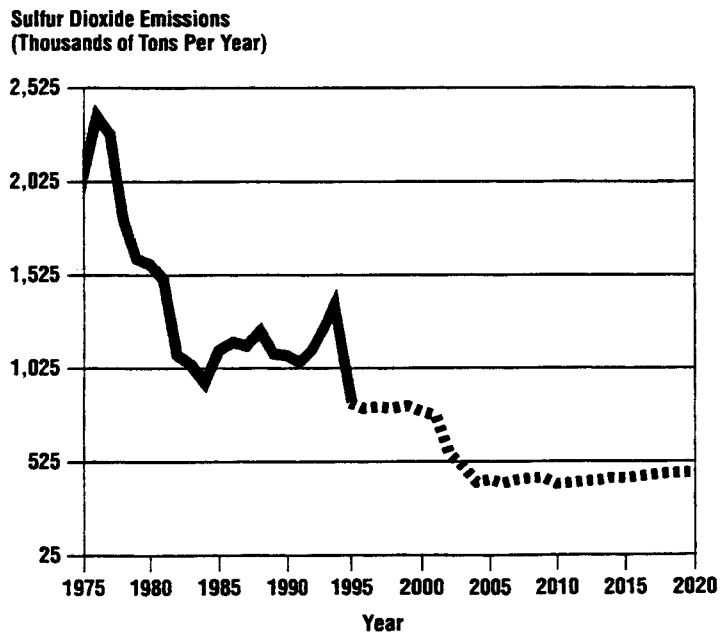
FIGURE T1-21. Total Emissions of Human-Produced Sulfur Dioxide, Nitrogen Oxides, Volatile Organic Compounds, and Total Suspended Particulate Matter from the 201-County TVA Service Area



Total emissions of sulfur dioxide, nitrogen oxides, and volatile organic compounds emissions from point, area, and mobile sources from the 201-county TVA service area are derived from Environmental Protection Agency 1990 Interim Inventory. Total suspended particulate matter emissions are derived from the 1985 Interim Inventory.

In the 201 counties of the TVA service area, TVA accounts for three-fourths of the total human-produced sulfur dioxide emissions as shown in *Figure T1-21*. In the greater source area that contributes to sulfur dioxide loadings in the Tennessee Valley, TVA's emissions are roughly one-fourth of total human-produced emissions. TVA sulfur dioxide emissions peaked in 1976 at 2,376,000 tons and have been reduced by two-thirds over the past two decades through installation of emission controls, coal washing, or switching to coals with lower sulfur content, as shown in the graph in *Figure T1-22*. Following full implementation of the 1990 Clean Air Act Amendments, TVA sulfur dioxide emissions are estimated to remain below 500,000 tons per year.

FIGURE T1-22. Historic and Projected TVA Emissions of Sulfur Dioxide



TVA emissions of sulfur dioxide have been reduced 60% since the1970s and will be further reduced in compliance with the 1990 Clean Air Act Amendments.

Ambient Trends

Figure T1-23 depicts emissions for each TVA coal-fired plant during fiscal year 1993. In 1995 scrubbers were placed into operation at the Cumberland Plant. This reduced sulfur dioxide emissions by 95 percent. Of the seven Valley counties with sulfur dioxide nonattainment areas in 1979, five have been reclassified as attainment areas, and two are pending reclassification. *(See Figure T1-14.)*

Future Regulations

The current national standard designates 3-hour, 24-hour, and annual average limits for ambient sulfur dioxide exposures. On November 15, 1994, the Environmental Protection Agency proposed to confirm the existing standards as adequate. They also proposed three alterna-

tive standards to address the possible health risk associated with short-term (five-minute) exposures by exercising asthmatic individuals. All three alternatives are likely to rely on increased monitoring in the vicinity of industrial sources to demonstrate compliance and could result in additional sulfur dioxide reductions.

Briefly, the three alternatives are:

- Revise National Ambient Air Quality Standard to include a 5-minute standard of 0.60 parts per million. This concentration could not be exceeded more than once per year.
- Establish a new regulatory program under section 303 (Emergency Powers) of the Clean Air Act. A five-minute standard of 0.60 parts per million would be used and action could be required after the first time concentrations are exceeded.
- Augment enforcement of existing standards through enhanced monitoring and by targeting sources that are most likely to produce high five-minute peak concentrations.

Sulfur dioxide monitoring in the vicinity of TVA coal-fired power plants is routinely collected as hourly rather than 5-minute averages. Extrapolating from this data, five-minute levels might exceed 0.60 parts per million at some TVA coal-fired plants. Implementation of a five-minute standard as described could result in additional sulfur dioxide control requirements at these plants.

NITROGEN DIOXIDE/NITROGEN OXIDES

Health and Welfare Concerns

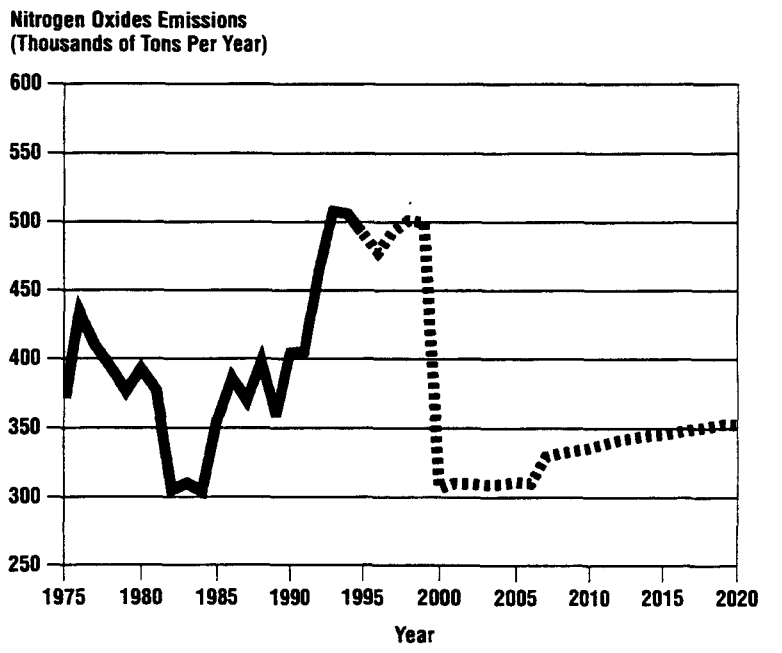
Depending on concentration, nitrogen dioxide can be a respiratory irritant. At current ambient levels in the TVA region, nitrogen dioxide health-related impacts are negligible. Nitrogen dioxide levels in the Tennessee Valley are well below the annual standard. There are no nitrogen dioxide nonattainment areas in the TVA region. Nitrogen oxides emissions do, however, contribute to regional acidic deposition and ozone formation. These are discussed in later sections. A very small amount (less than 5 percent) of the total nitrogen oxides emitted from a coal-fired power plant is nitrogen dioxide. Nitric oxide is the primary nitrogen species emitted and reacts rapidly with ozone in the atmosphere to form nitrogen dioxide.

Sources of Contribution

Natural sources of nitrogen oxides include microbial activity, lightning, and forest fires. Major human-produced sources include motor vehicles, fossil fuel power plants, industrial boilers, nitrogen fertilizers, and agricultural burning. The map in *Figure T1-24* displays total nitrogen oxides emissions from human sources, point (utility and industry), area (urban and small point source), and mobile (vehicle) sources in the greater source area likely to contribute to ozone levels in the Tennessee Valley, based on the Environmental Protection Agency's Interim 1990 emissions inventory. Within the 201 counties of TVA's service area, TVA emissions accounted for 33 percent of total human-produced nitrogen oxides, while mobile sources accounted for 31 percent. The map in *Figure T1-25* shows biogenic or natural emissions of nitrogen oxides estimated for the greater TVA source region. The Environmental Protection Agency's Biogenic Emissions Inventory, System II Model was used. Emissions of nitrogen oxides from fertilized soils on a hot, sunny summer afternoon can contribute up to 20 percent of daily nitrogen oxides emissions from all sources.

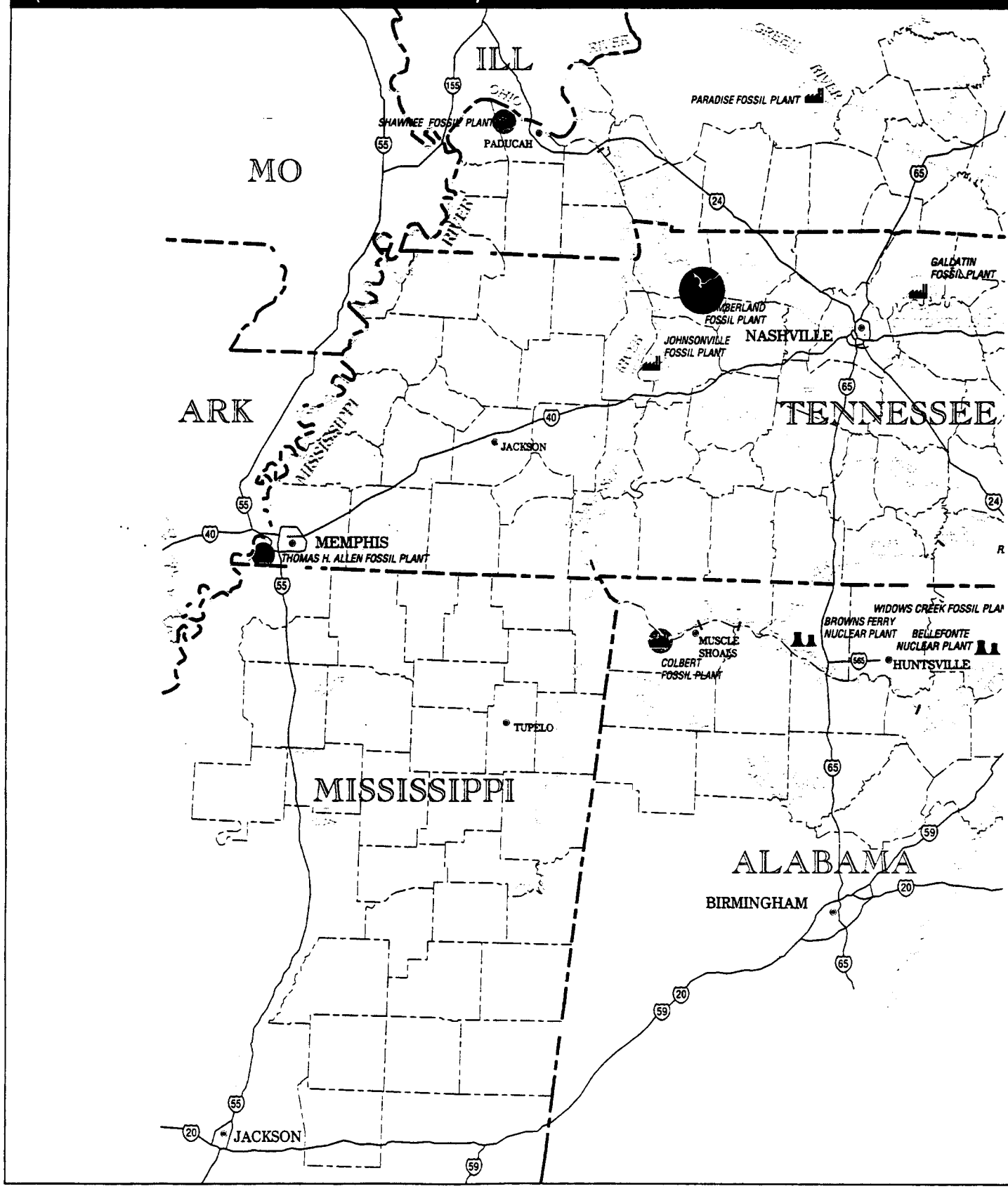
The graph in *Figure T1-26* illustrates TVA emissions of nitrogen oxides since 1975. The decline and rise of emissions between 1975 and 1990 is tied to coal use which varies with power system sales and the level of power production by nuclear

FIGURE T1-26. **Historic and Projected TVA Emissions of Nitrogen Oxides**



TVA nitrogen oxides emissions increased during the 1990s as coal-fired generation increased. Emissions will decrease as TVA complies with the 1990 Clean Air Act Amendments.

FIGURE T1-23. **Sulfur Dioxide Emissions From TVA Coal-Fired Power Plants in 1993 (Reductions From Cumberland Scrubbers Not Shown)**



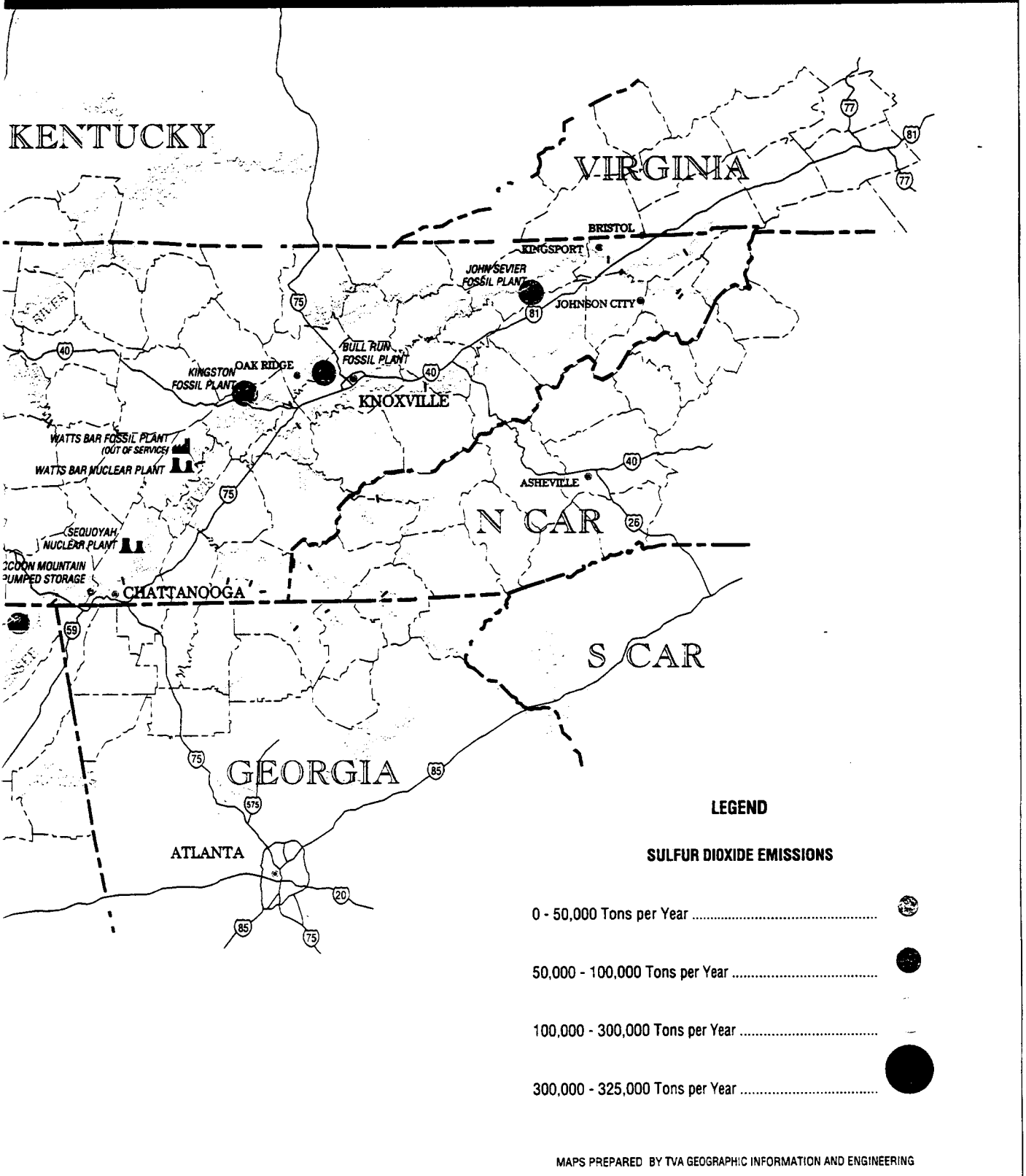
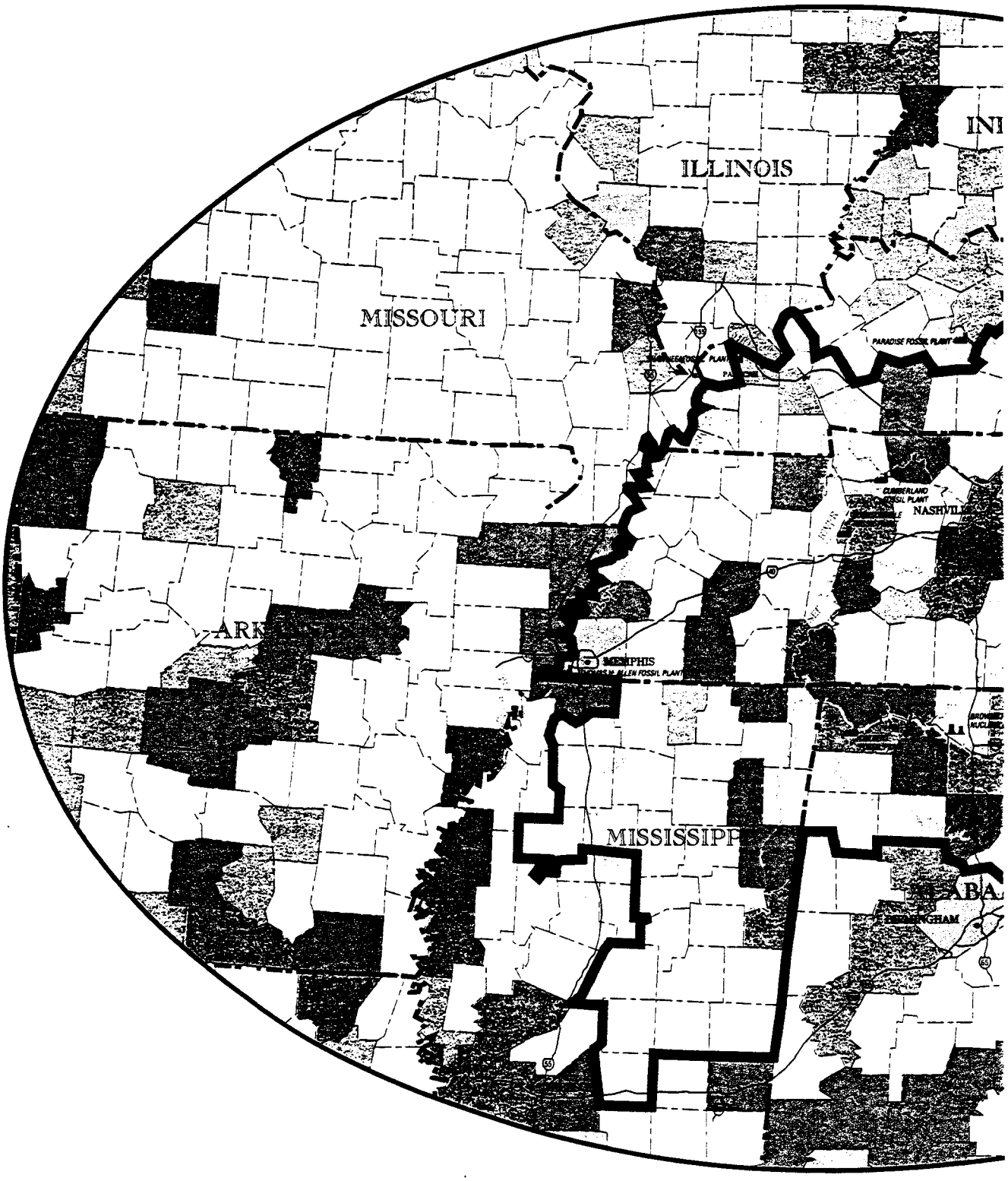
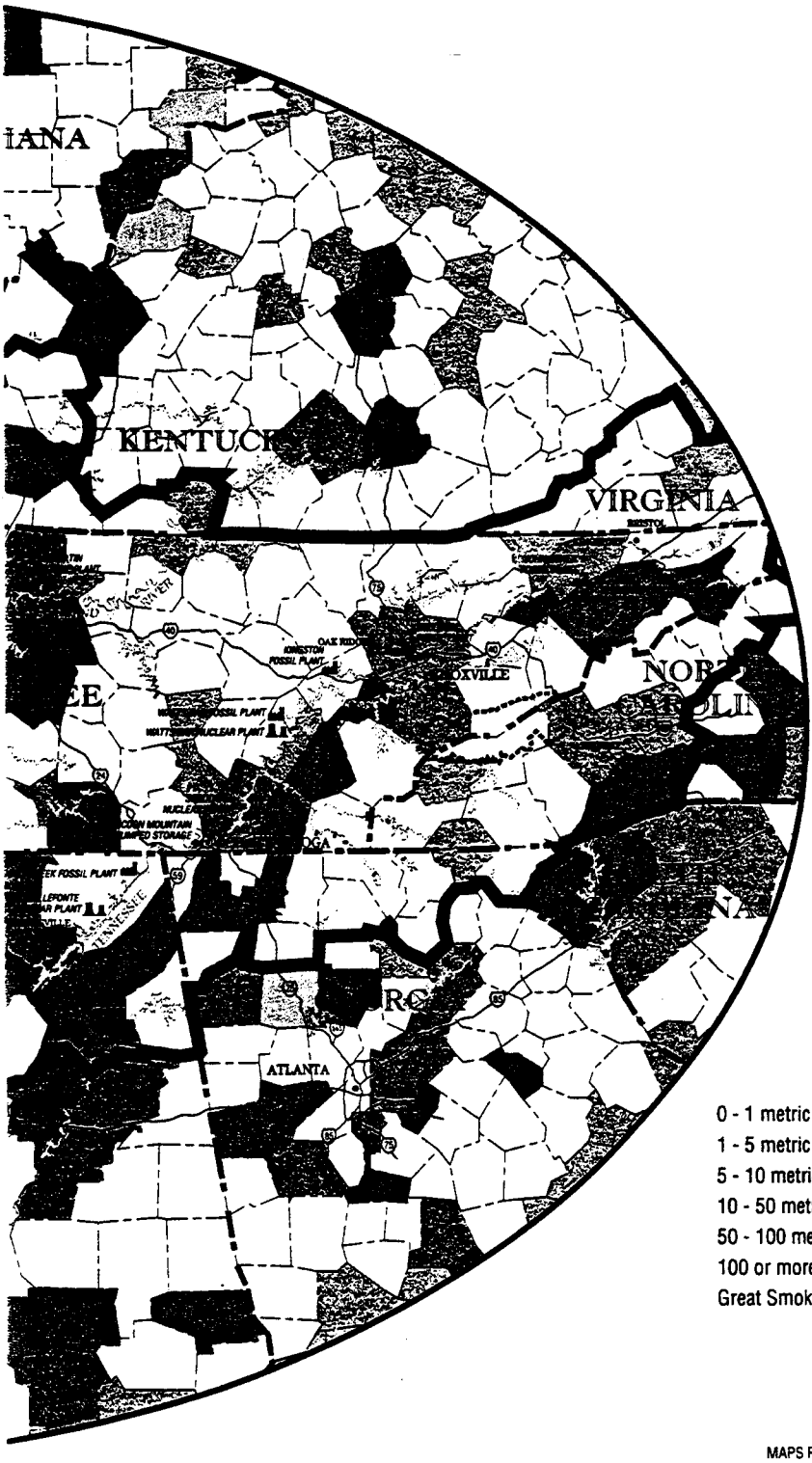

KENTUCKY
VIRGINIA
BRISTOL
KINGSPORT
JOHN SEVIER FOSSIL PLANT
JOHNSON CITY
BULL RUN FOSSIL PLANT
OAK RIDGE
KINGSTON FOSSIL PLANT
KNOXVILLE
WATTS BAR FOSSIL PLANT (OUT OF SERVICE)
WATTS BAR NUCLEAR PLANT
ASHEVILLE
N CAR
SEQUOYAH NUCLEAR PLANT
COON MOUNTAIN PUMPED STORAGE
CHATTANOOGA
S CAR
GEORGIA
ATLANTA
LEGEND
SULFUR DIOXIDE EMISSIONS
0 - 50,000 Tons per Year
50,000 - 100,000 Tons per Year
100,000 - 300,000 Tons per Year
300,000 - 325,000 Tons per Year
MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

FIGURE T1-24. **Total Nitrogen Oxides Emissions from Point, Area, and Mobile Sources in the Greater Source Area for Energy Vision 2020**





LEGEND

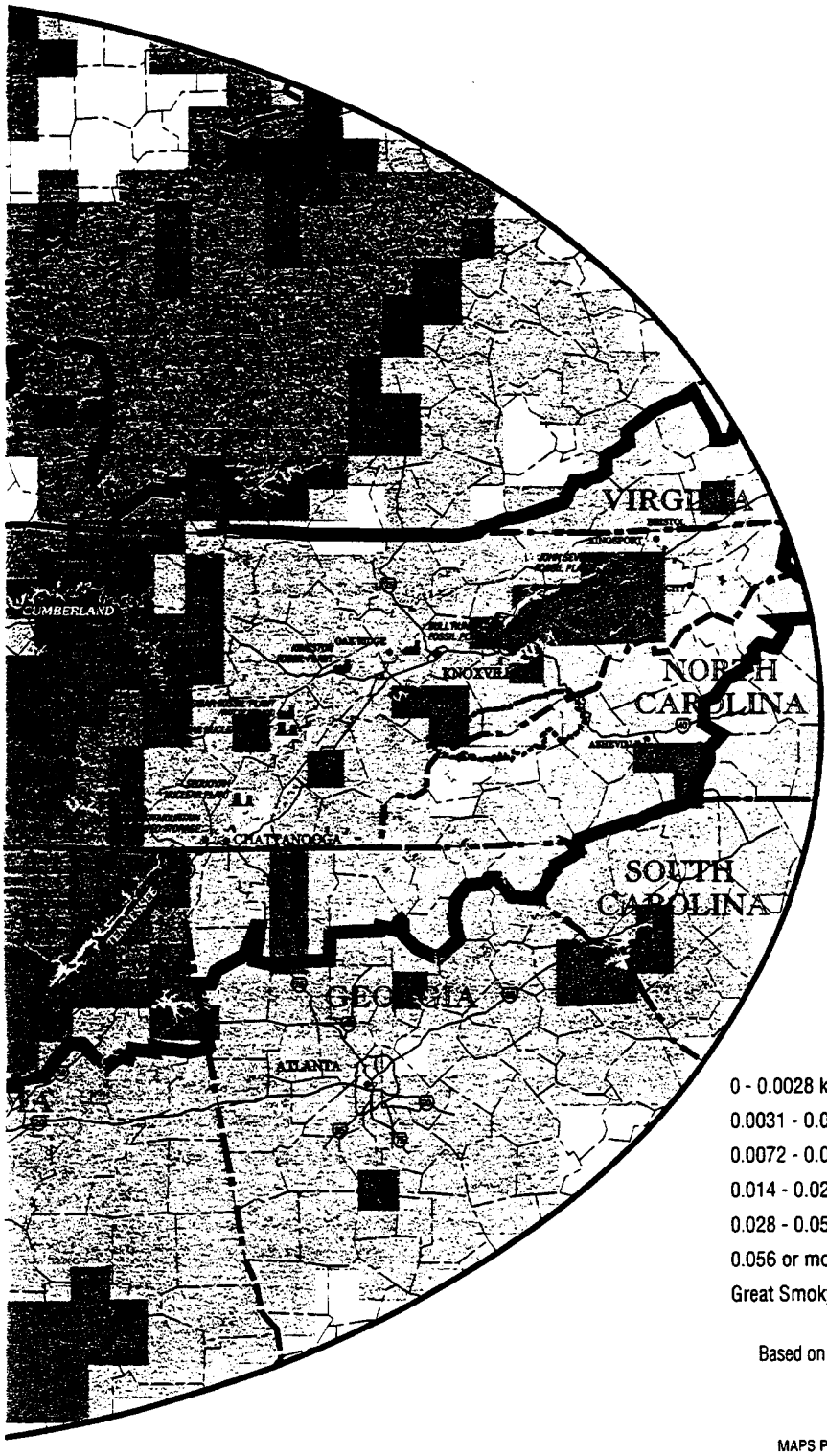
NITROGEN OXIDE EMISSIONS

- 0 - 1 metric tons per day
- 1 - 5 metric tons per day
- 5 - 10 metric tons per day
- 10 - 50 metric tons per day
- 50 - 100 metric tons per day
- 100 or more metric tons per day
- Great Smoky Mountains National Park

Interim 1990 Emissions Inventory

MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

FIGURE T1-25 **Summer Nitrogen Oxide Emissions from Natural Sources in the Greater Source Area for Energy Vision 2020**



LEGEND

- 0 - 0.0028 kilogram per hectare per day
- 0.0031 - 0.007 kilogram per hectare per day
- 0.0072 - 0.0139 kilogram per hectare per day
- 0.014 - 0.028 kilogram per hectare per day
- 0.028 - 0.055 kilogram per hectare per day
- 0.056 or more kilograms per hectare per day
- Great Smoky Mountains National Park

Based on results of EPA Biogenic Emissions Inventory System II Model

MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

power plants. Emissions, which have recently been about 700,000 tons per year, are projected to decline to approximately 300,000 tons per year following implementation of the 1990 Clean Air Act Amendments. They are also expected to increase roughly 17 percent over the years 2000 to 2020 as generation increases. *Figure T1-27* depicts fiscal year 1993 emissions of nitrogen oxides for each TVA coal-fired plant.

Future Regulations

In its 1994 review of the ambient air quality standard for nitrogen dioxide, the Environmental Protection Agency concluded that the current standard is adequate to protect human health and welfare. Additional nitrogen oxides control requirements are scheduled to be promulgated in 1997 under provisions of the 1990 Clean Air Act Amendments to address acid rain and ozone nonattainment areas.

CARBON MONOXIDE

Health and Welfare Concerns

Carbon monoxide is a colorless, odorless gas formed as a byproduct of fossil-fuel combustion. Exposure to carbon monoxide can reduce the oxygen-carrying capacity of the blood. At current ambient outdoor levels, carbon monoxide exposures are considered a low risk to human health.

Sources of Contribution

Natural sources of carbon monoxide are minor. The principal human-produced source is incomplete combustion of gasoline in motor vehicles. Carbon monoxide air pollution is primarily an urban problem, with highest levels occurring during heavy traffic under congested conditions. There has been a gradual but persistent improvement in average carbon monoxide levels throughout the last decade. In 1979 there were four nonattainment counties in the Tennessee Valley. Ambient levels of carbon monoxide in the Tennessee Valley are below the level of the National Ambient Air Quality Standards. Ambient concentrations of carbon monoxide should continue to decline as newer, less polluting vehicles make up an increasing portion of all vehicles driven in the region.

Future Regulations

The Environmental Protection Agency is not currently considering revisions to the carbon monoxide standard. TVA emissions account for less than 1 percent of total carbon monoxide emissions in the TVA service region and therefore will not be used as a factor to differentiate among strategies in Energy Vision 2020.

LEAD

Health and Welfare Concerns

The criteria pollutant lead is also one of a category of hazardous air pollutant that can be emitted from the combustion of coal. The Environmental Protection Agency established lead as a criteria pollutant because there was clear evidence of its sources and its impact on human health. Elevated exposures to lead can:

- Contribute to hypertension, heart attacks, and strokes in adults
- Increase the likelihood of birth defects and infant mortality
- Inhibit the growth and mental development of children

However, risk assessment models demonstrate that current lead emissions pose very little risk to human health (ORNL 1994).

Sources of Contribution

Lead exposure can occur through inhalation or ingestion. Children are the most vulnerable segment of the population because they ingest lead more often than do adults. Children swallow lead when they put toys or other objects bearing lead-contaminated dust in their mouths. Furthermore, a greater portion of ingested lead enters children's bodies than adults' bodies. Lead is now banned from use in gasoline, paints, solder, and metals that could contact drinking water, beverages, or foods. Concentrations of lead in the ambient environment have been reduced dramatically over the past two decades (ORNL 1994). Residual levels of lead in soils and flakes from lead-based paints remain a concern. Differences in lead emissions are not considered in evaluating TVA energy supply strategies.

TOTAL SUSPENDED PARTICULATE MATTER/PM10

Health and Welfare Concerns

Particulate matter is of concern because of the adverse effects it can have on visibility and on the respiratory function of sensitive individuals. Particulate matter was the focus of early air pollution control efforts because of the obvious visual impact of smoke and its association with acute air pollution episodes in England and the United States. Particulate matter consists of small aerosol particles in the atmosphere. Some particles are large enough to be seen with the naked eye, but the particulates of major concern for human health are less than 10 microns in size. Larger particles tend to be filtered out in the nose and throat and pose few health problems.

Particles emitted directly from a source are called primary particles. Those formed in the atmosphere from emitted gases are called secondary particles. Primary particles tend to be larger than 2.5 microns in size and are likely to be deposited within

50 kilometers of the source. Formation of secondary particles from sulfur dioxide and nitrogen oxides occurs in the atmosphere as the pollutants are transported downwind from the points of origin. Sulfate and nitrate particles are typically smaller than 1 micron in diameter and may remain aloft for days at a time (Mason 1971). Summer weather conditions favor the photochemistry that leads to sulfate and nitrate particle formation. Visibility is poorest in the summer because sulfate particles provide the major source for regional haze.

Sources of Contribution

Many natural and human sources produce particulate matter. Natural sources include wind-blown soil, volcanoes, forest fires, and the ocean. Human-produced sources include agriculture, waste incineration, industrial processing, fossil-fuel combustion, construction, and mining. On a global scale, natural emissions far exceed human-produced, but human-produced emissions predominate in urban and industrial areas. TVA contributed 5 percent of the total suspended particulates emitted in the 201 counties of the Tennessee Valley, according to the 1985 emissions inventory by the National Acid Precipitation Assessment Program *(See Figure T1-21)*. TVA emissions are primarily from coal-fired boilers. Particulate collection devices such as fabric filters or electrostatic precipitators have been installed on all TVA coal-fired boilers to remove particulates from the flue gases. Fugitive dust from TVA's operation of motor vehicles and from coal and other material-handling processes (e.g., coal transport and washing) also contributes low levels of fine particles.

Ambient Trends

Particulate control has been very successful, with removal efficiencies exceeding 95 percent. In 1979, parts of 21 counties in the Tennessee Valley did not attain the ambient particulate standard; now only 4 nonattainment areas remain. Loadings of fine particles are greatest in summer months. *Figure T1-28* illustrates the trend in particulate matter smaller than 10 microns from July through September, during 1986 to 1993, at 5 cities in the Tennessee Valley. These five cities are typical of trends for other cities in the Valley. For the majority of the sites, ambient concentrations of particles smaller than 10 microns decreased over this period.

Future Regulations

The National Ambient Air Quality Standard for particulate matter initially targeted concentrations of total suspended particulate matter. While this improved the visible particulate emissions problem, potential impacts to human health were still a problem. The total suspended particulate standard was amended in 1977 to address levels of particles smaller than 10 microns. Particulates of this size are respiratory irritants and pose greater risk to human health than the larger, more visible particles.

The Environmental Protection Agency is currently reviewing the adequacy of the particulate standard. A draft criteria document, which is the Environmental Protection Agency's state of science report on particulate matter, was published in November 1994, and peer review workshops were conducted in spring 1995. The final criteria document is to be completed by October 1995; the Federal Register proposal is due by April 1996; and the publication of final action is due not later than January 31, 1997. The draft criteria document reports an association between daily particulate matter concentrations and mortality rates, although the exact size fraction best predictive of health effects is not conclusively determined.

A comparative study of the health of individuals in six communities, including Kingston-Harriman in Tennessee, suggests

FIGURE T1-28. **Concentrations of Particulate Matter Less than 10 Microns (PM10) in Size During July-September for 5 Cities in the Energy Vision 2020 Study Area Have Been Decreasing**

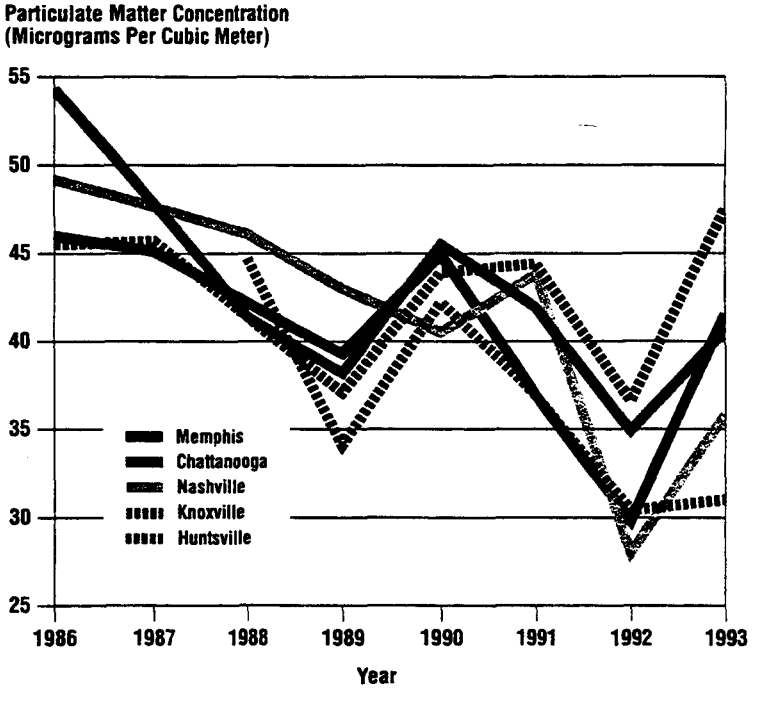
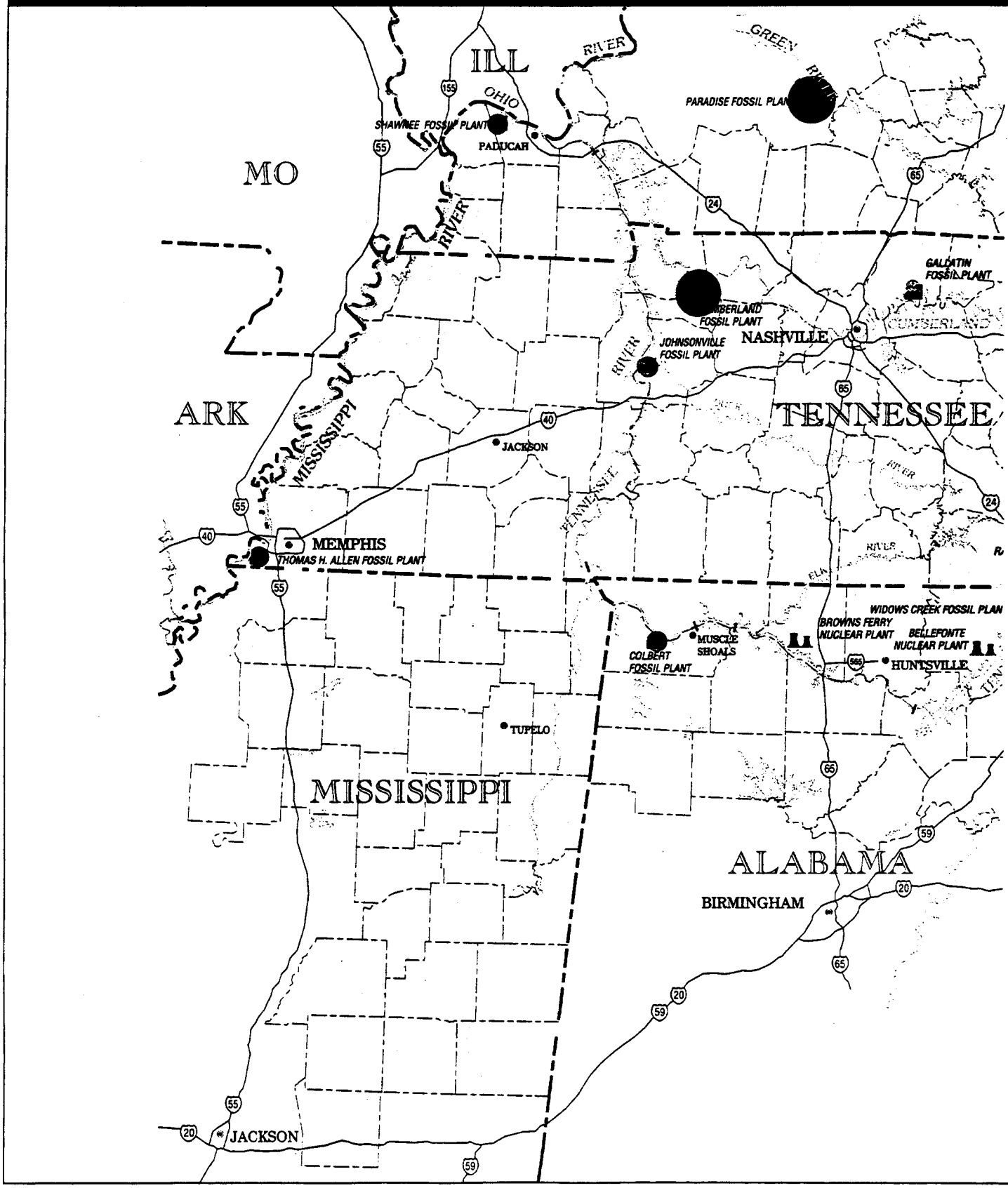
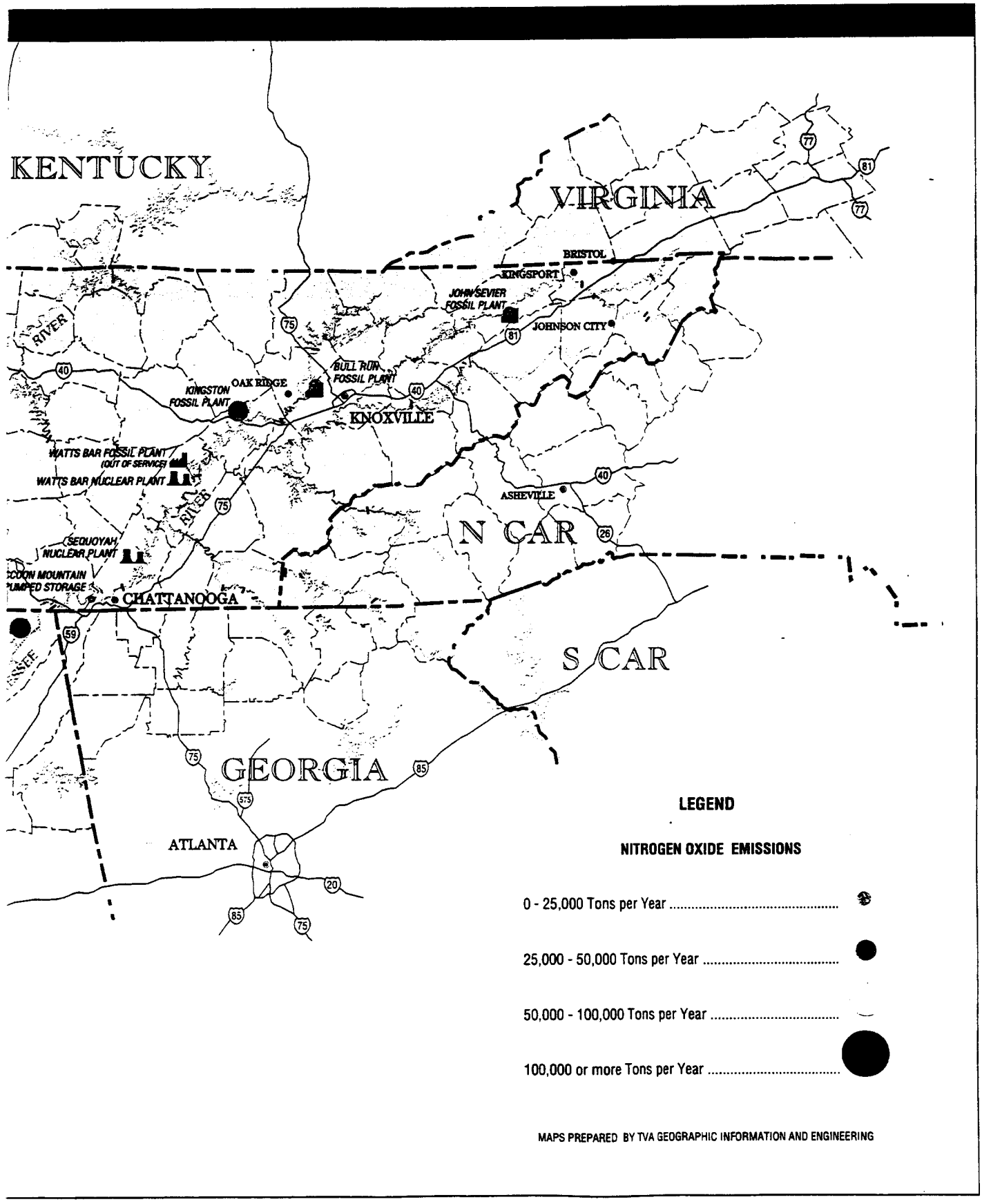


FIGURE T1-27. **Nitrogen Oxides Emissions From TVA Coal-Fired Power Plants in 1993**




KENTUCKY
VIRGINIA
BRISTOL
KINGSPORT
JOHN SEVIER FOSSIL PLANT
JOHNSON CITY
BULL RUN FOSSIL PLANT
OAK RIDGE
KINGSTON FOSSIL PLANT
KNOXVILLE
WATTS BAR FOSSIL PLANT (OUT OF SERVICE)
WATTS BAR NUCLEAR PLANT
ASHEVILLE
N CAR
SEQUOYAH NUCLEAR PLANT
CHATTANOOGA
S CAR
GEORGIA
ATLANTA
LEGEND
NITROGEN OXIDE EMISSIONS
0 - 25,000 Tons per Year
25,000 - 50,000 Tons per Year
50,000 - 100,000 Tons per Year
100,000 or more Tons per Year
MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

that increased particulate exposure increases health risk (Dockery et al. 1993). Characterizing the relationship between particulate concentration and health impacts is complicated by contributions of weather, other co-occurring environmental pollutants, and a lack of extensive measurements of particle sizes other than 10 microns. It has been difficult to identify a single causal factor when several air pollutants are elevated at the same time.

A fine-particulate standard is now being considered for particles less than or equal to 2.5 microns. Available monitoring data suggests that large areas of the country would not be in attainment with such a standard.

In addition to possible health effects, the Environmental Protection Agency's draft criteria document also addresses the contribution of secondary particles to regional haze. Title I of the 1990 Clean Air Act Amendments authorizes the development of control strategies to mitigate visibility impacts. The Environmental Protection Agency could use Title I provisions to respond to the federal land managers' findings of visibility impairment in Class I areas. The Environmental Protection Agency could alternatively use the ambient standard process to set a visual range goal.

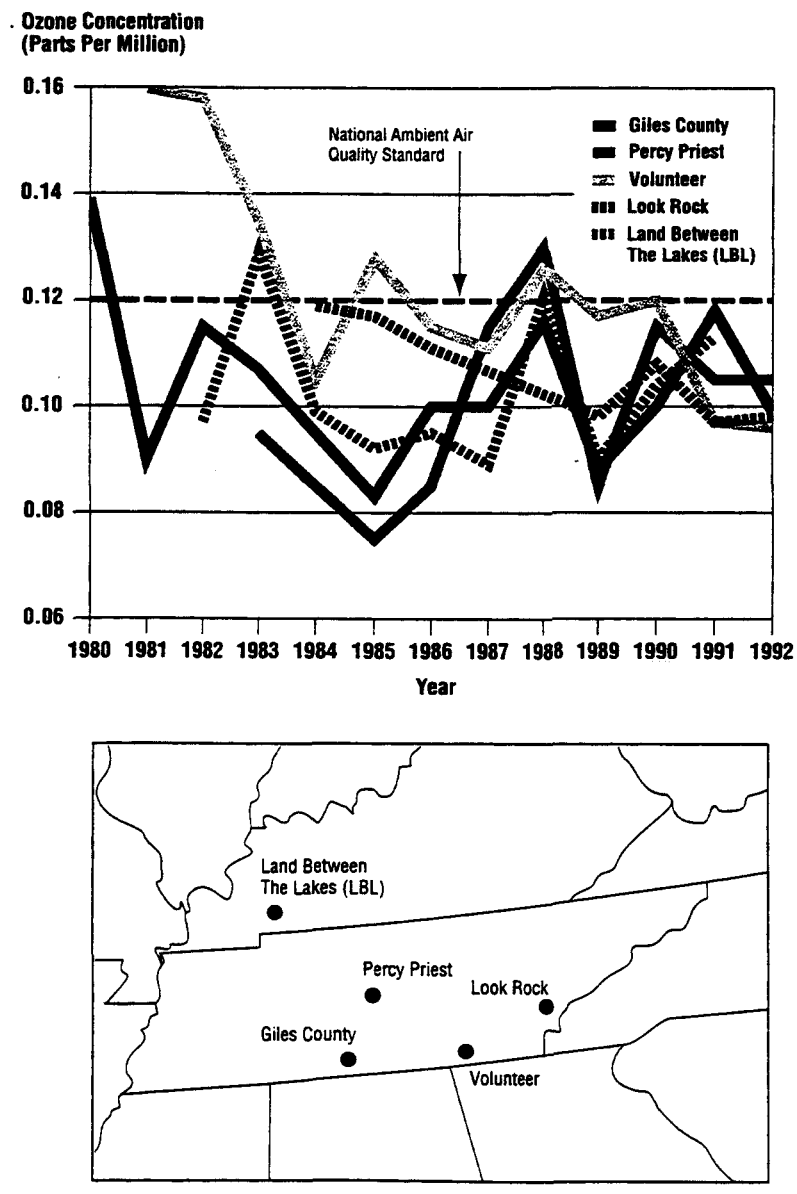
If the ambient standard were revised to limit fine particles (less than 2.5 microns in size), TVA would likely install higher efficiency electrostatic precipitators and add filters to coal-handling areas. Factors to differentiate among energy strategies do not include those to comply with uncertain future regulations of fine particles.

TROPOSPHERIC OZONE

Health and Welfare Concerns

Ozone is a secondary air pollutant produced in the presence of sunlight from the primary emissions of nitrogen oxides and volatile organic compounds in the lower atmosphere (troposphere). In some areas of the southeastern United States, ambient levels of ozone exceed levels demonstrated to impair human respiratory function and to impact crops, forests, and materials. Several urban areas in the Southea do not attain the current National Ambient Air Quality Standard (maximum one-hour average concentration not to exceed 0.12 parts per million more than three times in three years). The Environmental Protection Agency is considering revisions to the current standard to address health impacts from extended exposures and cumulative impacts to crops and forests. The National Park Service has reported that ambient levels of ozone are adversely

FIGURE T1-29. **Maximum Hourly Ozone Concentrations at Five Monitoring Sites in the Energy Vision 2020 Study Area Have Shown Little Improvement**

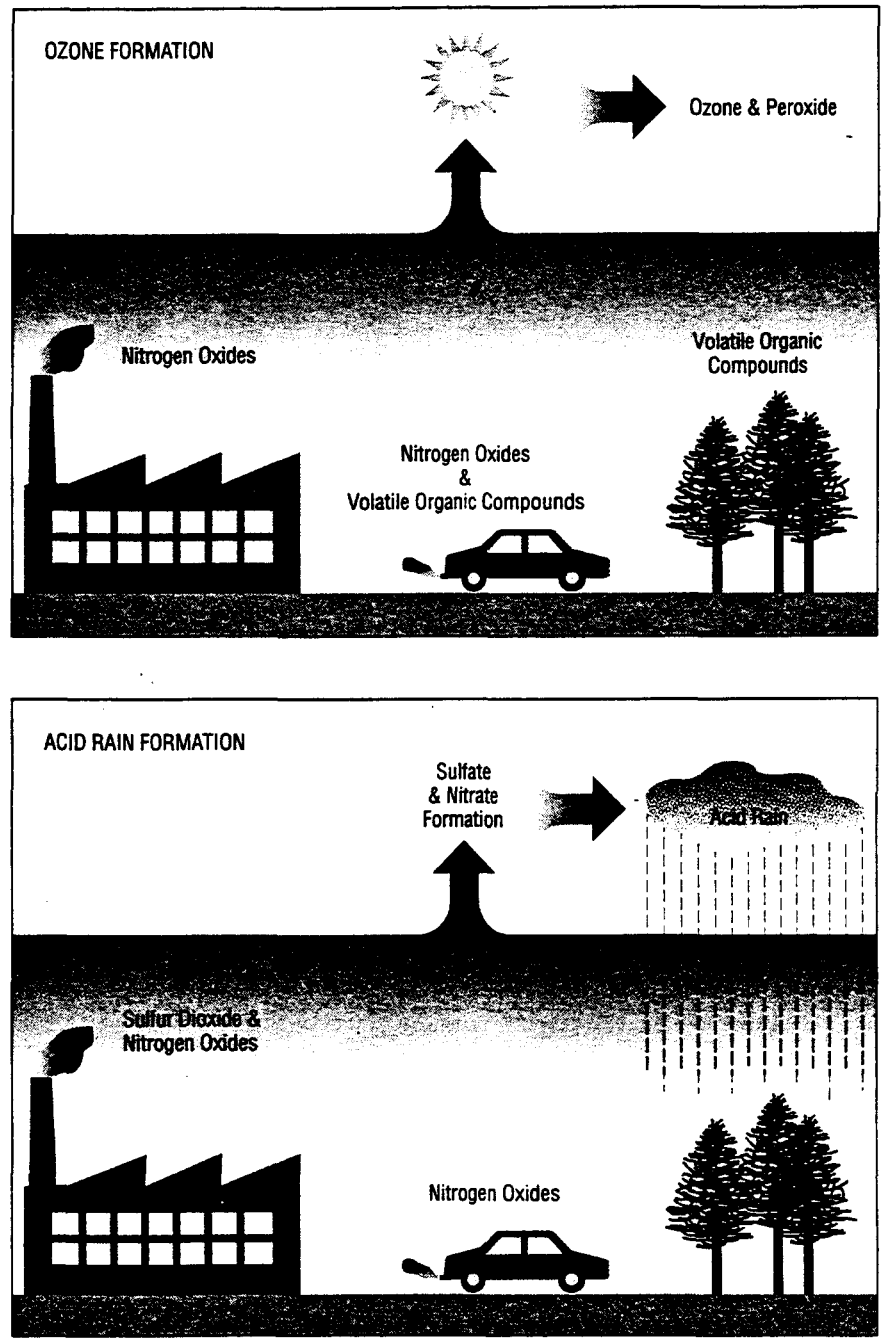


impacting resources in park and wilderness areas protected as designated Class I areas under the Clean Air Act (Shaver et al. 1994). For all these reasons, ozone is a major consideration for environmental consequences of energy strategies.

Ozone Formation

Sunlight is required for ozone formation. The rate of formation increases with increasing solar intensity and temperature. Thus, ozone levels are greater in the summer than in the winter and tend to be greater in drier years. The frequency and magnitude of ozone episodes is a function of meteorologic variables such as wind speed and direction, solar radiation, and humidity. The southeastern United States is particularly susceptible to elevated ozone exposures, due to its warm, sunny climate; the high frequency of air stagnation episodes; and the large contribution of natural emissions sources. *Figure T1-29* illustrates the maximum ozone concentration at five monitoring sites in the Tennessee Valley. *Figure T1-30* illustrates the way in which ozone is formed.

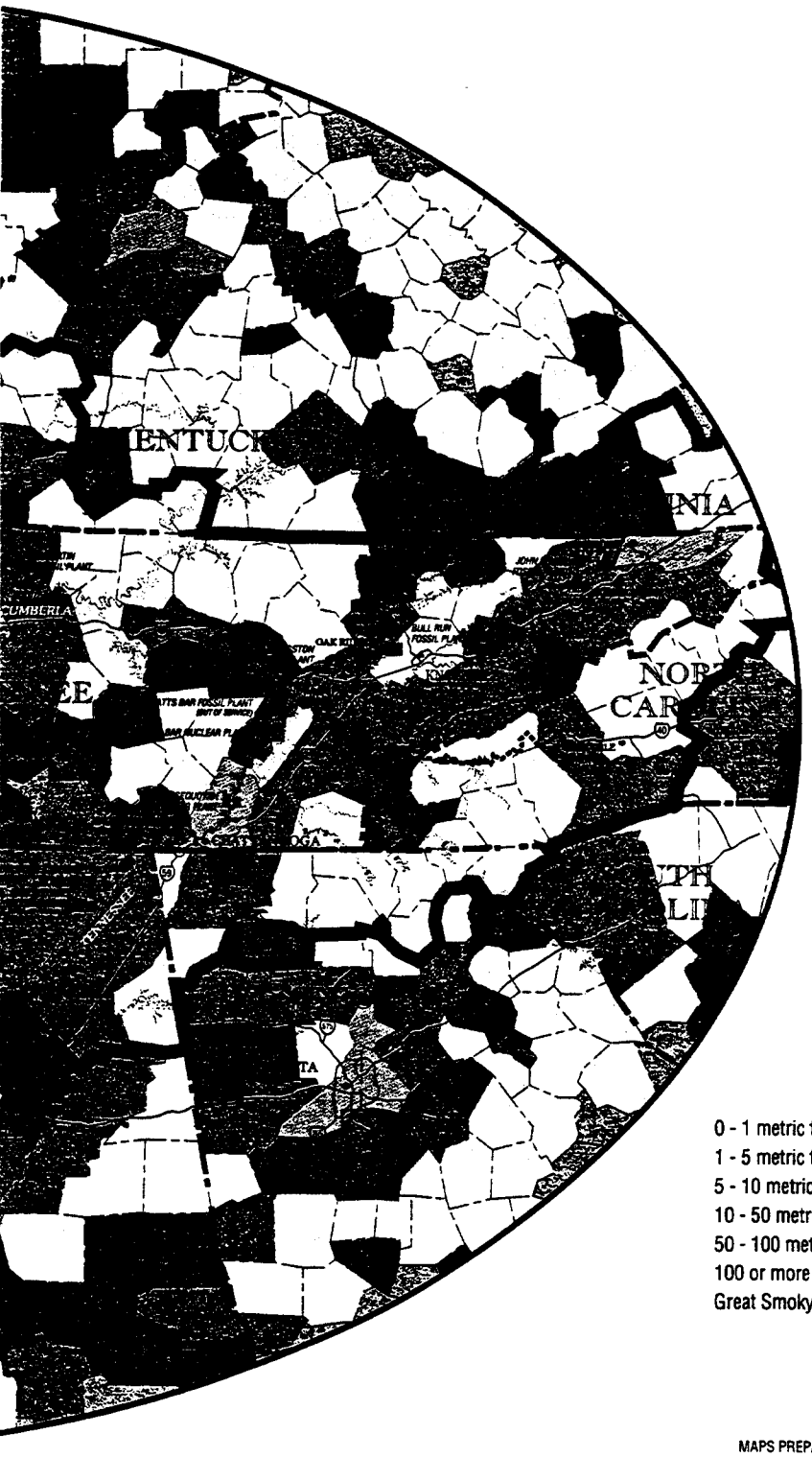
FIGURE T1-30 Ozone and Acid Rain Formation



Sources of Contribution

Human-produced and natural sources of nitrogen oxides were discussed previously. Human-produced sources of volatile organic compounds include motor vehicles, petrochemical storage and transport, chemical and industrial processing, and smaller sources such as dry cleaners and bakeries. The map in *Figure T1-31* illustrates human-produced point, area, and mobile sources of volatile organic compounds. Vegetation, microbial activity, and forest fires are natural sources of volatile organic compounds. Comparing *Figures T1-31* and *T1-32* shows that in many areas of the southeastern United States, natural sources can equal or exceed human-produced sources. *Figure T1-33* illustrates that TVA's emissions of volatile organic compounds are insignificant when compared to its emissions of other pollutants and to other sources of volatile organic compounds.

FIGURE T1-31: **Total Volatile Organic Compound Emissions from Point, Area, and Mobile Sources in the Greater Source Area for Energy Vision 2020**



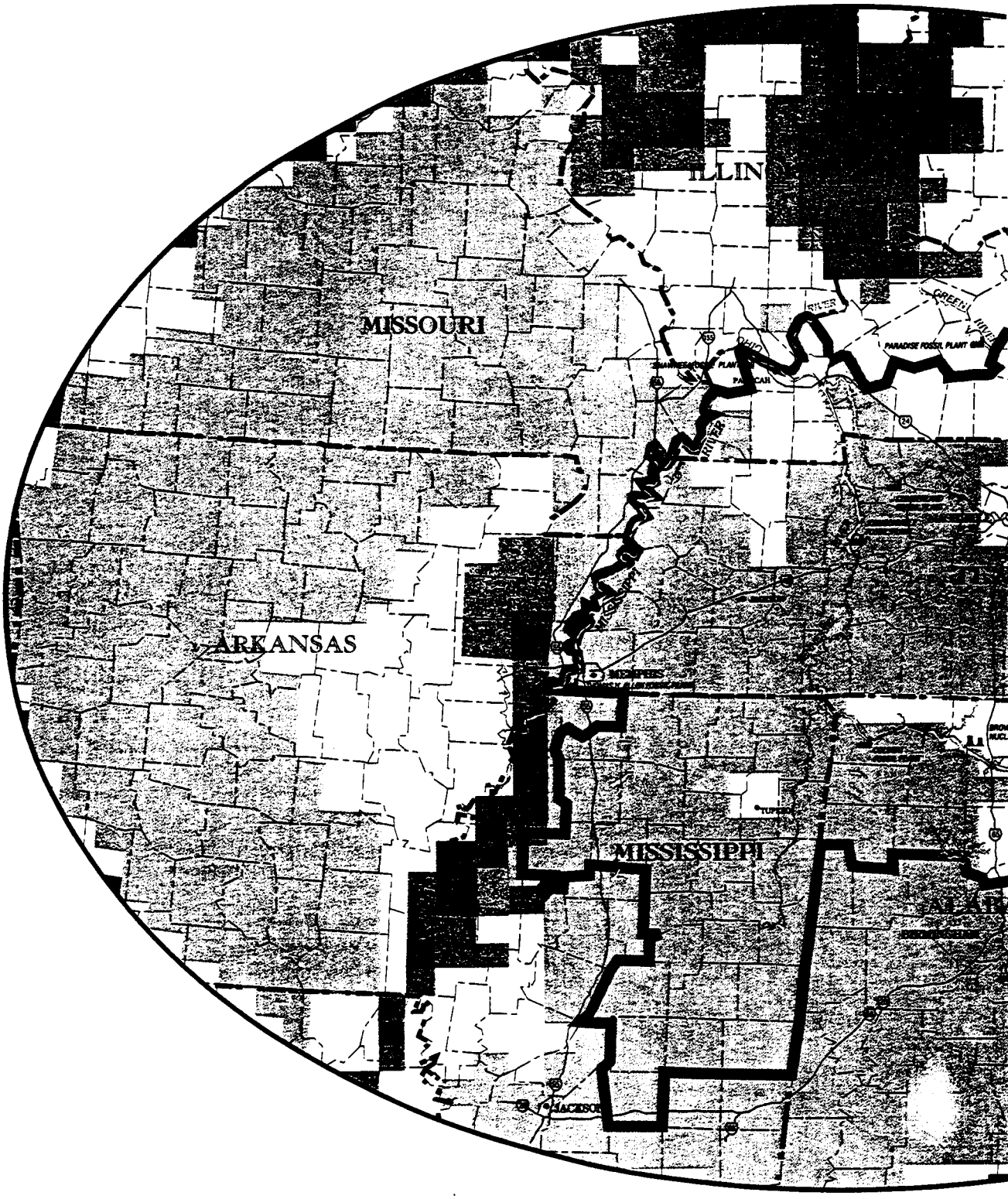
LEGEND

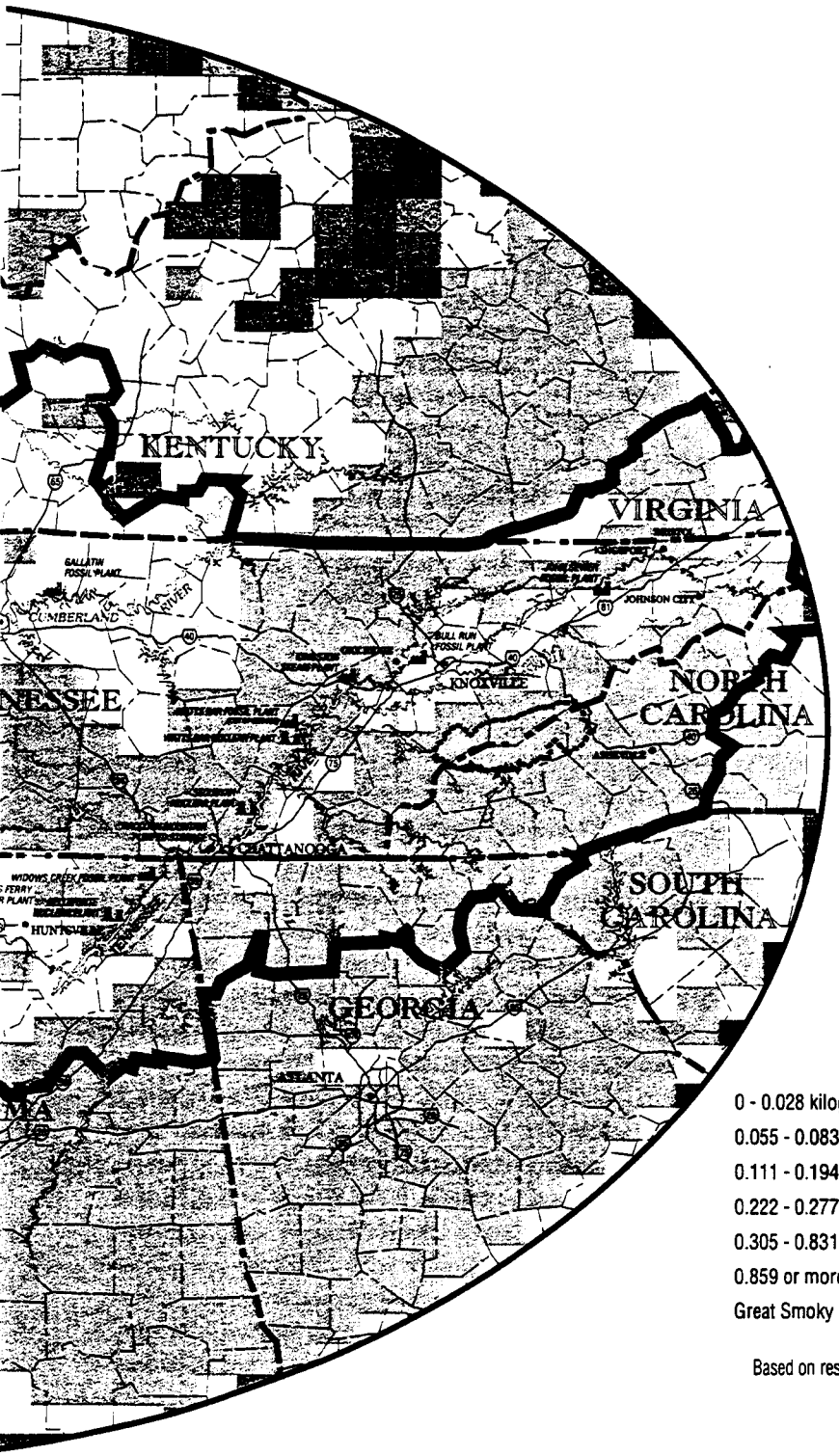
0 - 1 metric tons per day
1 - 5 metric tons per day
5 - 10 metric tons per day
10 - 50 metric tons per day
50 - 100 metric tons per day
100 or more metric tons per day
Great Smoky Mountains National Park

Interim 1990 Emissions Inventory

MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

FIGURE T1.48 Summer Volatile Organic Compound Emissions from Natural Sources in the Greater Source Area for Energy Vision 2020





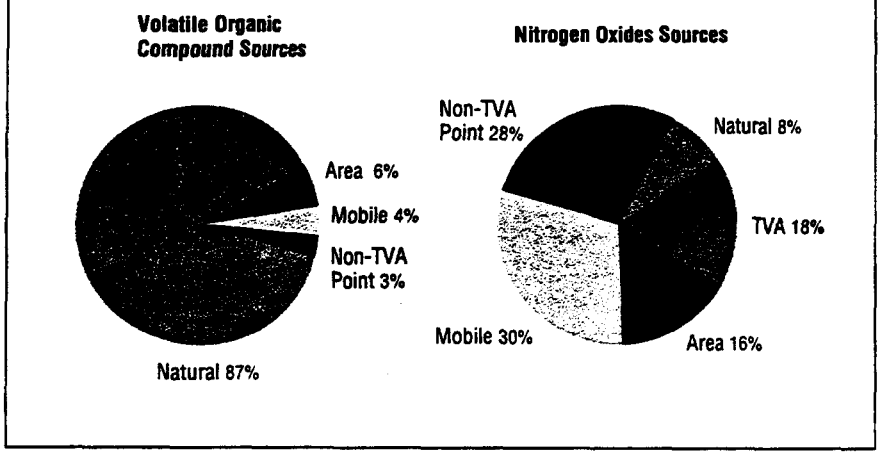
LEGEND

- 0 - 0.028 kilogram per hectare per day
- 0.055 - 0.083 kilogram per hectare per day
- 0.111 - 0.194 kilogram per hectare per day
- 0.222 - 0.277 kilogram per hectare per day
- 0.305 - 0.831 kilogram per hectare per day
- 0.859 or more kilograms per hectare per day
- Great Smoky Mountains National Park

Based on results of EPA Biogenic Emissions Inventory System II Model

. MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

FIGURE T1-33 Source Contributions to Ozone in Great Smoky Mountains National Park



Ambient Trends

Progress on ozone exposures has been mixed, despite the expenditure of billions of dollars on emission reductions in the Southeast over the past decade and a half. In the Tennessee Valley, the cities of Chattanooga, Knoxville, Memphis, and Huntsville have attained the ozone standard. However, Nashville and other cities in the southeastern United States (Atlanta, Charlotte, and Birmingham) remain in nonattainment status. (See nonattainment map in *Figure T1-15*.) Other measures of ozone exposure have not shown an improvement that is discernible above the annual variability in trends due to weather patterns.

Figure T1-34 shows trends during the ozone season (April to September) from 1980 to 1992 at five sites selected to represent urban and rural exposures in the Tennessee Valley.

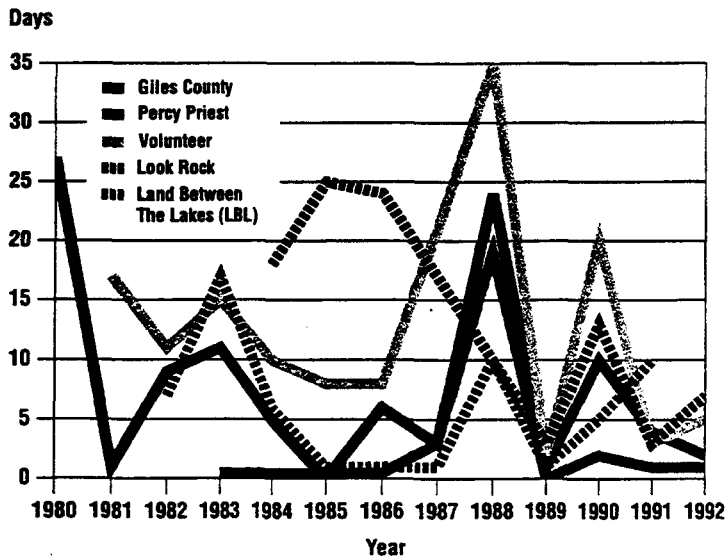
The maximum hourly ozone exposure shown in the graph in *Figure T1-29* provides insight into the annual variability in ozone trends. There has not been a demonstrable improvement over the past decade in maximum hourly ozone at these sites except at the Volunteer site located near Chattanooga. There can be annual variation in exposure that can occur simply as a function of weather patterns. The driest year on record in the Tennessee Valley was 1988; 1989 was the wettest *(Figure T1-11)*. While the maximum one-hour exposure at these sites was similar in 1988 and 1989, the frequency of hours of elevated ozone was much greater at all sites in 1988 than in 1989. During the 1988 ozone season, elevated exposures occurred much more frequently at urban sites (Volunteer site near Chattanooga, and Percy Priest site within Nashville) than at rural sites.

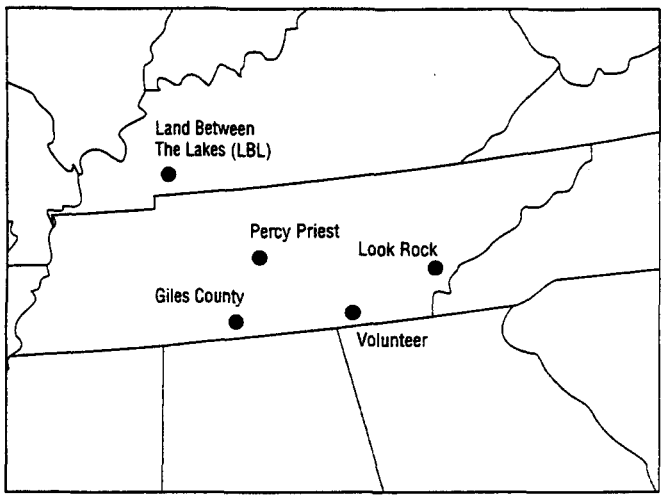
Since ozone formation is dependent on sunlight, the pattern for daily ozone exposure typically is lowest before dawn and builds over the day to peak in late afternoon and evening, as shown in the graph in *Figure T1-35*. In the presence of nitric oxide, ozone is consumed in the formation of nitrogen dioxide. Ozone consumed during evenings and nighttime hours is not replaced by ozone formation. In areas where nitric oxide is plentiful, ozone levels are commonly depleted during evening and nighttime hours. Monitoring at 40 stations in rural areas of the Southeast indicates that ozone levels are similar in daily cycles and timing of peaks as urban exposures (Lee and Ekles 1993). At high elevation (more than 2,500 feet) or remote sites, absence of local sources of nitrogen oxide emissions can cause ozone levels to remain elevated throughout the evening. Exposures at remote sites can also exhibit peaks later in the afternoon, evening, and night hours than nearby urban areas, indicating regional transport of ozone formed outside the remote areas (Mueller 1994; LeFohn 1994). *Figure T1-35* illustrates that ozone exposures can be greater at high elevation sites than at low elevation sites in the Valley.

Current Regulatory Issues

The National Ambient Air Quality Standard for ozone was initially set at 0.08 rather than 0.12 parts per million for the maximum one-hour standard. The level was raised in 1978 because the stricter standard was an unattainable goal for many urban areas in the country. Ozone nonattainment areas are classified as marginal, moderate, serious, severe, or extreme. Classifications are based on the frequency of episodes that exceed the standard. Nashville is currently classified as moderate. If meteorological conditions are mild in 1995, Nashville could achieve the requirement for three consecutive years without a violation of the 0.12 parts per million maximum one-hour standard, and would be designated as being in attainment with the ozone standard. If there is a violation of the standard this year, the current regulation requires that the Nashville area be reclassified as serious. A redesignation would require the State of Tennessee to consider additional emissions reductions to reduce ozone. Past emissions strategies have focused on reducing emissions of volatile organic compounds. Future strategies could consider sources of nitrogen oxides emissions, including TVA's Gallatin, Cumberland, and/or Johnsonville Fossil Plants. TVA is participating in the Southern Oxidants Study to better understand sources contributing to ozone formation in the Nashville area and the southeastern United States. (See discussion in section on cooperative research and assessment programs.)

FIGURE T1-34. **Frequency of Occurrence of 8-Hour Average Ozone Concentration Above 0.08 Parts per Million for Five Selected Sites in the Tennessee Valley**





Future Regulations

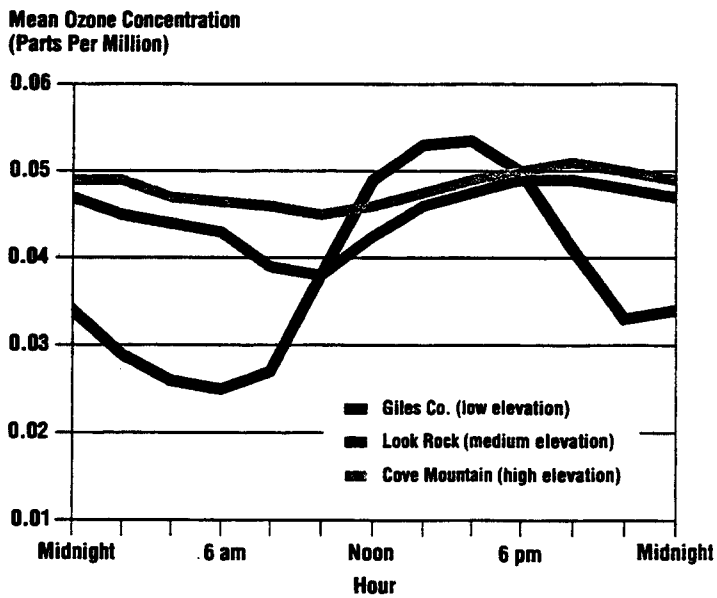
The Environmental Protection Agency is currently reviewing the adequacy of the one-hour maximum standard of 0.12 parts per million ozone to protect human health and welfare. While the Environmental Protection Agency has indicated that it expects to complete its review in 1997, the American Lung Association has sued the Environmental Protection Agency to complete its review by the end of 1995. The Environmental Protection Agency could decide to make the ozone standard more stringent. An Environmental Protection Agency staff paper released for review in spring 1995 (Environmental Protection Agency 1995a) summarized the human health risks and proposed alternative forms for a revised primary standard to protect human health. The revised primary standard could take the form of an eight-hour mean not to exceed 0.08 parts per million. An allowance of one to five exceedances per year are being considered.

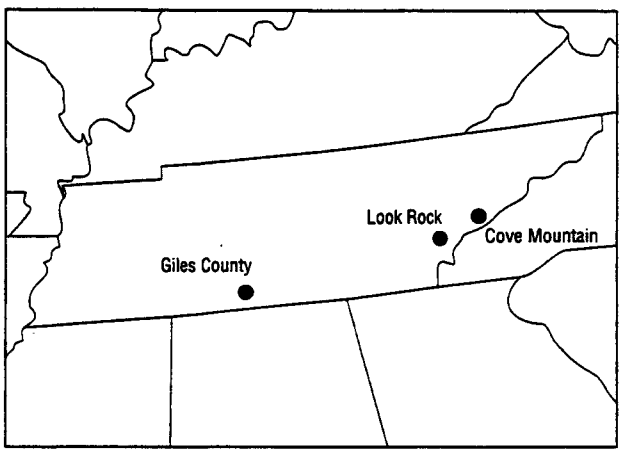
The Environmental Protection Agency is also considering a separate secondary ozone standard to better protect crops and forests. In the draft 1995 ozone criteria document (Environmental Protection Agency, 1995b), the Agency suggests a cumulative ozone exposure. calculated as the sum of all hours exceeding 0.06 parts per million (SUM06) during the maximum three-month period between April and October, that does not exceed 26.4 parts per million-hours would protect 50 percent of agricultural crops from a 10 percent yield reduction. Because plants respond more severely to the peak exposures, the frequency of hours greater than 0.10 may also be considered in the future in evaluating potential impacts of ozone exposures. This threshold is based on evidence from crop exposure studies. The threshold for damage to trees may be lower than that suggested for crops because trees have longer lives than annual crops and are therefore exposed to ozone for a greater period of time. (See discussion under crop and forest impacts.)

Further emissions reductions to reduce ambient ozone exposures in Class I areas of southern Appalachia are being recommended. The National Park Service has asked for emissions offsets from existing sources as a condition for new source permits. The Southern Appalachian Mountain Initiative, discussed earlier in this section, is considering emissions management options and could make recommendations to the states for emissions reductions that would go beyond the 1990 Clean Air Act Amendments.

The State of New York has petitioned the Environmental Protection Agency to consider states outside the Northeast Ozone Transport Region in its efforts to attain the ozone standard within New York. Research under the North American

FIGURE T1-35. Daily Ozone Trends at Different Elevations





Research Strategy on Tropospheric Ozone will help define sources contributing to ozone in the northeastern United States Results will assist development of regulatory policy.

Ozone Trends Under Revised Standards

The Environmental Protection Agency's proposed primary standard for ozone is more rigorous than the current maximum one-hour standard. The historical (1980-1992) frequency of occurrence of 8-hour average ozone concentrations greater than 0.08 parts per million for five selected Valley sites are shown in *Figure T1-34.* Depending on the number of occurrences above 0.08 parts per million allowed in one year, all five sites could be classified as nonattainment under a revised standard (currently only one of the sites, Percy Priest, is located in a nonattainment area). Notably, the Look Rock site, located on the western boundary of Great Smoky Mountains National Park, has a high frequency of 8-hour means greater than 0.08 parts per million. Data from 40 rural and urban monitoring stations in 1992, the year with the greatest number of rural monitoring stations, indicates that large areas of the southeastern United States would likely not be able to meet a revised standard of 8-hour mean not to exceed 0.08 parts per million. *(See Figure T1-36.)* The year 1992 was a comparatively mild ozone season. Sites where data is also available for 1990 and 1991 show that the number of days exceeding the 8-hour mean of 0.08 parts per million were greater in the earlier years than in 1992.

Most of the ozone monitoring in the United States has focused on establishing exposures in urban areas. The available data base for examining ozone trends in rural areas in the Southeast where crops and forests occur most frequently is limited prior to 1990. In 1990 the Southern Oxidants Study integrated existing rural sites and established new sites in a network to provide spatially representative coverage of ozone exposure in the rural Southeast. *Figure T1-37* presents the maximum three-month sum of hours exceeding 0.06 parts per million (SUM06) in 1992 at 40 urban and rural monitoring stations. The SUM06 ozone statistic was lowest in Middle Tennessee and highest in northeastern and southwestern Tennessee. Higher values in rural and high elevation areas reflect the higher evening and nighttime ozone exposures at sites removed from sources of nitric oxide.

The number of hours greater than 0.10 parts per million is a useful measure to describe the severity of ozone exposure, since both humans and plants are sensitive to peak exposures. Because nighttime ozone levels can be greater in rural than in urban areas, the SUM06 statistic may be equal to or greater at a rural site compared to an urban site, yet experience fewer hours greater than 0.10 parts per million. *Figure T1-38* illustrates that few areas in the Tennessee Valley experienced more than five hours greater than 0.10 parts per million of ozone during the period from April through September in 1992. The summer of 1992 was cooler than average. Analysis of Southern Oxidant Network data for 1990 and 1991 indicated these years

had higher cumulative exposures and greater numbers of hours exceeding 0.10 parts per million than occurred in 1990.

Understanding Emissions Contributing to Ozone

Ozone control strategies to date have focused on control of human-produced volatile organic compounds. Controls of volatile organic compounds have been less effective in reducing ozone levels than expected for several reasons:

- Natural organic compounds comprise more than half of total emissions of volatile organic compounds in the Southeast.
- Many human-produced sources were underestimated in early strategies.
- Vehicles and vehicular miles traveled have increased in number over the past decades.
- Nitrogen oxides levels were not considered.

The National Academy of Science in its 1991 review, "Rethinking the Ozone Problem in Urban and Regional Air Pollution," recommended reexamination of the strategy (National Research Council 1991). Past experience has demonstrated that the most effective strategy to reduce ozone depends on the relative concentrations of nitrogen oxides and volatile organic compounds in ambient air. In areas where nitrogen oxides concentrations exceed those of volatile organic compounds, ozone formation is limited by levels of volatile organic compounds. This means that reductions in volatile organic compound emissions will reduce ozone levels. These conditions occur most frequently in and downwind of large urban areas such as Nashville.

In an area where volatile organic compound emissions exceed nitrogen oxides, ozone formation is limited by levels of nitrogen oxides. This means that nitrogen oxides reductions will likely result in decreases in ozone. Given the high levels of natural volatile organic compounds, especially in forested areas, ozone production in much of the rural Southeast is limited by levels of nitrogen oxides (Fehsenfeld et al. 1994).

Exposures in rural and urban areas are closely interdependent. Studies in 1992 indicated that a large portion of ozone measured in the Atlanta urban nonattainment area was transported there from the surrounding region (Fehsenfeld et al. 1994). An extensive field study of rural and urban ozone formation was conducted in the Nashville area in summer 1995 by the Southern Oxidants Study. (See discussion of cooperative research and assessment programs on page T1-70.) Results will allow more accurate analysis of TVA emission contributions to regional ozone formation.

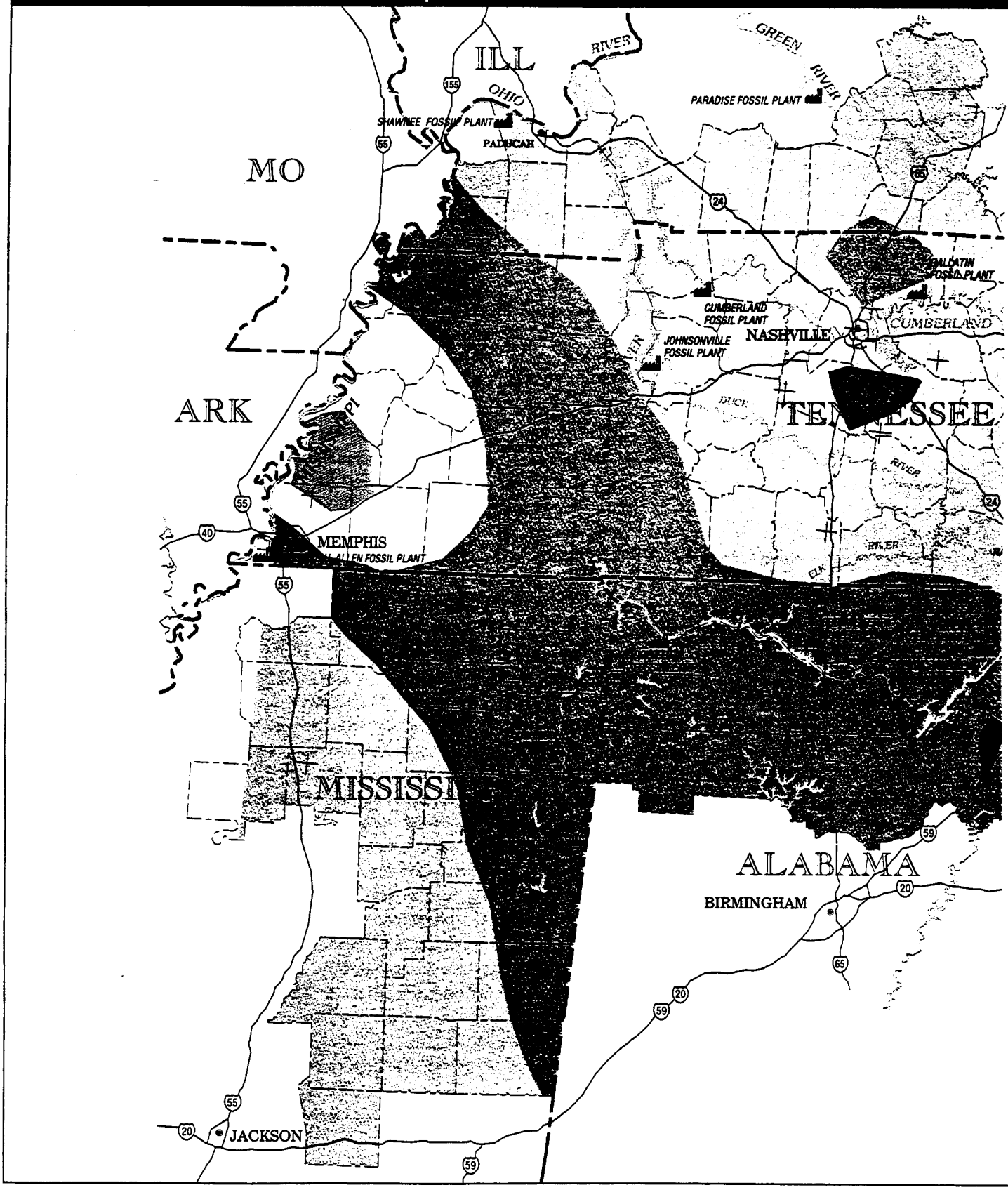
Nitrogen oxide emissions from a coal-fired power plant can either decrease or increase ambient ozone levels, depending on the local atmospheric mix of nitrogen oxides and volatile organic compounds. Within the first 20 kilometers of the source, nitric oxide emissions in a power plant plume will react with ozone to form nitrogen dioxide. Ambient ozone levels can be significantly decreased in this area. If the atmosphere is limited by concentrations of nitrogen oxides, nitrogen dioxide in a power plant plume will react photochemically with volatile organic compounds to form ozone. Ozone formation begins roughly 20 kilometers downwind of the emissions source.

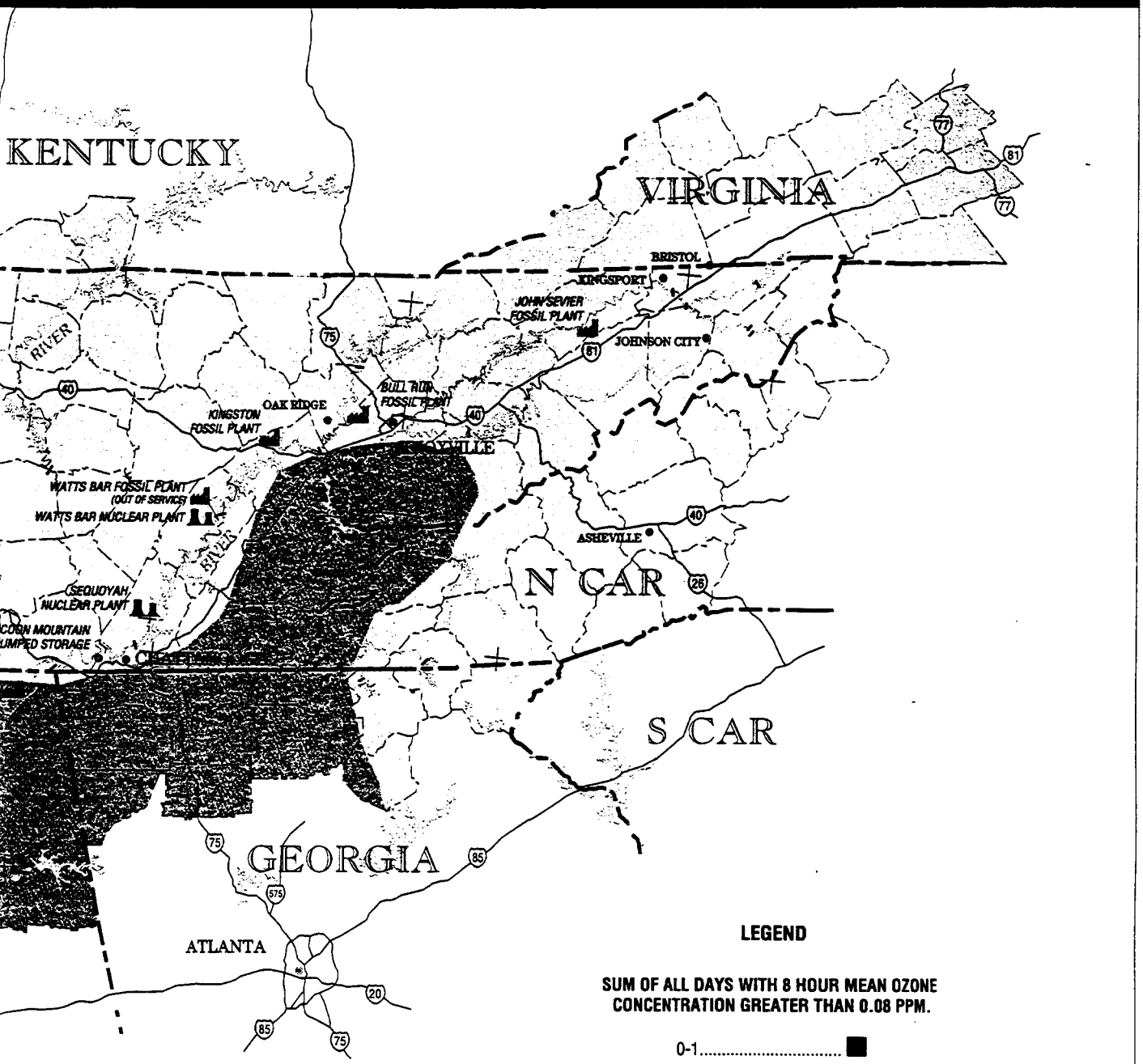
Nashville is currently classified as a "moderate" nonattainment area for ozone. TVA's Gallatin coal-fired power plant is located 15 kilometers east to northeast of the city. Depending on the prevailing weather pattern, nitrogen oxides emissions from Gallatin could reduce ozone in the metropolitan area to the southwest or contribute to ozone exposures in areas downwind. TVA's Johnsonville and Cumberland Fossil Plants are located west of Nashville and, depending on meteorology, could contribute to ozone exposures in the Nashville area. As part of TVA's compliance with the acid rain provisions (Title IV) of the 1990 Clean Air Act Amendments, TVA has already reduced nitrogen oxides emissions from Gallatin and Johnsonville and may reduce nitrogen oxides emissions from Cumberland prior to 2000.

Reliable assessment of source contributions requires detailed meteorological and atmospheric modeling that is beyond the scope of the current analysis. Simplifying assumptions can be made to estimate the source area contributing to ozone exposures in the Tennessee Valley. Ozone formation generally occurs within 12 hours after nitrogen oxides are emitted, depending on sunlight and levels of volatile organic compounds in the atmosphere. Once formed, ozone can be consumed in atmospheric reactions with other pollutants or transported hundreds of kilometers downwind.

Ozone transport is controlled by wind patterns both near the ground and aloft. Elevated power plant stacks emit nitrogen oxides hundreds of feet above the ground. Winds at this level are predominantly from the west through west-southwest directions in the Tennessee Valley *(Figure T1-12)*. Point sources emissions are generally elevated. Mobile and area source emissions and natural source emissions of nitrogen oxides occur near ground level. Surface winds that transport pollutants from near-ground sources usually flow from the south through southwest directions *(Figure T1-12)*. Winds from other directions also contribute to ozone transport. Average wind speeds and directions over the summer months would suggest that sources of nitrogen oxides 200 to 400 kilometers away could contribute to ozone levels in the Tennessee Valley *(Figure T1-24)*. During air stagnation episodes, local sources of nitrogen oxides and volatile organic compounds can predominate. Relative contributions of specific sources to specific receptors vary day to day as a function of

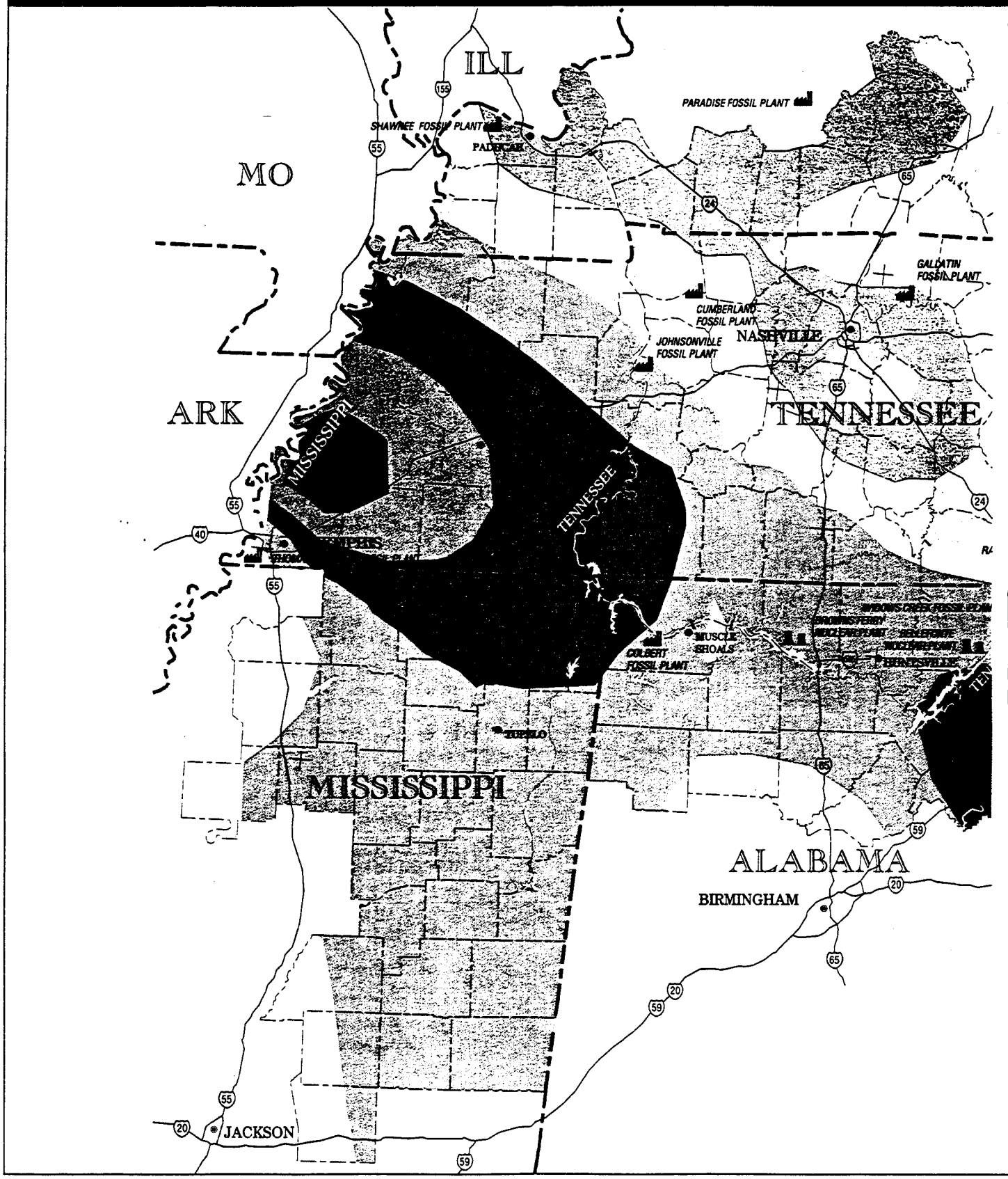
FIGURE T1-36 **Sum of All Days with 8-Hour Mean Ozone Concentration Greater Than 0.08 Parts per Million**

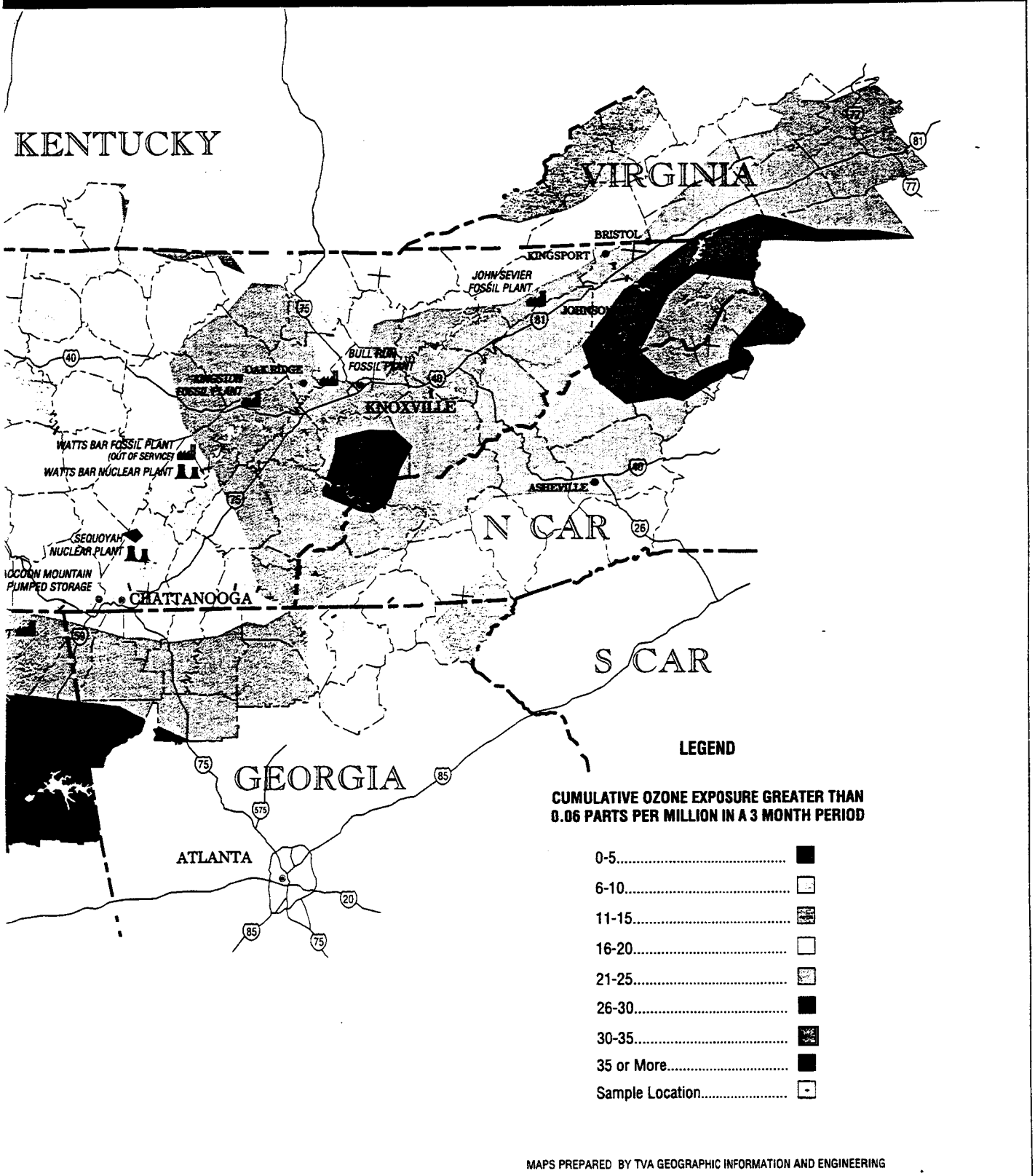




MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

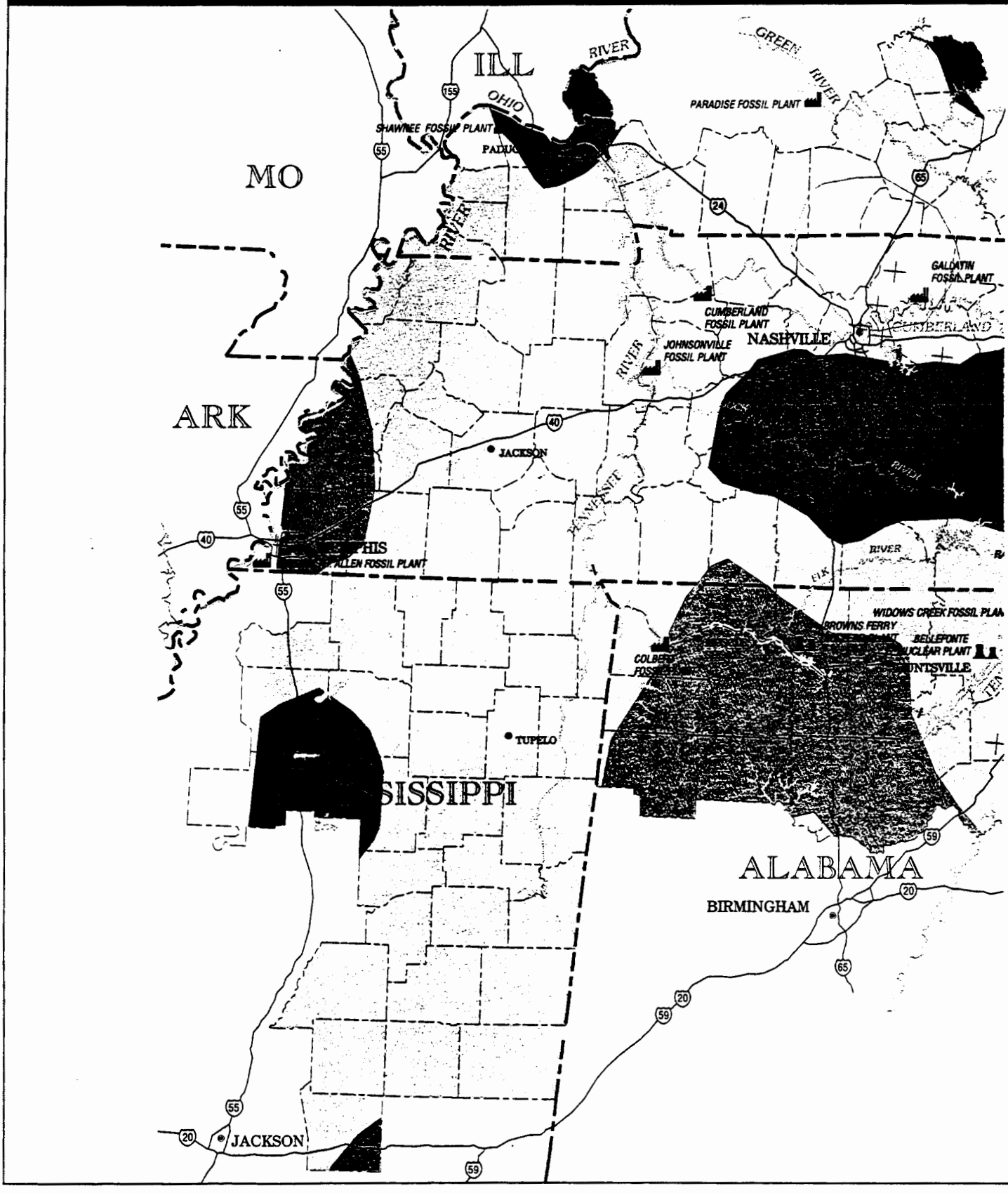
FIGURE T1-37. **Cumulative Ozone Exposure Greater Than 0.06 Parts Per Million in a 3-Month Period**

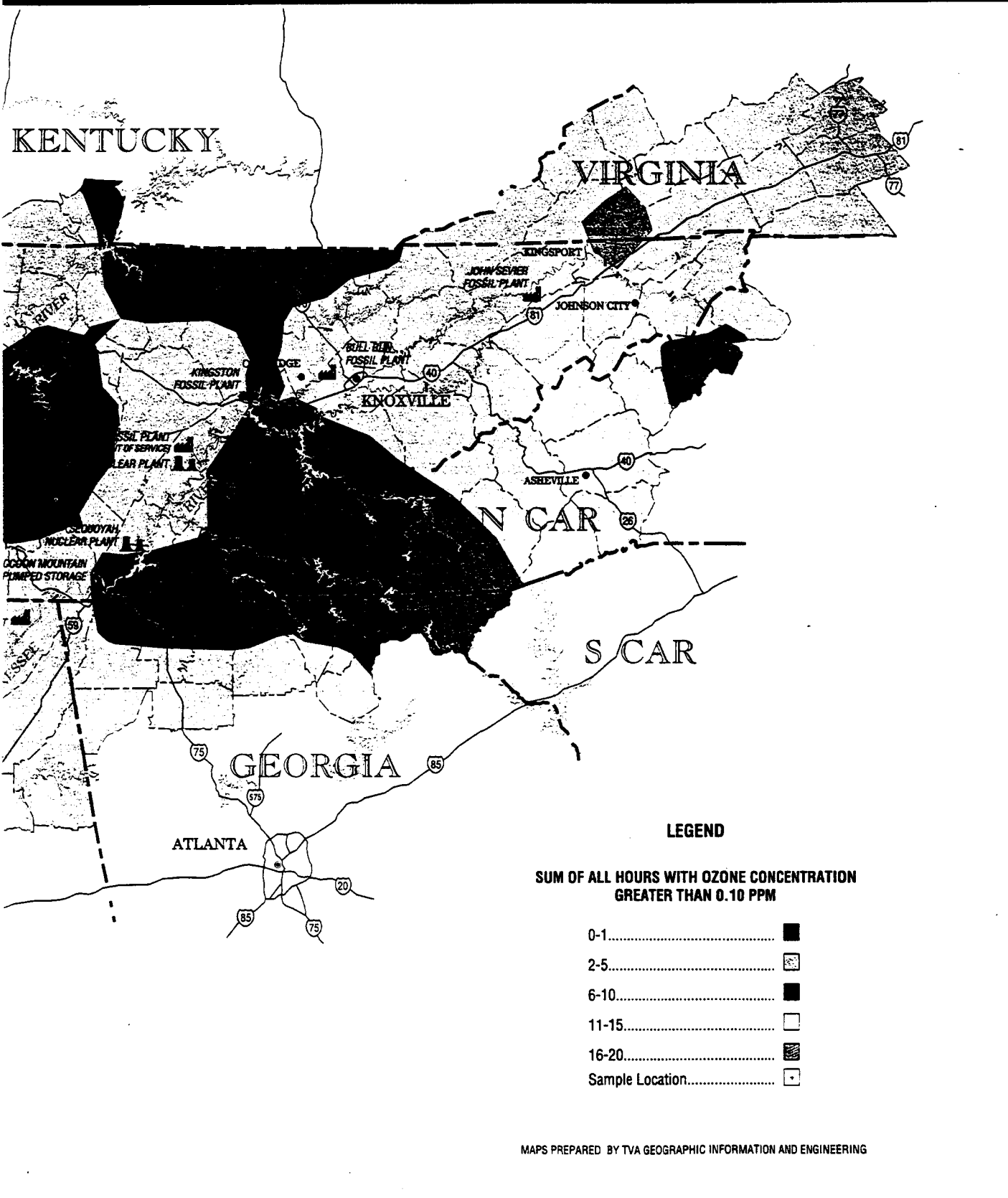




MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

FIGURE T1-38. **Sum of All Hours with Ozone Concentration Greater Than 0.10 Parts per Million**




KENTUCKY
VIRGINIA
KINGSPORT
JOHN SEVIER FOSSIL PLANT
JOHNSON CITY
BUEL BUR FOSSIL PLANT
KINGSTON FOSSIL PLANT
KNOXVILLE
ASHEVILLE
N CAR
S CAR
GEORGIA
ATLANTA
LEGEND
SUM OF ALL HOURS WITH OZONE CONCENTRATION GREATER THAN 0.10 PPM
0-1
2-5
6-10
11-15
16-20
Sample Location
MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

weather atmospheric mixing and transport. Similarly, TVA emissions of nitrogen oxides can contribute to ozone exposures at distances 200 to 400 kilometers downwind of specific sources. Percentage contribution cannot be accurately predicted without atmospheric modeling.

Based on prevailing wind speeds and direction, the source area for nitrogen oxide emissions contributing to ozone levels in the Great Smoky Mountains National Park is assumed to be a circle with a 300-kilometer radius and centered 150 kilometers west of the park. Within this source area and on a seasonal average basis, TVA emissions are estimated to be 18 percent of the total. Mobile, non-TVA point, area, and natural sources are estimated to contribute 30, 28, 16, and 8 percent, respectively, to ozone levels in the park *(Figure T1-33)*. Depending on the receptor and specific meteorologic conditions, TVA emissions may contribute 15 to 30 percent to ozone exposures in the TVA region.

ACID DEPOSITION

Acid deposition, acid rain, and acid precipitation are all terms used to describe the atmospheric input of acidic molecules, particularly sulfate and nitrate, to terrestrial and aquatic systems. Often this occurs as rainfall which is below natural pH levels. The term pH expresses the acidity or alkalinity of a concentration on a scale from 0 to 14, with 7 being neutral. Numbers less than 7 mean a concentration is acidic, while numbers greater than 7 mean the solution is alkaline. In the absence of human influence, precipitation would still be acidic due to the contribution of naturally occurring acids. Carbonic acid is formed when carbon dioxide is absorbed into cloud droplets. With other sources absent, precipitation would be weakly acidic with a pH of 5.2 to 5.6. Chloride, sulfate, and nitrate ions from natural sources such as sea salt, volcanic activity, and biological decay can further acidify precipitation. Alkaline substances in the atmosphere, particularly soil particles containing calcium, can have a neutralizing effect on cloud and rain water acidity. Acid deposition is of concern because human-produced emissions of sulfate and nitrate can acidify precipitation at levels well below that which would otherwise occur.

Acid deposition occurs in three forms: wet, dry, and cloud water.

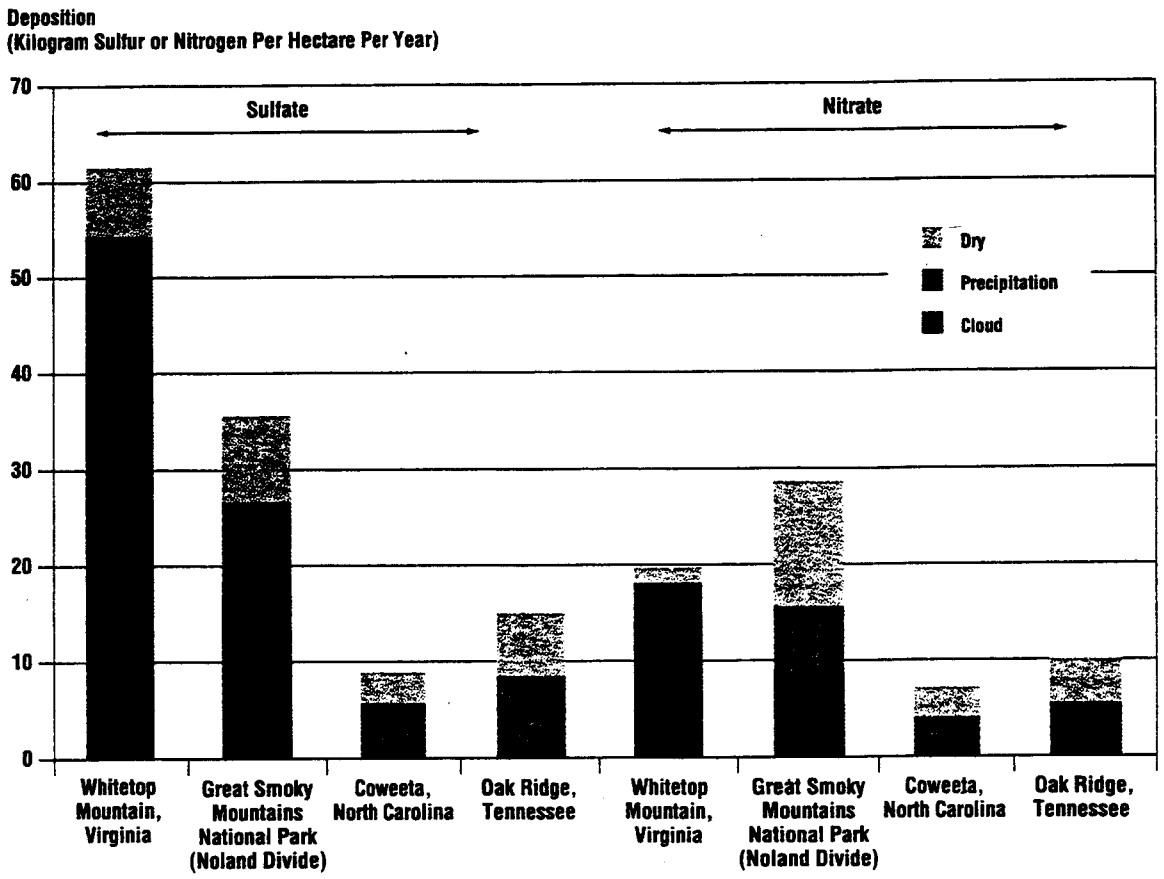
- Wet deposition is liquid or frozen precipitation. The concentration of acidic gases and particles in the atmosphere where clouds are formed determines the acidity of precipitation. Precipitation can deposit acidic pollutants hundreds of kilometers from the sources of origin.
- Dry deposition occurs when acidic aerosols such as sulfuric acid or acidic gases such as nitric and hydrochloric acids react with and deposit directly to surfaces without the presence of precipitation. Dry deposition processes occur constantly. The rate of deposition at any given location depends on the air concentrations of acidic gases and particles, the type of surface to which the deposition occurs, and the relative turbulence of the atmosphere just above the ground. Dry deposition is often greater near major sources of acidic pollutants.
- Cloud water deposition occurs when cloud droplets directly deposit their contents on surfaces. This phenomenon occurs primarily over elevated topography where clouds are intercepted. Acidic species are more concentrated in cloud water droplets than in rainwater. Forest canopies are especially efficient surfaces for cloud water interception. In areas such as the southern Appalachian Mountains, where immersion in clouds occurs frequently, cloud water deposition can be the predominant pathway for acidic deposition.

Ambient Trends

The relative importance of each deposition mechanism depends on site elevation, vegetation cover, and the location of a site relative to major human sources. At sites in the eastern United States where cloud deposition is not important, wet and dry depositions are about equal. In high elevation forests of the Appalachian Mountains, studies have found that cloud water can account for 50 percent or more of the total sulfate and nitrate deposition *(Figure T1-39)*. Cloud water pH, which averages about 3.6 in many areas, is typically lower than that of rainwater, which averages about 4.2 in the Appalachian region. Some sites may experience cloud interception more than 30 percent of the year (Mueller and Weatherford 1988; Lindberg and Lovett 1992; Lovett and Lindberg 1993). At these same sites, precipitation is often enhanced by the effect of the mountainous terrain lifting and cooling the air above it. Thus both the volume of precipitation and the total wet, dry, and cloud deposition at high elevation sites in the southern Appalachian Mountains can be greater than that of other areas of the Valley.

The trends for annual mean pH in precipitation for six low-elevation sites in the Tennessee Valley are presented in *Figure T1-40*. Annual mean pH generally increased over the period. The most acidic (lowest pH) precipitation in the Tennessee Valley region occurs in portions of Kentucky and east Tennessee, with slightly lower acidity to the east and south. Lowest annual pH values are near 4.2. Ranges of measured sulfate and nitrate concentrations at these sites are representative of all but the highest elevations of the Tennessee Valley. Loadings of sulfate are roughly twice loadings of nitrate in the Tennessee Valley and nationally according to data collected under the National Acid Deposition Program. This is the basis for targeting greater reductions in sulfur dioxide than in nitrogen oxides in the 1990 Clean Air Act Amendments. The Environmental Protection

FIGURE T1-39 **Growing Season Deposition of Sulfate and Nitrate Deposition by 3 Pathways at 4 Locations in the Eastern Part of the Tennessee Valley (1986 and 1987)**



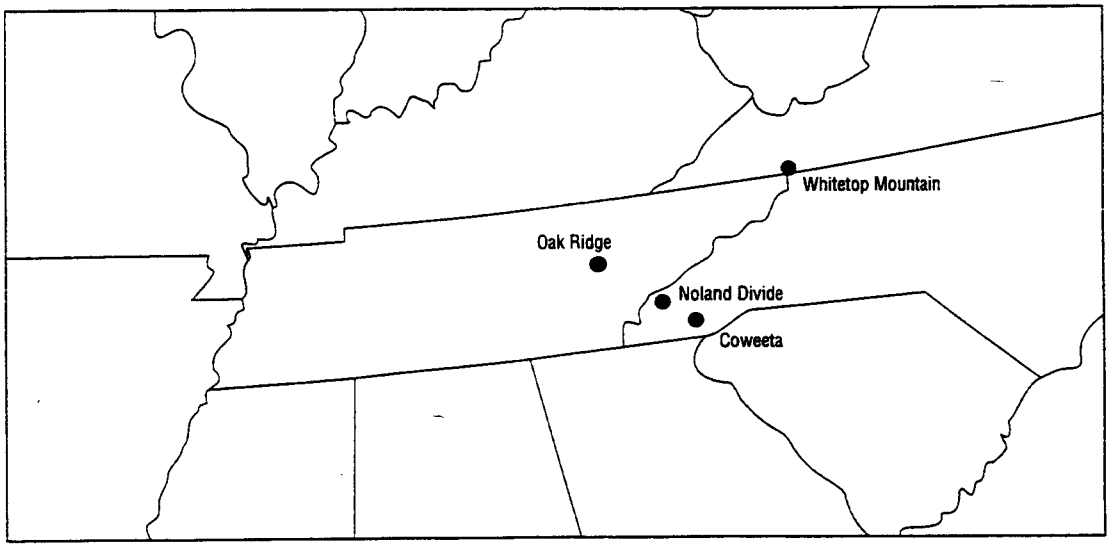
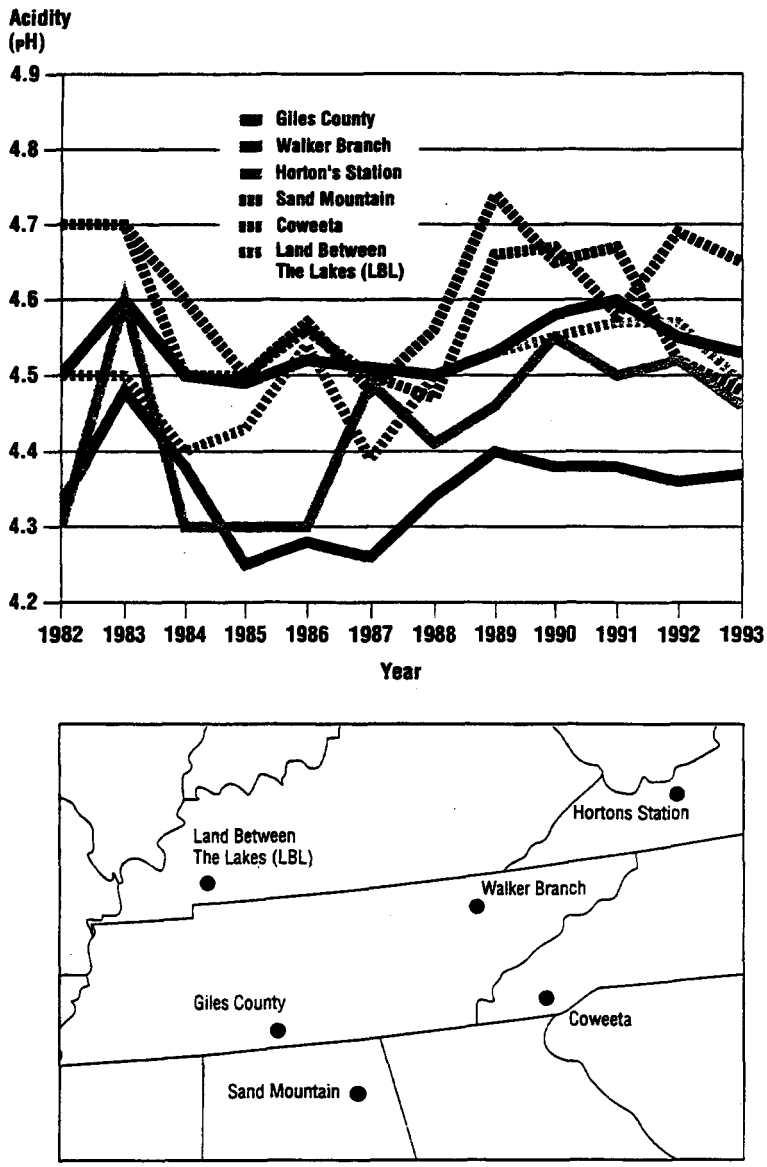


FIGURE T1-40 **Annual Mean Acidity (pH) of Precipitation at Six Monitoring Sites in the Energy Vision 2020 Study Area**



Agency is currently evaluating whether the reductions will be sufficient and is considering an acid deposition standard.

Some of the highest acidic inputs in the country are found in mountaintop forests of the southern Appalachians (Mueller and Weatherford 1988; Lindberg and Lovett 1992; Lovett and Lindberg 1993). Comparison of sulfate and nitrate deposition in 10 forest locations across the country indicates the highest loadings of sulfate and nitrate were measured at the Great Smoky Mountains site. Measurements at Whitetop Mountain and Mount Mitchell under the Mountain Cloud Chemistry Program (Vong 1990) support the same conclusions. However, because levels of cloud water deposited can vary twofold within a single forest stand, results from these specific sites cannot be generalized to be representative of all high elevation forests.

Understanding Emissions Contributions to Acid Deposition

The probable source region for nitrate in deposition is similar to that for ozone (200 to 400 kilometers). *(See Figure T1-24.)* The probable source region for sulfate deposition is larger than for nitrate and ozone because the rate of sulfate formation is slower. Oxidants, particularly peroxides, are required for sulfate formation. Summertime conversion of sulfur dioxide to sulfate occurs at a rate of roughly 1 percent per hour in the absence of clouds. Within clouds, conversion can reach 100 percent. In wintertime, oxidant levels, and thus rates of sulfate formation, are low. Assuming 24 to 48 hours for summertime formation and transport, sources 400 to 800 kilometers away are likely contributing to sulfate deposition in the Tennessee Valley *(Figure T1-20)*. As with ozone, local sources could predominate under some meteorological conditions, such as air stagnation episodes or favorable cloud chemistry. Sources within the assumed source area are not suggested to have equal contribution to deposition. Detailed atmospheric modeling would be required to determine contributions of specific sources to specific episodes. Based on the assumptions stated above, on a seasonal average basis, TVA sulfur dioxide emissions could contribute 18 percent to sulfate and 19 percent to nitrate deposited in the Great Smoky Mountains National Park. *(See Figure T1-41.)* TVA emissions could be greater under specific meteorological events.

Modeling results specifically linking TVA emissions with sulfate or nitrate deposition do not exist. The only modeling that has been done has grouped sources within geographic areas.

FIGURE T1-41. **Emission Comparisons for the Ozone Impact Source Region and the Acid Rain/Visibility Source Region**

SOURCE REGION FOR OZONE IMPACTS

POLLUTANT EMISSIONS (ca. 1990) [4,5]

Sources	Carbon Monoxide Tons/Day	Carbon Monoxide % of Total	Nitrogen Oxides [6] Tons/Day	Nitrogen Oxides [6] % of Total	Volatile Organic Compounds Tons/Day	Volatile Organic Compounds % of Total
Human Produced [1]	14,574	100.0	2,659	92.0	3,441	13.0
Natural [2]	0	0.0	237	8.0	23,273	87.0
Total	14,574	100.0	2,896	100.0	26,714	100.0
TVA Portion of Human Produced [3]	24	0.2	512	18.0	3	0.0

SOURCE REGION FOR ACID RAIN VISIBILITY IMPACTS

POLLUTANT EMISSIONS (ca. 1990) [4,5]

Sources	Nitrogen Oxides Tons/Day	Nitrogen Oxides % of Total	Sulfur Dioxide [7] Tons/Day	Sulfur Dioxide [7] % of Total	Volatile Organic Compounds Tons/Day	Volatile Organic Compounds % of Total
Human Produced [1]	5,841	87.0	15,177	100.0	6,767	10.0
Natural[2]	873	13.0	10	0.1	63,234	90.0
Total	6,714	100.0	15,187	100.0	70,001	100.0
TVA Portion of Human Produced [3]	598	9.0	2,736	18.0	4	0.0

1 Based on annual values in Environmental Protection Agency 1990 Interim Inventory/365.

2 For NO_X and VOC: based on BEIS2 model, ROM/SUPROXA domain land use data and "typical" ozone meteorology (max. temperature=35 C and full sun). For equivalent SO_2: estimated from data presented in (Placet, 1990).

3 Portion of 1990 Inventory allocated to TVA sources.

4 All rates are in metric tons.

5 TVA estimates that its 1990 emissions in this region were within 2-6% of the 1990 inventory values.

6 Emissions expressed as equivalent NO.

7 Natural SO_2 emissions are assumed to be negligible; estimates represent biogenic sulfur emissions expressed as equivalent SO_2.

Thus, National Acid Precipitation Assessment Program modeling results using the Regional Acid Deposition Model cannot distinguish between TVA emissions and those from other nearby sources.

TVA emissions of sulfur dioxide will be reduced significantly under Title IV requirements of the 1990 Amendments to the Clean Air Act. New emissions controls, such as the sulfur dioxide scrubbers recently installed on the two boilers at the TVA Cumberland power plant, further reduce TVA contributions to downwind sulfur deposition. TVA's future energy options project further reductions in sulfur dioxide emissions that are discussed in Volume 2, Document 2, Environmental Consequences.

VISIBILITY IMPAIRMENT

Visibility impairment refers to atmospheric conditions in which the ability of an observer to discern form, color, or texture of a distant vista is reduced from that which would have existed under natural conditions, causing the scenic value of that vista to be diminished. An adverse impact on visibility is defined by 40 CFR 51.301 federal regulation (Federal Register 1977) as "...visibility impairment which interferes with the management, protection, preservation or enjoyment of the visitor's visual experience of the Federal Class I area." *Figure T1-42* contains the pollutants causing visibility impairment, emissions, and control technologies.

Visibility impairment can be considered in two categories:

FIGURE T1-42. **Pollutants Causing Visibility Impairment, the Primary Emissions, and Their Control Technologies**

Secondary Pollutant	Primary Emission	Control Technology
Primary Fine Particulate Matter	Primary Fine Particles	Electrostatic Precipitator, Baghouse, Venturi Scrubber, Cyclones
Particulate Nitrates	Nitrogen Oxides	Low Nitrogen Oxides Burners
Particulate Sulfates	Sulfur Dioxide	Low Sulfur Coal, Coal Washing, Scrubbers, Fluidized Bed Combustion
Acid Mist	Sulfite	Ammonia Addition, Low Sulfur Coal
Nitrogen Oxides	Nitrogen Dioxide, Nitrogen Oxide, Nitrous Oxide	Low Nitrogen Oxides Burners, Selective Catalytic Reduction

- Regional haze that occurs over a wide geographical area and often persists for a few days
- Plume opaqueness that occurs when emissions from a specific source are observable, usually within 100 kilometers of the source and for shorter duration than a regional haze episode.

In the TVA region, both types of visibility impairment may occur.

Regional Haze

Visibility is affected by the concentrations of gases and particles in the air, the angle of the sun, the object being viewed, and the viewer. Gases that affect visibility include water vapor and nitrogen oxides.

The light that contributes to our perception of an image can be altered by three mechanisms:

- Light is scattered out of the sight path between the viewer and the object (vista).
- Light is absorbed in the sight path.
- Ambient light is scattered into the sight path and competes with the image—forming light to reduce the clarity of the image.

The sum of scattering and absorption of light is referred to as atmospheric light extinction.

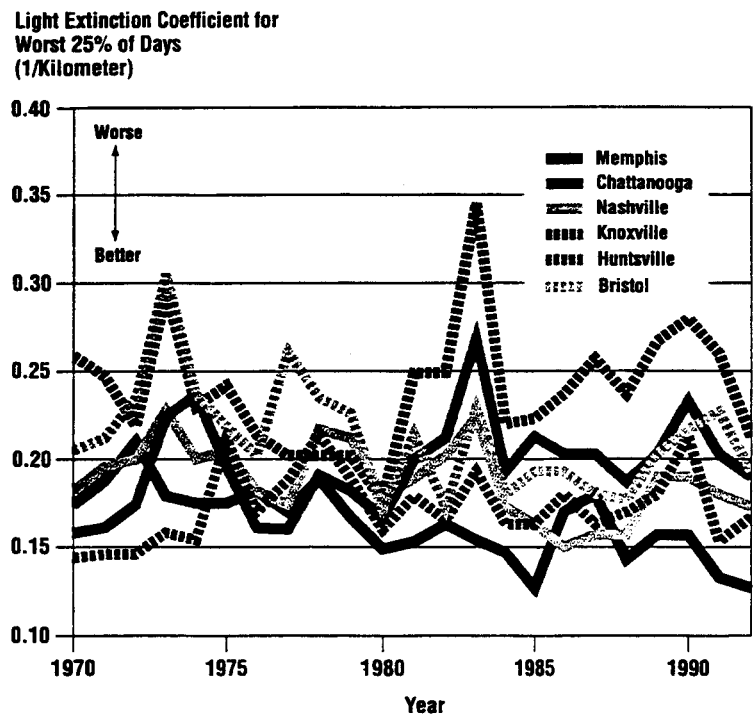
Atmospheric particles that reduce visual contrast and visual range by absorbing and scattering light have their origin in both natural and human-produced processes. Most of the soil components, such as silicates and other inorganic oxides, are of natural origin. Organic aerosols result from photochemical processes involving both natural and human-produced sources. The bluish haze characteristic of southern Appalachia originates from organic aerosols emitted by vegetation. Elemental carbon comes from combustion, including natural forest fires and human-made fires. Sulfates originate from human-produced sources of emissions, such as fossil fuel combustion and industrial processes. Natural sources such as volcanoes and hydrothermal vents, sea salt, and biogenic activity in the oceans and wetlands contribute significantly to global sulfate loadings (30 to 40 percent in the northern hemisphere). In the Tennessee Valley they are of minor importance. Formation of sulfate is seasonally dependent, with the rate of formation greater in the summer months. Compared to sulfate particulate matter, nitrate particulate matter is of secondary importance as a contributor to visibility impairment.

Relative humidity has a significant effect on light extinction, and thus visibility, in the eastern United States. Water vapor in the air provides surfaces for particles, especially sulfate, to bond. These particles grow in size to the size fraction (0.6 micrometers) that is most efficient in scattering light. Higher relative humidity in the eastern United States as well as higher emissions levels, explains why visibility is generally poorer in the eastern than western United States. Differences in relative humidity can also contribute to differences in average summer visibility trends between wetter and drier seasons. For example, visibility in cities in the Tennessee Valley was generally better in the dry summer of 1988 than the wet summer of 1989 *(Figure T1-43)*. Sulfate aerosol levels were 25 percent lower in the summer of 1988 than in the summer of 1989 (Eldred and Cahill 1994).

Ambient Trends

Several methods have been used to measure visibility. The longest record available is from human observations of visual range at airports across the country. Fine-particulate matter and some atmospheric gases scatter light in a phenomenon referred to as light extinction. This scattering causes objects to appear fuzzy or to merge with the background. Light extinction values are calculated from human observations. The measure of visual range is an inverse of the measure of light extinction; smaller extinction values represent clearer air and better visual range. Trends for light extinction at six urban airports in the Tennessee Valley from 1970 to 1992 during summer months (July to September) for the days with the worst 25 percent visibility are presented in *Figure T1-43*. Despite improvements in ambient levels of sulfur dioxide *(Figure T1-19)* and particulate matter less than 10 microns in size *(Figure T1-28)*, vis-

FIGURE T1-43. **Summer Visibility Trends for the Worst 25 Percent of Days in Six Cities in the Energy Vision 2020 Study Area as Shown by the Light Extinction Coefficient Have Shown Little Improvement**



ibility has not improved in the Tennessee Valley over this time period. Based on airport data, analyzes under the National Acid Precipitation Assessment Program concluded that visibility in the Southeast has decreased 60 percent since 1948 when measures were first made (Trijonis et al. 1990). Particulate matter in the fraction less than 2.5 microns would likely be better correlated with visibility, but there is very limited data available in the Southeast for particulates of this size.

Visibility has also been measured in Class I areas of southern Appalachia. Malm et al. (1994) report summertime 1985 extinction coefficients for Great Smoky Mountains National Park between 0.22 and 0.26 per kilometer. These are similar to values for Knoxville. *(See Figure T1-43).* Sulfate is the major contributor to the fine-particulate fraction that impairs visibility. In addition, soil dusts, elemental carbon, and organic aerosols also contribute to visibility impairment. Malm et al. (1994) estimated that sulfate was responsible for 48 percent of the measured light extinction for the 10 percent best summertime days in 1985 in the Great Smoky Mountains, 64 percent of the median days, and 76 percent of the worst days.

The Interagency Monitoring of Protected Visual Environments (IMPROVE) network began measuring visibility and particulate matter in Great Smoky Mountains National Park in 1984 and in Shenandoah National Park in 1982. IMPROVE sites have been established more recently at Mammoth Cave National Park and several national wilderness areas maintained by the U.S. Forest Service. Eldred and Cahill (1994) reported that sulfate concentrations at Great Smoky Mountain and Shenandoah National Parks increased from 1982 to 1993.

In addition to the IMPROVE data, camera images from the Class I areas are available for a longer time frame than are the light extinction measures of visibility. Camera data for the U.S. Forest Service wilderness areas will be published with the final report of the Southern Appalachian Assessment. Based on camera images in six U.S. Forest Service Class I wilderness areas, the median standard visual range in July and August is 25-30 kilometers. In December and January, median standard visual range is between 106 and 244 kilometers (Scott Copeland, unpublished data). The Southern Appalachian Mountain Initiative is also evaluating visibility and is considering emission sources contributing to visibility impairment. TVA's final analysis of environmental consequences may incorporate results from the Southern Appalachian Assessment and Southern Appalachian Mountain Initiative reports. (See discussion under Current Research and Assessment programs section in this document on page T1.70.)

Understanding Emissions Contributions to Regional Haze

The source area discussed for sulfate in acid deposition is also applicable to sulfate aerosols that scatter light and impair visibility. The relationship between sulfate levels and light extinction is not linear. This means that a reduction in sulfate levels may not lead to an equal improvement in light scattering due to sulfate.

In regions with high aerosol loadings, a decrease in the concentration particulate matter may lead to only a small improvement in visibility. The National Acid Precipitation Assessment Program (NAPAP) produced an early assessment of regional visibility impacts expected to result from changes in sulfate emissions. Malm et al. (1994) modeled the expected change in visibility that would result from a 10 million ton per year reduction in sulfur dioxide emission rates in the eastern United States as a result of the Clean Air Act Amendments of 1990. The

greatest improvement in visibility was projected to be in the Ohio River Valley. The emission reductions were projected to have an impact that, when averaged across the eastern United States, would result in a 5 percent (just perceptible) improvement in light extinction on the 15 days in the year having the highest sulfate concentration. Malm et al. projected impacts for three Class I areas, with the Great Smoky Mountains National Park being the one most likely influenced by TVA emissions. The park had a projected decrease in sulfate concentrations of 44 percent, and a net decrease in light extinction of 35 to 45 percent due to implementation of the 1990 Clean Air Act Amendments.

Based on the 1990 emissions inventory for the greater source area *(Figure T1-20)*, and averaged over summer conditions, TVA emissions are estimated to be roughly one quarter of total sources contributing to sulfate particle loadings in the Great Smoky Mountains National Park. TVA emissions could be a greater contributor during specific episodes.

FIGURE T1-44. **Hazardous Air Pollutants Studied at TVA Coal-Fired Power Plants**

Inorganics	Organics
Antimony (Sb)	Benzene
Arsenic (As)	Toluene
Beryllium (Be)	Formaldehyde [e.g., Benzo-a-Phrene (BAP)]
Cadmium (Cd)	Dioxins/Furans
Chlorine/Hydrogen Chloride (HCL)	Polycyollo Organic Matter (POM) [e.g., Benxo-a-Pyrene (BAP)]
Chromium (Cr)	
Cobalt (Co)	
Fluorine/Hydrogen Fluoride (HF)	
Lead (Pb)	
Manganese (Mn)	
Nickel (Ni)	
Mercury (Hg)	
Selenium (Se)	
Radionuclides	

Plume Blight and Opaqueness

Plume blight is the visual perception of a plume from a large industrial source located at a distance. Because large sources such as coal-fired power plants have elevated stacks, their emissions can sometimes travel great distances before they disperse to the ground. Opacity (or visible emissions) is a measurement of the visibility of a plume. Observations are made at the point of highest opacity in the plume, where condensed water vapor is not present. The visible emissions measure was originally a method for ensuring that the mass emissions from a facility were within the allowable limits. However, at coal-fired power plants, particularly those with flue gas desulfurization, the mass emission rate may be met while exceeding the allowable opacity.

Coal-fired power plants emit fine particles, gases that form fine particles in the atmosphere, and gases that directly absorb light. Fine particles scatter light. Emission controls typically remove more than 95 percent of the mass of fine-particulate matter. Those that escape scatter light and are the primary cause of plume blight and opacity. Secondary sulfate and nitrate particles and acid aerosols can also contribute to plume opacity.

HAZARDOUS AIR POLLUTANTS

Title III of the 1990 Clean Air Act Amendments identified 189 substances as hazardous air pollutants. This greatly expanded the number of chemicals subject to regulation. The Environmental Protection Agency is to develop regulations for each source category (i.e., each type of industrial facility) that emits the listed air toxics. The Environmental Protection Agency was directed to evaluate the hazards to human health and the environment from hazardous air pollutants emitted by electric utilities and to recommend whether emission reductions were warranted for utility plants. The Environmental Protection Agency was given until November 1993 to complete this study, but it is currently behind schedule. The Environmental Protection Agency issued a draft report for review in spring 1995. The final report is expected in November 1995. If the Environmental Protection Agency concludes that emissions reductions are warranted, it must establish necessary and appropriate control requirements. At the earliest, any new regulations would be proposed in 1996 and finalized in 1997. Utilities would have until approximately the year 2000 to bring their plants into compliance.

The Electric Power Research Institute and the Department of Energy have characterized toxic emissions for nearly 100 U.S. utility boilers representing a range of fuels, boiler configurations, and control technologies. Based on these results, the Electric Power Research Institute has estimated emissions and risk to human health from emissions at over 600 utility plants. (EPRI 1994). The Electric Power Research Institute's assessment indicated that no TVA plants and only 3 of the 600 plants posed cancer risks greater than the one-in-one-million identified in the statute and used by the Environmental Protection Agency as an accepted level of minimal risk. Calculated ambient exposures from all plants were below

FIGURE T1-45. **Human Health Risks in the Tennessee Valley Due to Air Concentrations of Heavy Metals**

Metal	Air Concentration at Fort Loudoun, Tennessee Milligram per Cubic Meter	Public Standard Milligram per Cubic Meter	Ratio: Observed to Standard
Arsenic	0.0015	0.3 [1]	1:200
Beryllium	No Data [2]	0.01 [3]	(1:25) [2]
Cadmium	0.007 [2]	50 [4]	(1:7000)
Chromium	0.002 [6]	No Standard [5]	
Copper	Not a Health Hazard by Inhalation Pathway		
Mercury	0.0016	No Standard	

[1] State of Washington standard — only agency to date to establish a standard.

[2] Survey of U.S. cities indicate the highest recorded level in any city was 0.0004 or about 1/25 of the current provisional Environmental Protection Agency standard.

[3] Current standard is a provisional Environmental Protection Agency criterion for a 30-day average (U.S. Public Health Service, 1989)

[4] U.S. Public Health Service standard for occupation exposure; no standard has been established for exposure of general public to ambient air.

[5] No Environmental Protection Agency standard has been set since hexavalent chromium is a carcinogen by inhalation pathway. Cancer risks have been identified for various exposures to hexavalent chromium.

[6] TVA has data only on total chromium, not hexavalent chromium, at the Fort Loudoun site. Approximately 0.2% of power plant emitted chromium is in the hexavalent state. Applying this factor to the measured value for total chromium, and using Environmental Protection Agency data on cancer risk, the cancer risk at this level is estimated to be 1 in 25,000,000.

known threshold levels for human toxicity, even when exposures from multiple sources were considered. TVA is estimating emissions of 19 hazardous air pollutants released from TVA coal-fired plants as part of its reporting requirement under Title V of the 1990 Clean Air Act Amendment *(Figure T1-44).*

Radionuclides are one of the hazardous air pollutants being evaluated by the Environmental Protection Agency in its study of utility industry hazardous air pollutant emissions. Coal-fired boilers emit trace amounts of radioactive elements (uranium, radium, thorium, and their decay products) found in the fuel. These radionuclides become incorporated into fly ash and are released to the air in the particulate matter emitted from the boilers. Particulate air pollution control equipment, such as electrostatic precipitators limit radionuclide emissions.

Risks to human health due to air concentrations of arsenic, beryllium, cadmium, chromium, and copper in the Tennessee Valley are extremely low. (See discussion under human health impacts section.) *(See Figure T1-45* and *T1-46.)* Environmental impacts from heavy metals are largely confined to aquatic ecosystems where concentrations are highest and organisms are often most sensitive. *Figure T1-47* indicates that water concentrations in Fort Loudoun reservoir would have to increase at least a hundredfold to approach thresholds for organism response to arsenic, beryllium, and chromium. Copper and cadmium concentrations measured at Fort Loudoun approach thresholds where some aquatic invertebrates may be affected. TVA is only one contributor to ambient levels of these metals in the Tennessee Valley. Nationally, electric utilities are estimated to contribute about 50 percent of the beryllium, 30-35 percent of the cadmium, 12-16 percent of the chromium, 2-5 percent of the copper, and less than 3 per-

FIGURE T1-46. **Human Health Risks in the Tennessee Valley Due to Water Concentrations of Heavy Metals**

Metal	Water Concentration at Fort Loudoun Reservoir, Tennessee (Milligrams/Liter)	Public Standard (Milligrams/Liter)	Ratio: Observed to Standard
Arsenic	0.034	50 [1]	1:150
Beryllium	Not a Carcinogen by Ingestion Pathway		
Cadmium	0.10	5 [2]	1:50
Chromium	0.46	50 [2]	
Copper	Not a Health Hazard by Ingestion Pathway		
Mercury	0.0058	No Standard [3]	

[1] Interim Maximum Contamination Level established by both Environmental Protection Agency and World Health Organization.

[2] Environmental Protection Agency drinking water standard.

[3] Standard based on fish concentrations for human consumption rather than water concentration.

FIGURE T1-47. Levels of Metals in Fort Loudoun Reservoir Compared to Threshold Exposures for Environmental Impacts

Metal	Water Concentration at Fort Loudoun Reservoir, Tennessee (Milligrams/Liter)	EPA Criterion: Biotic Effects (Milligrams/Liter)	Ratio: Observed to Standard
Arsenic	0.34	40[1]	1:100
Beryllium	Not measured (0.02[2])	5.3[3]	(1:250)
Cadmium	0.10	0.05[4]	2:1
Chromium	0.46	100[5]	1:200
Copper	0.8 (0.5 to 5)	5.6[6]	1:7

1 Threshold for embryo and larvae of vertebrates
2 Beryllium level of the highly-polluted Rhine River, demonstrating how low river levels of beryllium generally are.
3 Threshold for crustacean chronic toxicity.
4 Threshold for larvae and embryos of freshwater fish in water of hardness of 200 Milligram per Liter.
5 Threshold for freshwater invertebrates
6 U.S. Environmental Protection Agency criteria for aquatic life.

cent of the arsenic emitted annually to the atmosphere by human sources (Neme 1990).

Mercury

Mercury is used in Energy Vision 2020 as an indicator of hazardous air pollutants. Depending on the degree of concentration and length of exposure, mercury can have toxic effects on humans and wildlife. Organic mercury compounds, such as methyl mercury, are among the most toxic. Mercury salts released into the environment may be converted by bacteria into organic mercury compounds. Mercury accumulates in the environment and is carried through the food chain with ultimate consumption by humans.

Worldwide, approximately 6,000 tons of mercury are released into the air every year. Human activities account for half of this. Estimates vary widely, but United States electric utilities emit about 80 tons per year (EPRI 1993), representing 1.3 percent of the global or 20 percent of United States human-produced emissions. Measurement of the chemical forms of mercury in stacks and in plumes from coal-fired power plants indicate that mercury occurs in both gaseous (elemental) and particulate (oxidized salt) phases.

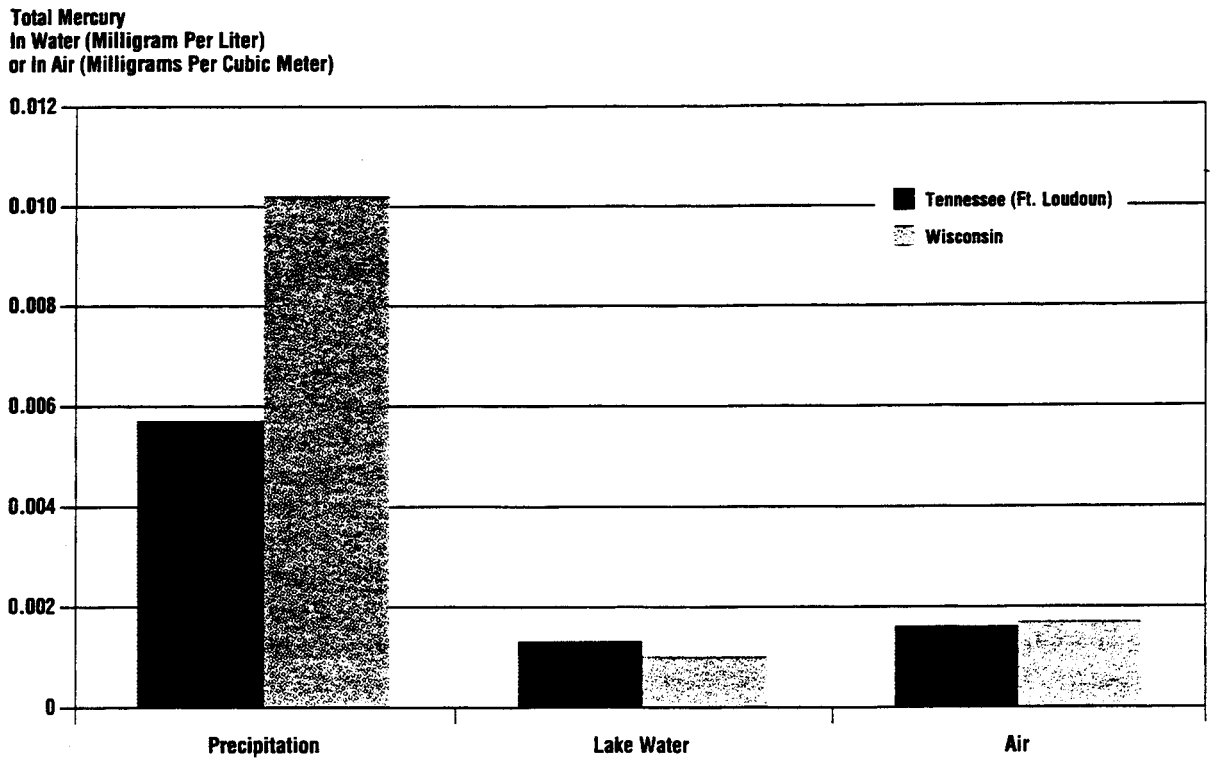
The 1990 Clean Air Act Amendments require the Environmental Protection Agency to study and report on United States mercury emissions. The Environmental Protection Agency's draft mercury study was available for public review in January 1995 with parallel peer reviews and public meetings.

TVA is cooperating in national studies with the Department of Energy and the Electric Power Research Institute to evaluate the efficiency of mercury removal by different control technologies. If the Environmental Protection Agency requires control of mercury emissions, likely controls include wet scrubbers, high efficiency electrostatic precipitators, fabric filters, and/or injection of a sorbent such as activated carbon into the flue gas. Human-produced emission sources are about equally divided among coal combustion, waste incineration, and other facilities.

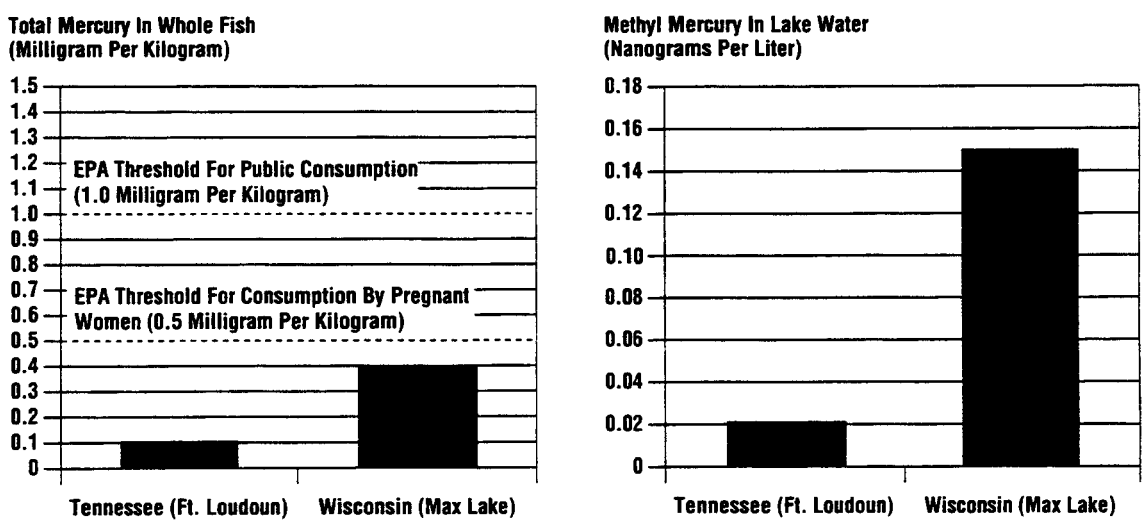
Globally, impacts of mercury are of concern for sensitive invertebrate and vertebrate species in aquatic ecosystems. Watershed characteristics determine whether atmospherically deposited mercury will accumulate in aquatic ecosystems. Dissolved organic carbon and sulfate ions facilitate mobilization and transport of mercury in aquatic systems. The Tennessee Valley has a higher land-to-surface water ratio and comparatively lower levels of dissolved organic carbon and sulfate than those areas of the country that are experiencing impacts (Joslin 1994). *(See Figure T1-48.)* Impacts of TVA's mercury emissions in the Tennessee Valley are likely to be minor, because the watersheds in the Valley are generally well buffered against mercury accumulation.

TVA emissions could contribute a small percentage to overall mercury loading in watersheds in the upper Midwest and Florida that are sensitive to mercury accumulation. Uncertainty regarding the extent to which mercury is deposited locally, regionally, or globally prevents more quantitative estimates of TVA's contributions to mercury loadings. TVA emissions of mercury are very small compared to its other emissions and compared to mercury emissions from other sources. Mercury emissions under TVA's future energy alternatives are tracked in Volume 2, Document 2, Environmental Consequences, as a surrogate for all toxic emissions from TVA's coal-fired power plants.

FIGURE T1-49. Comparisons of Environmental Mercury Concentrations



Concentrations of total mercury in precipitation, lake water, and air at Ft. Loudoun Reservoir, Tennessee, compared to those in northern Wisconsin.



Comparison of total mercury in whole fish and toxic methyl mercury in lake water in Ft. Loudoun Reservoir, Tennessee, and in Max Lake, Wisconsin.

GLOBAL CLIMATE CHANGE

The earth's climate is controlled by the radiative balance of the atmosphere. This refers to the radiant energy received from the sun and emitted by the earth back to space. Greenhouse gases include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and chlorofluorocarbons (CFC). With the exception of chlorofluorocarbons, these gases occur naturally. However, human-produced emissions have contributed to the increases in their concentrations. These gases absorb infrared radiation as it passes through the atmosphere and re-emit this energy. This results in a warming of the earth's surface. The greenhouse effect is a natural phenomenon that makes the earth inhabitable. The earth would be cooler by approximately 30 degrees C without the effect of naturally occurring gases. A recent estimate of the contribution by different human-produced activities shows carbon dioxide emissions from energy use and production are the largest contributors to greenhouse gases. The combined effect of the other trace gases presently is equal to that of carbon dioxide.

Globally, atmospheric concentrations of greenhouse gases are believed to have increased dramatically from pre-industrial levels. Atmospheric carbon dioxide has increased from 270 parts per million by volume prior to 1880 to 355 in 1990. The current rate of increase of carbon dioxide is 1.8 parts per million by volume per year or 0.5 percent per year. Fossil fuel combustion and global deforestation are the primary contributors to carbon dioxide buildup. The rate of global increase is projected to accelerate in the next decade as underdeveloped nations, particularly China and India, significantly increase power generation using coal.

Global circulation models predict an average global warming between 1.5 and 4.5 degrees C (2.7 and 8.1 degrees F), changes in precipitation amounts, and distribution (Bretherton et al. 1990; Mitchell et al. 1990) by the middle of the next century. These changes in global precipitation and distribution are also predicted to result in regional changes in crop and forest productivity, land use, water quality and quantity, and possible loss of ecosystems that cannot adapt to these changes. While the general circulation models generally agree that average temperatures in North America will rise, there is a great deal of uncertainty about the magnitude of changes in temperature and whether rainfall will increase or decrease. Current models do not have sufficient spatial resolution to predict magnitude or direction of changes on regional scales. At the current spatial resolutions, the models do not distinguish the southern Appalachian mountains as unique topographic features. Changes in temperature and rainfall within a region such as the Tennessee Valley could have far-reaching impacts on various sectors such as energy, transportation, agriculture, forestry, and socioeconomic factors. However, the science of global warming does not permit reasonable predictions of potential impacts.

The magnitude and scope of the potential climate change impacts are of concern for three areas of TVA operations:

- Those related to power production, including both adjustments to power demand and to power supply operations such as water availability for hydroelectric power production, and water temperature limits for nuclear and coal plant water usage
- Issues related to political or legislative constraints on emissions
- Impacts on the natural resources of the Valley, i.e., forests, water, and agriculture.

Despite the scientific uncertainties, TVA has already agreed, along with some 60 other utilities, to participate in the Department of Energy's Climate Challenge initiative and to voluntarily reduce equivalent TVA carbon dioxide emissions by the year 2000.

Aside from its present activities which seek to reduce equivalent carbon dioxide emissions, TVA is also evaluating how different energy resource options affect greenhouse gas emissions. For example, coal-based technologies emit over 200 pounds of carbon dioxide per million Btu of heat input. Nuclear, wind, solar, and hydroelectric power production essentially emit no carbon dioxide. Biomass fuel options that include burning of wood or herbaceous crops that recycle carbon stored in the vegetation after converting carbon dioxide from the atmosphere have less carbon dioxide emissions than coal-fired options. There may actually be a reduction of carbon dioxide since the root systems of these crops act to store carbon in the soil even after the crop has been harvested for fuel.

The carbon dioxide emissions level is one of the measures used to differentiate among TVA's energy strategies.

Cooperative Research and Assessment Programs

This document summarizes current scientific understanding. Uncertainties in current scientific understanding limit our ability to assess:

- The specific contribution of TVA emissions to regional pollutant loadings
- The relationships between pollutant levels and impacts to human health and the environment
- The expected benefits of specific emission reductions.

TVA is cooperating with several regional air pollution research and assessment programs to improve the scientific

understanding and to design regulatory policy that will be successful in the Tennessee Valley to mitigate present and prevent future impacts. Results of these regional programs will be available between 1995 and 1997. The programs are discussed below.

The Southern Appalachian Mountain Initiative (SAMI) and the Southern Appalachian Assessment (SAA) are two regional assessments being conducted under the public review process to evaluate air pollutant impacts in southern Appalachia. TVA is actively participating in both studies. The assessments summarize existing information on visibility impairment, acid deposition, and ozone impacts in southern Appalachia. The Southern Appalachian Mountain Initiative work is ongoing and may provide information that can be used by TVA. A final report for the Southern Appalachian Assessment is expected early in 1996. TVA's analysis may contribute to the assessments being developed by these groups and to their public information and policy decision-making process.

The Southern Appalachian Assessment considers both ecological and socioeconomic focuses. It is led by seven federal agencies in the southern Appalachian region. The Atmospheric Team of the Southern Appalachian Assessment will report by fall 1995 on visibility impairment, acid deposition, and ozone in southern Appalachia.

The Southern Appalachian Mountain Initiative focuses on policy development and regulatory recommendations for air emissions management. It includes state and federal regulatory agencies, federal land managers, industry, academia, and public interest groups. The Southern Appalachian Mountain Initiative is evaluating emissions management options to mitigate existing or prevent future air quality impacts in Class I areas of southern Appalachia. Existing information on air quality impacts will be evaluated and delivered by the Southern Appalachian Mountain Initiative's Technical Oversight Committee in fall 1995. In its technical assessment of emissions management options, the Southern Appalachian Mountain Initiative's Integrated Assessment Committee is designing a framework to integrate current understanding of relationships among emissions, exposures, and impacts. The technical assessment and recommendations on emissions management options are anticipated to be complete by 1997.

The Southern Oxidants Study is a research partnership between the pubic and private sector to better understand the processes and sources that contribute to regional ozone formation. Several federal agencies, state and local regulatory agencies, industries, and universities are participating in the partnership to study rural ozone exposures and source contributions to urban nonattainment areas in the southeastern United States. In the summer of 1995, the Southern Oxidants Study conducted an extensive field study of rural and urban influences on ozone formation in the Nashville area. TVA is leading the design and implementation of this multi-organizational field study. Results from this field study will allow better understanding of the total biogenic (natural) and human-produced sources contributing to regional ozone formation and the specific contributions of TVA nitrogen oxides emissions to ambient ozone exposures. The North American Research Strategy on Tropospheric Ozone is a national effort to understand why emission control strategies over the past two decades have not been effective in reducing ozone exposures. The Southern Oxidants Study is one component of the larger national program. Results of these studies were not available in time to be evaluated in TVA's analysis of environmental consequences of its future energy supply alternatives.

The Electric Power Research Institute is evaluating risks to human health and the environment due to ozone, fine-particulate, and hazardous air pollutant impacts. The Institute delivers results of its research and risk assessments to the Environmental Protection Agency and regulatory authorities to be considered in developing future emissions regulatory policies. TVA is cooperating with the Electric Power Research Institute, the National Park Service, and several southern utilities to measure visibility and particulate species (i.e. sulfates, nitrates, soil, primary particles, etc.) in the Great Smoky Mountains National Park during summer 1995. Results will not be available in time to be evaluated in TVA's final analysis of environmental consequences of TVA future energy strategies. TVA is also cooperating with the Electric Power Research Institute and the Department of Energy to characterize utility emissions of hazardous air pollutants, the efficiencies of different emissions control strategies, and mercury transport and deposition. The Institute's Air Toxic Risk Assessment will contribute to the Environmental Protection Agency's analysis of utility emissions of mercury and other hazardous air pollutants.

Present Impacts

HEALTH

Introduction

Potential impacts to human health are illustrated in *Figure T1-61*. There are potentially numerous health impacts from environmental air pollutants. Impacts range from temporary eye and lung irritation and headaches to progressive damage to the respiratory, cardiovascular, nervous, and immune systems. United States environmental and health policies are written to protect the general public from the unacceptable risk of adverse effects.

The National Ambient Air Quality Standards for criteria pollutants and the National Emission Standards for Hazardous Air Pollutants are set at levels for ambient outdoor exposure that are intended to protect the public health. These standards are periodically reviewed and revised. Evidence of impacts upon sensitive individuals at ambient levels of ozone and fine particulate matter is being reviewed in 1995 by the Environmental Protection Agency in a draft criteria document.

Health impacts can also occur from air pollutant exposures in indoor environments. Currently, indoor air quality is not regulated by national standards, but several of the same pollutants that occur in the ambient outdoor environment also occur indoors. The Environmental Protection Agency has developed guidelines for levels of other indoor pollutants such as radon.

Risk-Exposure Relationships

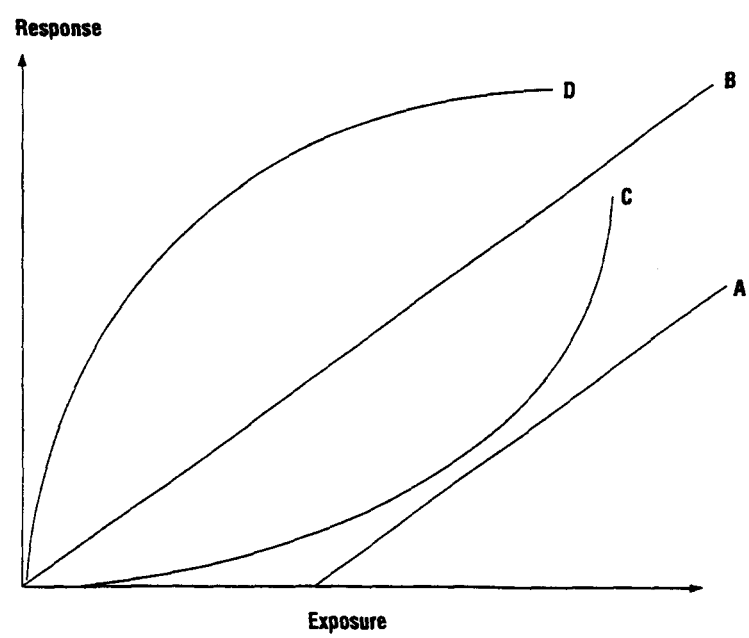
The health risk from exposure to pollutants requires an understanding of the level and duration of exposure. Adverse health effects can come from exposures to high levels for short periods of time and/or prolonged exposures to low levels. The graph in *Figure T1-49* shows examples of theoretical exposure-response relationships. Line A shows a linear relationship with a threshold. For line A, there is no risk for exposures below the threshold. Line B shows a linear relationship without a threshold. For line B, there is some risk at all levels of exposure. Lines C and D are examples of nonlinear relationships. The shape and slope of the exposure-response relationship have substantial implications for assessing the risks from air pollutants and for defining levels sufficient to protect human health. Evaluation of available data has not yielded definitive answers as to which of these curves best fit criteria air pollutants. As a result, the decisions regarding appropriate levels for air quality standards are based in large part on most plausible evaluations and policy goals (Samet et al. 1991). As health effects are better quantified, this evidence is used in reviews and revisions of the National Ambient Air Quality Standards and National Emission Standards for Hazardous Air Pollutants.

Sulfur Dioxide

Depending on concentration, exposure to sulfur dioxide can irritate the eyes, cause respiratory distress, and possibly permanently damage lung tissue. (Durenberger 1991) Under the current ambient standard for the 24-hour average sulfur dioxide concentration, only one group of people might suffer a direct health effect of gaseous sulfur dioxide: People with active asthma who are unmedicated and exercising out of doors might experience an aggravation of asthma symptoms. This occurs infrequently and only in locations near major sulfur dioxide sources (Graham 1990). At locations near major sulfur dioxide sources, short-term sulfur dioxide exposures may be elevated and still meet the 24-hour average standard. These short-term elevated sulfur dioxide exposures may aggravate asthmatics. The Environmental Protection Agency is considering whether a new five-minute sulfur dioxide standard should be set to address this impairment. However, available research indicates that any resulting aggravation is reversible, short-term, and can be avoided with moderation.

Sulfate aerosols that are formed as sulfur dioxide disperses and reacts in the atmosphere also raise concern for human health. The health effects from sulfate aerosols are included in the section that discusses fine-particulate matter. Some epidemiology studies show an association between 24-hour sulfur dioxide concentrations and respiratory illness that may be independent

FIGURE T1-49. **Four Theoretical Exposure-Response Relationships for Health Risks**



Line A = Linear Relationship With a Threshold
Line B = Linear Relationship Without a Threshold
Line C = Non-linear Relationship
Line D = Non-linear Relationships

of particulate concentrations. However, there is uncertainty about whether this is due to sulfur dioxide or the result of another factor correlated with sulfur dioxide (Graham 1990).

Nitrogen Oxides

Depending on its concentration, nitrogen oxides can irritate the eyes, damage the lungs, and lower resistance to respiratory illness and influenza. In its 1994 review of the ambient air quality standard for nitrogen dioxide, the Environmental Protection Agency concluded that the current standard is adequate to protect human health and welfare. The Environmental Protection Agency's annual average standard for nitrogen dioxide is 0.053 parts per million concentration. Current ambient levels of nitrogen dioxide in the Valley are 0.011 parts per million. Evidence from clinical studies suggests that short-term exposures to nitrogen dioxide in the 0.2 to 0.5 parts per million range may cause adverse symptoms for asthmatics. Evidence also suggests that nitrogen oxides from indoor sources such as gas-fired appliances may be associated with greater frequency of respiratory illness in children. This is consistent with some laboratory evidence of reduced resistance to illness. It is difficult at this time to extrapolate health effects from the indoor studies to outdoor levels of nitrogen oxides because the pattern of exposure is quite different. It is uncertain, for example, whether long-term cumulative exposures or peak-level exposures are most important. Some epidemiology studies using measures of outdoor nitrogen oxides have found an association between nitrogen oxides concentrations and acute illness. Other researchers have found no significant relationship (Environmental Protection Agency 1991).

Nitrogen oxides contribute to the formation of two pollutants that are a concern with respect to human health: nitrate aerosols and ozone. Nitrate aerosols are a component of fine-particulate matter and are discussed in that section. Ozone is discussed in the next section.

Ozone

Ozone exposure can cause respiratory tract problems such as difficulty breathing, reduced lung function, asthma, eye irritation, nasal congestion, reduced resistance to infection, and possibly premature aging of lung tissue. (Environmental Protection Agency 1995a.) Ozone levels present in the Tennessee Valley rarely exceed the 1 hour standard of 0.12 parts per million. Epidemiology studies have shown that health effects associated with ozone exposure for the general population include respiratory symptoms, such as acute cough, and minor, restricted activity days. Recent studies in Los Angeles and New York have found small but statistically significant evidence of risk of premature death associated with peak 1-hour ozone exposure at concentrations above 0.20 parts per million (Kinney and Ozkagmak 1990). A study in St. Louis, Missouri, and in Kingston-Harriman, Tennessee, found no increased risk of death at ozone exposure concentrations up to 0.15 parts per million. Extensive evidence exists relating to short term respiratory responses to controlled exposures to ozone in clinical studies. Ozone is also suspected in causing greater susceptibility to chronic respiratory illness, but there is not currently sufficient evidence available to quantify the risk (Krupnik and Kurland 1988; Lippman 1989; U.S. Environmental Protection Agency 1988).

Uncertainty is also associated with the threshold for human health impacts related to ozone. Some evidence indicates effects for certain individuals at levels below the current 1-hour National Ambient Air Quality Standard of 0.12 parts per million. Symptoms have not been observed below 1-hour averages of 0.06 to 0.10 parts per million (Krupnik and Kurland 1988).

Particulate Matter Smaller than 10 Microns

Recent epidemiological studies demonstrate links between particle exposure and respiratory disease in those over age 65 (Fisher et al. 1989). The Environmental Protection Agency standard for particles with diameters of 10 microns or less (PM10), is a concentration of 150 micrograms per cubic meter for 24 hours and 50 micrograms per cubic meter for an annual average. In studies conducted between 1972 and 1980, the Environmental Protection Agency correlated increased death rates with concentrations of PM10 of 100 micrograms per cubic meter. The Agency has also correlated an increase in hospitalizations for respiratory symptoms among people with chronic lung disease with concentrations at this level (Marwick 1991). Some investigators believe the threshold for health effects from particulate matter may be a concentration of 30 micrograms per cubic meter (ORNL 1994).

Some studies have attempted to determine whether the association between particle exposure and respiratory disease is due to sulfates and nitrates associated with fine particles (particles with diameters of 2.5 micron or less), but results have been inconclusive. These smaller particles remain airborne over longer times and distances. It is difficult to separate the potential impacts of sulfate versus acid aerosols because their day-to-day levels tend to be highly correlated. It appears that the association is strongest among the over-65 age group. Those who already suffer from chronic respiratory illness may be at greatest risk (Fisher et al. 1989).

Some studies associate chronic cough and bronchitis symptoms with the level of acidity of aerosols, rather than with sulfate levels or total concentrations of particles. Controlled studies have established a strong relationship between the bronchitis effects on asthmatics and the presence of sulfur dioxide and acidic aerosols at concentrations approaching the ambient standard for

sulfur dioxide (Samet et al.1991). Even so, the evidence to date is inconclusive as to whether acidic aerosols are any more harmful to human health than nonacidic aerosols of similar size (U.S. Environmental Protection Agency 1989).

Epidemiologic studies are limited by the difficulty of measuring exposure and of singling out the effect of acidic aerosols from other factors, particularly for such non-specific health effects as increased symptoms and reduction of lung function. Controlled exposures of volunteer subjects provide information concerning short-term effects. However, this approach cannot fully represent the exposures sustained in a community (Samet et al. 1991).

On a five-year cycle, the Environmental Protection Agency re-evaluates the science on which the National Ambient Air Quality Standards are based. The goal is to either modify or support the current sulfur dioxide and particulate matter standards. The Environmental Protection Agency is currently considering whether standards for acidic aerosols or fine-particulate matter are warranted.

Carbon Monoxide

Carbon monoxide impairs the ability of blood to carry oxygen. Carbon monoxide also affects the cardiovascular, nervous, and pulmonary systems. Carbon monoxide attacks the immune system, especially affecting anyone with heart disease, anemia, and emphysema and other lung diseases. Even at low concentrations, carbon monoxide can affect mental function, vision, and alertness.

Ambient levels of carbon monoxide in the Tennessee Valley are below the level of the National Ambient Air Quality Standards. The Environmental Protection Agency's limit for carbon monoxide is 9 parts per million. At this level, carbon monoxide binds 3 percent of the hemoglobin so that it cannot carry oxygen to body cells and tissues. Toll-booth workers exposed to a 10.8 parts per million level of carbon monoxide had a higher death rate due to heart disease than did toll-booth workers exposed to 6.2 parts per million. There is some question whether a threshold level exists for exposure to carbon monoxide (Marwick 1994). TVA emits less than 1 percent of the regional carbon monoxide emissions.

Air Toxics or Hazardous Air Pollutants

Depending on concentration and duration of exposure, hazardous or toxic air pollutants can increase the risk of cancer. The Environmental Protection Agency has listed 189 chemicals as air toxics. From this list, the air toxics of greatest concern related to coal-fired power plants are arsenic, beryllium, cadmium, chromium, copper, and mercury. Compounds of these toxics are released during combustion of fossil fuels and are ultimately deposited on land and water.

As evidenced in the data outlined in *Figures T1-45* and *T1-46*, the risks to human health appear to be extremely low from air inhalation or water ingestion of arsenic, beryllium, cadmium, chromium, copper, and mercury. Water concentrations of these metals as measured in and around Fort Loudoun, near Knoxville, Tennessee, are compared in *Figure T1-47* with standards set by the U.S. Environmental Protection Agency, the World Health Organization, and other agencies (Joslin 1994). In general, concentrations of these metals would have to increase by at least fiftyfold before established thresholds would be reached. Risk from chromium exposures in the Valley is difficult to evaluate because monitoring data are available only for total levels of chromium while only the hexavalent form of chromium is carcinogenic. Cadmium levels in human diets are considerably below health advisory levels, but levels in human diets have increased (Joslin 1994).

The risk to human health from mercury in the Tennessee Valley is low if one assumes an individual's diet is based on mercury concentrations in local fish and drinking water. High levels of mercury have been reported in fish in Canada, the northern United States, Scandinavia, and Florida. Recent surveys of the Tennessee River system found only one location where mercury in fish was elevated. That location is on the North Fork of the Holston River immediately downstream from Saltville, Virginia. The mercury level, which does not exceed the Environmental Protection Agency guidelines, is from an inactive industrial site unrelated to atmospheric deposition.

Acid Deposition

In addition to those health impacts associated with emissions of sulfur dioxide, nitrogen oxides, acidic aerosols, and fine-particulate matter that have already been discussed, acid deposition can indirectly affect health. Acidic species deposited to surface waters can mobilize metals in the environment. Mercury accumulation in the environment and biological food chains could be increased by acidic deposition under site-specific conditions. These include drinking water systems that use surface ponds or shallow wells and populations that obtain essentially all of their protein in the form of freshwater fish from acidified lakes. Even under these conditions, increased health risk due to increased mercury exposures is low (NAPAP 1991).

Indoor Air Quality

Indoor air quality also raises concern for human health. Exposure to air pollution is determined by the pollutant concentrations and the time that individuals experience those levels. Since Americans spend the majority of their time indoors,

exposures to indoor air pollutant can be a significant component of total personal exposure. Depending on the presence of indoor sources and building ventilation, indoor air pollutant levels can be much higher than outdoor levels. Air pollution advisories, issued when outdoor pollution levels become unhealthy, recommend that sensitive individuals restrict physical activity and time spent outdoors.

There are many kinds and sources of indoor air pollution:

- Combustion gases such as carbon monoxide, carbon dioxide, and nitrogen oxides from indoor combustion sources including wood heaters, unvented kerosene and natural gas space heaters, and other natural gas-fired appliances
- Small particles from smoking, fireplaces, wood heaters, and cooking
- Volatile organic compounds from insecticides, cleaning solvents, stored fuels, paint, vinyl, plastics, adhesives, and furniture and carpet stain repellents
- Biological contaminants such as allergens from pets, insects, and plants; molds and fungi from damp surfaces; and viruses and microorganisms from people and pets
- Radioactive gas (radon) from the earth beneath a structure.

Health complaints associated with poor indoor air quality are varied. They include dizziness, headache, nausea, irritation of the eyes and airways, impaired learning ability, allergies, sleepiness, rashes, abdominal and chest pains, respiratory illness, and cancer. Impacts discussed previously for sulfur dioxide, nitrogen oxides, carbon monoxide, fine-particulate matter, and hazardous air pollutants also apply if these pollutants are elevated in the indoor environment.

Well-designed and maintained heating, ventilating, and air conditioning systems can provide healthy and energy-efficient living spaces. However, indoor air pollution problems can sometimes be aggravated by weatherization or other energy conservation efforts. Reduced ventilation, the existing burden of indoor pollution, and the increased use of alternative heating sources, such as wood heaters and unvented natural gas or kerosene heaters, can lead to elevated indoor air pollutants. Indoor air pollutant levels can exceed regulatory standards for ambient outside air.

Many simple methods may be used to minimize indoor air pollution exposures:

- Use and maintain all appliances according to manufacturers' specifications and recommendations.
- Read the labels on household products such as cleansers, polishes, drain cleaners, and stove cleaners carefully to ensure proper use. Consider switching to "natural" cleaners and polishes.
- Ventilate kitchens and bathrooms during use to remove cooking smoke and excess moisture.
- Store paints, household cleaning products, and fuels in approved containers in well-ventilated areas.
- Avoid smoking indoors.
- In areas with elevated soil radon levels, consider testing to determine levels within the home or office.

Energy Vision 2020 strategies that promote increased conservation and weatherization methods could increase indoor air pollution exposures. It is assumed for this analysis that TVA will continue to provide guidance to minimize indoor pollutant concentrations. Consequently, indoor air quality impacts are not a measure used to differentiate among future TVA strategies.

VISIBILITY IMPAIRMENT

Visibility impairment is of special importance under the Prevention of Significant Deterioration provisions of the 1977 Clean Air Act Amendments. Impacts are discussed in the "Visibility Impairment" section under "Air Quality Concerns Since the 1977 Clean Air Act Amendments" earlier in this section.

CROPS AND FORESTS

Summary

Impacts of gaseous pollutants, including sulfur dioxide, nitrogen oxides, and ozone on crops and forests, have been described in scientific studies and reviewed in numerous reports. The 1990 National Acid Precipitation Assessment Report and the Environmental Protection Agency's Ozone Criteria Document serve as the primary references because they have undergone formal public review. Impacts from primary pollutant emissions (sulfur dioxide, nitrogen oxides, particulate matter) rarely occur at current ambient levels. Historically, acute impacts from gaseous pollutants are most dramatically illustrated by the deforestation and destruction of aquatic and terrestrial ecosystems in the Copper Hill, Tennessee, basin due to emissions from a chemical company. Prior to 1980, incidents of agricultural crop damage have been documented that occurred when TVA coal-fired power plant plumes were intercepted at ground-level (Jones et al. 1988). There was no opportunity for atmospheric mixing to dilute emissions below levels toxic to crops. Impacts of TVA emissions, particularly sulfur dioxide, to crops in the immediate vicinity of TVA power plants were well documented (Jones et al. 1988). Since 1976, TVA sulfur dioxide emissions have been reduced by two-thirds, as shown in the graph in *Figure T1-22*. Direct impacts of sulfur dioxide to crops and forests rarely occur now.

At current ambient exposures, sulfate and nitrate anions in acid deposition and ozone are the pollutants most likely to cause impacts. Such impacts can be cumulative over long-term chronic

(lower level) exposures. Episodes of high ozone exposures can injure foliage of both crops and forest species. Depending on extent and severity, exposure can lead to cumulative impacts to productivity. Impacts from short-term elevated loadings of sulfate and nitrate anions are infrequent but could potentially occur in the undisturbed forests if acid anions in soil solutions mobilized aluminum from soils at levels toxic to plant roots. Forests susceptible to aluminum toxicity are most likely to be in higher elevations of southern Appalachia (Joslin et al. 1992).

Sulfur Dioxide

The effect of sulfur dioxide on crops and other vegetation varies by species and by length and frequency of exposure (Environmental Protection Agency 1982; Shriner et al. 1990). Acute exposures and their associated visual symptoms were once frequently observed in the TVA region. They are very rarely observed today. The current National Ambient Air Quality Standards secondary standard is adequate to protect vegetation from significant negative impacts, based on the literature summarized in the sulfur dioxide criteria document (Environmental Protection Agency 1982) and in the subsequent National Acid Precipitation Assessment Program analysis (Shriner et al. 1990). There may also be a positive contribution of sulfur emissions to the sulfur requirements of agricultural crops (Noggle 1980). Concentrations of sulfur dioxide in most rural areas in the Valley are currently well below the standard and may drop further as the full effects of the 1990 Clean Air Act Amendments are felt.

Nitrogen Oxides

Nitrogen oxides refers to a family of atmospheric pollutants consisting of nitrogen oxide, nitrous oxide, nitrogen dioxide, nitric acid vapor, and various forms of nitrates (Shriner et al. 1990). In contrast to sulfur, which has decreased during the past two decades, the family of nitrogen oxides has increased. The most common phytotoxic (poisonous to plants) form of nitrogen is nitrogen dioxide, followed by the less frequent nitric acid vapor (Shriner et al. 1990). Within the Valley region, the potential impacts of nitrogen dioxide are minimal, since its plant-poisoning threshold concentration of 0.5 parts per million is well above current ambient levels. Nitrogen oxides in the atmosphere are currently a greater concern because they can contribute to acidic deposition impacts or can be utilized in the formation of ozone. The lack of nitrogen frequently limits plant growth in both cultivated and native vegetation. Therefore, nitrogen oxides deposition in many forms has the potential to increase plant growth. This contribution is probably of much greater importance in natural systems than in managed ones where fertilizer additions greatly outweigh other nitrogen sources.

Acidic Deposition—Crops

Impacts on crops attributable to acidic deposition were studied extensively during the last decade. Shriner et al. (1990) summarized the results of most of that work. They concluded that acidic deposition does not cause a reduction in crop yields. Potential reductions in fertility or increases in acidity can be offset by normal management practices. As discussed, the deposition of sulfur and nitrogen associated with acidic deposition in agricultural settings can be a potential benefit to most crop species. Atmospheric sulfur inputs ean satisfy much of the crop sulfur need, while nitrogen input is a very small portion of total crop requirements.

Acidic Deposition—Forests

The National Acid Precipitation Assessment Program conducted extensive research to determine the possible impacts of acidic deposition on forests in North America. The results of this research are summarized in the State of the Science Reports, SOS/T-16 (Barnard and Lucier 1990) and SOS/T-18 (Shriner et al. 1990), and in the 1990 National Acid Precipitation Assessment Program Integrated Assessment Report (NAPAP 1991). These studies concluded that, in general, the vast majority of forests in eastern North America are not in decline, either from pollution or other sources. However, atmospheric deposition may be implicated in the premature mortality of high elevation red spruce *(Picea ruben sug.)* in the Northeast.

Evidence of red spruce decline and pollution involvement in the southern Appalachians is less substantial. The red spruce-Fraser fir ecosystem occupies approximately 103 square miles (268 square kilometers) in the southern Appalachian mountains of southwestern Virginia, eastern Tennessee, and western North Carolina. The trees are generally confined to mountain peaks above 5,000 feet (1,525 meters) elevation, as shown in the map in *Figure T1-50*. National Acid Precipitation Assessment Program studies in the southern Appalachians have documented extensive mortality of Fraser fir and decreases in crown vigor and annual growth in red spruce. Fraser fir mortality, frequently pictured in popular publications, is the direct result of an insect, the balsam woolly adelgid.

Although it has been suggested that air pollution may have rendered fir more susceptible to the adelgid, supporting evidence is incomplete. In mixed stands with dying fir, spruce decline can be partially explained by increases in wind damage and soil temperatures (Nicholas et al. 1992). Symptoms of decline in spruce-dominated stands, at elevations with a high frequency of cloud interception, have led scientists to consider impacts of atmospheric deposition. Acid deposition components of sulfate, nitrate, and hydrogen ions at high elevations greatly exceed those at lower elevations. This is primarily due to the increased vol-

ume of precipitation and high ion concentrations in cloud water. Exposure to ambient cloud water with concentrated sulfate and nitrate anions (negatively charged ions) has also been shown to accelerate foliar leaching of essential cations (positively charged ions). In field studies, decreases in foliar calcium and magnesium have corresponded to decreases in foliar biomass. Field surveys and fertilization studies indicate that red spruce in the southern Appalachians are experiencing calcium and zinc deficiencies, while those in the Northeast are generally not.

National Acid Precipitation Assessment Program research, (Barnard and Lucier 1990, Shriner et al. 1990) as well as ongoing studies, (Nodvin et al. In Press) have demonstrated that the high elevation forests appear to be nitrogen-saturated. Nitrogen inputs from rain, snow, and cloud water combined with inputs from natural biological process exceed the capacity of soils and vegetation to immobilize nitrogen. The leaching of excess nitrogen depletes essential base cations from the soil and acidifies soil water. In addition, there is evidence that aluminum is being mobilized into soil water at levels that interfere with plant uptake of calcium, magnesium, and zinc. Soils in the southern Appalachians generally have a large capacity to absorb sulfate, but current sulfate loading rates will likely exceed soil sulfate absorption capacity within a few decades (Johnson and Lindberg 1992).

Exposure to ambient cloud water can reduce the cold tolerance of red spruce. Increases in winter damage to red spruce in the Northeast have contributed to crown damage and increased mortality in that region. This impact occurs infrequently in the southern Appalachians, where temperatures seldom approach the cold tolerance limits for red spruce.

National Acid Precipitation Assessment Program studies did not find a regional decline of southern pines (Barnard and Lucier 1990, Shriner et al. 1990). The U.S.D.A. Forest Service had reported widespread reductions in average tree growth rates in natural pine stands in the Southeast. Similar growth rate reductions have not been observed in tree plantations. Reduction in tree growth in natural pine stands is an anticipated consequence of historical land use patterns, increases in stand longevity and competition, and other natural factors. Available information is not adequate to determine whether the magnitude of reported growth reductions is greater or less than would be expected in the absence of acidic deposition and associated pollutants. The magnitude, extent, and timing of soil chemical changes due to acidic deposition and their long-term implications for forest health and productivity are uncertain. Available evidence does not support a hypothesis that acidic deposition has caused aluminum toxicity or nutrient deficiencies in southern pines.

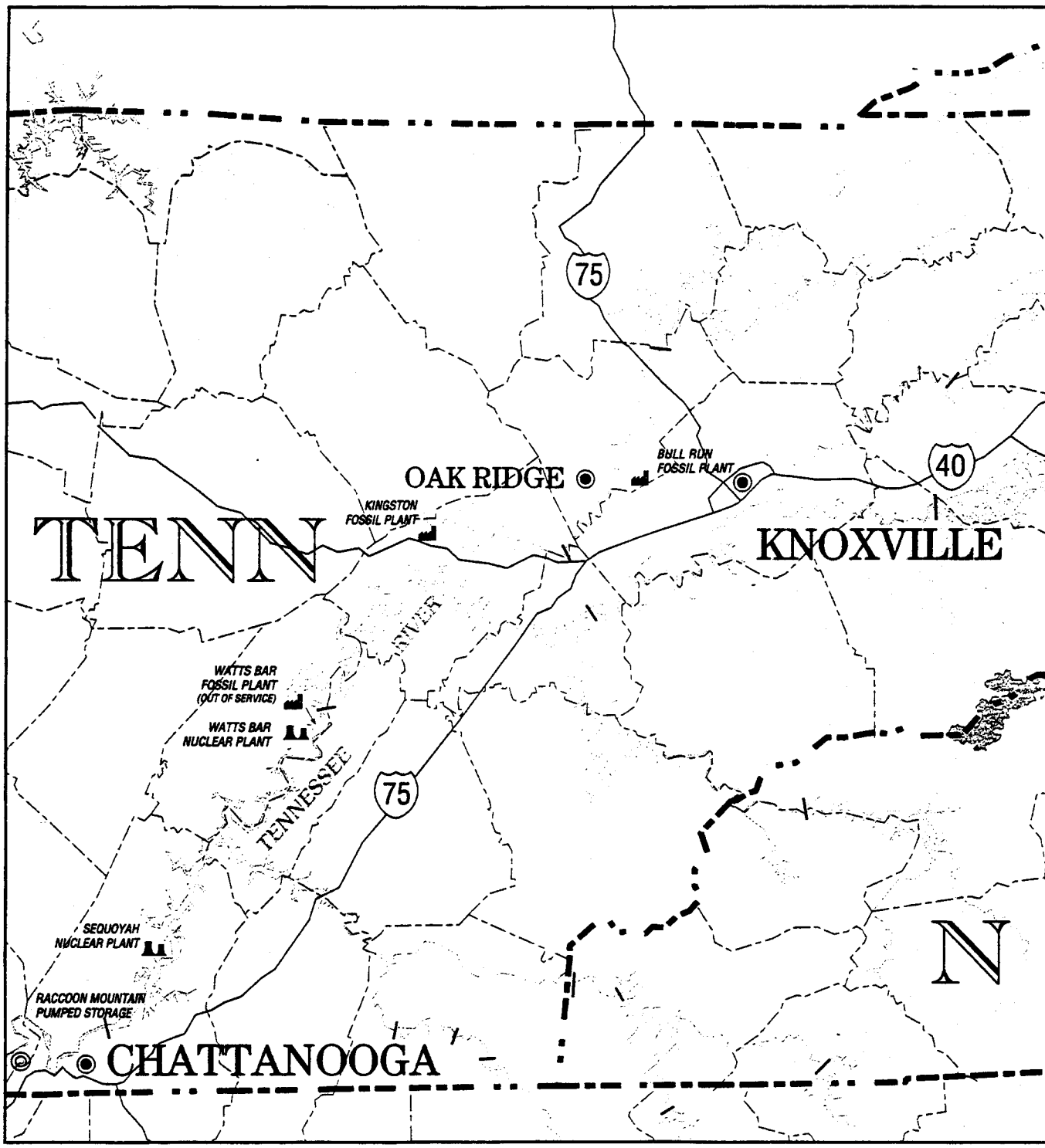
With the possible exception of the spruce-fir forests of southern Appalachia, most Valley forests are receiving acid rain at doses that have not had a serious impact on forest health and productivity. However, the cumulative effects of sulfate and nitrate deposition over several decades could be adverse for some soils. Sulfate and nitrogen oxides deposition increases leaching of nutrient cations from some forest soils and over the long term may reduce the fertility of soils with low buffering capacity or low mineral weathering rate. Nitrogen saturation, a concept currently under discussion in the regulatory arena, could be a long-term impact if nitrogen deposition continues at current rates. Nitrogen saturation is unlikely to occur in Valley forests outside of the high elevation spruce-fir forests or unmanaged old growth wilderness areas.

Impacts to forest soils and nutrient cycling are generally considered to be reversible. Decreases in sulfate deposition would ultimately result in decreases in cation leaching once a new soil equilibrium was established. Decreases in nitrate deposition would probably lead to equivalent decreases in cation leaching in high elevation forests thought to be at or near nitrogen saturation. The Nutrient Cycling Model (Liu et al. 1991) is one method to evaluate the potential benefits to forests that could result from reductions in sulfate and nitrate deposition.

The Nutrient Cycling Model accounts for the exchange of essential nutrients from deposition, vegetation, the forest floor, soils, and soil solutions. The model was applied to project nutrient cycling over a 30-year period in a spruce-fir forest at Noland Divide in the Great Smoky Mountains National Park. Levels of sulfate and nitrate in deposition were varied to simulate alternative reductions in sulfur dioxide and nitrogen dioxide emissions. The initial and no change projections reflect deposition levels monitored at Noland divide for the period 1985 to 1988. Reductions in sulfate and nitrate deposition of 20, 30, 40, or 50 percent compared to the 1980s were projected to represent probable benefits achieved from implementation of the 1990 Clean Air Act Amendments or future emissions reductions.

Calcium is an essential plant nutrient that is susceptible to leaching by acid deposition. Aluminum in soil solutions may be toxic to plant roots and may interfere with plant uptake of calcium. The effects of alternative deposition levels on the distribution of calcium in vegetation, forest floor, and soils and on aluminum and calcium in soil solutions are illustrated in *Figures T1-51* and *T1-52*, respectively (Dale Johnson unpublished data). Calcium is not deficient in this spruce-fir stand, and the model projected very small differences after 30 years in calcium in vegetation and the forest floor as a function of deposition levels. Calcium in the exchangeable soil pool is projected to be greater at lower levels of sulfate and nitrate deposition. Calcium and aluminum in soil solutions (an indication of nutrients lost from the ecosystem) are projected to be lower at lower levels of sulfate

FIGURE T1-50 **The Energy Vision 2020 Study Area Includes the Southern Appalachian Spruce-Fir, a Threatened Ecosystem**



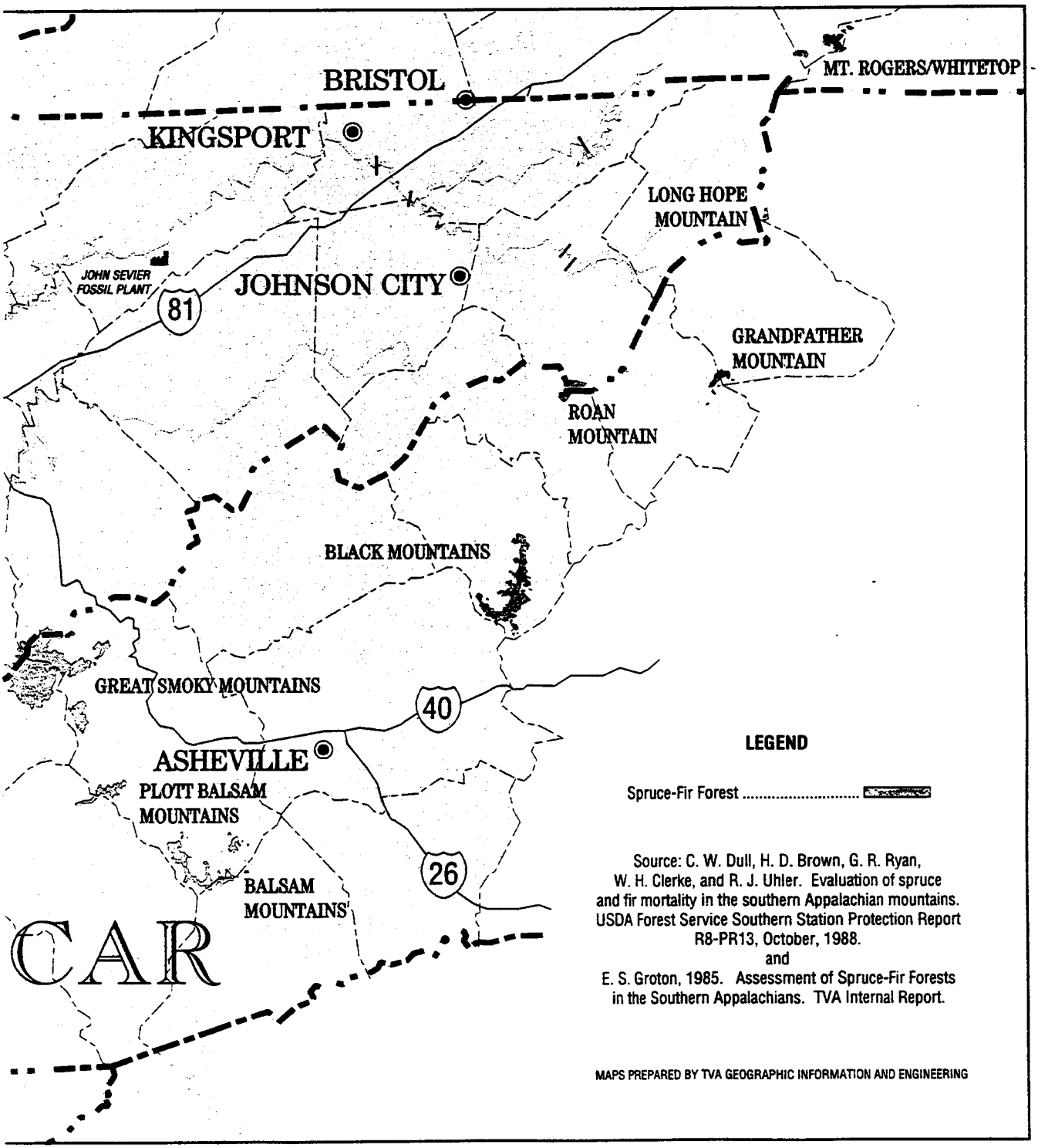
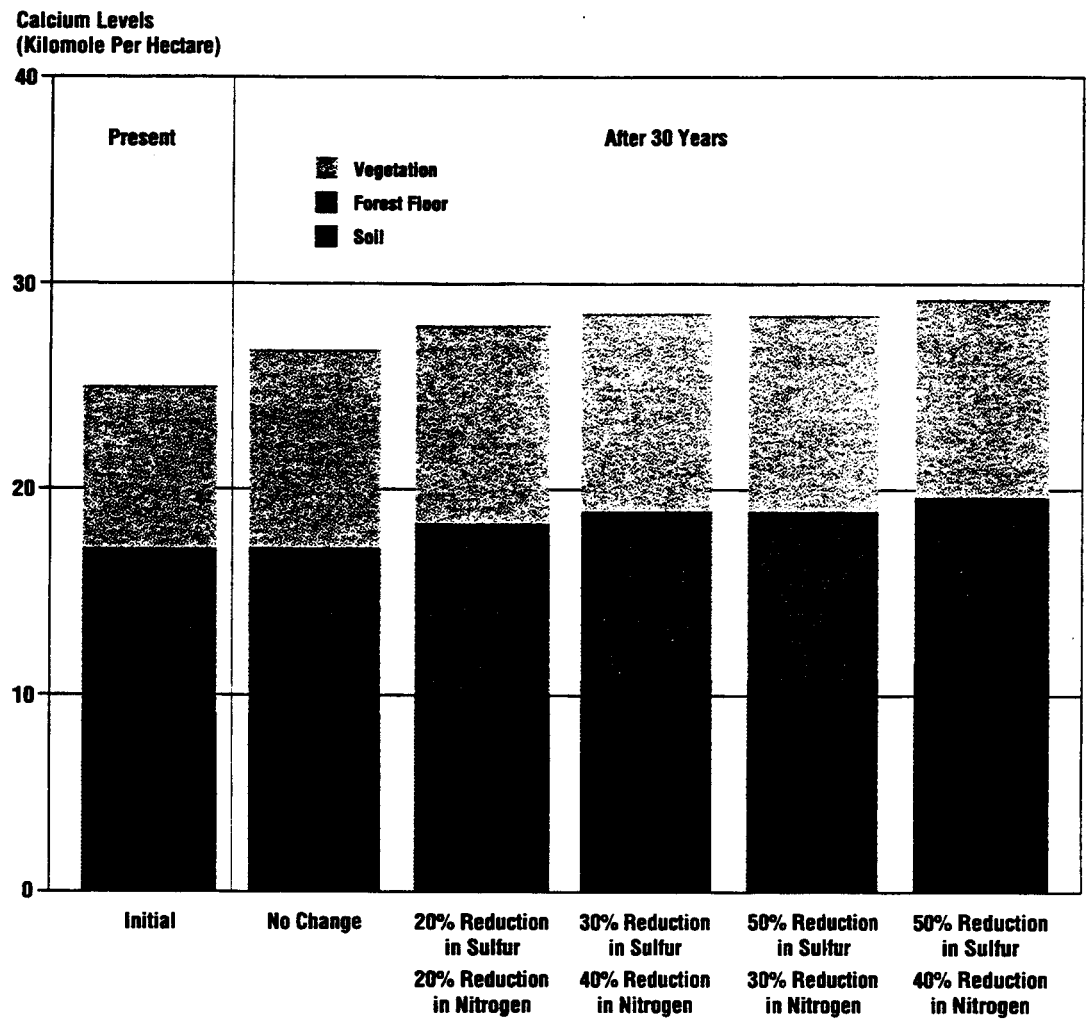

BRISTOL
KINGSPORT
MT. ROGERS/WHITETOP
LONG HOPE MOUNTAIN
JOHN SEVIER FOSSIL PLANT
JOHNSON CITY
81
GRANDFATHER MOUNTAIN
ROAN MOUNTAIN
BLACK MOUNTAINS
GREAT SMOKY MOUNTAINS
40
ASHEVILLE
PLOTT BALSAM MOUNTAINS
26
BALSAM MOUNTAINS
CAR
LEGEND
Spruce-Fir Forest
Source: C. W. Dull, H. D. Brown, G. R. Ryan, W. H. Clerke, and R. J. Uhler. Evaluation of spruce and fir mortality in the southern Appalachian mountains. USDA Forest Service Southern Station Protection Report R8-PR13, October, 1988.
and
E. S. Groton, 1985. Assessment of Spruce-Fir Forests in the Southern Appalachians. TVA Internal Report.
MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

FIGURE T1-51. **Changes in Calcium Levels in Vegetation, Forest Floor, and Soil Exchangeable Pools in a Spruce-Fir Forest at Noland Divide in the Great Smoky Mountains National Park Based on a 30-Year Simulation Using the Nutrient Cycling Model**



and nitrate. The greatest improvements are projected for the case representing implementation of the 1990 Clean Air Act Amendments compared to the no change (pre-1990 Clean Air Act Amendments) conditions. *Figure T1-52* illustrates that the ratio of aluminum to calcium would improve with reduced deposition levels, particularly during periods of high runoff.

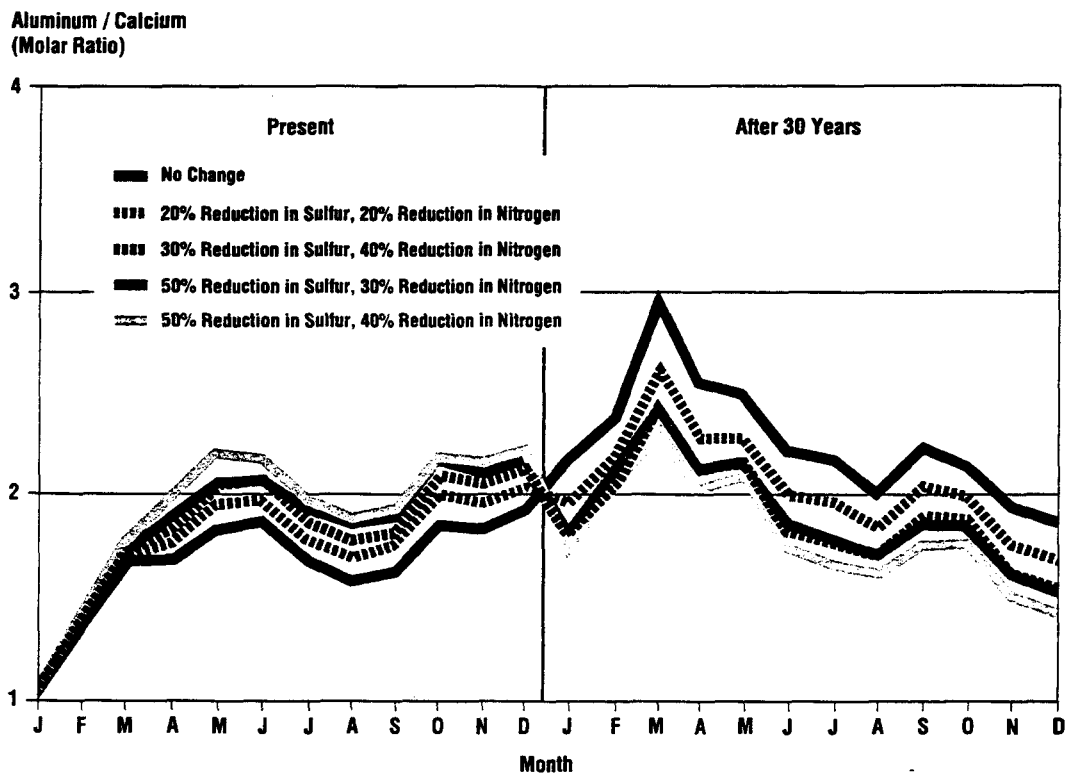
This model application illustrates a potential method to evaluate forest response to reduce deposition levels. Assessments under the Southern appalachian Mountain Initiative will further address methods to evaluate benefits of emissions reductions.

Ozone—Crops

Impacts of ozone are a function of concentration and duration of exposure (external to plants) and plant uptake (internal dose). Ozone is currently the most pervasive air pollutant in rural areas and the pollutant most likely to impact agricultural crops negatively. Impacts to crop productivity, physiology, reproduction, and economic yields have been well documented (Environmental Protection Agency 1995).

Ozone enters plants through the leaf stomates and may disrupt cellular function. High short-term exposures can injure or lead to death of cells in the vicinity of the stomates. The degree of impact increases with the ozone dose received. Visible dis-

FIGURE T1-52. **Changes in Aluminum to Calcium Soil Solution Molar Ratio in a Spruce-Fir Forest at Noland Divide in the Great Smoky Mountains National Park Based on a 30-year Simulation Using the Nutrient Cycling Model**



coloration of foliage may be a result of high short-term exposure to ozone or of the cumulative longer term ozone dose received over the growing season. At frequent, low-level exposures, ozone may inhibit photosynthetic function and reduce plant carbon reserves. Under ozone stress, a greater portion of the carbon fixed through photosynthesis must be used to repair injury to cells rather than contribute to growth. Allocation of carbon from leaves and stems to the root system, which stores carbon for future growth, is frequently limited by chronic ozone exposure. Thus, impacts from ozone can accumulate over the duration of exposure, which can last seasons or years.

At current ambient levels of ozone in the eastern United States, average reductions in crop yield are likely on the order of 10 to 15 percent (Environmental Protection Agency 1995). Some crops, such as tobacco, spinach, and grapes, are very sensitive to ozone and could experience greater than 15 percent reductions in annual yields at current ambient levels. Economic analyses (Kopp et al. 1985; Adams et al. 1989) have considered the economic impacts of yield reductions for major commodity crops such as wheat, corn, soybeans, and cotton. Studies summarized by the Environmental Protection Agency (1995) estimated that net economic losses attributable nationally to current levels of ozone are in the range of 1 to 2 billion dollars per year.

The effects of plant exposure to ozone accumulate over the growing season. Exposures above a threshold value cause greater impacts than lower exposures. Consequently, a cumulative index that sums the hours above a threshold is proposed in the Environmental Protection Agency's 1995 draft ozone criteria document. The Environmental Protection Agency suggests that the sum of hours exceeding a concentration of 0.06 parts per million (SUM06) for the maximum 3-month period between April and October should not exceed 26.4 parts per million-hour. This value was derived from the results of the National Crop Loss Assessment Network (Heck et al. 1990) and is intended to protect 50 percent of crops from 10 percent yield reduction.

Response to ozone can be highly modified by the plant's nutrient and water status. Environmental conditions that limit the extent that leaf stomates are open limit the uptake of ozone.

Consequently, ozone impact is less severe for crops exposed to crops under low moisture or fertility conditions compared to crops with the same exposure under high moisture and fertility conditions. The table in *Figure T1-53* summarizes the range in ozone exposure at which 10 percent yield reductions were observed for several common crop species in controlled exposure field studies conducted under the National Crop Loss Assessment Network (Heck et al. 1990). Exposure is expressed as the maximum 3-month sum of hours exceeding 0.06 parts per million (SUM06). Plants in these studies were well-watered and fertilized. Yield reductions in unwatered fields may be less than estimated in these studies. In 1992, the maximum 3-month sum of hours greater than 0.06 parts per million exceeded 26.4 parts per million-hour over large areas of the TVA region *(Figure T1-53)*.

FIGURE T1-53. **Crop Response to Ozone Projected by the National Crop Loss Assessment Network Using Controlled Exposure Field Studies**

Crop Species	Maximum 3-Month Sum of Hours Above a Concentration of 0.06 Parts per Million-Hour to Cause a 10% Yield Loss
Corn (2 cultivars)	42-56
Cotton (4 cultivars)	14-95
Kidney Bean (1 cultivar)	15-19
Lettuce (1 cultivar)	37
Peanut (1 cultivar)	36
Potato (1 cultivar)	10-20
Sorghum (1 cultivar)	68
Soybean (7 cultivars)	8-90
Tobacco (1 cultivar)	26
Turnip (4 cultivars)	6-10
Wheat (4 cultivars)	3-35

Source: Environmental Protection Agency 1995 Draft Ozone Criteria Document

Ozone–Forests

Impacts of ozone to forests and natural systems are less well understood than impacts to crops. The bulk of information on ozone impacts to unmanaged vegetation (mainly forest species) has been summarized recently by Barnard and Lucier (1990), Kiester (1990), Shriner et al. (1990), and Environmental Protection Agency (1995). Based on these summaries and other information, it appears that forests in the eastern United States are not in a general state of decline as a consequence of ozone or any other air pollutant. However, ozone has been implicated as the key air pollutant responsible for decreases in productivity in the mountains of southern California and for foliar injury to several forest tree species in the eastern United States. Based on controlled exposure studies with tree seedlings, the table in *Figure T1-54*, summarized from the 1995 draft ozone criteria document, identifies the ozone exposure at which 10 percent losses in biomass are projected for several tree species.

Ozone sensitivity increases in the following order: high elevation conifers, southern pines, late successional hardwoods such as oak, early successional hardwoods such as tulip poplar, black cherry and ash, lichens, and herbaceous forest species (Chappelka et al. 1993; Thornton et al. 1994; Kelly et al. 1993; Samuelson and Edwards 1993; and Samuelson 1994). Species sensitivity to ambient ozone exposures is greatly influenced by site environmental conditions. Species that occur in communities associated with moist sites are generally more sensitive than those species in communities associated with dry sites. While certain varieties of loblolly pine may be negatively impacted by ozone at current ambient levels, the Environmental Protection Agency (1995) concluded that there was no evidence to indicate a general decline in loblolly pine due to ozone in the region.

The National Park Service has documented foliar injury to several sensitive species based both on field surveys in natural forest stands and on controlled chamber exposure studies. (Neufeld and Renfro 1993; Shaver et al. 1994). In natural stands the extent of foliar injury is less than reported from controlled studies. Black cherry is particularly prone to foliar injury. While foliar injury does not necessarily indicate that plant growth has been reduced, it is an indicator of plant sensitivity. Reductions in photosynthesis and growth were documented in the controlled chamber exposures for several of the species sensitive to foliar injury. Results for black cherry and tulip poplar in *Figure T1-54* are from controlled exposure studies in the Great Smoky Mountains National Park (Neufeld and Renfro 1993). Current ambient levels of ozone in the Valley *(Figure T1-37)* exceed levels at which these species experienced biomass losses in controlled chamber studies. Cumulative ozone exposures in the Great Smoky Mountains can actually be greater than in other parts of the Valley because ozone levels in the mountains do not decline as quickly in the late afternoon and evening hours as generally occurs at lower elevations *(Figure T1-35)*. Thus, greater injury to forest species may be occurring in the Great Smoky Mountains than in other areas of the Valley.

Predictions of ozone impacts on forests are still subject to significant scientific uncertainty. The actual ozone dose (uptake) received by a plant is not always a linear function of the ambient exposure because interactions with moisture and fertility can limit stomatal function and ozone uptake. Ozone uptake and plant response to ozone exposures occurring in late afternoon and evening is not well understood. Also, the great bulk of information on tree response to ozone is based on con-

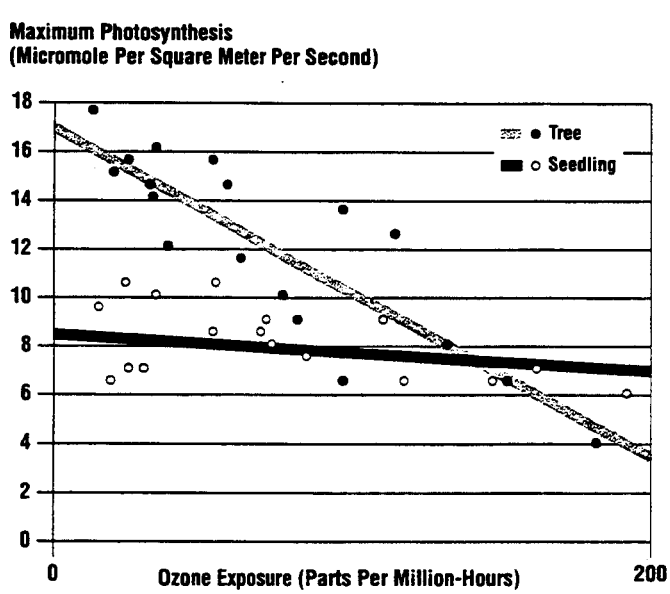
FIGURE T1-54. **Ozone Sensitivity for Several Tree Species Measured as 10 Percent Loss in Seedling Biomass in Controlled Exposure Field Studies**

Tree Species	Maximum 3-Month Sum of Hours Above a Concentration of 0.06 Parts per Million-Hour to Cause 10% Loss in Biomass[1]
Aspen (6 studies)	9-65
Black Cherry (2 studies)	13-17
Tulip Poplar (2 studies)	17-35
Ponderosa Pine (5 studies)	14-65
Red Alder (4 studies)	22-250
Eastern White Pine (1 study)	39-41
Sugar Maple (1 study)	39-105
Red Maple (1 study)	150
Douglas Fir (2 studies)	73-250
Loblolly Pine (1 study)	77-229
Virginia Pine (1 study)	250

[1] Actual ozone exposure in controlled field studies was weighted by duration of exposure to derive maximum 3-month sum of hours greater than 0.06 parts per million-hour. Weighted sum of hours above a concentration of 0.06 parts per million-hour allows sensitivity of tree seedlings to be compared to agricultural crops.

Source: Environmental Protection Agency 1995 Draft Ozone Criteria Document

FIGURE T1-55. **Maximum Photosynthesis of Seedling and Mature Red Oak Under Controlled Ozone Exposures in Chambers in Norris, Tennessee**



trolled exposures of seedlings. Recently completed work has indicated that, at least for northern red oak, mature trees may be more vulnerable to ozone than seedlings (Samuelson and Edwards 1993). *Figure T1-55* indicates that photosynthetical function in mature red oak trees is more sensitive than in seedlings and that ozone impacts increase over that of increased cumulative exposure. Field measures of incremental changes in diameter growth of mature loblolly pines growing on moist and dry sites indicate that ambient levels of ozone may reduce growth of loblolly pine. Site conditions, air temperature, and soil moisture levels were interactive with ambient ozone to affect growth (McLaughlin and Downing, in press).

The Environmental Protection Agency has proposed a new secondary standard that would provide additional protection for crops and forests. This reflects both the possible importance of exposure peaks and the cumulative nature of ozone impacts. The proposed secondary standard suggests a maximum 3-month sum of hours greater than 0.06 parts per million not to exceed 26.4 parts per million-hour. The proposal is based on evidence from agricultural crops, for which there is currently a more complete understanding of plant response to ozone. Because trees are exposed to ozone over several growing seasons, a standard lower than that recommended for annual crops may be necessary to protect sensitive tree species from injury. The next iteration of the ozone criteria document will more fully consider impacts to forests as current studies on mature tree responses provide better scientific evidence to define levels necessary to protect forest species. *(See Figure T1-55.)*

Hazardous Air Pollutants

Terrestrial Impacts

TVA's emissions of hazardous air pollutants primarily involve metals. At current ambient exposures, these metals are not likely to degrade crop and forest productivity. In fact, some vegetation species are very effective at removing metals from the soil and have been used as a biological remediation method to reclaim contaminated sites. The terrestrial ecosystem is a repository for metals deposited from the atmosphere. Soil and vegetation components influence the accumulation or the transport of metals to aquatic ecosystems. Concentrations of metals in tree wood and in lichens have been used as indicators of historical deposition patterns for metals because many of the metals accumulate in vegetation.

Aquatic Impacts

Impacts of metals in aquatic ecosystems are of concern for sensitive invertebrate and vertebrate species. Impacts of regional atmospheric deposition of metals are considered to be minor in

the Tennessee Valley *(Figure T1-47)*. Metals such as mercury or lead are more readily mobilized into soil solutions and transported by acid anions including sulfates, nitrates, and organics. In ecosystems sensitive to acidification, these metals may occur at elevated concentrations. However, the Tennessee Valley watersheds are generally well buffered against acidification, have a high land-to-surface water ratio, and have comparatively lower loadings of dissolved organic carbon than other regions of the country experiencing impacts (Joslin 1994). *Figure T1-48* indicates that levels of mercury in air precipitation, lake water and fish at Fort Loudoun reservoir on the Tennessee River are lower than levels in Wisconsin.

MATERIALS DAMAGE

Sulfur Dioxide

Exposure to gaseous sulfur dioxide at sufficient concentration causes corrosion of the protective zinc coating on galvanized steel and contributes to the erosion and pitting of other metals such as copper and aluminum. Sulfur dioxide forms white deposits called gypsum as it reacts with marble and limestone. It degrades protective paint coatings on steels and exterior wood surfaces and speeds the degradation of wood (Sherwood 1990, Sherwood and Lipfert 1990, Boedecker et al. 1990, Brown and Callaway 1990). Sulfur dioxide is also the major component of acid deposition, which is discussed below. Frequent cleaning reduces the impact of sulfur dioxide on materials. Repainting exposed surfaces as needed can largely mitigate the effects of sulfur dioxide.

Nitrogen Oxides

Exposure to gaseous nitrogen oxides at sufficient concentration causes corrosion of metals and other materials similar to the gaseous sulfur dioxide process described above. The effect is about 75 percent less than that for the same weight concentration of sulfur dioxide (ORNL 1994). The corrosion products are generally soluble, so there are no deposit buildups such as the gypsum associated with corrosion from sulfur dioxide. Nitrogen oxides are a significant component of acid deposition, which is discussed below.

Ozone

Ozone is a strong oxidant that can damage rubber and other elastic substances, textile fibers and dyes, paints, and other materials, including plastics and asphalt. Anti-ozonants and anti-oxidants have been incorporated in paints and other elastic substances to mitigate the effects of ozone. The damage to textile fibers and certain dyes tend to be of secondary effect over product lifetimes when compared with other factors such as abrasion, biological degradation, soiling, and changes in fashion. The studies of dose response are largely empirical, and the Environmental Protection Agency cautions that that they are not reliable (Environmental Protection Agency 1986).

Particulate Matter Smaller than 10 Microns

All exterior surfaces are subject to soiling from particulate matter 10 microns or less in size. Ventilated interior surfaces are also subject to soiling and require more frequent cleaning. Some materials, such as selected fabrics, can be permanently stained. Particulate matter can interact with acid deposits to accelerate the effect from acid deposition.

Acidic Deposition

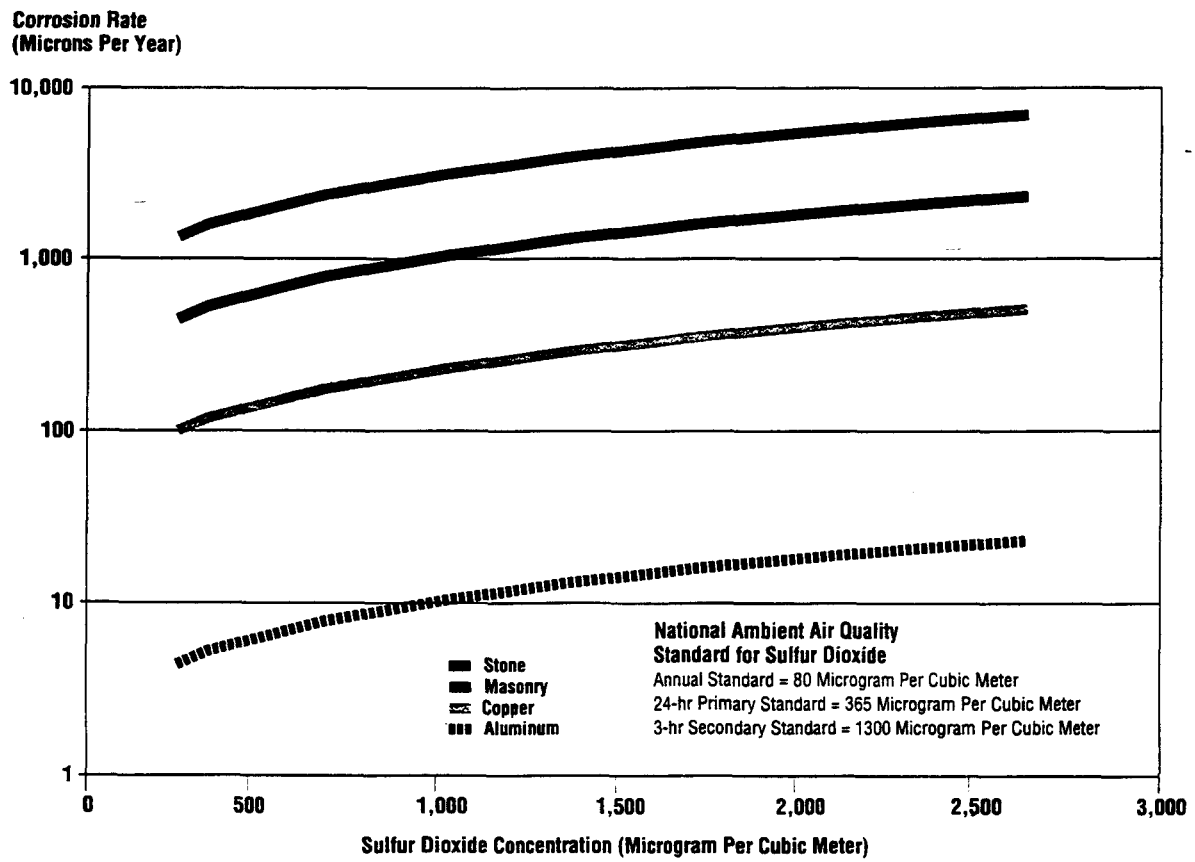
The National Acid Precipitation Assessment Program conducted extensive studies on the effects of acidic deposition on materials (Brown and Callaway 1990). Emissions of sulfur dioxide and nitrogen oxides from power plants are major contributors to acidic deposition. The chemistry of acid deposition involves the oxidation of both sulfur dioxide and nitrogen oxides to form strong acids, sulfuric acid, and nitric acid. These are deposited both directly by dry deposition and by wet deposition with rain, snow, and fog.

Materials that can be damaged from acid deposition include galvanized steel and other metals, painted steel (including automobiles), painted wood, mortar, and carbonate masonry (marble and limestone). Galvanized steel depends on zinc oxides for protection. Over time, these zinc oxides are slowly worn away by clean rain accelerated by acid deposition. Acid deposition corrodes the zinc oxide coating so that it is easily eroded by rain, thus exposing the substrate to corrosion. Copper and bronze develop a natural protective oxide patina that is attacked by acid deposition. As this natural patina is removed, a more porous sulfate patina develops. On copper this sulfate patina has a green color. Painted metals and wood can also be affected by acid deposition. The paints can be damaged, discolored, or spotted. Also, some paints are porous, allowing penetration to the substrate (Brown and Callaway 1990).

Exposures to ambient concentrations of sulfur dioxide can cause marble surfaces to lose 15 to 30 micrometers per year and limestone surfaces, 25 to 45 micrometers per year. Reactions to acidic deposition tend to accumulate as gypsum on the sheltered surfaces of carbonate stone buildings and monuments. Even small material losses can cause significant loss of artistic detail in statues and cultural or historic structures (Brown and Callaway 1990).

National Acid Precipitation Assessment Program corrosion studies in the 1980s have correlated decreased corrosion rates in the eastern United States with diminished sulfur dioxide concentrations. The graphs in *Figure T1-56* shows the

FIGURE T1-56. **Dose-Response Functions for Materials Exposed to Acidic Deposition**



dose-response relationship between sulfur dioxide levels and the corrosion rate on common materials (ORNL 1994).

While a correlation exists, caution should be taken in assuming a cause-and-effect relationship. The level of nitrogen oxides, ozone, acid deposition, and particulates also tended to track with sulfur dioxide, so the investigators could not isolate effects of individual pollutants. Therefore, this table is best viewed as showing the composite effect of acid deposition with sulfur dioxide acting as the marker.

The effects of acidic depositions can be reduced by frequent cleaning and repainting as needed. Paints and protective coatings that are more resistant to attack from acidic deposition need to be developed.

Air Indices and Rationale for Weightings

TVA's existing energy resources and many of the resource options considered for Energy Vision 2020 can affect air quality in different ways. Several air quality issues were identified as concerns in the scoping phase of the Energy Vision 2020 process. Air indices were developed to help characterize how TVA power system operations and alternative energy strategies might affect air quality impact areas. *Figure T1-57* contains the weightings used in Energy Vision 2020 for air emissions. The values in the index are weighted by the relative importance among TVA emissions in contributing to pollutant loadings that could affect human health and the environment. The index allows the emissions of greater concern for impacts to be given greater emphasis in multi-attribute analysis of alternative energy strategies.

To understand how the index translates to differences in impacts, it is necessary to understand how TVA emissions contribute to pollutant exposures and how changes in expo-

FIGURE T1-57. **Weighting Factors for Air Quality Evaluation Measures Used in Four Impact Area Indices**

	IMPACT AREAS			
Measure	**Health-Inhalation**	**Visibility Impairment**	**Forest and Crop Productivity**	**Materials Damage**
Sulfur Dioxide Emission	0.40	0.70	0.25	0.60
Nitrogen Oxides Emission	0.50	0.25	0.75	0.40
Total Suspended Particulate Emission	0.05	0.05		
Mercury Emission	0.05			

sures result in changes in impacts. Uncertainty in scientific understanding limits the ability to quantify the relationships among emissions, exposures, and impacts. In applying this index to multi-attribute analysis, percentile differences in the weights among strategies can be interpreted as differences in TVA contributions to the air pollutant loadings that cause impacts. The air index, as presented, does not provide a weighting of TVA's contribution to the total pollutant loading in the area of concern.

RELATIONSHIPS

Energy Vision 2020 defines TVA's future energy options as alternative energy supply strategies and does not define specific sites where TVA air emissions might increase. To understand impacts of specific TVA sources to specific receptors of concern, it is necessary to use atmospheric models to project the transformation and delivery of emissions under specific meteorologic conditions. This analysis does not attempt to model delivery of emissions from specific TVA sites to specific receptors. In TVA siting decisions for future energy supply, atmospheric modeling can be used to better project site-specific impacts from TVA emissions.

General relationships between pollutant loadings and impacts are illustrated in *Figures T1-58* through *T1-60* for acid deposition, ozone, and visibility. In these diagrams, factors that can be controlled, e.g. emissions management decisions, are illustrated in a box. Arrows illustrate dependencies between variables and end results. Impacts to human health, crop and forest productivity, materials, and visibility are the end results of decisions on levels of emissions from human activity and the many environmental variables that influence pollutant formation, transport, and exposure. The variables in these diagrams must be considered to evaluate what changes in impacts will occur as a result of changes in emissions under different TVA energy supply strategies. As can be seen from these figures, utility emissions are just one category of emissions that contribute to air pollution impacts.

TVA's contribution to total pollutant loadings can be estimated by using predominant wind speeds and directions for seasonal or annual time periods to define the general source area for the Tennessee Valley. (See discussions under ozone, acid deposition, and visibility impairment sections.) TVA's emissions within the source area are projected from 1996 to 2020, and changes in impacts are considered as a function of changes in loadings. Analyses assume that emissions from non-TVA sources will remain level over this period, and any changes in loadings will be a function only of changes in TVA's contribution.

Potential changes in impacts have been considered for the region and for sensitive receptors. For human health impacts, any reduction in loadings will have positive benefit. Environmental and material damages can be episodic (hours or days) or cumulative (seasonal, annual, or over decades) and can vary as a function of the site conditions. Reductions in pollutant loadings below a threshold level may be required before benefits are measurable.

WEIGHTINGS ASSIGNED TO EMISSIONS IN AIR INDICES

Weightings of key pollutants in the indices are given in *Figure T1-57.*

Human Health–Inhalation

Figure T1-61 contains a summary of possible health effects associated with various types of pollutants. Any TVA contributions to health impacts associated with inhalation of pollutants are primarily related to ozone and fine-particulate matter on respiratory functions of sensitive individuals. Ambient levels of sulfur dioxide associated with TVA's emissions are below levels that impact lung function directly. However, sulfur dioxide can be converted to sulfate particles that are of the size most irritating to lung function (particles less than 2.5 microns). Increased health risk has also been associated with elevated levels of the fine particles.

TVA's nitrogen oxides emissions contribute to ozone formation. Ambient levels of ozone are estimated to have slightly greater risks of respiratory impacts than fine particles. Because of the importance of ozone, nitrogen oxides were weighted slightly more than sulfur dioxide (0.5 versus 0.4).

TVA's emissions of hazardous air pollutants are estimated to have less risk than the Environmental Protection Agency's one-in-one million health risk threshold. Therefore, a low weighting of 0.05 was applied. TVA mercury emissions are tracked in the air index as a surrogate for other metals emitted in trace quantities from coal combustion because more quantitative data is available for mercury emissions than for other hazardous air pol-

FIGURE T1-58. **Acid Deposition: Relationships Among Emissions, Exposures, and Impacts**

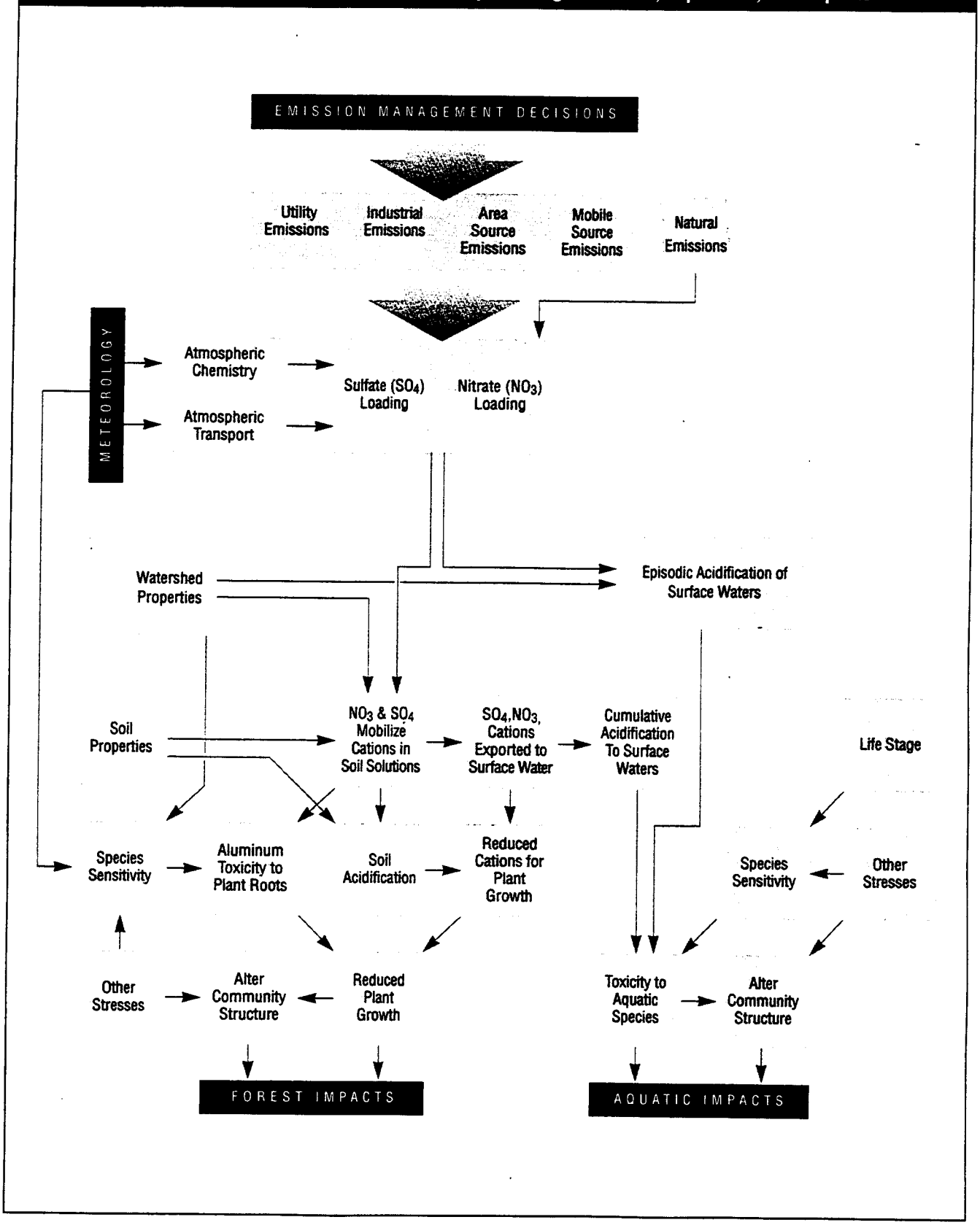


FIGURE T1-59. **Ozone: Relationships Among Emissions, Exposures, and Impacts**

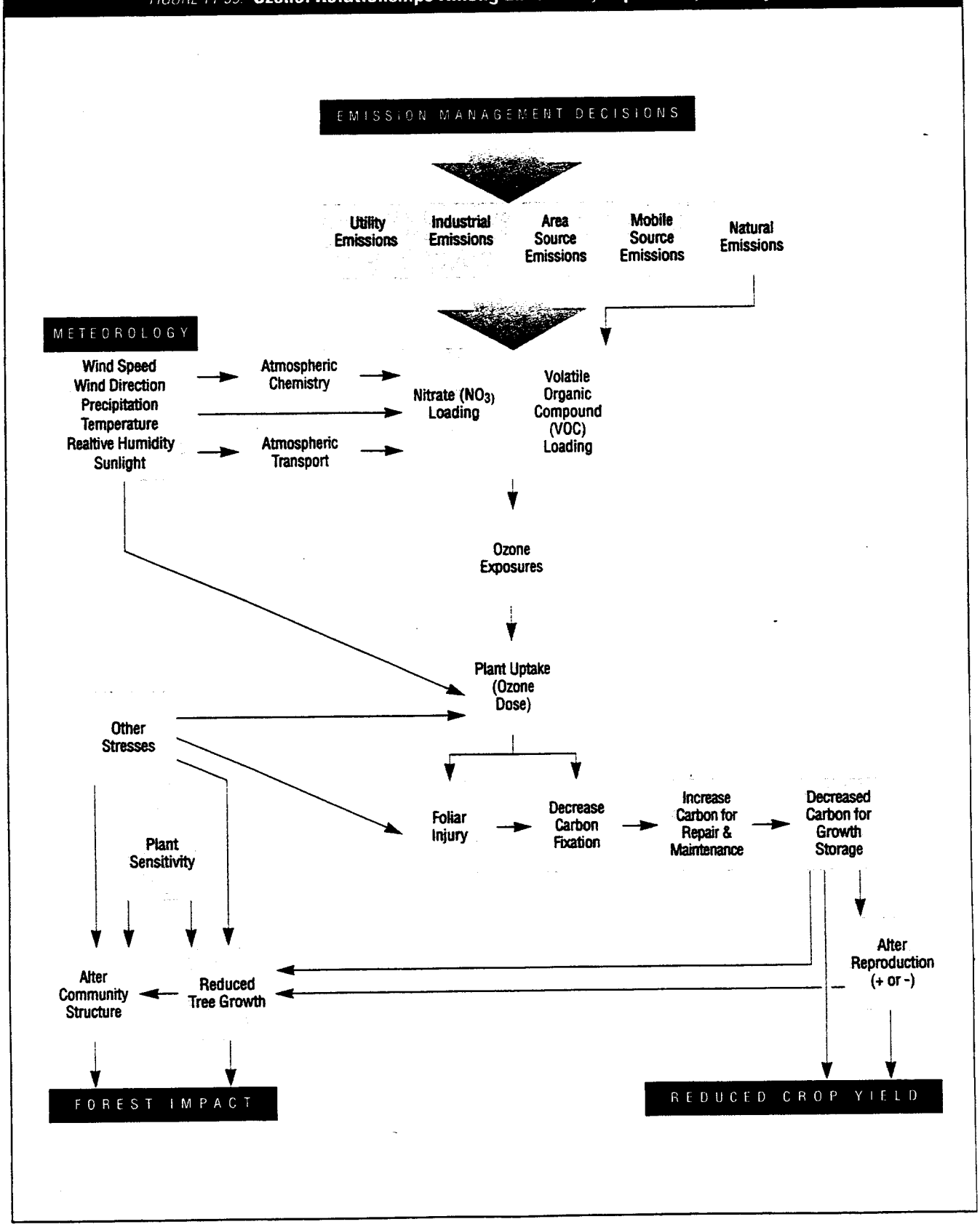
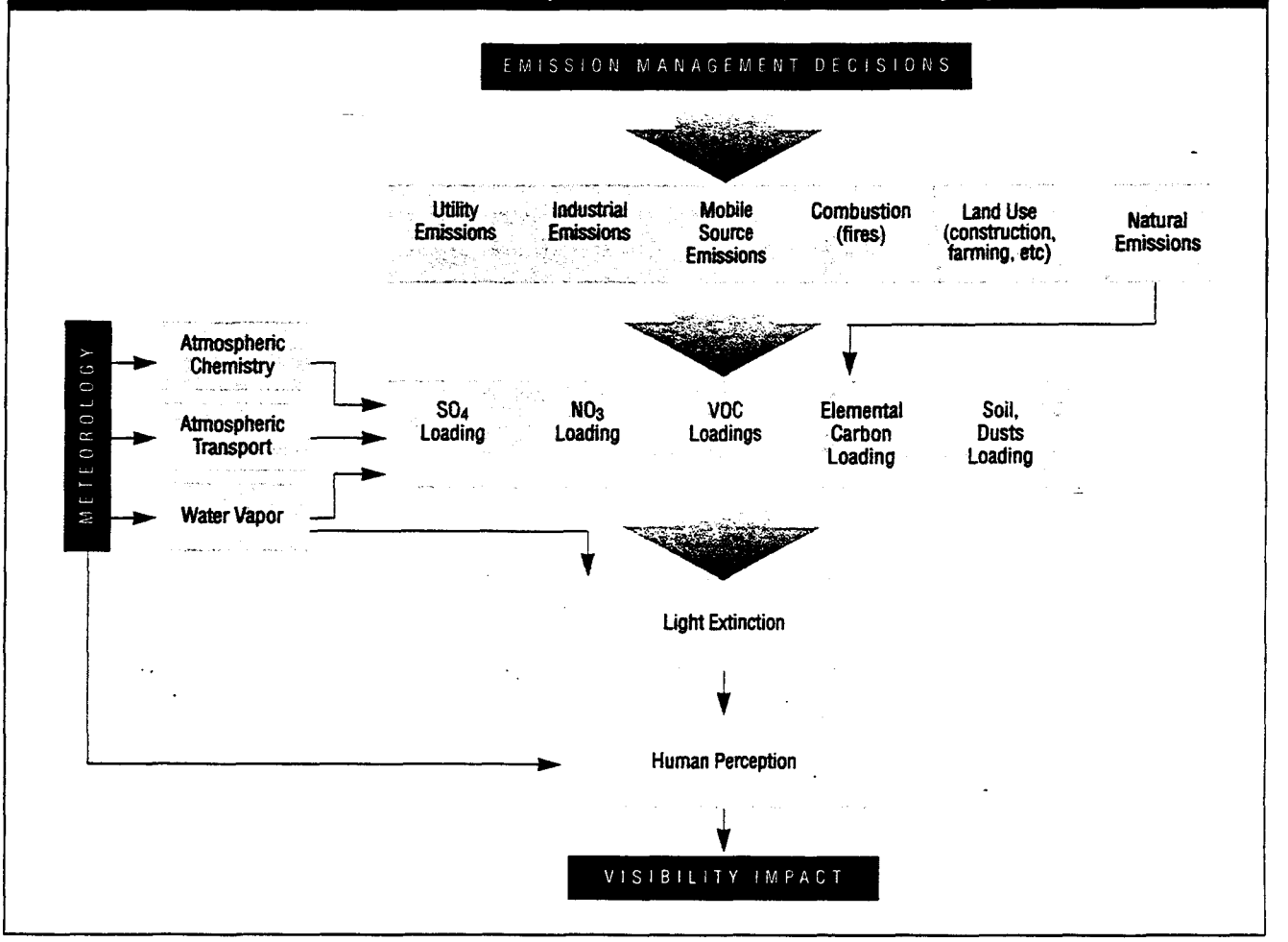


FIGURE T1-60. **Visibility: Relationships Among Emissions of Particulate Matter, Gaseous Pollutants, and Visibility Impairment**



lutants. Mercury effects are discussed in the water resources section of this section.

TVA's emissions of primary particulates are a minor component of the fine-particulate size contributing to health risk. For this reason, total suspended particulates received a weight of only 0.05.

Any reduction in emissions is assumed to have positive benefits for human health.

Visibility Impairment

TVA's contribution to regional visibility impairment is primarily associated with fine sulfate particles. Because sulfate production from sulfur dioxide in the atmosphere is slow, TVA sulfur dioxide emissions contribute very little to visibility impairment in the Great Smoky Mountains National Park.

TVA's nitrogen oxides emissions contribute only indirectly to visibility impairment through their role in ozone formation and the conversion of sulfate particles to organic aerosols. As a result, sulfur dioxide was weighted as almost three times more significant than nitrogen oxides (0.70 versus 0.25).

TVA's emissions of primary particles are a minor component of the fine-particulate size most responsible for scattering light in the atmosphere and thus impairing visibility. Because of this minor role, total suspended particulates received a weight of only 0.05.

Forests and Crops

Any TVA contributions to crop and forest impacts are primarily associated with ozone and with nitrate and sulfate in acid deposition. TVA's sulfur dioxide emissions contribute to sulfate in acid deposition, and nitrogen oxides emissions contribute to both ozone and nitrate in acid deposition. At ambient ozone levels, several crop and forest species in the Tennessee Valley are sensitive and exhibit foliar injury and reduced productivity. Sulfate in acid deposition is not thought to have adverse impacts to vegetation and

may have slight positive benefits as a plant nutrient where soils are low in native sulfur. For crops and many forests growing on nitrogen-deficient soils, nitrate in deposition has positive benefits. However, loadings of sulfate and nitrate from wet, dry, and cloud deposition are greatest at high elevation, and high-elevation spruce and fir forests in the southern Appalachians are sensitive to acidification.

Nitrate in deposition has greater impact than sulfate for high elevation forests because soils in the southern Appalachians generally are able to absorb sulfate. Biological processes that use nitrogen are slower at high elevation. When nitrogen deposition exceeds the biological demand for nitrogen, nitrates in soil water can combine with and remove nutrients such as calcium and magnesium that are essential for plant growth. Nitrate can acidify soil waters, leading to aluminum toxicity for sensitive plants. Due to its contributions to ozone and nitrate in acid deposition, nitrogen oxides emissions have been weighted three times greater for their impact to crop and forest productivity than sulfur dioxide emissions (0.75 versus 0.25).

Materials (Structural and Cultural)

Any TVA contribution to damage of materials is associated with both acid deposition and ozone. Acid deposition can erode surfaces of paint, limestone, and metals. Ozone can oxidize some materials such as rubber. Sulfate is considered more corrosive than nitrate in acid deposition, and acid deposition can damage a greater variety of surfaces than ozone, including cultural resources such as historic buildings and tombstones. Therefore, sulfur dioxide emissions are weighted as more significant than nitrogen oxides emissions for material damage (0.60 versus 0.40). Material damage is cumulative, so any reductions in current ambient exposures will likely reduce the rate of material degradation.

FIGURE T1-61. **Summary of Possible Health Effects Associated with Certain Types of Pollutants**

Emission	Pollutant	Health Effect	Air Quality Index [1] Weighting Factor
Sulfur Dioxide	Sulfur Dioxide Sulfate Aerosols Sulfate Fine Particulate (PM10)	Eye Irritation Respiratory Distress Lung Damage	0.40
Nitrogen Oxides	Nitrogen Oxides Nitrate Aerosols Nitrate Fine Particulate (PM10) Ozone	Respiratory Distress Lung Damage Eye Irritation	0.50
Carbon Monoxide	Carbon Monoxide	Headaches Reduced Mental Alertness Heart Damage	0.00
Primary Particulates	PM10	Respiratory Distress Lung Damage Eye Irritation	0.05
Mercury	Mercury	Neurotoxin Brain Damage	0.05

[1] Weighting of the relative importance among TVA air emissions is qualitative, based on estimated magnitude of health impact in the Tennessee Valley and TVA's relative contribution to loadings in that pollutant category. Weightings do not attempt to estimate TVA contribution to health impacts outside the Tennessee Valley.

Greenhouse Gases

A separate measure was also developed to sum the net greenhouse gas emissions for alternative future energy supply strategies. The measure is expressed in equivalent tons of carbon dioxide, the most common greenhouse gas. Other greenhouse gases, principally methane, are converted to equivalent carbon dioxide by multiplying emissions by the radiative forcing potential. *(See Figure T1-62.)* The radiative forcing potential for any greenhouse gas is an indication of the relative effect of the gas on the global warming potential compared to carbon dioxide, which has a radiative forcing potential of one. For example, methane has a radiate forcing potential of 21, which means its effect on global warming is 21 times greater than that of an equivalent weight of carbon dioxide.

An explanation of the process used to develop measures for environmental evaluation criteria and the calculations for indices can be found in Volume 1, Chapter 5, Evaluation Criteria, and Volume 2, Technical Document 4, Evaluation Criteria.

FIGURE T1-62. **Weighting Factors for Greenhouse Gases**

Environmental Measure	Units [1]	Total Equivalent Carbon Dioxide (Millions of Tons)
Carbon Dioxide Emissions	Annual Average Thousands of Tons	1
Coalbed Methane Emissions Avoided	Annual Average Tons	-21
Nat. Gas Methane Emissions	Annual Average Tons	21
Landfill Methane Recovered	Annual Average Tons	-21
Wood Waste Methane Avoided	Annual Average Tons	-21
Wood Waste Carbon Dioxide Avoided	Annual Average Tons	-1
Short Rotation Woody Crops Carbon Dioxide Avoided	Annual Average Thousands of Tons	-1

[1] Annual Average Equivalent TVA Carbon Dioxide Emissions

SECTION 4: WATER RESOURCES

Introduction

The scope of the Energy Vision 2020 water resources study covers the entire Tennessee River basins and portions of the Cumberland, lower Ohio, lower Mississippi, and Green River basins, as shown in the map in *Figure T1-63*. Fresh water abounds in this area and generally supports most beneficial uses, including fish and aquatic life, public water supply, industrial water supply, waste assimilation, agriculture, and water contact recreation such as swimming.

Water quality concerns in the region include the following:

- Point sources of pollution such as wastes from sewage treatment facilities and industrial plants
- Non-point sources of pollution such as agricultural and urban runoff
- Toxic substances found both in sediment and fish in some reservoirs
- Occurrences of low dissolved oxygen levels in tailwaters downstream of certain dams. (A tailwater is the water immediately downstream from a dam, including water released from the dam.)

Principal water quality concerns in TVA reservoirs are shown in the table in *Figure T1-64*. Principal water quality concerns in Tennessee Valley watersheds are shown in the table in *Figure T1-65*.

Water quality and aquatic habitats differ substantially according to the type of aquatic environment. Aquatic environments in the region can be characterized as follows:

- Unregulated streams and stream reaches sufficiently far downstream of dams to have returned to "stream-like" conditions
- Mainstream reservoirs (reservoirs on large rivers such as the Tennessee River)
- Tributary reservoirs and associated tailwaters.

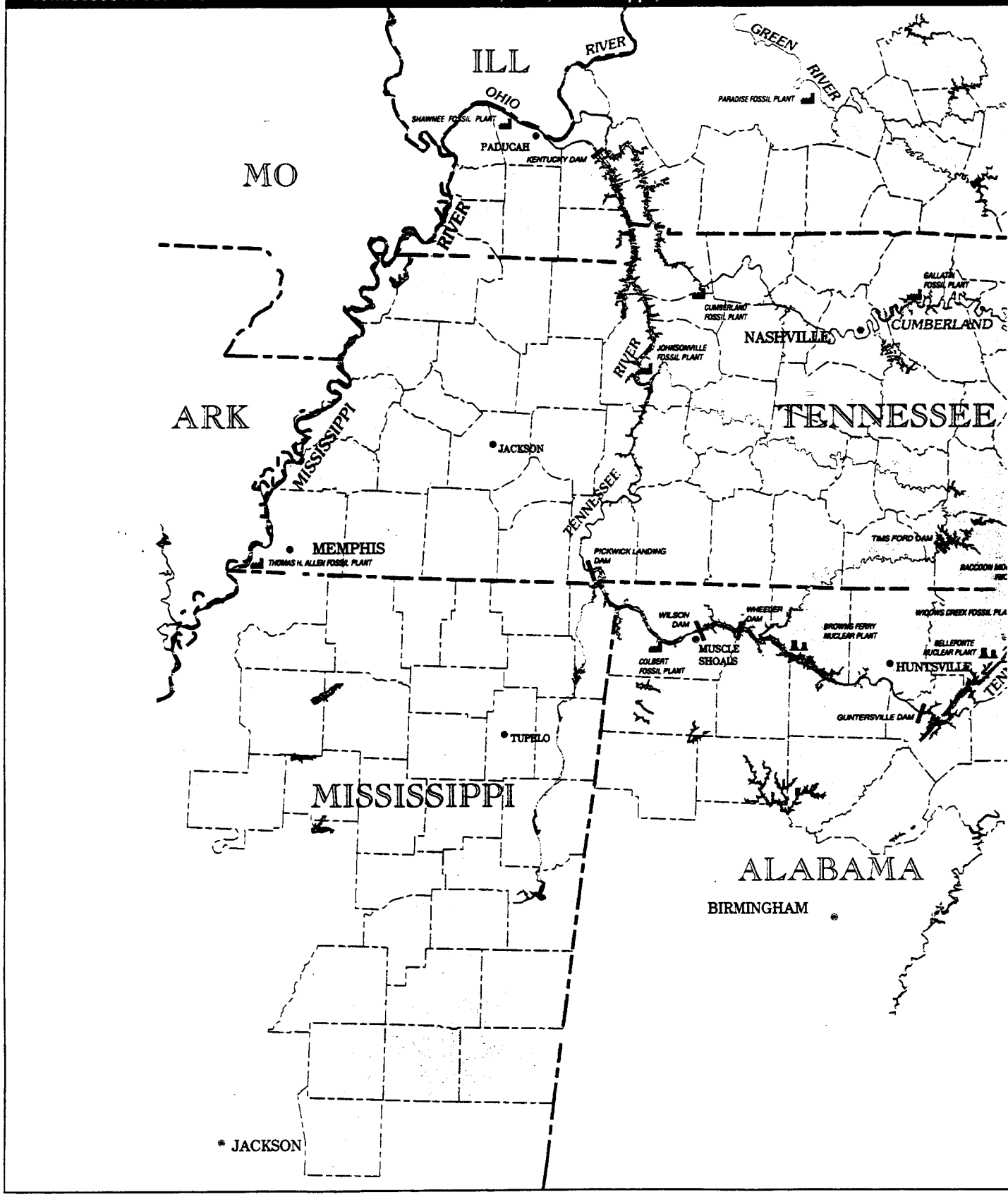
For the most part, smaller streams and some reaches of larger streams in the region are unregulated or free-flowing. Stream habitats vary from cold water mountain streams to lowland warm water creeks and small rivers. The water quality and aquatic life in these streams are affected by the characteristics of the watershed (the area draining into a stream or river), as well as human activities. Many small streams are susceptible to impacts from runoff, waste discharges, and contaminated groundwater seepage. The small streams that form in the Appalachian mountains have a low buffering capacity (ability to absorb acids and bases without altering the stream pH). This makes them particularly vulnerable to the effects of acid mine drainage and acid precipitation. Mining produces coal for many TVA power plants, and emissions from TVA coal-fired power plants contribute to acid precipitation.

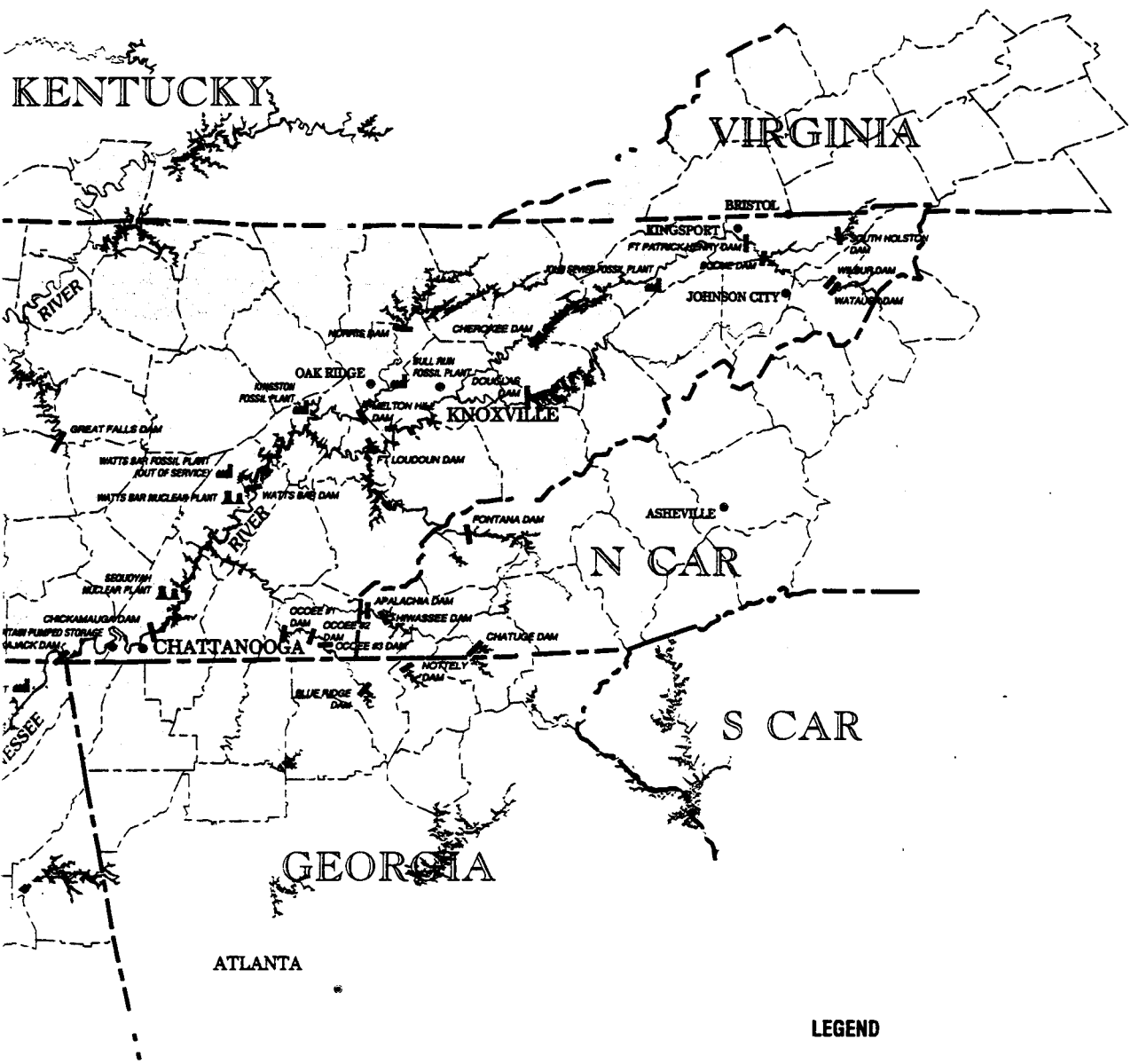
Mainstream dams on the Tennessee River are operated primarily for navigation, flood control, and hydroelectric power production. They form relatively shallow, run-of-the-river reservoirs that exhibit characteristics of both lakes and rivers. The upstream portions of the reservoirs are more riverine with a gradual downstream transition to lake-like conditions. The relatively higher flow rates in these mainstream reservoirs aid in maintaining adequate dissolved oxygen levels. Thermal stratification (layering of water with different temperatures—warmer near the surface and colder near the bottom) occurs to some extent in the downstream, lake-like portions of the reservoirs but generally does not occur in the upstream portions.

Tributary reservoirs are operated for flood control, hydroelectric power production, and to a lesser extent, augmentation of downstream water supplies. They are relatively deep, lake-like reservoirs that thermally stratify during the summer and fall. Releases from the lower levels of stratified reservoirs are often low in dissolved oxygen and may have elevated concentrations of metals such as iron and manganese. Also, operation of hydro power units to meet peak power demands often results in low or intermittent downstream water flows. Therefore, the quality of the water released intermittently from the reservoirs during the summer may be characterized by low dissolved oxygen levels and elevated concentrations of some metals.

TVA, through its Lake Improvement Plan, is reaerating reservoir releases and providing minimum continuous water flows downstream of most of its tributary reservoirs. The establishment of minimum flows and aeration of releases will recover over 170 miles of aquatic habitat lost from intermittent drying of the river bed below TVA tributary dams and improve levels of dissolved oxygen in over 300 miles of river where water quality is now impaired in the late summer and fall by releases through TVA dams. Proposed summer lake levels in tributary reservoirs will also improve, as will reservoir fisheries, by increasing survival of young fish.

Figure T1-63. **Water Resources Considered in Energy Vision 2020 Include the Entire Tennessee River Basin and Portions of the Cumberland, Ohio, Mississippi, and Green River Basins**




KENTUCKY
VIRGINIA
BRISTOL
KINGSPORT
JOHNSON CITY
OAK RIDGE
KNOXVILLE
ASHEVILLE
N CAR
S CAR
GEORGIA
CHATTANOOGA
ATLANTA
RIVER
CHEROKEE DAM
NORRIS DAM
BULL RUN FOSSIL PLANT
KINGSTON FOSSIL PLANT
DOUGLAS DAM
FT LOUDOUN DAM
GREAT FALLS DAM
WATTS BAR FOSSIL PLANT (OUT OF SERVICE)
WATTS BAR NUCLEAR PLANT
WATTS BAR DAM
FONTANA DAM
SEQUOYAH NUCLEAR PLANT
CHICKAMAUGA DAM
APALACHIA DAM
CHATUGE DAM
NOTTELY DAM
BLUE RIDGE DAM
SOUTH HOLSTON DAM
WILBUR DAM
WATAUGA DAM
BOONE DAM
LEGEND
State Boundary
County Boundary
Stream, Tributary, Lake
TVA Power Facilities; Fossil, Hydro
Nuclear, Pumped Storage
Major Cities
MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

Tennessee River

The Tennessee River basin contains all but one of TVA's dams and covers most of the TVA region.

The Tennessee River is formed by the Holston and French Broad Rivers joining at Knoxville, Tennessee, 652 river miles from where it empties into the Ohio River near Paducah, Kentucky. The entire length of the Tennessee River is regulated by a series of nine locks and dams built mostly in the 1930s and 40s that allow navigation to Knoxville. Virtually all the major tributaries have at least one dam, creating 14 multi-purpose storage reservoirs and 7 single-purpose power reservoirs. *Figure T1-63* is a map of the basin, showing dams and reservoirs. This system of dams and their operation is the most significant factor affecting water quality and aquatic habitats in the Tennessee River and its major tributaries.

SURFACE WATER

Major water quality concerns within the Tennessee River drainage basin include point and non-point sources of pollution that degrade water quality at several locations on mainstream reservoirs and tributary rivers and reservoirs. Toxic substances have also been found in sediment and fish in reservoirs that oth-

FIGURE T1-64. **Principal Water Quality Concerns in TVA Reservoirs**

	USES AFFECTED				SOURCE	
Navigation & West Tributary Reservoirs	**Aquatic Life**	**Fish Consumption**	**Recreation**	**Water Supply**	**Point**	**Non-Point**
Kentucky			Aquatic Plants			
Normandy	Low Dissolved Oxygen			Taste, Odor, Iron, Manganese	X	
Pickwick				Algae		X
Wilson	Low Dissolved Oxygen			Taste, Odor		X
Wheeler	Low Dissolved Oxygen	DDT			X	X
Tims Ford	Low Dissolved Oxygen					X
Guntersville			Aquatic Plants			X
Nickajack		PCBs, Chlordane			X	X
Chickamauga	Low Dissolved Oxygen				X	X
Watts Bar	Low Dissolved Oxygen	PCBs			X	X
Melton Hill		PCBs				X
Ft. Loudoun		PCBs	Bacteria		X	X
Tellico	Low Dissolved Oxygen	PCBs				X
East Tributary Reservoirs						
Norris	Low Dissolved Oxygen					X
Cherokee	Low Dissolved Oxygen				X	X
Ft. Patrick Henry						
Boone	Low Dissolved Oxygen	Metals, Toxics			X	X
South Holston	Low Dissolved Oxygen					X
Wilbur						
Watauga						
Douglas	Low Dissolved Oxygen			Color	X	X
Nolichucky	Siltation		Siltation	Siltation		X
Fontana	Low Dissolved Oxygen					X
Ocoee 1-3	Metals, Siltation	PCBs	Siltation		X	X
Blue Ridge						
Appalachia						
Hiwassee	Low Dissolved Oxygen					X
Nottely	Low Dissolved Oxygen				X	X
Chatuge	Low Dissolved Oxygen					X

erwise have good water quality. Other water quality concerns include occurrences of low dissolved oxygen levels downstream of dams, which stresses aquatic life and limits the ability of the water to assimilate wastes.

The principal water quality concerns in TVA reservoirs and watersheds are summarized in *Figures T1-64* and *T1-65*. This information was derived primarily using data and analysis generated through TVA's comprehensive ecological health and use suitability monitoring program as well as other TVA aquatic monitoring and assessment activities. The criteria used in making the determinations were state water quality standards and fish consumption advisories. This summary reflects the current understanding of the causes and effects of point and non-point sources of pollution on water quality.

Point and Non-Point Sources of Pollution

Point and non-point sources of pollution include:

- Heat-release – Utility and industrial plants may release water into streams or lakes that has been heated above the temperature of the body of water.
- Wastewater – Sewage treatment systems, utilities, industry, and others dispose of waste into streams and lakes.
- Runoff from agriculture, urban uses, and mined land.
- Air pollution – Pollutant concentrations in the air can affect surface waters through rain and deposition.

Heat Releases

Power plants use water from streams or lakes for various purposes. The water returned to the streams or lakes is often heated above the temperature of the body of water. When the Clean Water Act was first considered, little was known about the effects of waste heat on freshwater ecosystems. Many possible consequences were postulated, including direct mortality, blockage, or interruption of fish spawning migrations; advanced spawning of fish or hatching of aquatic insects; increased toxicity of certain pollutants; and shift of phytoplankton populations to less desirable species. Because of the uncertainty surrounding this issue, extremely conservative thermal water quality criteria and permit limitations were established based primarily on laboratory studies of these potential effects. To provide relief to dischargers from the unnecessarily stringent limitations that would in many cases likely be imposed , the Act provided for alternative thermal limits where dischargers could demonstrate to regulators that the waste heat limits imposed were more stringent than necessary to protect indigenous aquatic communities. Many of TVA's power plants are now operating under alternative thermal limits granted as a result of such demonstrations.

TVA conducts extensive aquatic monitoring programs to ensure that thermal and other discharges do not cause adverse impacts even at permitted levels. Recently, programs have focused primarily on potential effects on spawning and development of cool-water fish species such as sauger (*Stizostedion canadense*) and walleye (*Stizostedion vitreum*), but have also included attraction of fish to thermal plumes from power plants and possible increases in undesirable aquatic microorganisms, such as blue-green algae. In general, these monitoring programs have failed to detect significant negative effects resulting from release of heated water from TVA facilities.

There are presently 2 operating nuclear plants and 11 operating coal-fired plants in the TVA power system. A third nuclear plant is scheduled to begin operating in 1996. Each of these plants withdraws process cooling water from the river upon which it is located. The heated water is then discharged back into the river at or below the temperature necessary to meet the thermal discharge limitations stated in each plant's discharge permit. Permits normally state a maximum allowable temperature after mixing of the thermal discharge with the receiving stream, as well as a maximum temperature change relative to upstream conditions and a maximum rate of temperature change.

Various measures are used by TVA to ensure compliance with thermal limits. All three nuclear plants and one fossil plant have cooling towers that

FIGURE T1-65. **Principal Water Quality Concerns in Tennessee Valley Watersheds[1]**

Aquatic Watershed	Fish Life	USES AFFECTED[2] Consumption	Recreation	SOURCE Point	Non-Point
Chickamauga-Nickajack		PCBs	Bacteria		X
Pickwick-Wilson	Toxics				X
Watts Bar-Melton Hill	Siltation	PCBs	Bacteria		X
Duck River	Siltation		Bacteria		X
Guntersville-Sequatchie	Siltation		Bacteria		X
Clinch-Powell	Siltation				X
Wheeler-Elk		DDT, PCBs	Bacteria		X
Holston	Toxics	Mercury	Bacteria	X	X
French Broad	Siltation	Dioxin	Bacteria	X	X
Little Tennessee	Siltation	PCBs		X	X
Hiwassee	Metals, Siltation			X	X

[1] As designated by TVA's Clean Water Initiative

[2] Uses are affected by the problem noted on at least one stream in the watershed.

may be used as appropriate to dissipate heat to the atmosphere before water is discharged. Depending on conditions and permit requirements, these plants may continually recirculate cooling water through the towers, they may pass the heated water through the towers once before discharging, or they may bypass the towers altogether and discharge the heated water directly to the river. Heated water at nuclear plants is discharged to the river through diffusers that extend well out into the river to produce rapid mixing.

Three coal-fired plants that do not have cooling towers may experience conditions during certain times of some years when they cannot operate at full power and still meet thermal limits. During those times, electricity generation is cut back to reduce the amount of waste heat released to the river. A few plants can discharge once-through cooling water without either cooling towers or operational cut backs because of their location on large water bodies that quickly assimilate waste heat discharges.

Wastewater

Discharges of pollutants from point sources, such as sewage treatment facilities and industrial plants, are regulated by the U.S. Environmental Protection Agency and the states to achieve a certain level of water quality. As a result, impacts from these sources have been greatly reduced.

Nuclear Plant Wastewater

Nuclear power plants have non-complex wastewaters that are subjected to various levels of treatment and usually discharged to surface waters. These releases are controlled through state-issued National Pollutant Discharge Elimination System permits, which are part of Federal Clean Water Act statutes. Wastewater (discharged cooling tower and steam generator recirculation water, turbine building sump, sanitary wastewater, intake screen and strainer backwash, water treatment neutralization wastes, etc.) from various plant systems is normally mixed with heated condenser cooling water before being discharged to surface water. Periodic toxicity testing is performed on this discharge as part of the National Pollutant Discharge Elimination System permit to ensure that plant effluents do not contain chemicals at deleterious levels that could affect aquatic life. In addition, storm water runoff is monitored at regular intervals as part of the National Pollutant Discharge Elimination System.

Radiological wastewater releases to surface waters are controlled by the U.S. Nuclear Regulatory Commission and plant Technical Specifications, as well as the state-issued National Pollutant Discharge Elimination System permit. A radiological monitoring program is also conducted on the body of water receiving the wastewater, fish, intake water, river sediment, and aquatic invertebrates on a routine basis.

Coal-Fired Plant Wastewater

Coal-fired plants have several liquid waste streams that are treated and released to surface waters. These releases are permitted by each state environmental agency under the National Pollutant Discharge Elimination System. Biomonitoring of wastewater is required to ensure that there are no acute toxic effects to aquatic life.

At many plants, fly ash is sluiced to an ash storage pond. The sluicing water, which is drawn from the river or reservoir serving the plant, flows continuously. Metal cleaning waste is a waste stream that may be acidic or basic. After treatment for neutralization, these wastes are also typically discharged to the ash pond for mixing with the pond water and, potentially, additional treatment. On-site treatment of domestic sewage occurs at some plants that are not connected to a local community sewage collection and treatment system. After treatment, the wastewater is typically discharged to the ash storage pond for mixing with the pond water and possible further treatment. Stormwater runoff from the plant site is also typically routed to the ash ponds, where it mixes with the ash pond water.

Rainfall and Runoff Pollutants

Non-point sources of pollution have not been subjected to government regulations or control in most cases. They contribute as much as five times more dissolved oxygen-consuming wastes than point sources. Principal causes of non-point source pollution are agriculture, including runoff from fertilizer and pesticide applications, erosion, and animal wastes; mining, including erosion and acid mine drainage; and urban runoff. Mining is necessary to extract coal and uranium used as fuel by power plants.

Air Pollution

Atmospheric deposition of air pollutants is another source of pollution affecting water quality, particularly in relation to acid rain and fallout of toxic metals, especially mercury. Section 3 in this document (Volume 2, Technical Document 1, Comprehensive Affected Environment) discusses air pollution, its effects, and TVA's contribution in some detail.

Low Dissolved Oxygen Levels

Another major water quality concern in the Tennessee River is low dissolved oxygen levels in streams below TVA dams on tributary rivers. When rivers are dammed, organic material from normal runoff, upstream pollution sources, and fallout from living organisms in the upper water levels tends to accumulate in sediments behind the dams. As this organic material decomposes, it uses up the oxygen in the overlying deep water layer. When turbines in the dam are operated to generate electricity, this low-oxygen water is released downstream, creating poor habitat for

aquatic life. TVA addressed this issue in its 1990 environmental impact statement, "Tennessee River and Reservoir System Operation and Planning Review" (TVA 1990). As a result, TVA has initiated a program to improve dissolved oxygen levels in water discharged from its dams based on this study.

To understand the causes of low dissolved oxygen levels in water released through TVA dams, it is necessary to understand the changes in temperature and dissolved oxygen content that occur in deep tributary reservoirs during a typical year. Tributary reservoirs begin to stratify (layering of the water with warmer water near the surface and cooler water near the bottom) during the spring as a result of surface heating and reduced stream flows. The dissolved oxygen content of the upper 10 to 20 feet usually remains at an acceptable level due to surface reaeration and exposure to the atmosphere and to light. Planktonic algae absorb the light and through photosynthesis produce oxygen in the water. However, oxygen levels in the lower portion decline because there is no photosynthesis in the bottom waters due to a lack of light, and they are isolated from surface reaeration. The existing oxygen is used by decaying algae and other organic matter as it settles in the water column.

Hydroelectric plants at TVA dams were designed to withdraw water from near the reservoir bottom to provide maximum flexibility for operation and maintenance of the turbines. These low level intakes maximize generating potential, and allow the hydroelectric plant turbines to operate during the winter season when reservoir levels are kept low to provide flood storage capacity, or during other times of the year under drought conditions. As a result, the water released through TVA dams in the process of hydroelectric power generation from mid-summer to early fall can contain no or low concentrations of dissolved oxygen.

In some reservoirs, discharge from the deep water layer also contributes to the release of dissolved sulfides, iron, and manganese in the tailwaters below the dams affecting water supplies and aquatic life. The presence of sulfides has been documented in the tailwaters of upper Bear Creek and Douglas Reservoirs. The presence of iron and manganese has been documented at these and other projects.

Temperatures in deep tributary reservoirs follow an annual cycle that begins with large amounts of cold, well-mixed water in storage at the beginning of spring. During the spring, surface water in the reservoir is heated, while deeper water remains at a relatively constant winter temperature. As spring and summer progress, flows enter the reservoir at an intermediate depth. Three layers form:

- The warm, stagnant surface layer
- The spring and summer interflow layer
- The cold winter layer on the bottom.

Turbine operation during the summer gradually draws off the cold water at the bottom of the reservoir. At some point in late summer or early fall, withdrawal of the colder water and gradual reduction in air temperature act in concert to again cause mixing of surface and bottom water. Completely mixed conditions last through the winter while the temperature of the reservoir is gradually lowered. The annual cycle then begins to repeat during the next spring season, when reservoirs are again filled.

GROUNDWATER

Power plants often use fuels such as coal, natural gas, and uranium. Extracting these fuels from the ground can affect the quality of groundwater. Also, ash ponds at coal-fired plants can potentially affect groundwater.

Uses

Groundwater refers to water located beneath the ground in rock formations known as aquifers. Six major aquifer areas exist in the Tennessee Valley region. One of the most important is in the Valley and Ridge Province, which is characterized by its Karst geology. Approximately half the region has limited groundwater availability because of natural geohydrological conditions. Decreasing water table levels indicate that too much water is being pumped from aquifers in the central and western portions of the region.

More than 64 percent of the region's residents rely totally, or in part, on groundwater for potable drinking water. For every public surface water supply system, three public groundwater systems exist; but, in general, the groundwater systems serve fewer people. Over 1.7 million residents (22 percent) in the region maintain individual household groundwater systems, usually a well. All the areas in the Tennessee Valley region can generally supply enough water for at least domestic needs. Groundwater is also used by nearly 3,700 community water systems, businesses, industries, hospitals, churches, campgrounds, and schools.

Supply and Quality

Precipitation is the source of both surface water and groundwater. In an average year, precipitation across the Tennessee Valley region ranges from 40 to 85 inches, with an average of 52 inches. Water entering the groundwater system is stored in the pore spaces in unconsolidated sediments, or in fractures and solution openings in the bedrock. All groundwater in storage moves toward areas where it is discharged, such as springs, streams, and wells. Consequently, the base flow of streams is related to the amount of groundwater available. Stream baseflow is that portion of the stream flow that is sustained by groundwater, rather than rain-

fall runoff. During the dry season, when rainfall is lowest, stream flow is sustained primarily by groundwater discharging into the stream. Groundwater in relatively shallow carbonate aquifers is discharged rapidly during dry periods, causing a decline in water table levels in unconfined aquifers and thus reduced stream flow. Groundwater discharge in a normal year approximately equals the annual baseflow of streams (over half the annual rainfall runoff into streams).

For the most part, groundwater quality is sufficient to support existing water supply uses, though some minimal treatment, such as filtration and chlorination, may be required. However, no agency maintains a network of observation wells to detect groundwater contamination from routine human activities. There have been some instances of groundwater contamination in the region from improper waste disposal, coal mining activities, oil and gas exploration, agricultural activities, septic tanks, industries, coal-fired plant ash ponds, and general urbanization activities. Contamination has required closure of well and spring supplies in some areas. Toxic compounds have been found in the groundwater at some locations. The degree and extent of contamination vary from case to case.

Groundwater is naturally mineralized and exhibits variable characteristics. In some local areas, it can possibly affect health. Fluoride, for example, can exceed Interim Primary Drinking Water Standards in parts of the Highland Rim physiographic province, and hydrogen sulfide can give a "rotten egg" odor to water in other areas.

Some parameters can vary by a factor of 10 to 100 in concentration among the physiographic provinces (e.g., the sulfate concentrations in groundwater of the Blue Ridge province generally are less than 20 milligrams per liter, but in the coastal plain province, concentrations can exceed 1,400 milligrams per liter). See Section 5 in this document (Volume 2, Technical Document 1, Comprehensive Affected Environment) for a description and illustration of the physical geographic (physiographic) provinces in the TVA region.

The quality can change dramatically at a single location depending on the depth of the well, the aquifer used, and how the well is constructed. If several aquifers exist in an area, the water quality depends upon the depth of the well and which aquifer is tapped. Shallow aquifers generally have better quality than deeper aquifers because they are low in dissolved solids, soft, and only slightly acidic. Extremely deep water is generally so high in dissolved solids (brine) that it is considered unsuitable for most uses. Water that comes in contact with sandstone or shale containing pyrite can have high iron or sulfur content. Acidic water (such as rainfall) reacts with limestone and dolomite rocks to release bicarbonates, calcium, and magnesium, which tend to make the water hard and alkaline.

Bacteriological contamination of groundwater can occur in carbonate rock areas where contaminated surface drainage enters the ground through sinkholes or disappearing streams. Springs located in carbonate rock areas are particularly susceptible to contamination during storm periods, but wells can also be affected. Natural groundwater quality is generally believed good.

AQUATIC LIFE

The construction of the TVA dam and reservoir system fundamentally changed the character of the Tennessee River and its tributaries. While dams promote navigation, flood control, power benefits, and reservoir-based recreation by moderating the flow effects of floods and droughts throughout the year, they also disrupt the daily, seasonal, and annual patterns that are characteristic of a river (TVA 1990). Characteristics include water, sediments, nutrients, and organic material that affect the health, number, and diversity of aquatic life. Aquatic life can also be affected by runoff and erosion due to construction of power plants and runoff and acid drainage from mines to extract fuel to use in power plants.

In broad terms, aquatic life in the Tennessee River basin can be considered to exist in the three habitat types previously described, i.e., flowing streams, tributary reservoirs and tailwaters, and mainstream reservoirs. The following descriptions of these three types of environments are to a large extent general and apply to all river basins and reaches included in this study.

Flowing Streams

Small first- and second-order streams in the Tennessee Valley typically provide unstable habitat conditions. These support only those relatively few species able to survive and reproduce under such conditions. The small streams that rise in the Appalachian Mountains and the Cumberland plateau commonly have steep gradients, large rock substrates (stream beds), and cold temperatures. The aquatic community contains relatively few fish and insect species, and other types of aquatic life are rare. Rainbow, brown, and native brook trout (*Salvelinus fontinalis*) occur in these streams. These small streams rising in the Blue Ridge province of the southern Appalachian Mountains contain little carbonate alkalinity. Therefore, they have little capacity to resist pH change from acidic precipitation or other acidic inputs. Data exists to indicate decreased alkalinity through time in many of these streams. However, the actual effect of these acidification processes on the ecological quality of surface waters in the Southeast is virtually unknown. Other types of lower gradient small stream habitats seldom support aquatic life of direct use to people.

A virtual explosion in the diversity of aquatic life accompanies the perennial flow and diversity of habitats in larger creeks and small rivers. These streams flow within well-established chan-

nels with a flood plain that becomes part of the watercourse during high flows. A variety of fish, insects, crustaceans, mollusks, and other aquatic groups colonize each habitat. Over time, complex communities have evolved, including resident species and those which migrate from one habitat to another during the year or over the course of their development. Stream habitats support large sunfish (*Lepomis* spp.) and bass populations sought by sports fishermen all year, as well as other species, such as white bass (*Morone chrysops*), sauger (*Stizostedion canadense*), and suckers (*Catostomus* spp.) that are harvested during seasonal spawning migrations.

A few of the larger tributary rivers in the Tennessee Valley remain unimpounded (undammed), including the Emory, Sequatchie, North Fork Holston, and Buffalo Rivers. Also, extensive stream reaches exist above reservoirs on the Clinch, Powell, and French Broad Rivers, and there are long stretches of flowing streams below headwater reservoirs on both the Duck and Elk Rivers. These large free-flowing rivers, like their smaller tributaries, support extremely diverse aquatic communities.

Tributary Reservoirs and Tailwaters

Reservoirs on tributary rivers of the Tennessee River are typically deep storage reservoirs that retain waters for long periods of time. Little flow and regular periods of thermal stratification result in oxygen depletion in the deeper water. These aquatic habitats are simplified relative to undammed streams, and fewer species are found. However, some species relatively rare in streams (e.g., largemouth bass [*Micropterus salmoides*], gizzard shad [*Dorosoma cepedianum*]) develop large populations in these reservoirs. Other non-native fish species, such as striped bass (*Morone saxatilis*), have been introduced into some reservoirs to fill unexploited niches, producing popular sport fisheries.

Even though TVA attempts to enhance fish spawning by providing stable pool levels for a two-week period during the peak of the spring spawning season, certain aspects of reservoir operations are detrimental to fish populations in tributary reservoirs. The most productive region of a reservoir is the shoreline because of submerged vegetation for cover and organic material and aquatic invertebrates (benthos) for food. Operations that alter this reservoir margin have a variety of negative effects. Water level drawdowns for hydroelectric power production destroy cover and reduce the food supply for young-of-year fish. Drastic changes in levels due to flood control can discourage spawning, strand fish eggs on the shoreline, and leave fish in isolated pools.

Lack of minimum flows in the first few miles below tributary dams may severely limit the habitat needed by native fish. It may restrict their movement, migration, reproduction, and available food supply. On days when turbine use is intermittent, daily temperature variations of 5 to 9 degrees C (41 to 48 degrees F) are common in tributary tailwaters and can stress some fish species. Dissolved oxygen levels of less than 5 or 6 milligrams per liter affect fish growth, and levels of less than 3 or 4 milligrams per liter lead to decreased survival and poor reproduction. TVA has recently implemented a plan to improve dam tailwater conditions by maintaining minimum continuous flows and aerating releases below 16 dams to increase dissolved oxygen. TVA will also delay unrestricted summer drawdown until the first of August on 10 tributary reservoirs to improve recreation and associated economic development.

For the most part, TVA tributary reservoir releases support healthy stocked cold-water fisheries, primarily rainbow and brown trout (*Salmo trutta*). The ability of tailwaters below dams to support these fisheries is one of the positive effects of TVA reservoir system construction. The Chatuge Reservoir tailwater supports a self-sustaining wild trout population. A few tailwaters, such as those below Douglas and Cherokee reservoirs, support cool- and warm-water fisheries.

Benthic invertebrates (benthos), are a vital part of the food chain of aquatic ecosystems. Benthos refers to the wide variety of animals that live on or in the first few inches of the mud, sand, gravel, or other material that makes up the bottom of streams and lakes. Benthic life includes worms, snails, and crayfish, which spend all of their lives in or on the substrate, and aquatic insects, mussels and clams, which live there during all or part of their life cycle. They transform nutrients and organic material into biomass and provide a food base for fish and other vertebrate predators.

Most benthic organisms have specific habitat requirements in terms of physical, chemical, and biological factors. Alterations of these factors cause changes in both the composition and productivity of the benthic community. Many benthic organisms have narrow habitat requirements that are not always met in reservoirs or tailwaters. Benthic organisms generally are extremely limited in the deep portions of tributary reservoirs because of the low water flow and low dissolved oxygen. Shoreline habitat is limited because of water level fluctuations. In the tailwater areas below tributary dams, only those species survive that can tolerate low dissolved oxygen, high turbulence, and cold temperatures. Further downstream, the number of benthic species increases as natural reaeration occurs, dissolved oxygen rises, and temperatures climb.

Because most tributary reservoirs are deep and have long hydraulic retention times, they tend to follow the pattern described above. They have thermal stratification persisting during the warm months and one period of complete mixing that lasts throughout the colder months. During stratification, light and nutrients in the mixed layer combine to produce phyto-

plankton, microscopic plant life, which in turn supports a growing zooplankton microscopic animal life community. The productivity of this layer is usually limited by nutrient inflows from the watershed and varies from reservoir to reservoir.

During the period of complete mixing, nutrients and organic materials that have accumulated in the deeper water and sediments are recycled to the surface, where they promote the growth of phytoplankton. Because most of the inflowing nutrients and organics are retained in the reservoir, less are released downstream, so the tailwaters tend to be less productive than the river before it was dammed.

Mainstream Reservoirs

The nine mainstream reservoirs on the Tennessee River differ from tributary reservoirs primarily in that they are more shallow, have greater flows, and thus have much lower hydraulic retention times. They generally do not become as strongly stratified as tributary reservoirs. Although dissolved oxygen in the deeper regions of the reservoir is often reduced, it is seldom depleted. Winter drawdowns on mainstream reservoirs are much less severe than on tributary reservoirs, so bottom habitats generally remain wet all year. This benefits benthic organisms and promotes the growth of aquatic plants in the extensive shallow overbank areas of some reservoirs. These plants benefit fisheries by providing cover and nursery habitat, but create extensive mosquito breeding areas and have led to conflicts among fishermen, boaters, and shoreline landowners whose access to the water is limited by thick vegetation.

The lack of stratification in mainstream reservoirs creates a habitat where plankton are constantly cycled into and out of the zone with sufficient sunlight for growth. This creates some of the same inhibitions on growth that limit plankton production in large undammed rivers. Ordinarily, however, these factors are sufficiently muted to permit sufficient plankton growth to support healthy aquatic communities. Phytoplankton growth in Tennessee River mainstream reservoirs is more likely to be limited by light than by nutrient availability.

Since oxygen depletion near the bottom is rare, benthic communities occur in the mainstream reservoirs. However, species diversity is low in comparison to the rivers before reservoirs were formed. Benthic communities in mainstream reservoirs tend to be dominated by midge larvae, aquatic worms, mayflies, mussels, and sometimes caddisflies and snails.

The effect of dams on benthic species diversity is most readily apparent in mussels. Because of their long lives, sedentary nature, and tendency to occur clumped in areas of suitable habitat, mussels are highly vulnerable to disruptions of habitat or changes in environmental factors. Prior to the formation of reservoirs, the Tennessee River and its tributaries supported a large and diverse mussel fauna. Damming the rivers reduced the amount of suitable habitat (shallow, flowing water over stable gravel or cobble bottom). Today, there are only about 175 miles of suitable mussel habitat in the Tennessee River. This represents 27 percent of what once existed. Nearly all of this is located in Guntersville, Wheeler, Pickwick, and Kentucky reservoirs, where commercial musseling is still carried on. Pollution, sedimentation, and commercial overharvesting have adversely affected mussel stocks that survived the destruction of habitat due to dams. Recent investigations indicate that mussel stocks in the main river and most tributaries are continuing to decline. Mussel species dominate the list of threatened and endangered species in the Tennessee Valley.

The Asiatic clam *(Corbicula fluminea)* was introduced into the Tennessee river from the West Coast during the 1950s. It is now a major component of the benthic community throughout the Tennessee system and has been implicated as a fouling agent in water intake structures.

A more recent and potentially more troublesome invader is the zebra mussel *(Dreissena polymorpha)*, which recently reached the Tennessee River via barge traffic from the Great Lakes area, where it was introduced from Eurasia in the mid-1980s. Zebra mussels are now present in low numbers throughout the length of the river and are likely to increase in numbers during the next few years. Because of their tendency to attach in large numbers to firm substrates, zebra mussels have enormous potential for biofouling (clogging) power plant water intakes and other systems that use raw water. It is estimated that zebra mussels will cost water users in excess of $5 billion in the Great Lakes area alone by the year 2000. Zebra mussels will be a major factor in future decisions regarding the type and location of any new water-using facilities in the TVA region.

Tennessee River mainstream reservoirs generally support healthy fish communities, ranging from about 50 to 90 species per reservoir. There are good to excellent sport fisheries, primarily for black basses (*Micropterus* spp.), crappie (*Pomoxis* spp.), sauger (*Stizostedion canadense*), white (*Morone obrysops*) and striped basses (*Morone saxatilis*), sunfish (*Lepomis* spp.), and catfish (*Ictalurus* spp.). The primary commercial species are channel (*Ictalurus punctatus*) and blue catfish (*Ictalurus furcatus*) and buffalo (*Ictiobus* spp.). Fish consumption advisories have been issued for some reservoirs, notably Wheeler for DDT contamination and Nickajack, Watts Bar, and Fort Loudoun for PCB contamination.

Cumberland River

The Cumberland River is formed by the junction of the Poor and Clover Forks in Harlan County, Kentucky, about 693 miles above its confluence with the Ohio River near Smithland, Kentucky *(Figure T1-63)*. The river flows westerly, then southwesterly into Tennessee. At Nashville it turns northwesterly back into Kentucky, emptying into the Ohio River about 58.5 miles upstream of the junction of the Ohio and Mississippi rivers. The drainage area of the Cumberland is 17,598 square miles. A system of locks and dams makes the Cumberland commercially navigable (maintained 9 foot channel) from the Ohio to mile 381.0 at Celina, Tennessee. TVA operates two fossil plants on the Cumberland, Gallatin on Old Hickory Lake and Cumberland on Barkley Lake. The hydroelectric plant at Great Falls Dam on the Caney Fork is also part of the TVA system.

The Nashville District United States Army Corps of Engineers operates nine multi-purpose reservoirs which incorporate hydroelectric production facilities on the Cumberland River and tributaries. Approximately half the power production from eight of these projects is marketed through the Southeastern Power Administration to TVA. The Corps of Engineers does not anticipate any significant changes in these power resources. The Corps of Engineers has, however, completed a hydropower optimization feasibility study at Lake Cumberland which focused on uprating the existing six units at Wolf Creek Powerhouse for peaking operation. On the middle Cumberland River reservoir regulation integrates the need for adequate cooling water at TVA's Gallatin and Cumberland City Fossil Plants on Old Hickory Lake and Lake Barkely, respectively. In addition, the Corps of Engineers has performed a preliminary analysis of pumpback at Laurel Lake on the Upper Cumberland River.

SURFACE WATER

The Cumberland River and its tributaries generally exhibit moderate to high concentrations of calcium and magnesium and a slightly alkaline pH because much of the basin is comprised of limestone and dolomitic bedrock. Total dissolved solids concentrations, a measure of all salts in solution, range from 1.0 to 100 milligrams per liter (mg/L) in the upper Cumberland, upstream of Nashville. These low values contrast with the generally higher concentrations of dissolved solids in the lower Cumberland watershed, in particular the mainstream river downstream of Nashville (U.S. Army Corps of Engineers 1975). There total dissolved solids concentrations range from 100 to 300 milligrams per liter. These increased concentrations are due in part to a change in rock formation in the Nashville area. The area east of Nashville is underlain by Ordovician Age limestones and shales, which is more resistant and less soluble than the Mississippian Age limestones, found in the area west of Nashville. The first is more resistant and less soluble than the latter.

Generally, the mainstream Cumberland River exhibits lower suspended solids concentrations than its tributaries. Suspended solids in the mainstream and in the upper Cumberland watershed tributaries usually range in concentrations from 0 to 300 milligrams per liter. The lower Cumberland watershed tributaries, west of Nashville, are characterized by higher suspended solids concentrations ranging from 300 to 2,000 milligrams per liter. The higher values in the lower Cumberland watershed tributaries are caused in part by differences in soils and rock formation. The Mississippian materials of the lower watershed are generally more erosion prone than the Ordovician materials of the upper watershed. Topography and land usage also influence the erodibility of the lower Cumberland tributary valleys.

Erosion due to runoff in the lower Cumberland watershed is the primary source of the suspended solids described above. Shoreline and stream-bank erosion are also thought to be major contributors of silts and clays. The generally lower suspended solids levels in the mainstream river result from dredging for the navigation channel of the river. This has created areas of reduced velocity and formed deposits of sediment. Sediment deposition also occurs in the upper Cumberland flood control reservoirs, upstream of the study area. Wolf Creek Dam, Dale Hollow Dam, Center Hill Dam, and J. Percy Priest Dam trap large amounts of suspended solids and sediments, and discharge waters with relatively low suspended solids levels into areas downstream.

GROUNDWATER

The formations that comprise the Mississippian carbonate aquifer in the Highland Rim and the Ordovician carbonate aquifer in the Central Basin of the Cumberland River basin are primarily limestone and dolomite, with small amounts of shale. Water in these carbonate aquifers occurs in solution-enlarged openings and resides in confined-to-partly-confined space near the land surface. It can also be confined at depth in aquifers. These aquifers are important sources of drinking water for rural users and some public supplies.

The Mississippian carbonate and Ordovician carbonate aquifers are connected to land surface by caves and sinkholes in many areas and are susceptible to contamination. In general, the water hardness exceeds 200 milligrams per liter as calcium carbonate. In the Highland Rim, iron and sulfate concentrations in water from the Mississippian carbonate aquifer may exceed 0.30 and 500 milligrams per liter, respectively. The odor of sulfide is detectable in water from some wells.

SURFACE WATER

The Ohio River supplies more than one-half of all surface water withdrawn in the state. It forms the northern boundary of Kentucky for a distance of 664 stream miles. The river system drains an area of 33,300 square miles in Kentucky (about 82 percent of the state). Identifying sources of contamination in such a large basin is difficult. The Ohio River Valley Water Sanitation Commission is responsible for evaluating water quality in the mainstream.

GROUNDWATER

The alluvial aquifer, an aquifer which exists in material deposited by flowing water, along the Ohio River is by far the most intensively used aquifer in Kentucky. Many towns and industries located along the river depend upon large surface supplies from the river and on groundwater supplies from shallow wells in the alluvium. Properly constructed wells near the river can induce infiltration of stream flow, which ensures dependable supplies. The quality of water in the alluvium generally is suitable for most uses but may require treatment for excessive hardness and iron for some uses. Hardness commonly exceeds 300 milligrams per liter as calcium carbonate, and iron commonly exceeds 1 milligram per liter. Contamination of the aquifer by wastes from industrial sites and from landfills and septic tank systems in urban areas poses the most serious water quality-related problem. High groundwater levels are a potential problem in the Louisville area, where water levels are just a few feet below structures in some places.

AQUATIC LIFE

The lower Ohio River is a large river habitat, often turbid or cloudy, with swift currents. Bottom substrates or stream beds are often rocky near shore, with cobble, gravel, and sand in the channel. The benthic community includes a substantial mussel population in certain areas, which is threatened by zebra mussels. Zebra mussels are now found in large numbers throughout the lower Ohio River. A very high percentage of native mussels from Smithland Dam to the Mississippi River have been found to have zebra mussels attached to their shells. Large numbers of attached zebra mussels interfere with the feeding and movement of native mussels. In other areas, they have resulted in the virtual elimination of native mussel populations.

New dams on the lower Ohio (i.e., Newburgh, Uniontown, and Smithland) have created reservoirs on that section of the river. These reservoirs have in turn created additional flooded brush and timber habitat, as well as small embayments in the lower portions of tributary streams. The fishery for black bass (*Micropterus* spp), crappie (*Pomoxis* spp.), and bluegill (*Lepomis macrochirus*) has been greatly enhanced by this additional habitat. The tailwaters of these dams provide outstanding fisheries for striped bass (*Morone saxatilis*) and sauger (*Stizostedion canadense*).

Fish consumption advisories have been placed on paddlefish (*Polyodon spathula*), paddlefish eggs (harvested for caviar), channel catfish (*Ictalurus punctatus*), carp (*Cyprinus carpio*), and white bass (*Morone obrysops*) along the entire length of the Ohio River bordering Kentucky because of chlordane, a pesticide, and PCB contamination. Little Raven Creek, a tributary below Paducah, has a consumption advisory for all fish species due to PCB contamination. Also, the West Kentucky Wildlife Management Area Lakes, which are oxbow and overflow lakes that drain into the Ohio River below Paducah, have a consumption advisory for largemouth bass (*Micropterus salmoides*) because of mercury contamination.

Green River

The Green River Basin is located in south central Kentucky and north central Tennessee. The drainage area is 9,273 square miles, of which 377 are in Tennessee. The Green River rises in Lincoln and Casey Counties in Kentucky and flows generally westward for 330 miles to its confluence with the Ohio River just upstream from Henderson, Kentucky. A system of seven locks and dams enables navigation on the downstream portion of the Green River.

The upper basin is characterized by rugged, hilly terrain. The central part of the basin drains the Karst region, an area that is interlaced with large cave systems. The Karst region includes Mammoth Cave National Park. In the Karst region, surface streams are almost non-existent. Most of the water drainage is subterranean, eventually draining to the Green River via large springs. The lower basin consists primarily of alluvial plains. TVA's Paradise Fossil Plant is located on the Green River about 100 miles from the mouth.

SURFACE WATER

The Green River basin contains about one-fourth of Kentucky's land area and is the largest drainage basin in the state. Reservoirs have been constructed by the U.S. Army Corps of Engineers on the Rough, Nolin, and Barren Rivers, as well as on the mainstream of the Green River in the upper basin. The topography in this section of the Interior Low Plateaus is characterized by gently rolling terrain underlain by limestone in the upper basin and hills and broad flood plains underlain by sandstone, shale, and coal in the lower basin. Land uses in the upper basin include agriculture, urban areas, and mining or drilling. Major sources of stream contamination in the upper basin are agriculture

(sediment, nutrients, and pesticides); mining or drilling (chloride); on-site and municipal wastewater-treatment systems (decomposable organic matter, nutrients, and bacteria); and urban stormwater runoff (toxic metals, nutrients, and sediment).

Concentrations of chloride in the upper basin of the Green River are higher than those recorded at other locations in the basin and have been associated with brines from oil production. However, dissolved solids concentrations in the upper basin were not high relative to those in other Kentucky streams. Concentrations of sulfate, another major component of dissolved solids were low in samples collected during 1987-89. The relatively high median concentrations of nitrite (0.87 milligrams per liter) and suspended sediment (27 milligrams per liter) were among the highest for Kentucky's monitoring locations. The high values possibly were due to agricultural and urban runoff and municipal wastewater discharges.

GROUNDWATER

The Pennsylvanian aquifer system in the Green River basin is in the coal mining regions of eastern and west central Kentucky. Wells tapping these aquifers are used for domestic and livestock supplies.

Concentrations of dissolved solids in water from the shallow groundwater circulation zone of the Pennsylvanian aquifer system in eastern Kentucky generally do not exceed the drinking water standard. The water is moderately hard, with only about 25 percent of the hardness values being larger than 120 milligrams per liter. The water generally contains iron in excess of the secondary drinking water standard. Concentrations of chloride generally are smaller than 110 milligrams per liter, and 90 percent of the nitrate concentrations are smaller than 1.2 milligrams per liter.

Water from the Pennsylvanian aquifer system in west central Kentucky generally contains dissolved solids concentrations larger than 500 milligrams per liter. Water from these aquifers is hard to very hard—the median hardness is 120 milligrams per liter. Concentrations of iron generally are larger than 300 micrograms per liter, and chloride concentrations normally are smaller than 60 milligrams per liter. Concentrations of nitrate are larger in the western Kentucky Pennsylvanian aquifers than in the eastern Kentucky Pennsylvanian aquifers. In the western Kentucky aquifers, 25 percent of the nitrate concentrations are larger than 1.2 milligrams per liter, compared to 10 percent for the eastern Kentucky Pennsylvanian aquifers.

The coal mining regions of eastern and western Kentucky are being mined and extensively explored for oil and gas reserves. Water samples from deep oil-test wells commonly are salty.

AQUATIC LIFE

The four reservoirs in the Green River basin are headwater reservoirs. They generally possess the same characteristics in terms of depth, stratification, water level fluctuations, and impacts on aquatic communities as the tributary reservoirs described in the Tennessee River basin. In addition to these reservoirs, there are also six navigation locks and dams on the Green River and one on the Barren River. These are virtually run-of-the-river dams and appear to stabilize the river substrate or stream beds and protect aquatic life.

Green River contains a varied habitat which supports 146 fish species representing 22 taxonomic families. Additionally, Green River contains a diverse benthic community including a number of mussel species. Some of the upper basin tributary streams and reservoir tailwaters support good sport fisheries for rainbow (*Oncorhynchus mykiss*) and brown trout (*Salmo trutta*). Additionally, a good muskellunge (*Esax masquinongy*) fishery exists in the central and upper basins in both reservoirs and major streams. The reservoirs and the larger streams in the lower basin provide good warm-water fisheries for largemouth bass (*Micropterus salmoides*), white crappie (*Pomoxis* spp.), blue (*Ictalurus furcatus*) and channel catfish (*Ictalurus punctatus*), and bluegill (*Lepomis macrochirus*).

The major source of pollution in the Green River Basin is mining in the western coal-fields region of the lower basin. The river is very turbid or cloudy due to runoff from these coal fields and extensive barge traffic. Other sources of pollution in the basin include municipal wastewater-treatment plants and agricultural runoff. Two streams in the basin currently have fish consumption advisories in place for PCB contamination: Drakes Creek from the city of Franklin to the Barren River, and Mud River from the city of Russellville to the Green River.

Mississippi River

The lower Mississippi River in the reach that borders west Tennessee is one of the largest rivers in the world. Its drainage basin includes nearly all of the United States between the Rocky Mountains and the Appalachian Mountains. The drainage basin is 1,247,000 square miles and includes the nation's most productive industrial and agricultural regions. Ships can travel the river for more than 1,800 miles from Minneapolis, Minnesota, to the Gulf of Mexico. TVA operates the Allen Fossil Plant on the Mississippi River at Memphis, Tennessee.

SURFACE WATER

The Mississippi River has an average daily discharge of 312,000 million gallons per day at Memphis, Tennessee, and 377,000 million gallons per day at Vicksburg, Mississippi. In general, the quality of water in the Mississippi is suitable for most uses. The median concentrations of alkalinity (106 milligrams per liter), sulfate (55 milligrams per liter), dissolved solids (239 milligrams per liter), and nitrite plus nitrate (1.2 milligrams per liter) were much less than the federal criteria for untreated drinking water supplies. About half of the sulfate in the Mississippi River is due to runoff over weathered rock, and the other half is due to biochemical processes and human activities.

GROUNDWATER

The most extensive and productive aquifer in Tennessee is the Tertiary sand, along the Mississippi River, which supplies about 190 million gallons of water per day to the city of Memphis. Calcium bicarbonate-type water from this confined aquifer has small concentrations of dissolved solids (90 percent of analyses are less than 163 milligrams per liter), and is generally soft (median hardness is 39 milligrams per liter). The only major water quality problem is a large iron concentration, which requires that the water be treated before use. The median iron concentration is 600 micrograms per liter.

There is concern, however, that leakage of contaminated water from the overlying alluvial aquifer may degrade water quality in the Tertiary sand. In addition, several hazardous waste sites are located in recharge areas of this important aquifer.

The chemical characteristics of water in the shallow (less than 200 feet below land surface) Mississippi River alluvial aquifer are fairly uniform throughout the aquifer. A chemical quality change occurs gradually, with depth as the result of ion exchange and other natural geochemical processes. Dissolved solids concentrations and pH values of water at depths of about 100 feet or less in recharge areas may be much smaller than 100 milligrams per liter and 7 standard units, respectively.

AQUATIC LIFE

The lower Mississippi River is turbid and swift, with shifting sand and silt substrates or stream beds that are not conducive to colonization by benthic organisms. Commercial fishing occurs on the Mississippi, primarily for catfish (*Ictalurus* spp.) and buffalo (*Ictiobus* spp.). Zebra mussels now occur throughout the Mississippi River. A significant sport fishery for largemouth bass (*Micropterus salmoides*), crappie (*Pomoxis* spp.), and bluegill (*Lepomis macrochirus*) exists in the numerous cutoffs, oxbows and backwater sloughs found in this section of the river. A fish consumption advisory for chlordane contamination is in effect for all fish species in the Mississippi River adjacent to Shelby County, Tennessee (Memphis), and McKellar Lake, Wolf River, Loosahatchie River and Nonconnah Creek, which are tributaries to the Mississippi River in Shelby County.

Water Quality Indices and Rationale for Weightings

TVA's existing energy resources and many of the energy resource options considered for Energy Vision 2020 can affect water quality. The primary impact categories evaluated for Energy Vision 2020 include: human health by ingestion, water supply and waste assimilation, and fish and aquatic life and biodiversity. A full explanation of the process used to develop measures for environmental evaluation criteria can be found in Volume 2, Technical Document 4, Evaluation Criteria.

Water Quality Indices

Water quality indices were developed to help characterize how TVA power system operations might contribute to each of the impact areas selected. The indices provide measures to evaluate environmental impacts of alternative future energy supply strategies. Measures in the indices are weighted by the relative contribution of TVA power system operations to water quality impacts and issues.

Eight measures of power system operation that affect water quality are used to evaluate the three impact areas. There are two direct measures: water consumption and water use. Six surrogate measures were used: coal burned; heat releases to surface water; power production by coal-fired, nuclear, and hydroelectric plants; and the number of new power plants constructed. A surrogate measure is a substitute measure that varies in the same way as the pollutant it represents. The uses of these eight measures in the index and their weighting factors are given in the table in *Figure T1-66*.

HUMAN HEALTH—INGESTION

The discharge of toxic metals in waste streams from coal-fired power plant sites presents the greatest potential risk to health from ingestion (eating or drinking) and is estimated at 50 percent of TVA's effects. These discharges are made directly to water bodies that supply drinking water for humans and livestock and serve as habitats for aquatic organisms. As a result, toxic metals can become concentrated in fish tissue.

FIGURE T1-66 Weighting Factors for Water Quality Evaluation Measures Used in Three Impact Area Indices

Environmental Measure	Health Ingestion	Water Supply and Waste Assimilation	Fish and Aquatic Life and Biodiversity
Heat Releases to Surface Water		0.10	0.05
Water Consumption		0.10	
Water Use			0.03
Coal Burned			0.20
Nuclear Power Production	0.05		0.02
Coal Power Production	0.60		0.05
Hydroelectric Peaking Power Production	0.35	0.80	0.60
New Power Plants Constructed			0.05

For effects on human health, the hazards of atmospheric deposition are considered low and are estimated at 10 percent of total human health-ingestion effects. Mercury in flue gases is the contaminant of main concern. Its concentration in the gas is small, and atmospheric dispersion decreases the concentration further. A secondary consideration is acid rain effects on water bodies resulting in the mobilization of metals in lakes and streams. This is not an important issue in the TVA region, however, because the geology of most of the region, with the exception of some Appalachian Mountain areas, provides ample buffering capacity to resist changes in pH. The surrogate measure for coal-fired power plant effects is millions of kilowatt-hours of coal-fired production. The weighting for the combined effects discussed above is 60 percent or a factor of 0.60.

Hydroelectric power plant discharge of metals released from sediments is second in importance for effects on human health due to ingestion of toxic metals and is estimated at 35 percent of total human-health effects. It is assigned a weighting factor of 0.35. It is second to coal-fired plant releases because it is likely to contain a smaller variety of metals and would only be important at tributary dams during summer months. Biomagnification may be a more important pathway for ingestion in this situation because the entire flow of the river may be contaminated, as opposed to a contaminant plume that organisms could avoid. The surrogate measure for hydroelectric plant effects is millions of kilowatt-hours of peaking hydroelectric production.

Because of the relatively small quantities of metals and the minute quantities of radionuclides present in nuclear plant discharges, the effect on human health by ingestion is estimated at only 5 percent (weighting factor of 0.05) of the total TVA effects. The surrogate measure for nuclear plant effects is millions of kilowatt-hours of nuclear plant production.

WATER SUPPLY AND WASTE ASSIMILATION

The primary effects on water supply and waste assimilation result from operation of hydroelectric plants. Operations alter the flow regime of the river downstream, both reducing flows and dissolved oxygen concentration at certain times. This effect is estimated at 80 percent (weighting factor of 0.80) of total TVA effects on water supply and waste assimilation and is measured by millions of kilowatt-hours of peaking hydroelectric power production. Coal-fired and nuclear power plants consume water and release heat to surface water. Water consumption adversely affects both water supply and waste assimilation, whereas heat releases only affect waste assimilation. These effects are very minor compared to the effects of altering the flow of the river and are each estimated at 10 percent (weighting factor of 0.10) of the total TVA effects. Water consumption (millions of gallons) is a direct measure, and the heat release rate (billions of Btu) is the surrogate measure for thermal effects.

FISH AND AQUATIC LIFE AND BIODIVERSITY

TVA's action in damming the Tennessee River and its tributaries to generate power, control floods, and allow navigation primarily affects aquatic life in surface waters by changing water quality and aquatic habitats. These effects are most pronounced in tributary tailwaters where altered flow patterns from hydroelectric plant releases result in dramatic reductions in numbers and kinds of aquatic life. Because these releases commonly are drawn from near the bottom of the reservoir, they cause tailwaters to be colder, lower in dissolved oxygen, and higher in toxic materials derived from sediments than undammed portions of the stream. This combination of factors is estimated to account for about 60 percent (weighting factor of 0.60) of power generation-related effects on aquatic life. The best surrogate measure would be one proportional to the amount of hydroelectric plant operation on the rivers most vulnerable to these effects. This led to the choice of millions of kilowatt-hours of peaking hydroelectric plant production.

The next most important category of effects on aquatic life is associated with the fuel cycle, specifically habitat destruction from the mining of coal and the effects of runoff from mines. These effects are widespread and difficult to quantify, but are estimated to account for about 20 percent (weighting factor of 0.20) of all TVA power system aquatic life impacts. The best surrogate measure for such effects is tons of coal burned in the pro-

duction of electric power. This should be directly proportional to mining activities.

Coal-fired generated power is estimated to account for about 5 percent of aquatic ecosystem effects. Liquid discharge from coal-fired plants, including those from ash storage and disposal, and effects of materials reaching surface waters through fallout and rainout of air pollutants are the primary factors involved. The best surrogate measure of these effects is millions of kilowatt-hours of coal-fired generated power.

The effects of releases of heated water on aquatic life were once expected to be important, but experience has shown that not generally to be the case. Releases of heated water are judged to contribute 5 percent of the overall aquatic effects by TVA, and to be best measured in gross terms by the total amount of heat released to the river from TVA coal-fired and nuclear power plants.

A related effect is drawing plankton and fish through equipment or injuring or killing them by causing them to collide with intake screens when cooling water is being drawn from the river or lake. This has been shown to cause only minor local effects (about 3 percent of the total TVA effects) on fish and aquatic life and biodiversity and is best measured by the total amount of water used by TVA power plants.

Localized effects of power-related construction activities, such as new or modified plants or transmission facilities, are considered to be minor, perhaps 5 percent, measured by the number of new plants built. Non-thermal discharges of radionuclides and miscellaneous chemicals from nuclear power plants are also relatively minor, with a 2 percent estimated weighting factor, measured by millions of kilowatt-hours of nuclear power generated.

SECTION 5: LAND RESOURCES

Introduction to Land Resources and Problems

The TVA region encompasses some 58 million acres. Of this area, non-federal rural land occupies about 50 million acres. Some of the most diverse and beautiful natural resources in the United States are in this seven-state region.

With few exceptions, virtually the entire Tennessee Valley and its adjacent region have been affected by human influences through agriculture, timber harvesting, or other land uses. Over half the Tennessee Valley region is forest lands and about 35 percent is in agricultural land uses. The remaining area is composed of open water, urban areas, and other miscellaneous land uses.

This section contains information about geology and groundwater, agricultural land, forest resources, biological resources, Class I areas, cultural resources, recreational resources, and other land uses.

Geology and Groundwater

The potential of power plants to affect the quality of groundwater is discussed in Section 3 of this document (Volume 2, Technical Document 1, Comprehensive Affected Environment). Groundwater occurs in aquifers of porous soils, sediments, and in fractures and openings of rock formations. Groundwater movement in the region ranges from very slow to very rapid and is completely dependent on site-specific hydrogeology. The distribution of groundwater in the TVA region is influenced by variability in geology, hydrology, and topography among six different physiographic regions.

PROVINCES OF PHYSICAL GEOGRAPHY

The map in *Figure T1-67* shows the TVA region's areas of physical geography. Physical geography determines the location and types of aquifers containing groundwater and the susceptibility of groundwater to various forms of pollutants. Erosion and pollutant runoff into streams are related to physical geography and soil type when power plants or other facilities are built. These aspects will be considered in environmental reviews when a site is chosen for a power plant.

The easternmost part of the region is in the Blue Ridge physiographic province, an area composed of the remnants of an ancient mountain chain. This region has a greater variation in terrain than any other region in the Tennessee Valley. Terrain ranges from nearly level along floodplains to rugged mountains that reach elevations of more than 6,000 feet. The rocks of the Blue Ridge have been subjected to much folding and faulting and are mostly shales, sandstones, conglomerates, and slate (sedimentary and metamorphic rocks of Precambrian age). A few areas, such as Cades Cove, in the Great Smoky Mountains National Park, are underlaid by carbonate rocks that contain large amounts of groundwater in solution openings. In most places, the dense, massive bedrocks contain little groundwater except where they have faulted and fractured.

Located east of the Cumberland Plateau and west of the Blue Ridge province, the Valley and Ridge province has complex folds and faults with alternating valleys and ridges trending northeast to southwest. Ridges have elevations of up to 3,000 feet and are generally capped by dolomites and resistant sandstones on the west sides, while valleys have developed in more soluble limestones and dolomites. The dominant soils in this province are residual clays and silts derived from in-situ weathering. Groundwater occurs mostly in the solution-widened fractures, joints, and bedding planes. Karst features such as sinkholes and springs are numerous in the Valley and Ridge. ("Karst" refers to a type of topography that is formed in carbonate rocks by dissolution and that is characterized by sink holes, caves, springs, and underground drainage.)

The Cumberland Plateau rises about 1,000 to 1,500 feet higher than the adjoining Valley and Ridge Province and Highland Rim. It extends about 175 miles, ranging northeast to southwest across central Tennessee. The bedrock is a sequence of near horizontal Pennsylvanian sandstones, shales, conglomerates, and coals, underlaid by Mississippian and older shale and carbonates. The area underlaid by the resistant Pennsylvanian sandstones has produced a "table-top" landscape. Groundwater usually occurs in areas of shallow, sandy soils and in deeper cracks in the bedrock. At depth, the Mississippian carbonates possess mature Karst features. Sinkholes, large caves, sinking streams, and springs typify the landscape, resulting in a complex aquifer system. Rapid groundwater movement is typical.

The Highland Rim section of the Interior Low Plateaus province presents a gently rolling plateau that occupies much of central Tennessee and parts of Kentucky and northern Alabama. The bedrock of the Highland Rim is flat-lying Mississippian carbonates. These formations constitute the most extensive aquifer in the Tennessee region. The Mississippian formations weather to form a deep flinty overlay typically exhibiting a rubble zone at the interface of the soil and bedrock. In places this overlay may rest directly on Chattanooga shale, which

serves as an aquitard. In many places the carbonate bedrock transports groundwater rapidly. However, in the broad dissected highlands, streams barely cut into the overlay and therefore have little effect on the discharge of water.

The Central Basin (Nashville Basin) of the Interior Low Plateaus province is an oval area in middle Tennessee lying about 200 feet below the surrounding Highland Rim. The bedrock is carbonate rocks that are generally flat-lying but are locally folded. Soil cover is usually thin, and surface streams cut into bedrock. Groundwater usually occurs in areas of carbonate rock that have been dissolved by water and in cracks in bedrock. The lack of unconsolidated overlay, along with open joints in rock, allows rapid runoff and infiltration of precipitation. Water is briefly stored above stream level and rapidly discharged to streams and springs through solution openings. As a result, small streams respond quickly to precipitation and have poorly sustained base flows.

The Coastal Plain province extends along the western edge of the region, and the Tennessee River flows along the eastern boundary against the edge of the Highland Rim. The major aquifers of the Coastal plain section lie in unconsolidated formations. They are of alluvial origin and consist of a heterogeneous assemblage of gravels, sands, silts, and clays. Occurrence of groundwater in the alluvial aquifers depends, in part, on the thickness of the formation and hydraulic characteristics of media composing the aquifer.

SOILS

A complex and diverse mosaic of soils reflects the great contrasts in geology and topography in the TVA region. Typically, the valley and river bottom soils are quite fertile and are used primarily for agriculture. In contrast, the forested ridges and mountains often have soils which have been highly leached and are therefore less fertile.

Impacts/Acidic Deposition and Deposition of Nitrogen

Current levels of acidic deposition are not thought to have significant impacts on the soils of the TVA region, with the exception of those in the higher elevations in the eastern portion of the region (Irving, 1991). TVA's contribution to acidic deposition is discussed earlier in Section 2 of this document (Volume 2, Technical Document 1, Comprehensive Affected Environment). Higher inputs of acidic deposition could accelerate depletion of base nutrients beyond the soil's natural ability to replenish them in soils with low buffering capacities and nutrient levels. Nutrient deficiencies could eventually occur and adversely impact forest productivity. As soil acidifies, toxic metals, such as aluminum, become more mobile and can damage plant roots. Fish and other aquatic life may be affected when aluminum is leached from the soil into surface waters. Other metals such as lead, cadmium, and zinc are also considered toxic and may be mobilized as soil acidification continues. Soil acidification and its associated impacts are of particular concern in the Great Smoky Mountains National Park, located in the eastern portion of the Energy Vision 2020 study area, and in Class I wilderness areas.

In some instances, acidic deposition can be beneficial to soils and plants through its fertilizing effects. Sulfur and nitrogen, essential plant nutrients, are often found in limited concentrations or unavailable forms in the soil. Studies have shown that atmospheric inputs of these elements can meet specific crop needs. Nitrogen, an essential element required by all plants will generally have a positive impact in most Tennessee Valley forests; however, it can become detrimental when present in excessive amounts, especially in high elevation forests. Excess nitrogen in high elevation forests can trigger adverse physiological changes within certain plants and can contribute to soil acidification. TVA's contribution of nitrogen oxides is discussed earlier in Section 2, Air Resources of this document (Volume 2, Technical Document 1, Comprehensive Affected Environment).

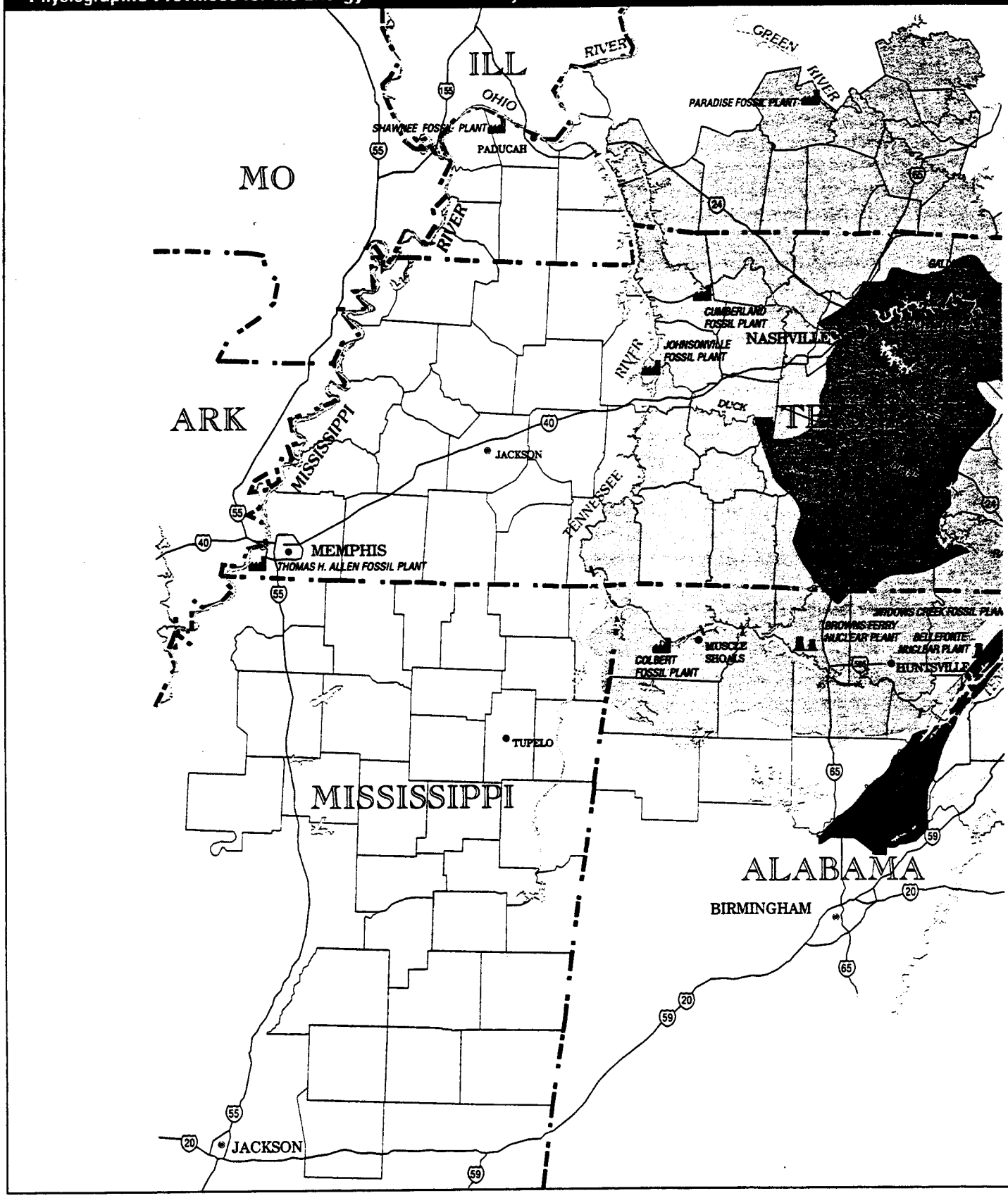
Soil Erosion

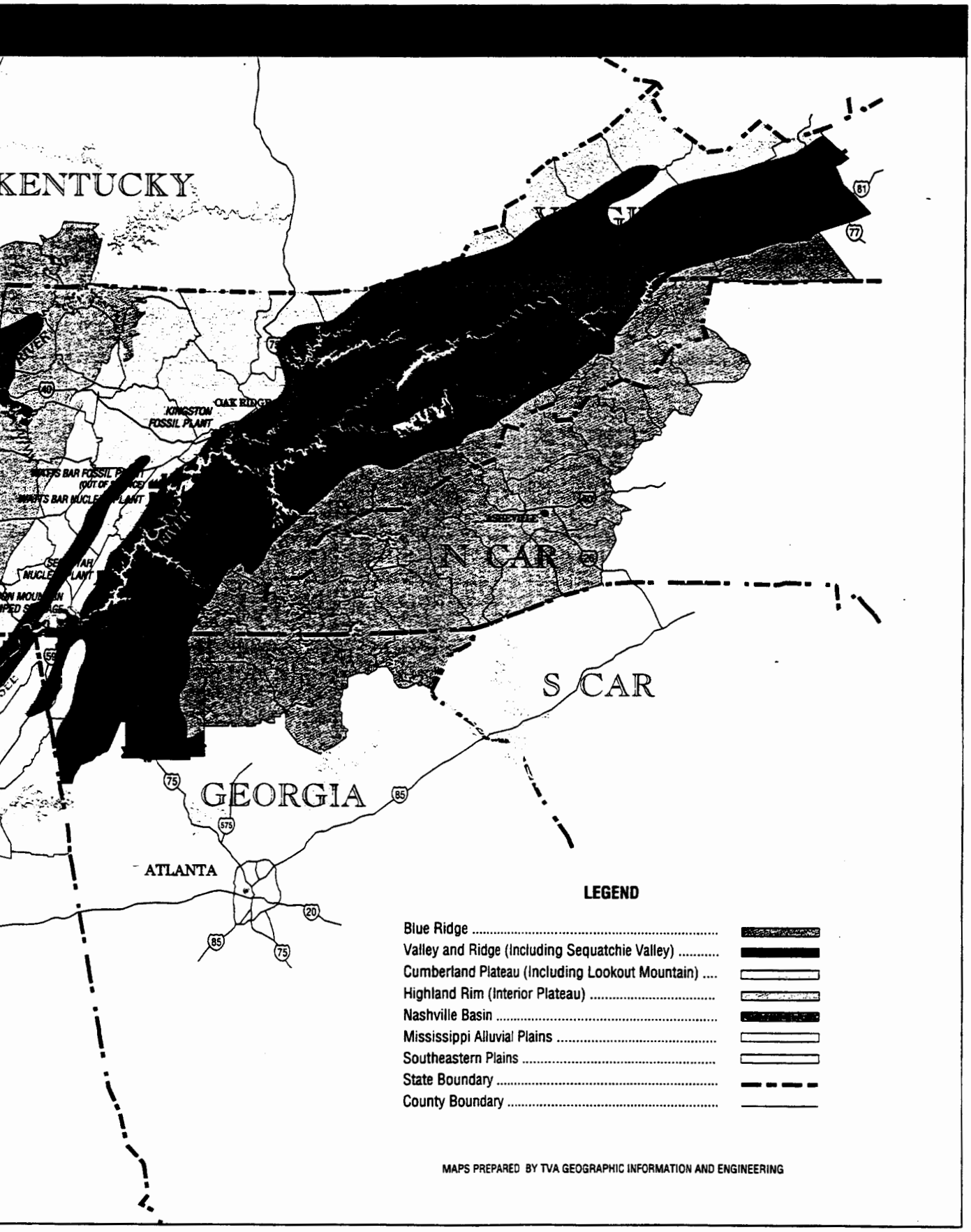
As in all areas inhabited by man, resource problems do exist. Erosion from all land uses in the region due to water or runoff is estimated to be 187 million tons annually (NRI 1982). Eighty-four percent of the erosion is considered to exceed tolerance levels for sustaining present land uses established by the Natural Resource Conservation Service.

Regionally, cropland has the largest percentage of land with excessive erosion. Cropland acreage represents approximately one-fourth of the region, and 51 percent of this acreage is estimated to be eroding at rates exceeding tolerance. This excessive erosion can be linked to the extreme vulnerability of the region's soils to the loss of productivity, which in turn affects farm income.

Some of the coal used to fuel TVA's power plants comes from surface mining. TVA's coal usage is discussed in Volume 2, Technical Document 2, Environmental Consequences. Soil erosion resulting from surface mining remains a concern for some parts of the region. Although production techniques have improved greatly, surface mining still promotes soil degradation and erosion to some extent.

FIGURE T1-67. **The Surface Geography Shown as Physiographic Provinces for the Energy Vision 2020 Study Area**




KENTUCKY
KINGSTON FOSSIL PLANT
OAK RIDGE
N CAR
S CAR
GEORGIA
ATLANTA
LEGEND
Blue Ridge
Valley and Ridge (Including Sequatchie Valley)
Cumberland Plateau (Including Lookout Mountain)
Highland Rim (Interior Plateau)
Nashville Basin
Mississippi Alluvial Plains
Southeastern Plains
State Boundary
County Boundary
MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

Agricultural Lands

INTRODUCTION

Crops in the TVA region can be either positively or negatively affected by emissions from TVA power plants. Section 2, Air Resources in this document (Volume 2, Technical Document 1, Comprehensive Affected Environment) contains a discussion of potential effects.

Small farms that grow and market a wide diversity of agricultural products characterize agriculture in the Tennessee Valley. This region encompasses a wide range of soil types and properties. They range from the delta soils of the western region, producing abundant row crops, to the mountainous topography of the east, dotted with small farms producing a variety of traditional crops and high-income products such as Christmas

FIGURE T1-68 U.S. Crop Production Rankings of States in the TVA Region

	TVA REGION STATES						
Crops	**Alabama**	**Georgia**	**Kentucky**	**Mississippi**	**North Carolina**	**Tennessee**	**Virginia**
GRAINS							
Rice (All)				5			
Corn (Sweet)		9					
Rye		2			4		
VEGETABLES							
Tomatoes (F)		6				8	5
Tomatoes (P)							
Cucumbers (F)		4			9		7
Cucumbers (P)					3		
Lima Beans (F)		2					
Snap Beans (F)		4			8	5	9
Snap Beans (P)						9	
Onions (F)							
Watermelons (F)		5			9		
Cantaloupes (F)		5					
Bell Peppers (All)			8		7		10
Cabbage (F)		4			9		8
Spinach (F)							6
Sweet Potatoes	6	7		5	1		10
Spring Potatoes	6				3		
Summer Potatoes							5
FRUITS AND NUTS							
Strawberries (All)					9		
Blueberries		6			4		
Peaches (Freestone)		3			8		9
Grapes (All)		10					
Apples (All)					7		6
Pecans	4	1		7	10		
Peanuts	3	1			4		7
OTHER							
Hay (non-Alfalfa)			3			4	
Tobacco (All)		6	2		1	3	5
Cotton (All)	9	7		3	10	8	

Note: (F) = Fresh, (P) = Processed, (All) = Fresh and Processed.
Source: USDA National Agricultural Statistics Service (NASS), 1993.

trees, tobacco, vegetables, and other specialty crops. Farm sales in the Tennessee Valley have shifted from a predominantly row-crop agriculture to one that is more balanced. Forest products have increased in importance.

A minimal portion of prime farmland could conceivably be affected by building new power plants. Any future site-specific environmental reviews for power plant siting would assess any impact to prime farmland. The major impact is conversion to industrial/residential uses associated with urban growth. Power plants can affect urban growth by supporting new industry location to the region.

AGRICULTURAL LANDS AND CROP PRODUCTION

The Tennessee Valley region is a predominantly rural area with 40 percent of the land area in crop production or pasture and hay, and 55 percent in forest cover. Major crops produced in the region are tobacco, corn, cotton, soybeans, and wheat. (See the table in *Figure T1-68.*) With the exception of wheat, average yields of these major crops in the region have been consistently below the national average. While average yields are generally increasing for major crops, the rate of increase does not appear to be as great within the region as it is nationwide. The region is also a major production area for poultry broilers as well as non-poultry livestock. (Arkansas ranks number one, Georgia ranks number two, and Alabama ranks number three, with major growing areas in Kentucky and Tennessee.)

PRIME FARMLAND

Prime farmland is land that has the best combination of physical and chemical characteristics for producing food, feed, forage, fiber, and oilseed crops and is also available for these uses. It combines favorable soil quality, a good growing season, and adequate moisture. It produces the highest crop yields with the least amount of fuel, fertilizers, and labor. About 14 million acres of prime farmland occupy the Tennessee Valley region, with 55 percent crop land, 23 percent pasture, 20 percent forest, and 2 percent nonagricultural. This is about one-fourth of the region's non-federally owned land. The proportion of prime farmland is highest in the western portion of the region and lowest in the eastern portion. Under careful management, it can be farmed continuously without harming the environment or the resource base. According to the 1992 National Resource Inventory, there are 19,793,200 acres in the TVA 201-county region of prime farmland (48% cropland, 22% pasture land, 23% forest land, and 6% non agricultural use).

Agricultural Lands and Energy Crops

Energy crops include short rotation and woody crops that potentially could provide fuel for power plants. If enough energy crops were grown, other crops could be displaced. In 1993, Oak Ridge National Laboratory published a study, "The Potential Supply and Cost of Biomass from Energy Crops in the TVA Region," that concluded agricultural land in the TVA region could potentially support 18,000 megawatts of capacity fired by wood or 30,000 megawatts of capacity fired by switchgrass. This is more than the total additional capacity needed by TVA during the planning period for Energy Vision 2020.

Forest Resources

Forests in the TVA region can be affected by emissions from power plants. Section 2 in this document (Volume 2, Technical Document 1, Comprehensive Affected Environment) contains discussion of potential effects. The information used to produce the data in this section was obtained from U.S.D.A. Forest Service Experiment Station statewide forest inventories (Alabama, 1990; Georgia, 1989; Kentucky, 1988; Mississippi 1987; North Carolina, 1990; Tennessee, 1989; and Virginia, 1992). These inventories use a sampling scheme combining a forest-nonforest classification of points on aerial photographs with measurements on forested locations at the intersection of a sampling grid. At these locations, per-acre estimates are obtained from measured trees. Each forested sample point represents from 3,000 to 7,000 acres of forest.

FOREST LANDS

The 201 counties of the Tennessee Valley region contain 58.3 million acres. Fifty-three percent of the area is forested *(Figure T1-69).* Reserved forest land, consisting of parks, wilderness areas, and other forested lands specifically withdrawn from commercial timber cutting by legislation or administrative designation, totals 944,976 acres. The remainder of the forested area, 30 million acres, or 97 percent of the forest, is classified as timberland. The following sections examine this timberland.

Non-industrial private landowners own 76.8 percent of the timberland; forest industries control 9.3 percent. Public holdings total 4.3 million acres or about 14 percent. National forests located mainly in the southern Appalachian region on the eastern edge of the TVA study area account for about 62 percent of public timberlands.

FOREST TYPES

The forest type classifications are derived from the frequency with which a species or combination of species occurs on the timberland of an area. The primary forest type in the 201-county area is the oak-hickory forest type (64 percent), followed by the loblolly-shortleaf type and the oak-pine type (14 percent each). Other forest types including oak-gum-cypress, elm-ash-cottonwood, maple-beech-birch, and white pine-hemlock (less than 9 percent).

FOREST INVENTORY

The total standing inventory of live trees 5 inches in diameter or larger is 1,447 million green tons, including growing stock and rough and rotten trees. "Growing stock" refers to wood from live trees of traditional commercial quality. "Rough and rotten trees" are of less than usual commercial quality. These two classifications may be further divided by species group into hardwood and softwood. The hardwood growing stock in the affected area is 1,033 million green tons or 91 percent; rough and rotten trees total 99 million tons or 9 percent. Softwood growing stock totals 310 million green tons (98 percent), and softwood rough and rotten totals 5 million tons (2 percent).

Among growing stock species, yellow-poplar *(Liriodendron tulipifera)* is the most common individual species (9.8 percent of total volume) followed by white oak *(Quereus alba)* (9.3 percent) and loblolly pine *(Pinus taeda)* (8.1 percent). Among hardwood groups, the oaks *(Quercus spp.)* total 37 percent of the inventory and hickory *(Carya spp.)* 7.9 percent.

GROWTH AND HARVESTS

Ideally, in order for forests to be sustainable, the volume harvested should not exceed forest growth. It is important to examine the relationship of growth and harvests (also referred to as removals) within the 201-county Tennessee Valley region.

FIGURE T1-69. **TVA Region Forest Statistics**

	Volume (Cubic Feet)	
Growing Stock	41,826,310	
Growing Stock Hardwoods	32,161,815	
Growing Stock Softwoods	9,664,495	
Rough & Rotten Stock	3,224,914	
Rough & Rotten Hardwoods	3,071,501	
Rough & Rotten Softwoods	153,413	
All Trees	45,051,224	
Hardwoods	35,233,316	
Softwoods	9,817,908	
Growth		
Total	1,429,355	
Hardwoods	1,016,785	
Softwoods	412,570	
Removals		**Ratio**
Total	870,641	1.64
Hardwoods	500,332	2.03
Softwoods	370,309	1.11
		Rate
Net Change	558,714	1.24%
Hardwoods	516,453	1.61%
Softwoods	42,261	0.44%

	Area	
	Acres	Percent of Total
Land Use		
Nonforest Land	26,375,886	45.22%
Timberland	31,005,678	53.16%
Other Forest	944,976	1.62%
Total	58,326,540	100.00%
Ownership		
National Forest	2,673,559	8.62%
Other Public	1,652,496	5.33%
Forest Industry	2,874,900	9.27%
Farmer	7,723,525	24.91%
Misc. Private	16,081,198	51.87%
Total	31,005,678	100.00%
Forest Type		
White Pine-Hemlock	282,626	0.91%
Spruce-Fir	13,130	0.04%
Longleaf-Slash	11,359	0.04%
Loblolly-Shortleaf	4,260,862	13.74%
Oak-Pine	4,221,778	13.62%
Oak-Gum-Cypress	1,712,320	5.52%
Oak-Hickory	19,933,723	64.29%
Elm-Ash-Cottonwood	141,722	0.46%
Maple-Beech-Birch	428,158	1.38%
Total	31,005,678	100.00%

Data for growing stock trees were obtained from the U.S. Forest Service inventories and does not include the effects of any harvests started after the last periodic inventory. Data for harvests indicate the average annual removal of timber from timberland since the time of the last survey (usually 7 to 9 years).

For the total growing stock resource in the 201-county area, net annual growth totals 51.3 million tons and estimated annual harvests total 31.3 million tons. Thus, annual net change in the area is 20 million tons. The net change rate (net change volume/growing stock inventory) is 1.3 percent per year.

Another measure for comparing growth and harvests is the growth/drain ratio. It is derived by dividing the volume of growth by the volume of harvests. For example, if the growth/drain ratio is 1.0, growth and harvests are in balance. In the 201-county area, the growth/drain ratio of all growing stock is 1.6.

Examining these statistics by species group can provide more insight on the changes taking place. In the TVA region, softwood growing stock growth is 14.8 million tons and harvests are 13.3 million tons, for a net change of 1.5 million tons. The growth/drain ratio is 1.1. In comparison, the annual growth for hardwoods is 36.5 million tons, and annual harvest totals 17.9 million tons, resulting in a net change of 18.6 million tons. The net change rate is 1.6 percent, and the growth/drain ratio is 2.0.

Class I Air Quality Areas

The Clean Air Act gives special protection to national parks and national wilderness areas. These areas are designated "Class I Areas" and air quality is regulated within their boundaries. According to EPA regulations, air pollution effects constitute an unacceptable adverse impact in Class I Areas if they meet any of the following criteria:

- Diminish the national significance of the area
- Impair the quality of the visitor experience
- Impair the structure and function of the ecosystem.

Federal land managers are required to assess air quality in Class I Areas and determine possible impacts of air pollutants on resources.

There are seven Class I Areas in the Tennessee Valley region, as shown in the map in Figure T1-18 (U.S. EPA 1993). These Class I Areas include Sipsy, Alabama; Cohutta, Georgia; Mammoth Cave, Kentucky; Joyce Kilmer/Slickrock, North Carolina; Linville Gorge, North Carolina; Shining Rock, North Carolina; and the Great Smoky Mountains, Tennessee/North Carolina. An additional class 1 area, the Mingo National Wilderness Area is just outside the TVA region in Missouri.

Cultural Resources

Potential impacts to cultural resources can be caused by construction of power plants, air pollutants, and by coal and uranium mining and provision of biomass fuels for power plants. Although air quality can negatively impact cultural resources within the TVA region, these potential impacts are for the most part insignificant and can generally be managed or mitigated.

A more direct potential impact to cultural resources is the procurement of fossil and biomass fuels. Strip mining for coal (fossil fuel) can impact both archaeological sites and historic structure resources. Timber harvesting (biomass fuel) can also impact archaeological sites and standing structures. Increased use of biomass fuels may also lead to changes in land use patterns through the establishment of more corporate-owned tree plantations, which can lead to the abandonment or destruction of historically or architecturally important farm complexes.

Future site-specific environmental reviews for power plant siting would assess any impacts to cultural resources and archaeological sites.

The Tennessee Valley region is renowned for its numerous archaeological sites. The National Historic Preservation Act requires all federal agencies to identify, protect, and manage significant cultural resources on their land or those affected by their undertakings whether on federal or nonfederal property. Cultural resource management is concerned with maintaining the integrity of significant archaeological remains, man-made structures or features, and sites of historical importance.

Recreational Resources

Recreational resources can be affected by power plant emissions leading to visibility impairment, by water releases for hydroelectric power production, and by other activities that could result from the selection of future resources in Energy Vision 2020. The Tennessee Valley region affords diverse scenic and outdoor recreation resources. The lakes, rivers, and mountains of the region provide a wide variety of outdoor recreation activities including fishing, skiing, swimming, hiking, hunting, wildlife observation, sightseeing, and camping and are dependent upon clean water and healthy, diverse flora and fauna. Public lands including national parks and monuments, national forests, TVA lands, and state parks and forests provide significant recreation opportunities. These public lands, as well as private lands, also provide an aesthetic "backdrop" for recreation and tourism activities in the region. Significant river-based recreation resources are provided as shown in *Figure T1-70*. The TVA reservoirs named in *Figure T1-63* are also significant river-related recreation

resources. A [illegible]plete listing of natural areas can be [illegible]d in the 18 Categories of Natural Areas Appendix at the end of this document.

In the 1980s, the South accounted for more than half of the nation's population growth and is expected to be one of the dominant growth regions into the twenty-first century. As a growing portion of the United States population leaves the active labor force, growth of retirement centers and associated travel in the South and Southwest may increase even more rapidly than in the past. Travel and tourism present significant and growing contributions to the economic activity in the Tennessee Valley region. In 1991, travel and tourism accounted for 126,000 jobs, about 5.5 percent of non-farm employment.

FIGURE T1-70 **Designated River Recreation Resources in the TVA Region**

Wild and Scenic Rivers	National Recreation Rivers
Obed-Emory Rivers (Tennessee)	Big South Fork River (Tennessee/Kentucky)
Horsepasture River (North Carolina)	Chattahoochee (Georgia)
New River & South Fork New River (North Carolina)	
Chattooga River (South Carolina/Georgia)	
Sipsey River (Alabama)	
Black River (Mississippi)	

Other Land Use Conditions

ELECTRIC AND MAGNETIC FIELDS

Implementation of Energy Vision 2020 strategies for the future may result in the construction of new transmission lines and in the installation of energy-efficient electrical appliances. Either of these activities could result in the production of electric and magnetic fields (EMF). EMF arises from both nature and human activity. For example, the earth and individual human beings produce direct current magnetic fields. Lightning is an extremely powerful electric charge. Human-produced EMF can be caused by direct current, such as the voltage from batteries, or alternating current, such as the voltage from most electric power lines in the United States. Every device that generates, transmits, or uses electricity produces electric and magnetic fields. This list includes electric appliances, motor vehicles, and electric wiring. There is no place on earth where an individual is not exposed to EMF. In modern societies, individuals are exposed to varying levels of EMF throughout their daily activities.

EMF from electric devices and power lines is generally much weaker than that produced by the human body itself and is usually too small to be noticed (Carnegie Mellon University 1989). Because this induced EMF is weak, scientists thought for many years that it had no adverse health effects. However, a 1979 epidemiological study suggested a potential link between magnetic fields associated with electric distribution lines and childhood leukemia (Bonneville Power Administration 1989). After 15 years of research, the results have been mixed. A few additional studies have suggested similar links to various forms of cancer, particularly studies of EMF exposures in occupational settings. Other studies have found no such links and no studies have yet found a cause-and-effect relationship. If EMF does pose a risk, most researchers believe the risk is low, and most scientists familiar with the issue agree that more research into the effect of EMF on health is needed. It is likely to be many years before more definitive conclusions can be reached.

High-voltage power lines have been the subject of much of the research into the potential health effects of EMF. Transmission lines are the means by which TVA-generated power reaches distribution points. When a new supply-side resource is added to the TVA system, it must be connected to the TVA transmission system. A supply-side resource built at a new plant site would require new transmission lines and possibly result in additional population exposures to EMF. In addition, other resource options, such as those involving dispersed power generation, may result in increased population exposures since they are usually built in more populated areas.

No federal regulations govern EMF exposure levels. A few states have established guidelines or standards for electric field levels. Two states, New York and Florida, have magnetic field standards. Some municipalities have established electric or magnetic field standards. None of the states in which TVA operates have set or proposed EMF standards.

TVA adopted interim guidelines in 1993 that address EMF exposures. Under these guidelines, TVA will take into account EMF exposure when planning new transmission lines. Whenever practical, TVA will route new lines to avoid homes, schools, and other densely populated areas. In addition, TVA will design new transmission lines and upgrades of existing lines to reduce EMF levels.

COAL PROCUREMENT

The amount of coal purchased by TVA and whether it comes from underground or surface operations can have differing environmental effects. Site-specific environmental impact reviews will address TVA fuel requirements in some detail.

Most of TVA's fossil plants are located near two major coal-producing regions. These regions are the southern Appalachian region, which includes eastern Kentucky, Virginia, West Virginia, Tennessee, northern Georgia, and northern Alabama; and the eastern interior region, including western Kentucky, southern Illinois, and southern Indiana. TVA purchases about 35 to 40 million tons of coal annually to fuel its 11 operating fossil plants.

TVA's eastern coal procurements are about 7.1 percent of the eastern United States production (east of the Mississippi River) and about 0.36 percent of the western United States production. The maps in *Figures T1-71* and *T1-72* show the location and intensity of TVA coal procurement in the eastern and western United States by county for fiscal year 1994. The table in *Figure T1-73* gives TVA the amount and percent of coal procurement by state.

The acquisition of low-sulfur western coal serves as one component of the compliance strategy for sulfur dioxide emission reductions required under the Clean Air Act amendments of 1990. In fiscal year 1994, 1.59 million tons, or 4.2 percent of coal procurements, were from western states. For the 1995 to 2000 period, the estimate for annual procurement of western coal is 4.2 million tons. In fiscal year 1994, 6.5 million tons of coal were procured from surface mines, 17 from underground mines, and the source of 14.3 tons was either surface or underground mines.

Land-related environmental impacts of mining are primarily the direct and indirect impacts of changes in land use. Past impacts have included acid drainage from exposed sulfur-bearing rock, erosion from disturbed mining areas and coal transport roads, loss of wildlife habitat, deforestation, stream siltation, unstable land situations, and fugitive dust; however, the Surface Mining Control and Reclamation Act (SMCRA) now addresses these issues in permitting enforcement. Other land-related mining impacts can include loss of prime farm land, encroachment on threatened or endangered species, and loss of cultural and archaeological resources.

FIGURE T1-73 **TVA Coal Procurement by State**

State	FISCAL YEAR 1994 Thousands of Tons	Percent
Colorado	1,196	3.2
Illinois	3,907	10.3
Kentucky	27,091	71.7
Ohio	213	0.6
Pennsylvania	567	1.5
Tennessee	1,008	2.7
Utah	365	1.0
Virginia	1,282	3.4
West Virginia	2,118	5.6
Wyoming	29	0.1
Total	**37,776**	**100.0**

Mines in the southern Appalachians are often developed on lands which are not well suited to agriculture. Ideally, commercial timber is harvested and marketed prior to excavation for mining. Aesthetics is another potential environmental concern. Mining operations usually clash with the surrounding landscape, and in the case of high elevation ridge-side or ridge-top surface mining, the operation may be visible for many miles, either as a distinct feature or as a disruption of the skyline. Mine reclamation requires restoration to original contour, and appropriate re-vegetation can mitigate long-term visual aesthetics impacts, as well as impacts resulting from changes in land-use.

Mining in the eastern interior region is more likely to involve either agricultural or forested lands. Long-range visual aesthetic impacts are less likely to be significant because of topography.

COAL COMBUSTION SOLID WASTES

The amount of coal used as fuel is related to the solid waste produced. The combustion of pulverized coal in power plant boilers produces solid wastes as fly ash and bottom ash (or boiler slag in some boiler designs). The primary constituents of ash and slag are silica (SiO_2), alumina (Al_2O_3), and iron oxide (Fe_2O_3). Flue gas desulfurization by wet limestone scrubbers for environmental control produces a gypsum sludge ($CaSO_42H_2O$) solid waste. Coal washing residue creates another waste. Any of these wastes may be marketed as byproducts depending on their quality and market conditions.

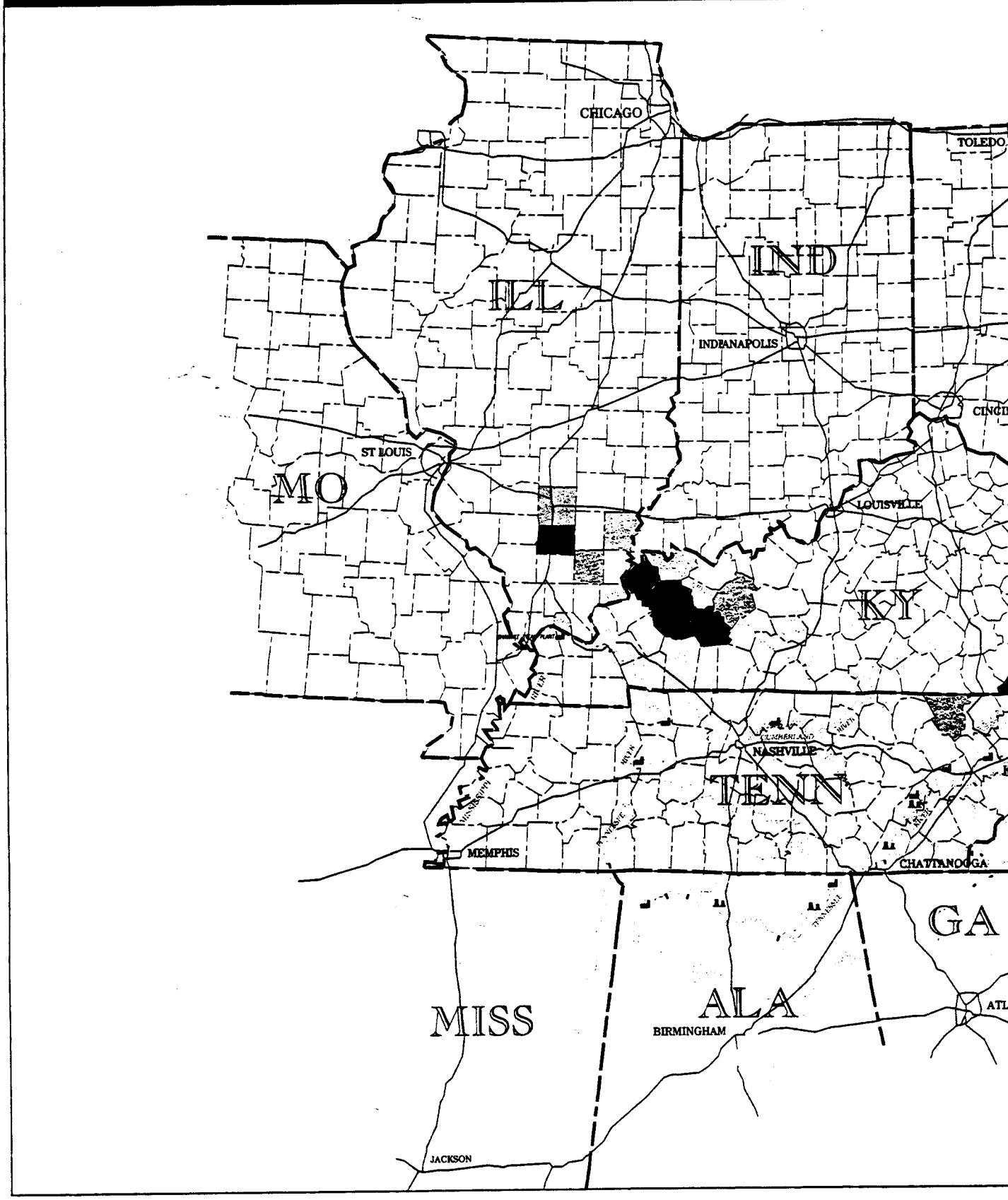
TVA coal-fired plant production of these byproducts during fiscal year 1994 is listed in *Figure T1-74*. TVA's total coal combustion byproduct utilization from 1989 to 1994 is summarized in *Figure T1-75*. Selected coal combustion byproduct usage is shown in *Figure T1-76*. The total production of byproducts was nearly 6 million tons with almost half being fly ash. Bottom ash/slag, flue gas desulfurization, and gypsum sludge accounted for 20 percent each.

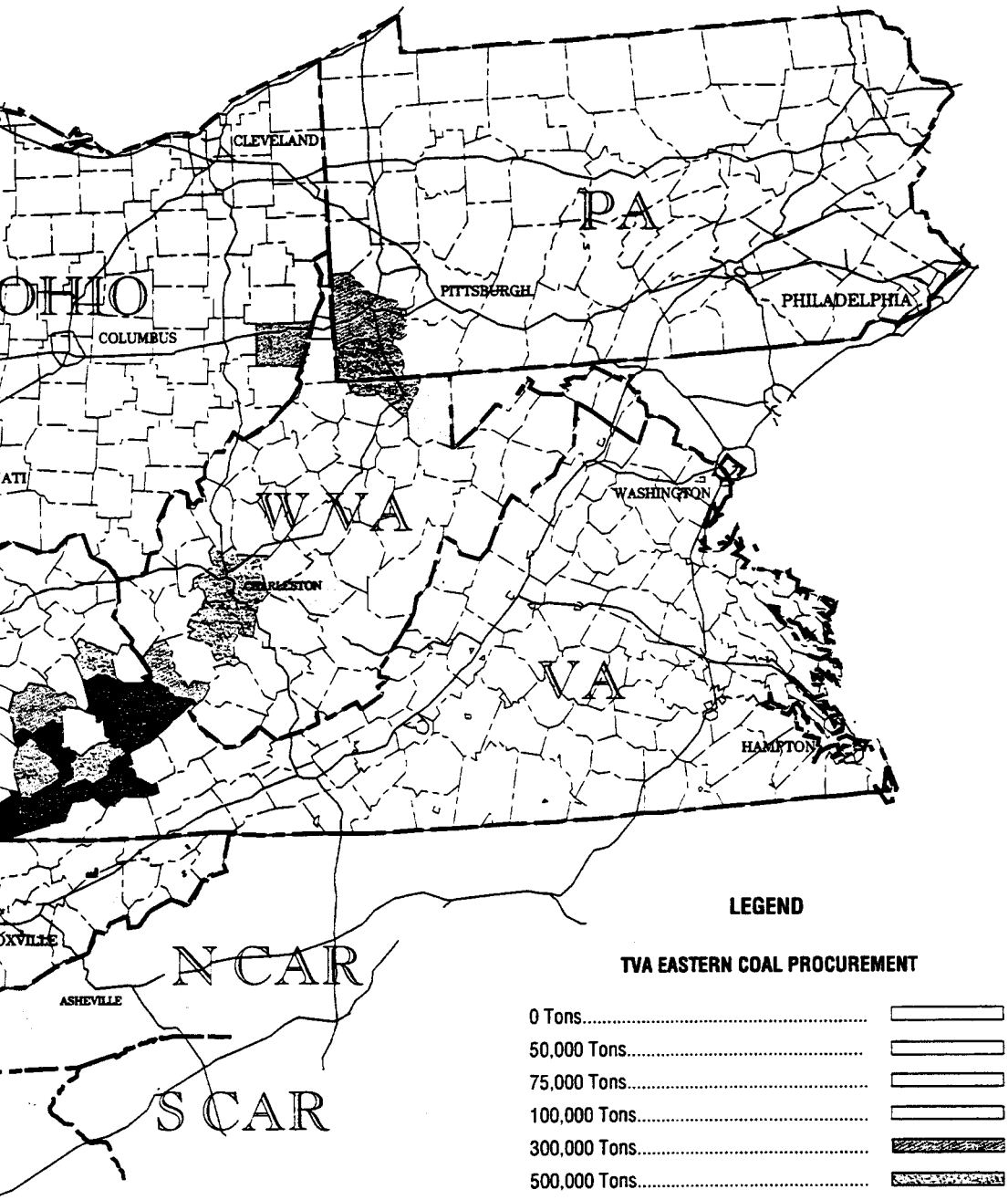
The remainder of the byproducts is either disposed of or stored on the plant site in ash ponds or dry-stacked landfills. The liquid waste discharges from ash ponds are permitted according to the National Pollution Discharge Elimination System. At some plants, possible groundwater contamination is monitored by sampling groundwater in the nearby area.

URANIUM PROCUREMENT

The natural uranium for TVA's nuclear plants comes from uranium producing areas all over the world. The world's major ura-

FIGURE T1-71 **TVA Procured Coal from Seven Eastern States in Fiscal Year 1994**





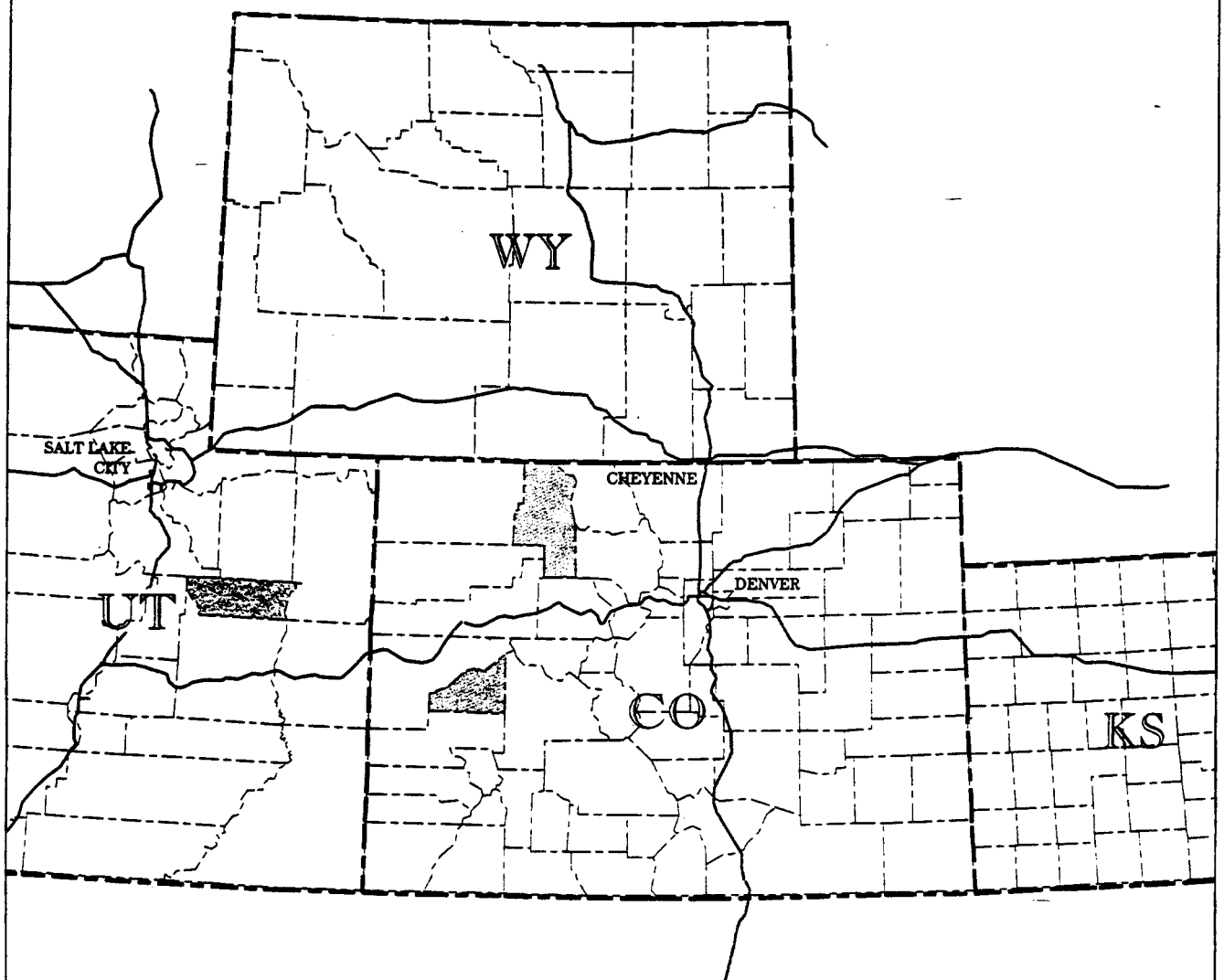
LEGEND

TVA EASTERN COAL PROCUREMENT

- 0 Tons
- 50,000 Tons
- 75,000 Tons
- 100,000 Tons
- 300,000 Tons
- 500,000 Tons
- 1,000,000 Tons
- 2,000,000 Tons
- 3,000,000 Tons
- 4,000,000 Tons

MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

FIGURE T1-72. **TVA Procured Coal from Three Western States in Fiscal Year 1994**



LEGEND

TVA WESTERN COAL PROCUREMENT

- 0 Tons
- 50,000 Tons
- 75,000 Tons
- 100,000 Tons
- 300,000 Tons
- 500,000 Tons

MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

FIGURE T1-74. TVA Coal Combustion Byproduct Production, Fiscal Year 1994

	COAL		BYPRODUCT			
Plant	Coal Burn (Tons)	Coal Ash (%)	Fly Ash (Tons)	Bottom Ash/Slag (Tons)	Gypsum (Flue Gas Desulfurization Sludge) (Tons)	Coal Wash (Tons)
Allen	2,023,847	8.31	42,045	126,136		
Bull Run	2,119,542	8.79	158,362	27,946		
Colbert (1-4)	1,826,608	11.59	169,363	42,341		
Colbert (5)	1,158,004	9.92	91,899	22,975		
Cumberland	5,766,501	10.26	473,314	118,329	964,577	
Gallatin	2,522,861	7.99	161,261	40,315		
John Sevier	2,047,223	11.53	188,836	47,209		
Johnsonville	3,555,731	10.01	284,743	71,186		
Kingston	3,925,284	8.94	280,736	70,184		
Paradise (1-2)	3,482,965	8.74	76,103	228,308	559,631	539,860
Paradise (3)	2,020,667	8.57	43,293	129,878		313,203
Shawnee (1-9)	3,302,792	10.13	267,658	66,915		
Shawnee (10)	380,970	7.28	137,239	43,857		
Widows Creek (1-6)	1,629,437	10.29	134,135	33,534		
Widows Creek (7)	1,162,420	11.01	102,386	25,596	221,886	
Widows Creek (8)	1,474,021	10.87	128,181	32,045	400,346	
TOTALS	**38,398,872**		**2,739,555**	**1,126,754**	**2,146,440**	**853,063**

FIGURE T1-75. TVA Coal Combustion Byproduct Utilization, Fiscal Years 1989 to 1994

Fiscal Year	Utilization (Tons)
1989	487,309
1990	625,761
1991	770,921
1992	1,038,244
1993	701,822
1994	1,176,568

FIGURE T1-76. Selected Coal Combustion Byproduct Uses

	BYPRODUCT			
Byproduct Use	Fly Ash	Bottom Ash	Boiler Slag	Flue Gas Desulfurization Sludge
Cement/Concrete Products	X	X	X	X
Asphalt Products		X	X	
Roofing Granules			X	
Roadbed, Road Surfacing, Embankments	X		X	
Grit for Snow/Ice Control		X	X	
Blasting Grit			X	
Landfill and Structural Fill	X	X		
Gypsum Wall Board				X

nium producing countries are Canada, Australia, South Africa, Niger, Russia, Namibia, Uzbekistan, Tajikistan, Kazakhstan, and the United States. Current annual world production is approximately 80 million pounds of U3O8. TVA's five nuclear units use a total of about 2.5 million pounds of U3O8 per year. TVA currently has sufficient inventory to last until 1999.

Much of the world's uranium is produced in dry, arid thinly populated areas like the southwestern United States and the Australian outback. Mining methods range from open-pit mining to deep-pit mining to low impact leaching operations. Environmental management is an integral part of overall mining operations. Extensive monitoring programs are implemented. One of the main objectives of environmental plans is to return as much of the mining site to its former state as possible once mining operations are completed. Decommissioning plans are made, funded, and implemented.

After mining, the natural uranium is transported to either of the two conversion plants located in Illinois or Ontario, Canada, for further refinement and processing. Subsequently, the natural uranium is typically shipped to one of the federal government's uranium enrichment plants located at Paducah, Kentucky or Portsmouth, Ohio. TVA receives its nuclear fuel in the form of fabricated nuclear fuel assemblies in which the uranium has been encapsulated in metal tubes.

TVA and a number of other United States utilities are expected to soon be using commercial grade slightly enriched

uranium derived from nuclear warheads in the true sense of swords to plowshares. Under this program, the highly enriched uranium obtained from both United States and Russian nuclear warheads will be diluted to low levels, which allows its use in commercial nuclear plants. A substantial reduction in the quantity of nuclear warheads in the world is a major benefit to the environment and mankind.

NUCLEAR WASTE

Introduction

The nuclear fuel used for power plants produces radioactive solid wastes requiring storage and disposal. These wastes are placed in two categories: low-level radioactive waste and high-level radioactive waste. These indicate the type of radioactive material, the intensity of its radiation, and the time required for decay of the radiation intensity to natural levels.

High-Level Nuclear Waste

Background

Ninety-nine percent of high-level waste from commercial nuclear plants is used fuel that has released most of its energy. The fuel that runs nuclear power plants is made up of small uranium pellets. These are placed inside long metal fuel rods. These fuel rods are grouped together into fuel assemblies, which are placed inside a reactor. In the fission process, uranium atoms begin to split in a chain reaction, one after another. The fission process yields energy in the form of heat for power plant operation.

Certain changes take place in the fuel during the fission process. Most of the fission products—the nuclei left over after the atom has split—are radioactive. Over time, these trapped fission products reduce the efficiency of the chain reaction. Approximately every 18 months, the oldest fuel assemblies that have already released their energy are removed and replaced with fresh fuel. Operation of TVA's 5 nuclear units will produce about 115 metric tons of used fuel each year.

After it is removed from the reactor, used fuel is stored at nuclear plant sites either in pools (steel-lined, concrete vaults filled with water) or in dry casks (above-ground concrete or steel containers). The radioactive waste remains locked inside the uranium pellets which are still encased in the fuel rods. Used fuel has been stored safely at nuclear plant sites since the late 1950s, when the first nuclear energy plants began making electricity.

Within six months of fuel removal and storage at the plant site, 98 percent of the fuel's radiation has dissipated. Forty to 50 years after the spent fuel is removed from the reactor, its radioactivity has decreased to 1 percent of its initial radioactivity. A very small percentage of nuclear wastes remain radioactive for thousands of years.

Radioactive waste has been a prominent topic in the controversy over nuclear energy. Often the attention focuses on the disposal of spent fuel from nuclear reactors. Radiation has been studied for nearly a century, and scientists can detect even the smallest amount. Scientists and engineers believe they know how to safely isolate radioactive material underground so it will not pose a danger to current or future generations. A permanent repository with multiple barriers, both natural and man-made, is to be designed and built by the Department of Energy to ensure radioactivity does not escape and waste is isolated from the environment. Waste will be sealed in metal canisters and placed a half-mile or more underground in a stable geological environment.

The feasibility of underground waste repositories has been demonstrated in studies and test projects. Geologic repositories deep underground have been endorsed by independent scientific organizations around the world, including the National Academy of Sciences, the National Research Council, and the Congressional Office of Technology Assessment. Almost all other countries with a nuclear energy program, including Germany, France, and Japan, have determined that deep geologic disposal is the safest system of permanent nuclear waste management.

The Nuclear Waste Policy Act (NWPA) of 1982 established a program to build the nation's first underground high-level waste repository early in the next century. The act and its amendments charge the Department of Energy (DOE) with the following tasks:

- Locating, building, and operating a deep-mined geologic permanent repository for high-level waste
- Evaluating the need for a monitored retrievable storage facility—a short-term, continuously monitored facility for the interim storage of spent fuel
- Developing a transportation system that safely links United States nuclear power plants, the monitored retrievable storage, and the permanent repository.

In 1987, amendments to the Nuclear Waste Policy Act of 1982 designated the remote area of Yucca Mountain, Nevada, northwest of Las Vegas, for study as a possible permanent repository site. The Department of Energy has begun site characterization, the comprehensive scientific investigation of Yucca Mountain's suitability. The permanent repository facility must meet strict licensing requirements of the U.S. Nuclear Regulatory Commission. Additional oversight will be provided by the U.S. Environmental Protection Agency, the State of Nevada, and the Technical Review Board appointed by the President.

Concern about the transportation of high-level waste is another issue related to disposal. The federal government has established controls and regulations to ensure that radiation exposure from accidents does not occur under either normal or abnormal conditions. To date, there have been more than one million ship-

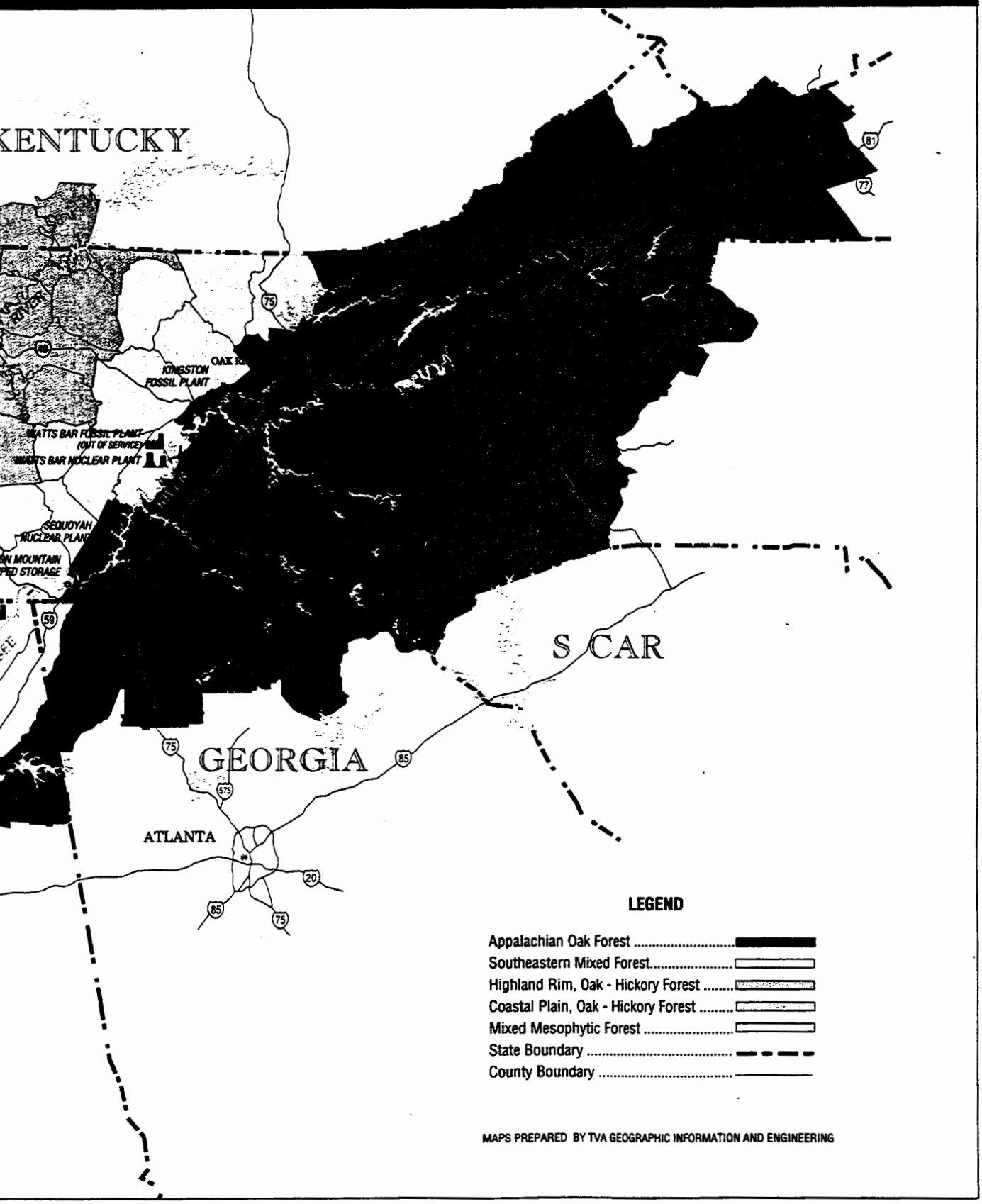

KENTUCKY
KINGSTON FOSSIL PLANT
WATTS BAR FOSSIL PLANT (OUT OF SERVICE)
WATTS BAR NUCLEAR PLANT
SEQUOYAH NUCLEAR PLANT
S CAR
GEORGIA
ATLANTA
LEGEND
Appalachian Oak Forest
Southeastern Mixed Forest
Highland Rim, Oak - Hickory Forest
Coastal Plain, Oak - Hickory Forest
Mixed Mesophytic Forest
State Boundary
County Boundary
MAPS PREPARED BY TVA GEOGRAPHIC INFORMATION AND ENGINEERING

FIGURE T1-78. Trees in the Major Forest Regions and Sections of the Tennessee Valley

The Mixed Mesophytic Forest Region—Cumberland Mountains Section

Tuliptree	*Liriodendron tulipifera*
Basswood	*Tilia heterophylla*
Sugar maple	*Acer saccharum*
Beech	*Fagus grandifolia*
Northern Red oak	*Quercus rubra*
Yellow buckeye	*Aesculus octandra*
White ash	*Fraxinus americana*
Cucumber magnolia	*Magnolia acuminata*
Red maple	*Acer rubrum*
Black gum	*Nyssa sylvatica*

Cumberland and Allegheny Plateaus Section

Beech	*Fagus grandifolia*
Tuliptree	*Liriodendron tulipifera*
Basswood	*Tilia heterophylla*
Sugar maple	*Acer saccharum*
Northern Red oak	*Quercus rubra*
White ash	*Fraxinus americana*
White oak	*Quercus alba*
Cucumber magnolia	*Magnolia acuminata*
Shagbark hickory	*Carya ovata*
Mockernut hickory	*Carya tomentosa*
Black gum	*Nyssa sylvatica*
Red maple	*Acer rubrum*

The Western Mesophytic Forest Region—Nashville Basin Section

Tuliptree	*Liriodendron tulipifera*
Sugar maple	*Acer saccharum*
White oak	*Quercus alba*
Northern Red oak	*Quercus rubra*
Hackberry	*Celtis laevigata*
American elm	*Ulmus americana*
Red cedar	*Juniperus virginana*
Winged elm	*Ulmus alata*
Shagbark hickory	*Carya ovata*
Black gum	*Nyssa sylvatica*
Chinkapin oak	*Quercus muehlenbergii*
Post oak	*Quercus stellata*
Redbud	*Cercis canadensis*
Beech	*Fagus grandifolia*
Wild cherry	*Prunus serotina*
White ash	*Fraxinus americana*
Bitternut hickory	*Carya cordiformis*
Fraser magnolia	*Magnolia fraseri*
Red maple	*Acer rubrum*
Chestnut oak	*Quercus prinus*
Black oak	*Quercus velutina*
Scarlet oak	*Quercus coccinea*

The Oak-Chestnut Forest Region—Southern Appalachians Section, Cove Hardwoods and Oak-Chestnut Communities

Basswood	*Tilia heterophylla*
Sugar maple	*Acer saccharum*
Northern red oak	*Quercus rubra*
Yellow buckeye	*Aesculus octandra*
Silverbell	*Halesia caroliniana*
Canadian hemlock	*Tsuga canadensis*
Yellow birch	*Betula lutea*
Sweet birch	*Betula lenta*

The Oak-Pine Forest Region—Gulf Slope Section

Chestnut oak	*Quercus prinus*
Pignut hickory	*Carya glabra*
Loblolly pine	*Pinus taeda*
Shortleaf pine	*Pinus echinata*
Southern red oak	*Quercus falcata*
Post oak	*Quercus stellata*
Black oak	*Quercus velutina*
Blackjack oak	*Qoercus marilandica*
Mockernut hickory	*Carya tomentosa*

Southeastern Evergreen Forest Region—Mississippi Alluvial Plain Section

Silver maple	*Acer saccharinum*
American elm	*Ulmus americana*
Pin oak	*Quercus palustris*
Cottonwood	*Populus deltoides*
White oak	*Quercus alba*
Sweetgum	*Liquidambar styraciflua*
Cherrybark oak	*Quercus pagodaefolia*
Sycamore	*Platanus occidentalis*
Black oak	*Quercus velutina*
Red mulberry	*Morus rubra*
Sassafras	*Sassafras albidum*
Walnut	*Juglans nigra*
Honeylocust	*Gleditsia triacanthos*

animal communities. About 70 species of mammals, 300 species of birds (including 175 that nest within the region), 65 species of reptiles, and 77 species of amphibians regularly occur in the region. Several salamander species are only found in the TVA region. Few other terrestrial vertebrate species are restricted to the TVA region.

Except for many birds, game species, and species listed as endangered or threatened (see species list at the end of this document in the Threatened and Endangered Species Appendix), little population trend information is available for terrestrial animals. Systematic censuses conducted since the mid-1960s show that populations of about 18 percent of the bird species nesting in the region are declining, while about 10 percent are increasing (Nicholson in press). About 30 percent of the bird species are encountered too infrequently by this survey to show population trends. The majority of the birds with declining population trends are species that nest in North America and winter in Latin America. Many of these species require large tracts of forest and are adversely affected by forest fragmentation resulting from land use changes such as road and power line construction and suburban and agricultural development. Several bird species that require early successional habitats, both permanent residents and long-distance migrants, also show a decline.

Twenty-two species of mammals and 34 species of birds are legally hunted or trapped in the TVA region. The population trends of these species in the region generally parallel their trends elsewhere, with northern bobwhite *(Colinus virginianus)* and most duck species declining, and white-tailed deer *(Odocoileus virginianus)*, wild turkeys *(Meleagris gallopavo)*, geese, and wood ducks *(Aix sponsa)* increasing.

Vegetation

The six physiographic regions within TVA's 201-county area contain approximately 4,300 species of herbs, shrubs, and trees in numerous habitats and plant communities. It also contains several non-forested plant communities, such as cedar glades, balds, remnant prairies, gravel bars, and cliff faces. These areas are extremely small compared to the extensive forests that characterize this region.

Based on an analysis of late successional forests, Braun (1950) recognized five major forest regions in the TVA region. (See *Figure T1-77.*) Three of these regions are further divided into sections, generally along physical geology boundaries. The major tree species in these regions are listed in *Figure T1-78.*

Local vegetation types vary greatly within Braun's divisions because of variation in elevation, relief, soil fertility, moisture, and the degree of human disturbance. The tree species composition of early to mid-successional forests (forests in the early to middle stages of their cycle) is fairly uniform across the TVA region on sites with similar environmental conditions. Red cedar *(Juniperus virginiana)* and mixed cedar types are common on reverting old fields and on sites with shallow, basic soils. Yellow pines (especially loblolly *[Pinus taeda]*, Virginia *[P. virginiana])* and shortleaf *(P. echinata)* are widespread and occur both in tree plantations and naturally in early successional stands. Oak-hickory forests, often mixed with yellow pines, are widespread on drier, upland sites. Bottomland hardwoods containing such species as oaks, sweetgum *(Liquidambar styraciflua)*, maples *(Acer spp.)*, and other wet-site hardwoods are typical of rich alluvial lowlands. Sugar maple *(Acer saccharum)* and American beech *(Fagus grandifolia)* frequently occur on rich, north slopes and, along with species such as hemlock *(Tsuga canadensis)*, northern red oak *(Quercus rubra)*, and basswood *(Tilia heterophylla)*, are common at higher elevations in the eastern portion of the region.

STRESSORS TO THE FORESTS OF THE TENNESSEE VALLEY

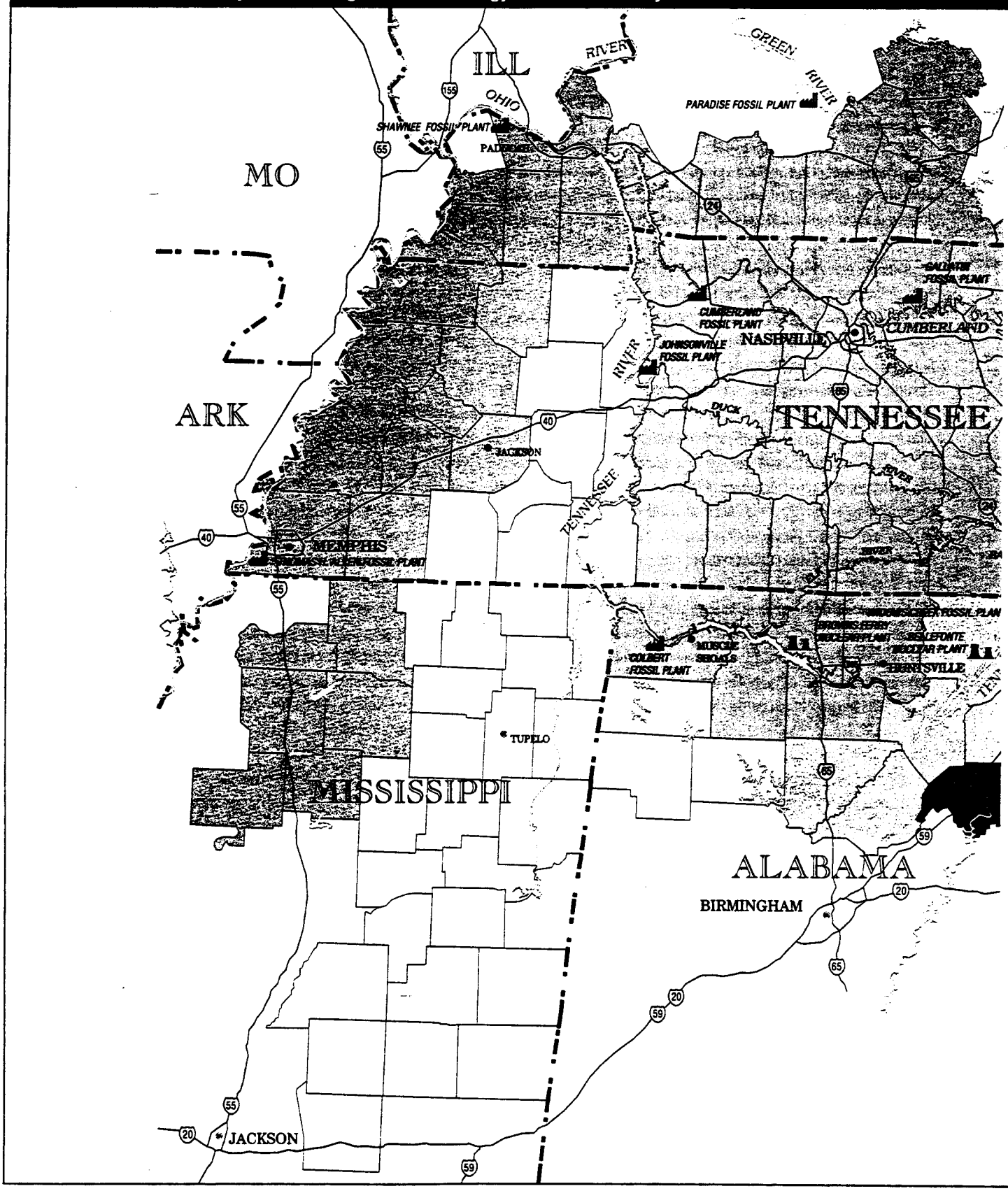
Power plant emissions are one of several stressors to forests in the Tennessee Valley. Power plant emissions and their potential effects have been discussed previously. Since the cumulative effects of various stressors can negatively affect forests, all key stressors are discussed in this section.

The forests of the Tennessee Valley are in a constant state of change. Presence or repression of fire, environmental conditions, people, and introduced pests have helped shape the current landscape. Forest stressors include past land use practices that resulted in erosion and site degradation, extreme climatic conditions (freezing injury, ice damage, drought, flooding), air pollutants, and exotic as well as native forest insects and diseases.

Currently, several stressors raise concern for the health of forests in this region. Tropospheric ozone is produced by complex photochemical reactions involving sunlight and the emission of volatile organic compounds and nitrogen oxides from automobiles, power plants, factories, and other sources of high temperature combustion. Ozone in the troposphere, the portion of the atmosphere 7 to 10 miles from the earth's surface, can occur at levels that cause visible injury to numerous plants and have potentially deleterious interactions with other forces in forest settings (Johnson and Lindberg 1992). Acidic deposition is also considered to be a forest health stressor, especially to red spruce *(Picea rubens)*, the most sensitive regional tree species.

A number of diseases and pests introduced to the Tennessee Valley have recently or will soon impact the forest (Ferguson and Bowman 1994; Great Smoky Mountains National Park 1993; Langdon and Johnson 1992). The gypsy moth *(Lymantria dispar)*, is of major concern. It is projected to reach the northeast

FIGURE T1-77 **The Five Major Forest Regions of the Energy Vision 2020 Study Area**



ments of radioactive materials, mostly for medical purposes, with a lower than average vehicle accident rate. No one has ever been injured due to radiation exposure from the 6,000 spent fuel assemblies transported to date in the United States.

Spent fuel is shipped in specially constructed casks, each of which must be licensed by the Nuclear Regulatory Commission (NRC). The casks must be able to withstand several severe shocks without leaking—a 30-foot drop onto a flat, unyielding horizontal surface with the cask oriented to cause maximum damage; a 40-inch drop onto the pointed end of a steel bar, also with the cask oriented for maximum damage; exposure to a 1,475 degrees F fire for 30 minutes with no artificial post-fire cooling; and immersion in water to a depth of three feet for at least eight hours immediately following the fire test. The Nuclear Regulatory Commission tests required to license shipping casks are more stringent than conditions the casks would be subjected to in actual accidents.

Below is a listing of other federal agencies involved in the management of high-level radioactive waste:

- The Environmental Protection Agency issues generally applicable environmental radiation standards effective outside the boundaries of sites that possess radioactive materials.
- The Nuclear Regulatory Commission develops and enforces regulations to protect the public health and safety from all domestic commercial nuclear activities. Rules on mined geologic repositories have been formulated that will specifically implement the general environmental standards set forth by the Environmental Protection Agency.
- The Department of Transportation governs the shipment of all privately owned radioactive materials, including nuclear waste, by all modes of transport. It also administers the labeling, classification, and marking of all radioactive waste packages.
- The Department of Interior through the U.S. Geological Survey cooperates with the Department of Energy on technical activities in the earth sciences, including geologic investigations in support of waste disposal.

Status of TVA Spent Fuel Storage

TVA plans to continue to store spent nuclear fuel on-site at plant locations where it is generated until the Department of Energy accepts physical custody by shipment off-site to a monitored retrievable storage facility or to a permanent underground repository for ultimate disposal by burial. TVA is currently storing some 760 and 417 metric tons of used fuel on site at Browns Ferry and Sequoyah Nuclear Plants, respectively. Current spent fuel storage capacity is sufficient at Sequoyah Nuclear Plant until 2004 and at Browns Ferry Nuclear Plant until 2007. Based on one-unit operation at Watts Bar Nuclear Plant, spent fuel storage capacity will be sufficient until 2018. TVA has sufficient outside site area at each of its nuclear facilities to store any high-level waste associated with decommissioning activities and life-of-plant quantities of used fuel. As the pools approach the current storage limits, TVA will initiate studies to increase on-site storage capacity.

Low-Level Nuclear Waste

Low-level radioactive waste consists of items that have come into contact with radioactive materials. Activities that use radioactive materials, and therefore produce low-level waste, include biomedical and pharmaceutical research, industrial processes, diagnosis and medical treatment, and nuclear-generated energy. In a nuclear energy plant, the low-level radioactive waste comes primarily from small particles in the internal reactor-cooling water that are captured in filters, deposited in valves and pumps, or collected on surfaces inside the plant. Many items such as filters, cloth and paper wipes, plastic shoe covers, tools and materials, water purification media (resins), and other residues collect varying quantities of radioactivity.

The radioactive particles in low-level radioactive waste emit the same types of radiation that occur in nature. About 90 percent of low-level radioactive waste fades away through radioactive decay into natural levels of radioactivity within 10 years. About 99.9 percent of it diminishes to natural levels in less than 300 years.

Low-level radioactive waste is measured by volume generated or volume disposed of, usually in cubic meters. Generators of low-level radioactive waste have worked to reduce the volume sent to disposal sites. TVA regularly compares its low-level radioactive waste volumes to the best and median volume generators in the nuclear industry. Low-level radioactive waste production at TVA nuclear plants is currently about 70 percent of the industry average. Reduction of waste volume is accomplished through a combination of on-site volume minimization and off-site volume reduction processes. Waste volume is reduced through compaction, incineration, and decontamination.

Low-level waste that is shipped to disposal sites travels by ground transportation in special boxes, drums, or steel containers designed to meet Nuclear Regulatory Commission and Department of Transportation standards for impact resistance. The type of container required depends on the amounts and types of radioactive elements in the waste. There has never been a serious transportation incident involving the disposal of radioactive material.

The purpose of low-level radioactive waste disposal is to isolate the waste from both people and the environment. Designs for building disposal facilities include shallow land bur-

ial, a below-ground vault, an above-ground vault, modular concrete canister disposal, and earth-mounded concrete bunkers. Although the disposal approach may vary, depending on the location, all disposal facilities use a series of natural and engineered barriers to prevent the radioactive material from reaching the environment. All of them meet strict federal and state requirements for isolating the waste until the radioactivity has faded to natural background levels.

In 1980, Congress passed the Low-Level Radioactive Waste Policy Act. That law requires every state to develop an adequate disposal site for its own waste or to form "compacts" with other states to provide regional disposal. The states participating in the Southeast Compact Commission have selected North Carolina as the host state to select, license, and construct a new disposal site. The current schedule calls for this facility to be complete in 1998. Until July 1995, the low-level waste generators located in the eight Southeastern states were required to dispose of their waste at the Barnwell, South Carolina disposal facility. In July, South Carolina withdrew from the Southeast Compact Commission in order to open the Barnwell facility to all states except North Carolina. Barnwell is expected to remain open to these users for another 7 to 10 years. TVA plans to continue to use the Barnwell facility for low-level radioactive waste disposal until the North Carolina facility is opened. Should either or both of the disposal facilities close unexpectedly, low-level radioactive waste will be stored in on-site facilities at the TVA nuclear plants. These facilities are sized to handle any anticipated storage needs for the foreseeable life of the plants.

Below is a listing of agencies involved in the regulation of low-level radioactive waste:

- The **U.S. Nuclear Regulatory Commission** licenses many of the facilities that produce low-level waste, including nuclear energy plants, and regulates low-level radioactive waste disposal.
- The **U.S. Environmental Protection Agency** develops general standards to protect the public from radiation.
- The **U.S. Department of Transportation** regulates the interstate shipment of privately owned radioactive materials.
- The **U.S. Department of Energy** coordinates national planning with the states for managing low-level radioactive waste.
- The **U.S. Geological Survey** offers technical assistance with studies of hydrology and geology of proposed sites.
- **State governments** are responsible for disposal of the low-level radioactive waste generated in their states or for joining a regional compact. State governments are responsible for selecting and licensing a site according to federal standards and monitoring its operation. Most states have licensing authority from the Nuclear Regulatory Commission for low-level waste disposal within their state.
- **The Nuclear Regulatory Commission** regulations cover the off-site disposal of low-level radioactive waste; the Nuclear Regulatory Commission and the U.S. Department of Transportation cover the transportation of waste; and the Nuclear Regulatory Commission regulations cover on-site storage.

Biological Resources

INTRODUCTION

Biological resources such as wetlands, wildlife, vegetation, sensitive ecosystems, endangered species, and unique natural areas can potentially be affected by dams, power plant emissions, and sites for power plants. The Tennessee Valley region contains a wide diversity of flora, fauna, and biological habitats. Biological resources of the Valley are summarized in this section.

TERRESTRIAL ECOLOGY

Wetlands

Wetlands are defined as lands that are covered by shallow water or with the water table near the surface. They support vegetation typically found in wet habitats, have soils wet enough to produce anaerobic conditions, and/or have a substrate saturated or covered with water at some time during the growing season (Cowardin et al. 1979). Although wetlands occur throughout the TVA region, they are most extensive in the south and west. There are two main types of wetlands—palustrine, or marshy, and lacustrine, formed by lakes (U.S. Fish and Wildlife Service National Wetland Inventory data). The most common palustrine types are forested wetlands (also the most extensive type in the TVA region), scrub-shrub wetlands, and emergent wetlands. The most common lacustrine wetland type is aquatic bed wetlands.

Over half of the wetland acreage that originally occurred in the seven states forming the TVA region has been lost (Dahl 1990). The major causes of wetlands loss are agricultural conversion, inundation by reservoirs, and conversion to urban or other non-agricultural land uses. The rate of wetland loss has slowed in recent years, and further destruction of wetlands is discouraged by Executive Order 11990, the North American Wetlands Conservation Act, and other regulations. Any future site-specific environmental reviews for power plant siting will consider wetlands in assessing potential impacts.

Wildlife

The TVA region contains portions of six physiographic regions (see the map in *Figure T1-67*) and a great variety of plant and

corner of Tennessee in 15 to 20 years. Oak trees are the most susceptible. Stands with a higher component of oaks are also more susceptible to dieback and decline. Oak decline, a slow-acting disease complex, is caused by a combination of age, stress factors, and normally non-aggressive insects and fungi. A natural process, oak decline, is hastened and compounded by past land use, loss of species such as the American chestnut *(Castanea dentata)*, replacement with species less adapted to the site, and other conditions.

Dogwood anthracnose is a disease caused by the fungus *Discula destructiva*. It was detected in the southern Appalachians in the late 1980s and has spread throughout much of the Valley. Flowering dogwood *(Cornus florida)* is the target species. At some sites all dogwood trees have been killed, while some trees at lower elevations on drier sites have sustained little damage. Other hardwood diseases include Dutch elm disease, caused by the *Ceratocytis ulmi* fungus, which attacks American *(Ulmus americana)*, slippery *(U. rubra)*, and winged elms *(U. alata)*. High levels of mortality among elm trees follow disease outbreaks. Butternut canker, caused by the fungus *Seriococcus claviginetiiuglandacearum* has a lethal effect on butternut *(Juglans cinerea)*. This fungus went unnoticed in the southeastern United States until less than a decade ago. Butternut populations are plummeting, and in 1990 butternut was added to the federal list of candidates for protection by the Endangered Species Act. Beech bark disease was detected in the Great Smoky Mountains several years ago. The disease is caused by a combination of the beech bark scale insect *(Cryptococcus fagisuga)* and the *Nectria* fungus. High levels of American beech mortality are expected if the disease spreads.

Three insects are serious pests to Valley coniferous forests (Ferguson and Bowman 1994). The balsam woolly adelgid *(Adelges piceae)* was detected in the southern Appalachians in the late 1950s. It is a non-native mortal pest of mature Fraser fir *(Abies fraseri)* native to the southern mountains. Virtually all natural stands of fir have been infested, and few mature firs remain. The hemlock woolly adelgid *(Adelges tsugae)*, accidentally imported from Asia, has already infested many Eastern hemlocks in Virginia. Widespread mortality is expected. This adelgid is expected to move throughout the Appalachians and may eliminate most of the hemlock, both the Eastern type and the native Carolina hemlock *(T. caroliniana)*. Most species of conifers are susceptible to attack during intense outbreaks by the native southern pine beetle *(Dendroctonus frontalis)*. In the Tennessee Valley all shortleaf, loblolly, and Virginia, Table-Mountain pines *(P. pungens)* pitch pines *(P. rigida)*, and eastern white pines *(P. strobus)* are attacked. Overstocked or homogeneous stands are the most susceptible to high mortality during periodic beetle outbreaks.

Harmful non-indigenous invasive plant species also pose a threat. Both privet *(Ligustrum spp.)* and Japanese honeysuckle *(Lonicera japonica)* are shade-tolerant and form a dense layer of low vegetation, altering forest regeneration patterns. Another pervasive shade-tolerant plant is bittersweet *(Celastrus scandens)*, but it is not yet known to hamper stand regeneration. The grass microstegium *(Microstegium vimineum)* carpets moist forest understories, changing the composition of the herbaceous layer. Some shade-intolerant species introduced, such as autumn olive *(Elaeagnus umbellata)*, multiflora rose, *(Rosa multiflora)*, and kudzu *(Pueraria lobata)* can cause local problems. A potential problem species that is spreading south is mile-a-minute weed *(Polygonum perfoliatum)*, an aggressive annual spread by animals that eat its fleshy fruits.

Usually these pests, pathogens, or agents of damage are viewed individually. However, they often work together and impact the forest through a multiple stressor system complex.

SENSITIVE OR THREATENED ECOSYSTEMS

The TVA region includes several terrestrial communities that are either restricted to the TVA region, are best represented here, or include a large proportion of their total area in the region. These include the Southern Appalachian spruce-fir, cedar glade, and limestone cave systems. Several endangered and native plant and/or animal species, as well as species not found outside the TVA region, occur in each of these communities. Therefore, knowledge of these threatened ecosystems is important for the future implementation of energy resources including the site-specific environmental reviews to be performed.

Southern Appalachian Spruce-Fir Forest

The Southern Appalachian spruce-fir forest is an ecosystem rich in animals and native and rare plants. However, these forests have experienced serious disturbances in the last century. Commercial logging and associated fires of the early 1900s reduced the forests to a fraction of their former expanse (Korstian 1937). Currently these forests are being severely impacted by the balsam woolly adelgid, an imported insect first detected in the southern Appalachians in the late 1950s (Spears 1958). Mature Fraser fir, a southern mountain endemic, is highly susceptible to the adelgid, with death occurring in two to seven years after infestation. Furthermore, some evidence suggests a red spruce growth decline in the past 20 years, as well as canopy crown deterioration since the mid-1980s (Peart et al. 1992; McLaughlin et al. 1987).

The red spruce-Fraser fir ecosystem occupies approximately 103 square miles in the southern Appalachian mountains of southwestern Virginia, eastern Tennessee, and western North Carolina and is generally confined to mountain peaks above 5,000-

foot elevation. The larger stands are shown in the map in *Figure T1-50*. Spruce-fir forests occur as a series of island-like stands at high elevation. The largest contiguous area of red spruce-Fraser fir forest (48,721 acres) is located in the Great Smoky Mountains National Park (Dull et al. 1988). The remaining 26 percent of the ecosystem is located in the Black Mountains (7,221 acres), Balsam Mountains (4,648 acres), Roan Mountain including Unaka Mountain (1,699 acres), Mt. Rogers Area including Whitetop Mountain (1,582 acres), Plott Balsams (952 acres), Grandfather Mountain (928 acres), and Long Hope Mountain (498 acres) (Dull et al. 1988; Groton 1985).

Cedar Glades

Cedar glades are areas of exposed limestone bedrock, gravel, and/or shallow soil over limestone bedrock, sparsely vegetated with low-growing herbaceous plants and red cedars (Quarterman 1989). Their greatest concentration occurs within the Interior Low Plateaus physiographic province in central Kentucky, central Tennessee, and northern Alabama. A few glades also occur within the Ridge and Valley province of Virginia, Tennessee, Georgia, and Alabama. Twenty-two species or subspecies of plants are only found on these southeastern glades. The total area of cedar glades, most of which are within the TVA region (Baskin and Baskin 1986), is only a few thousand acres. Many have been destroyed or heavily disturbed by urban and suburban development, highway construction, and reservoir impoundment.

Caves

Over 5,000 caves and related Karst features such as sinkholes have been identified in the TVA region (TVA undated). They are widespread in the eastern two-thirds of the region. Many species of invertebrates, as well as one fish, and one salamander, are restricted to caves in the TVA region. Several of these species occur in only one or two caves. Several of these species, as well as several bats inhabiting caves, are listed as endangered or under consideration for endangered listing. Important stresses to cave ecosystems include groundwater pollution, changes in cave climate and hydrology resulting from modifications to cave entrances, and disturbances to cave formations and fauna by human visitation.

THREATENED AND ENDANGERED SPECIES

Knowledge of threatened and endangered species in the TVA region is important for the future deployment of energy resources including the site-specific environmental reviews to be performed. Thirty-eight species of plants and 100 species of animals in the TVA region are either listed as endangered or threatened species or formally proposed for such listing by the U.S. Fish and Wildlife Service (USFWS). These species, their distribution by river basin, and their habitats are listed in the Threatened and Endangered Species Appendix. An additional 380 species in the TVA region have been identified by the U.S. Fish and Wildlife Service as candidates for listing (USFWS 1993, 1994a, 1994b). The distribution of many candidate species is poorly known and not included here.

The 83 aquatic animals are endangered by loss of habitat due to the building of reservoirs; alterations of flow, temperature, and water chemistry regimes in river stretches downstream of dams; stream channel modifications such as channeling; and habitat degradation from point and non-point pollution. Most plants and terrestrial animals are endangered by loss of habitat due to land use changes such as agricultural clearing, highway construction, and suburban development.

The 83 aquatic species presented in the Threatened and Endangered Species Appendix occur in 4 broad habitat types, 3 of which have been described in some detail in Section 3, Water Resources in this document (Volume 2, Technical Document 1, Comprehensive Affected Environment). Under-ground aquifer habitats, not mentioned in Water Resources, are inhabited by three listed species. Each of these species (Alabama cavefish, *Speoplatyrhinus poulsoni;* Alabama cave shrimp, *Pulaemonias alabamae;* and Kentucky cave shrimp, *Pulaemonias ganteri*) occurs in one or a few caves located in an extremely limited geographic area.

The vast majority of the listed aquatic species presented in the Threatened and Endangered Species Appendix (65 of the 80 remaining species) typically occur in smaller rivers and creeks that have not been substantially affected by impoundment or other large-scale modifications. Twenty-five of these species occur in various Gulf drainages, while the remaining 40 species occur in interior basin streams, primarily the Tennessee and Cumberland river systems. Most of these small-stream listed species survive where habitat conditions and aquatic communities retain much of their original characteristics. Several of these species occur together as members of diverse communities in important and often protected stream reaches such as the upper Clinch, Powell, and Duck rivers in the Tennessee system; the middle portion of the Green River; and the Cahaba River, Mobile system.

Tributary reservoirs and their tailwaters make up the second aquatic habitat discussed in Water Resources, but they contain no listed species. Since these habitats are substantially different from the original character of the streams they do not meet the needs of listed species.

Large river habitats, even though substantially affected by dams, still support surviving populations of 15 listed species included in the Threatened and Endangered Species Appendix. Four of these species occur in the Mobile River system, while the other 11 exist in the mainstreams of the Tennessee,

Cumberland, Ohio, Green, and/or the Mississippi rivers. Most of these species survive in sections of large rivers where important original habitat conditions persist. Often these sections occur just downstream from the dams. Several of these species typically occur together as parts of diverse communities in locations such as the Tennessee River downstream from Pickwick Landing Dam and the Cumberland River downstream from Cordell Hull Dam.

UNIQUE AND SIGNIFICANT NATURAL AREAS

Siting of power plants and emissions for pollutants from power plants can potentially affect unique and significant natural areas. Site-specific environmental reviews would address any impacts to these areas as future resources are implemented. Natural areas in the TVA region include national, state, and privately owned lands that are managed for significant ecological resources, including forest, wildlife, water, rare plants and animals, or research. Most areas are managed to maintain their wild character and scenic beauty, to serve as a vital habitat for migrating birds and large mammals or endangered species, to provide important outdoor recreation resources in natural landscapes, or to serve as a nature educational tool. Many areas are managed to allow natural processes to predominate.

Natural areas contain an array of significant natural resources, from large wilderness areas, national wildlife refuges, and national parks, to intensively managed forests and recreational parks. Aquatic natural areas include state and national scenic rivers, mussel sanctuaries, and critical habitats for rare fishes. Natural areas vary in size from a few acres to several thousand acres. Many cross state boundaries or are managed cooperatively by several agencies. Categories of natural areas can be found at the end of this document in the Seventeen Categories of Natural Areas Appendix.

Threatened and Endangered Species Appendix

Distribution of Endangered and Threatened Species in the TVA Region by River Basins

Name	Common Name	Status [1]	Tennessee	Cumberland	Green	New	Lower Ohio
MAMMALS							
Canis rufus	Red wolf	LE	X				
Glaucomys sabrinus coloratus	Northern flying squirrel	LE	X			X	
Myotis grisescens	Gray bat	LE	X	X	X		
Myotis sodalis	Indiana myotis	LE	X	X	X	X	X
Plecotus townsendii virginianus	Townsend's big-eared bat	LE				X	
BIRDS							
Falco peregrinus	Peregrine falcon	LE	X	X			
Haliaeetus leucocephalus	Bald eagle	LE/PT	X	X			X
Picoides borealis	Red-cockaded woodpecker	LE	X	X	X		
Sterna antillarum athalassos	Interior least tern	LE					X
Vermivora bachmanii	Bachman's warbler	LE			X		
REPTILES							
Alligator mississippiensis	American alligator	LT				X	
Graptemys oculifera	Ringed map turtle	LT					
Nerodia eryth rogaster neglecta	Copperbelly water snake	PT					X
Sternotherus depressus	Flattened musk turtle	LT					
FISHES							
Acipenser oxyrhynchus desotoi	Gulf sturgeon	LT					
Cyprinella caerulea	Blue shiner	LT					
Cyprinella monacha	Spotfin chub	LT	X				
Erimystax cahni	Slender chub	LT	X				
Etheostoma boschungi	Slackwater darter	LT	X				
Etheostoma chienense	Relict darter	LE					
Etheostoma etowahae	Etowah darter	LE					
Etheostoma n sp.	Bluemask darter (=jewel)	LE		X			
Etheostoma percnurum	Duskytail darter	LE	X	X			
Etheostoma (Ulocentra) sp.	Cherokee darter	LT					
Etheostoma wapiti	Boulder darter	LE	X				
Notropis albizonatus	Palezone shiner	LE	X	X			
Noturus baileyi	Smoky madtom	LE	X				
Noturus flavipinnis	Yellowfin madtom	LT	X				
Noturus stanauli	Pygmy madtom	LE	X				
Percina antesella	Amber darter	LE					
Percina aurolineata	Goldline darter	LT					
Percina jenkinsi	Conasauga logperch	LE					
Percina tanasi	Snail darter	LT	X				
Phoxinus cumberlandensis	Blackside dace	LT		X			
Scaphirhynchus albus	Pallid sturgeon	LE					
Speoplatyrhinus poulsoni	Alabama cavefish	LE	X				

[1] Status codes: LE - Listed Endangered; LT - Listed Threatened; PE - Proposed Endangered; PT - Proposed Threatened

[2] Ex = Extirpated

Mississippi Main Stem	Mississippi Tributaries	Pearl	Pascagoula	Mobile	Savannah	Santee	Habitat
							Forests, fields
						X	Spruce-fir/hardwood ecotone
	X			X			Caves, rivers, lakes
X	X			X			Caves, riparian areas
							Caves, nearby forests
	X			X		X	Cliffs, large rivers, reservoirs
X	X						Lakes, large rivers, wooded shorelines
	X	X	X	X			Mature/old growth pine forests
X							Large rivers, sandbars
				X			Swamp forests
		X					Lakes, swamps
		X					Large rivers
X							Forested wetlands, streams
				X			Small rivers
				X			Large rivers
				X			Small rivers, large creeks
							Small rivers, large creeks
							Small rivers
							Small creeks, springs
	X						Small creeks
				X			Small rivers
							Small rivers, large creeks
							Small rivers, large creeks
				X			Small creeks
							Small rivers, large creeks
							Small rivers, large creeks
							Large creeks
							Small rivers, large creeks
							Small rivers
				X			Small rivers
				X			Small rivers
				X			Small rivers
							Large rivers, small rivers
							Small creeks
X							Large rivers
							Cave streams

Threatened and Endangered Species Appendix

Distribution of Endangered and Threatened Species in the TVA Region by River Basins (continued)

Name	Common Name	Status [1]	Tennessee	Cumberland	Green	New	Lower Ohio
CLAMS							
Alasmidonta atropurpurea	Cumberland elktoe	PE		X			
Alasmidonta raveneliana	Appalachian elktoe	LE	X				
Conradilla caelata	Birdwing pearlymussel	LE	X				
Cyprogenia stegaria	Fanshell	LE	X		X		
Dromus dromas	Dromedary pearlymussel	LE	X	X			
Epioblasma brevidens	Cumberland combshell	PE	X	X			
Epioblasma capsaeformis	Oyster mussel	PE	X				
Epioblasma florentina florentina	Yellow-blossom pearlymussel	LE	Ex [2]				
Epioblasma metastriata	Upland combshell	LE					
Epioblasma obliquata obliquata	Catspaw	LE		X	X		
Epioblasma othcaloogensis	Southern acornshell	LE					
Epioblasma penita	Southern combshell	LE					
Epioblasma torulosa gubernaculum	Green blossom pearlymussel	LE	X				
Epioblasma torulosa rangiana	Northern riffleshell	LE			X		
Epioblasma torulosa torulosa	Tuberculed blossom pearlymussel	LE	Ex [2]	Ex [2]			Ex [2]
Epioblasma turgidula	Turgid blossom pearlymussel	LE	X				
Epioblasma walkeri	Tan riffleshell	LE	X	X			
Fusconaia cor	Shiny pigtoe pearlymussel	LE	X				
Fusconaia cuneolus	Fine-rayed pigtoe	LE	X				
Hemistena lata	Cracking pearlymussel	LE	X	X	X		
Lampsilis abrupta	Pink mucket	LE	X	X	X		X
Lampsilis altilis	Fine-lined pocketbook	LT					
Lampsilis perovalis	Orange-nacre mucket	LT					
Lampsilis virescens	Alabama lampmussel	LE	X				
Medionidus acutissimus	Alabama moccasinshell	LT					
Medionidus parvulus	Coosa moccasinshell	LE					
Obovaria retusa	Ring pink	LE	X	X	X		
Pegias fabula	Little-wing pearlymussel	LE	X	X			
Plethobasus cicatricosus	White wartyback	LE	X				
Plethobasus cooperianus	Orange-foot pimpleback	LE	X	X	X		X
Pleurobema clava	Clubshell	LE	X		X		
Pleurobema curtum	Black clubshell	LE					
Pleurobema decisum	Southern clubshell	LE					
Pleurobema furvum	Dark pigtoe	LE					
Pleurobema georgianum	Southern pigtoe	LE					
Pleurobema gibberum	Cumberland pigtoe	LE		X			
Pleurobema marshalli	Flat pigtoe	LE					
Pleurobema perovatum	Ovate clubshell	LE					
Pleurobema plenum	Rough pigtoe	LE	X	X	X		

[1] Status codes: LE - Listed Endangered; LT - Listed Threatened; PE - Proposed Endangered; PT - Proposed Threatened

[2] Ex = Extirpated

Mississippi Main Stem	Mississippi Tributaries	Pearl	Pascagoula	Mobile	Savannah	Santee	Habitat
							Small rivers, creeks
							Small rivers, creeks
							Small rivers
							Rivers
							Rivers
							Small rivers
							Small rivers
							Large rivers
				X			Small rivers
							Large rivers
				X			Small rivers, creeks
				X			Small rivers, creeks
							Small rivers
							Small rivers, creeks
							Large rivers
	X						Creeks
							Small rivers, creeks
							Small rivers, creeks
							Small rivers, creeks
							Rivers, large creeks
							Rivers
				X			Small rivers, creeks
				X			Small rivers, creeks
							Creeks
				X			Small rivers, creeks
				X			Small rivers, creeks
							Rivers
							Creeks
							Large rivers
							Large rivers
							Rivers, large creeks
				X			Small rivers, creeks
				X			Small rivers, creeks
				X			Small rivers, creeks
				X			Small rivers, creeks
							Small rivers, creeks
				X			Small rivers, creeks
				X			Small rivers, creeks
							Rivers

Threatened and Endangered Species Appendix

Distribution of Endangered and Threatened Species in the TVA Region by River Basins (continued)

Name	Common Name	Status [1]	Tennessee	Cumberland	Green	New	Lower Ohio
CLAMS continued							
Pleurobema taitianum	Heavy pigtoe	LE					
Potamilus capax	Fat pocketbook	LE					X
Potamilus inflatus	Inflated heelsplitter	LT					
Ptychobranchus greenii	Triangular kidneyshell	LE					
Quadrula cylindrica strigillata	Rough rabbitsfoot	PE	X				
Quadrula fragosa	Winged mapleleaf	LE	Ex [2]				
Quadrula intermedia	Cumberland monkeyface	LE	X				
Quadrula sparsa	Appalachian monkeyface	LE	X				
Quadrula stapes	Stirrupshell	LE					
Toxolasma cylindrellus	Pale lilliput	LE	X				
Villosa perpurpurea	Purple bean	PE	X				
Villosa trabalis	Cumberland bean	LE	X	X			
SNAILS							
Anguispira picta	Painted snake coiled forest snail	LT	X				
Athearnia anthonyi	Anthony's river snail	LE	X				
Marstonia ogmorhaphe	Royal marstonia	LE	X				
Mesodon clarki nantahala	Noonday globe	LT	X				
Tulotoma magnifica	Tulatoma	LE					
ARTHROPODS							
Microhexura montivaga	Spruce-fir moss spider	PE	X				
Palaemonias alabamae	Alabama cave shrimp	LE	X				
Palaemonias ganteri	Kentucky cave shrimp	LE			X		
Lirceus usdagalun	Lee County cave isopod	LE	X				
Orconectes shoupi	Nashville crayfish	LE		X			
FLOWERING PLANTS							
Apios priceana	Price potato-bean	LT	X	X			X
Arabis perstellata var. ampla	Rockcress	PE		X			
Arenaria cumberlandensis	Cumberland sandwort	LE		X			
Astragalus bibullatus	Ground-plum	LE		X			
Betula uber	Virginia roundleaf birch	LT	X				
Clematis morefieldii	Morefield's leather flower	LE	X				
Clematis socialis	Alabama leather flower	LE					
Conradina verticillata	Cumberland rosemary	LT	X	X			
Dalea foliosa	Prairie clover	LE	X	X			
Echinacea laevigata	Purple-coneflower	LE				X	
Echinacea tennesseensis	Tennessee coneflower	LE		X			
Euphorbia purpurea	Glade spurge	LT	X				
Geum radiatum	Spreading avens	LE	X				

[1] Status codes: LE - Listed Endangered; LT - Listed Threatened; PE - Proposed Endangered; PT - Proposed Threatened

[2] Ex = Extirpated

Mississippi Main Stem	Mississippi Tributaries	Pearl	Pascagoula	Mobile	Savannah	Santee	Habitat
				X			Small rivers, creeks
							Rivers, creeks
				X			Small rivers
				X			Small rivers, creeks
							Small rivers
							Small rivers
							Small rivers
				X			Small rivers
				X			Small rivers
							Creeks
							Small rivers, creeks
							Small rivers, creeks
							Forested bluffs
							Spring runs
							Cliffs
				X			Rivers
						X	Spruce-fir forests
							Caves
							Caves
							Caves
							Large creeks
				X			Hardwood forests, forest edges
							Calcareous slopes
							Sandstone overhangs
							Cedar glades
							Creek terraces
							Hardwood forests
				X			Forest edges, open woodlands
							Riverine gravel bars
							Cedar glades
							Cedar glades, open woods, limestone bluffs
							Cedar glades
							Rich or swampy woods
							High elevation acidic rock outcrops

Threatened and Endangered Species Appendix

Distribution of Endangered and Threatened Species in the TVA Region by River Basins (continued)

Name	Common Name	Status [1]	Tennessee	Cumberland	Green	New	Lower Ohio
FLOWERING PLANTS continued							
Hedyotis purpurea var. montana	Mountain bluet	LE	X				
Helianthus eggertii	Eggert sunflower	PT	X	X	X		
Helonias bullata	Swamp pink	LT	X				
Isotria medeoloides	Small whorled pogonia	LT	X				
Lesquerella lyrata	Lyre-leaf bladderpod	LT	X				
Lesquerella perforata	Spring Creek bladderpod	PE		X			
Liatris helleri	Blazing star	LT				X	
Marshallia mohrii	Barbara buttons	LT	X				
Pityopsis ruthii	Ruth golden aster	LE	X				
Ptilimnium nodosum	Harperella	LE	X				
Sagittaria fasciculata	Arrowhead	LE	X				
Sagittaria secundifolia	Arrowhead	LT	X				
Sarracenia oreophila	Green pitcher plant	LE	X				
Sarracenia rubra ssp. jonesii	Mountain sweet pitcher plant	LE	X				
Schwalbea americana	Chaffseed	LE					
Scutellaria montana	Mountain skullcap	LE	X				
Sisyrinchium dichotomum	Reflexed blue-eyed grass	LE					
Solidago spithamaea	Blue ridge goldenrod	LT	X				
Spiraea virginiana	Virginia spiraea	LT		X			
Trillium persistens	Persistent trillium	LE					
Xyris tennesseensis	Yellow-eyed-grass	LE	X				
FERNS AND FERN ALLIES							
Phyllitis scolopendrium var. americanum	American harts-tongue fern	LT	X				
Thelypteris pilosa var. alabamensis	Alabama streak-sorus fern	LT					
LICHENS							
Gymnoderma lineare	Rock gnome lichen	PE	X				

[1] Status codes: LE - Listed Endangered; LT - Listed Threatened; PE - Proposed Endangered; PT - Proposed Threatened

[2] Ex = Extirpated

Mississippi Main Stem	Tributaries	Pearl	Pascagoula	Mobile	Savannah	Santee	Habitat
						X	High elevation acidic rock outcrops
				X			Hardwood forests
						X	Bogs, meadows, edges of meandering streams
							Hardwood forests
							Cedar glades
							Flood plains, agricultural fields
						X	Acidic soils of high elevation outcrops
				X			Marshes, wet meadows
							Boulders in rivers
				X			Gravel bars, rocks in rivers
							Non-forested seepage areas
							Gravel bars, rocks in rivers
				X			Bogs, wet meadows, moist woodlands
							Mountain bogs and streamsides
				X			Open, sandy, acidic pine woods
				X			Hardwood, mixed forests
						X	Rich basic soils of clearings, woodland edges
						X	Acidic, sandy balds
							Riverine gravel bars
					X		Rich ravines
				X			Forested seeps
							Cave, sinkhole mouths
				X			Crevices of Pottsville sandstone
							High elevation cliffs

Seventeen Categories of Natural Areas Appendix

National Wildlife Refuges

Name	State
Wheeler National Wildlife Refuge	AL
Lake Isom National Wildlife Refuge	TN
Reelfoot Lake National Wildlife Refuge	TN
Tennessee National Wildlife Refuge	TN
Hatchie National Wildlife Refuge	TN
Chickasaw National Wildlife Refuge	TN
Noxubee National Wildlife Refuge	MS
Cross Creeks National Wildlife Refuge	TN
Blowing Wind Cave National Gray Bat Sanctuary	AL

Wilderness Areas

Name	State
Kimberling Creek Wilderness Area	VA
Gee Creek Wilderness Area	TN
Beartown Wilderness Area	VA
Ellicott Rock Extension Wilderness Area	GA
Cohutta Wilderness Area	GA
Bald River Gorge Wilderness Area	TN
Joyce Kilmer-Slickrock Wilderness Area	NC
Ellicott Rock Wilderness Area	GA
Southern Nantahala Wilderness Area	NC
Citico Creek Wilderness Area	TN
Lewis Fork Wilderness Area	VA
Shining Rock Wilderness Area	NC
Big Frog Wilderness Area	TN
Little Dry Run Wilderness Area	VA
Little Wilson Creek Wilderness Area	VA
Sipsey Wilderness Area	AL
Linville Gorge Wilderness Area	NC

Fish Hatcheries

Name	State
Buffalo Springs State Fish Hatchery	TN
Dale Hollow National Fish Hatchery	TN
Summerville State Fish Hatchery	AL
Flintville State Fish Hatchery	TN
Cohutta National Fish Hatchery	GA
Summerville State Fish Hatchery	GA
Lake Burton State Fish Hatchery	GA
Eagle Bend State Fish Hatchery	TN
Chattahoochee National Fish Hatchery	GA
Erwin National Fish Hatchery	TN

State Scenic Rivers

Name	State
Tuckahoe Creek State Scenic River	TN
Harpeth State Scenic River	TN
Conasauga State Scenic River	TN
Chattooga National Wild And Scenic River	GA
Roaring River State Scenic River	TN
Hiwassee State Scenic River	TN
French Broad State Scenic River	TN
Spring Creek State Scenic River	TN
Hatchie State Scenic River	TN
Collins State Scenic River	TN
Blackburn Fork State Scenic River	TN
Buffalo State Scenic River	TN

Outstanding Resource Waters

Name	State
Metropolis Lake	KY
Mammoth Cave Underground River System	KY
Murphys Pond	KY
Ohio River (Livingston County)	KY
Tennessee River	KY
Barren River	KY
Ohio River (McCracken County)	KY
Green River (Butler County)	KY
Green River (Edmonson County)	KY

State Forests

Name	State
Pickett State Forest	TN
Bledsoe State Forest	TN
Scott State Forest	TN
Lewis State Forest	TN
Prentice Cooper State Forest	TN
Standing Stone State Forest	TN
Stewart State Forest	TN
Chickasaw State Forest	TN
Natchez Trace State Forest	TN
Cedars Of Lebanon State Forest	TN
Lone Mountain State Forest	TN
Franklin-Marion State Forest	TN
Chuck Swan State Forest	TN
Lebanon Forests State Forest	TN
Pennyrile State Forest	KY

Pocket Wilderness Areas

Name	State
North Chickamauga Creek Pocket Wilderness Area	TN
Virgin Falls Pocket Wilderness	TN
Laurel-Snow Pocket Wilderness	TN
Stinging Fork Falls Pocket Wilderness	TN

Mussel Sanctuaries

Name	State
Cumberland River No. 3 State Mussel Sanctuary	TN
Kentucky Reservoir No. 2 State Mussel Sanctuary	TN
Cumberland River No. 1 State Mussel Sanctuary	TN
Tennessee River Mussel Sanctuary	KY
Powell River State Mussel Sanctuary	TN
Guntersville Reservoir State Mussel Sanctuary	TN
Kentucky Reservoir No. 1 State Mussel Sanctuary	TN
Cumberland River No. 2 State Mussel Sanctuary	TN
Clinch River State Mussel Sanctuary	TN
Cumberland River Mussel Sanctuary	KY
Duck River State Mussel Sanctuary	TN
Nickajack Reservoir State Mussel Sanctuary	TN
Chickamauga Reservoir State Mussel Sanctuary	TN

Federal Committee on Ecological Reserves Research Natural Areas

Name	State
Berry Island FCER Research Natural Area	TN
Plott Cove FCER Research Natural Area	GA
Old Robinson Road FCER Research Natural Area	MS
Hematite FCER Research Natural Area	KY
Bluff City FCER Research Natural Area	AL
Walker Cover FCER Research Natural Area	NC
Black Mountain FCER Research Natural Area	NC
Dividing Ridge FCER Research Natural Area	KY
Bee Branch FCER Research Natural Area	AL
Pond Hollow FCER Research Natural Area	KY
Britton Ford FCER Research Natural Area	TN
Morgan Hill FCER Research Natural Area	MS
Goose Pond Upland Swamp FCER Research Natural Area	TN
Sinking Pond Upland Swamp FCER Research Natural Area	TN

National Natural Landmarks

Name	State
Chestnut Oak Disjunct National Natural Landmark	MS
Cedar Glade Natural Area National Natural Landmark	TN
Dismals National Natural Landmark	AL
Mt. Mitchell State Park National Natural Landmark	NC
Cathedral Caverns National Natural Landmark	AL
Beaverdam Creek Swamp National Natural Landmark	AL
Harrell Prairie Hill National Natural Landmark	MS
Reelfoot Lake National Natural Landmark	TN
Morgan Hill Research Natural Area	MS

National Natural Landmarks (continued)

Name	State
Bienville Pines Scenic Area National Natural Landmark	MS
May Prairie National Natural Landmark	TN
Big Bone Cave National Natural Landmark	TN
Taylor Hollow National Natural Landmark	TN
Piney Falls National Natural Landmark	TN
McAnultys Woods National Natural Landmark	TN
Cumberland Caverns National Natural Landmark	TN
Sinking Pond National Natural Landmark	TN
Newsome Sinks Karst Area National Natural Landmark	AL
Long Hope Creek Spruce Bog National Natural Landmark	NC
Savage Gulf National Natural Landmark	TN
Lost Sea National Natural Landmark	TN
Shelta Cave National Natural Landmark	AL
Grassy Cove Karst Area National Natural Landmark	TN
Conley Hole National Natural Landmark	TN
Goose Pond National Natural Landmark (Coffee County)	TN
Thumping Dick Cove National Natural Landmark	TN

Critical Habitat Areas

Name	State
Slender Chub Designated Critical Habitat	TN
Kentucky Cave Shrimp Designated Critical Habitat	KY
Conasauga Darter Designated Critical Habitat	GA
Indiana Bat Designated Critical Habitat	KY
Alabama Cavefish Designated Critical Habitat	AL
Spotfin Chub Designated Critical Habitat	TN
Smoky Madtom Designated Critical Habitat	TN
Slackwater Darter Designated Critical Habitat	AL
Yellowfin Madtom Designated Critical Habitat	TN
Amber Darter Designated Critical Habitat	GA

Nature Preserves

Name	State
Chaney Lake State Nature Preserve	KY
Sandy Mitchell Hollow TNC [1] Preserve	TN
Metropolis Lake State Nature Preserve	KY
Mill Creek Heronry TNC [1] Preserve	TN
Mantle Rock Nature Preserve	KY
Cressy Creek TNC Preserve	VA
Big Sheep Cliff Ridge TNC [1] Preserve	NC
Couchville Cedar Glade TNC [1] Preserve	TN
Flat Rock Glade State Nature Preserve	KY
Sunset Barrens Nature Preserve	KY
Raymond Athey Barrens State Nature Preserve	KY
Wash Morgan Hollow TNC [1] Preserve	TN
Taylor Hollow TNC [1] Preserve	TN

[1] The Nature Conservancy

Nature Preserves (continued)

Name	State
Little River Canyon National Preserve	AL
Pendleton Island TNC [1] Preserve	VA
Barnett Woods TNC Preserve	TN
Eller TNC Preserve	NC
Timber Ridge TNC Preserve	NC
Obion Creek Nature Preserve	KY
Jenkins Cranberry Bog TNC Preserve	TN
Logan County Glade State Nature Preserve	KY
Big Yellow Mountain TNC Preserve	NC
Aimee M. Rosenfield Memorial Preserve	KY
The Pinnacle TNC Preserve	VA
Woodburn Glade Nature Preserve	KY
Henry Wright TNC Preserve	NC
Hubbards Cave TNC Preserve	TN
Sneed Road Cedar Glade TNC Preserve	TN
Ochlawaha Bog TNC Preserve	NC
Mt. View Road Glade TNC Preserve	TN
Yarn Property TNC Preserve	GA
Terrapin Creek State Nature Preserve	KY
Roan Mountain TNC Preserve	NC
Powell River TNC Preserve	TN
Oak Ridge Barrens Preserve	TN

Wildlife Observation Areas

Name	State
Duck River Bottoms State Wildlife Observation Area	TN
Univ. Of Tenn. Arboretum State Wildlife Observation Area	TN
Eagle Bend Hatchery State Wildlife Observation Area	TN
Eastern State Wildlife Observation Area	TN
Chota Peninsula State Wildlife Observation Area	TN
Kingston Steam Plant State Wildlife Observation Area	TN
Big Hill Pond State Park State Wildlife Observation Area	TN
Cross Creeks National Wildlife Refuge Wildlife Observ. Area	TN
Blythe Ferry State Wildlife Observation Area	TN
Raccoon Mountain Pumped Storage State Wildlife Observ. Area	TN
Willow Grove/Lillydale State Wildlife Observation Area	TN
Nolichucky Reservoir State Wildlife Observation Area	TN
Savannah Bay/Chickamauga State Wildlife Observation Area	TN
Goose Pond State Wildlife Observation Area (Coffee County)	TN
Ijams Audubon Nature Center State Wildlife Observation Area	TN
Cove Lake State Park State Wildlife Observation Area	TN
Bledsoe Creek State Park State Wildlife Observation Area	TN
Signal Point State Wildlife Observation Area	TN
Old Hickory Trail State Wildlife Observation Area	TN
Herb Parsons Lake State Wildlife Observation Area	TN
Bays Mountain State Wildlife Observation Area	TN
Nickajack Cave State Wildlife Observation Area	TN
Monsanto Ponds Wildlife Observation Area	TN
Cyrpess Grove Nature Park Wildlife Observation Area	TN
Candies Creek/Chickamauga State Wildlife Observation Area	TN
Sugar Creek State Wildlife Observation Area	TN

Wildlife Observation Areas (continued)

Name	State
Lichterman Nature Center State Wildlife Observation Area	TN
Norris Songbird Trail State Wildlife Observation Area	TN
Erwin National Fish Hatchery State Wildlife Observation Area	TN
Elm Hill Sink Hole Wildlife Observation Area	TN
Dyson Ditch State Wildlife Observation Area	TN
Rankin Bottoms State Wildlife Observation Area	TN
Amnicola Marsh State Wildlife Observation Area	TN
Reelfoot Lake State Wildlife Observation Area	TN
Wilbur Lake State Wildlife Observation Area	TN
Alcoa Farm State Wildlife Observation Area	TN
Lake Graham State Wildlife Observation Area	TN
Mt. Roosevelt Overlook State Wildlife Observation Area	TN
Pace Point State Wildlife Observation Area	TN
Ft. Pillow Historic Area State Wildlife Observation Area	TN
Cheatham Reservoir Wildlife Management Area	TN
Percy Priest Wildlife Observation Area	TN
Radnor Lake State Wildlife Observation Area	TN
Cades Cove State Wildlife Observation Area	TN
Laurel Hill Lake State Wildlife Observation Area	TN

TVA Natural Areas

Name	State
Comby Ridge TVA Small Wild Area	TN
Riley Creek Islands TVA Habitat Protection Area	TN
Marble Bluff TVA Habitat Protection Area	TN
Possum Creek TVA Habitat Protection Area	TN
Whites Creek TVA Small Wild Area	TN
Chickamauga Shoreline TVA Habitat Protection Area	TN
Huff Branch TVA Habitat Protection Area	TN
Beech Island TVA Small Wild Area	TN
Chigger Point TVA Habitat Protection Area	TN
Big Ridge TVA Habitat Protection Area	TN
Fooshee Bend Islands TVA Habitat Protection Area	TN
Mink Creek TVA Habitat Protection Area	AL
Stowe Bluff TVA Habitat Protection Area	TN
Coffee Bluff TVA Habitat Protection Area	AL
Foster Falls TVA Small Wild Area	TN
Little Gizzard Creek TVA Small Wild Area	TN
Tribble Woods TVA Habitat Protection Area	TN
Metropolis Lake TVA Habitat Protection Area	KY
Hemlock Bluff TVA Small Wild Area	TN
Honey Bluff TVA Habitat Protection Area	AL
Clendenin Creek TVA Habitat Protection Area	TN
Lady Finger Bluff TVA Small Wild Area	TN
Sugar Grove TVA Habitat Protection Area	TN
Monks Corner TVA Small Wild Area	TN
Eagle Roost TVA Habitat Protection Area	TN
Blythe Ferry TVA Habitat Protection Area	TN
Grasshopper Creek TVA Habitat Protection Area	TN
Bayou Creek Ridge TVA Habitat Protection Area	KY
Cave Mountain TVA Small Wild Area	AL

TVA Natural Areas (continued)

Name	State
River Bluff TVA Small Wild Area	TN
Grassy Creek TVA Habitat Protection Area	TN
Stiners Woods TVA Habitat Protection Area	TN
Johnson Bend Islands TVA Habitat Protection Area	TN
Soddy Creek TVA Habitat Protection Area	TN
Fairview Slopes TVA Habitat Protection Area	TN
Armstrong Bend TVA Habitat Protection Area	TN
Butcher Bluff TVA Habitat Protection Area	TN
Norris Dam Cave TVA Habitat Protection Area	TN
Paint Rock Bluff TVA Small Wild Area	TN
Berry Island TVA Ecological Study Area	TN
Tellico Bluff TVA Ecological Study Area	TN
Three B TVA Habitat Protection Area	TN
Ware Branch Bend TVA Habitat Protection Area	TN
Honeycomb Creek TVA Small Wild Area	AL
Hematite Lake TVA Ecological Study Area	KY
Shellmound Road Bluff TVA Habitat Protection Area	TN
Nickajack Cave TVA Habitat Protection Area	TN
Little Cedar Mountain TVA Habitat Protection Area	TN
Thief Neck Island TVA Ecological Study Area	TN
Big Spring Creek TVA Small Wild Area	AL
Little Cedar Mountain TVA Small Wild Area	TN
Polecat Creek Slopes TVA Habitat Protection Area	TN
Marney Bluff TVA Habitat Protection Area	TN
Blue Springs Peninsula TVA Habitat Protection Area	TN
Murphy Hill TVA Habitat Protection Area	TN
Eaves Bluff TVA Habitat Protection Area	TN
Blowing Wind Cave TVA Habitat Protection Area	AL
Nickajack Cave TVA Small Wild Area	TN
Johnson Bottoms TVA Habitat Protection Area	TN
Panther Creek Swamp TVA Habitat Protection Area	KY
Alley Bluff TVA Habitat Protection Area	TN
Coon Gulf TVA Small Wild Area	AL
Dividing Ridge TVA Ecological Study Area	KY
Pond Hollow TVA Ecological Study Area	KY
Bear Creek TVA Habitat Protection Area	TN
Old First Quarters TVA Small Wild Area	AL
Rayburn Bridge TVA Habitat Protection Area	TN
Mccuiston Woods TVA Habitat Protection Area	KY
Long Island TVA Habitat Protection Area	TN
Cooper Falls TVA Habitat Protection Area	MS
Short Springs TVA Small Wild Area	TN
South Sauty Creek TVA Small Wild Area	AL
Big Ridge TVA Small Wild Area	TN
Fooshee Peninsula TVA Small Wild Area	TN

State Parks

Name	State
Marion Bridge TVA Habitat Protection Area	TN
Hungry Mother State Park	VA
Mousetail Landing State Rustic Park	TN
Tishomingo State Park	MS
Joe Wheeler State Park	AL
Pickwick Landing State Resort Park	TN
Reelfoot Lake State Resort Park	TN
Big Ridge State Rustic Park	TN
Meeman-Shelby Forest State Recreational Park	TN
Black Rock Mountain State Park	GA
Lake Lowndes State Park	MS
Lake Malone State Park	KY
Kenlake Resort State Park	KY
Fort Mountain State Park	GA
Tombigbee State Park	MS
Norris Dam State Resort Park	TN
Cedars Of Lebanon State Recreational Park	TN
Cumberland Mountain State Rustic Park	TN
Warriors Path State Recreation Park	TN
Rough River Dam Resort State Park	KY
Cossar State Park	MS
Shot Tower State Historical Park	VA
Blackburn State Park	GA
Monte Sano State Park	AL
Rickwood Caverns State Park	AL
Lake Barkley State Resort Park	KY
Bucks Pocket State Park	AL
Edgar Evins State Rustic Park	TN
Chickasaw State Rustic Park	TN
Long Hunter State Recreation Park	TN
Roan Mountain State Resort Park	TN
Rock Island State Rustic Park	TN
Panther Creek State Recreation Park	TN
T.O. Fuller State Recreation Park	TN
Grayson Highlands State Park	VA
Kentucky Dam Village State Resort Park	KY
Dale Hollow Lake State Park	KY
Mt. Mitchell State Park	NC
Cathedral Caverns State Park	AL
Lake Guntersville State Park	AL
Pennyrile Forest Resort State Park	KY
Breaks Interstate State Park	VA
Vogel State Park	GA
Roosevelt State Park	MS
Wall Doxey State Park	MS
Big Hill Pond State Park	TN
Henry Horton State Resort Park	TN
David Crockett State Recreation Park	TN
Trace State Park	MS
Indian Mountain State Camping Park	TN
Pickett State Rustic Park	TN
Bledsoe Creek State Camping Park	TN

State Parks (continued)

Name	State
Paris Landing State Resort Park	TN
Davy Crockett Birthplace State Historical Park	TN
Booker T. Washington State Recreation Park	TN
Cove Lake State Recreation Park	TN
Montgomery Bell State Resort Park	TN
Tims Ford State Rustic Park	TN
Standing Stone State Rustic Park	TN
Fall Creek Falls State Resort Park	TN
Natchez Trace State Resort Park	TN
Cloudland Canyon State Park	GA
J.P. Coleman State Park	MS
John W. Kyle State Park	MS
Bays Mountain Park State Natural Area	TN
Moccasin Creek State Park	GA
James H. Sloppy Floyd State Park	GA
Desoto State Park	AL
Columbus-Belmont Battlefield State Park	KY
Natural Tunnel State Park	VA
Ft. Mountain State Park	GA
George P. Cossar State Park	MS
Harrison Bay State Recreation Park	TN

State Natural Areas

Name	State
Flat Rock Mountain Registered State Natural Area	NC
Basin Spring Registered State Natural Area	TN
Shortleaf Pine State Natural Area	MS
Trotters Woods Registered State Natural Area	TN
White Oak State Natural Area	MS
Big Yellow Mountain Registered State Natural Area	NC
Grandfather Mountain Registered State Natural Area	NC
Walterhill Floodplain State Natural Area	TN
Stinging Fork State Natural Area	TN
Bayou Creek Registered State Natural Area	KY
Radnor Lake State Natural Area	TN
Factory Road Glade Registered State Natural Area	TN
Warren Wilson College Biol. Reserve Registered State Nat. Area	NC
Natural Bridge State Natural Area	TN
Colditz Cove State Natural Area	TN
Falling Waters Falls State Natural Area	TN
Honey Creek State Natural Area	TN
Carter Caves State Natural Area	TN
Sandy Bottom Registered State Natural Area	NC
Zahnd State Natural Area	GA
Goose Pond Registered State Natural Area (Coffee County)	TN
Balsam Gap Registered State Natural Area	NC
Lesser Alcoa Marsh Registered State Natural Area	TN
Big Clifty Prairie State Natural Area	KY
Bear Creek Rookery State Natural Area	KY
Sweetwater Branch Registered State Natural Area	TN
Ochlawaha Bog Registered State Natural Area	NC

State Natural Areas (continued)

Name	State
Gap Bog Registered State Natural Area	NC
Redbank Cove Registered State Natural Area	NC
Mt. Mitchell Park Registered State Natural Area	NC
Mt. Pisgah Registered State Natural Area	NC
Twin Arches State Natural Area	TN
Satulah Mountain Summit Registered State Natural Area	NC
Riverwoods State Natural Area	TN
James Avent Woodlot Registered State Natural Area	TN
Ames Plantation Registered State Natural Area	TN
Wildcat Hollow Registered State Natural Area	TN
Franklin Bog Registered State Natural Area	NC
Laurel-Snow State Natural Area	TN
Dunbar Cave State Natural Area	TN
Camp Branch Falls/Nantahala Gorge Registered State Natural Area	NC
Slagle Hollow Knobs/Steele Creek Park Registered State Nat. Area	TN
Barkley Prairie State Natural Area	KY
Browder Woods Registered State Natural Area	TN
Booger Swamp Registered State Natural Area	TN
Brady Mountain Registered State Natural Area	TN
Olive Preserve Registered State Natural Area	NC
Dripping Rock Bluff Registered State Natural Area	TN
Piney Falls State Natural Area	TN
Oak Ridge Barrens Registered State Natural Area	TN
Wright White Pine Stand Registered State Natural Area	TN
Metropolis Lake Registered State Natural Area	KY
Bear Creek Registered State Natural Area	TN
Grassy Pond Registered State Natural Area	TN
Steestachee Bald/Wesner Bald Registered State Natural Area	NC
Carmack Falls Registered State Natural Area	TN
Toxaway Creek/Rock Creek Registered State Natural Area	NC
Virgin Falls State Natural Area	TN
Short Mountain Registered State Natural Area	TN
Morrill Cave State Natural Area	TN
Fall Creek Falls State Natural Area	TN
Richland Balsam Registered State Natural Area	NC
Burgess Falls State Natural Area	TN
Hicks Gap State Natural Area	TN
North Fork Natural Area Registered State Natural Area	NC
Sinking Pond Registered State Natural Area	TN
Big Sheep Cliff Ridge Registered State Natural Area	NC
Sullenger Bend Registered State Natural Area	TN
Waterrock Knob Registered State Natural Area	NC
Memmingers Woods Registered State Natural Area	NC
Henry Wright Preserve Registered State Natural Area	NC
Great Smoky Mts. National Park/NC Registered State Nat. Area	NC
Bluebell Island Registered State Natural Area	TN
Julian Price Park Wetlands Registered State Natural Area	NC
Grandfather Mountain Corridor Registered State Natural Area	NC
Reelfoot Lake State Natural Area	TN
Scales Mountain Knobs Registered State Natural Area	TN
House Mountain State Natural Area	TN
Cedars Of Lebanon State Forest State Natural Area	TN

State Natural Areas (continued)

Name	State
Thompson Fossil Bed Registered State Natural Area	TN
Tanager Hill Registered State Natural Area	TN
The Craggies Registered State Natural Area	NC
Fork Ridge Balds/Mt. Hardy Registered State Natural Area	NC
Walker Branch Registered State Natural Area	TN
Frying Pan Gap Registered State Natural Area	NC
Back Slough/Laketon State Natural Area	KY
Tallahatchie State Natural Area	MS
Mosley Pond State Natural Area	KY
Malcolm Creek Rookery State Natural Area	KY
Rials Woods State Natural Area	KY
Forest Mill Pond Registered State Natural Area	TN
Hampton Creek Cove Class I State Natural Area	TN
Big Cypress Tree State Natural Area	TN
Joe Bryson Branch Registered State Natural Area	NC
Metal Ford Registered State Natural Area	TN
May Prairie State Natural Area	TN
Round Top Mountain State Natural Area	TN
Little Swan Creek Registered State Natural Area	TN
Pinky Falls Preserve Registered State Natural Area	NC
Horsepasture River Gorge/Windy Falls Registered State Nat. Area	NC
Hunter Bog Registered State Natural Area	TN
Little Buffalo River Bottoms Registered State Natural Area	TN
Short Mountain State Natural Area	TN
Pineola Bog Registered State Natural Area	NC
Warner Parks Registered State Natural Area	TN
Shelby Farms Forest State Natural Area	TN
Frozen Head State Natural Area	TN
Buck Creek Olivine Barrens Registered State Natural Area	NC
Stones River Mustard Field State Natural Area	TN
Sunk Lake State Natural Area	TN
Flat Laurel Registered State Natural Area	NC
Chestnut Bald/Silvermine Bald Registered State Natural Area	NC
Laurel Ridge Registered State Natural Area	NC
Flint River Bottoms Registered State Natural Area	TN
Wootens Bluff Registered State Natural Area	TN
Hawkins Cove State Natural Area	TN
Bone Cave State Natural Area	TN
Lacefield Falls Registered State Natural Area	TN
High Swan Natural Area Registered State Natural Area	NC
Grundy Forest State Natural Area	TN
Bays Mountain Park State Natural Area	TN
Piney Point State Natural Area	MS
McClures Bog Registered State Natural Area	NC
Dulany Bog Registered State Natural Area	NC
Savage Gulf State Natural Area	TN
Lake Barkley Rookery State Natural Area	KY
Big Ridge Registered State Natural Area	TN
Bottomland Hardwood State Natural Area	MS
Ozone Falls State Natural Area	TN
Greater Alcoa Marsh Registered State Natural Area	TN
Magendanz Falls Registered State Natural Area	TN

State Natural Areas (continued)

Name	State
Dennis Prairie State Natural Area	KY
Lick Creek State Natural Area	VA

Wildlife Management Areas

Name	State
Bean Switch Refuge State Wildlife Management Area	TN
Black Bayou Refuge State Wildlife Management Area	TN
Edgar Evins State Park Wildlife Management Area	TN
Ernest Rice Sr. State Wildlife Management Area	TN
Gallatin Steam Plant State Wildlife Management Area	TN
Haley-Jaqueth State Wildlife Management Area	TN
Horns Bluff Refuge State Wildlife Management Area	TN
Jackson Swamp State Wildlife Management Area	TN
Jarrell Switch State Wildlife Management Area	TN
Keyes-Harrison State Wildlife Management Area	TN
Maness Swamp Refuge State Wildlife Management Area	TN
Mustin Bottoms Refuge State Wildlife Management Area	TN
Obion River State Wildlife Management Area	TN
Pea Ridge State Wildlife Management Area	TN
White Lake Refuge State Wildlife Management Area	TN
Upper Sardis State Wildlife Management Area	MS
M.T.S.U. State Wildlife Management Area	TN
White Oak State Wildlife Management Area	TN
Bienville State Wildlife Management Area	MS
Caney Creek State Wildlife Management Area	MS
Catoosa State Wildlife Management Area.	TN
Johns Mountain State Wildlife Management Area	GA
Oak Ridge State Wildlife Management Area	TN
Perryville State Wildlife Management Area	TN
Chickamauga State Wildlife Management Area	TN
Big Sandy State Wildlife Management Area	TN
Tradewater Wildlife Management Area	KY
Normandy State Wildlife Management Area	TN
Watts Bar State Wildlife Management Area	TN
Percy Priest State Wildlife Management Area	TN
Phipps Bend Refuge State Wildlife Management Area	TN
Freedom Hills State Wildlife Management Area	AL
Cove Creek Peninsula State Wildlife Management Area	TN
Cordell Hull Refuge State Wildlife Management Area	TN
Nolin Lake State Wildlife Management Area	KY
Tellico Lake State Wildlife Management Area	TN
Skyline State Wildlife Management Area	AL
Reelfoot Lake/Tenn. State Wildlife Management Area	TN
Chickasaw/Miss. State Wildlife Management Area	MS
Eastern State Wildlife Management Area	TN
Barkley Reservoir/Tenn. State Wildlife Management Area	TN
Barkley Lake Wildlife Management Area	KY
Aedc And Woods State Wildlife Management Area	TN
Tigrett State Wildlife Management Area	TN
Grenada Waterfowl Refuge State Wildlife Management Area	MS
Coopers Creek State Wildlife Management Area	GA

Wildlife Management Areas (continued)

Name	State
North Sauty Creek State Wildlife Management Area	AL
Hidden Valley State Wildlife Management Area	VA
Buffalo Springs State Wildlife Management Area	TN
Peal Land Wildlife Management Area	KY
Gallatin Steam Plant State Wildlife Management Area	TN
Pigeon Mountain State Wildlife Management Area	GA
Shelby Forest State Wildlife Management Area	TN
Cumberland Cove State Wildlife Management Area	TN
Cohutta State Wildlife Management Area	GA
Dale Hollow Lake Wildlife Management Area	KY
Land Between The Lakes/Tenn. State Wildlife Management Area	TN
Mallard-Fox Creek State Wildlife Management Area	AL
Fall Creek Falls State Wildlife Management Area	TN
Sevenmile Island State Wildlife Management Area	AL
Lick Creek State Wildlife Management Area	TN
Eagle Creek State Wildlife Management Area	TN
Cumberland Springs State Wildlife Management Area	TN
Cedar Hill Swamp State Wildlife Management Area	TN
Camden State Wildlife Management Area	TN
Alpine Mountain State Wildlife Management Area	TN
Cherokee (South) State Wildlife Management Area	TN
Chilhowee Mountain State Wildlife Management Area	TN
Hermitage State Wildlife Management Area	TN
Chuck Swan State Wildlife Management Area	TN
Anderson-Tully (Lower) State Wildlife Management Area	TN
Blythe Ferry State Wildlife Management Area	TN
Flintville Hatchery State Wildlife Management Area	TN
Rich Mountain State Wildlife Management Area	GA
Pennyrile Forest State Wildlife Management Area	KY
Swallow Creek State Wildlife Management Area	GA
Old Hickory State Wildlife Management Area	TN
Clinch Mountain State Wildlife Management Area	VA
Land Between The Lakes/Ky State Wildlife Management Area	KY
Swan Creek State Wildlife Management Area	AL
Ohio River Islands Wildlife Management Area	KY
Coleman River State Wildlife Management Area	GA
Raccoon Creek State Wildlife Management Area	AL
Henderson Island Refuge State Wildlife Management	TN
West Sandy State Wildlife Management Area	TN
Hiwassee Refuge State Wildlife Management Area	TN
Reelfoot Lake/Ky State Wildlife Management Area	KY
Volunteer Army Ammunition Plant State Wildlife Management Area	TN
Black Warrior State Wildlife Management Area	AL
Barren River Lake State Wildlife Management Area	KY
Prentice Cooper State Wildlife Management Area	TN
Lake Burton State Wildlife Management Area	GA
Jones Keeney Wildlife Management Area	KY
Yellow Creek State Wildlife Management Area	MS
West Kentucky State Wildlife Management Area	KY
Warwoman State Wildlife Management Area	GA
Ft. Campbell State Wildlife Management Area	KY

Wildlife Management Areas (continued)

Name	State
Choctaw State Wildlife Management Area	MS
Calhoun County State Wildlife Management Area	MS
Coosawattee State Wildlife Management Area	GA
Natchez Trace State Wildlife Management Area	TN
Kaler Bottoms Wildlife Management Area	KY
Chestatee State Wildlife Management Area	GA
Mud Creek State Wildlife Management Area	AL
Chattahoochee State Wildlife Management Area	GA
Okitibbee State Wildlife Management Area	MS
Blue Ridge State Wildlife Management Area	GA
Harmon Creek State Wildlife Management Area	TN
Winford Pond State Wildlife Management Area	KY
Chickasaw/Tenn. State Wildlife Management Area	TN
Old Hickory Lock 5 State Wildlife Management Area	TN
Pickett State Wildlife Management Area	TN
New Hope State Wildlife Management Area	TN
Cheatham State Wildlife Management Area	TN
Cordell Hull State Wildlife Management Area	TN
Standing Stone State Wildlife Management Area	TN
Gooch State Wildlife Management Area	TN
Lauderdale County State Wildlife Management Area	AL
Rankin Bottom State Wildlife Management Area	TN
Moss Island State Wildlife Management Area	TN
Doe Mountain State Wildlife Management Area	TN
Kingston Refuge State Wildlife Management Area	TN
Nathan Bedford Forrest State Wildlife Management Area	TN
Nolichucky State Wildlife Management Area	TN
Cheatham Reservoir Wildlife Management Area	TN
Rough River State Wildlife Management Area	KY
Talking Rock State Wildlife Management Area	GA
Little River State Wildlife Management Area	AL
John Bell Williams State Wildlife Management Area	MS
Crow Creek Refuge State Wildlife Management Area	AL
Kentucky Lake Wildlife Management Area	KY
Laurel Hill State Wildlife Management Area	TN
Sardis Waterfowl Refuge State Wildlife Management Area	MS
Cherokee (North) State Wildlife Management Area	TN
Crow Creek State Wildlife Management Area	AL
Lamarion State Wildlife Management Area	AL
Cheatham Reservoir State Wildlife Management Area	TN
Royal Blue State Wildlife Management Area	TN
Mt. Roosevelt State Wildlife Management Area	TN

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Glossary

The development of Energy Vision 2020, using TVA's interactive planning process, requires the careful, consistent use of certain key terms and phrases. Below are definitions of terms used often in Volume 2, Technical Document 1, Comprehensive Affected Environment. (Terms in definitions which are themselves defined in the Glossary are printed in *italics.*)

A

Acid Deposition—The wet or dry deposition of acid chemical compounds from the atmosphere.

Acid Rain—A complex chemical and atmospheric phenomenon that occurs when *emissions* of sulfur and nitrogen compounds and other substances are transformed by chemical processes in the atmosphere, often far from the original sources, and then deposited on Earth in either a wet or dry form. The wet forms, popularly called "acid rain," can fall as rain, snow, or fog. The dry forms are acidic gases or *particulates.*

Aesthetics—The perception or appearance of visual features in relation to the sense of beauty.

Agricultural Sector—The group of non-residential customers engaged in the production of crops or livestock, forestry, fishing, hunting, or trapping.

Air Toxins—Various man-made and naturally occurring materials that are known or suspected of causing serious public health impacts, but for which no *National Ambient Air Quality Standards* exist.

Alluvial—Sediment deposited by flowing water.

Ambient—Surrounding.

Ambient Air Quality Standards—National standards set by the U.S. *Environmental Protection Agency* that are permissible concentration levels of certain pollutants (new *ozone, carbon monoxide, particulates (PM 10), sulfur dioxide, nitrogen dioxide,* and *lead*) in the *ambient* air.

Anaerobic—Life in the absence of air or free oxygen.

Aquatic—Characteristic of and/or pertaining to water.

Aquifer—A water-bearing rock, rock formation, or group of rock formations.

Archaeological Resources—Material remains of past human activity.

Attainment Areas—Those areas that meet all *National Ambient Air Quality Standards* as determined by monitoring of air pollutant levels.

B

Benthic Invertebrates—An animal lacking a backbone or spinal column and living on lake bottoms.

Benthos—Organisms that live on or in the first few inches of mud, sand, gravel, or other materials that make up the bottom of streams and lakes, e.g. worms, snails, crayfish, mussels, clams.

Biodiversity—The diversity of life in all its forms and all its levels of organization. Also termed "biological diversity".

Biomagnification—The bioaccumulation of chemicals in organisms beyond the concentration expected if the chemical was in equilibrium between the organism and its surroundings. Biomagnification can occur in both terrestrial and *aquatic* environments.

Biomass—Organic material. Often involves the harvesting of stands of close-growing whole trees, truck transport, tree storage, and drying using air heated by boiler flue gas and combustion of whole trees in a special deep-bed burner at the bottom of the furnace.

Buffering Capacity—Ability of a stream to absorb acids and bases without altering the stream *pH.*

C

Canopy—Refers to the layer of foliage in a forest formed by the crowns of trees.

Carbon Dioxide (CO_2)—A colorless, odorless, nonpoisonous gas that results from fossil fuel combustion and is normally a part of the *ambient* air. Increasing levels of *carbon dioxide* in the atmosphere are contributing to the *greenhouse effect.*

Carbon Monoxide (CO)—A colorless, odorless, poisonous gas produced by incomplete fossil fuel combustion.

Cedar Glades—Distinctive plant communities occurring where certain types of limestone weather to produce bare rock outcrops or thin layers of soil.

CFCs—*Chlorofluorocarbons.*

CH_4—*Methane.*

Chlorofluorocarbons (CFCs)—A family of inert, nontoxic, and easily liquefied chemicals used in refrigeration, air conditioning, packaging, and insulation or as solvents and aerosol propellants. Because *CFCs* are not destroyed in the lower atmosphere, they drift into the upper atmosphere, where their chlorine components destroy *ozone.*

Class I Areas—Areas designated by the Prevention of Significant Deterioration section of the *Clean Air Act Amendments of 1977* that includes national parks and wilderness areas, providing special protection for air quality and air quality-related values.

Clean Air Act Amendments of 1970—Enabling legislation which instructs the *Environmental Protection Agency (EPA)* to set air quality standards for pollutants of concern.

Clean Air Act Amendments of 1977—Legislation that provides greater regulatory authority and sets specific provisions to protect national parks and wilderness areas designated as *Class I areas.*

Clean Air Act Amendments of 1990—Legislation that adds additional regulatory authority to enforce compliance in *nonattainment areas.* Also sets new requirements for *acid rain, hazardous air pollutants,* and monitors and reports air *emissions.*

Climate Change Action Plan—The principal utility industry component of the U.S. Department of Energy's Climate Change Action Plan, provides for a voluntary reduction of *greenhouse gases* (primarily *carbon dioxide emissions*).

CO—*Carbon Monoxide.*

CO_2—*Carbon Dioxide.*

Community—An assemblage of plants, animals, bacteria, and fungi that live in an environment and interact with one another, forming a distinctive living system with its own composition, structure, environmental relations, development, and functions.

Criteria—Used in integrated resource planning. They are derived from issues or concerns. Examples include concerns over future rates, acceptable levels of environmental impacts, etc.

E

Ecosystem—Any unit that includes all organisms (i.e., the *community*) in a given area interacting with the physical environment. The flow of *energy* leads to a clearly defined trophic structure, biotic diversity and material cycles (i.e., exchange of materials between living and nonliving parts within the system).

Effluent—Wastewater—treated or untreated—that flows out of a treatment plant, sewer, or industrial outfall. Generally refers to wastes discharged into surface waters.

Electric and Magnetic Fields (EMF)—Two types of *energy* fields which are emitted from any device that generates, transmits, and uses electricity.

Embayment—A body of water forming a bay.

EMF—*Electric and Magnetic Fields.*

Emission—Pollution discharged into the atmosphere from smokestacks, other vents, and surface areas of commercial or industrial facilities; from residential chimneys; and from motor vehicle, locomotive, or aircraft exhausts.

Endangered Species—Any species in danger of extinction throughout all or a significant portion of its range or territory.

Energy—The amount of power consumed over a period of time, measured in watt hours, *kWH, MWh,* or *GWh.*

Environmental Protection Agency (EPA)—A federal agency established to permit coordinated and effective governmental action for protection of the environment by the systematic abatement and control of pollution through integration of research monitoring, standard setting, and enforcement activities.

EPA—*Environmental Protection Agency.*

Erosion—The process by which soil particles are detached and transported by water and gravity to some downslope or downstream point.

F

Fly Ash—The small ash particles that are carried out of a combustor with the existing flue gas. These particles are collected by appropriate equipment prior to discharging the flue gas to the atmosphere.

Forest Cover Type—A descriptive classification of forest land based on present occupancy of an area by tree species (also known as "forest type"), such as:

- **Oak-hickory.** Forests in which upland oaks and/or hickory, make up the majority of trees.
- **Oak-pine.** Forests in which hardwoods (usually upland oaks) constitute the majority of trees but in which pines

account for 25 to 50 percent of the stocking. (Common associates include gum, hickory, and yellow poplar.)

Fossil Fuel Power Plant—A plant using coal, oil, natural gas or other fossil fuel as its source of *energy*.

G

Geography—Belonging to or characteristic of a particular region.

Global Warming—The theory that certain gases such as *carbon dioxide* (CO_2), *methane* (CH_4), and *chlorofluorocarbon (CFC)* in the earth's atmosphere effectively restrict radiation cooling, thus elevating the earth's *ambient* temperatures.

Greenhouse Effect—The build-up of *carbon dioxide* or other trace gases that allows light from the sun's rays to heat the Earth but prevents a counterbalancing loss of heat.

Greenhouse Gas Emissions—A gas whose presence in the upper atmosphere contributes to the *greenhouse effect* by allowing visible light to pass through the atmosphere while preventing heat radiating back from the Earth from escaping. Greenhouse gases from human produced sources include *carbon dioxide, nitrous oxide, methane*, and *chlorofluorocarbons (CFCs)*. There also are even larger quantities of naturally occurring greenhouse gases, notably *ozone* and water vapor, whose concentrations may be affected by interactions with atmospheric pollutants.

Groundwater—Water within the earth or geologic stratum that supplies wells and springs.

H

Habitat—The total environmental conditions on a unit of land including food, cover, and water within the home range.

Habitat Diversity—The variety and variability of habitat types, as well as their interrelationships on a given area and scale.

HAP—*Hazardous Air Pollutants*.

Hardwoods—Angiosperms, usually broadleaf and deciduous. Soft hardwoods are soft-textured hardwoods such as boxelder, red and silver maples, hackberry, sweetgum, yellow poplar, blackgum, sycamore, black cherry, and elm. Hard hardwoods are hard-textured hardwoods such as sugar maple, hickory, dogwood, persimmon, black locust, beech, ash, black walnut, and all commercial oaks.

Hazardous Air Pollutants (HAP)—Air pollutants that are not covered by *ambient* air quality standards but that present, or may present, a threat of adverse health or environmental effects. These include an initial list of 189 chemicals designated by Congress and subject to revision by the *Environmental Protection Agency*.

Hazardous Waste—A byproduct of society that can pose a substantial or potential hazard to human health or the environment when improperly managed. Possesses at least one of four characteristics (ignitability, corrosivity, reactivity, or toxicity) or appears on special *Environmental Protection Agency* lists.

Haze—Atmospheric moisture, dust, smoke, and vapor suspended to form a partly opaque condition.

Heavy Metals—Natural elements such as lead, mercury, cadmium, and nickel. They are mined from the earth and used in numerous manufacturing processes and countless products.

High-Level Waste—Material that is highly radioactive. In a nuclear power plant high-level waste is *spent fuel*.

Historic Site—See *Archaeological Resources*.

Hydroelectric Power Generation—A dam creates an upper and a lower water reservoir. The height difference between the two reservoirs establishes potential *energy* that is used to generate electricity by allowing water from the upper reservoir to flow through a hydro *turbine* to the lower reservoir.

I

Impoundment—A body of water or sludge confined by a dam, dike, floodgate, or other barrier.

K

Karst (Topography)—The relief of an area underlaid by limestone that dissolves in differing degrees, thus forming numerous depressions or small basins.

Karst Region—A particular geographic region of irregular limestone in which *erosion* has produced fissures, sinkholes, underground streams, and caverns.

L

Lacustrine—Living or growing in lakes; of or related to lakes.

Lead (Pb)—A *heavy metal* that is hazardous to health if breathed or swallowed. Its use in gasoline, paints, and plumbing compounds has been sharply restricted by federal regulations, but enormous quantities of

lead already released into the environment are causing significant problems.

Low-Level Waste—Radioactive material that is slightly or moderately radioactively contaminated. Low-level radioactive waste consists largely of ordinary trash and other items that have come into contact with radioactive materials.

M

Mainstream Reservoirs—Reservoirs on large rivers such as the Tennessee River.

Manganese (Mn)—A hard and brittle metallic element that resembles iron but is not magnetic.

Mature Trees—Stands of trees that have grown into the sawtimber class but have not yet begun to decline and die from natural processes.

Methane (CH_4)—A *greenhouse gas* that is colorless, nonpoisonous, and flammable and is created by anaerobic decomposition of organic compounds.

Mobile Sources—Transportation air pollution sources, primarily automobiles and trucks.

Multi-Attribute Trade-off Analysis/ Technique—An approach designed for interactive participation by a group to make dual comparisons among different attributes for many strategies. It provides an open framework for public involvement to investigate different attributes, futures, and strategies.

N

N_2O—*Nitrous Oxide.*

NAAQS—*National Ambient Air Quality Standards.*

NAPAP—*National Acid Precipitation Assessment Program.*

National Acid Precipitation Assessment Program (NAPAP)—A 10-year scientific study conducted by the federal government from 1980 to 1990 to determine the effects of, and sources contributing to, *acid deposition.*

National Ambient Air Quality Standards (NAAQS)—Uniform, national air quality standards established by the *Environmental Protection Agency* that restrict *ambient* levels of certain pollutants to protect public health (primary standards) or public welfare (secondary standards). Standards have been set for *ozone, carbon monoxide, particulates (PM10), sulfur dioxide, nitrogen, nitrogen dioxide,* and *lead.*

Native Species—Species normally indigenous to an area; not introduced by man.

Natural Resources—The elements of the natural environment that are evaluated as resources (i.e., water resources, forests).

Nitrogen Dioxide (NO_2)—The result of *nitric oxide* combining with oxygen in the atmosphere. A major component of photochemical smog.

Nitrogen or Nitrous Oxide (NOx)—A product of combustion by mobile and stationary sources and a major contributor to the formation of *ozone* in the *troposphere* and *acid deposition.*

NO_2—*Nitrogen Dioxide.*

Nonattainment Area—A geographic area that does not meet one or more of the *National Ambient Air Quality Standards* for the *criteria* pollutants designated in the Clean Air Act.

Non-Point Sources—Pollution sources that are diffuse and do not have a single point of origin or are not introduced into a receiving stream from a specific outlet. The pollutants are generally carried off the land by storm water runoff.

NO_X—*Nitrogen Oxide or Nitrous Oxide.*

O

Ozone (O_3)—A substance found in the stratosphere and the *troposphere.* In the stratosphere (the atmospheric layer beginning 7 to 10 miles above the Earth's surface) ozone is a form of oxygen found naturally that provides a protective layer shielding the Earth from ultraviolet radiation. In the *troposphere* (the layer extending up 7 to 10 miles from the Earth's surface), ozone is a chemical oxidant and a major component of photochemical smog.

Ozone can seriously affect the human respiratory system and is one of the most widespread of all the *criteria* pollutants. Ozone in the *troposphere* is produced through complex chemical reactions of *nitrogen oxides,* which are among the primary pollutants emitted by combustion sources; hydrocarbons, released into the atmosphere through the combustion, handling, and processing of hydrocarbon products and sunlight.

P

Palustrine—Relating to marshes or wetlands.

Particulate—Minute separate particles.

Particulate Collection Devices—Environmental control systems (i.e., electrostatic precipitators, baghouses) designed to remove suspended particulate matter (i.e., *fly ash*) from coal-fired boiler flue gas.

Parts per Million—The number of parts of a given substance or pollutant in a million parts of a base material; a measure of concentration.

PCBs—Polychlorinated byphenals.

pH—A measure of the acidity or alkalinity of a solution. pH is represented on a scale of 0 to 14, with 7 being a neutral state, 0 most acid, and 14 most alkaline.

Physiographic Provinces—Systematic description of areas with some point of physical geology in common.

Plume—A flowing, often somewhat conical, trail of *emissions* from a continuous *point source.*

Point Sources—A stationary location or fixed facility from which pollutants are discharged or emitted. Also, any single identifiable source of pollution, for example, a pipe, ditch, ship, ore pit, or factory smokestack.

PM10—Minute separate particles equal to 10 microns or less.

Prevention of Significant Deterioration (PSD)—An *Environmental Protection Agency* program in which state or federal permits are required that are intended to restrict *emissions* for new or modified sources in places where air quality is already better than required to meet primary and secondary *ambient air quality standards.*

Primary Particulate Matter—Particles emitted directly from a source.

R

Radionuclides—Radioactive nuclides.

Regional Haze—A type of visibility impairment which is the result of dispersed and intermixed pollutants from many sources.

Residential—The group of customers to whom electricity is sold for household purposes, including space heating, water heating, air conditioning, lighting, and appliances in single-family, multifamily, and mobile homes.

River Substrate—A layer of material or substance in a river.

S

Scrubber—A device that removes *sulfur dioxide* from flue gas using lime or limestone.

Scrubber Sludge—The *effluent* from a scrubber that is then discharged and is stored in a solid landfill, principally as a calcium sulfate.

Secondary Particulate Matter—Particles formed in the atmosphere from emitted gases.

Sedimentation—The action or process of depositing sediment.

Seedling—Live trees of species less than 1.0 inch in diameter at 4.5 feet above ground that are expected to survive and develop.

Sensitive Species—Species that are listed with states as needing special management.

Short Rotation Woody Crops—Plants grown on a relatively short rotation schedule for the explicit purpose of harvesting for use in power production.

SO_2—*Sulfur Dioxide.*

Soil—A dynamic natural medium composed of mineral and organic materials in which plants grow.

Sorbent—A substance that takes up and holds or absorbs.

Species—A class of individuals having common attributes and designated by a common name.

Spent Fuel—Nuclear fuel that can no longer economically sustain a chain reaction.

Streams—A continually, frequently, or infrequently flowing body of water that follows a defined course. The three classes of streams are:

- **Ephemeral.** A channel that carries water only during and immediately following rainstorms. Also known as a "dry wash."
- **Intermittent.** A watercourse that flows in a well-defined channel during the wet seasons of the year, but not the entire year.
- **Perennial.** A watercourse that flows throughout the year or nearly so (90 percent of time) in a well-defined channel.

Succession—A process of biotic community development that involves changes in species, structure, and community processes over time.

Sulfur Dioxide (SO_2)—A heavy, pungent, colorless, gaseous air pollutant formed primarily by the combustion of fossil-fuel plants.

Surface Water—Streams, rivers, ponds, lakes, and man-made reservoirs.

Surrogate Measure—A substitute measure that varies in the same way as the pollutant and environmental effects it represents.

T

Tailwater—Water downstream from a dam, including those waters released from the dam.

Thermal Rejection—Release of heat.

Thermal Stratification—Layering of water with different temperatures, where it is warmer near the surface and colder near the bottom.

Threatened Species—Any species which is likely to become an endangered species within the foreseeable future.

Topography—The physical features of a place or region. Commonly refers to land forms and variation in elevation.

Troposphere—Lower atmosphere.

TSP—Total suspended *particulate* matter.

Turbine—A machine for directly converting the kinetic and/or thermal *energy* of a flowing fluid (air, hot gas, steam, or water) into useful rotational *energy*.

V

Visibility Impairment or Degradation—*Aesthetic* damage where the ability to discern form, color, or texture is reduced and therefore the scenic value is also diminished. Or, as stated in 40 CFR 51.30, visibility impairment is "...any humanly perceptible change in visibility (visual range, contrast, coloration) from that which would have existed under natural conditions."

Visual Quality Zones (VQZs)—Areas of the landscape denoted by specified distances from the observer. Used as a frame of reference in which to discuss landscape characteristics or activities of man, sometimes referred to as "distance zones."

Volatile Organic Compounds (VOCs)—Any organic compound that participates in atmospheric photochemical reactions except for those designated by the *Environmental Protection Agency* administrator as having negligible photochemical reactivity.

W

Water Quality—A term used to describe the chemical, physical, and biological characteristics of water, usually with respect to its suitability for a particular purpose.

Watershed—The entire area that contributes to a drainage or stream.

Wetland—Area with soils saturated with water during the growing seasons and supporting plants characteristic of wet conditions.

Z

Zebra Mussel—An imported mussel which interferes with, among other things, water intake structures.

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Energy Vision

2020

Volume 2, Technical Document

2 Environmental Consequences

Summary

One of TVA's broad strategic goals is environmental responsibility. Energy Vision 2020 approaches this goal in a way that is fundamentally different than most environmental reviews—environmental concerns have been fully integrated into the planning process.

This document addresses the environmental aspects of the evaluation process and provides additional scientific and analytical, or technical, basis for comparing the impact of alternative energy strategies on the environment. Cumulative potential environmental impacts are addressed. In addition, potential socioeconomic impacts are addressed.

The assessment is made at a macro, or regional, scale rather than at a micro, site-specific scale.

Volume 2, Technical Document 2

Environmental Consequences

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Environmental Consequences

Introduction

Numerous surveys and opinion polls indicate that most Americans hold protection of the environment as very important. TVA Board Chairman Craven Crowell has emphasized that no major business activity will succeed without a high regard for the environment and that TVA must be environmentally responsible.

In keeping with these sentiments, one of TVA's broad strategic goals is environmental responsibility. Energy Vision 2020 approaches this goal in a way that is fundamentally different than most environmental reviews—environmental concerns have been fully integrated into the planning process. This has allowed TVA to reformulate energy resource strategies to mitigate potential environmental impact, lessening the need to trade off environmental protection for economic cost savings.

This document addresses the environmental aspects of the evaluation process and provides additional scientific and analytical, or technical, basis for comparing the impact of alternative energy strategies on the environment. The document also examines and compares both direct and indirect potential environmental impacts associated with each strategy. Cumulative environmental impacts are addressed. In addition, potential socioeconomic impacts are addressed.

ENVIRONMENTAL IMPACT CONTEXT

Integrated resource planning is broad and strategic; therefore, the environmental review has been programmatic rather than site-specific. When energy resource options are implemented, there can be important environmental effects, depending on how options are deployed and where they are located. These potential option and site-specific impacts will be considered in the environmental reviews that tier from the Energy Vision 2020 review. Such reviews will give TVA decision makers and the public an opportunity to consider any potentially significant impacts before decisions are made.

These site-specific reviews can avoid potentially significant impacts to wetlands, sensitive habitats, prime farmland, threatened or endangered species, cultural and historic resources, alteration of sensitive aquatic habitats, aesthetics and noise, and socioeconomic impacts. Proper site selection and detailed modeling can also avoid local air impacts such as plume impact on elevated terrain. Site selection may also influence some indirect impacts such as those from fuel sources and transportation.

Evaluation Method

The analytical approach used for Energy Vision 2020 is the multi-attribute tradeoff method. This approach allows TVA to quantitatively integrate the identified environmental impacts of proposed strategies and formulate alternative strategies to mitigate them while retaining other beneficial characteristics. The approach also allowed the public to help set the values (criteria) by which strategies were judged and to see how those values can result in tradeoffs.

TVA developed 2,000 different strategies for Energy Vision 2020. These strategies consist of different combinations of energy resource options that were first screened for acceptable performance using multiple criteria, including environmental criteria. The strategies themselves were analyzed through the use of computer models to identify those particular combinations of resource options that best meet the criteria and effectively deal with various uncertainties. In this process, the environmental performance of the strategies was fully integrated into the evaluation in the same manner as financial, rate, economics, and other criteria.

The multi-attribute tradeoff method allowed potential environmental impacts of each strategy to be compared to all other evaluation criteria and to all other strategies on an objective basis. This process identified where there were real tradeoffs among criteria. One of the most important tradeoffs occurred between better environmental performance and lower electric rates. Achieving better environmental performance (less impacts) typically produces higher rates or costs. In the past, utilities usually chose between lower costs or better environmental performance.

The integrated, multi-attribute tradeoff method allowed TVA to mitigate potential environmental tradeoffs by reformulating strategies to lessen the degree of tradeoff. Energy resource options that were primarily responsible for producing undesirable results in more favorable strategies were replaced by options that produced more desirable results. These modified strategies were then reintegrated and their performance with respect to

the evaluation criteria and tradeoffs they produce was reexamined. This was done several times until seven modified strategies were created that respond reasonably well to all Energy Vision 2020 criteria, including environmental criteria. Potential tradeoffs were sharply reduced.

As a result of this process, the final strategies have similar, although not identical, energy resource options. This tends to produce similar environmental impacts. With the final seven strategies, it is possible to meet the future needs of TVA's customers with much better environmental performance compared to other unmitigated strategies.

Environmental Protections

As stated, one of TVA's strategic goals is environmental responsibility. This leads TVA toward those energy resource options that are more environmentally friendly. Apart from this goal, environmental regulations reduce the risk of significant environmental impacts from the implementation of energy resource options. The Clean Air Act, the Clean Water Act, the Endangered Species Act, the Surface Mining Reclamation and Control Act, and the Resource Conservation and Recovery Act are just a few of the major laws in this country that are formulated to prevent or lessen various environmental impacts. In addition, as a federal agency, TVA must consider the potential environmental impacts of proposed decisions under the National Environmental Policy Act.

No major energy resource can be constructed without complying with a substantial number of federal, state, and local environmental requirements. These regulatory processes typically provide multiple opportunities for public comment and participation. Most federal environmental laws allow citizens to bring suit to enforce compliance with requirements, and various federal, state, and local environmental regulatory agencies exist to police compliance.

Although these environmental laws and their implementing regulations do not eliminate all risk of environmental impacts, they substantially reduce impacts. Consequently, the risk of significant impacts associated with the implementation of any of the final strategies identified in Energy Vision 2020 is lessened substantially. Moreover, such impacts should be identified in the subsequent environmental reviews that TVA will conduct before it decides to put specific resource options in place.

SECTION 1: DESCRIPTION OF ALTERNATIVE STRATEGIES

Purpose

This section describes TVA's final seven alternative strategies developed through the integration process and the reference, or "No Action," strategy. In addition, the general features of the strategies that distinguish them from one another are described. As a result of the integration process discussed in the preceding section, most of the strategies are very similar and differences in their environmental performance are relatively small.

Note that, for purposes of the National Environmental Policy Act, the terms "strategy", "alternative", and "alternative strategy" should be considered synonymous.

Elements of a Strategy

As described in Volume 1, Chapter 9, Resource Integration/Alternative Strategy Comparisons, each strategy includes some component of each of the elements described below. Understanding these elements will help understanding of why there are environmental differences among the strategies.

SUPPLY PROFILE

The supply profile refers to actions TVA may take to provide for generation of electricity for its customers. These "supply side" options vary by fuel type, technology, and commercial terms. Coal, natural gas, and nuclear have been the dominant fuels for electricity supply for the utility industry historically and are dominant in TVA's final strategies. However, certain renewable resources, such as biomass, wind, and landfill methane, that may either be continuously replenished or are not consumed, are also considered as viable options in the final strategies. (Hydroelectric power is also a renewable resource, but for purposes of this evaluation, is considered separately and not included in the general renewables category.) Different technologies may use the same fuel. Natural gas can be used to generate electricity from simple cycle combustion turbines, combined cycle facilities, fuel cells, etc. Also, TVA may choose to build, own, and operate a new electricity generating facility, purchase the energy from another electric utility, or purchase the energy from a non-utility independent power producer (IPP) or cogenerator.

ENVIRONMENT

While all elements of a strategy affect its environmental performance, certain decisions specifically targeting alternative ways of meeting environmental constraints have been included in this element. These decisions include the approach to complying with Phase II of the 1990 Clean Air Act Amendments and control options associated with carbon dioxide reduction and TVA's commitment to the U.S. Department of Energy's Climate Challenge.

CUSTOMER SERVICE, PRICING/RATES

The options included in this element include activities that directly influence the amount of electrical energy consumed by TVA's customers. Demand side management (DSM) includes both actions that may decrease total consumption (conservation) and those that change the time of day when consumption occurs (load shaping). Off-system sales (sales to other utilities) increase the need for electricity and can be controlled by marketing and pricing activities. Similarly, marketing and pricing programs (electric rate programs) can be put in place to either increase or decrease system consumption. For example, time-of-day pricing may be used to shape or curb consumption, while a "declining block" rate structure that lowers price as consumption increases may be an inducement to increase consumption. Beneficial electrification options (for example, variable speed electric motors, electric arc steel furnaces) are intended to increase the consumption of electricity while reducing the consumption of other primary fuels with a net benefit to the environment.

TRANSMISSION

Options that represent improvements to the TVA electricity transmission system by reducing transmission losses were included. None of the final strategies being evaluated include these transmission improvement options.

Strategy Definition

Figure T2-1 defines the reference strategy, or "No Action" strategy (Strategy D) and the seven alternative strategies evaluated in Energy Vision 2020 in general terms by strategic element.

For purposes of comparison, Strategy D is the reference or "No Action" strategy for Energy Vision 2020. The "No Action" strategy was to identify those resource options which TVA would most likely have employed to meet demand in the absence of the information and analysis produced as a result of the Energy Vision 2020 process. Taking into account the difficulties TVA has encountered in completing the nuclear units that it has had under construction, it was determined that TVA would likely have looked to some mix of combined cycle combustion turbines, new coal-fired units and limited amounts of purchased power. These became the core elements of the

FIGURE T2-1. **Characteristics of Final Energy Vision 2020 Strategies, Resource Options Embedded in Each Strategy**

Strategy	Supply-Side Characteristics	Customer Service Characteristics	Environmental Controls
Strategy D Combined Cycle, Purchased Power, Coal (Reference)	Supply-side options emphasize a blend of TVA-built, Independent Power Producers, and cogenerators to reduce production cost and debt • Combustion turbines • Combined cycle • Independent Power Producers and cogeneration natural gas combined cycle • Independent Power Producer coal • Clean coal [1]	Low-price block of Demand-Side Management (block one) reduces demand with minimum rate increase	Sulfur Dioxide • Scrubbers are added at several existing fossil units • Switching to lower sulfur coals at several existing fossil units
Strategy J Bellefonte Coproduct, Renewables, Independent Power Producers	Supply-side expansion features an integrated coal gasification plant that produces a high-value chemical coproduct, projected for siting at Bellefonte Nuclear Plant • Combustion turbines • Bellefonte conversion to integrated gasification combined cycle with chemical coproduct • Independent Power Producer combined cycle • Landfill and coalbed methane • Clean coal • Hydro modernization	Low-price block of Demand-Side Management (block one) reduces demand with minimum rate increase	Sulfur Dioxide • Scrubbers are added at several existing fossil units • Switching to lower sulfur coals at several existing units Carbon Dioxide and other fossil emissions • A customer service level of biomass (waste wood) cofiring of 0.3%
Strategy M Combined Demand-Side Management and Off-System Sales	Supply-side options mix emphasizes coal expansion and low-cost renewables for low production cost • Combustion turbines • Pulverized coal at an existing plant • Clean coal • Landfill and coalbed methane • Pulverized coal with scrubbers • Hydro modernization	Low-price and low-cost Demand-Side Management (two blocks) reduces need for generation Off-system sales	Sulfur Dioxide • Scrubbers are added at several existing fossil units • Switching to lower sulfur coals at several existing units Carbon Dioxide and other fossil emissions • A customer service level of biomass (waste wood) cofiring of 0.3%

[1] Clean coal technologies include integrated gasification - combined cycle and integrated gasification - cascaded humidified advanced turbine.

FIGURE T2-1. **Characteristics of Final Energy Vision 2020 Strategies, Resource Options Embedded in Each Strategy** *CONTINUED*

Strategy	Supply-Side Characteristics	Customer Service Characteristics	Environmental Controls
Strategy O Bellefonte Coproduct, More Demand-Side Management, More Off-System Sales	Supply-side expansion features an integrated coal gasification plant that produces a high-value chemical coproduct, projected for siting at Bellefonte Nuclear Plant • Combustion turbines • Bellefonte conversion to integrated gasification combined cycle with chemical coproduct • Independent Power Producer combined cycle • Landfill and coalbed methane • Clean coal • Hydro modernization	Low-price and low-cost block of Demand-Side Management (two blocks) reduces need for generation Off-system sales	Sulfur Dioxide • Scrubbers are added at several existing fossil units • Switching to lower sulfur coals at several existing units Carbon Dioxide and other fossil emissions • A customer service level of biomass (waste wood) cofiring of 0.3%
Strategy Q Flexible Strategy with External Options	Supply-side expansion features purchase options with rights, but not obligations, to purchase power • Combustion turbines • Bellefonte conversion to integrated gasification combined cycle with chemical coproduct • Independent Power Producers combined cycle • Purchase of peaking capacity • Flexible base capacity purchase • Flexible peaking capacity purchase • Landfill and coalbed methane • Clean coal • Hydro modernization	Low-price block of Demand-Side Management (block one) reduces demand with minimum rate increase Low-level beneficial electrification provides improved rate impact Off-system sales	Sulfur Dioxide • Scrubbers are added at several existing fossil units • Switching to lower sulfur coals at several existing units Carbon Dioxide and other fossil emissions • A customer service level of biomass (waste wood) cofiring of 0.3%
Strategy R Flexible Strategy with Internal Options	Supply-side expansion features preplanning, design, and siting work to support flexible start dates of TVA-built options • Combustion turbines • Bellefonte conversion to integrated gasification combined cycle with chemical coproduct • Independent Power Producer combined cycle • Combined cycle • Purchase of peaking capacity • Flexible base capacity purchase • Landfill and coalbed methane • Clean coal • Hydro modernization	Low-price block of Demand-Side Management (block one) reduces demand with minimum rate increase Low-level beneficial electrification provides improved rate impact Off-system sales	Sulfur Dioxide • Scrubbers are added at several existing fossil units • Switching to lower sulfur coals at several existing units Carbon Dioxide and other fossil emissions • A customer service level of biomass (waste wood) cofiring of 0.3%

FIGURE T2-1 Characteristics of Final Energy Vision 2020 Strategies, Resource Options Embedded in Each Strategy *CONTINUED*

Strategy	Supply-Side Characteristics	Customer Service Characteristics	Environmental Controls
Strategy S Low Cost, Low Rates, Improved Environment	Supply-side expansion features an integrated coal gasification plant that produces a high-value chemical coproduct, projected for siting at Bellefonte Nuclear Plant • Combustion turbines • Bellefonte conversion to integrated gasification combined cycle with chemical coproduct • Independent Power Producers combined cycle • Landfill and coalbed methane • Clean coal • Hydro modernization	Low-price block of Demand-Side Management (block one) reduces demand with minimum rate increase Low-level beneficial electrification provides improved rate impact Off-system sales spread fixed cost over more sales	Sulfur Dioxide • Scrubbers are added at several existing units • Switching to lower sulfur coals at several existing units Carbon Dioxide and other fossil emissions • A customer service level of biomass (waste wood) cofiring of 0.3%
Strategy T Low-Cost Renewables, Low-Price Demand-Side Management, Repowering, Bellefonte Coproduct Partnership	Supply-side expansion relies on low emission options, renewables, and an integrated coal gasification plant that produces a high-value chemical coproduct, projected for siting at Bellefonte Nuclear Plant • Natural gas combined cycle repowering of several existing coal units • Bellefonte conversion to integrated gasification combined cycle with chemical coproduct • Combustion turbines • Independent Power Producers combined cycle • Clean coal • Compressed air energy storage • Landfill and coalbed methane • Wind • Pulverized coal • Hydro modernization	Low-price block of Demand-Side Management (block one) reduces demand with minimum rate increase	Sulfur Dioxide • Gas repowering of some existing units • Switching to lower sulfur coals at several existing units Carbon Dioxide and other fossil emissions • Carbon dioxide penalty added to assumed cost of generation options to shift generation to lower emission sources • A customer service level of biomass (waste wood) cofiring of 0.3%

Energy Vision 2020 "No Action" strategy and formed the reference strategy for purposes of analysis and benchmarking integration results across alternative strategies.

TVA considered but rejected a second approach to defining the "No Action" strategy. This approach was to cease acquiring new resources to meet future demand for electricity from the TVA system. Except for additional demand that could be met through more efficient use of the energy generated by TVA's existing resources, future demand (new loads) would not be met. This is the approach used to define a "No Action" alternative by the Bonneville Power Administration in its February 1993 resource plan environmental impact statement. Because of TVA's statutory responsibilities and duty to serve demand in its region as a public utility, such a "no-serve" approach was considered fictitious and rejected in favor of the first approach.

Figure T2-2 provides an example of how each strategy might be implemented, based on the results of the computer modeling evaluations described in Volume 1, Chapter 9, Resource Integration/Alternative Strategy Comparisons and Volume 2, Technical Document 8, Resource Integration. While it is highly unlikely that the actual implementation of the strategies would follow the exact sequence given in this figure, these implementation strategies represent credible sequences for resource selection and form the basis for the analysis and comparisons that follow.

FIGURE T2-2. **Implementation of Final Energy Vision 2020 Strategies, Cumulative Capacity Additions (Megawatts)**

		YEAR				
Strategy	**Resource Option**	**2000**	**2005**	**2010**	**2015**	**2020**
D-Reference	Combustion Turbines	1,050	2,550	3,750	4,800	5,700
	Combined Cycle—Independent Power Producer	0	450	750	750	750
	Integrated Gasification—Combined Cycle	0	0	735	2,205	3,675
	Combined Cycle	470	1,880	2,820	2,820	2,820
	Integrated Gasification—Cascaded Humidified Advanced Turbine	0	0	420	1,260	2,100
	Combined Cycle—Cogeneration	0	175	175	175	175
	Coal-Independent Power Producer	0	300	300	300	300
	Total Capacity	**1,520**	**5,355**	**8,950**	**12,310**	**15,520**
J	Bellefonte IGCC Conversion with Coproduct	0	484	484	484	484
	Coalbed Methane Recovery	0	250	1,000	1,000	1,000
	Combustion Turbines	1,500	2,550	3,900	4,950	5,850
	Hydroelectric Improvements	0	0	162	162	162
	Integrated Gasification—Combined Cycle	0	0	735	2,940	4,410
	Integrated Gasification—Cascaded Humidified Advanced Turbine	0	0	420	1,260	2,100
	Independent Power Producer	150	1,650	1,950	1,950	1,950
	Landfill Methane Recovery	0	500	500	500	500
	Total Capacity	**1,650**	**5,434**	**9,151**	**13,246**	**16,456**
M	Coal	0	1,610	1,610	1,610	1,610
	Coalbed Methane Recovery	0	0	250	1,000	1,000
	Combustion Turbines	1,050	2,400	3,600	4,800	5,550
	Hydroelectric Improvements	0	0	162	162	162
	Integrated Gasification—Combined Cycle	0	0	735	2,205	3,675
	Integrated Gasification—Cascaded Humidified Advanced Turbine	0	0	420	1,260	2,100
	Landfill Methane Recovery	0	0	500	500	500
	Shawnee Fossil Plant Unit 11	0	168	168	168	168
	Total Capacity	**1,050**	**4,178**	**7,445**	**11,705**	**14,765**
O	Bellefonte IGCC Conversion with Coproduct	0	484	484	484	484
	Coalbed Methane Recovery	0	0	750	1,000	1,000
	Combustion Turbines	1,050	2,550	3,750	4,950	5,700
	Hydroelectric Improvements	0	0	162	162	162
	Integrated Gasification—Combined Cycle	0	0	735	2,940	4,410
	Integrated Gasification—Cascaded Humidified Advanced Turbine	0	0	420	1,260	2,100
	Independent Power Producer	0	900	1,050	1,050	1,050
	Landfill Methane Recovery	0	500	500	500	500
	Total Capacity	**1,050**	**4,434**	**7,851**	**12,346**	**15,406**

Combustion Fuel Use

A comparison of the combustion fuel used in implementing each strategy provides useful information that directly relates to the comparison of environmental consequences. *Figure T2-3* identifies the capacity and electricity generation by fuel for each strategy in the years 2005 and 2020. Note that every energy strategy uses coal and natural gas. Also, most strategies employ renewable fuels (co-fired wood used along with fossil fuel in a boiler, landfill methane recovery and coal seam methane recovery) in differing amounts. The table in *Figure T2-4* gives the coal and co-fired biomass average annual tonnage and gas volume for each strategy. Biomass refers to wood and perennial grasses used for fuel. Coal use increases from the current level of 35 to 40 million tons annually to 46 to 52 million tons for all strategies including the reference, or "No Action," strategy. Strategy T uses the

FIGURE T2-2. **Implementation of Final Energy Vision 2020 Strategies, Cumulative Capacity Additions (Megawatts)** *CONTINUED*

		YEAR				
Strategy	**Resource Option**	**2000**	**2005**	**2010**	**2015**	**2020**
Q	Bellefonte IGCC Conversion with Coproduct	0	484	484	484	484
	Coalbed Methane Recovery	0	500	1,000	1,000	1,000
	Combustion Turbines	0	900	3,000	4,050	4,800
	Flexible Baseload	0	1,189	289	289	289
	Flexible Peakload	900	900	0	0	0
	Hydroelectric Improvements	0	0	162	162	162
	Integrated Gasification—Combined Cycle	0	0	2,205	3,675	5,145
	Integrated Gasification—Cascaded Humidified Advanced Turbine	0	0	840	1,680	2,520
	Independent Power Producer	300	300	300	300	300
	Landfill Methane Recovery	0	500	500	500	500
	Peak Power Purchases	300	900	900	900	900
	Total Capacity	**1,500**	**5,673**	**9,680**	**13,040**	**16,100**
R	Bellefonte IGCC Conversion with Coproduct	0	484	484	484	484
	Combined Cycle	0	470	470	470	470
	Coalbed Methane Recovery	0	500	1,000	1,000	1,000
	Combustion Turbines	750	2,100	3,150	4,200	4,950
	Flexible Baseload	0	289	289	289	289
	Hydroelectric Improvements	0	0	162	162	162
	Integrated Gasification—Combined Cycle	0	0	1,470	3,675	5,145
	Integrated Gasification—Cascaded Humidified Advanced Turbine	0	0	840	1,680	2,520
	Independent Power Producer	150	300	300	300	300
	Landfill Methane Recovery	0	500	500	500	500
	Peak Power Purchases	900	900	900	900	900
	Total Capacity	**1,800**	**5,543**	**9,565**	**13,660**	**16,720**
S	Bellefonte IGCC Conversion with Coproduct	0	484	484	484	484
	Coalbed Methane Recovery	0	750	1,000	1,000	1,000
	Combustion Turbines	1,500	2,850	4,050	4,950	5,850
	Hydroelectric Improvements	0	0	162	162	162
	Integrated Gasification-Combined Cycle	0	0	1,470	3,675	4,410
	Integrated Gasification- Cascaded Humidified Advanced Turbine	0	0	840	1,680	2,520
	Independent Power Producer	300	1,050	1,050	1,050	1,050
	Landfill Methane Recovery	0	500	500	500	500
	Total Capacity	**1,800**	**5,634**	**9,556**	**13,501**	**15,976**
T	Bellefonte IGCC Conversion with Coproduct	0	484	484	484	484
	Compressed Air Energy Storage	0	0	1,011	1,011	1,011
	Coal	0	0	0	710	710
	Coalbed Methane Recovery	0	0	0	500	1,000
	Combustion Turbines	1,050	2,550	3,750	3,900	4,800
	Hydroelectric Improvements	0	0	162	162	162
	Integrated Gasification—Cascaded Humidified Advanced Turbine	0	0	0	420	1,260
	Independent Power Producer	0	450	450	450	450
	Landfill Methane Recovery	0	0	500	500	500
	Repowering Existing Coal-Fired Plants	1,410	3,045	3,045	4,320	5,170
	Shawnee Fossil Plant Unit 11	0	0	0	168	168
	Wind Turbines	0	800	2,000	2,000	2,000
	Total Capacity	**2,460**	**7,329**	**11,402**	**14,625**	**17,715**

FIGURE T2-3. **Strategy Matrix – Capacity and Energy by Fuel Type**

		Nuclear		Coal		Natural Gas		Hydro and Storage		Renewables		Purchases		Demand-Side Management	
Strategy	**Year**	**(MW)**	**(GWH)**	**(MW)**	**(GWH)**	**(MW)**	**(GWH)**	**(MW)**	**(GWH)**	**(MW)**	**(GWH)**	**(MW)**	**(GWH)**	**(MW)**	**(GWH)**
Existing System	2005	5,577	30,171	14,968	96,212	2,292	1,009	5,498	19,268	0	0	1,800			
Existing System	2020	5,577	32,414	14,968	100,654	2,292	1,403	5,498	20,780	740	5,898.5	1,000			
D-Reference	2005	5,577	32,778.4	14,968	108,471.8	6,722	7,652.3	5,498	20,426.8	0	0.0	2,725	6,163.5	-997	2,934.6
	2020	5,577	32,778.4	20,743	149,405.5	10,812	10,549.1	5,498	20,854.4	0	0.0	2,225	6,845.9	-517	1,481
J	2005	5,577	32,778.4	15,452	109,999.5	4,842	2,502.5	5,498	20,426.8	750	6,180.7	3,450	5,258.6	-998	2,934.6
	2020	5,577	32,778.4	21,962	151,251.9	8,142	3,780.2	5,660	20,857.9	1,500	12,361.4	2,950	3,979.7	-517	1,481
M	2005	5,577	32,778.4	16,746	116,322.6	4,692	2,885.5	5,498	20,426.8	0	0.0	1,800	725.3	-2,047	8,194.8
	2020	5,577	32,778.4	22,521	150,338.7	7,842	4,602.6	5,660	20,857.9	1,500	12,361.4	1,000	78.8	-957	1,481
O	2005	5,577	32,778.4	15,452	109,112.1	4,842	2,884.3	5,498	20,426.8	500	4,120.5	2,700	3,169.4	-2,049	8,194.8
	2020	5,577	32,778.4	21,962	150,196.2	7,992	4,572.4	5,660	20,857.9	1,500	12,361.4	2,050	2,279.9	-958	1,481
Q	2005	5,577	32,778.4	15,452	110,182.6	3,192	1,454.0	5,498	20,426.8	1,000	9,240.9	5,089	7,444.8	-999	1,404.9
	2020	5,577	32,778.4	23,117	154,951.1	7,092	4,169.2	5,660	20,857.9	1,500	12,361.4	2,489	1,519.4	-517	1,481
R	2005	5,577	32,778.4	15,452	110,364.9	4,862	3,466.7	5,498	20,426.8	1,000	8,240.9	3,289	4,984.4	-999	1,404.9
	2020	5,577	32,778.4	23,117	155,148.6	7,712	4,339.7	5,660	20,857.9	1,500	12,361.4	2,489	1,988.0	-517	1,481
S	2005	5,577	32,778.4	15,452	109,099.8	5,142	3,011.9	5,498	20,426.8	1,250	10,304.0	2,850	3,819.8	-999	1,404.9
	2020	5,577	32,778.4	22,382	151,793.4	8,142	4,778.0	5,660	20,857.9	1,500	12,361.4	2,050	2,334.5	-517	1,481
T	2005	5,577	32,778.4	13,521	100,215.7	8,517	18,585.2	5,498	20,426.8	0	0.0	2,250	3,882.9	-998	2,934.6
	2020	5,577	32,778.4	15,659	116,157.0	13,042	29,929.6	6,672	25,307.4	2,500	15,111.0	1,450	3,366.0	-517	1,481

MW= Megawatts
GWH= Thousands of Megawatt-Hours

least amount of coal and the largest amount of natural gas. All remaining strategies use 51.7 to 52.2 million tons of coal annually.

Strategy T uses 162 billion standard cubic feet of natural gas annually (one standard cubic foot of natural gas contains approximately 1,000 Btu). The range of natural gas use of other strategies extends to a minimum of 41 billion standard cubic feet, which is 75 percent less than Strategy T. Landfill methane recovery and coalbed methane recovery use vary from a low of 23.4 to a high of 48.9 billion standard cubic feet. Methane recovery varies from 15 to 80 percent of the natural gas used for the same strategy.

FIGURE T2-4. **Combustion Fuel Required for Each Strategy (Annual Average Mass or Volume)**

Strategy	Coal (Millions of Tons)	Biomass Cofiring (Tons)	Landfill/ Coalbed Methane (Billions of Standard Cubic Feet)	Natural Gas (Billions of Standard Cubic Feet)
D-Reference	52.1	0	0	93.5
J	51.3	184,643	45.8	64.9
M	52.2	187,909	34.8	41.0
O	51.2	184,493	44.2	53.9
Q	51.7	186,227	48.9	68.4
R	51.9	186,956	48.9	63.4
S	51.8	186,903	49.4	59.2
T	45.9	186,903	23.4	162.0

No generating facilities specifically designed for short rotation woody crops or refuse-derived fuels are found in the seven strategies. However, significant co-firing of wood with coal in existing boilers is used in all strategies.

Both wood and landfill methane are renewable energy sources. Additionally, the use of coalbed methane recovery, landfill methane recovery, and wood waste fuel reduces the greenhouse warming potential of these emissions. This is a result of using captured or recovered methane as a fuel source. When methane, with a radiative forcing function of 21, is combusted, the resultant emissions are carbon dioxide with a radiative forcing function of one. The radiative forcing potential for any greenhouse gas is an indication of the relative effect of the gas on potential global warming compared to carbon dioxide, which has a radiative forcing potential of one. For example, methane

has a radiate forcing potential of 21, which means its effect on potential global warming is 21 times greater than that of an equivalent weight of carbon dioxide. Similarly, wood waste left to decay converts about 25 percent of the carbon mass to methane; thus, when burned, a methane release is avoided. The table in *Figure T2-5* presents the fuels on an energy content basis. The chart in *Figure T2-6* shows how the annual average combustion fuel energy use varies with each strategy for the entire period of the study.

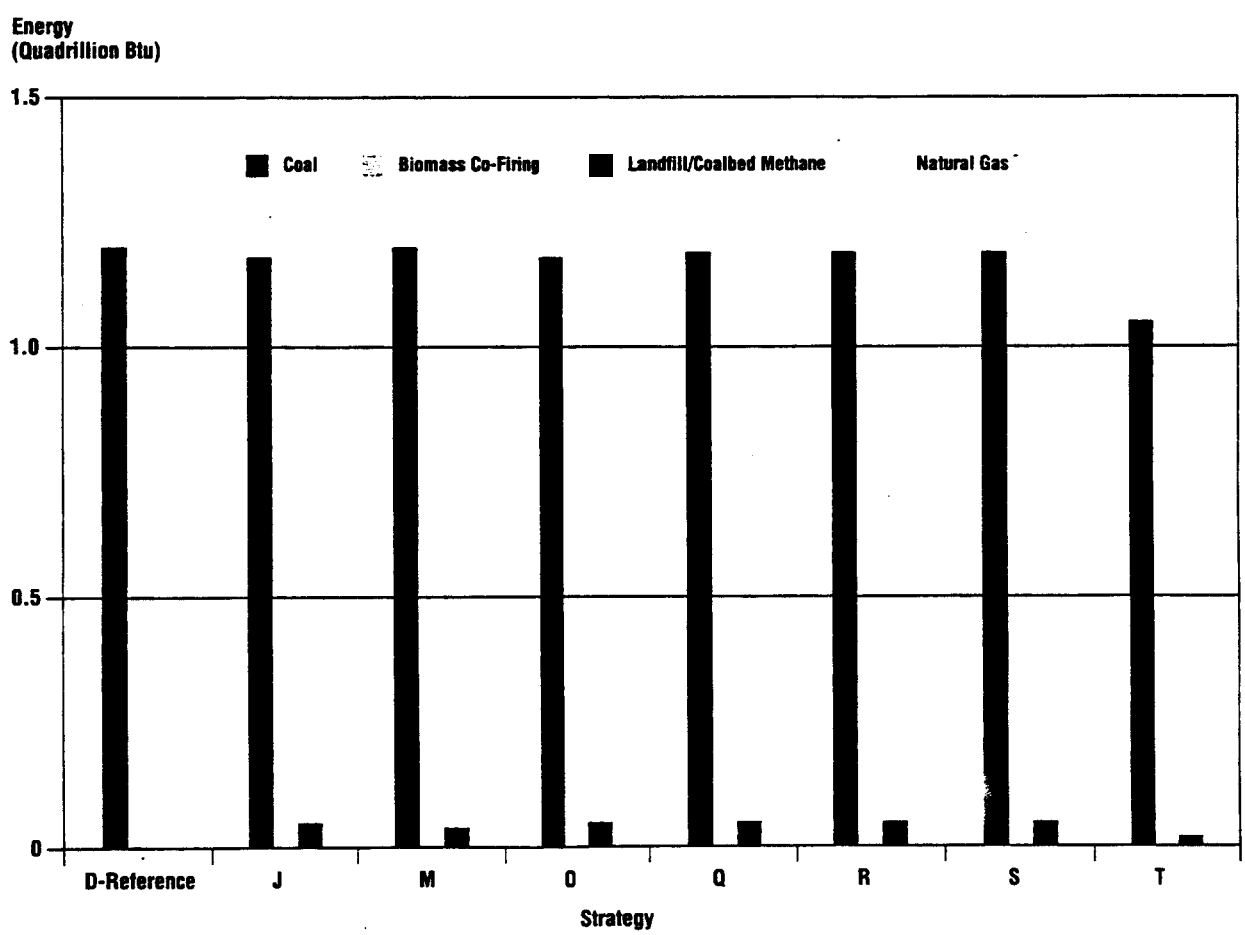
On an energy basis, 1.05 to 1.2 quadrillion Btu's of fuel energy is supplied by coal in each strategy. The energy content of the other combustion fuels combined is 0.1 to 0.2 quadrillion Btu's per strategy. Total combustion fuel energy use is between 1.25 and 1.31 quadrillion Btu's.

All strategies expand TVA's use of combustion fuels over present levels, while diversifying the types or sources of these fuels.

FIGURE T2-5. **Combustion Fuel Energy Use for Each Strategy (Annual Average)**

Strategy	Coal (Quadrillion Btu)	Biomass Cofiring (Quadrillion Btu)	Landfill/ Coalbed Methane (Quadrillion Btu)	Natural Gas (Quadrillion Btu)
D-Reference	1.20	0.00000	0.0000	0.0955
J	1.18	0.00166	0.0468	0.0664
M	1.20	0.00169	0.0356	0.0419
O	1.18	0.00166	0.0452	0.0551
Q	1.19	0.00168	0.0500	0.0699
R	1.19	0.00168	0.0500	0.0648
S	1.19	0.00168	0.0505	0.0605
T	1.05	0.00168	0.0239	0.1660

FIGURE T2-6. **Combustion Fuel Energy Use for Each Strategy (Annual Average)**



Sources of Energy Supply by Strategy

Every energy strategy includes TVA's existing resources plus proposed new resources. Each strategy depends on coal-fired, natural gas-fired, nuclear, and hydroelectric, including pumped storage, energy supply options. Certain strategies depend to differing degrees on landfill methane and coalbed methane combustion, wood waste co-firing, wind turbine operation, and demand-side management programs.

The table in *Figure T2-7* quantifies the different types of energy sources included in the strategies to meet the need for power in 2020. There are six groupings: coal, nuclear, natural gas, hydroelectric (including pumped storage), renewables, and demand-side management. The chart in *Figure T2-8* shows how the use of each energy supply group varies for the strategies. Coal-fired generation is the dominant supply source, varying from 55 percent for Strategy T to 64 percent of all energy supplied for the

FIGURE T2-7. **Energy Sources Used to Meet the Need for Power in 2020 (Megawatt-Hours)**

Strategy	Coal	Nuclear	Natural Gas	Hydroelectric/ Storage	Renewables	Demand-Side Management	Total
D-Reference	120,139	32,557	11,743	20,406	0	2,387	187,232
J	119,545	32,557	7,273	20,406	7,252	2,387	189,420
M	121,382	32,557	3,817	20,406	5,521	6,318	190,002
O	119,607	32,557	5,614	20,406	7,005	6,318	191,507
Q	122,142	32,557	6,450	20,406	7,746	1,346	190,647
R	122,080	32,557	6,549	20,406	7,746	1,346	190,685
S	121,924	32,557	6,248	20,406	7,829	1,346	190,310
T	104,677	32,557	20,518	22,338	6,961	2,387	189,439

FIGURE T2-8. **Energy Sources to Meet the Need for Power in 2020**

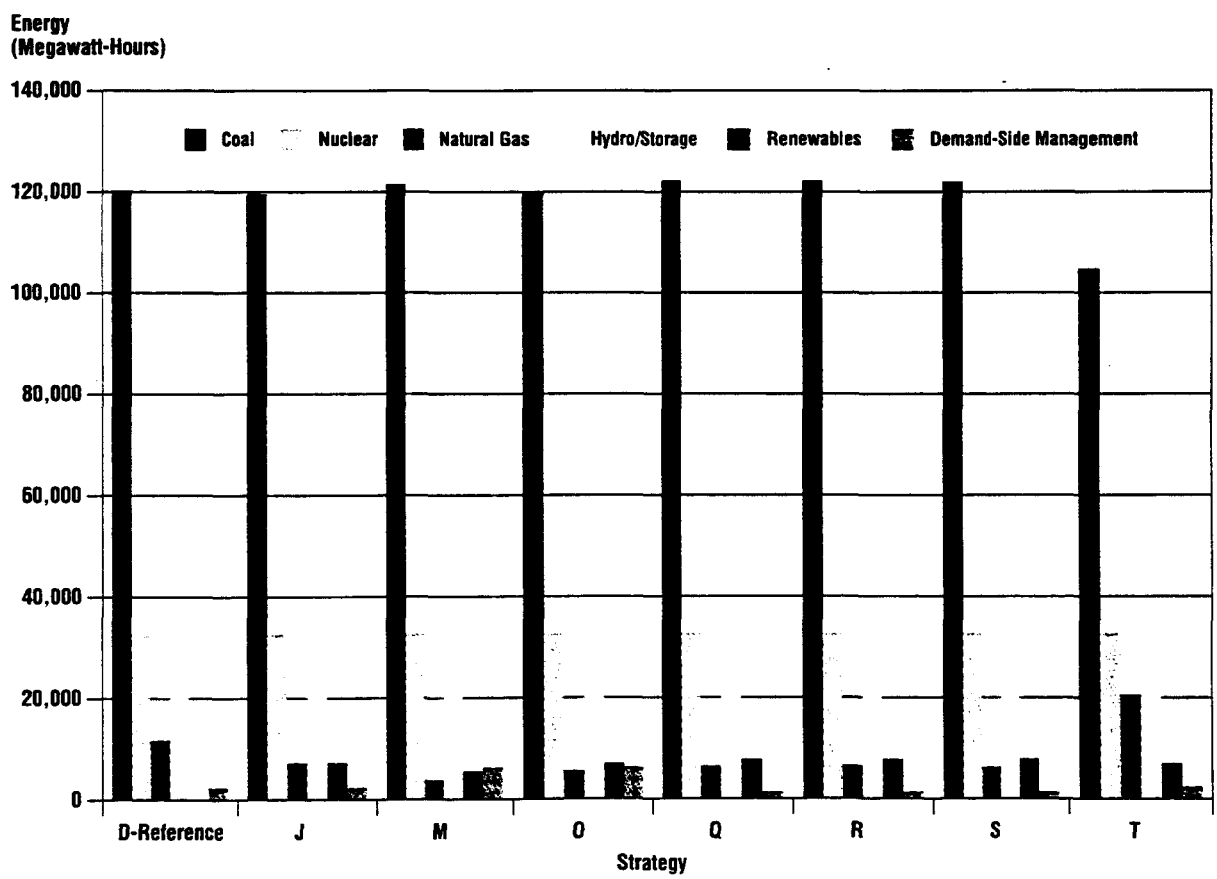


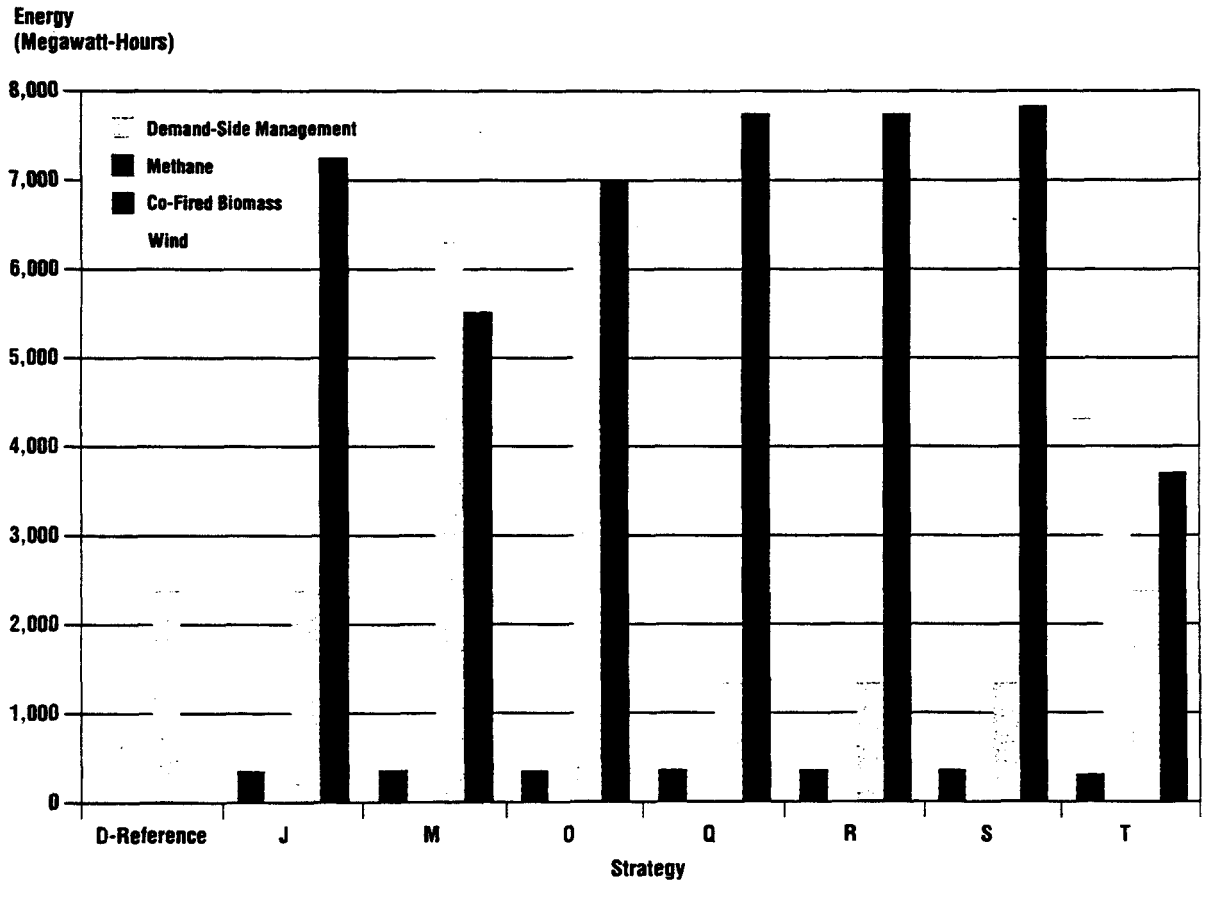
FIGURE T2-9. **Energy Supplied in 2020 by Renewable and Demand-Side Management Options (Megawatt-Hours)**

Strategy	Wind	Methane	Demand-Side Management	Total
D-Reference	0	0	2,387	2,387
J	0	7,252	2,387	9,639
M	0	5,521	6,318	11,839
O	0	7,005	6,318	13,323
Q	0	7,746	1,346	9,092
R	0	7,746	1,346	9,092
S	0	7,829	1,346	9,175
T	3,252	3,708	2,387	9,347

reference, or "No Action," strategy. Nuclear is about 17 to 19 percent of energy supplied, followed by hydroelectric, and pumped storage, with 11 percent. Natural gas-fired generation varies from 2 percent for Strategy M to 11 percent for Strategy T. Renewables are 3 to 4 percent of energy supplied. Demand-side management provides 0.7 to 3.3 percent of energy supplied.

The table in *Figure T2-9* gives the breakout of the energy supplied by demand-side management and various renewable energy options that vary with each strategy. The chart in *Figure T2-10* graphically illustrates the variation of different types of renewables and demand-side management across strategies.

FIGURE T2-10. **Energy Supplied in 2020 by Renewable and Demand-Side Management Sources**



Energy Savings by Strategy

The amount of energy saved in the various strategies is due to improved power system efficiency, as well as demand-side management programs. The reference strategy uses 1.29 quadrillion Btu's of non-renewable combustion fuels and Strategy T uses 1.22 quadrillion. Compared to the reference strategy, Strategy T represents an annual savings of 0.07 quadrillion Btu's, which is the maximum savings for any strategy. The fuel energy savings for each strategy is given in *Figure T2-11*. The electric energy reductions of demand-side management vary from 1,346 to 6,318 thousand kilowatt-hours as given in *Figure T2-9*.

FIGURE T2-11. **Energy Savings of Non-Renewable Combustion Fuel**

Strategy	Coal and Natural Gas Fuel Energy Used (Quadrillion Btu)	Energy Reduction From the Reference Strategy (Quadrillion Btu)
D-Reference	1.29	0.00
J	1.25	0.05
M	1.24	0.05
O	1.23	0.06
Q	1.26	0.03
R	1.26	0.04
S	1.25	0.04
T	1.22	0.07

SECTION 2: SOCIOECONOMIC IMPACTS OF ALTERNATIVE STRATEGIES

Economic Development

Energy Vision 2020 defines economic development as growth in regional economic activity. Measurement criteria include total personal income in "constant" 1994 dollars (i.e., with inflation accounted for) and total non-farm employment. These provide measures for the effects of various Energy Vision 2020 strategies on the overall, long-term health or welfare of the economy for the next 25 years. This analysis concentrates on changes to the welfare of the overall economy due to Energy Vision 2020 strategies. It does not address changes to the distribution of income or employment.

Three types of factors associated with Energy Vision 2020 options affect regional economic development:

- Direct expenditures for labor and materials incurred in the Tennessee Valley during the construction and operation phases of an energy resource option
- Changes to TVA electric rates resulting from implementation of a particular option
- Changes to customers' disposable income as a result of increased or decreased costs from the implementation of a particular option in a distinct Energy Vision 2020 strategy (changes could be caused either by customer expenditures or electric bills)

In general, the greater the direct regional expenditures associated with a particular option, the more positive are the effects on regional economic development. This can be offset, however, by the fact that higher rates caused by higher costs have a negative effect on regional economic development. Thus, an option that has high expenditures in the Tennessee Valley compared to other options may also have high costs and high rates. The overall effect on economic development of a particular option may be positive or negative compared to other options, depending on the net sum of the expenditure effects and the rate and cost effects.

This section describes the methodology used to calculate how alternative strategies affect economic development. The final strategies analyzed in Energy Vision 2020 are described in *Figures T2-1* through *T2-3*. The tables in *Figures T2-12* and *T2-13* present the results of analysis for each Energy Vision 2020 strategy in terms of changes in income and employment compared with a base case reference, or "No Action," strategy (Strategy D).

FIGURE T2-12. **Economic Development Impacts (Annual Average, 1996-2020), IRP Strategies Relative to Strategy D - Reference or "No Action" Case**

			TOTAL IMPACT		IMPACTS DUE TO OPTION EXPENDITURES (DIRECT AND INDIRECT)		IMPACTS DUE TO RATES		IMPACTS DUE TO TOTAL RESOURCE COSTS	
Strategy	Category/Rank [2]		Employment	Income [1]	Employment	Income [1]	Employment	Income	Employment	Income
D- Reference	poor	14	0	0	0	0	0	0	0	0
J	good	5	16,569	739,482	4,176	184,171	9,787	420,773	2,606	134,537
M	moderate	8	11,884	529,624	6,232	273,954	4,146	176,989	1,506	78,681
O	good	4	19,976	893,436	5,484	240,868	11,256	482,723	3,236	169,844
Q	good	2	23,970	1,046,616	6,806	297,746	15,104	641,810	2,060	107,060
R	good	1	24,240	1,060,647	6,934	302,862	15,187	647,444	2,119	110,341
S	good	3	21,288	927,450	6,222	269,018	13,383	570,775	1,683	87,657
T	good	6	15,743	692,771	2,509	105,974	11,090	476,690	2,144	110,107

[1] Income in thousands of 1994 $

[2] Out of 21 strategies

METHODOLOGY

The indirect effects of direct expenditures and rate and total resource cost changes were calculated using TVA's Regional Economic Simulation Model. This model maps the Valley's economic structure, its inter-industry linkages, and responses to TVA rate and cost changes In addition to being used for Energy Vision 2020, the model is also used to provide the economic outlook for TVA's load forecasting. Volume 2, Technical Document 5, Load Forecast, contains more information about this model. The analysis includes data on direct expenditures in terms of applicable payrolls, material and supply purchases, and fuel costs for all energy resource options which comprise a particular strategy. It also includes data on TVA rates and total resource cost resulting from each strategy. A three-step process calculated the total economic development effects for each strategy:

- Direct expenditures for options were evaluated for both the construction and operation periods, and combined into the overall strategies.
- The economic model was used to calculate the indirect effects associated with the direct expenditures resulting from each strategy.
- The results of these analyses were combined with the projections from the model of direct economic development effects due to rates and costs for each strategy.

CONSTRUCTION PERIOD EVALUATION

Only supply-side options, including independent power producers, had project construction associated with them. Data on payroll income for the construction period associated with each option was used as the input into the economic model for the construction phase analysis. The model measures two types of indirect effects:

- The increase in goods manufactured in the Valley as a result of the material and supply purchases in the region associated with a project
- The additional income generated in the regional economy resulting from spending by workers hired as a result of the construction activity

Model results were evaluated in terms of changes in the Valley's income and employment between strategies involving construction compared to a strategy that had no construction activity, the "No Action" strategy.

TVA verified model projections by comparing them with available figures regarding material and supply purchases. It was estimated that 20 to 40 percent of purchases could be regional. The economic model captured regional increases due to purchases relative to payrolls for an average construction project. If a project had a ratio of purchases to payrolls significantly different than the average, the model results would not produce a correct accounting of the regional purchase effect without being adjusted. The increase in regional manufacturing evidenced in model results for the options was not significantly different than the average. Thus, the model results did not have to be adjusted for the analysis.

OPERATIONS PERIOD EVALUATION

Both supply-side and demand-side options had operational activities associated with them. The analysis of operations was similar to that for construction. Data on payrolls for the option was

FIGURE T2-13. **Direct and Indirect Economic Development Impacts Due to Option Expenditures (Annual Average, 1996-2020), IRP Strategies Relative to Strategy D - Reference or "No Action" Case**

	IMPACTS DUE TO OPTION EXPENDITURES (DIRECT AND INDIRECT)		DIRECT IMPACTS DUE TO OPTION EXPENDITURES		INDIRECT IMPACTS DUE TO OPTION EXPENDITURES	
Strategy	Employment	Income [1]	Employment	Income	Employment	Income
D- Reference	0	0	0	0	0	0
J	4,176	184,171	675	29,553	3,501	154,618
M	6,232	273,954	1,469	62,242	4,762	211,711
O	5,484	240,868	1,082	45,831	4,402	195,037
Q	6,806	297,746	1,314	56,189	5,492	241,557
R	6,934	302,862	1,340	56,936	5,593	245,926
S	6,222	269,018	1,189	50,663	5,033	218,355
T	2,509	105,974	-43	-1,981	2,552	107,955

[1] Income in thousands of 1994 dollars

entered into the economic model, and changes in income and employment between strategies including the project and those without the project were calculated. Estimates provided for material and supply purchases in the region served as a check against model results. In this case, several options had purchase estimates that were higher than those calculated by the model. To compensate, supplemental regional expenditures were added to the model results for these options.

Since fuel adds another cost factor to operations, TVA also analyzed fuel purchase patterns to determine what purchases would occur within the region. Natural gas comes from outside the region, and coal purchases generally come from the part of Kentucky outside the region. Of the final strategies, only the reference strategy had regional fuel effects which were generated by lignite assumed to be purchased within the region. For the reference strategy, the fuel purchases were entered into the economic model as part of operations to calculate the overall economic development effects.

TOTAL ECONOMIC DEVELOPMENT EFFECTS FOR ENERGY VISION 2020 STRATEGIES DUE TO OPTION EXPENDITURES

Once each option had been evaluated over both the construction and operation period, the direct payroll effects for each option were compiled by strategy and year. This data was input into the economic model and included any necessary accounting for above average purchases and regional fuel purchases during operations. The model was then run for each strategy in order to measure the overall economic development effects for each strategy, including indirect effects. Model results were evaluated in terms of changes in the Valley's income and employment for each strategy compared with the reference, or "No Action," strategy.

TOTAL ECONOMIC DEVELOPMENT EFFECTS FOR ENERGY VISION 2020 STRATEGIES DUE TO RATES AND COSTS

Effects upon economic development due to differences in rates among strategies were evaluated by entering data on rates by year for each strategy before running the model. The economic model captures the effects on the economy due to TVA rate changes to manufacturing customers and the impact of these changes upon the overall economy.

The analysis also estimated the effects of total resource cost differences among strategies. Differences in electric bills and other costs, such as participant costs of demand-side management programs, affect the amount of available disposable income. Net cost changes add to or subtract from the spending capacity of customers and thus affect the amount of disposable income available for spending. This is known as the "re-spending effect," since disposable income when returned to the economy generates additional economic growth.

Estimates of annual total resource costs for each strategy were used to estimate net cost differences among strategies. These were used with the TVA regional economic simulation model to compute the re-spending effects of each strategy.

TOTAL ECONOMIC DEVELOPMENT EFFECTS FOR ENERGY VISION 2020 STRATEGIES

Total economic development effects were calculated by adding the income and employment effects due to direct expenditures, rates, and total resource costs for each strategy by year and then calculating annual averages. Overall economic development effects were rated relative to the reference, or "No Action," strategy. Three possible rankings estimated the degree of economic development impact of each strategy (good, moderate, and poor). *Figure T2-12* shows the total economic development effects for each strategy. *Figure T2-13* shows the effects due to expenditures broken out with direct and indirect effects.

Environmental Justice

Executive Order No. 12898 directs certain federal agencies to consider environmental justice in the environmental reviews of their programs and activities. Although TVA is not one of the agencies designated in the executive order, it has considered the issue of environmental justice in the context of Energy Vision 2020.

Environmental justice refers primarily to ensuring that no segment of the population bears a disproportionate burden of health and environmental impacts of society's activities. Some studies suggest that poor, predominantly minority populations are exposed disproportionately to adverse health and environmental impacts because hazardous waste management facilities and other industrial facilities with potentially impactive air and water releases are sited in their communities. Other studies dispute these findings.

In the context of the generation and transmission of electric energy, various populations can be affected in a number of ways. The environmental analysis done for Energy Vision 2020 indicate that air pollution from the combustion of coal probably poses the greatest risk of adverse health and environmental impacts. Many air pollutant impacts, however, occur on a regional scale and do not affect any population segment disproportionately. Depending upon the situation, however, measurements have revealed that there can be more localized effects associated with short-term exposures to higher pollutant concentrations due to plume downwash. TVA's coal-fired plants

are located in largely rural settings, and except for TVA's Allen Fossil Plant, the surrounding populations are largely white. Incomes in rural areas, however, tend to be at the low-median level for the region. Allen Fossil Plant is located in Memphis, Tennessee, one of the areas in the TVA region that has a higher non-white population.

The siting of industrial facilities has raised the most concern with respect to environmental justice. Because Energy Vision 2020 is a programmatic-level review, the siting of energy resource options is not addressed in detail. When putting discrete options in place is proposed in the future, additional environmental reviews will be conducted and environmental justice concerns and effects will be addressed in those reviews as appropriate. Depending on the nature of the particular resource option and the kinds of impacts it may have, TVA will make a special effort to involve potentially affected low-income and minority populations in the review of options.

Concerns have been expressed nationally about rate impacts due to the implementation of some demand-side management programs. Depending on how demand-side management programs are structured, nonparticipants could subsidize the costs of programs delivered to participants who enjoy the benefits of such programs. Low-income electricity users can be affected in this way. However, measures can be taken to lessen the risk of this happening. TVA has designed a number of its demand-side management programs to avoid this, as explained in Volume 1, Chapter 8, Customer Service Options.

SECTION 3: AIR QUALITY IMPACTS OF ALTERNATIVE STRATEGIES

Understanding Air Quality Impacts

This section discusses the differences among TVA's final energy strategies with respect to potential impacts on air resources. A description of these strategies can be found in *Figures T2-1* through *T2-3*.

Air impacts to be considered in the evaluation of TVA's future energy alternatives are (1) human health, (2) visibility, (3) crop and forest productivity, (4) materials damage, and (5) greenhouse gases. Volume 2, Technical Document 1, Comprehensive Affected Environment provides an overview of air quality issues, emissions contributions, air pollution trends, and current impacts. The term "ambient air" is used to describe the surrounding air. These analyses conclude that the health and environmental impacts of greatest concern at current ambient exposures in the Tennessee Valley are:

- Potential impacts to health of sensitive individuals due to fine particles in the air, ozone, or potentially from short-term sulfur dioxide exposures
- Ozone impacts to crop and forest health and productivity
- Acid deposition impacts to sensitive forest and aquatic ecosystems
- Visibility impairment due to fine particles in the air
- Some degradation of material surface due to acid deposition or ozone

Ambient air loadings of hazardous air pollutants to which TVA is a contributor are of low risk to human health and the environment in the Tennessee Valley. Impacts of greenhouse gases are scientifically uncertain. Levels of emissions of greenhouse gases are tracked as an indirect measure of potential impacts.

As discussed in Volume 2, Technical Document 1, Comprehensive Affected Environment, many variables affect the relationships between emissions, exposures, and impacts. Typically, assessments of source contributions are done through meteorological and atmospheric chemistry modeling. However, these models require accurate meteorological, land cover, topographic (physical geography), emissions, and background air quality data. Modeling TVA contributions to impacts at specific receptors would require:

- Detailed emissions inventories for all contributing sources
- Atmospheric modeling of secondary pollutant formation and transport as a function of specific meteorological conditions
- Quantitative assessment of the relationships between exposures and the impacts of concern

Much of these data are not available at a regional scale, and exposure and impact relationships are also not always well understood. Consequently, simplifying assumptions were made to estimate TVA's contribution to air pollutant levels in the Tennessee Valley. These are discussed in Volume 2, Technical Document 1, Comprehensive Affected Environment.

Source-specific atmospheric modeling was also not undertaken in the Energy Vision 2020. TVA's purpose in Energy Vision 2020 is to select a preferred future energy supply strategy and does not include site-specific details of how that strategy might be implemented. The current analysis focuses on probable differences in impacts among candidate strategies and is based on projected future emissions and estimated TVA contributions to total pollutant loadings. When TVA considers site-specific actions to implement selected options, it will, as appropriate, conduct more detailed source-specific atmospheric modeling.

ASSUMPTIONS FOR FUTURE REGULATIONS

The Environmental Protection Agency is currently considering revising the national ambient air quality standards for ozone, particulate matter, and sulfur dioxide, and establishing a new acid deposition standard. Any of those regulatory decisions could require further reductions in TVA's sulfur dioxide and nitrogen oxides emissions. However, these reductions would most likely impact TVA's existing coal-fired power plants more than future new power supply sources, since standards for new plants or sources are more stringent than those for existing plants.

The Environmental Protection Agency is also currently considering whether utility emissions of hazardous air pollutants should be regulated. Mercury is receiving specific regulatory consideration. If mercury emissions from utility sources are regulated, controls would likely be national in scope and include TVA sources.

TVA has already voluntarily committed to limit potential increases in its carbon dioxide emissions. Legislation has been proposed to stabilize or reduce carbon dioxide emission levels.

In projecting future emissions trends, uncertainty in future regulations was addressed by assigning probability to alternative regulatory outcomes. All energy strategies incorporate the same probabilities of future regulation. Among the strategies, the reference, or "No Action," strategy relies most heavily on fossil fuels and represents maximum probable environmental impacts of the TVA system.

Analysis of Energy Vision 2020 Strategies

AIR QUALITY INDICES FOR ALTERNATIVE STRATEGIES

TVA's existing energy resources and many of the resource options considered for Energy Vision 2020 can affect air quality in different ways. Air indices were developed to help characterize how TVA power system operations and alternative energy strategies might affect air quality impact areas which include:

- Human health - inhalation
- Visibility impairment
- Forest and crops
- Materials (structural and cultural)

Potential effects of emissions of greenhouse gases, a fifth air quality impact area of interest, is considered in a separate index.

Indices were developed to help characterize how the emissions associated with alternative strategies might contribute to these five air impact categories. *Figure T2-14* shows these indices. Results for the air indices are derived by weighting the annual average air emissions from 1996 to 2020 in each strategy by the relative importance assigned to each air emission. The relative importance was assigned based on TVA's contribution to pollutant loadings that could affect human health and the environment. Additional information about these measurements and how they were weighted can be found in Volume 2, Technical Document 1, Comprehensive Affected Environment. The indices allow the emissions of greater concern for impacts to be given greater emphasis in multi-attribute analysis of alternative energy strategies.

TVA's final strategies were compared to the "No Action" strategy (Strategy D), which is the reference strategy in Energy Vision 2020. Strategy D was assigned a value of 1.0 for all indices. The values for the other final strategies then indicated whether they are better or worse than Strategy D with respect to the impact in question (a value greater than 1.0 indicates a worse effect, less than 1.0 a better effect).

The reference, or "No Action," Strategy D and Strategy M use the most coal, while Strategy T uses the least coal and the most natural gas and renewables. The air indices values (0.91) for Strategy T are the lowest compared to the reference strategy (value of 1.0) and represent a 9 percent difference in TVA contribution to total pollutant loadings compared to the reference strategy.

The differences in index values do not represent differences in ultimate impact contributions. For example, if TVA is estimated to contribute less than 25 percent of secondary pollutant load-

FIGURE T2-14. **Air Quality Impact Environmental Indices for Each Strategy and Impact Area**

	IMPACT AREAS				
Strategy	Health-Inhalation	Visibility Impairment	Forest & Crops Productivity	Materials Damage	Greenhouse Gases
D- Reference	1.00	1.00	1.00	1.00	1.00
J	0.98	0.97	0.98	0.97	0.93
M	0.94	0.93	0.95	0.93	0.91
O	0.95	0.94	0.96	0.94	0.90
Q	0.94	0.92	0.95	0.93	0.93
R	0.95	0.94	0.96	0.95	0.93
S	0.95	0.94	0.96	0.95	0.93
T	0.91	0.91	0.91	0.91	0.87

Air indices have been developed for health-inhalation impacts, visibility impairment, forest and crop productivity, materials damage, and greenhouse gases.

ings in the Tennessee Valley, a 9 percent difference in TVA's contribution might result in a 2.25 percent difference in total exposures. Such a difference would be difficult to measure given the large annual variability in secondary pollutant formation caused by climate conditions. For individual episodes of highest pollutant loadings, differences in loadings due to differences in TVA strategies may be detectable.

All strategies improve on the index for greenhouse gases compared to the reference strategy. Improvements range from 7 percent for strategies J, Q, R, and S to 13 percent for Strategy T.

SUMMARY OF EMISSIONS AS A FUNCTION OF ENERGY STRATEGIES

TVA's emissions of sulfur dioxide and nitrogen oxides are the primary measures that can be used to differentiate among impacts of TVA future energy strategies. However, TVA's sulfur dioxide, nitrogen oxides, particulate matter, hazardous air pollutants, and carbon dioxide emissions are all primarily functions of the annual amount of coal burned. Strategies that rely on existing coal-fired power plants are more likely to have higher sulfur dioxide and nitrogen oxides emissions than new coal-fired sources because new sources have more efficient emission controls. Regulatory actions that lower permitted emissions are likely to raise the costs of operating existing sources and may shift economics to favor new generation.

If other factors are equal, energy strategies that reduce projected coal use will have lower air quality impacts. Natural gas has negligible sulfur dioxide emissions and all strategies incorporate natural gas for new energy supply. Natural gas also has lower nitrogen oxides emissions than coal. Energy supply requirements that are met by renewables and demand-side management will have lower air emissions than equivalent supply from fossil fuels. If other factors are equal, these supply options will have positive benefits to the environment in proportion to their usage in various strategies.

The air indices do not address differences due to siting of future energy supply resources. New or expanded sources of emissions located in the eastern Tennessee Valley might contribute more to ozone in the southern Appalachians than sources sited in the western Valley. New or expanded sources located in western Tennessee could impact ozone levels and nonattainment conditions in the Nashville metropolitan area and potentially affect sulfate loading in southern Appalachia. The indices also do not address where impacts will occur. Impacts to visibility in Class I areas have greater legal implications than degraded visibility in urban areas of the Tennessee Valley. Power supplied by purchases outside the Tennessee Valley could have impacts on resources in areas other than the Tennessee Valley.

When specific energy supply strategies are implemented affects the timing of emission reductions and differs among the strategies considered. Earlier emission reductions are assumed to be environmentally preferable to equivalent reductions occurring later over the period 2000 to 2020. For example, earlier reduc-

FIGURE T2-15. **Emissions and Percent Changes Between 1996 and 2020 by Strategy**

	SULFUR DIOXIDE			NITROGEN OXIDES			MERCURY			CARBON DIOXIDE		
	Tons		%	Tons		%	Pounds		%	Thousands of Tons		%
Strategy	1996	2020	Change	1996	2020	Change	1996	2020	Change	1996	2020	Change
D-Reference	810,000	483,176	-40.35	468,530	452,866	-3.34	4,884	5,669	16.07	103,144	157,126	52.34
J	810,000	429,003	-47.04	468,530	436,944	-6.74	4,884	5,218	6.84	103,144	141,380	37.07
M	810,000	412,232	-49.11	468,530	429,493	-8.33	4,884	4,897	0.00	103,144	140,593	36.31
O	810,000	421,120	-48.01	468,530	433,653	-7.44	4,884	5,134	5.10	103,144	139,698	35.44
Q	810,000	396,791	-51.01	468,530	423,914	-9.52	4,884	4,915	0.63	103,144	141,486	37.17
R	810,000	398,084	-50.85	468,530	424,402	-9.42	4,884	4,929	0.42	103,144	141,682	37.36
S	810,000	421,123	-48.01	468,530	433,614	-7.45	4,884	5,152	5.49	103,144	142,382	38.04
T	810,000	448,843	-44.59	468,530	409,504	-12.60	4,884	5,032	3.03	103,144	128,853	24.93

FIGURE T2-16. **Average Annual Emissions and Change From the Reference Strategy**

	SULFUR DIOXIDE		NITROGEN OXIDES		MERCURY		CARBON DIOXIDE	
Strategy	Tons	% Change From Ref	Tons	% Change From Ref	Pounds	% Change From Ref	Thousands of Tons	% Change From Ref
D-Reference	563,048	0	455,804	0	5,490	0	130,352	0
J	541,563	-4	450,220	-1	5,335	-3	120,531	-8
M	511,777	-9	439,000	-4	5,159	-6	119,041	-9
O	518,733	-8	442,052	-3	5,299	-3	116,811	-10
Q	508,166	-10	439,015	-4	5,163	-6	121,351	-7
R	522,283	-7	443,399	-3	5,266	-4	121,639	-7
S	522,499	-7	443,366	-3	5,270	-4	121,261	-7
T	516,696	-8	411,742	-10	5,014	-9	115,042	-12

tions in nitrogen loading as a function of TVA energy supply strategies could result in earlier improvement in ozone impacts to human health, crop and forest productivity, and materials. Earlier reductions in nitrogen oxides could also result in improved soil nutrient content at sensitive receptors where nitrogen saturation has negative environmental impacts. However, for most crops and forests in the Tennessee Valley, current levels of nitrogen deposits have neutral to positive impacts. Earlier reductions in sulfate could produce earlier benefits to human health, visibility, aquatic impacts from acid deposition, and materials.

SUMMARY OF TRENDS IN TVA EMISSIONS

The trends in TVA's emissions during the Energy Vision 2020 period provide additional information about the potential effect of Energy Vision 2020 strategies that is not reflected in the indices. For each strategy, *Figure T2-15* gives the amount of the first and last year emissions and the percentage change from the first year of the study period (1996) to the last year (2020). (Because impacts from fine particulate matter are related more to secondary particles than primary particulate emissions, trends in primary particulate emissions are not considered here.) The graphs in *Figure T2-17* through *T2-20* illustrate the emissions trend for each strategy over the study period. Sulfur dioxide and nitrogen oxides emissions are projected to decrease between 1996 and 2020 for all strategies, despite increases in coal usage in all strategies. Mercury emissions remain the same or increase while carbon dioxide emissions increase in all strategies between 1996 and 2020. (*See Figure T2-15.*)

The table in *Figure T2-16* differs from *Figure T2-15* in that *Figure T2-16* indicates the total emissions for each of the final strategies averaged over the 25-year study period. This table also differs from *Figure T2-15* in presenting the percent change in average emissions for each final strategy compared to the reference strategy. Since the total emissions averaged over the study period best indicate total emissions, these quantities (*Figure T2-16*) are used in calculating the air quality impact indices shown in *Figure T2-14*.

Sulfur Dioxide

When comparing emissions at different points in time, sulfur dioxide emissions in the reference strategy are projected to be reduced from 1996 levels by about 40 percent in 2005 with smaller reductions after 2005. All other strategies have larger reductions in sulfur dioxide emissions than the reference strategy. (See *Figure T2-15.*) *Figure T2-17* projects trends in sulfur dioxide emissions for each strategy.

When comparing total emissions averaged over the study period against the reference strategy, sulfur dioxide emissions for all final strategies are 4 to 10 percent lower compared to the reference strategy (*Figure T2-16*).

- The reductions in sulfur dioxide would lead to reductions in sulfate contributing to acid deposition and fine particulate matter. However, reductions in sulfate concentrations would be less than projected TVA sulfur dioxide reductions. For example, sulfate formation can be limited by availability of oxidants (e.g., hydrogen peroxide or ozone) that react with the sulfur dioxide to form sulfate. Also, TVA is only one contributor to sulfur dioxide emissions that contribute to sulfate formation.
- Some improvement in TVA's contribution to potential impacts on human health, visibility, and rates of degradation of materials are expected for all strategies, due to reductions in TVA sulfur dioxide emissions. However, these benefits may not occur within the Tennessee Valley but at some distance beyond it, since the rate of sulfate production is slow and the air mass into which the sulfur dioxide is emitted may travel outside the Tennessee Valley before the sulfate is produced.
- Potential benefits to crops and forests from projected reductions in TVA emissions of sulfur dioxide are expected to be

small because sulfur is a less important pollutant than nitrogen for these systems.

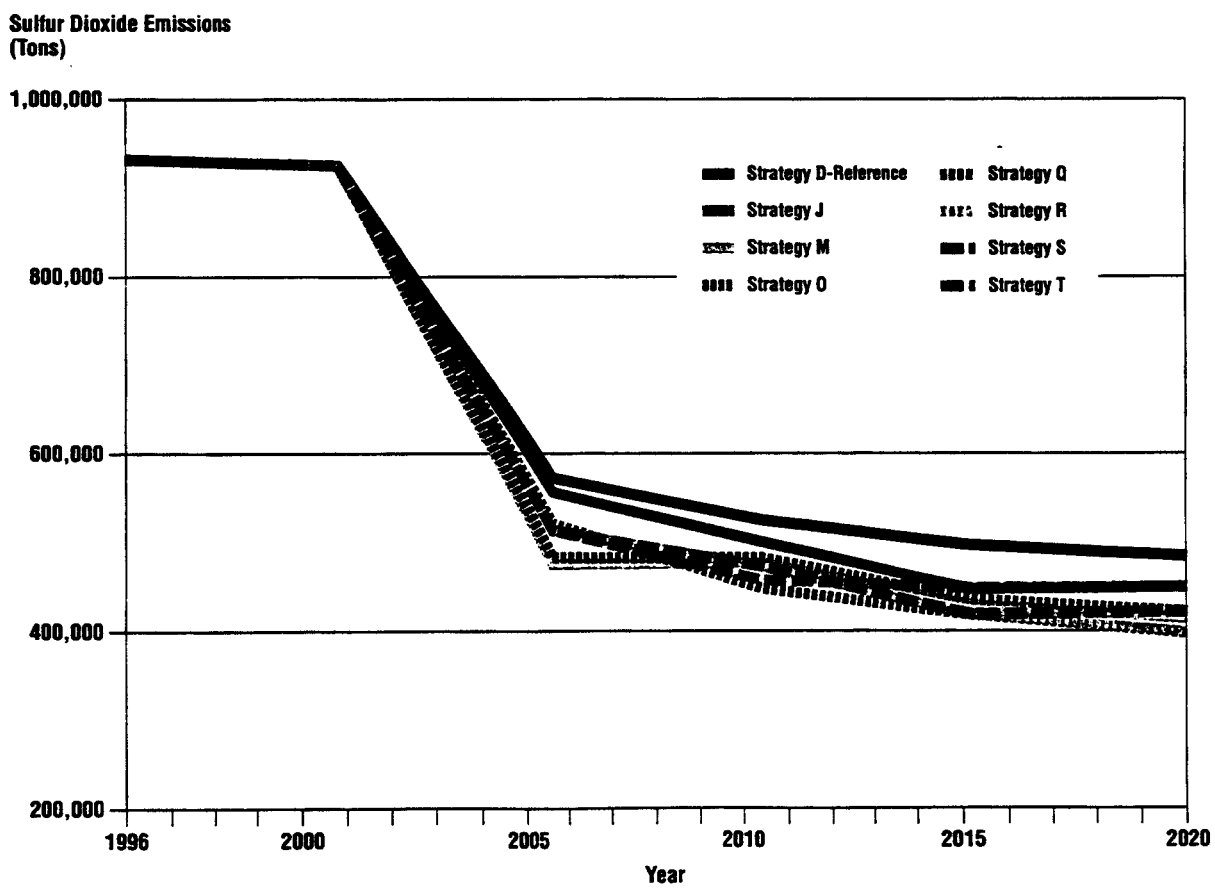
Nitrogen Oxides

Nitrogen oxides emissions are projected to drop from 10 to 20 percent, depending upon the strategy, between 1996 and 2000 due to implementation of Phase II controls under the 1990 Amendments to the Clean Air Act. After the year 2000, nitrogen oxides emissions are projected to increase for all strategies as a function of increasing generation. Emissions are projected, however, to remain 3 to 13 percent lower than 1996 levels (*Figure T2-15*). *Figure T2-18* shows the nitrogen oxides emissions trend for each strategy.

When comparing total emissions averaged over the study period against the reference strategy, the strategy with the lowest emissions, Strategy T, has 10 percent lower nitrogen oxides emissions than the reference strategy (*Figure T2-16*).

- Reductions in TVA emissions of nitrogen oxides could lead to an improvement in ozone (a chemical oxidant that can affect the respiratory system of exercising unmedicated asthmatics) exposures in the Tennessee Valley if TVA reductions are not offset by increases in nitrogen oxides emissions from other sources. For example, emissions from automobiles and other mobile sources are likely to increase substantially during this same period.
- For all strategies, benefits to human health could occur as a result of TVA reductions of nitrogen oxides emissions. Small benefits to visibility, crop and forest productivity, and materials could also result.
- In the immediate vicinity of TVA coal-fired power plants (within about 20 kilometers), where ozone is consumed in the plume, TVA nitrogen oxides emission reductions could actually increase ambient ozone levels.

FIGURE T2-17. **Yearly Sulfur Dioxide Emissions for Each Strategy**



Mercury

When comparing emissions at the beginning and end of the study period, mercury emissions are projected to increase 16 percent in the reference strategy (*Figure T2-15*). All other strategies either have no increase or smaller increases. *Figure T2-19* projects the trend for mercury emissions for each strategy.

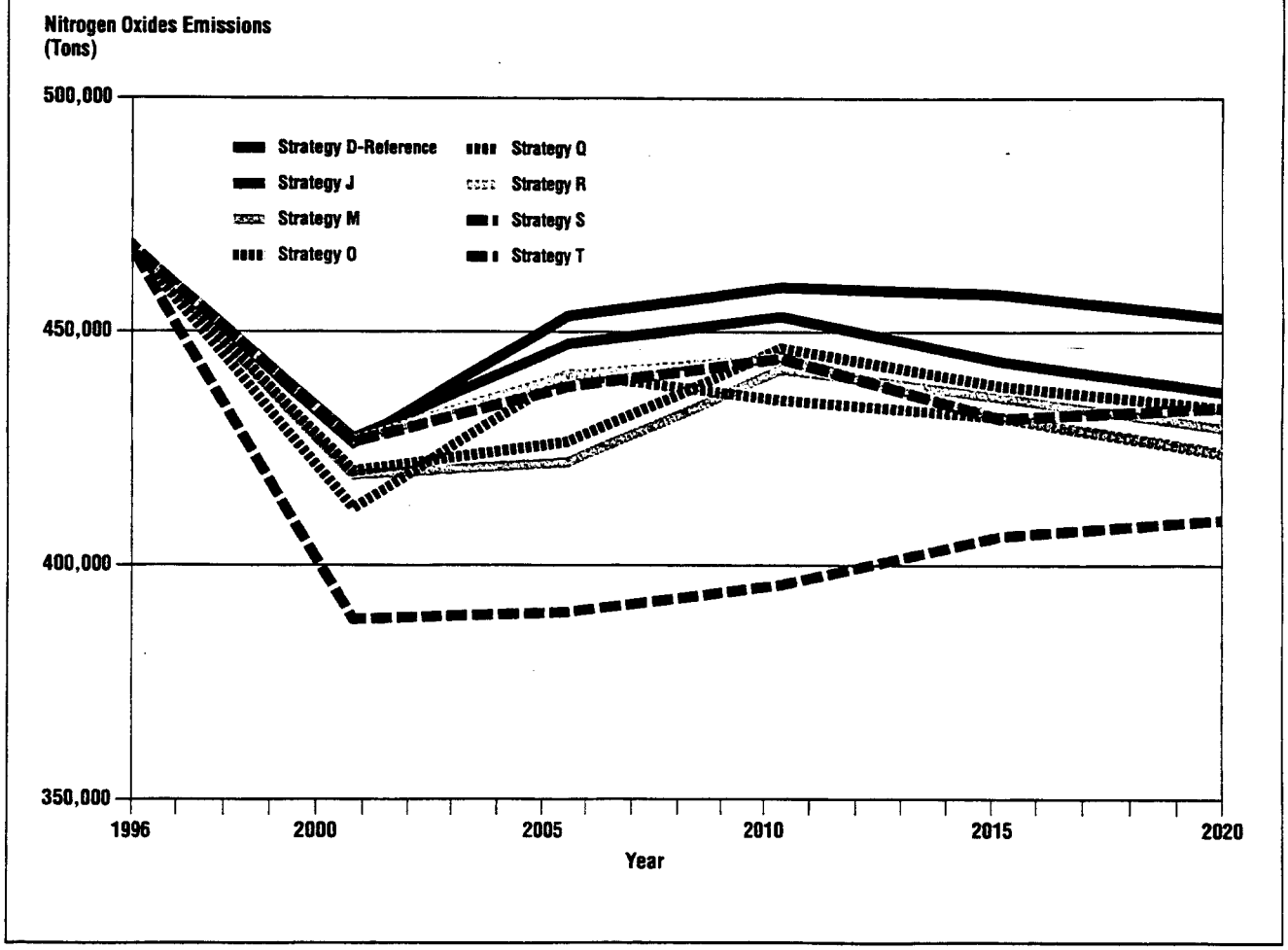
When comparing total emissions for all final strategies averaged over the study period against the reference strategy, mercury emissions are 3 to 9 percent lower compared to the reference strategy (*Figure T2-16*).

Differences in mercury loadings in the Tennessee Valley due to TVA future energy strategies may be detectable. However, because impacts of atmospheric deposition of mercury in the Tennessee Valley are small, changes in impacts as a function of TVA strategies would be very small. TVA emissions are a very small fraction of total mercury impacting sensitive ecosystems outside the Tennessee Valley; thus, these differences in mercury levels are not expected to be detectable at sensitive receptors.

Carbon Dioxide

There remains considerable uncertainty regarding the possible effect of carbon dioxide and other emissions on global climate. However, at the Earth Summit in Rio de Janeiro, Brazil in June 1992, the United States and over 150 other nations signed the United Nations Framework Convention on Climate Change, establishing the objective of stabilizing greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous manmade interference with the climate system. In October 1993, the President announced the Climate Change Action Plan which has the goal of returning United States greenhouse gas emissions to 1990 levels by the year 2000. As part of this action plan the United States Department of Energy initiated the Climate Challenge

FIGURE T2-18. **Yearly Nitrogen Oxides Emissions for Each Strategy**



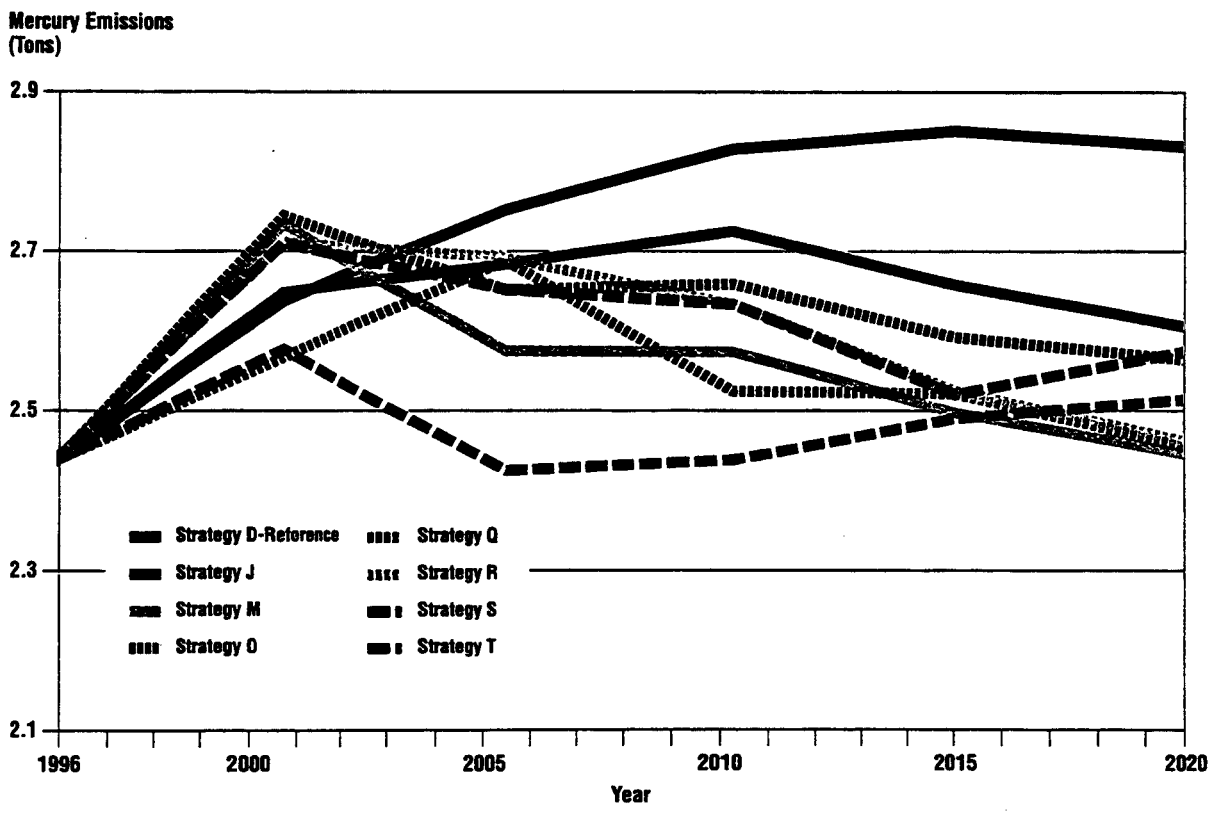
which is a voluntary program to manage United States electric utility greenhouse gases through reduction, avoidance, or sequestering of greenhouse gases.

On April 20, 1994, the Climate Challenge Memorandum of Understanding was signed by the Department of Energy, four utility organizations, and TVA. Subsequently, 104 individual Climate Challenge Participation Accords have been signed with the Department of Energy that represent 487 utilities including TVA. The efforts taken by TVA and the other 450 plus Climate Challenge participants will mitigate possible negative effects utility emissions may have on global climate in a more cost-effective manner than other control measures such as emissions regulations or carbon taxes. A 22.7 million ton reduction in carbon dioxide by the year 2000 is committed to in TVA's Climate Challenge Participation Accord. These reductions are projected from TVA's 1987 to 1990 baseline emissions and the emissions projected by a year 2000 modified reference case. Primarily, TVA greenhouse gas reductions by the year 2000 come from increased use of nuclear power, biomass cofiring, demand-side management programs, fossil-fueled power plant efficiency improvements, transmission system improvements, and hydroelectric power plant modernization.

Although actual carbon dioxide emissions increase under all strategies *(see Figure T2-20)*, the rates of increase have been mitigated by the Climate Challenge actions and are also less than increases under the Energy Vision 2020 reference strategy. Additionally, the carbon dioxide emitted per unit of electric energy produced would be 10 to 15 percent lower than TVA's present power system *(see Figure T2-24)* by the year 2005. This increase in efficiency throughout the planning period is due to: (1) increased production of nuclear power, (2) hydroelectric power plant modernization; (3) addition of more efficient fossil-fired plants, (4) increased use of renewables, and, (5) in some strategies, the repowering of existing coal-fired plants with more efficient energy conversion systems.

The possibility of future carbon dioxide regulation was

FIGURE T2-19. **Yearly Mercury Emissions for Each Strategy**

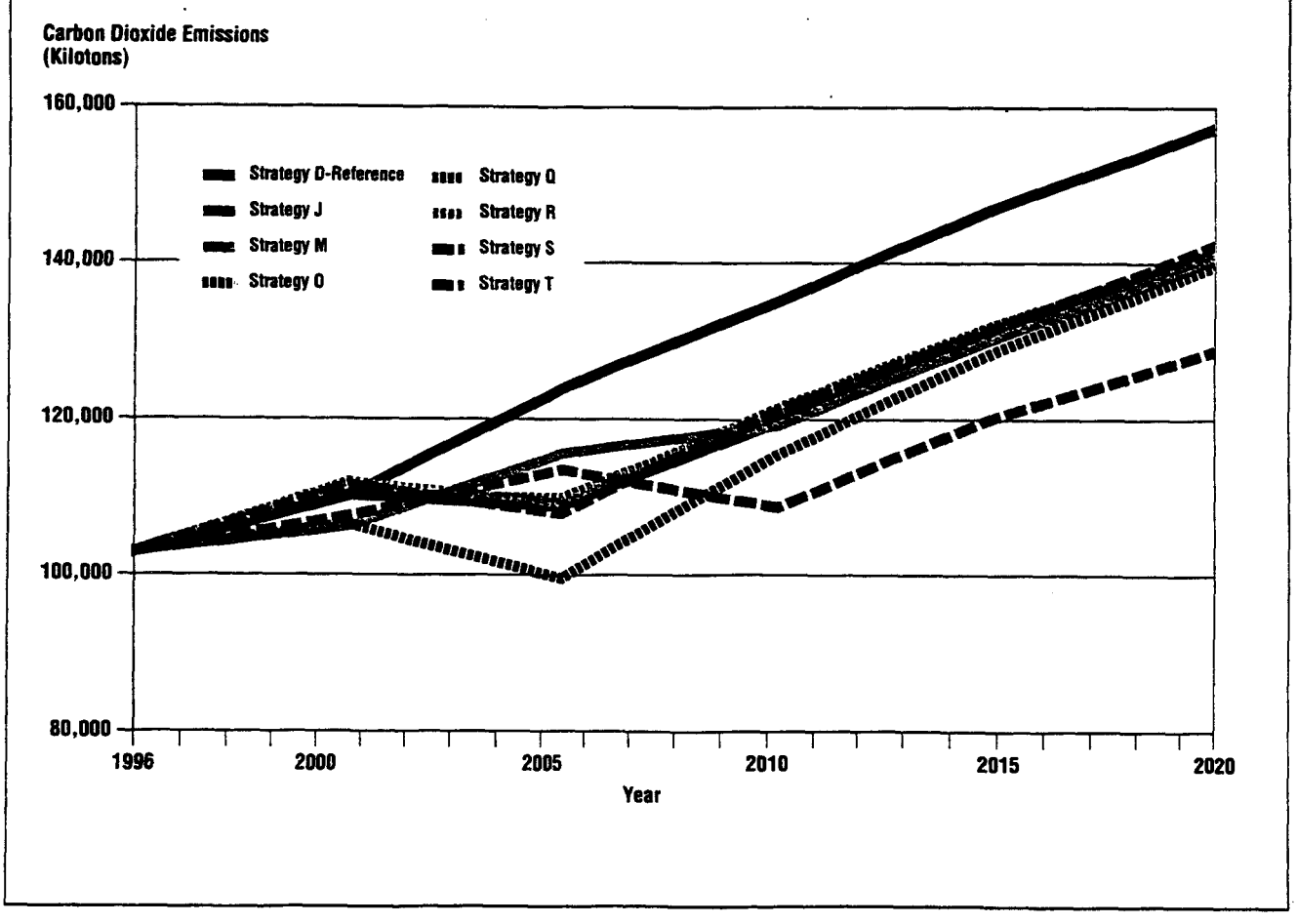


also evaluated in Energy Vision 2020 as an uncertainty. It was assumed for purposes of this uncertainty that there would be a cap on carbon dioxide emissions beginning in the year 2000 at 1990 levels. Any carbon dioxide emissions above this cap could be purchased at $10 per ton of carbon dioxide and any emissions below the cap could be sold for the same price. Because of this cap there would be a direct reduction of carbon dioxide emissions of 2 million to 3 million tons per year on the TVA system. Also, long-term costs were increased sufficiently to reduce emissions to 1990 levels assuming a cost of $10 per ton of carbon dioxide. The cost of this emission reduction averaged $257 million per year for TVA.

Improvements in greenhouse gas emissions (primarily carbon dioxide) for a strategy results from conservation of energy, use of a lower carbon content fuel (e.g., natural gas), the use of noncombustion energy sources, and specific options or measures that offset greenhouse gas releases. Demand-side management programs conserve energy and avoid combustion of fuels, thus reducing the release of carbon dioxide. More efficient power plant cycles also reduce combustion fuel use. Hydroelectric and renewable energy sources, such as wind, supply electricity without combustion of fuels.

Another renewable energy source, landfill methane recovery, has a different advantage. Methane is a greenhouse gas that has 21 times more potential to absorb solar radiation than carbon dioxide. Combustion of landfill methane for energy production releases carbon dioxide, but greenhouse gas impacts are 21 times less than the methane that would have otherwise been released to the atmosphere from the landfill through natural losses. Also, use of wood waste as a cofired fuel at coal-fired power plants recycles carbon dioxide that trees have removed from the atmosphere, rather than the one-way release of carbon dioxide from fuels such as coal and natural gas. Additionally, the methane released to the atmosphere from natural wood waste decomposition in disposal areas is avoided by combustion of the wood waste. Because of the carbon dioxide offsets, equivalent carbon diox-

FIGURE T2-20. **Yearly Equivalent Carbon Dioxide Emissions for Each Strategy**



ide emissions were computed. *Figure T2-25* gives the weightings of various pollutants to obtain the equivalent of carbon dioxide for purposes of considering greenhouse gas emissions.

Greenhouse gas credits and offsets are assigned equivalent carbon dioxide values and are included in the values shown for each strategy, including the index values in *Figure T2-26*.

When comparing emissions at the beginning and end of the study period, equivalent carbon dioxide emissions are projected to increase by 52 percent in the reference strategy (*Figure T2-15*). No strategy provides a decrease in carbon dioxide equivalents when comparing emissions in 1996 and 2020. Carbon dioxide emission trends, including equivalent levels of other greenhouse gases, are projected in *Figure T2-20* for all final strategies.

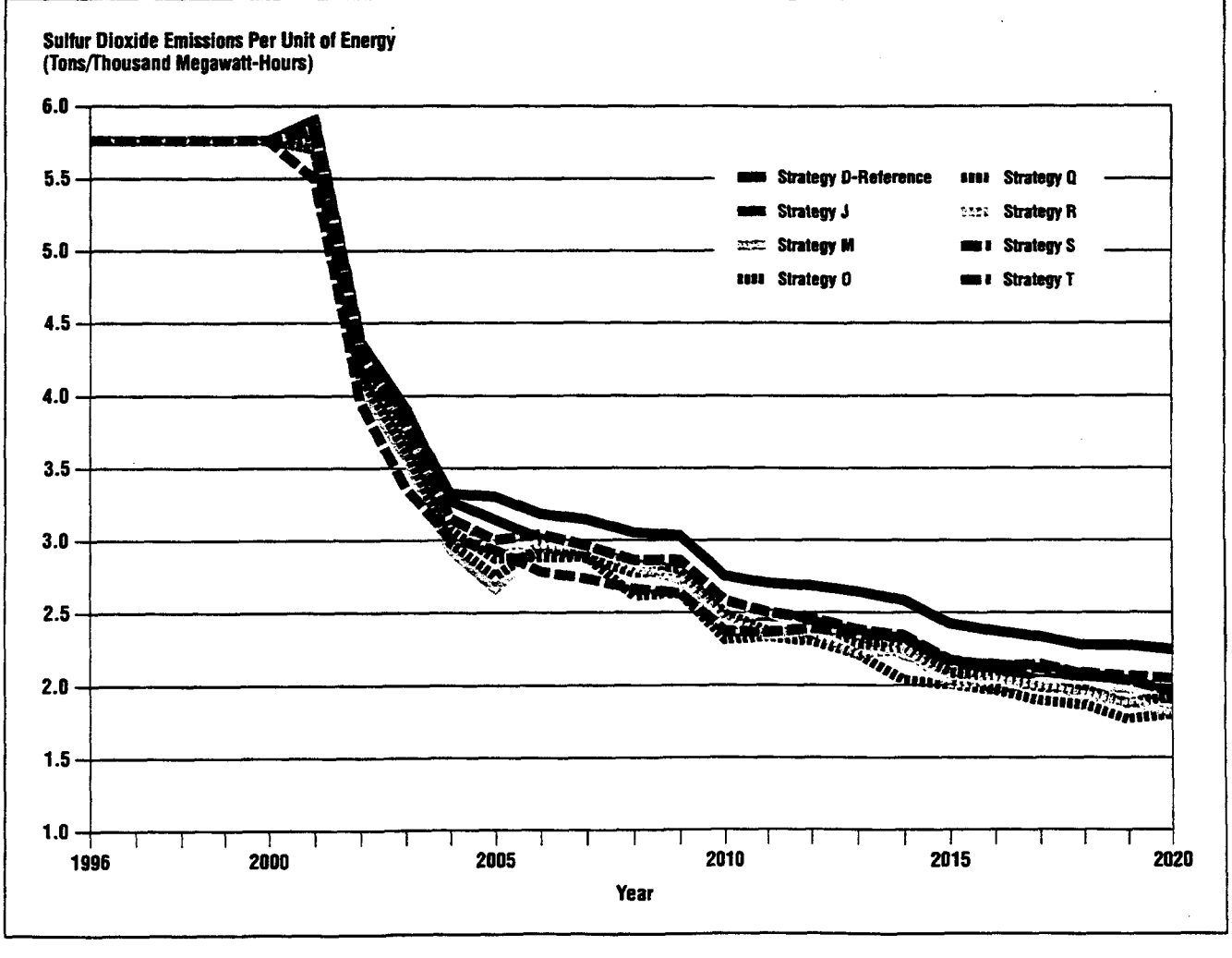
When comparing total emissions averaged over the study period against those for the reference strategy, the smallest increase is forecast for Strategy T with 12 percent lower emissions than the reference strategy (*Figure T2-16*).

Increased use of natural gas-fueled resources, renewables, and demand-side management in Strategy T results in lower levels of greenhouse gas emissions, Gas-fueled resources have 40 percent lower carbon dioxide emissions per unit of energy consumed than the coal-fired plants they re-power. Current scientific understanding is insufficient to project impacts of these increases in the Tennessee Valley.

Emissions Control Efficiencies

The ratio of emissions per unit of electric energy production is a measure of the efficiency of emission controls or the efficiency of energy production itself. All strategies have similar expansion in electric energy production over the planning period so the simple ratio of emissions to unit of electric energy production can be compared. This ratio is shown over the period 1996 to 2020 for sulfur dioxide, nitrogen oxides, mercury, and equivalent carbon dioxide in *Figures T2-21* through *T2-24*. These ratios for sul-

FIGURE T2-21. **Yearly Sulfur Dioxide Emissions for Each Strategy per Unit of Energy Generated**



fur dioxide, nitrogen oxides, and mercury improve over the planning period. These improvements reflect increased plant efficiency, increased use of natural gas, and environmental controls.

As shown in *Figure T2-24*, all strategies have small improvements in efficiencies of carbon dioxide emissions by the year 2000. After 2000, the reference strategy maintains a near-constant ratio of carbon dioxide equivalent emissions to energy production while all other strategies further decrease the ratio. Strategy T has the lowest ratio during the last 10 years of the planning period. These ratios indicate that the projected increases in carbon dioxide equivalents are a function of increased generation.

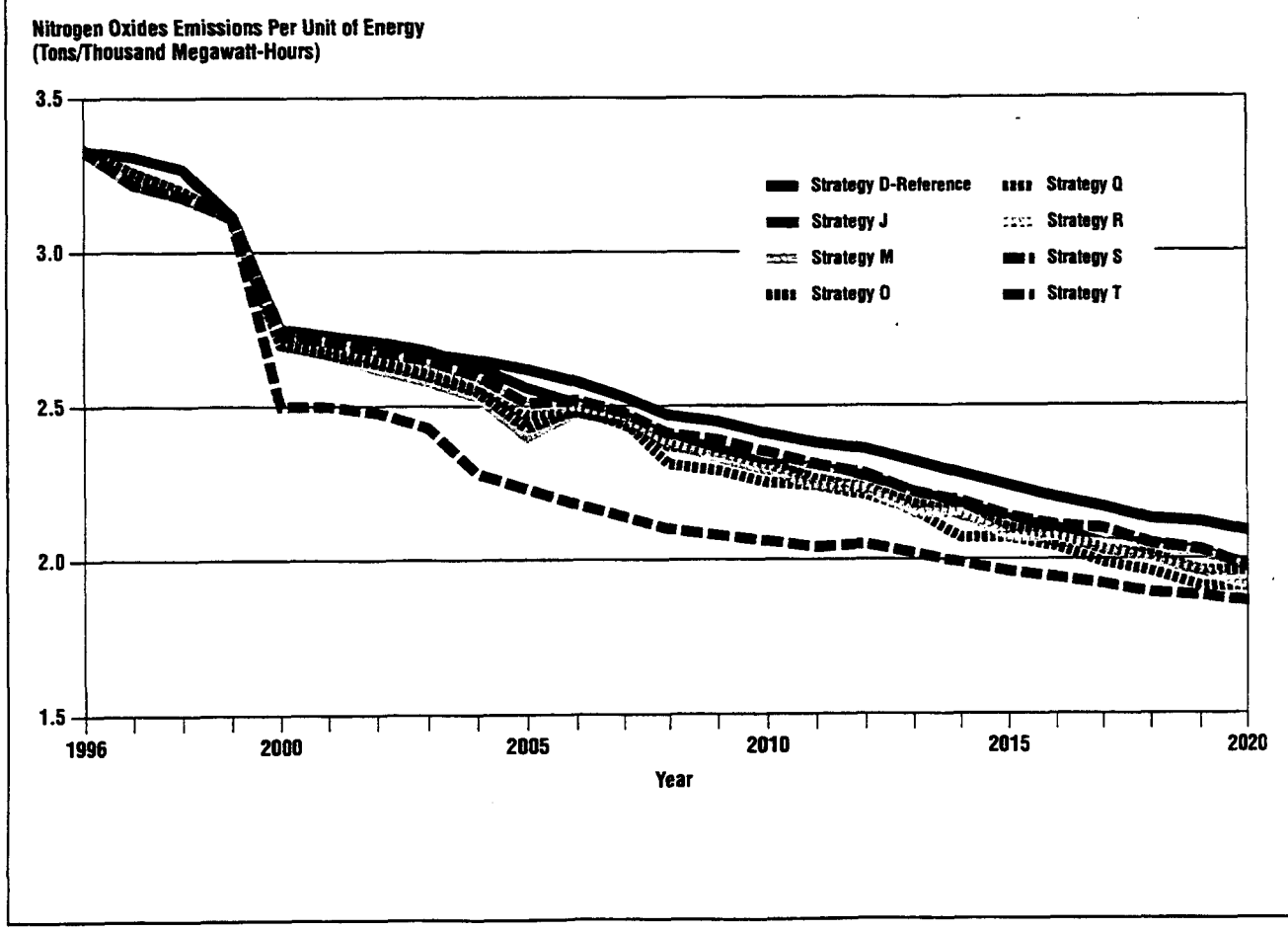
STRATEGY-BY-STRATEGY COMPARISON OF AIR IMPACTS

Air quality impacts related to each energy strategy are addressed separately in this section. *Figures T2-1* to *T2-3* describe each strategy in terms of proposed energy production facilities. Pollutants from all energy resources are considered, including those from purchased power. Levels of TVA emissions of primary particulate matter and volatile organic compounds are negligible compared to emissions from other sources and are not considered in the discussions of specific strategies.

One of the most important conclusions to be drawn from TVA's Energy Vision 2020 evaluation is that TVA's existing coal-fired units are responsible for most of TVA's contribution to the identified environmental impacts. TVA's coal-fired plants produce air pollution, water pollution, and solid waste. These environmental outputs are associated with a number of environmental problems.

TVA's contribution to many environmental problems has been substantially reduced over the years and is being reduced still further. For example, TVA's sulfur dioxide emissions from its coal-fired units have been reduced by over 60 percent since the mid-1970s and will be reduced still further to comply with the

FIGURE T2-22. **Yearly Nitrogen Oxides Emissions for Each Strategy per Unit of Energy Generated**



Clean Air Act Amendments of 1990. These reductions lessen TVA's contribution to such impacts as acid rain and visibility impairment. However, compared to most new energy resource options, TVA's existing coal-fired units are significantly worse environmental performers.

Energy Vision 2020 focuses primarily on what additional energy resource options, if any, should be added to TVA's system in the future. Consequently, repowering of selected less-efficient coal-fired units is one of the better options for reducing emissions.

Any new sources that are constructed, regardless of the type, will meet all applicable federal, state, and local air quality regulations. Thus, new sources will have minimal air quality impacts on the local (within 50 kilometers) scale. Construction of facilities creates temporary local impacts, such as fugitive particle emissions and volatile organic compound emissions from construction equipment. Regional impacts are difficult to project without site-specific information on emissions.

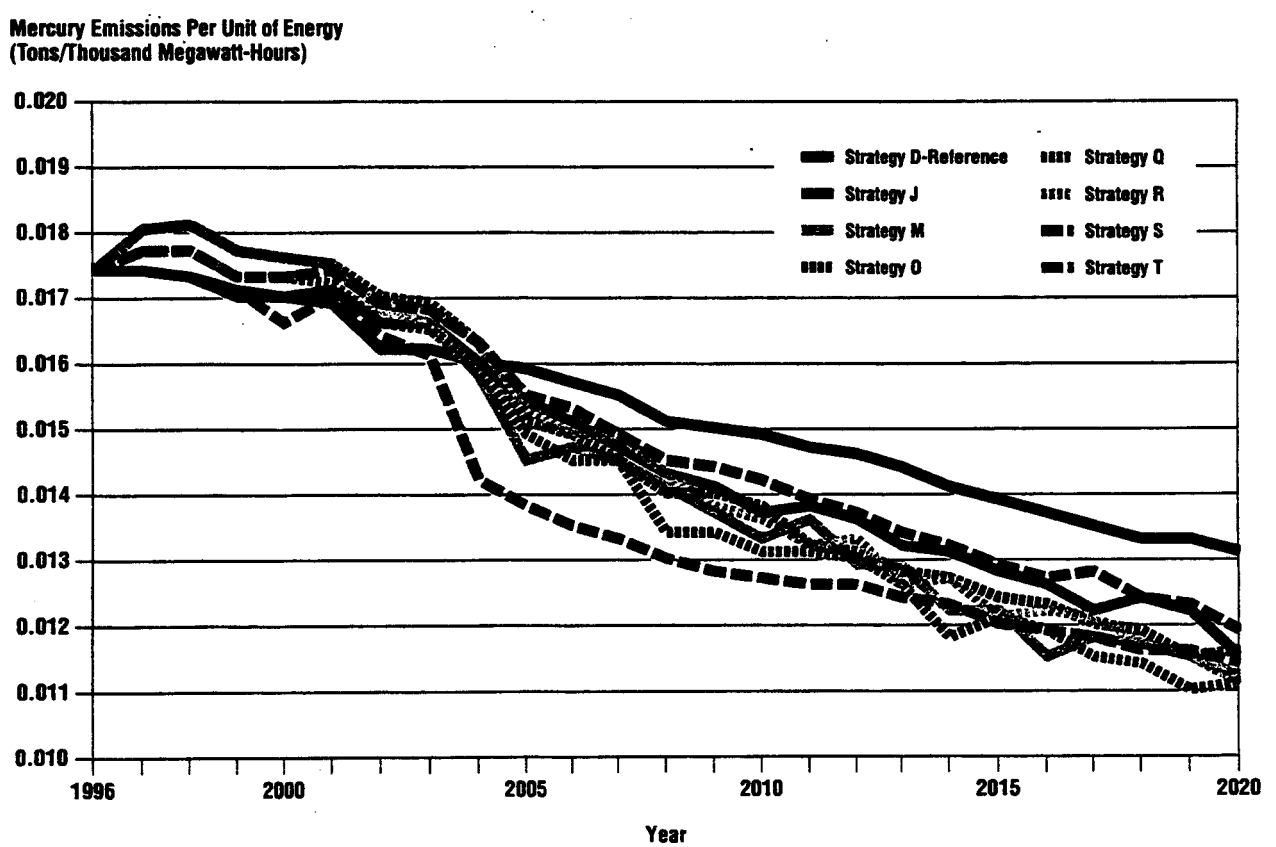
Strategy D – Reference, or "No Action" Strategy

Under Strategy D, existing facilities would continue to operate, although emissions would be reduced from those in 1996 in response to the 1990 Clean Air Act Amendments. New capacity would come primarily from gas-fired turbines fueled by natural gas or gas from coal-gasification facilities.

Sulfur Dioxide

The reference strategy has the highest average annual sulfur dioxide emissions of all the final strategies, greater than 560,000 tons, as shown in *Figure T2-16*. However, all final strategies, includ-

FIGURE T2-23. **Yearly Mercury Emissions for Each Strategy per Unit of Energy Generated**

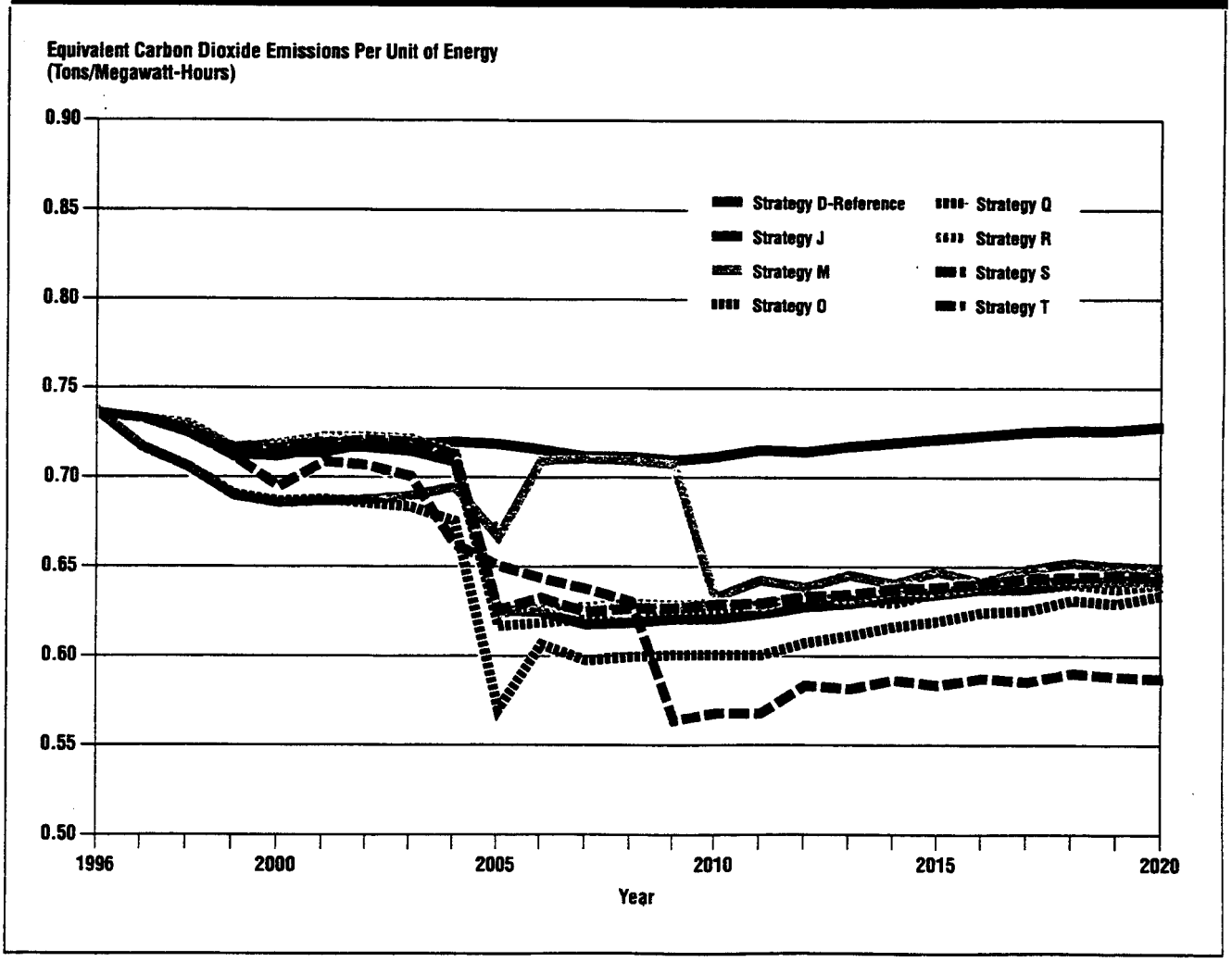


ing the reference strategy have large reductions in sulfur dioxide emissions compared to current emissions (*Figure T2-15*). These reductions would result in a proportional decrease (varying for each facility) in ambient sulfur dioxide concentrations around TVA plants where the reductions occur. This would also be expected to benefit air quality in areas that are sensitive to acid deposition and visibility impairment. However, the magnitude of the benefit is not directly proportional to the emission reductions. For example, a 50 percent reduction in sulfur dioxide emissions would yield less than a 50 percent reduction in acid deposition in the southern Appalachian Mountains. This is due to the fact that TVA emissions are only a fraction of the total sulfur dioxide emissions affecting the southern Appalachians. In addition, some of the proposed emission reductions would be at TVA plants too close to the southern Appalachians to have substantial effect in terms of acid deposition or visibility impairment. Locations further downwind to the east/northeast would derive the most benefit from emission reductions at TVA plants in east Tennessee.

Likewise, because the relationship between "light extinction" and atmospheric particle concentration is highly non-linear, there would be a less than 50 percent improvement in visibility. ("Light extinction" refers to reduced atmospheric light due to the absorption and scattering of light by gas molecules and particles.) If TVA emissions are assumed to be 20 percent of total sulfate loadings at sensitive receptors in southern Appalachia, then a 50 percent reduction in TVA emissions would result in a 10 percent improvement in sulfate loadings. That improvement should be detectable in improved visibility and reduced sulfate in deposition.

Strategy D represents the smallest reduction in sulfur dioxide; therefore, all other strategies should have greater benefits.

FIGURE T2-24. **Yearly Carbon Dioxide Emissions for Each Strategy per Unit of Energy Generated**



Nitrogen Oxides

The reference strategy has the highest average annual nitrogen oxides emissions of all the final strategies, greater than 455,000 tons, as shown in *Figure T2-16*. However, all final strategies, including the reference strategy, have reductions in nitrogen oxides emissions compared to current emissions (*Figure T2-15*). Any changes in ozone exposures resulting from this strategy are likely to be small because proposed nitrogen oxide reductions are small. Also, other sources of nitrogen oxides are projected to increase (e.g. vehicular traffic) and could offset any reductions by TVA. Assuming TVA contributes 25 percent of total nitrogen oxides contributing to ozone formation, and that nitrogen oxide levels limit ozone formation, a 10 percent reduction in TVA contribution would result in a 2.5 percent reduction in ozone exposures, depending on the location. Improvement could be much greater than this average for individual episodes or specific receptors when TVA emissions contribute more than 25 percent of total nitrogen oxides emissions. Within 20 kilometers of TVA power plants, ozone levels could actually increase. (Ozone is consumed in the conversion of nitric oxide to nitrogen dioxide.)

Lower nitrogen oxides emissions would also lead to a slight decline in regional levels of nitrate aerosols. Because nitrogen oxides contribute to ozone and because ozone facilitates the conversion of sulfur dioxide to sulfate, lower nitrogen oxide emissions could also lead to slightly lower sulfate levels. However, the effect on visibility would probably be difficult to perceive. In addition, small improvements of nitric acid in acid deposition could also result.

Mercury

The reference strategy has the highest average annual mercury emissions, almost 5,500 pounds, as shown in *Figure T2-16*. All final strategies, including the reference strategy, represent the same or an increase from current mercury emissions (*Figure T2-15*).

The quantity of mercury emissions is a function of the quantity of coal burned and whether flue gas desulfurization devices (scrubbers) are installed that are partially effective in removing mercury. TVA emissions increases may be detectable in the Tennessee Valley if other sources remain constant or decrease. However, because impacts of atmospheric mercury deposition to natural resources in the Tennessee Valley are small, impacts of increases in TVA emissions are likely to be very small. TVA emissions may contribute to total mercury deposition at sensitive receptors outside the Tennessee Valley. Specific atmospheric modeling would be required to determine if TVA's contribution and increases in TVA emissions would be detectable at sensitive receptors, but this is not likely.

Carbon Dioxide

The reference strategy has the highest average annual equivalent carbon dioxide emissions of all final strategies, over 130,000 tons, as shown in *Figure T2-16*. All final strategies, including the

FIGURE T2-25. **Weighting Factors to Obtain Carbon Dioxide Equivalents for Considering Greenhouse Gas Emissions**

Environmental Measure	Units	Greenhouse Gases Total Equivalent Carbon Dioxide
Carbon Dioxide Emission	Annual Average Thousands of Tons	1
Coalbed Methane Emissions Avoided	Annual Average Tons	-21
Natural Gas Methane Emissions	Annual Average Tons	21
Landfill Methane Recovered	Annual Average Tons	-21
Wood Waste Methane Avoided	Annual Average Tons	-21
Wood Waste Carbon Dioxide Avoided	Annual Average Thousands of Tons	-1
Short Rotation Woody Crops Carbon Dioxide Avoided	Annual Average Thousands of Tons	-1

FIGURE T2-26. **Equivalent Carbon Dioxide Index**

Strategy	Total Equivalent Carbon Dioxide (Millions of Tons)
D-Reference	1.00
J	0.93
M	0.91
O	0.90
Q	0.93
R	0.93
S	0.93
T	0.87

reference strategy, represent an increase from current equivalent carbon dioxide emissions (*Figure T2-15*). The greenhouse gas index for the reference strategy includes effects from existing demand-side management programs.

Strategy J – Bellefonte Coproduct and Renewables Strategy

The resource option differences between Strategy J and the reference, or "No Action," strategy lie in converting Bellefonte Nuclear Plant to an integrated gasification combined cycle plant and relying more on renewable fuel sources.

Because the integrated gasification combined cycle at Bellefonte is proposed in Strategy J, there would be nitrogen oxides emissions from the site that would not have existed under Strategy D. Thus, nitrogen oxides concentrations would increase within about 20 kilometers of Bellefonte and ozone concentrations would likely decrease. Beyond this distance, ozone concentrations would increase at a rate dependent on plant size, design, and other factors. However, the Bellefonte site is not sufficiently near any ozone non-attainment areas to materially affect attainment efforts. Also, the nitrogen oxides emissions from gasification are very low. Emissions from such a Bellefonte facility could theoretically contribute to ozone levels in the southern Appalachians, but this contribution would probably be small. The reason is the distance (about 210 kilometers) and the complex topography between Bellefonte and the southern Appalachians. Both factors act to increase pollutant dispersion and keep low the concentrations that could eventually reach sensitive receptor sites. Moreover, any new facility at Bellefonte would coincide with nitrogen oxides emission reductions in other parts of the TVA system. Detailed site-specific ambient air quality modeling may be required if a non-nuclear Bellefonte option were proposed to be implemented.

Strategy J has the least average annual sulfur dioxide, nitrogen oxides, and mercury reductions (with Strategy O also having the least mercury reductions) compared to the reference strategy (*Figure T2-16*).

For all impact areas other than greenhouse gases, this strategy produces the smallest air quality benefits of all the final strategies relative to Strategy D (the "No Action" strategy) because the fuels mix is so similar. (Air quality indices of 0.98 or 0.97 compared to 1.0 for Strategy D, see *Figure T2-14*).

The greenhouse gases index rating for equivalent carbon dioxide is 0.93, lower than the 1.00 for the reference strategy, Strategy D. The equivalent carbon dioxide emission decrease results from demand-side management (517 megawatts), hydroelectric improvements (163 megawatts), landfill methane capture (500 megawatts), coalbed methane capture (1000 megawatts) and 0.3 percent biomass co-firing for coal-fired facilities.

Strategy M – Combined Demand-Side Management and Off-System Sales Strategy

Strategy M emphasizes natural gas and demand-side management early in the planning period. It includes a new coal-fired unit at the Shawnee plant site, and additional power purchases from independent power producers. Sulfur dioxide and nitrogen oxides emissions from the new Shawnee unit would be more than offset by reductions elsewhere in the TVA system under this strategy. Changes in local air quality impacts around Shawnee and regional air quality impacts, including health impact changes, of this strategy are expected to be small. Site-specific environmental evaluations would be performed before putting a new coal-fired unit at Shawnee in place.

Among the final strategies, Strategy M offers neither the smallest nor the largest average annual emissions reductions for any pollutant when compared to the reference strategy (*Figure T2-16*).

For all impact areas other than greenhouse gases, air quality indices range between 0.93 to 0.95, neither the smallest nor the largest impacts, compared to 1.0 for the reference strategy (*Figure T2-14*).

The greenhouse gases index rating for Strategy M is 0.91, lower than 1.0 for the reference strategy. The equivalent carbon dioxide emission decrease results from demand-side management (958 megawatts), hydroelectric improvements (163 megawatts), landfill methane capture (500 megawatts), coal field methane capture (1000 megawatts), and 0.3 percent biomass co-firing for coal-fired facilities.

Strategy O – Bellefonte Coproduct, Demand-Side Management Blocks One and Two, and More Off-System Sales Strategy

Strategy O is similar to Strategy M, but includes an integrated gasification combined cycle plant at Bellefonte rather than the Shawnee coal-fired unit. Among the final strategies, Strategy O offers the smallest average annual emissions reductions (along with Strategy J) when compared to the reference strategy (*Figure T2-16*).

For all impact areas other than greenhouse gases, index values range from 0.94 to 0.96, neither the smallest nor the largest impacts, compared to the reference strategy of 1.0 (*Figure T2-14*).

The greenhouse gases index rating for Strategy O is 0.90, the second best rating for all final strategies. The decrease in equivalent carbon dioxide emissions results from use of the resource options identified in the discussion of Strategy M.

Strategy Q – Flexible Strategy with External Options

Strategy Q is similar to Strategy O, but with more emphasis placed on off-system power purchases. This strategy (along with Strategies R and S) produces the smallest average annual

reduction in carbon dioxide compared to the reference strategy. It has, however, the greatest annual reductions in average annual sulfur dioxide emissions compared to the reference strategy (*Figure T2-16*).

For all air impact areas other than greenhouse gases, air quality indices range from 0.92 to 0.95, neither the largest nor the smallest impacts, compared to the reference strategy of 1.0 (*Figure T2-14*).

The greenhouse gases index rating for Strategy Q is 0.93, neither the largest nor the smallest impacts, compared to 1.00 for the reference strategy. The decrease in equivalent carbon dioxide emissions results from use of demand-side management (492 megawatts), hydroelectric improvements (163 megawatts), landfill methane capture (500 megawatts), coal field methane capture (1000 megawatts), and 0.3 percent biomass co-firing for coal-fired plants.

Strategy R – Flexible Strategy with Internal Options

Strategy R is similar to Strategy Q, except that one gas-fired combined cycle unit is added and off-system purchases are de-emphasized. Among the final strategies, Strategy R (along with Strategies Q and S) has the smallest average annual equivalent carbon dioxide emissions reduction compared with the reference strategy (*Figure T2-16*).

For all impact areas other than greenhouse gases, air quality indices range from 0.94 to 0.96, neither the smallest nor the largest impacts, compared to the reference strategy (*Figure T2-14*).

The greenhouse gases index rating for Strategy R is 0.93 as compared to 1.00 for the reference strategy. The equivalent carbon dioxide emission decrease results from demand-side management (492 megawatts), hydroelectric improvements (163 megawatts), landfill methane capture (500 megawatts), coal field methane capture (1000 megawatts), and 0.3 percent biomass co-firing for coal-fired plants.

Strategy S – Low Cost, Low Rates, and Improved Environment Strategy

Strategy S is similar to Strategy O, with the exception that off-system purchases are increased short-term and coal-gasification, mid-term. Among the final strategies, Strategy S (along with Strategies Q and R) have the smallest average annual emission reductions for equivalent carbon dioxide when compared with the reference strategy (*Figure T2-16*).

As shown in air quality indices in *Figure T2-14*, impacts from this strategy are neither the largest nor the smallest impacts when compared to the reference strategy.

The greenhouse gases index rating for Strategy S is 0.93 compared to 1.00 for the reference strategy. The equivalent carbon dioxide emission decrease results from demand-side management (492 megawatts), hydroelectric improvements (163 megawatts), landfill methane capture (500 megawatts), coal field methane capture (1000 megawatts), and 0.3 percent biomass co-firing for coal-fired plants.

Strategy T – Low-Cost Renewables, Low Price Demand-Side Management, Repowering, and Bellefonte Coproduct Partnership Strategy

Strategy T relies heavily on renewable energy sources, new gas-fired turbines (natural gas or coal-gasification), and natural gas repowering at some coal-fired units. Also included is a small amount of new coal-fired capacity and an integrated gasification combined cycle plant at the Bellefonte site. Impacts from the integrated gasification combined cycle plant are addressed under Strategy J. This strategy projects the lowest average annual nitrogen oxides, mercury, and equivalent carbon dioxide emissions compared to the reference strategy (*Figure T2-16*). A large shift to natural gas combustion is an important factor. (Gas combustion produces only about 60 percent as much nitrogen oxides as coal combustion per unit of heat energy produced.) Low mercury emissions correlate with a low reliance on coal combustion.

Because the air quality indices are tied strongly to system-wide nitrogen oxides and sulfur dioxide emissions, this strategy has the best ratings (0.91) for all impact areas compared to the reference strategy of 1.0. The reduction in potential air quality impacts as a result of implementing this strategy would be the largest of all strategies considered. (See *Figure T2-14*.)

The greenhouse gases index rating for Strategy T is 0.87, the best rating of all final strategies when compared to the reference strategy with 1.0. The equivalent carbon dioxide emission decrease results from demand-side management (517 megawatts), hydroelectric improvements (162 megawatts), compressed air energy storage (1011 megawatts), landfill methane capture (500 megawatts), coal field methane capture (1000 megawatts), wind (2000 megawatts), and 0.3 percent biomass co-firing for coal-fired plants.

SECTION 4: WATER RESOURCE IMPACTS OF ALTERNATIVE STRATEGIES

Understanding Water Resource Impacts

This section summarizes the differences among TVA's final strategies with respect to potential impacts on water resources. Three water-quality impacts were considered: (1) human health impacts by ingestion, (2) impacts on water supply and waste assimilation, and (3) impacts on fish, aquatic life, and aquatic biodiversity. Volume 2, Technical Document 1, Comprehensive Affected Environment, provides an overview of water quality issues, existing water quality impacts, sources of pollutants, water pollution trends, and regulations.

All new TVA generating resources included in the strategies assume certain constraints:

- Cooling towers will be constructed as necessary to deal with significant amounts of waste heat.
- All applicable water quality standards will be met through compliance with state-issued permits under the National Pollutant Discharge Elimination System, as is the case with existing facilities.

Prior to the development of a new energy resource, a site-specific environmental review would be done that examined direct and indirect water quality effects. For major facilities, water and aquatic life systems would be carefully monitored during construction and initial operation to identify adverse effects. Possible effects of construction and operation of new facilities on sensitive environmental resources such as wetlands or threatened or endangered aquatic species would be addressed in these site-specific reviews.

FUTURE REGULATORY TRENDS

The U.S. Congress is in the process of reauthorizing the Clean Water Act (P. L. 92-500, as amended), the Safe Drinking Water Act (P. L. 93-523, as amended), the Endangered Species Act (P. L. 93-205, as amended), and Superfund (P.L. 96-100, as amended). Changes proposed for all of these laws have the potential to affect the regulation of water resources (surface water and groundwater). Proposed changes to the Clean Water Act include clearer delineation of what constitutes a wetland, repeal of the current stormwater permitting program, greater latitude for the states in reducing nonpoint pollution sources, and the use of risk assessments and cost-benefit analysis in the Environmental Protection Agency rule- making process. These changes have the potential to affect the permits currently held by operating TVA power plants as well as the siting of new facilities, including transmission lines.

Most of the debate surrounding reauthorization of the Safe Drinking Water Act centers around the issue of risk. Currently the Environmental Protection Agency's rulemaking policy is one of zero risk. Opponents argue that the stringent drinking water standards resulting from this policy are too costly and without justifiable health benefits. How drinking water standards are set can affect the environmental siting process and ultimately the level to which contaminated groundwater must be cleaned.

The Endangered Species Act is under review. Opponents believe it goes too far in protecting the habitats of threatened and endangered species, infringes on property rights, and adversely affects federal land management policies. Loosening of the Act's provisions could affect the siting of new plants and transmission lines.

Almost everyone involved in the Superfund debate believes reform is needed. Some want major changes to the law's liability structure and cleanup standards while others favor more modest changes. The result of this debate in the Congress has the potential to significantly affect the cost of cleanup of contaminated sites associated with power production and transmission facilities.

Analysis of Energy Vision 2020 Strategies

WATER QUALITY INDICES FOR ALTERNATIVE STRATEGIES

TVA developed water quality indices to help characterize how alternative energy resource strategies may contribute to:

- Human health
- Water supply and waste assimilation
- Fish and aquatic life and biodiversity

The final strategies are described in *Figures T2-1* through *T2-3*. *Figure T2-27* shows the values for the water indices. Volume 2, Technical Document 1, Comprehensive Affected Environment (Section 4, Water Resources), contains detailed information about the measures used in deriving these water quality indices and a discussion of how they were weighted.

In developing the indices, TVA used eight weighted measures to evaluate the three impact areas above. There were three direct measures:

- Heat released
- Water consumed, (i.e., when water is not returned to the originating source)
- Water used (i.e., when water is returned to the originating source)

FIGURE T2-27. Water Quality Impact Environmental Indices for Each Strategy and Impact Area

Strategy	IMPACT AREAS: Health-Ingestion	Water Supply and Waste Assimilation	Fish and Aquatic Life and Biodiversity
D - Reference	1.00	1.00	1.00
J	1.00	1.00	0.99
M	1.01	1.00	1.00
O	1.00	0.99	0.99
Q	1.01	0.99	0.99
R	1.01	1.00	1.00
S	1.01	1.00	1.00
T	0.92	0.99	0.96

Water indices have been developed for health-ingestion, water supply and waste assimilation, and fish and aquatic life and biodiversity.

Surrogate measures were also used. (A surrogate measure is one that moves in the same direction as another that is more difficult to measure.)

- Coal burned
- Power produced by nuclear, coal, and hydroelectric plants
- The number of new power plants constructed

Three of the measures received most of the weighting for the impact areas:

- Hydroelectric peaking power production
- Coal power production
- Coal burned

The water health-ingestion index uses three weighted measures:

- Power production from nuclear
- Coal-fired
- Peaking hydro

Hydro peaking and nuclear power production are constant for all final seven strategies as well as the reference strategy. As a result, differences in coal-fired (existing plants) power production governs the index. Strategies M, Q, R, and S all have increased coal-fired power production from existing plants compared to the reference strategy. This results in index values slightly greater than 1.0.

SUMMARY OF FINDINGS

TVA's final strategies are compared to the "No Action" strategy or the reference strategy for Energy Vision 2020 (Strategy D). As indicated, there are only slight differences among TVA's final seven strategies and Strategy D for most water resource effects. Because less coal is burned under Strategy T (low-cost renewables) and coal use produces some water resource-related consequences, only this strategy shows a noticeable improvement. The following major conclusions have been reached:

- The effects of damming rivers, including operation of existing hydroelectric units, is responsible for the more important water resource impacts. However, since no new dams are proposed in the final strategies or the reference strategy, this impact is the same across all strategies.
- Increasing the capacity of TVA's existing hydroelectric plants is environmentally beneficial. This produces new capacity without constructing new plants. New plant construction, particularly a new hydroelectric dam, is more environmentally damaging. Also, new turbine designs used in increasing the capacity of existing hydroelectric plants may also incorporate technology that introduces oxygen and helps combat the low dissolved oxygen problem that exists today below a number of TVA dams.
- TVA's existing coal-fired plants are responsible for most of TVA's contribution to water pollution. As described in the section on Air Resource Impacts, cost-effective repowering of selected less-efficient coal-fired units provides some of the best options for water quality.
- Repowering or adding capacity at any existing facility is preferable from a water resource perspective because it lessens the risk of impacts to those resources. Generally, from a water quality viewpoint, repowering of existing units is preferable to construction of new plants because the repowered units would have less of an impact on aquatic resources than the older units they replaced. Also, there is a risk of adverse effects from construction runoff and the disturbance of small streams associated with construction of new plants at sites that have not yet been developed. Construction of additional transmission lines on new rights of way could affect aquatic communities in small streams crossed by the lines. However, these construction effects can be greatly reduced or avoided through the use of construction best management practices that properly control contaminated runoff.
- Strategies that include increased use of coal, either for combustion or gasification, will result in increased risk of environmental impacts on water resources. This is due primarily to adverse effects in the fuel cycle, including those resulting from sediment runoff from strip-mined land and acid mine drainage. Streams in Appalachia and western

Kentucky are currently degraded by coal mining and increased use of coal may, without proper mitigation, result in continued degradation. However, various regulatory processes are in place to reduce the risk of adverse impacts and to require the appropriate use of mitigative measures. This includes the regulations implementing the Surface Mining Control and Reclamation Act.

- Unlike coal combustion, coal gasification does not produce large quantities of ash, which can adversely affect surface and groundwater during handling and disposal. Coal gasification produces an inert glass-like slag that can be used as a construction material.
- Generally, new capacity from demand-side management will result in few, if any, negative water resource impacts.
- The production and disposal of contaminated groundwater during the collection of coalbed or coal seam methane can pose problems and unless handled appropriately could affect water quality and aquatic communities.

STRATEGY-BY-STRATEGY COMPARISON OF WATER IMPACTS

Strategy D: Reference, or "No Action" Strategy

Strategy D is considered the "No Action" strategy, or TVA's most likely course of action for adding new capacity during the next 25 years had the Energy Vision 2020 process not been undertaken. Well over half of the new capacity added during that time would come from new gas-fired simple-cycle combustion turbines and combined cycle combustion/steam turbines. More than a third would be produced by integrated gasification combined cycle and coal gasification systems. Seven percent would be purchased from independent power producers using gas-fired simple and combined cycle cogeneration systems. Demand-side management, as a percentage of new capacity, would steadily decrease from 30 percent in 2000 to 3 percent in 2010. Since this reference strategy would not involve decommissioning or repowering existing facilities, any operational or fuel cycle aquatic effects from existing facilities would remain unchanged.

Under the "No Action" strategy, effects on water quality and aquatic communities would tend to be localized and associated with construction and operation of new facilities at undeveloped sites. Fuel cycle effects from drilling and mining at remote locations could be expected, albeit the significance of such effects would be reduced through the operation of various regulatory processes. Localized or site-specific effects would be addressed in subsequent reviews of specific resource options that are proposed.

Construction impacts are generally associated with the erosion/runoff of disturbed soil during storm events. The suspended soil entering a stream or river can carry contaminants (e.g., cleaning solvents, fuels) spilled during construction activities. Suspended material in a stream or river can also absorb heat and increase ambient temperature. Discharges of small amounts of chemicals used in cleaning of equipment and sewage treatment plant effluents (wastewater) could also have minor impacts. New gas pipelines would be required for some options and possibly barge unloading facilities for the coal gasification options.

Siltation can affect aquatic life by clogging fish gills, smothering fish eggs and benthic organisms, and reducing photosynthesis of phytoplankton and aquatic plants. Dredging destroys benthic (i.e., bottom-dwelling) organisms in dredged areas, and chemicals can cause direct toxic effects or indirect effects through bioaccumulation in the tissues of aquatic organisms. Sewage effluents (wastewater) contain human pathogens and oxygen-demanding substances. However, all of these potential effects on the aquatic environment can be minimized or avoided through the use of appropriate site management practices and proper treatment of effluents.

Operational aquatic effects in receiving waters can be caused by thermal discharges, process discharges, coal and ash handling, and small amounts of chemical and sanitary wastes. This reference strategy and nearly all the strategies being considered envision a large portion of new power from integrated coal gasification combined cycle technologies. While integrated coal gasification combined cycle plants are an attractive alternative to conventional power production methods, a number of challenges remain, one of which is water and wastewater management.

Overall, there is very little information generally available on the treatment of integrated coal gasification combined cycle wastewater, and only a limited amount of commercial experience in treating such wastewater. Gasifier design and type of coal used are the principal variables that determine the composition of gasification wastewater. Gas treatment after gasification produces wastewater that may contain organic material, phenolics, cyanides, sulfides (and other reduced forms of sulfur), and ammonia. These are not present in wastewater from conventional coal-fired power plants. Many of these compounds are highly toxic to aquatic life and would pose a significant threat without adequate treatment and removal.

However, technology is available to treat integrated coal gasification combined cycle wastewater to meet the most stringent standards. All operational impacts would be mitigated through the states' National Pollutant Discharge Elimination System permitting processes. In most, if not all, cases these facilities would be considered "new sources" under the Clean Water Act. As such, they would be subject to effluent limitations under New Source Performance Standards for steam electric power plants and chemical manufacturing plants where co-production is planned.

These would be more stringent standards than those at existing plants.

Possible effects of heated effluents on aquatic life that have been suggested include mortality, advanced fish spawning, increased toxicity of certain pollutants, and shift of phytoplankton populations toward less desirable species. Since any new facilities would likely dissipate waste heat through cooling towers, the possibility of these impacts occurring at new TVA facilities is minimized. However, if cooling systems at new facilities are operated in closed cycle, elevated levels of dissolved solids (including metals) will occur in discharged recirculation water through evaporative concentration of solids (including metals). The significance of this would depend on site-specific factors such as speed of mixing, degree of dilution, and metal concentrations in intake water.

National Pollutant Discharge Elimination System permits strictly regulate chemical and sanitary wastes. The use of various oxidizing and non-oxidizing chemicals for control of biofouling organisms can be expected to increase at existing power facilities due to the recent introduction of the zebra mussel *(Dreissena polymorpha)* into surface waters in the TVA service area. The permitting process will establish appropriate limits on biofouling control chemicals to protect aquatic resources, but increased use of such chemicals poses an increased risk of adverse effects. Such controls will also be required at new facilities, but careful advance planning can reduce the threat of zebra mussels and minimize the need for control chemicals.

Aquatic life could be affected by killing or injuring adult fish by impinging (colliding) on intake screens and entraining (drawing through equipment) plankton and fish larvae contained in intake cooling water. Factors such as the location and design of intake structures, the volume of water used, and other site-specific factors would alter the magnitude of such effects. Careful attention during the planning and design phases of facility construction can reduce these potential impacts to acceptable levels.

Aquatic effects associated with coal ash disposal at existing coal-fired units would be minimized in the proposed coal gasification schemes. The process would convert ash to an inert glass-like slag that is non-leachable and suitable for use as a construction material. Mining of high sulfur coal used to fuel the integrated coal gasification facilities could result in some aquatic environmental effects from acid and chemical drainage, land destabilization, and erosion. This would occur both inside and outside the TVA service area. Coal deposits are usually accompanied by pyretic materials that, when exposed to air and water, form sulfuric acid. This and other chemical compounds from mining can pollute water and affect aquatic organisms. There are, however, regulatory processes that are formulated to reduce or eliminate such possible effects. Similarly, activities associated with drilling for natural gas can cause localized aquatic effects, primarily from physical disturbance of habitats and disposal of co-produced groundwater, which may be high in salinity.

Measurements for surface and groundwater environmental evaluation criteria relating to (1) human health (ingestion), (2) water supply and waste assimilation, and (3) fish and aquatic life and biodiversity have been combined and summarized into indices for each of these areas. The score of 1.00 represents the effects of Strategy D, the "No Action" strategy. Based on this analysis, the water impacts of all of the alternatives presented vary only slightly from the reference, or "No Action," strategy, except Strategy T, which is somewhat better in all three areas. The reference, or "No Action," strategy and the final seven strategies analyzed are described in *Figures T2-1* to *T2-3*.

Strategy J – Bellefonte Coproduct and Renewable Strategy

In this strategy, about half of the new capacity in 2020 would be natural gas-based, from either TVA-owned simple cycle turbines or purchased from combined cycle plants owned by independent producers. About 40 percent would be coal gasification combined cycle, including converting Bellefonte to integrated gasification combined cycle with methyl tertiary butyl ether as a marketable coproduct. The other resource options that make up this strategy include renewables (landfill and coalbed methane) and modernization of hydroelectric plants. There would be no repowering or retiring of existing operating plants. Therefore, there would be no reduction in existing water quality or aquatic life impacts due to selection of this strategy.

Off-site impacts on groundwater related to natural gas drilling operations would have the greatest potential for aquatic resource impacts under this alternative. Some potential surface water effects could occur as a result of gas pipeline construction. Also, the construction of new facilities could cause localized effects from erosion of disturbed soils. These impacts would generally be limited to the transport of adsorbed contaminants during rainfall/runoff events. Contaminants of concern would be those spilled or uncontrolled during construction activities (e.g., solvents, fuels). These impacts would be reduced or avoided through the utilization of appropriate erosion control practices.

Operational effects on water quality can be caused by the discharge of heated cooling water and small amounts of chemical and sanitary wastes. The discharge of these contaminants would be regulated by the state National Pollutant Discharge Elimination System's permitting process and potential impacts would be minimized or avoided.

The primary difference between this and Strategy D (the "reference" strategy) is the conversion of the partially constructed Bellefonte Nuclear Plant to an integrated coal gasification combined cycle plant with a facility for coproduct-production of methyl tertiary butyl ether. As discussed, gasification process wastewaters may contain toxic components not associated with conventional coal-fired power plants and therefore may be potentially more damaging to aquatic life in receiving waters. The specifics of the water and wastewater characteristics of this plant would be detailed in a site-specific environmental analysis that would be prepared if this option were selected. In any case, integrated coal gasification combined cycle wastewater is treatable and discharges would be strictly controlled under National Pollutant Discharge Elimination System permits. That would also be true of wastewater associated with a methyl tertiary butyl ether co-production facility.

The additional hydroelectric generation in this strategy would be obtained by undertaking additional modernization projects at existing hydroelectric plants. No new hydroelectric plant construction is contemplated. Of the renewable options, only coalbed methane poses major wastewater disposal problems. This is primarily due to contaminated coproduced groundwater that could affect surface water resources. Coproduced water is often disposed of by returning it to the source from which it was drawn.

Water quality indices for Strategy J are identical to the reference, or "No Action," strategy except for the fish and aquatic life and biodiversity index. This index is rated 0.99, which indicates a very slight improvement over the reference, or "No Action," strategy. This improvement is due to a reduction in the amount of coal burned, relative to the reference strategy.

Strategy M – Combined Demand-Side Management and Off-System Sales Strategy

Strategy M emphasizes natural gas and demand-side management in the near term with a shift toward more coal combustion and coal gasification options in the long term. Coalbed and landfill methane recovery options also come into play in the later years of the study. Shawnee Fossil Plant would add one new unit to its existing 10 coal-fired units.

Increases in natural gas usage could impact off-site groundwater and surface water. Drilling operations could affect the former, gas pipeline construction the latter. Similarly, additional coal utilization could add impacts from increased mining activities. Aquatic effects from the construction of new facilities would also be a possibility. However, there are regulatory processes and best management practices that would reduce or eliminate the risk of such impacts.

Increased coal usage can affect ground and surface water quality due to coal-ash disposal. The integrated coal gasification combined cycle and related options generate complex and potentially toxic wastewaters. The coalbed methane option also presents a potential threat to aquatic communities because of the possible coproduction of contaminated groundwater that would require disposal. The state discharge permitting process would mitigate or avoid impacts to surface waters. Groundwater impacts, however, are much more difficult to control and costly physical mitigation measures may be required, such as synthetic liners for treatment or holding ponds.

The water quality indices are identical with the reference, or "No Action," strategy, except for the health ingestion index. This index is rated at 1.01, which indicates a slightly higher impact than the reference, or "No Action," strategy. The water health ingestion index uses three weighted surrogate measures: power production from nuclear (5%), coal-fired (60%), and peaking hydro (35%). Hydro peaking and nuclear power production are constant for all final seven strategies as well as the reference strategy. As a result, differences in coal-fired (existing plant) power production governs the index. This strategy, as well as strategies Q, R, and S, have increased coal-fired power production from existing plants relative to the reference strategy which results in index values slightly greater than 1.0.

Strategy O – Bellefonte Coproduct, Demand-Side Management Blocks One and Two, and More Off-System Sales Strategy

This strategy is similar to Strategy M in that it also emphasizes demand-side management in the near term and gas and coal gasification in the long term. It includes converting Bellefonte Nuclear Plant to a coal gasification process with coproduction of methanol and its derivatives. Other resource options include landfill and coalbed methane recovery. Unlike Strategy M, however, no new pulverized coal units are included, and there is a greater emphasis on independent power purchases.

Potential impacts on water quality under this strategy include those listed in Strategy M. Additional impacts could be associated with converting Bellefonte Nuclear Plant to coal gasification as described under Strategy J. Construction effects generally tend to be localized and temporary and can be minimized with appropriate materials handling and erosion controls.

Landfill and coalbed methane utilization could impact water quality through facility and pipeline construction and disposal of coproduced contaminated groundwater.

The water quality index for health-ingestion for Strategy O is identical to the reference strategy. The fish and aquatic life and biodiversity index and the water supply and waste assimilation index are rated 0.99, which is only a very slight improvement over the reference, or "No Action," strategy. The fish and

aquatic life improvement is due to a reduction in the amount of coal burned and the water supply index improvement is due to reductions in thermal discharges and water consumption relative to the reference strategy.

Strategy Q – Flexible Strategy with External Options

This strategy essentially duplicates the options in Strategy O with the addition of purchased power and flexible options that involve the off-system purchase of options to buy power at a certain time and price. Strategy Q includes only about half as much demand-side management as Strategy O.

This strategy differs from Strategy O in its off-system power purchase and management, which do not affect water quality in the Tennessee Valley, but could pose risks to water resources where they are located. The water quality index for health-ingestion for Strategy Q is rated 1.01, which indicates a very slightly increased risk for impacts, for the reasons noted above for Strategy M. The water supply and waste assimilation index and the fish and aquatic life and biodiversity index are rated at 0.99, which indicates a very slight improvement over the reference, or "No Action," strategy. The fish and aquatic life improvement is due to a reduction in the amount of coal burned, and the water supply index improvement is due to reductions in thermal discharges and water consumption relative to the reference strategy.

Strategy R – Flexible Strategy with Internal Options

This strategy contains the same options as Strategy Q with the same capacities. except for one new gas-fired combined cycle unit, and a considerably reduced reliance on off-system power option purchases.

Potential impacts on water quality under this strategy are identical to Strategy Q, except for additional impacts that may be associated with a gas-fired combined cycle unit. These potential ground and surface water impacts could result from off-site drilling operations and facility construction. The water quality indices for Strategy R are the same as for the reference, or "No Action" strategy, except for health-ingestion. This index is rated 1.01, which indicates a very slight increased risk, as discussed under Strategy M.

Strategy S – Low Cost, Low Rates, and Improved Environment Strategy

This strategy contains the same options as Strategy O, with more purchased power in the short term, a higher level of coal gasification generation in the middle years, and about half as much demand-side management overall.

Potential impacts on water quality under Strategy S are indexed identically to the reference, or "No Action," strategy, except for health-ingestion. This index is rated at 1.01, which indicates a very slight increased risk over the reference, or "No Action," strategy, for the reasons outlined under Strategy M.

Strategy T – Low-Cost Renewables, Low-Price Demand-Side Management, Repowering, and Bellefonte Coproduct Partnership Strategy

Much of the new capacity added by 2020 under this strategy would be from new natural gas-fired turbines, natural gas repowering of some existing coal-fired units, and coal gasification. A number of renewable and energy storage options, including wind, landfill and coalbed methane, hydroelectric plant improvement, and compressed air energy storage, make up about 25 percent of all new capacity. A small amount of capacity would result from new pulverized coal units.

This is the most diverse mix of generating options among the strategies under consideration. By virtue of its emphasis on renewables and repowering of old coal-fired units, this strategy is the one likely to result in the least overall impact on aquatic ecosystems. The environmental indices for this mix are 0.92 for health-ingestion, 0.99 for water supply and waste assimilation, and 0.96 for fish and aquatic life and biodiversity. This represents the greatest improvement compared to the reference strategy. The improvement in the health index is due to an 8 percent reduction in total fossil generation, the fish and aquatic life improvement is due to a reduction in the amount of coal burned, and the water supply index improvement is due to reductions in thermal discharges and water consumption relative to the reference strategy.

Under this strategy, water quality effects from the use of natural gas could occur in association with off-site drilling operations (groundwater effects) and potentially from the construction of facilities and pipelines (surface water effects). Construction impacts would tend to be localized, temporary, and generally in association with storm runoff. Mitigation of construction effects could be accomplished with the implementation of best management practices.

Additional coal-fired units could have potential impacts on ground and surface water mainly in association with ash disposal. Chemical contaminants in coal-ash are dependent on the type of coal, and the potential effects are well documented. Mitigation could involve physical measures, such as disposal pond lining to protect groundwater. The repowering of older coal-fired units to natural gas-fired combined-cycle units would tend to have an overall mitigating effect on coal-related impacts because new sources are held to more stringent requirements than the old sources they replace. All surface water discharges from plants would be regulated under state National Pollutant Discharge Elimination System permitting limitations.

SECTION 5: LAND RESOURCE IMPACTS OF ALTERNATIVE STRATEGIES

Understanding Land-Related Environmental Impacts

Volume 2, Technical Document 1, Comprehensive Affected Environment, provides an overview of land resource issues and land use. Because land resource impacts tend to be so site-specific in nature, developing indices for such impacts was not practical. Land resource impacts can be more fully and meaningfully evaluated when proposals to implement specific energy resource options are made in the future. These impacts will be addressed in subsequent environmental reviews.

However, certain conclusions or observations can be made at this programmatic level of review based on the generic attributes of various energy resource options.

Factors such as siting of generation facilities, siting of transmission facilities, fuel sources, and waste disposal, all affect land use. Resulting impacts can include:

- Long-term loss of land use
- Loss of plant and animal habitats
- Long-term aesthetic loss
- Fragmentation of forests
- Electric and magnetic fields exposure

Figure T2-28 gives the estimated total land requirements that would likely be required by TVA's final strategies and Strategy D, the reference strategy. Land use estimates range from 10,300 acres for the reference strategy to 62,000 acres for Strategy T. The larger amount of land used for Strategy T is due primarily to the extensive acreage that is needed to support wind turbines. *Figures T2-1* to *T2-3* describe the final strategies considered in the analysis.

The construction of new power generating facilities has greater potential for directly affecting land resources than does retrofitting or altering power sources for existing generation facilities. A new plant would consume additional land acreage, whereas altering existing facilities would not likely require significant additional acreage.

This section deals primarily with the direct effects to land resources resulting from the implementation of new power generating facilities. Discussion has been restricted to a general level. More detailed analysis and discussions will result from the environmental reviews performed for new facilities as they are sited. Specific issues such as endangered species, wetlands, and other site-specific concerns would be examined in these reviews. Discussion in this section deals with issues such as land consumption, land use changes, and land disturbance.

FIGURE T2-28. **Estimates of Direct Land Use for Plant Siting, Power Transmission, and Plant Access for Each Strategy**

Strategy	Capacity in Year 2020 (Megawatts)	Total Land Use (Acres)
D-Reference	15,520	10,336
J	16,456	17,711
M	14,765	16,299
O	15,406	16,080
Q	16,100	15,335
R	16,720	15,685
S	15,976	16,541
T	17,715	61,957

The analysis of potential impacts on land resources was conducted at two levels:

- Potential effects resulting directly from the siting of the power plant itself
- Potential consequences associated with fuel sourcing, power generation, and waste

This analysis is also based on fuel sources, rather than on specific strategies. Potential consequences of siting various types of generating facilities were analyzed based on fuel source. This approach simplifies comparison of individual strategies. The fuel sources (i.e., fuel cycles) evaluated include:

- Coal
- Natural gas
- Biomass
- Hydroelectric
- Solar and wind
- Nuclear

Environmental consequences from the plant "footprint" (i.e., the area occupied by the plant proper) are difficult to quantify. In general, these "footprint" effects are comparable, but not identical, across fuel options. Potential effects relate to the total acreage required and the acreage occupied by buildings, parking areas,

switchyards, coal piles, and other elements. Additional acreage to provide visual or noise buffers increases overall plant acreage considerably over the actual amount of acreage required for the plant itself. These buffer lands may continue to have uses such as pasture, forest management, or row crops thus reducing impacts.

The construction of new generating facilities can bring with it the construction of a distribution network of transmission lines, substations, and switchyards. Since a distribution network would be necessary regardless of power generation method, potential effects from these facilities would not likely differ by fuel source.

Considerable acreage of land is required for transmission line rights-of-way. A 100-foot wide right-of-way occupies about 12.1 acres per mile of transmission line. Permanent woody vegetation is not permitted within the rights-of-way, but pasture and agricultural land uses are allowed. When rights-of-way cross large forested areas, forest fragmentation can occur. Aesthetic impacts can occur in situations where rights-of-way are especially noticeable or visible.

The following summary sections, which focus on fuel types, describe potential "footprint" effects and operational effects resulting from fuel sourcing, power generation, and waste.

SUMMARY OF DIRECT LAND-USE IMPACT FINDINGS

- Resource options that involve expansions at existing plants or the repowering of existing units may have little or no land resource impacts. These include options at the Bellefonte Nuclear Plant site, co-generation options, some option purchase agreements, hydroelectric plant improvements, repowering that makes existing plants more efficient, and generating units added at existing coal plants.
- Coalbed methane may require a network of access roads to install and maintain the gas wells, collection rights-of-way piping, and smaller generating units distributed over larger areas. Factors such as the remoteness of the area, distance between wells, size and distribution of power plants, and installation of transmission lines to connect the power plants to the TVA power system influence land use. Five acres per megawatt was assumed for the analysis as a conservative estimate of land use for access and transmission. However, coalbed methane recovery from existing mines would impact land resources less.
- The 2,000 megawatts of wind energy capacity in Strategy T is estimated to require 50,000 acres of land at high elevations. Wind turbines have a lower power output per acre of land use compared to most generation options. Groups of wind turbines, termed a wind farm, are interconnected to a common switchyard. These turbines are often located in remote regions because wind is best at higher elevations on ridgelines and bluffs. Large-scale use of wind energy would require extensive tracts of land for locating hundreds of visually prominent wind turbines. Since wind resources are limited in the Tennessee Valley, the likelihood of disturbing sensitive ecological areas increases with the amount of wind power produced.
- Methane gas collected from landfills is a renewable energy source that prevents the release of this greenhouse gas to the atmosphere. Methane collection and its use as decentralized or distributed power returns these lands to a productive use, but would have effects similar to those associated with the infrastructure needed to support use of coalbed methane. However, landfill methane recovery would have lesser impacts than coalbed methane recovery since roads and transmission lines may already be in place. Landfill methane recovery and coalbed methane recovery are both considered direct land use, since power generation is integrated into the collection activity.
- There is sufficient land in the TVA region to allow energy resource options to be put in place without impacting sensitive land resources such as wetlands or endangered species. Land resources should not be a constraint on the deployment of any of the energy resource options identified in TVA's final strategies, with the possible exception of wind turbines.
- Other land-use conditions potentially impacted are aesthetics, electric and magnetic field exposure, and noise. Conventional power plants, typically located in rural areas, are out of character with their surroundings. Local topography, site layout and natural buffering, plant design, and population density and distribution all determine the kinds of potential site-specific impacts.

SUMMARY OF INDIRECT LAND-USE IMPACT FINDINGS

- Fuel acquisition and waste disposal are involved in power generation and affect indirect land use. Coal mining, particularly surface mining, is a disruptive land use activity. All of TVA's final strategies, including the reference strategy, expand TVA's use of coal. Total coal use rises about 35 percent from present levels for most strategies. Only Strategy T is significantly different, using about 12 percent less coal than the reference, or "No Action," strategy but still 21 percent more coal than current levels.
- Coal-fired plants have a waste stream of combustion byproducts. The byproducts—fly ash, bottom ash, and slag—are all marketable, depending on both their quality and market conditions. Unmarketed byproducts must either be stored or disposed of. This typically requires long-term land use and management.
- Natural gas drilling is typically less environmentally disruptive than coal surface mining activity for equivalent energy supply.

Also, gas-fired plants have no significant solid waste by-product. All the strategies make significant use of natural gas. Strategy T uses the most, 1.7 to 4 times more than the other strategies. Natural gas is used for repowering of existing coal-fired units. This provides additional benefits by eliminating coal byproduct production and increasing plant efficiency.

- Use of residue or waste wood fuel would reduce landfill requirements and some methane production.

SUMMARY OF NATURAL RESOURCE IMPACT FINDINGS

- Most potential impacts on land resources are site or project-specific, and would be assessed in siting studies and environmental reviews for generation and transmission facilities. These potential impact areas include threatened and endangered species, plant and animal habitats, sensitive or important ecosystems, forest fragmentation, and aesthetics.
- There may be air pollution impacts on land remote from a plant site. These impacts are addressed in the air resources section of this document.

Analysis of Fuels Used In Energy Vision 2020 Strategies

FUEL SOURCING

Fuel sourcing for hydroelectric, solar, and wind power plants are not addressed in this section because these power sources create energy from water, sunlight, and wind, respectively, and as a fuel generally do not have land resource impacts. (The creation of hydroelectric dams can have significant land resource impacts but the "fuel," water, is produced by rainfall.) Only the coal, biomass fuel for co-firing, and nuclear sections address waste-related effects, since natural gas, hydroelectric, solar, and wind power plants do not produce waste byproducts.

COAL-FIRED PLANT IMPACTS

The coal-related environmental impacts for the various strategies are affected by the amount of coal used by each strategy. Use of coal by strategy is shown in *Figure T2-29*. The environmental impacts of coal as a fuel are discussed in the following section.

FIGURE T2-29. **Coal Use for Each Strategy (Annual Average)**

Strategy	Tons
D-Reference	52,073,962
J	51,253,835
M	52,163,285
O	51,187,739
Q	51,669,092
R	51,883,575
S	51,847,911
T	45,860,676

Site Effects

Coal-fired generating plants tend to require relatively large acreage. They need coal-loading facilities, a coal pile, and ash disposal facilities that require many acres of land, and visual screens or noise buffering. Existing TVA coal-fired plants are located along navigable waterways to provide barge access for transporting coal to the plant and/or as a source of boiler and cooling water.

Aesthetic effects of a coal plant are difficult to address because such effects tend to be subjective. However, unless the plant is remote or obscured by hills, its facilities tend to be noticed by the public. Tall flue gas stacks, which are typical of coal-fired plants, can be seen from large distances depending on the stack height and surrounding terrain and often result in degradation of aesthetic character. Especially tall stacks may be visible for several miles. Strobe lights mounted on stacks are effective safety measures, but result in further aesthetic effects. Coal-fired plants can also have cooling towers. Natural draft cooling towers may be as tall as the stacks and have visible water vapor plumes during most weather conditions.

Operational Effects

Noise is almost always a concern in power generation from fossil sources. However, plant designs normally accommodate noise concerns. New plant construction would also meet any applicable noise and emission limitations; however, such limitations are rare in the Valley.

Other than potential impacts due to air pollutants, coal-fired generation options do not directly impact land resources as a result of their operation. However, coal plants can have fuel sourcing and waste generation effects. These are described below.

Fuel Sourcing Effects

TVA purchases about 35 to 40 million tons of coal per year to fuel its 11 existing fossil plants. The process of obtaining this coal involves land disturbances. Obviously, coal must be removed from the earth. According to recent figures, about 75 percent of TVA's current coal demands are supplied from subterranean mines (i.e., underground or "deep mines"), while the remainder comes from surface (i.e., strip) mines. Coal supplied from deep mines results in minimum surface land disturbance. Supplying coal from strip mines results in surface disturbance. However, current mining regulations require coal operators to

FIGURE T2-30 **Combustion Byproduct for Each Strategy (Annual Average)**

Strategy	Tons
D-Reference	6,166,437
J	5,809,790
M	6,663,316
O	5,826,405
Q	5,964,794
R	5,929,001
S	5,921,821
T	5,238,745

FIGURE T2-31. **Natural Gas and Methane Recovery Use for Each Strategy (Annual Average)**

Strategy	Landfill and Coalbed Methane (Billions of Standard Cubic Feet)	Natural Gas (Billions of Standard Cubic Feet)	Total (Billions of Standard Cubic Feet)
D-Reference	0	93.5	93.5
J	45.8	64.9	110.7
M	34.8	41.0	75.9
O	44.2	53.9	98.1
Q	48.9	68.4	117.3
R	48.9	63.4	112.3
S	49.4	59.2	108.6
T	23.4	162.0	185.4

restore the land to its original approximate contour, which helps to reduce potential impacts.

The amount of surface acreage affected by supplying coal varies and depends mainly on the thickness of the coal seam. For comparison, a coal seam one foot thick yields about 1,800 tons per acre. Assuming the average TVA coal-fired plant requires 3.4 million tons of coal per year (37 million tons for 11 plants), and that 25 percent of this total comes from surface mines, then about 840,000 tons of coal per year comes from surface mines. At a yield of about 1,800 tons per acre (for a 1-foot thick seam), approximately 465 acres per year would be required. Thicker seams would reduce this acreage accordingly (i.e., a two-foot thick seam would result in approximately 235 acres being disturbed).

The table in *Figure T2-29* gives the annual average coal use for the planning period for each strategy. All strategies use about 35 percent more in an average year than the FY 1994 procurement level of 38 million tons. Compared to the reference strategy, only Strategy T has a significant difference in coal usage, 45 million tons less, or 12 percent less coal.

Once mined, coal must be moved to the power plant. This can require the construction of new roads and/or rail lines and the consumption of additional acreage. From a fuel transportation standpoint, coal removed from existing mines would not likely result in additional effects to land resources. Because much of the coal is currently delivered via rail, construction of any new coal plants at greenfield sites could result in construction of new rail lines to those plants.

Waste

Coal-fired power plants generate various amounts of ash and other solid byproducts. For fiscal year 1995, TVA estimates that existing coal facilities will generate about 3 million tons of fly ash, 1.25 million tons of bottom ash/slag, 1.2 million tons of gypsum (from flue gas desulfurization control equipment - scrubbers), and 1 million tons of coal wash refuse. The amount and type of solid waste depend on the technology used to collect this material, as well as the characteristics of the coal burned. All these plants generate ash of some sort, which must be discarded or used. This material is usually placed in ash ponds, slurried, or dry stacked. Ash disposal areas are typically located on-site or adjacent to the generation facility. The acreage required for disposal depends on the net ash generation rate of the facility and the per-acre storage capacity of the disposal area.

Not all ash must be stored or disposed of on-site. Markets exist for coal combustion or pollution control byproducts. Depending on the ash collection system and the quality of the ash, this material may be used in the manufacture of building materials, mainly gypsum products such as wall board (i.e., sheetrock), or as soil amendments, and as filler in paving and construction materials (e.g., concrete.). Some existing coal plants dispose of a large proportion of their ash via commercial markets.

A range of disposal site lifetimes exists at TVA's existing coal-fired plants. The rate of byproduct production and use contributes to the lifetimes of the disposal/storage sites. Additional land acquisition and/or land use may be required over the life of the plants.

The alternative energy strategies have a range of annual average byproduct production from 5,238,745 tons for Strategy T to 6,166,437 tons for the reference strategy during the 1996-2020 planning period shown in the table in *Figure T2-30*. TVA has an average byproduct utilization rate of 25.4 percent. By the year 2000, the rate is projected to be over 33 percent. The current national average is about 21.8 percent.

TVA analyzed a full range of possible byproduct applications based on the chemical and radiological properties and behavior of ash and slag from its plants in an environmental assessment. The assessment concluded that none of the applications examined would create significant environmental impacts. No

significant environmental impacts are anticipated from new storage or disposal areas that are permitted as landfills by the states. However, site-specific environmental reviews would be done for any new disposal or storage area.

NATURAL GAS-FIRED AND METHANE RECOVERY PLANT IMPACTS

The environmental impacts of natural gas for the various strategies vary with the amount of natural gas and methane recovery. (See *Figure T2-31* for strategy use of natural gas and methane recovery.) The environmental impacts of natural gas and methane fuels are discussed in the following section.

Site Effects

Acreage required for natural gas-fueled power generating plants is comparable to that required for a coal-fired plant with similar capacity. The overall facility "footprint" would be somewhat smaller than for a coal-fired facility with the same generating capacity because fuel off-loading facilities (i.e., railyards, etc.) and ash disposal areas are not required. Flue gas stacks are typically the most prominent feature of gas-fired plants but are typically not as tall as stacks for coal-filled plants. Strobe lights mounted on stacks are effective safety measures, but result in further aesthetic detractions. These plants would not have cooling towers if an existing coal-fired plant is repowered. Mechanical draft cooling towers would be used at a new plant and would have a visible vapor plume during most weather conditions.

Operational Effects

The operation of gas-fired generation facilities causes few effects to land resources. Ash disposal areas are not required and there is very little solid waste (e.g., ash), compared to coal-based generation. Power generation by natural gas-fueled facilities also causes minimal potential impact on land resources.

Noise-related effects are similar to those for coal plants. Potential noise effects would be accommodated by plant design and siting criteria.

Fuel Sourcing Effects

Natural gas is a mixture of gaseous hydrocarbons, mostly methane, which occurs naturally in the earth. Natural gas deposits often accompany petroleum deposits and are found in various locations across the United States. An extensive network of pipelines distributes natural gas to users.

Drilling, exploration activities, and delivery systems (pipelines) have the greatest potential for effects to land. This analysis assumes that delivery to the plant site would be by pipeline.

Because there is an abundance of natural gas reserves, including capped wells, the likelihood of additional impacts to land resources from increased demand for natural gas is reduced. Nevertheless, drilling for natural gas is relatively innocuous and is not necessarily detrimental to land resources.

Methane, the major component of natural gas, can be collected from landfills. Energy Vision 2020 considers this option. Landfill-generated methane is typically of lower quality (i.e., less pure methane) and has a lower energy yield than naturally occurring methane. Depending on its quality, landfill-derived methane may have to be purified to meet emission standards before use. Nevertheless, use of methane from this source would provide an alternative natural gas source and would have an overall beneficial environmental effect.

Coalbed methane recovery is another technology for supplying gas-fired plants. Gas wells are drilled into a coal seam to recover the naturally generated methane. A system of wells would feed gas through a network of collection piping to a small generating unit such as a fuel cell or diesel generator. This method of fuel sourcing could be land intensive, requiring access roads to reach well heads, rights-of-way for collection piping, and power transmission lines to decentralized power plants. Methane can also be recovered from existing coal mines. This would require less additional land area.

The need to construct new gas pipelines as a result of building new gas-fired plants or repowering existing plants is difficult to determine. For economic reasons, repowering of existing generating facilities with natural gas would most likely occur at those plants currently near transmission pipelines.

Gas pipelines are usually located underground for safety reasons. On the land surface, a fixed right-of-way is maintained to prevent establishment of permanent woody vegetation. The right-of-way is maintained in a pasture-like condition or used for row crop agriculture; trees are not allowed. This situation does not preclude the use of the right-of-way for productive uses. However, forest fragmentation can occur if the pipeline crosses extensive forest areas. A pipeline requires approximately the same

FIGURE T2-32. **Biomass Cofiring for Each Strategy (Annual Average)**

Strategy	Tons
D-Reference	0
J	184,643
M	187,909
O	184,493
Q	186,227
R	186,956
S	186,903
T	186,903

acreage as a transmission line right-of-way, and potential effects are generally comparable to transmission line rights-of-way.

Figure T2-31 shows the range of natural gas and recovered methane in the alternative energy strategies. Strategy M uses 19 percent less gas than the reference, or "No Action," strategy. Strategy T has the lowest coal use and the highest gas use, 185 billion standard cubic feet, or 98 percent higher than the reference strategy.

BIOMASS-FUEL IMPACTS

Biomass-related environmental impacts of the various strategies vary with the annual average tons of wood co-firing detailed in *Figure T2-32*. Wood co-firing in coal-fired plants is the only type of biomass included in the final strategies analyzed. However, this section discusses the environmental impacts of wood waste as a fuel, as well as other biomass.

Site Effects

Biomass fuels are usually mixed with coal as a supplement, and biomass fuel options typically involve modification of existing coal-fired plants. Therefore, there would be few, if any, additional site-related impacts. Wood waste storage would have to be established, but such a facility would be compatible with the other industrial-type uses found at coal-fired power plants.

Operational Effects

Operational effects of burning biomass fuels are essentially the same as those for coal-firing because biomass fuels would likely constitute only a small or moderate percentage of the fuel burned in the boiler. Thus, any unique emissions associated with biomass fuels would tend to be lost in the much larger emission volumes resulting from burning coal. Potential changes in emissions are one of the issues that would be examined in more detail in site-specific reviews.

Fuel Sourcing Effects

Fuel Types

Wood waste is the primary biomass fuel. Mill and logging residues are byproducts that can be an inexpensive fuel source. Mill residue is the wood discarded either by primary mills, such as sawmills, or secondary mills, such as furniture companies. Residues may be in the form of chips, bark, shavings, or sawdust. The main cost involved is transportation, so residue availability depends on the number of forest product industries in a 50- to 75-mile radius of a power plant. Plants producing these residues do not always produce a consistent volume, as volume changes in response to economic conditions.

Logging residues are the unused growing stock or sawtimber volume of trees cut or killed by logging and left in the woods. Logging residues are generally composed of the tree crown (i.e., branches and limbs that are not large enough to be sold as timber). The volume of timber operations in a 50- to 75-mile plant radius would determine supply availability. Depending on soil conditions, logging residues can provide valuable nutrients to the soil as it decays. Removal of logging residues could therefore negatively impact nutrient cycling capabilities.

Short rotation woody energy crops provide a source of woody biomass. Primary species include eastern cottonwood, sweetgum, sycamore, and black locust. Since short rotation woody crops would be planted to replace conventional agricultural crops such as cotton, corn, and soybeans, a number of potential environmental benefits would result. These include: reduced erosion; reduced runoff of pesticides and nutrients; less risk of contamination of groundwater with nitrates, herbicides, and other pesticides; improved soil physical properties; increased storage of carbon above and below ground; and increased variety of microorganisms, mammals, birds, and other wildlife.

Short rotation woody crops involve intensive forestry operations such as seedling planting and fertilization and herbicide treatments (usually about once per "crop" rotation). Crop plantations would be grown on marginal-to-good former cropland with less than a 5 percent slope. Suitable areas within the Tennessee Valley region include limestone valley soils in northern Alabama, alluvial delta and coastal plain soils in northern Mississippi, and delta lands and loess belt soils in western Tennessee. Production estimates range from 2.3 to 4.3 dry tons per acre per rotation, but tonnage production is projected to double in the next decade due to genetic improvement research. Crop rotation time is expected to be 5 to 6 years.

Switchgrass may be another biomass fuel option. Although switchgrass is not currently produced for commercial sale, it may be a feasible biomass option since farm operators already own the necessary production and harvesting equipment. Production estimates range from 6 to 9 dry tons per acre per year. Energy yield is estimated to be 14.5 million Btu per dry ton.

Amount of Biomass

The amount of biomass required for power generation depends on whether it is the primary fuel or co-fired with coal. When biomass is co-fired with coal, the amount of biomass used will depend on the degree of energy input. Biomass can be a low energy input (1 to 5 percent), moderate energy input (10 to 15 percent), or high energy input (20 to 50 percent). When biomass is the primary fuel, approximately 1,000 acres of short rotation woody crop plantations per megawatt are needed for sourcing. This results in harvests of approximately 200 acres per year per megawatt.

Final strategies examined for Energy Vision 2020 were limited to wood co-firing at coal-fired plants. The reference strategy

uses no co-firing. All other strategies co-fire at a rate of 0.3 percent to the coal energy input for the existing coal-fired system.

Noise and Aesthetics

Biomass harvesting and transportation raise few concerns associated with noise. Also, there are no significant aesthetic considerations associated with mill residues, short rotation woody crops, and switchgrass. Short rotation woody crops would be harvested from recently converted traditional cropland, and would not likely result in the conversion of existing forest lands. Switchgrass is harvested like hay.

Transportation

Transportation costs would dictate that distance from source to power plant be kept to a minimum for mill and logging residues, short rotation woody crops, and switchgrass, which are high-volume, low-value commodities. Transportation costs for wood are approximately three times that for coal on a Btu basis. Current cost projections indicate that biomass sources should be within 50 to 75 miles of power plant locations. Transportation impacts would be those typically associated with large truck uses. These would include some road surface deterioration, possible traffic impediments, and increased risk of accidents. these potential problems would be examined in subsequent, option-specific environmental reviews.

Generation Effects

Most options for biomass fuel usage in Energy Vision 2020 involve co-firing with coal. Wood can be co-fired with coal in various ways:

- For low energy inputs, wood is co-pulverized with coal and fed to the boiler, along with coal.
- For moderate energy inputs, separate wood and coal handling systems and burners are required.
- High wood energy inputs perform best in fluidized-bed boilers. Use of switchgrass as a fuel may require it to be pelletized first.

Co-firing options would not result in any additional plant siting, size, noise, or aesthetic considerations beyond those discussed for coal power plants.

One option for biomass fuel usage is a whole-tree energy boiler power plant. This is a new direct combustion technology that depends entirely on short rotation woody crops as a fuel source. Siting "footprints" of a biomass-fired plant would be similar to that of a coal-fired plant. This option was not, however, included in TVA's final strategies.

Waste

Waste byproducts produced by a biomass co-fired plant are similar to those of a coal power plant, except that ash has a somewhat higher carbon content. Some coal ash byproduct is currently sold as a concrete additive. Research is underway to determine if the carbon content in biomass co-fired ash is too high to be used in concrete manufacturing. Biomass storage areas may also produce an acidic tannin leachate (mainly from wood bark), but common leachate control measures, as well as site best management practices, can satisfactorily reduce the risk of adverse impacts from such leachate.

HYDROELECTRIC PLANT IMPACTS

Only existing hydroelectric plants are included in the final strategies analyzed. The land-related environmental impacts of hydroelectric plants are discussed below.

Site Effects

Of necessity, hydroelectric plants are located at dams. Their actual plant "footprint" is typically small. In most instances, little land is consumed except for transmission facilities (e.g., switchyards), maintenance areas, and parking areas. Their visual impact is minimal, since hydroelectric generating facilities are incorporated into the dam structure. Because no new hydroelectric facilities would be built under any of the strategies considered, there would be no additional site effects.

Operational Effects

Hydroelectric facilities produce no waste materials that affect land resources. They also produce low noise levels compared to coal-fired plants. Power generation from these facilities does not have significant effects on land resources.

Fuel Sourcing Effects

For purposes of discussion, water is considered to be the "fuel" used in hydroelectric production. Hydroelectric plants depend on hydrostatic pressure (i.e., the pressure of deep water) to turn generators. This process produces electricity. A reservoir must be created to produce sufficient pressure and have the recharge capacity to maintain adequate depth at the dam.

Covering land with water to create reservoirs removes it from productive use. Typically, these river bottom lands are fertile and constitute productive forest land, farmland, and wetlands. These uses are lost by flooding. See Volume 2, Document 1, Comprehensive Affected Environment, for additional information about effects of damming rivers. Because no new hydroelectric facilities would be built under the strategies considered, there would be no additional "fuel sourcing" impacts from hydroelectric production.

WIND AND SOLAR IMPACTS

Wind is one of the renewable energy resource options included in TVA's final seven strategies. The land-related environmental impacts of wind and solar power are discussed below.

Site Effects

Wind-powered generation facilities usually have a network of windmills feeding a central switchyard. These windmills are typically located on ridge lines, ridge tops, and along bluffs where ambient wind velocities are capable of providing adequate wind power. Such locations are generally visible from a long distance. Thus, the potential for visual impact from new facilities is high.

Solar facilities require large amounts of relatively flat, open areas in order to collect adequate amounts of solar radiation. Depending on location, the visual impact of new solar facilities could be objectionable. Solar facilities produce very little noise and no waste byproducts. Wind and solar power plants do not use any fuels or produce any emissions; therefore, only generation issues are discussed.

Operational Effects

Wind

Wind-powered generation facilities are composed of a number of wind turbines connected to the utility grid system through one or more interconnections. Turbines produce approximately 0.3 megawatts and are arranged one per 1 to 2 acres. Approximately 1,250 acres would be required for a 50-megawatt power plant. Site requirements are highly specific. The best sites feature a minimum 2,000 to 3,000 foot elevation on abrupt, prominent ridges. Two areas in or adjacent to TVA's Northeast Tennessee Service Area (one on the Cumberland escarpment and another near Johnson City) together have potential for 750 megawatts of economically variable wind capacity. A nearby location in southwest Virginia has potential for another 1,250 megawatts of economically viable wind capacity.

Noise may result from wind power plants. It is caused by air moving over the turbine blades (aerodynamic noise) and by the turbine's mechanical components. However, recent blade design changes have substantially reduced aerodynamic noise. In the past, television interference near wind plants occurred when metal components of older wind turbines reflected broadcast TV signals. Composite materials are now used in many turbine components and reflection of television signals has been diminished. Cable signals are not affected by wind turbines.

Wind power plants may impact wildlife populations. Although mammals do not appear to be affected very much, bird fatalities, especially raptors (birds of prey), have been reported at some plant locations. Avian casualties are caused by several factors including electrocution from exposed contacts on the tops of riser poles and collisions with transmission lines, guy wires, and turbines. Steps can be taken to reduce bird fatalities, including capping all exposed terminals on risers.

Strips of trees cannot be used for visual or noise buffering around wind power plants because of the need for a large acreage of open land free of trees. Turbine blades are high enough to allow multiple uses of land at plant sites. Typical uses include farming, ranching, and some forestry activities. Some land is also left as open space. Typically 85 to 95 percent of the site can be used for nonpower-generating activities, depending on the turbine spacing required.

Solar

Solar-photovoltaic power facilities located in North America are most effective in lower-latitude areas with low cloud cover. In the Tennessee Valley, the Memphis region could have suitable sites. Because the best commercial solar cells operate at about 12 percent conversion efficiency, the maximum power available is about 120 watts per square meter. A typical site size would require 0.5 square mile (320 acres) of land area for a 50-megawatt power plant. There is little noise associated with solar-photovoltaic power plants.

NUCLEAR PLANT IMPACTS

Only existing nuclear plants are included in the final strategies analyzed. Environmental impacts of TVA's nuclear plants are discussed in site-specific environmental impact statements and other environmental documents.

Site Effects

No Energy Vision 2020 strategies call for building new nuclear plants. Therefore, there would be no site effects due to new construction. Some options involve converting partially-constructed nuclear plants, but these options would likely result in few additional site-specific effects.

Operational Effects

Operation of TVA's existing nuclear power plants results in several different kinds of impacts. Small quantities of radioactivity are released to the air and water. Minor quantities of heat and non-radioactive wastewater are released to the Tennessee River and major quantities of heat and water vapor can be released to the atmosphere from plant cooling towers. Because of the size of the sites and their locations, noise is typically not a nuisance. However, because cooling towers are visible, they can be aesthetically objectionable.

Waste

Compared to the wastes or byproducts generated by coal-fired energy processes, nuclear generation produces relatively little waste. Nuclear waste storage is not expected to impact additional land area in the Tennessee Valley. Currently, low-level radioactive waste is disposed at a Barnwell, South Carolina, facility. The states participating in the Southeast Compact Commission have selected North Carolina as the host state to design, license, and construct a new disposal site that is scheduled to open in 1998. TVA plans to continue to use the Barnwell facility for low-level radioactive waste disposal until the North Carolina facility is opened. Should either or both of the disposal facilities close unexpectedly, low-level radioactive waste will be stored in on-site facilities at the TVA nuclear plants. These facilities are sized to handle any anticipated storage needs for the foreseeable life of the plants. Operation of TVA's five nuclear units will produce about 115 metric tons of used fuel each year. High level radioactive waste, known as "spent fuel," is stored on-site in pools or dry storage until the Department of Energy (DOE) accepts physical custody. DOE is required by the Nuclear Waste Policy Act to take responsibility for the management and safe disposal of spent fuel that is generated in this country. DOE is to arrange shipment of spent fuel to a monitored retrievable storage facility or to an underground repository for ultimate disposal by burial. The nation's first underground high-level waste repository is not expected to be in operation until at least 2010. Current spent fuel storage capacity is sufficient at Sequoyah until 2004 and at Browns Ferry until 2007. Based on one unit operating at Watts Bar, spent fuel storage capacity will be sufficient until 2018. Several technologies are available to extend the on-site storage lives.

There are no technological impediments to the safe transportation and storage of high-level radioactive waste. The feasibility of underground waste repositories has been demonstrated in studies and test projects. Waste repositories can be designed with multiple natural and man-made barriers that ensure radioactivity does not escape into the environment. The National Academy of Sciences, the National Research Council, and the Congressional Office of Technology Assessment have endorsed deep geological repositories for storage of high-level waste. High-level waste can also be transported with minimal risk. Specially-constructed casks are used and various regulatory controls apply to such shipments.

Transmission Line Impacts

LAND USE

Construction of new generating resources at greenfield sites would require additional transmission line facilities. Prior to the decision to construct such facilities, more detailed environmental reviews would be conducted. Absent unusual site conditions, construction of transmission lines typically does not result in significant physical environmental impacts. Most vegetation on rights-of-way is removed, but there is some flexibility in locating rights-of-way and in placing structures so that impacts to sensitive resources can be avoided or minimized. The amount of new land committed to rights-of-way would be reduced by the multiple use of existing transmission line rights-of-way.

The construction of new transmission lines and the installation of energy-efficient electrical appliances could result in exposing additional individuals to EMF. Experts disagree on the potential impacts of EMF exposures. Such impacts could depend in large part on proximity to lines and field strength and would be addressed in site-specific environmental reviews.

RIGHT-OF-WAY MAINTENANCE

Safe operation of transmission line rights-of-way requires control of vegetation height. This involves mechanical cutting or mowing or the use of chemical herbicides. The method selected is determined on a case-by-case basis, taking into consideration factors such as terrain, right-of-way accessibility, type of vegetation, land use, wetland status, and economics.

If chemical control is used, only U.S. Environmental Protection Agency-registered nonrestrictive herbicides and licensed applicators would be used. Any use of herbicides must comply with Environmental Protection Agency label restrictions and TVA guidelines for herbicide applications.

"Danger" trees, those outside the right-of-way but tall enough to threaten the safety of the lines if they were to fall, are also periodically identified and selectively cut.

Estimates of Direct Land Use for All Strategies

Generation options directly affect land use. Impacts are caused by siting of the plant and the construction of transmission lines to connect the plant to the power system. Some plants will have little or no additional land requirements because they are located at an existing site. These include options at the Bellefonte Nuclear Plant, cogeneration options, some option purchase

agreements, hydroelectric improvements, and landfill methane recovery. Other options have varying site requirements that are listed in the table in *Figure T2-33*. Transmission right-of-way requirements vary widely, depending on plant location and the number of different plant sites used for an option. For the sake of simplicity, 0.5 acre per megawatt of capacity was assumed for most options not located at an existing plant site with transmission lines in place.

Two notable exceptions to this assumption are coalbed methane recovery and wind turbines. Coalbed methane may require a network of access roads to install and maintain the gas wells, collection piping, and power plants. The remoteness of the area being utilized, the distance between wells, and the size and distribution of power plants would be the primary factors in the resulting land use. Also, transmission lines would be required to connect the power plants to the TVA power system. For these reasons, 5 acres per megawatt was assumed as a conservative estimate of land use for access and transmission. Wind turbines are typically located in remote regions because the wind resource is best at higher elevations on ridgelines and bluffs. Also, wind turbines have a low power density compared to most generation options, so groups of wind turbines are interconnected to a common switchyard. Based on experience in wind turbine siting, 25 acres per megawatt was used to calculate the total of all types of land use.

The resulting land uses for the options making up each strategy are stated in the table in *Figure T2-33*. Land use estimates range from approximately 10,300 acres for the reference strategy to 62,000 acres for Strategy T, which contains 2,000 megawatts of wind turbine capacity using an estimated 50,000 acres.

Aesthetics

Transmission lines and structures are visually intrusive to most people; therefore, the addition of new transmission lines would be aesthetically impactive. The significance of such impacts would depend on the subjective views of each individual and, in part, on the aesthetic setting of a new line. Aesthetic impacts of power plants are discussed in this section under specific types of fuel.

FIGURE T2-33. **Estimates of Direct Land Use for Plant Siting, Power Transmission, and Plant Access for Each Strategy**

Strategy	Type	Capacity in Year 2020 (Megawatts)	Site Land Use (Acres/Megawatt)	Transmission/Access Land Use (Acres/Megawatt)	Total Land Use (Acres)
D-Reference	Combustion Turbines	5,700	0.05	0.50	3,135
	Combined Cycle - Independent Power Producers	750	1.22	0.50	1,290
	Integrated Gasification - Combined Cycle	3,675	0.40	0.50	3,308
	Combined Cycle	2,820	0.07	0.00	197
	Integrated Gasification - Cascaded Humidified Advanced Turbine	2,100	0.40	0.50	1,890
	Combined Cycle - Cogeneration	175	0.00	0.00	0.00
	Coal - Independent Power Producers	300	1.22	0.50	516
	D Total	**15,520**			**10,336**
J	Bellefonte IGCC Conversion with Coproduct	484	0.00	0.00	0
	Coalbed Methane Recovery	1,000	0.03	5.00	5,030
	Combustion Turbines	5,850	0.05	0.50	3,218
	Hydroelectric Improvements	162	0.00	0.00	0
	Integrated Gasification - Combined Cycle	4,410	0.40	0.50	3,969
	Integrated Gasification - Cascaded Humidified Advanced Turbine	2,100	0.40	0.50	1,890
	Independent Power Producers	1,950	1.22	0.50	3,354
	Landfill Methane Recovery	500	0.00	0.50	250
	J Total	**16,456**			**17,711**

FIGURE T2-33. **Estimates of Direct Land Use for Plant Siting, Power Transmission and Plant Access for Each Strategy** *CONTINUED*

Strategy	Type	Capacity in Year 2020 (Megawatts)	Site Land Use (Acres/Megawatt)	Transmission/Access Land Use (Acres/Megawatt)	Total Land Use (Acres)
M	Coal	1,610	1.22	0.50	2,769
	Coalbed Methane Recovery	1,000	0.03	5.00	5,030
	Combustion Turbines	5,550	0.05	0.50	3,053
	Hydroelectric Improvements	162	0.00	0.00	0
	Integrated Gasification - Combined Cycle	3,675	0.40	0.50	3,308
	Integrated Gasification - Cascaded Humidified Advanced Turbine	2,100	0.40	0.50	1,890
	Landfill Methane Recovery	500	0.00	0.50	250
	Shawnee Fossil Plant Unit 11	168	0.00	0.00	0
	M Total	**14,765**			**16,299**
O	Bellefonte IGCC Conversion with Coproduct	484	0.00	0.00	0
	Coalbed Methane Recovery	1,000	0.03	5.00	5,030
	Combustion Turbines	5,700	0.05	0.50	3,135
	Hydroelectric Improvements	162	0.00	0.00	0
	Integrated Gasification - Combined Cycle	4,410	0.40	0.50	3,969
	Integrated Gasification - Cascaded Humidified Advanced Turbine	2,100	0.40	0.50	1,890
	Independent Power Producers	1,050	1.22	0.50	1,806
	Landfill Methane Recovery	500	0.00	0.50	250
	O Total	**15,406**			**16,080**
Q	Bellefonte IGCC Conversion with Coproduct	484	0.00	0.00	0
	Coalbed Methane Recovery	1,000	0.03	5.00	5,030
	Combustion Turbines	4,800	0.05	0.50	2,640
	Flexible Baseload	289	0.00	0.00	0
	Flexible Peakload	0	0.00	0.00	0
	Hydroelectric Improvements	162	0.00	0.00	0
	Integrated Gasification - Combined Cycle	5,145	0.40	0.50	4,631
	Integrated Gasification - Cascaded Humidified Advanced Turbine	2,520	0.40	0.50	2,268
	Independent Power Producers	300	1.22	0.50	516
	Landfill Methane Recovery	500	0.00	0.50	250
	Peak Power Purchases	900	0.00	0.00	0
	Q Total	**16,100**			**15,335**
R	Bellefonte IGCC Conversion with Coproduct	484	0.00	0.00	0
	Combined Cycle	470	0.07	0.50	268
	Coalbed Methane Recovery	1,000	0.03	5.00	5,030
	Combustion Turbines	4,950	0.05	0.50	2,723
	Flexible Baseload	289	0.00	0.00	0
	Hydroelectric Improvements	162	0.00	0.00	0
	Integrated Gasification - Combined Cycle	5,145	0.40	0.50	4,631
	Integrated Gasification - Cascaded Humidified Advanced Turbine	2,520	0.40	0.50	2,268
	Independent Power Producers	300	1.22	0.50	516
	Landfill Methane Recovery	500	0.00	0.50	250
	Peak Power Purchases	900	0.00	0.00	0
	R Total	**16,720**			**15,685**

FIGURE T2-33. **Estimates of Direct Land Use for Plant Siting, Power Transmission and Plant Access for Each Strategy** *CONTINUED*

Strategy	Type	Capacity in Year 2020 (Megawatts)	Site Land Use (Acres/Megawatt)	Transmission/Access Land Use (Acres/Megawatt)	Total Land Use (Acres)
S	Bellefonte IGCC Conversion with Coproduct	484	0.00	0.00	0
	Coalbed Methane Recovery	1,000	0.03	5.00	5,030
	Combustion Turbines	5,850	0.05	0.50	3,218
	Hydroelectric Improvements	162	0.00	0.00	0
	Integrated Gasification - Combined Cycle	4,410	0.40	0.50	3,969
	Integrated Gasification - Cascaded Humidified Advanced Turbine	2,520	0.40	0.50	2,268
	Independent Power Producers	1,050	1.22	0.50	1,806
	Landfill Methane Recovery	500	0.00	0.50	250
	S Total	**15,976**			**16,541**
T	Bellefonte IGCC Conversion with Coproduct	484	0.00	0.00	0
	Compressed Air Energy Storage	1,011	0.04	0.50	546
	Coal	710	1.22	0.50	1,221
	Coalbed Methane Recovery	1,000	0.03	5.00	5,030
	Combustion Turbines	4,800	0.05	0.50	2,640
	Hydroelectric Improvements	162	0.00	0.00	0
	Integrated Gasification - Cascaded Humidified Advanced Turbine	1,260	0.40	0.50	1,134
	Independent Power Producers	450	1.22	0.50	774
	Landfill Methane Recovery	500	0.00	0.50	250
	Repowering Existing Coal-Fired Plants	5,170	0.07	0.00	362
	Shawnee Fossil Plant Unit 11	168	0.00	0.00	0
	Wind Turbines	2,000	5.00	20.00	50,000
	T Total	**17,715**			**61,957**

Injuries, Accidents, and Illnesses

There can be accidental injuries, deaths, and illnesses, both occupational and non-occupational, associated with power system activities. These activities include the direct effects of constructing and operating power system facilities and indirect effects from activities such as fuel procurement and its transportation. Accidental injury or death to the public (non-occupational) from power facility construction or operation are especially unlikely because the public is isolated from these facilities, which are generally secured from public access. One exception is boating and other water recreation near hydroelectric facility discharges where the public must take precautions and heed warnings to avoid unnecessary risk. The risk of accidental injuries and deaths and illnesses are examined for TVA's nuclear plants and pumped storage facilities in site-specific environmental impact statements (TVA 1971, 1972, 1974, 1976).

As decisions are made to add resources to the power system, project-specific environmental reviews will examine these issues to ensure that mitigation measures are considered. Because all strategies expand the power system to meet anticipated increases in power demand and energy use, it is reasonable to conclude that there may be some increase in accidental injuries, deaths, and illnesses.

SECTION 6: ENVIRONMENTAL EVALUATION OF THE PREFERRED PORTFOLIO ALTERNATIVE

Rather than selecting a discrete strategy as its long-term energy plan, TVA has identified as its preferred alternative a portfolio approach. The options in this portfolio are the options identified in the final strategies that TVA developed during the IRP process. In addition, several other options that respond particularly well to certain possible future events ("uncertainties") have been included in the portfolio. TVA believes that this portfolio approach will better achieve TVA's goals and the Energy Vision 2020 criteria than any discrete strategy.

Rationale for Portfolio Approach

After carefully analyzing 2,000 long-term energy resource strategies, TVA used the multi-attribute tradeoff technique to identify seven strategies that achieve reasonably well all of the Energy 2020 criteria, including environmental criteria. The mix of energy resource options in these seven strategies help mitigate the potential adverse environmental impacts associated with meeting the energy needs of the TVA region and result in comparably low environmental impacts.

One approach that TVA could use is to choose one of these strategies as its long-term energy plan and proceed to implement it. As events unfold, elements of the plan would be revised to account for the events (for example, an unexpected rapid increase in natural gas prices). Options in the plan would be Implemented differently than initially contemplated in the plan, or other options would be substituted for those in the plan that were better able to respond to the new event.

One of the important conclusions that TVA has reached in Energy Vision 2020 is that no strategy is likely to be robust enough to adequately respond to all of the uncertain events of the future. The world has become too uncertain. Competition in the utility industry is likely to produce far-reaching changes. Events will happen that will require changes in a chosen, discrete strategy.

This explains the importance of another conclusion that TVA reached in Energy Vision 2020. Flexibility is the key to responding to future uncertainties. The ability to alter long-term plans as events unfold (the definition of flexibility) will be critical. The final seven strategies provide hedges against key uncertainties and this allows TVA to better manage risk.

A second approach that provides more flexibility than choosing a single strategy is to maintain as many good resource options as possible for as long as possible. This would allow TVA to better respond to future events and needs. TVA's portfolio of resource options contains all of the options that make up the final set of seven strategies, as well as a few other options that respond particularly well to certain uncertainties. Much like a portfolio of stocks is chosen to manage risk and accomplish specific objectives, the portfolio approach to energy resource planning enables TVA to meet customer needs while hedging risks and balancing costs, rates, environmental impacts, debt, and economic development.

(In the broadest sense, the portfolio approach is itself a strategy. However, unlike a traditional, discrete Energy Vision 2020 strategy, TVA would not be purporting to decide to implement all of the options in the portfolio if it chooses the portfolio approach. The Short-Term Action Plan discusses the specific actions TVA will be taking in the short-term. The specific options that would actually be implemented from the portfolio would depend on future events, and would be decisions that are made later.)

Analysis of Impacts

The Energy Vision 2020 evaluation was summarized beginning on page 1 of this document. Because of the nature of the evaluation process (how strategies were developed, modified, and reanalyzed), the final seven strategies share many common characteristics, especially environmentally-important characteristics. These strategies and their potential environmental impacts are described in detail earlier in this document.

Because they share many important environmental characteristics, all of the final strategies, except Strategy T, have very similar potential environmental impacts. Strategy T would perform noticeably better environmentally than the other six strategies, except for potential land resource impacts. It has the lowest (best) air and water indices in all seven environmental impact categories. This occurs primarily because some of TVA's existing coal-fired units would be repowered with natural gas under this strategy and natural gas has fewer environmental impacts

than coal. How TVA's existing coal-fired plants are operated in the future under each strategy largely dictates how well the strategies perform environmentally.

The other important strategy presented in detail in Energy Vision 2020 is the reference strategy (TVA's "No Action" strategy, Strategy D). This strategy assumes a typical coal-based expansion of the TVA system to meet future energy needs. Because it relies heavily on coal, it would have worse air quality impacts and worse or only slightly better water quality impacts compared to any of the other final strategies.

The potential impacts associated with the portfolio approach (TVA's preferred alternative) depend on which resource options are eventually implemented, when they are implemented, and how they are implemented. Future events will dictate this. Prior to implementation of resource options, for the future, any needed additional environmental reviews would be conducted. At the implementation stage, TVA will be able to identify potential impacts on a site-specific basis, if appropriate.

Although the impacts of the portfolio approach cannot be assessed definitively at this time, the impacts identified for the final seven strategies likely bound those impacts. Because the portfolio contains all of the options that make up TVA's best seven discrete strategies, it is highly unlikely that implementation of the portfolio approach would achieve better or worse environmental performance than these discrete strategies. At best, implementation of the portfolio approach would produce the same environmental results as Strategy T if future events led TVA to deploy only the options contained in that strategy. At worse, the portfolio approach would have the worst environmental impacts associated with the other six final strategies.

All of the final strategies are expected to generally perform better environmentally than the reference, or "No Action," strategy. Unlike the seven best strategies, the "No Action" Strategy (Strategy D) was not formulated to achieve the best possible results across the Energy Vision 2020 criteria. Consequently, Strategy D performs poorly on a number of criteria, including environmental concerns. Because Strategy D contains resource options that have worse environmental impacts than the resource options contained in the portfolio, it is highly unlikely that implementation of the portfolio would produce impacts that are worse than those that would result from Strategy D.

In conclusion, the potential environmental impacts of TVA's preferred alternative (the portfolio approach) would likely be somewhat worse than those identified for Strategy T but would be no worse than those impacts identified for the other six final strategies. In all likelihood, the portfolio approach would perform better (probably much better) environmentally than Strategy D for most impacts. However, the subsequent environmental reviews that will be done at the implementation stage will more definitively identify potential impacts. The TVA decision-makers and the public can consider these impacts before implementation decisions are made.

Environmental Control Options

TVA's Energy Vision 2020 also addresses the potential environmental impacts of alternative environmental control strategies (the ways TVA could comply with Phase 2 sulfur dioxide acid rain control requirements of the Clean Air Act Amendment of 1990 and achieve greenhouse emission goals). The proposed portfolio of options contain a number of control options that could be implemented to achieve these specific environmental objectives.

The environmental control options contained in the portfolio include fuel switches, sulfur dioxide scrubbers, natural gas repowering, system improvements, and biomass cofiring. The actual implementation of specific control options depend on a number of factors that are specific to the issue of environmental controls. This includes such things as the price of sulfur dioxide emission allowances in the future, the enactment of new environmental legislation, and the promulgation of control-related environmental regulations.

Implementation of specific control options also depends in part on the energy resource options that are eventually implemented. As indicated in *Figure 9-3*, Volume 1, Chapter 9, environmental control options vary somewhat across the final seven strategies because the energy resource mix varies somewhat, particularly in Strategy T. For example, the repowering of several existing coal units with natural gas, which is an option in Strategy T, would obviate the need to add scrubbers at several existing units.

As with the process of implementing energy resource options, the implementation of specific environmental control options would be preceded by appropriate environmental reviews. These reviews would examine the site-specific impacts of proposed control.

SECTION 7: RELATIONSHIP BETWEEN PRODUCTIVITY AND RESOURCES

Relationship Between Local Short-Term Uses of the Environment and Enhancement of Long-Term Productivity

The adoption and implementation of a long-term energy resource strategy would have various short- and long-term consequences. These depend in part on the actual energy resource options that are implemented. Site-specific or option-specific environmental reviews will be conducted before final decisions are made to use certain resources and will examine potential environmental consequences in more detail.

In both the short and long term, TVA would continue to generate electric energy to serve its customers and the public. The availability of electric energy will continue to sustain the economic well-being of the region and allow it to grow. Although the demand for electricity has slowed from the 7 percent annual increases experienced in the 1960s and the early 1970s, customers in both the TVA region and nationally continue to add more electric appliances and equipment to their homes and businesses. Some of these energy uses can be met with alternative sources, such as natural gas, but most require electricity. Electricity has contributed and will continue to contribute to the enhancement of the quality of life in the Tennessee Valley both in the short and long term.

However, the production of electric energy may have both short- and long-term environmental impacts. In the short term, the public may be exposed to elevated concentrations of various air pollutants that are emitted by coal-fired power plants or radioactive releases from nuclear units. The operation of hydroelectric units can release water with low-dissolved oxygen and produce conditions detrimental to aquatic life. Other examples of potential short-term impacts are identified in this document.

Potential long-term impacts have also been identified in the environmental consequences sections of the document. These include potential decreases in the productive capacity of some agricultural lands, degradation of some building materials, and possible adverse effects on forest health. The exposure of some members of the public to certain air pollutants and electric and magnetic fields (EMF) may also have long term, adverse health consequences. Continued generation of nuclear waste will require that waste be stored safely for an indefinite period. This will require that some location or locations be devoted to long-term nuclear waste storage.

Irreversible and Irretrievable Commitments of Resources

The continued generation of electricity by TVA will irreversibly consume various amounts of fuels (natural gas, oil, coal, and uranium). Continued maintenance of TVA's existing energy resources and the construction of any new energy resources will irreversibly consume certain amounts of energy and materials. The siting of most new energy resources will essentially irretrievably commit the sites used to an industrial use because of the substantial disruptions to the sites that would occur and the relative permanence of the structures themselves. The continued generation of nuclear power will produce nuclear waste; therefore, some site or sites will have to be devoted to the safe storage of such wastes. Any such site would essentially be irretrievably committed to long-term storage of nuclear waste.

A number of resource options included in TVA's preferred portfolio strategy are demand-side management and renewable energy resources such as wind or landfill or coalbed methane. Reliance on these resources would lessen the irreversible commitment of other energy fuel sources, but would still involve the irreversible commitment of materials and sites to such resources.

SECTION 8: MITIGATION OF ADVERSE ENVIRONMENTAL AND UNAVOIDABLE IMPACTS

TVA will mitigate site-specific environmental impacts from the construction and operation of new power facilities through a combination of planning, pollution prevention, and environmental controls. However, one of the most important mitigative measures associated with Energy Vision 2020 is the multi-attribute tradeoff method used for the evaluation. This method allowed proposed strategies to be reformulated in order to reduce potential impacts.

Planning

Planning allows assessment (and possible avoidance) of direct construction impacts of the site, community infrastructure, environmental justice, and local economy. An effective planning analysis requires detailed and comprehensive knowledge about the natural resources, infrastructure, economy, and demographics in and around the site. These are the same factors that would be assessed for an environmental review under the National Environmental Policy Act. The table in *Figure T2-34* contains a partial listing of factors and information requirements in these two areas. Population growth and demographic changes, expected urbanization, and/or industrialization in the vicinity of a proposed site would also be considered.

Site selection can affect both temporary construction impacts and the long-term, cumulative impacts of operation. Also, the extent of the impacts requiring mitigation can be controlled and reduced. The site screening and selection process used by TVA evaluates the natural resources and socioeconomic factors both in the immediate plant site vicinity and the larger area of influence of the plant. The area of influence for the plant would be governed by:

- Extent of air pollutant fate and transport at non-negligible concentrations
- Extent of water effects due to thermal rejection and wastewater effluents
- Extent of fuel procurement and use of transportation modes
- Other similar factors that occur off-site

These planning data allow assessment (and possible avoidance) of direct construction impacts on the site, community infrastructure impacts, environmental justice effects, and effects on

FIGURE T2-34. **Environmental Planning Factors and Information Required for Mitigation Analysis**

Plant Site and Vicinity	Area of Influence
NATURAL RESOURCES	NATURAL RESOURCES
• Hydrogeologic Survey	• Survey of Terrestrial and Aquatic Life
• Meteorology	• Threatened and Endangered Species
• Ambient Air Quality	• Sensitive Habitat/Important Ecosystems
• Water Resources	• Air Quality Data
• Water Quality	• Meteorological Data
• Survey of Terrestrial and Aquatic Life	• Fuel Availability
• Threatened and Endangered Species	
• Sensitive Habitat/Important Ecosystems	
• Prime Farm Land	
• Wetlands	
• Recreation Resources	
• Cultural Resources Survey	
• Aesthetic Resources	
• Ambient Noise	
SOCIOECONOMIC	SOCIOECONOMIC
• Population Demographic	• Population Demographic
- Age, Race, Sex, etc.	- Age, Race, Sex
- Income	- Infrastructure
• Infrastructure	- Transportation
- Transportation	• Economy
- Housing	
- Solid Waste Disposal	
- Wastewater Treatment	
- Other Utilities, Fire, Police, etc.	
• Economy	

the local economy. Proper planning can play an important role in minimizing long-term receptor exposure and the potential cumulative effects of air and water pollutants.

Pollution Prevention

Pollution prevention results from process design. That is, the selection of fuel type, energy conversion technology, and other plant features provides inherent pollution reduction. For example, some fuels such as hydro, wind, and solar have no direct air pollution. The final seven strategies continue the use of regional hydroelectric resources, and one strategy makes significant use of wind energy. Other fuels such as natural gas offer little potential for emission of some pollutants such as metals and sulfur dioxide. Energy conversion cycles that require wet cooling towers to be economical must address concentration and disposal or discharge of water pollutants as cooling tower recirculation water discharge or cooling pond concentration. Other technologies may have no such potential for pollution.

Increased process efficiency reduces fuel requirements and offers inherent reductions in all related waste streams since less fuel is consumed for a given amount of electric energy produced. Energy Vision 2020 evaluated a wide range of efficient thermodynamic cycles including combined cycle, integrated gasification combined cycle, and integrated gasification with cascaded humidified advanced turbine, all of which were resource options in the final seven strategies.

Efficiency through load conservation (demand-side management) also reduces the fuel use and related pollution because of reduced electric production requirements. A number of demand-side management programs are a feature of the final Energy Vision 2020 strategies.

Environmental Controls

Environmental controls have commonly been used on new and existing plants to meet regulatory standards that protect human health and the environment. The most prominent use of controls are for air pollution and waste heat release into surface water. Air pollution controls in particular have been costly to construct and operate and have either reduced plant efficiency or have significant power requirements themselves. Cooling towers prevent thermal release to surface waters but have cost and operational penalties, as well as wastewater effluent. Nevertheless, these controls are effective mitigation measures that can be engineered to meet regulatory requirements.

Adverse Environmental Effects That Cannot Be Mitigated

The mere adoption of a long-term energy strategy has no adverse environmental effects, but the implementation of that strategy would. The nature and potential significance of the environmental effects will depend on the energy resource options eventually implemented under the strategy. However, there are resource options that are common in each strategy, including TVA's portfolio strategy, and these have associated adverse effects that cannot be realistically avoided.

Under every strategy, TVA would continue to operate most of its existing energy resources (its coal-fired units, nuclear units, hydroelectric units, combustion turbines, and hydroelectric pumped storage units). The operation of these units can result in the release of various air and/or water pollutants, depending on the kind of unit. Although the emissions and discharges from electric generating units are relatively well-controlled, certain residual emissions and discharges will continue to be released from TVA's existing units for the duration of Energy Vision 2020. As has been discussed, these residual emissions and discharges can contribute to a variety of environmental impacts such as visibility impairment, acid rain, crop and forest impacts, or low-dissolved oxygen. The operation of coal-fired and nuclear units will continue to expose adjacent populations to small residual quantities of radioactivity and other toxic pollutants.

The implementation of new generating resources would unavoidably result in a change in land use unless new resources are located at existing generating sites. The conversion of land from a non-industrial use to an industrial use will either unavoidably result in the loss of agricultural capabilities or the destruction of wildlife habitat.

The generation and transmission of electric energy unavoidably produces electric and magnetic fields (EMF). Although the health significance of EMF exposures is uncertain, such exposures could have adverse health consequences.

SECTION 9: ENVIRONMENTAL CONSULTATION, REVIEW, AND PERMIT REQUIREMENTS

A number of environmental consultation, review, and permit requirements would apply to the energy resource options that TVA eventually implements. The nature of these requirements vary depending on the kind of option. Fairly substantial requirements would apply to the more environmentally impactive options. This has the effect of substantially reducing the potential significance of impacts and protecting human health and other environmental values. Many of these requirements have associated opportunities for public review and comment. The following identifies and briefly discusses the more important requirements.

National Environmental Policy Act

The National Environmental Policy Act (NEPA), 42 U.S.C. 4321 et seq., requires all federal agencies, including TVA, to consider the potential environmental impacts of proposed actions before deciding whether to proceed with the actions. Under TVA's National Environmental Policy Act procedures and the regulations promulgated by the Council on Environmental Quality, there are three levels of environmental review: (1) categorical exclusions, (2) environmental assessments, and (3) environmental impact statements (EIS). The significance of the potential impacts associated with a proposed action dictate which of these types of review are to be used. Analysis become more detailed and public involvement more extensive as an agency moves from a categorical exclusion review to an environmental impact statement. Energy Vision 2020 has been prepared as both an integrated resource plan and an environmental impact statement. Actual implementation of options identified in the plan would be "tiered" off of Energy Vision 2020 and, as appropriate, would be preceded by more site-specific National Environmental Policy Act reviews.

Air Pollution Reviews

All of the states in which TVA operates require potential major sources of air pollution to obtain construction and operating permits. A major source is generally a source that emits 100 tons or more of pollutant but smaller sources can be major sources if they are located in a nonattainment area (an area that does not comply with a National Ambient Air Quality Standard) or if they emit hazardous air pollutants. Depending on the kind of source, its location, and the pollutants it emits, the source would be required to employ the best available control technology to reduce its potential emissions or even more stringent controls. Other requirements also can apply, such as the need to offset emissions (obtain a better than one-to-one reduction from existing sources) in some areas. The U.S. Environmental Protection Agency (EPA) has the opportunity to review and comment on permits for proposed sources, and there are usually multiple opportunities for public review and comment.

Wastewater Discharge Reviews

All of the states in which TVA operates require potential dischargers of wastewater to obtain a National Pollutant Discharge Elimination System (NPDES) stormwater permit before site preparation and construction activities can commence. A National Pollutant Discharge Elimination System permit must also be obtained for the direct discharge of pollutants to surface waters during facility operation. National Pollutant Discharge Elimination System permit limits are set to protect water quality and water uses. The Environmental Protection Agency has an opportunity to review and comment on proposed permits, as does the general public.

Solid and Hazardous Waste Management

A number of local, state, and federal laws and regulations govern how solid and hazardous wastes are to be managed. Typically, before solid waste can be disposed of on a plant site, state solid waste disposal permits must be obtained. This permitting process controls the design, monitoring, operation, and closure of disposal areas. The requirements for management of hazardous waste are even more stringent. Hazardous waste is regulated from "cradle to grave" (from the point of generation to ultimate treatment or disposal). During the permitting of solid or hazardous waste disposal sites, the public typically has one or more opportunities to comment.

Protection of Wetlands and Floodplains

Because of their biological value, wetlands receive special protection under federal law. Before most wetlands can be disturbed, a permit must be obtained from the U.S. Army Corps of Engineers under Section 404 of the Clean Water Act. The Environmental Protection Agency and the public typically have opportunities to review and comment on proposed permits. As part of the permitting process, the pertinent state is asked to determine whether the proposed action would violate state water quality standards. Federal agencies are required to avoid impacting wetlands with new construction to the extent practicable and to otherwise minimize potential wetland impacts under Executive Order No. 11990 (Protection of Wetlands). Federal agencies are also directed to avoid occupying or modifying floodplains to the extent practicable and to otherwise minimize potential impacts to floodplain values under Executive Order No. 11988 (Floodplain Management).

Endangered Species

Under the Endangered Species Act, 16 U.S.C. 1536 et. seq., federal agencies are to ensure that their actions are not likely to jeopardize the continued existence of any endangered or threatened species or adversely modify any critical habitat of such sensitive species. If a proposed action may affect one of these species, the agency must consult with the U.S. Fish and Wildlife Service and obtain that agency's determination of the potential for impacting these species.

Cultural Resources

A number of federal laws protect cultural and archaeological resources, including the National Historic Preservation Act and the Archaeological Resources Protective Act. Before disturbing cultural and archaeological resources that have historical significance, an agency is required to consult with the State Historic Preservation Officer and in some circumstances, the Federal Advisory Council on Historic Preservation.

Farmland Protection

Under the Farmland Protection Policy Act, federal agencies are required to identify and take into account potential adverse effects of a proposed action on farmlands. Typically, analysis and review are undertaken as part of a National Environmental Policy Act review.

Other Review and Permit Processes

A number of other review and permit processes may be important, depending on the nature of the proposed option and its potential environmental effects. These include reviews under or involving:

- Structures in navigable waters (Rivers and Harbors Act of 1898)
- The Safe Drinking Water Act
- The licensing and monitoring of nuclear facilities (Atomic Energy Act)
- The Toxic Substances Control Act
- The Noise Control Act
- The Federal Insecticide, Fungicide, and Rodenticide Act
- The Comprehensive Environmental Response, Compensation, and Liability Act

Although the actual implementation of an energy resource could require the approval and involvement of other federal or state agencies, the selection of an energy resource plan, which is programmatic in nature, does not have review or consultation requirements. The selection of an energy resource plan for TVA is left to the discretion of TVA's Board of Directors.

SECTION 10: RELATED ENVIRONMENTAL DOCUMENTS

The following documents are related to TVA's Energy Vision 2020 planning process. They can be found in TVA's Corporate Library.

Final Environmental Impact Statement, Bellefonte Nuclear Plant Units 1 and 2, Volumes 1 and 2, 1974.

Final Environmental Impact Statement, Browns Ferry Nuclear Plant Units 1, 2, and 3, 1974.

Final Environmental Impact Statement, Policies Relating to Electric Power Rates, 1974.

Final Environmental Impact Statement, Policies Relating to Sources of Coal Used by the Tennessee Valley Authority for Electric Power Generation, 1971.

Final Environmental Impact Statement, TVA Raccoon Mountain Pumped Storage Project, 1976.

Final Environmental Impact Statement, Sequoyah Nuclear Plant Units 1 and 2, 1971.

Final Environmental Impact Statement, Tennessee River and Reservoir System Operation and Planning Review, 1990.

Final Environmental Impact Statement, Watts Bar Nuclear Plant Units 1 and 2, 1972.

Final Supplement 1 to NUREG-0439, Final Environmental Impact Statement related to the operation of Watts Bar Nuclear Plant Units 1 and 2, (Nuclear Regulatory Commission, April 1995) (Adopted by the Tennessee Valley Authority, June 1995).

Supplemental Environmental Review (Final), Operation of Watts Bar Nuclear Plant Units 1 and 2 (Tennessee Valley Authority, June 1995).

Glossary

The development of Energy Vision 2020, using TVA's interactive planning process, requires the careful, consistent use of certain key terms and phrases. Below are definitions of terms used often in Volume 2, Technical Document 2, Environmental Consequences. (Terms in definitions which are themselves defined in the Glossary are printed in *italics.*)

A

Acid Deposition—The wet or dry deposition of acid chemical compounds from the atmosphere.

Aerosol—A gaseous suspension of ultramicroscopic particles of a liquid or a solid.

Aesthetics—The perception or appearance of visual features in relation to the sense of beauty.

Air Toxins—Various man-made and naturally occurring materials that are known or suspected of causing serious public health impacts, but for which no *National Ambient Air Quality Standards* exist.

Ambient—Surrounding.

Ambient Air Quality Standards—National standards set by the U.S. *Environmental Protection Agency* that are permissible concentration levels of certain pollutants (new *ozone, carbon monoxide, particulates (PM 10), sulfur dioxide, nitrogen dioxide,* and *lead*) in the *ambient* air.

Aquatic—Characteristic of and/or pertaining to water.

Archaeological Resources—Material remains of past human activity.

Ash—The noncombustible component of coal or other fuels.

Attainment Areas—Those areas that meet all *National Ambient Air Quality Standards* as determined by monitoring of air pollutant levels.

B

Benthic Invertebrates—An animal lacking a backbone or spinal column and living on lake bottoms.

Benthos—Organisms that live on or in the first few inches of mud, sand, gravel, or other materials that make up the bottom of streams and lakes, e.g. worms, snails, crayfish, mussels, clams.

Biomass—Organic material. Often involves the harvesting of stands of close-growing whole trees, truck transport, tree storage, and drying using air heated by boiler *flue gas* and combustion of whole trees in a special deep-bed burner at the bottom of the furnace.

Biomass Cofiring—The use of *biomass* as a secondary fuel supplement in a coal-fired plant.

BLN—Bellefonte Nuclear Plant

Bottom Ash—Heavier ash (noncombustible component of coal or other fuels) that settles in the bottom of the boiler rather than being carried out with *flue gas.*

C

Carbon Dioxide (CO_2)—A colorless, odorless, nonpoisonous gas that results from fossil fuel combustion and is normally a part of the *ambient* air. Increasing levels of carbon dioxide in the atmosphere are contributing to the *greenhouse effect.*

Carbon Monoxide (CO)—A colorless, odorless, poisonous gas produced by incomplete fossil fuel combustion.

Cascaded Humidified Advanced Turbine (CHAT)—An advanced Ericson cycle that employs intercooling, recuperation, reheat, and humidification of a combustion *turbine* with a cascaded topping *turbine.*

CHAT—*Cascaded Humidified Advanced Turbine.*

Class I Areas—Areas designated by the Prevention of Significant Deterioration section of the *Clean Air Act Amendments of 1977* that includes national parks and wilderness areas, providing special protection for air quality and air quality-related values.

Clean Air Act Amendments of 1970—Enabling legislation which instructs the *Environmental Protection Agency (EPA)* to set air quality standards for pollutants of concern.

Clean Air Act Amendments of 1977—Legislation that provides greater regulatory authority and sets specific provisions to protect national parks and wilderness areas designated as *Class I areas.*

Clean Air Act Amendments of 1990—Legislation that adds additional regulatory authority to enforce compliance in *non attainment areas.* Also sets new requirements for *acid rain, hazardous air pollutants,* and monitors and reports air *emissions.*

Coal Gasification—Process of converting coal into gas.

Coal Plant—A generation plant using coal as its main source of *energy*.

Coalbed Methane—A gas that is present in all coal seams throughout the United States.

Cogeneration—The sequential production of electricity and useful thermal *energy* (generally steam or hot water) from a single fuel source.

Coproduction—A secondary product that is produced usually in an industrial process in addition to the primary product.

Cradle-To-Grave—System including the generation (e.g., mining), transportation, storage, treatment, and disposal of a fuel or wastes.

Criteria—Measuring rods used in integrated resource planning. They are derived from issues or concerns. Examples include concerns over future rates, acceptable levels of environmental impacts, etc.

Cultural Resources—Any prehistoric or historic district, site, building, structure, or object that may yield information regarding past human endeavors.

D

Delta—In load forecasting, the increase or decrease in the forecast sales caused by the high or low levels of any of the assumptions in the forecast.

Demand—The amount of electric *energy* used at a specific point in time, measured in watts (or multiples thereof, such as *KW, MW,* or *GW*). Demand is measured for individual customers, for groups or classes of customers, and for TVA's system as a whole.

Demand-Side Management (DSM)—Activities which influence electricity use on the customer's side of the meter. Examples include home weatherization, use of compact fluorescent lighting, etc.

DSM—*Demand-Side Management.*

E

Ecosystem—Any unit that includes all organisms (i.e., the community) in a given area interacting with the physical environment. The flow of energy leads to a clearly defined trophic structure, biotic diversity, and material cycles (i.e., exchange of materials between living and nonliving parts within the system).

Effects—These include: (a) direct effects caused by an action and occur at the same time and place; (b) indirect effects caused by an action and are later in time or further removed in distance, but still reasonably foreseeable. Effects and impacts as used in this document are synonymous.

Effluent—Wastewater—treated or untreated—that flows out of a treatment plant, sewer, or industrial outfall. Generally refers to wastes discharged into surface waters.

EIS—Environmental Impact Statement.

Electric and Magnetic Fields (EMF)—Two types of energy fields which are emitted from any device that generates, transmits, and uses electricity.

EMF—*Electric and Magnetic Fields.*

Emission—Pollution discharged into the atmosphere from smokestacks, other vents, and surface areas of commercial or industrial facilities; from residential chimneys; and from motor vehicle, locomotive, or aircraft exhausts.

Endangered Species—Any biotic species formally listed as in danger of extinction throughout all or a significant portion of its range.

Energy—The amount of power consumed over a period of time, measured in watt hours, *kWh, MWh, or GWh.*

Environmental Mitigation—Making environmental pollutants less severe.

Environmental Protection Agency (EPA)—A federal agency established to permit coordinated and effective governmental action for protection of the environment by the systematic abatement and control of pollution through integration of research monitoring, standard setting, and enforcement activities.

F

Flexible Option—An option that can be altered or modified in accordance with TVA needs.

Flexible Strategy—A combination of options that can be easily altered over time to meet TVA's power needs.

Flexibility—The degree to which resource decisions can be changed over time as events unfold and near-term futures become more clearly known.

Flue Gas—Gaseous combustion products from a furnace or boiler.

Fly Ash—The small ash particles that are carried out of a combustor with the existing flue gas. These particles are collected by appropriate equipment prior to discharging the flue gas to the atmosphere.

Fossil Fuel Plant—A plant using coal, oil, natural gas or other fossil fuel as its source of energy.

Fuel Cell—A cell that converts chemical *energy* directly into electrical *energy*, with electric power being produced as a part of a chemical reaction between the electrolyte and a fuel such as kerosene or industrial fuel gas.

G

Gas-fired Combined Cycle—A generating unit consisting of a combustion *turbine* generator and a steam turbine-generator. The primary fuel will be natural gas.

Geographic—Belonging to or characteristic of a particular region.

Gigawatt (GW)—An amount of electric power equal to 1,000 *MW*, or 1 billion watts.

Gigawatt hour—GWh, an amount of *energy* equal to 1,000 MWh, or 1 billion watt-hours.

Greenhouse Effect—The build-up of *carbon dioxide* or other trace gases that allows light from the sun's rays to heat the Earth but prevents a counterbalancing loss of heat.

Greenhouse Gas Emissions—A gas whose presence in the upper atmosphere contributes to the *greenhouse effect* by allowing visible light to pass through the atmosphere while preventing heat radiating back from the Earth from escaping. Greenhouse gases from human produced sources include *carbon dioxide, nitrous oxide,* methane, and *chlorofluoro-carbons* (*CFCs*). There also are even larger quantities of naturally occurring greenhouse gases, notably *ozone* and water vapor, whose concentrations may be affected by interactions with atmospheric pollutants.

Groundwater—Water within the Earth or geologic stratum that supplies wells and springs.

GW—Gigawatt, an amount of electric power equal to 1,000 *MW*, or 1 billion watts.

GWh—Gigawatt hour, an amount of *energy* equal to 1,000 *MWh*, or 1 billion watt-hours.

H

Habitat—The total environmental conditions on a unit of land including food, cover, and water within the home range.

Hazardous Waste—A byproduct of society that can pose a substantial or potential hazard to human health or the environment when improperly managed. Possesses at least one of four characteristics (ignitability, corrosivity, reactivity, or toxicity) or appears on special *Environmental Protection Agency* lists.

Herbicide—Any substance or mixture of substances intended to prevent the growth of or destroy unwanted plants or vegetation.

Hg—Mercury.

High-Level Waste—Material that is highly radioactive. In a nuclear power plant high-level waste is *spent fuel*.

Historic Site—Cultural sites more than 50 years old.

Hydroelectric Power Generation—The movement of water from a higher to lower elevation. The difference between the two elevations establishes potential *energy* that is used to generate electricity by allowing water to flow through a hydro *turbine*.

I

Independent Power Producer (IPP)—Any person who owns or operates, in whole or in part, one or more new independent power production facilities.

Integrated Gasification Combined Cycle (IGCC)—Integration of a coal gasification plant with a combined cycle plant. A coal gasification plant is a facility that converts coal into a synthetic fuel gas.

Integrated Resource Planning (IRP)—A utility planning process that evaluates *supply-side resources* and *DSM resources* on a level playing field to reliably meet the future *energy* needs of customers.

Integration—As used in this document, integration means combining options to become strategies and uncertainties to become futures. Strategies are combined with futures to create scenarios.

IPP—*Independent Power Producer.*

IRP—*Integrated Resource Planning.*

K

Kilowatt—kW, which is the amount of power equal to 1,000 watts.

Kilowatt-hour—kWh, which is the amount of *energy* equal to 1,000 watt-hours.

KM—Kilometer, unit of length equal to 1,000 meters.

kW—Kilowatt, which is the amount of power equal to 1,000 watts.

kWh—Kilowatt-hour, which is the amount of *energy* equal to 1,000 watt-hours.

L

Lignite—An imperfectly formed coal, usually dark brown and often having woody texture.

Low-Level Waste—Radioactive material that is only slightly or moderately radioactively contaminated. Low-level radioactive waste consists largely of ordinary trash and

other items that have come into contact with radioactive materials.

M

Megawatt—MW, the amount of power equal to 1,000 KW or 1,000,000 watts.

Meteorology—The science dealing with weather and weather conditions.

µg/m³—Micrograms per cubic meter.

Mitigation—Measures taken to reduce adverse impacts on the environment.

Mobile Sources—Transportation air pollution sources, primarily automobiles and trucks.

Monitored Retrievable Storage (MRS)—A temporary (40 years) collection and storage facility for *spent fuel* rods until a permanent waste repository is available.

Multi-Attribute Tradeoff Analysis/ Technique—An approach designed for interactive participation by a group to make dual comparisons among different attributes for many strategies. It provides an open framework for public involvement to investigate different attributes, futures, and strategies.

MW—Megawatt, the amount of power equal to 1,000 KW or 1,000,000 watts.

MWh—Megawatt hour, the amount of power equal to 1,000 kWh or 1,000,000 watt hours.

N

National Ambient Air Quality Standards (NAAQS)—Uniform, national air quality standards established by the *Environmental Protection Agency* that restrict *ambient* levels of certain pollutants to protect public health (primary standards) or public welfare (secondary standards). Standards have been set for *ozone, carbon monoxide, particulates PM (10), sulfur dioxide, nitrogen, nitrogen dioxide,* and *lead.*

Natural Resources—The elements of the natural environment that are evaluated as resources (i.e., water resources, forests).

NEPA—National Environmental Policy Act.

New Construction—Buildings and facilities that are constructed during the current year; it may also include major renovations of existing facilities.

Nitrogen or Nitrous Oxides (NO_X)—A product of combustion by mobile and stationary sources and a major contributor to the formation of *ozone* in the troposphere and *acid deposition.*

Nonattainment Area—A geographic area that does not meet one or more of the *National Ambient Air Quality Standards* for the *criteria* pollutants designated in the Clean Air Act.

O

Off-System Sales—Sales by TVA to utilities outside the TVA service area.

Option—Actions TVA can take to resolve an issue. For example, if TVA forecasts an energy deficit, it has the option to meet it with *DSM* programs or other resources.

Ozone (O_3)—A substance found in the stratosphere and the troposphere. In the stratosphere (the atmospheric layer beginning 7 to 10 miles above the Earth's surface) ozone is a form of oxygen found naturally that provides a protective layer shielding the Earth from ultraviolet radiation. In the troposphere (the layer extending up 7 to 10 miles from the Earth's surface), ozone is a chemical oxidant and a major component of photochemical smog.

Ozone can seriously affect the human respiratory system and is one of the most widespread of all the *criteria* pollutants. Ozone in the troposphere is produced through complex chemical reactions of nitrogen oxides, which are among the primary pollutants emitted by combustion sources; hydrocarbons, released into the atmosphere through the combustion, handling, and processing of hydrocarbon products; and sunlight.

P

Particulate—Minute separate particles.

Peaking Capacity—Capacity that is available for use and used to meet peak load. Such capacity, usually represented by combustion *turbines* and pumped storage, often has low capital costs and high fuel costs, and is designed to operate for relatively short periods of time.

Pesticide—Chemical materials used to control undesirable insects, animals, diseases, vegetation, or other forms of life.

Pulverized Coal—Crushed coal used to fuel a coal plant. Currently the principal electric generation technology in the United States.

R

Reactor Fuel Cycle—The process of extracting fuels, preparing fuel elements and assemblies for use in a reactor, using these elements in reactor operation, recovering radioactive byproducts from *spent fuel,* and reprocessing remaining fissionable material into new fuel elements.

Renewable Resources—Power plants or other generating devices whose fuel source is generally considered to be renewable. These include generators

fueled by biomass, water, photovoltaics, solar, wave, or wind *energy*.

Renewables—Wind, solar, landfill, methane, and biomass (trees and grasses used for fuel).

Repowering—Replacing or adding to the source of power of an existing electric generating station.

S

Scenario—The combining of one *strategy* with one future.

Scrubber—A device that removes *sulfur dioxide* from *flue gas* using lime or limestone.

Seedling—Live trees of commercial species less than 1.0 inch in diameter 4.5 feet above ground that are expected to survive and develop.

Short Rotation Woody Crops—Plants grown on a relatively short rotation schedule for the explicit purpose of harvesting for use in power production.

Slag—Ash that has been melted during the combustion process and then solidified as it is removed from the boiler.

Soil—A dynamic natural medium composed of mineral and organic materials in which plants grow.

Species—A class of individuals having common attributes and designated by a common name.

Spent Fuel—Nuclear fuel that can no longer economically sustain a chain reaction.

Strategy—A combination of *options* intended to fulfill a particular resource goal. For example, an energy deficiency in 2007 might be met with a combination of *supply-side resources* and *DSM* resources.

Streams—A continually, frequently, or infrequently flowing body of water that follows a defined course. The three classes of streams are:

Ephemeral: A channel that carries water only during and immediately following rainstorms. Also known as a "dry wash."

Intermittent: A watercourse that flows in a well-defined channel during the wet seasons of the year, but not the entire year.

Perennial: A watercourse that flows throughout the year or nearly so (90 percent of the time) in a well-defined channel.

Sulfur Dioxide (SO_2)—A heavy, pungent, colorless, gaseous air pollutant formed primarily by the combustion of fossil-fuel plants.

Supply-Side Resource—Resources that meet customer needs by increased production of electricity (e.g. hydro, fossil, nuclear, combustion *turbines*, etc.).

Surface Water—Streams, rivers, ponds, lakes, and man-made reservoirs.

Surrogate Measure—A substitute measure that varies in the same way as the pollutant and environmental effects it represents.

T

Threatened Species—Any species which is likely to become an *endangered species* within the foreseeable future.

Topography—The physical features of a place or region. Commonly refers to land forms and variation in elevation.

TSP—Total suspended *particulate* matter.

Turbine—A machine for directly converting the kinetic and/or thermal *energy* of a flowing fluid (air, hot gas, steam, or water) into useful rotational *energy*.

U

Uncertainties—Issues or concerns that may impact energy resources in the future.

V

Visibility Impairment or Degradation—Visibility Impairment or degradation is usually defined as *aesthetic* damage where the ability to discern form, color, or texture is reduced and therefore the scenic value is also diminished. Or, as stated in 40 CFR 51.30(x), visibility impairment is "...any humanly perceptible change in visibility (visual range, contrast, coloration) from that which would have existed under natural conditions."

Volatile Organic Compounds (VOCs)—Any organic compound that participates in atmospheric photochemical reactions except for those designated by the *Environmental Protection Agency* administrator as having negligible photochemical reactivity.

W

Watershed—The entire area that contributes to a drainage or stream.

Wetland—Area with soils saturated with water during the growing seasons and supporting plants characteristic of wet conditions.

Wind Farm—Groups of wind *turbines*.

Z

Zebra Mussel—A non-native mussel which fouls, among other things, water intake structures.

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Energy Vision

2020

Volume 2, Technical Document

3 Existing Power System

Volume 2, Technical Document 3

Existing Power System

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Existing Power System

Capabilities and Characteristics

TVA's existing power system of 25,600 megawatts is projected to provide 27,995 megawatts of summer net dependable capacity by 2005. Summer net dependable capacity is the amount of generating capacity available to the system after accounting for internal uses. Summer capacity is used because TVA anticipates summer as the most limited season in the future. This is due to a seasonal loss in generating capacity and the continued higher growth rate of summer demand as compared to other seasons.

TVA's generating capacity comes from a mix of generating resources including hydro, coal-fired, combustion turbines, and nuclear plants. *Figure T3-1* shows the projected generating mix for TVA.

This projected capacity takes into consideration generation sources that will be added or modified through 2005. Specifically, TVA will begin generating power from Watts Bar Nuclear Plant Unit 1 and will restart Browns Ferry Nuclear Unit 3 during 1996, adding 1,170 and 1,065 megawatts, respectively. Ongoing hydro modernization projects will result in an additional 360 megawatts available from existing hydro units. The installation of pollution control equipment at some steam plants may reduce generation capacity by approximately 35 megawatts as TVA implements Phase II compliance with the Clean Air Act Amendments. TVA will also see a loss of 72 megawatts due to the sale of steam from the Johnsonville Fossil Plant to a nearby industry.

For the purposes of Energy Vision 2020, the additions and reductions in generation output described in the paragraph above are considered as part of the existing power system, since they are planned for the immediate future.

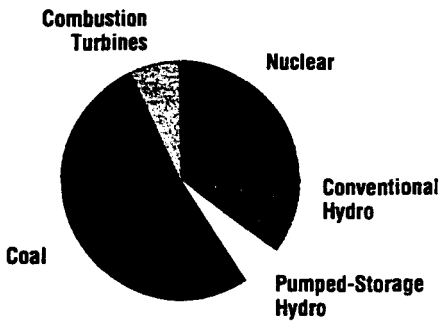
Description of TVA's Generating Resources

TVA'S HYDRO SYSTEM

The TVA hydro system includes 109 conventional hydroelectric generating units and 4 pumped-storage units at Raccoon Mountain. These units are located at 9 main river and 20 tributary plants.

Included with TVA's hydro power capacity is 405 megawatts available from the U.S. Corps of Engineers' facilities through

FIGURE T3-1. **Projected System Capacity in 2005**



	MW	%
Pumped-Storage Hydro	1,532	5
Combustion Turbines	1,952	7
Conventional Hydro	4,404	17
Nuclear	5,517	20
Coal	14,590	51
Total	**27,995**	**100**

This figure shows TVA's generating mix and the percentage supplied by each type of generating resource.

contracts with the Southeastern Power Administration and 321 megawatts available from hydro units owned by Aluminum Company of America and operated by TVA as part of the TVA power system. *Figure T3-2* lists TVA's hydro generating units, including information on location, capacity, years in service, etc.

As noted earlier, TVA's hydro generation capacity will be increased based on ongoing modernization projects. Initial projects will add approximately 360 megawatts of generating capacity and improve efficiency by 3 percent by 2005. Subsequent modernization projects could add 163 megawatts of capacity by 2005

FIGURE T3-2. **Hydro Generating Units**

Hydro Generating Unit	Location	Units	1995 Plant Summer Net Capacity (MW) [1]	Commercial Operation Date	Comments
Appalachia	Polk County, TN	2	76	1943	Tributary
Blue Ridge	Fannin County, GA	1	10	1931	Tributary
Boone	Sullivan & Washington Counties, TN	3	99	1953	Tributary
Chatuge	Clay County, NC	1	10	1954	Tributary
Cherokee	Jefferson County, TN	4	135	1942	Tributary
Chickamauga	Chattanooga, TN	4	130	1940	Main River
Douglas	Sevier County, TN	4	136	1943	Tributary
Fontana	Swain & Graham Counties, NC	3	235	1945	Tributary
Fort Loudoun	Lenoir City, TN	4	140	1943	Main River
Fort Patrick Henry	Sullivan County, TN	2	36	1953	Tributary
Great Falls	Rock Island, TN	2	32	1916	Tributary
Guntersville	Near Guntersville, AL	4	117	1939	Main River
Hiwassee	Cherokee County, NC	2	135	1940	Tributary
Kentucky	Near Paducah, KY	5	183	1944	Main River
Melton Hill	Loudon County, TN	2	75	1964	Tributary
Nickajack	Near Chattanooga, TN	4	96	1967	Main River
Norris	Near Norris, TN	2	100	1936	Tributary
Nottely	Union County, GA	1	17	1956	Tributary
Ocoee #1	Polk County, TN	5	22	1912	Tributary
Ocoee #2	Polk County, TN	2	18	1913	Tributary
Ocoee #3	Polk County, TN	1	27	1943	Tributary
Pickwick	Hardin County, TN	6	240	1938	Main River
South Holston	Near Bristol, TN	1	40	1951	Tributary
Tims Ford	50 miles south of Nashville, TN	1	40	1972	Tributary
Watauga	Near Elizabethton, TN	2	60	1949	Tributary
Watts Bar	Near Spring City, TN	5	179	1942	Main River
Wheeler	Near Town Creek, AL	11	380	1936	Main River
Wilbur	Near Elizabethton, TN	4	11	1912	Tributary
Wilson	Near Muscle Shoals, AL	21	629	1925	Main River
	Total TVA Hydro	**109**	**3,408**		
SEPA	Various		405		
Tapoco			321		
	TOTAL DISPATCHABLE HYDRO		**4,134**		
Raccoon Mountain Pumped-Storage	Near Chattanooga, TN	4	1,532	1978	Pumped-Storage

[1] Based on 1995 SERC IE 411 report.

TVA has 109 conventional hydro generating units located along the Tennessee River and its tributaries.

and have been included as supply-side options for consideration in TVA's integrated resource planning process.

TVA's conventional hydro plants fall into two broad types: main river and tributary. Main river plants are located on the Tennessee River and are generally operated to maintain seasonal lake levels, taking into account recent and predicted rainfall. Tributary plants are located on streams that feed into the Tennessee River and are generally the higher head (vertical change in water elevation) plants located in mountain valleys with deep drawdown possible to provide flood storage capability.

FIGURE T3-3. **TVA's Hydro System**

Hydro System in Fiscal Year	Capacity (MW)	EAF (%)	Total O&M ($/kW)	Total A&I ($/kW)
1994 (Actual)	4,044	97	7.7	13.3 [1]
2005	4,404	97	7.6	6.1

[1] Includes hydro modernization capital expenditures.

Hydro capacity is expected to remain a reliable generating source for TVA, providing 4,404 megawatts with an availability factor of 97 percent.

TVA's hydro facilities are generally operated on five basic considerations:

1. **Flood Control** – In accordance with the TVA Act, the primary responsibility at the dams is flood control.
2. **Environment** – Minimum flow, lake level, and water quality considerations factor into hydro generation.
3. **Power Generation** – In fiscal year 1994, TVA generated or purchased 20.2 billion kilowatt-hours of hydro energy, which represented approximately 15.4 percent of all TVA power generation. In addition to significant power generation, the hydro system is operated to maintain system voltage and provide ready reserve and peaking capability.
4. **Recreation** – System operations are sometimes under constraints to be compatible with white water rafting, fishing, and other recreational activities.
5. **Navigation** – TVA has constructed an extensive system of locks to support river traffic from Paducah, Kentucky to Knoxville, Tennessee. In low rainfall periods, TVA must maintain minimum river levels to support transportation.

Operating reliability is measured by "equivalent availability factor." Equivalent availability factor (EAF) is the ratio of the energy a unit could have generated, if called on, and if sufficient water was available, to the energy the unit would have produced if it had run at full load over the entire period, expressed as a percentage. The hydro system equivalent availability factor for fiscal year 1994 was 97 percent. TVA projects the availability factor for the plants to be 95 percent through 2005 and 97 percent for 2005 through 2020. The drop in availability factor through 2005 is due to the hydro modernization program, which will require that some units be removed from service for refurbishing.

Hydro generation is TVA's lowest cost generation source. Operating and cost features of TVA's hydro generation system, including capacity, equivalent availability factor (EAF), operations and maintenance (O&M) cost, and additions and improvements (A&I) costs, are listed in *Figure T3-3*.

FIGURE T3-4. **Coal-Fired Generating Plants**

Coal-Fired Generating Plants	Location	Units	1995 Plant Summer Net Capacity (MW) [1]	Commercial Operation Date (First Unit) (Last Unit)	Comments
Allen	Memphis, TN	3	744	May 1959 October 1959	Cyclone Furnace
Bull Run	Oak Ridge, TN	1	879	June 1967	Supercritical Pulverized Coal
Colbert	Near Muscle Shoals, AL	5	1,179	January 1955 November 1965	Pulverized Coal
Cumberland	Cumberland City, TN	2	2,448	March 1973 November 1973	Supercritical Pulverized Coal with Scrubbers
Gallatin	Gallatin, TN	4	976	November 1956 August 1959	Pulverized Coal
John Sevier	Rogersville, TN	4	704	July 1955 October 1957	Pulverized Coal
Johnsonville	New Johnsonville, TN	10	1,206	October 1951 August 1959	Pulverized Coal
Kingston	Kingston, TN	9	1,434	February 1954 December 1955	Pulverized Coal
Paradise	Drakesboro, KY	3	2,159	May 1953 February 1970	Supercritical Pulverized Coal Units 1 & 2 Have Scrubbers
Shawnee 1-9	Paducah, KY	9	1,206	April 1953 June 1957	Pulverized Coal
Shawnee 10	Paducah, KY	1	140	December 1989 (AFBC conversion)	Atmospheric Fluidized Bed Combustion
Widows Creek	Bridgeport, AL	8	1,610	July 1952 February 1965	Pulverized Coal; Units 7 & 8 Have Scrubbers
	TOTAL	**59**	**14,685**		
Watts Bar (Idle)	Near Spring City, TN	4	240		Pulverized Coal

[1] Based on 1995 SERC IE 411 Report.

TVA has 59 coal-fired units available for service with a generating capacity of 14,685 megawatts.

TVA'S COAL-FIRED SYSTEM

TVA has 59 active coal-fired units at 11 sites. Four 60-megawatt coal-fired units are now out of service at a twelfth site on the Watts Bar Reservation. The coal-fired units range in size from 107 megawatts each for units 1-4 at the Johnsonville Fossil Plant to 1,224 megawatts for each unit at Cumberland. TVA's oldest active coal-fired unit was placed in service in 1951. The newest unit was placed in service in 1973. One unit at Shawnee was converted to atmospheric fluidized bed combustion (AFBC) in 1989. The average age of TVA's coal-fired generating units is almost 40 years. However, a recent review identified no technical problems that would prevent the continued operation of these plants through the Energy Vision 2020 study period.

Figure T3-4 lists key characteristics and locations of TVA's coal-fired facilities.

TVA's coal-fired units have a 1995 combined net summer capacity of 14,685 megawatts. TVA anticipates reductions in coal system capacity for: (1) loss in Johnsonville capability due to supplying steam to a nearby industry and (2) a possible loss from various units if scrubbers (pollution control equipment) are added. The installation of scrubbers is planned as part of a clean air strategy that is included in the integrated resource plan.

TVA is meeting Phase 1 of the acid rain control program of the 1990 Clean Air Act Amendments (CAAA) by the addition of sulfur dioxide scrubbers at Cumberland Units 1 and 2 and by the purchase of lower sulfur coal. In addition, low nitrogen oxides

FIGURE T3-5. Coal-Fired Plant Emissions

	Sulfur Dioxide				Nitrogen Oxides				Carbon Dioxide			
	AVERAGE 1990-1994		ESTIMATED CY95		AVERAGE 1990-1994		ESTIMATED CY95		AVERAGE 1990-1994		ESTIMATED CY95	
Plant/ CAAA Phase	**Tons SO_2**	**LB SO_2/ MMBTU**	**Tons SO_2**	**LB SO_2/ MMBTU**	**Tons NO_X**	**LB NO_X/ MMBTU**	**Tons NO_X**	**LB NO_X/ MMBTU**	**Tons CO_2**	**LB CO_2/ MMBTU**	**Tons CO_2**	**LB CO_2/ MMBTU**
Allen Phase I	66,120	3.34	25,205	1.00	33,729	1.70	42,849	1.70	4,094,359	205	5,167,025	205
Bull Run Phase II	45,087	1.75	77,775	2.50	15,659	0.60	18,666	0.60	5,317,540	205	6,377,550	205
Colbert Phase I	74,605	2.30	97,892	2.89	28,442	0.84	16,918	0.50	6,775,078	205	6,936,175	205
Cumberland Phase I	325,956	4.48	28,334	0.29	97,119	1.36	127,017	1.30	15,257,644	205	20,518,050	210
Gallatin Phase I	129,241	4.24	82,335	3.30	18,345	0.60	11,228	0.45	6,307,466	205	5,114,750	205
Johnsonville Phase I	95,044	2.79	94,908	3.30	26,518	0.83	13,674	0.48	7,064,874	205	5,895,800	205
John Sevier Phase II	57,549	2.35	57,450	2.50	15,308	0.64	13,788	0.60	5,045,858	205	4,710,900	205
Kingston Phase II	87,630	1.86	90,252	2.60	33,013	0.70	90,252	0.70	9,651,209	205	90,252	205
Paradise 1&2 Ph II, 3 Ph I	138,684	2.45	177,349	2.50	120,247	1.74	127,638	1.80	14,543,214	205-210	14,729,700	208
Shawnee 1-9 Ph II, 10 Ph I	55,117	1.62	71,330	1.46	29,803	0.88	40,578	0.83	7,330,461	205-210	10,044,600	206
Widows Creek Phase II	32,685	0.77	54,777	0.95	31,955	0.79	43,316	0.75	8,893,920	205-210	11,938,700	208

This figure shows the historical average for calendar years 1990 - 1994 and 1995 estimate of sulfur dioxide, nitrogen oxides, and carbon dioxide in tons per year and annual average pounds per million Btu by plant. The average is for calendar years 1990 - 1994 with the tons per year being a simple average and the pounds per million Btu being a weighted average.

burners will be added to numerous small units by the end of 1995; also a combination of low nitrogen oxides burners and, possibly, coal reburn at other units will be implemented by 2000.

Phase II sulfur dioxide compliance with the Clean Air Act Amendments will be guided by Energy Vision 2020. Options being considered include sulfur dioxide scrubbers at Paradise Unit 3 and at the Allen Fossil Plant, fuel switching at a number of locations, and natural gas combined cycle repowering of various coal units.

Figure T3-5 lists the coal-fired plants and the average emissions for 1990-1994 and an estimate for 1995 of sulfur dioxide, nitrogen oxides, and carbon dioxide.

Major capital expenditures are anticipated through 2000 (and possibly longer) for compliance with the Clean Air Act Amendments and major overhauls of the large coal-fired units. Capital costs will average between $150-200 million annually for Clean Air Act Amendment compliance and more than $300 million for overhauls to coal-fired plants through 2000.

Figure T3-6 provides cost and performance characteristics for the coal-fired system, including capacity, equivalent availability factor (EAF), heat rate, fuel cost, operations and maintenance (O&M) cost, and additions and improvements (A&I) cost.

FIGURE T3-6 **TVA's Coal-Fired System**

Coal System in Fiscal Year	Summer Net Capacity (MW)	EAF (%)	Heat Rate (Btu/kWh)	Fuel Cost ($/MWh)	Total O&M ($/kW)	Total A&I ($/kW)
1994 (Actual)	14,743	78.9	10,021	13.3	21.9	22.1 [1]
2005	14,590 [2]	85.0	9,884	15.8	26.2	24.0

[1] Does not include clean air compliance capital cost.
[2] Assumes a reference clean air strategy.

TVA expects some decrease in generating capacity from its coal-fired plants by 2005 due to the installation of additional pollution control equipment and the diversion of steam that will be sold to a local industry. Availability factor is expected to increase by 2005 due to plant improvements that will increase plant efficiency and reliability.

TVA'S COMBUSTION TURBINES

TVA has 48 combustion turbines located at 4 coal-fired plant sites. Twenty-eight of these combustion turbines are capable of burning natural gas or oil; the other 20 combustion turbines have oil capability only. Combustion turbines have a low fixed cost but very high operating cost due to the relatively high cost of gas and oil. These units are normally reserved for use during peak periods only.

The combined summer net dependable capacity of these combustion turbines is 1,952 megawatts. The average age of TVA's combustion turbine units is approximately 23 years. All units are anticipated to be available through the Energy Vision 2020 study period.

Figure T3-7 lists the locations and capacities of the combustion turbines in the TVA system.

TVA recently upgraded the reliability of its combustion turbines. Forced outage factor (FOF) is a measure of combustion turbines' reliability. Forced outage factor is defined as the number of hours a unit is on forced outage divided by the total hours in a period and is expressed as a percentage. A forced outage is defined as those hours when the system needs generation from a unit, but the unit is not able to generate power. Hours when a unit's outage has been planned (for example, scheduled maintenance) do not count as a forced outage.

Figure T3-8 shows significant performance and cost characteristics of TVA's combustion turbines, including capacity, forced outage factor (FOF), heat rate, fuel cost, operations and maintenance (O&M) cost, and additions and improvement (A&I) cost.

FIGURE T3-7. **Combustion Turbine Generating Plants**

Combustion Turbine Generating Plants	Location	Units	1995 Plant Summer Net Capacity (MW)	Commercial Operation Date (First Unit) (Last Unit)	Comments
Allen	Memphis, TN	20	488	June 1971 September 1972	Natural Gas or #2 Fuel Oil
Colbert	Near Muscle Shoals, AL	8	384	September 1972	Natural Gas or #2 Fuel Oil
Johnsonville	New Johnsonville, TN	16	784	June 1972	#2 Fuel Oil
Gallatin	Gallatin,TN	4	296	July 1975	#2 Fuel Oil
TOTAL		**48**	**1,952**		

TVA has 48 combustion turbine plants located at four steam plant sites. Combustion turbines, used primarily for peaking power, have a generating capacity of 1,952 megawatts.

FIGURE T3-8. **TVA's Combustion Turbine System**

Combustion Turbines In Fiscal Year	Summer Net Capacity (MW)	FOF (%)	Heat Rate (Btu/kWh)	Fuel Cost ($/MWh)	Total O&M ($/kW)	Total A&I ($/kW)
1994 (Actual)	1,952	3.5	12,500 [1]	51.1	1.7	4.7
2005	1,952	2.0	12,500	46.9	2.5	0.4

[1] Allen 17-20 heat rate for oil fuel is given as representative of system average.

Combustion turbines are expected to remain a reliable source of power through 2005 with a reduction in forced outage factor due to plant upgrades.

TVA'S NUCLEAR PLANTS

Five nuclear units, located at three sites, are included in existing generating assets—Browns Ferry Nuclear Plant Units 2 and 3, Sequoyah Nuclear Plant Units 1 and 2, and Watts Bar Nuclear Plant Unit 1. *Figure T3-9* gives the locations and capacities of these units.

In 1985 TVA shut down its nuclear operation and construction program to correct significant weaknesses. Operating characteristics since restart from this regulatory outage are anticipated to be more representative of future operations because of the changes in personnel, procedures, and equipment as compared to the pre-1985 period. Since return to service from the regulatory outages, Sequoyah Units 1 and 2 and Browns Ferry Unit 2 have recorded, respectively, a 66 percent, 65.4 percent, and 80.6 percent equivalent availability (explained previously in the section covering TVA's hydro system).

Figure T3-10 gives the significant characteristics for TVA's nuclear system, including capacity, equivalent availability factor (EAF), heat rate, fuel cost, operations and maintenance (O&M) cost, and additions and improvement (A&I) cost.

Although TVA has scaled back its nuclear construction program, nuclear generation is expected to play a vital role in helping TVA meet energy supply demands through the Energy Vision 2020 study period. The nuclear units at Browns Ferry will reach the end of their operating licenses during the study period (2014 for Browns Ferry Unit 2 and 2016 for Browns Ferry Unit 3). It is anticipated that these two units will be excellent candidates for license extension for two reasons. First, boiling water

FIGURE T3-9. **Nuclear Generating Units**

Nuclear Generating Plants	Location	Units	1996 Plant Summer Net Capacity (MW)	Commercial Operation Date (First Unit) (Last Unit)	Comments
Browns Ferry	Near Athens, AL	2 [1]	2,130	1975 1977	General Electric Boiling Water Reactors
Sequoyah	Near Chattanooga, TN	2	2,217	1981 1982	Westinghouse Pressurized Water Reactors
Watts Bar	Near Spring City, TN	1 [2]	1,170	Projected COD in FY 1996	Westinghouse Pressurized Water Reactor
TOTAL		**5**	**5,517**		

[1] Browns Ferry Unit 1 has been idled since 1983. Major modifications are required to bring the plant to current standards. Recovery of this unit is included as a supply-side option within the IRP.
[2] Watts Bar Unit 2 is approximately 68 percent complete. Completion of this unit is included as a supply-side option within the IRP.

Five nuclear units are expected to provide 5,517 megawatts of TVA's generating capacity.

FIGURE T3-10. TVA's Nuclear System

Nuclear in Fiscal Year	Summer Net Capacity (MW)	EAF (%)	Heat Rate (Btu/kWh)	Fuel Cost ($/MWh)	Total O&M ($/kW)	Total A&I ($/kW)
1994 (Actual)	3,282	65.6	10,140 [1]	11.0 [2]	90.7	29.8 [3]
2005	5,517	67	10,475	5.4	113.6	19.1

[1] Sequoyah 2 heat rate given is typical of all nuclear units.
[2] In 1994 TVA took steps to write off sunk interest charges on excess fuel inventory. This will result in future fuel expenses that are significantly lower but are more in line with market costs.
[3] Capital expenditures for SQN 1, SQN 2, and BFN 2 plus central office TVAN only.

TVA expects an increase in availability factor for its nuclear system due to plant upgrades. Fuel costs are projected to drop significantly following the write-off of interest charges on excess fuel inventory in 1994.

reactors, such as those at Browns Ferry, are not as susceptible to vessel aging as pressurized water reactors; second, these units have been brought up to current standards. TVA will follow closely the proposed Nuclear Regulatory Commission rule making on license extensions, but TVA anticipates these facilities will be available over the Energy Vision 2020 study period.

TVA has established a nuclear decommissioning fund for all of its operating nuclear reactors. Investments of power funds have been made since 1982 to provide for the accumulation of funds for decommissioning nuclear plants. By September 1993, the lowest interest rate environment in 20 years resulted in a situation where the market value of the decommissioning investments was significantly higher than their book value of $210 million. TVA elected to exercise the flexibility of the internal fund, and sold the investments through a competitive bid for $373 million.

TVA elected to return the proceeds to the decommissioning fund over a three year period beginning in fiscal year 1994. At the end of fiscal year 1994 the fund had $150 million. Plans are to add an additional $100 million by the end of fiscal year 1995 and an additional $123 million by the end of fiscal year 1996.

TVA's policy is to collect funds for decommissioning through rates based on a constant dollar amount adjusted for inflation over the life of the operating license of a nuclear plant. This policy is based on the theory that all ratepayers that benefit from the electric production of a nuclear plant should share equally in the cost of decommissioning. If TVA front-loaded the collection of the nuclear plant decommissioning funds, this would put an undue burden on the ratepayers receiving power generated during the early years of operation of the nuclear plant. On the other hand, if not enough funds were collected throughout the life of the plant, the ratepayers receiving power at the end of the operating license would have an unfair decommissioning burden.

Decommissioning expense has been recovered from ratepayers annually based on the present value of amounts not provided through earnings on the fund. In fiscal year 1990, these

FIGURE T3-11. Projected Availability of Power Through Interchanges

	BLOCK 1		BLOCK 2		BLOCK 3	
YEAR	Quantity (MW)	Price $/MWh	Quantity (MW)	Price $/MWh	Quantity (MW)	Price $/MWh
1995	250	23	250	27	1800	40
2000	300	27	300	32	1500	56
2005	0	N/A	300	39	1500	75
2010	0	N/A	0	N/A	1100	106
2015	0	N/A	0	N/A	1000	135
2020	0	N/A	0	N/A	1000	165

This figure shows the amount of power expected to be available through the interchange system through 2000. For each year, power is shown to be available in blocks with varying cost.

collections amounted to $18 million. TVA temporarily suspended decommissioning collections from customers after operating license life extensions were obtained for Browns Ferry and Sequoyah. The temporary suspension was made in an effort not to front-load decommissioning collections. Cashing in the gain on the market value of the fund in 1993 has resulted in a reduction of the annual decommissioning expense collection through rates to $13 million currently based on a projected long-term return of 8 percent. If alternative investments with a higher rate of return could be achieved, the annual collection could be lowered further. Collections for the decommissioning fund will resume in fiscal year 1995.

Interchanges with Neighboring Utilities

TVA has various types of interchange arrangements with neighboring electric systems that allow TVA and these utilities to buy, sell, and exchange power at times when it is mutually beneficial to do so. TVA anticipates that there will be some quantities of non-firm spot market power available, even during peak periods, for the future. Spot market power is power that is available for purchase on the open market, usually surplus power that may be available at any given time from a generating utility. "Non-firm" implies that TVA will not pay capacity charges for the power, and other utilities will not guarantee that it is available.

For planning purposes, TVA has assumed the quantities and price shown in *Figure T3-11*. These blocks are representative of purchase power from neighboring utilities. Depending on the economic loading of the power system, these blocks can be used to offset more expensive internal generating resources.

TVA also anticipates that it will be able to make off-system sales because of differences in timing of system peaks between TVA and neighboring utilities. Over the Energy Vision 2020 study period, these interchange purchases and sales are anticipated to be roughly in balance.

FIGURE T3-12. **Interchange with Neighboring Utilities**

Neighboring Utilities with Transmission Ties	Interconnections
Associated Electric Cooperative Incorporated	1
Appalachian Power Company	7
Big Rivers Electric Cooperative [1]	7
Carolina Power & Light	1
Central Illinois Public Service	1
East Kentucky Power Cooperative	6
Electric Energy, Inc. (DOE Paducah)	8
Energy Services (Arkansas Power & Light and Mississippi Power & Light Co.)	6
Kentucky Utilities Company	8
Louisville Gas & Electric Company	1
Nantahala Power & Light Company	1
Southern Company (Alabama Power and Georgia Power)	9
Union Electric	1
TOTAL	**57**

[1] Delivery points for power purchased by Big Rivers from the Southeastern Power Administration.

TVA has the capability to exchange power with 13 neighboring utilities which allows power to be bought, sold, or wheeled to meet utility needs.

Transmission System

TVA's transmission system serves an area of more than 80,000 square miles, serving a population of approximately 7.7 million. The system includes approximately 16,000 miles of transmission line, including 9,800 miles of 161,000 volt lines and 2,400 miles of 500,000 volt lines.

The system is used to transmit power to 160 distributors of TVA power. These distributors include 50 electric cooperatives, 107 municipal electric systems, and 3 county-operated systems. TVA also directly serves over 60 large industries and Federal installations. In addition, the transmission system is connected directly with 13 neighboring utilities. These interconnections allow TVA to buy power from and sell power to other utilities and to wheel electricity from one utility to another using TVA's power transmission system.

Figure T3-12 lists the electric utilities with which TVA has exchange agreements and the number of interconnections TVA has with each.

TVA is a member of the Southeastern Electric Reliability Council, a voluntary industry oversight organization dedicated to promoting electric system reliability by identifying and enforcing good engineering and operating practices. The Southeastern Electric Reliability Council is a subgroup of the North American Electric Reliability Council, which provides oversight for the entire North American grid. Through these arrangements, TVA has access to emergency backup power.

Energy Vision

2020

Volume 2, Technical Document

4 Evaluation Criteria

Volume 2, Technical Document 4

Evaluation Criteria

Contents

The four major sections of this document named below are working papers that were presented by TVA to support discussions on evaluation criteria during the development of Energy Vision 2020.

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Evaluation Criteria

COST/BENEFIT TESTS

1. What are cost-benefit tests?

Cost-benefit tests are a means for any organization to determine if the cost of taking an action is greater than the benefit that is gained from that action. At TVA, cost-benefit tests were used to determine if a given supply-side resource and demand-side management goal can help achieve certain company goals.

2. What cost-benefit tests are used by TVA in the Energy Vision 2020 integrated resource plan?

To determine cost-effectiveness, the standard tests used are:

- Participant Test – Examines the costs and benefits from the perspective of participants in demand-side management programs. Programs that do not pass the participant test have little chance of success.
- Rate Impact Measure (RIM) – Takes the perspective of non-participants and measures the impact of resource options on rates. A program that passes the Rate Impact Measure test will not cause rates to increase and therefore will benefit both program participants and non-participants.
- Total Resource Cost (TRC) – Considers the options of both participants and non-participants and is a measure of economic efficiency for society. Programs that pass the Total Resource Cost test provide energy service at the lowest cost to society as a whole.

Figure T4-1 illustrates the differences among the tests.

3. What assumptions are made to apply the standard tests?

The ability of the standard tests to measure the potential achievement of the desired goals depends on a set of assumptions that are often not acknowledged, namely:

- Customers use the same amount of energy service both before and after the program
- Customers receive the same quality of energy service both before and after the program
- Customers do not change their usage of energy services due to program-induced rate changes

In short, all of the reasons that customers choose not to install a DSM measure (the hidden or market barrier or transactions costs) are assumed to be completely eliminated by the utility program according to the standard tests. These are strong assumptions that often do not hold true even though the standard tests assume they do.

4. How does TVA take into account that the test assumptions named do not always hold true? For example, the purpose of demand-side options is to negate the first assumption—that "customers use the same amount of energy service both before and after the program."

TVA realizes that the assumptions upon which the standard tests are based do not always hold true. For example, a demand-side option may offer an incentive program for purchases of more energy efficient manufacturing equipment. This equipment increases productive efficiency even though it may use more electricity. This makes the first assumption untrue because the amount of energy used would not remain the same. In response, TVA uses the Value Test to measure the value of this increased productivity. Although the Value Test is not one of the standard tests used by regulated utilities, all of the additional measures included in the test are mentioned in the California Standard Practice Manual, *Economic Analysis of Demand-Side Management Programs.*

5. What is the economic basis for the Value Test?

The Value Test is developed rigorously from the principle of economic efficiency. A program that increases economic efficiency is one that increases customer value by either lowering energy service costs or increasing the quality of services. Since the Value Test is a complete measure of economic efficiency, it allows for the relaxation of the four assumptions discussed above associated with the standard tests of cost-effectiveness.

6. Are there any other advantages to the Value Test?

Because the Value Test is a complete test of economic efficiency that acknowledges the fallacy of the assumptions of the standard tests, the Value Test allows all types of Customer Service Options (including DSM) to be evaluated on a level playing field. Customer Service Options include anything that TVA and distributors can do on the end-use customers' side of the meter to increase the value of electricity consumption, making this is a useful test for Energy Vision 2020.

7. Are the components of the Value Test more difficult to measure?

Virtually all costs and benefits associated with customer service and supply-side options are estimated and involve some degree of uncertainty. The techniques that have been developed for the Value Test provide means to develop parameters for the range of uncertainty associated with the estimates of the different costs and benefits.

FIGURE T4-1. Cost Effectiveness Test—Residential New Homes Program Example

	PARTICIPANT TEST		RATE IMPACT MEASURE (RIM) (NON-PARTICIPANT IMPACTS)		TOTAL RESOURCE COST (TRC TEST*)	
Benefits:	+Electric Bill Reduction	$226,868	+Avoided Supply Costs	$173,420	+Avoided Supply Costs	$173,420
	+Incentives	$46,664				
Costs:	-Participant Costs	$90,944	-Utility Costs	$13,539	-Participant Costs	$90,944
			-Incentives	$46,664	-Utility Costs	$13,539
			-Revenue Loss	$226,868		
	Net Benefits	$182,588	Net Benefits	- $113,650	Net Benefits	$68,937
	Benefit/Cost Ratio	3.01	Benefit/Cost Ratio	0.60	Benefit/Cost Ratio	1.66

**Note: The TRC is the sum of participant and RIM or non-participant impacts.*

Note: The value test—as shown below—adds components to the participant test and the RIM (non-participant) test that have been omitted as a result of simplifying assumptions.

	PARTICIPANT		NON-PARTICIPANT IMPACTS		TOTAL VALUE	
Benefits:	+Electric Bill Reduction	$226,868	+Avoided Supply Costs	$173,420	+Avoided Supply Costs	$173,420
	+Incentives	$46,664			*+Benefits due to low price of services [1]*	$12,441
	+Benefits due to low price of services [1]	$12,441			*+Reduction in mkt barrier costs [2]*	$6,268
	+Reduction in mkt barrier costs [2]	$6,268				
Costs:	-Participant Costs	$90,944	-Utility Costs	$13,539	-Utility Costs	$13,539
	-Transactions Cost [3]	$38,021	-Incentives	$46,664	-Participant Costs	$90,944
			-Revenue Loss	$226,868	*-Transactions Cost [3]*	$38,021
			-Long-Run Rate Impact [4]	$2,585	*-Long-Run Rate Impact [4]*	$2,585
	Net Benefits	$163,276	Net Benefits	- $116,235	**Net Benefits**	**$47,040**
	Benefit/Cost Ratio	2.27	Benefit/Cost Ratio	0.60	**Benefit/Cost Ratio**	**1.32**

Listings in italic type indicate additions to participant test and non-participant test that differentiate the value test from the TRC test

1,2 Additional benefits to participants that reflect a lower price of services because of efficiency improvements or quality improvements plus reduced market barrier costs achieved by the utility program

3 Transactions costs to participants that reflect market barrier costs not removed by the program

4 Long-run rate impact to non-participants reflects the reaction of non-participants to higher prices caused by the program

TREATMENT OF ENVIRONMENTAL CONCERNS EXPRESSED BY THE PUBLIC

Introduction

Environmental values are a fundamental part of the American value system. No enterprise in today's society can safely proceed in ignorance of the environmental consequences of its activities. TVA Board Chairman Craven Crowell has said:

> *In the years ahead, no major corporation will succeed without a high regard for the environment... We must blend environmental consciousness into everything that we do—from managing our power system to managing our system of lakes and dams, from managing our land use to promoting rural development in ways to support environmental quality.*

There are potentially significant differences in environmental impacts between energy resource strategies. Those differences can result in widely differing economic effects in the form of increased or lessened pollution control costs. Those differences can also result in greater or lesser public acceptance of resource plans.

Environmental Responsibility and Energy Vision 2020

Recognizing the importance of environment values, the TVA Board included environmental responsibility among the four broad strategic goals for TVA. Those goals are:

1. Customer Driven
2. Employee Sensitive
3. Environmentally Responsible
4. Growth Oriented

The ultimate objective of Energy Vision 2020 is to develop a resource plan that will enhance TVA's competitiveness in a manner that meets or exceeds customers' expectations. TVA has defined "competitiveness" broadly to include promoting "sustainable" economic growth.

National Environmental Policy Act

One of the tools to help TVA in this task is the National Environmental Policy Act and its implementing regulations. Since the enactment of the National Environmental Policy Act on January 1, 1970, federal agencies (including TVA) have been required to consider any significant environmental impacts that may result from their proposed actions. The National Environmental Policy Act and its implementing regulations define a process to guide federal agencies in evaluating environmental impacts and involving the public in reviewing this evaluation. The most comprehensive level of review in the process is the environmental impact statement. It provides a structure for involving the public and sets certain minimum analytical requirements, such as the identification of reasonable alternatives to the proposed action.

TVA has prepared an environmental impact statement as part of Energy Vision 2020. This allowed TVA to use the environmental impact statement process to obtain public input, to inform the public about potential environmental impacts, and to ensure that the environmental impacts of alternative strategies are considered.

TVA prepared a "programmatic" level environmental impact statement as opposed to a "project" or site-specific environmental impact statement. This is in keeping with the kind of action under consideration—the formulation of a long-term energy strategy. Because of the programmatic nature of the action, the environmental analyses focuses primarily on regional or broad-scale environmental impacts and those impacts that are normally associated with certain categories of energy options. The environmental impact statement and TVA's integrated resource plan have been merged and collectively consist of Volume 1 and Volume 2.

A particular energy resource strategy may eventually result in individual projects with site-specific impacts. The potential impacts of future resource projects would be addressed through site-specific environmental reviews prior to their development.

FIGURE T4-2. **Environmental Concerns Identified through TVA's Energy Vision 2020 Public Participation Process**

- Acid Rain
- Acid Rain Strategy/Pollution Credits
- Aesthetics
- Air Toxics
- Chlorofluorocarbons (CFC)
- Clean Air/Air Quality/Fossil Pollutants
- Clean Water/Water Quality
- Coal-Mine Reclamation
- Electric and Magnetic Fields (EMF)
- Environmental Regulations
- Externalities
- Global Warming/Greenhouse Gases/Carbon Offsets/CO_2 Constraints
- Human Health
- Lake Levels
- Land Use/Land Impacts
- Nuclear Safety
- Nuclear Waste
- Polychlorinated Biphenyls (PCB)
- Refuse-Derived Fuel (RDF)
- Regional Forests
- Right-of-Way Maintenance
- Smog/Volatile Organic Compounds
- Solid Waste
- Sustainability/Protection of Natural Resources
- Visibility
- Wetlands
- Wildlife
- Zebra Mussels

Treatment of Environmental Concerns and Issues

The analytical process for environmental issues started with the identification of environmental concerns. Through interactions with the public and various stakeholder groups, such as the Energy Vision 2020 Review Group, TVA identified an initial list of environmental concerns. In no particular order of importance, the environmental concerns are identified in *Figure 4-2.* Since the National Environmental Policy Act requires that the environmental impacts of alternatives be considered by the decision-maker, a process was developed to link these concerns to environmental impacts or consequences.

First, these environmental concerns were linked with scientific or regulatory environmental issues based on the associated pollutants or activities.

The public's stated concerns were translated into commonly used scientific or environmental terms that are more concise and amenable to analysis. For example, "smog" from a technical standpoint is associated with ozone, regional ozone, and particulate. TVA's proposed linkage of these concerns with issues/pollutants is identified in *Figure T4-3.*

Second, the environmental impacts or consequences of the environmental issues were identified.

Third, issues that contribute to the same environmental impact or consequences were then grouped together and measures developed to provide capability for quantitative evaluation *(see Figure T4-4).* Constraints were also identified for certain environmental issues, which are discussed later in this section.

Environmental Impacts and Measures

Each of the issues from *Figure T4-4* was associated with an environmental impact measure in order to combine the multi-attribute trade-off analysis approach with the National Environmental Policy Act requirement that the decision-maker consider the environmental consequences or impacts of alternative strategies under consideration. These impacts, typical of those evaluated in other environmental impact statements, are treated as evaluation criteria. The relative magnitude of these impacts have been analyzed among alternative energy strategies.

In many cases, more than one issue will contribute to an impact. For example, human health impact through inhalation pathways is associated with the acid aerosol (sulfate), ozone, indoor air quality, and hazardous air pollutants (e.g., mercury). Both regional ozone and acid deposition issues contribute to crop damage. Other impacts may be linked to only one issue. *Figure T4-4* identifies the proposed environmental impacts and shows the relationship between environmental issues (derived from concerns) and these environmental impacts.

Comparing the relative environmental impacts of strategies requires identification of measures that either directly or indirectly indicate the impact area. Where multiple measures are associated with an impact, the importance of each measure is considered.

Some of these measures are relatively straightforward and can be considered direct measures of the risk of impacts. For example, the possibility of impacts to fish and aquatic life from the discharge of heated condenser cooling water can be measured by the heat (BTUs) discharged to the rivers. Measurements for other issues/pollutants are not so straightforward, but certain pollutants that contribute to or cause an impact can serve as indirect measures of impacts. For example, sulfur dioxide (SO_2) and nitrogen oxides (NO_X) are precursor pollutants that are the primary contributors to acid deposition and associated impacts on forests, crops, fish and other aquatic life and materials. By measuring these pollutants for various strategies, it is possible to obtain some understanding of the potential relative effect of a strategy on environmental impacts.

FIGURE T4-3. **Environmental Concerns and Linkage to Scientific Issues/Pollutants**

Environmental Concern	Issue/Pollutant (Linkage)
Acid Rain	Acid aerosols, acid deposition, acid clouds
Acid Rain Strategy, Pollution Credits	Alternative representative strategies will be evaluated in the IRP
Aesthetics	New construction, windmills
Air Toxics	Hazardous air pollutants, mercury inhalation/deposition
Chlorofluorocarbons (CFC)	Unimportant IRP issue – being phased out by law
Clean Air, Air Quality, Fossil Pollutants	Acid aerosols (sulfate), ozone, particulates, indoor air quality, hazardous air pollutants, regional ozone, acid deposition, acid clouds, combustion byproducts, natural gas leakage, landfill/coal mine, methane, visibility
Clean Water, Water Quality	Point source releases, solid waste, fuel production, air emissions, construction site runoff, general site runoff, acid mine drainage (non-point source pollution), low dissolved oxygen, hydro power releases, releases of nutrients/oxygen demanding substances, discharge of heated condenser cooling water, acid deposition, surface water intakes (including pumped storage), facility construction and operation, mining operations, evaporative water losses and cooling tower drift (consumption), water withdrawal (usage), ground water contamination.
Coal Mine Reclamation	Fuel production, acid mine drainage
Electric and Magnetic Fields	Addressed qualitatively in IRP/EIS
Environmental Regulations	Captured as uncertainties in the analysis
Externalities	Captured by multi-attribute analysis – addressed qualitatively in IRP/EIS
Global Warming, Greenhouse Gases, Carbon Offsets, CO_2 Constraints	Combustion byproducts, natural gas leakage, landfill/coal mine methane
Hazardous Waste	Hazardous waste
Indoor Air Quality	Indoor air quality
Lake Levels	Addressed in TVA's Lake Improvement EIS; IRP assumption
Land Use, Land Impacts	New construction, new plants, new dams, new coal mines, new rights-of-way, energy crops, nuclear and hazardous wastes generated, combustion byproducts and management (ash and pollution control byproducts), generation, transmission, windmills, strip mining
Nuclear Safety	Addressed as a financial uncertainty (nuclear moratorium), addressed qualitatively in IRP/EIS
Nuclear Waste	Low- and high-level nuclear waste
Polychlorinated Biphenyls	Unimportant IRP issue, being phased out on TVA system (PCBs)
Refuse-Derived Fuel (RDF)	RDF is treated as an IRP option
Regional Forests	Regional ozone, acid deposition, acid clouds
Right-of-Way Maintenance	To be addressed qualitatively in Energy Vision 2020
Smog, Volatile Organic Compounds	Ozone, regional ozone, particulates
Solid Waste	Combustion byproduct
Sustainability, Protection of Natural Resources	Addressed qualitatively in IRP/EIS; components of sustainability are captured by criteria (environmental impact, economic impact, energy efficiency)
Visibility	Acid aerosols (sulfate), ozone, particulates
Wildlife	New construction, new plants, new rights-of-way, strip mining, windmills, energy crops
Wetlands	Unimportant IRP issue; site-specific
Zebra Mussels	Point source releases, surface water intakes, water withdrawal

Developing measurements for some impacts is even more difficult; therefore, for a number of impacts, surrogate measures were used. For example, the amount of coal burned provides an indication of the amount of pollutants affecting aquatic life and biodiversity. Finally, for a few impacts, TVA has not been able to identify reasonably, appropriate direct, indirect, or surrogate measures. These potential impacts have been considered qualitatively in Energy Vision 2020. *Figure T4-4* shows the measures proposed for each environmental impact.

ENVIRONMENTAL CONSTRAINTS

A constraint is an absolute limit on a measure. These can be externally imposed in the form of a legal requirement or internally imposed as a policy. A constraint can also result from physical limitations such as the maximum loading that a transmission line can carry or the maximum capacity of a generating unit.

Two environmental constraints have been identified: one affects sulfur dioxide emissions, and the other affects greenhouse gas emissions. In addition, two assumptions have been made

FIGURE T4-4 **Issues, Related Environmental Impacts, and Measures**

Issues/Pollutants	Environmental Impact	Measurements/Treatment
Acid aerosols (sulfate), ozone, particulates, indoor air quality, hazardous air pollutants, mercury inhalation	Human health—inhalation	SO_2, NO_X, TSP, mercury emissions—also Qualitative
Acid aerosols (sulfate), ozone, particulates	Visibility	SO_2, NO_X, VOC—also Qualitative
Regional ozone, acid deposition, acid clouds	Forests, crops	SO_2, NO_X—also Qualitative
Acid deposition, ozone	Materials (structural and cultural)	SO_2, NO_X—also Qualitative
Point source releases, hazardous air pollutants, mercury deposition, groundwater contamination, facility operation	Human health—ingestion	Nuclear power sales, fossil power sales, hydro peaking power sales—also Qualitative
Discharge of heated condenser cooling water, point source releases, mining operations, evaporative water losses and cooling tower drift (consumption), water withdrawal (usage), facility construction and operation, groundwater contamination	Water supply, waste assimilation	Thermal rejection to river, water consumed, hydro peaking power sales—also Qualitative
Point source releases, solid waste, fuel production, air emissions, mercury deposition, construction site runoff, general site runoff, acid mine drainage (nonpoint source pollution), low dissolved oxygen, hydro power releases, releases of nutrients/oxygen demanding substances, discharge of heated condenser cooling water, acid deposition, surface water intakes (including pumped-storage), facility construction and operation	Aquatic life, biodiversity	Thermal rejection to river, water used, coal burned, nuclear power sales, fossil power sales, hydro peaking power sales, new power plants—also Qualitative
New construction, windmills	Aesthetics/visual	Qualitative
New coal mines, new plants and dams, energy crops	Agricultural land loss	Qualitative
New coal mines, new plants, new rights-of-way, energy crops	Biodiversity	Qualitative
Low- and high-level nuclear and hazardous waste generated, new plants, new rights-of-way, new dams, strip mining, combustion by-products and management (ash and pollution control byproducts)	Land consumption, land management	Qualitative
Combustion byproducts, natural gas leakage, landfill/coal mine methane, carbon sequestration	Greenhouse gas emissions	CO_2—also Qualitative
Indoor air quality		Qualitative
Right-of-way maintenance		Qualitative
Electric and magnetic fields		Qualitative
Sustainability, protection of natural resources		Qualitative

for purposes of analyses. These assumptions behave like constraints: one involves those formulated in TVA's *Tennessee River and Reservoir System Operation and Planning Review*, more commonly known as TVA's Lake Improvement Plan. The other environmental constraint involves releases from new fossil plants. These constraints and assumptions are described below.

System Sulfur Dioxide (SO_2) Emissions Constraint

Sulfur dioxide emissions from TVA's fossil-fuel units must meet acid rain control requirements on a system-wide basis.

Greenhouse Gas Emissions Constraint

TVA has committed, along with some 60 other utilities, to participate in the President's Climate Challenge Program, which is a voluntary greenhouse gas reduction or stabilization program. Program participants have substantial flexibility in formulating reduction or stabilization strategies. TVA has agreed to voluntarily reduce equivalent TVA carbon dioxide emissions by the year 2000. These commitments will have to be met by all Energy Vision 2020 strategies.

Lake Improvement Plan Assumption

In 1991, TVA committed to improving water quality and aquatic habitat by increasing minimum flows and aerating releases from a number of TVA dams. TVA is also committed to extending the recreation season on a number of TVA reservoirs by delaying the drawdown of reservoirs for other operating purposes, primarily hydropower generation. These commitments will be met regardless of the strategy.

Minimum Fossil Fuel Plant Releases

Because of the trend toward increasing environmental regulation, it is assumed that all new fossil fuel-fired units will have minimal water discharges as well as lined waste storage areas and will employ best available technology to control air emissions.

CALCULATION OF ENVIRONMENTAL INDICES

TVA's existing energy resources and many of the resource options considered for Energy Vision 2020 can affect the natural environment in different ways. Indices were developed to help characterize how TVA power system operations and alternative energy strategies might affect the environment. All indices were calculated relative to the reference strategy, which was used as a baseline for comparison (See Technical Document 8, Resource Integration). The reference strategy is TVA's "No Action" alternative for purposes of its environmental review.

Each measure was normalized to cancel out the engineering units which may vary among the measures. An illustrative example of computing the air quality index for forest and crop productivity for three strategies is given at the right.

Step 1. Select strategies and determine values for the measures (Tons of SO_2 and NO_X for the Forests and Crops Productivity Index)

	MEASURE/WEIGHTING FACTOR	
Strategy	**Sulfur Dioxide/.25**	**Nitrogen Oxides/.75**
Reference	500,000 Tons	300,000 Tons
Strategy A	600,000 Tons	350,000 Tons
Strategy B	400,000 Tons	250,000 Tons

Step 2. Divide each measure quantity by the maximum measure quantity and multiply by the Weighting Factor for that measure.

	MEASURE/WEIGHTING FACTOR	
Strategy	**Sulfur Dioxide/.25**	**Nitrogen Oxides/.75**
Reference	0.833 x 0.25	0.857 x 0.75
Strategy A	1.0 x 0.25	1.0 x 0.75
Strategy B	0.667 x 0.25	0.714 x 0.75

Step 3. Sum the index components across for each strategy (raw index) and divide by the raw index for the reference strategy to obtain the Forest and Crop Productivity Index for each strategy baselined to the reference strategy.

	MEASURE/WEIGHTING FACTOR	
Strategy	**Sulfur Dioxide/.25**	**Nitrogen Oxides/.75**
Reference	0.208	0.643
Strategy A	0.25	0.75
Strategy B	0.133	0.536

Strategies	**Forest and Crop Productivity Index**
Reference	$\frac{(0.208+0.643)}{(0.208+0.643)} = 1.0$
Strategy A	$\frac{(0.25+0.75)}{(0.208+0.643)} = 1.175$
Strategy B	$\frac{(0.133+0.536)}{(0.208+0.643)} = 0.786$

TVA'S APPROACH TO EVALUATING EXTERNALITIES RESULTING FROM THE PRODUCTION AND CONSUMPTION OF ELECTRICITY

Nature of the Problem

Externalities are activities that result from the production and consumption of goods and services that impose costs or benefits on society that are not reflected in the prices of those goods or services. For example, negative externalities such as pollution and sonic booms can impose costs on a society that are not reflected in the prices of those goods associated with the pollution or sonic boom. Not all externalities impose costs. Positive externalities create benefits to society that are not reflected in those goods and services. For example, positive externalities can result from public parks, flood protection, and the shade resulting from the neighbors' recently planted tree.

Since the costs or benefits of externalities are not reflected in prices or costs of goods and services, the economic allocation of resources is inefficient because consumers and purchasers do not account for external costs and benefits in their resource decisions.

Discussions of externalities in the utility industry have generally dealt with environmental externalities arising from various forms of pollution. Although most of the discussion in this section deals with environmental externalities, it should be noted that the principles would also apply to other negative or positive externalities.

From an economic viewpoint, economic efficiency can be maximized by reducing negative externalities to the point where the marginal benefits from reduced externalities equals the marginal cost of reducing the externalities. The marginal benefits of reduced negative externalities are generally measured by the reduction in the marginal environmental costs imposed on society. The general economic recommendation to reduce environmental externalities is to internalize in prices of products and services the external costs of the externality.

These concepts have led to the policy of social costing in the electric utility industry. Generally, it is stated that economic efficiency can be improved if the external costs of an activity can be included in the private costs for utility decision-making. The external costs of various pollutants are monetized, a value is put on external costs and added to the private costs as indicated in *Figure T4-5*.

In the example in *Figure T4-5*, the private costs (fuel, operation and maintenance, and capital costs) of a combined cycle exceed those for a coal-fired plant. If the external costs associated with sulfur dioxide, nitrous oxide, and carbon dioxide are included, the combined cycle plant has lower costs than the coal-fired plant.

The inclusion of those external costs in utility planning and operation (i.e., system dispatch) has been the subject of debate in the electric utility industry in the last several years.

This section provides a brief summary of industry experience, issues in the application of externalities, and the potential application at TVA.

Environmental Externalities – World, U.S., and Utility Experience

The application of various policy instruments in pollution control or the reduction of external costs is shown in *Figure T4-6* for the United States, Canada, and other countries. Other countries are represented primarily by the European community.

The United States and Canada have experience with command and control policies and market approaches where limits are placed on emissions with trading of offsets or allowances

FIGURE T4-5. **Private and External Costs of Coal and Combined Cycle**

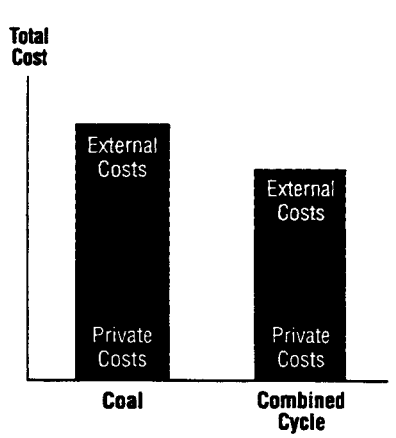


FIGURE T4-6. **Application of Policy Instrument in Pollution Control**

		MARKET					COMMAND AND CONTROL			
Pollutant Area	Country	Trading/ Offsets	Taxes	Fees	Liability	Subsidies	Emissions Standards	Fuel Choice Standards	Technology Standards	Pollution Reduction Target
SO_2	U.S.	●		●			●	●	●	●
	Canada	●					●	●		●
	Others	●	●		●	●	●	●	●	●
NO_X	U.S.	●				●	●	●	●	●
	Canada	●				●	●	●	●	●
	Others		●			●	●	●	●	●
VOC	U.S.	●				●	●	●	●	●
	Canada	●				●	●	●	●	●
	Others					●	●	●		●
CFC	U.S.	●	●							●
	Canada									●
	Others		●							●
CH_4	U.S.									
	Canada									
	Others									
N_2O	U.S.									
	Canada									
	Others									

similar to the policy approach to acid rain. Other countries, particularly European countries, have experience with the same techniques but also have substantial experience with the use of taxes to control or reduce pollution.

Figure T4-7 indicates the methods various state regulatory agencies (public utility commissions) have used to incorporate externalities into utility planning and operations. Currently, eight states monetize externalities as of early 1993. States use a variety of techniques from percentage cost adders for certain technologies to qualitative treatment of external costs. Several states have rejected a monetization of externalities, including Michigan, Alaska, Colorado, Delaware, and Connecticut.

For the states that have included external costs in utility resource decisions, the values used to represent the external costs are shown in *Figure T4-7*. There are two features in *Figure T4-7* that should be noted. First, there is a wide range of value estimates for external costs of any particular pollutant. Second, most of the pollutants involved are air pollutants.

Issues in the Application of Monetizing Externalities

Below is a summary of arguments both for and against for monetizing externalities in the electric utility industry.

PROS

1. Society's resources would be allocated more efficiently.
As previously discussed, internalizing the external costs and benefits of an externality in the production of goods and services would increase the economic welfare or well-being of society.

2. The risk of future environmental control costs would be reduced.
Another argument for internalizing externalities stems from a desire to mitigate the risk of future environmental control costs or other abatement strategies, such as carbon taxes, that could lead to future increases in a utility's costs and to rate increases. One example is the Wisconsin Public Service Commission's decision "to purchase 'insurance' against the risk of future costs" by adopt-

ing adders for greenhouse gases and promoting resources that will reduce emissions of these gases now and at a cheaper price than would occur by waiting for future regulations requiring reductions in emission of such gases.

3. Different resources can be compared consistently.
Proponents also believe that explicit recognition of the environmental effects of different demand and supply options is necessary to make consistent comparisons among resource options with different prices, environmental impacts, and non-price features. The use of adders and other techniques, they argue, will encourage resource developers and/or bidders to develop options that are relatively environmentally clean, since these options will have a relative competitive advantage, when compared to resource options with greater environmental impacts.

CONS

1. Commission action is inefficient and unnecessary.
Many opponents of environmental regulation by state commissions contend that adding externalities to the regulatory agenda is inefficient and unnecessary. They argue that additional action by state commissions is unneeded, given the existence of state and

FIGURE T4-7. Externality Values Used in Utility Resource Decisions (1992 $/lb.)

	POLLUTANT									
AGENCY/REGION	SO_2	NO_X	VOC [1]	CO	TSP [2]	CO_2 [3]	CH_4	N_2O	Water Use	Land Use
New York PSC[A]	0.637	3.0405			0.1665	0.0006			0.1/kWh	0.4/kWh
Massachusetts DPU[B]	0.85	3.6	2.95	0.48	2.2	0.012	0.12	2.2		
Nevada PSC[C]	0.822	3.583	0.622	0.485	2.203	0.012	0.116	2.182		
California PUC (SDG&E/SCE)	11.745	15.724	11.231		3.402	0.0042				
California PUC (PGE&E)	2.243	4.56	2.118		1.312	0.0042				
CA PUC (attainment areas)[D]	0.86	3.733	0.6505		2.304	0.0042				
BPA (west side)	0.79	0.466			0.812	0.0032			0.0002/kWh	0.0002/kWh
BPA (east side)[E]	0.79	0.0364			0.088	0.0032				
Wisconsin PSC[F]						0.0075	0.075	1.35		

1 *Volatile Organic Compound (VOC) values for California represent ROG (reactive organic gases)—a more inclusive definition, which includes the VOC gases and a few others.*
2 *Total Suspended Particulates (TSP) values for California represent values for PM10 — a more specific definition, which includes particulate matter most harmful to human health.*
3 *CO_2 values for BPA were draft cost. No final cost was issued.*

The implicit price deflator for Gross Domestic Product is used to convert the adders to 1992 dollars. The deflators for 1987, 1989, 1990, and 1992 are 101.2, 110.1 115.0 and 121.2, respectively. (Economic Report of the President, *U.S. Government Printing Office, Washington, DC, Table B-3, January 1993.)*

SOURCES:

A *New York State Energy Office. Draft New York State Energy Plan, Vol. 3, July 1991, pp.-18 (issue 8), and pp. 1-51 (issue 9).*
B *Massachusetts Department of Public Utilities, "Investigation by the Department of Public Utilities on its own motion as to the environmental externality values to be used in resource cost-effectiveness tests by electric companies subject to the Department's jurisdiction," D.P.U. 91-131, November 10, 1992.*
C *Mitchell, Cynthia, "State Regulatory Experiences in Attempting to Quantify and Incorporate Environmental Externalities: The Nevada Experiences," 1991.*
D *California Public Utilities Commission, Decision 91-06-022, June 5, 1991.*
E *Buchanan, Shepard C., "Dancing with the Bear: Lessons Learned in Applying Externality Costs to Real World Resources," paper presented at the National Association of Regulatory Utility Commissioners/U.S. Department of Energy Fourth National Integrated Resource Planning Conference, Burlington, VT, September 15, 1992.*
F *"Wisconsin PSC Orders that $15/ton CO_2 Value Be Added to Utility Power Project Plans," Utility Environment Report, May 29, 1992, p. 1.*

federal environmental regulators and the large expenditures on environmental controls. Further, if the existing regulations are inadequate, they feel state commissions are not well-positioned to make corrections.

2. Further regulations of electric utility industry could reduce economic benefits because of piecemeal problems.

One of the key principles for reducing external costs is that all external costs and benefits that result from a full range of relevant pollutants from all sources should be considered in order to minimize total social cost. Not adhering to this principle can result in a host of so-called "piecemeal" problems. "Piecemeal" problems are costs or benefit changes that potentially increase social costs due to situational, rather than broad-based, development and application of policies designed to address external costs of pollutants. This could occur by singling out one source of pollution out of many sources, one geographic area out of many areas, one economic sector of industry, or one fuel source from many. For example, as indicated in *Figure T4-8*, the utility industry accounts for only 36 percent of carbon dioxide emissions, while industrial and transportation sectors account for approximately 52 percent of total U.S. emissions. If the external costs of carbon dioxide are included only in electric utility planning and operation, there may be undesirable cost changes or actions created in the electric utility sector.

Some of these undesirable changes or distortions in minimizing social costs would include fuel switching from electricity to other fuel and economic dislocation between sectors of the economy (e.g., electricity, transportation). The economic distortion could include the movement of industry from areas that include external costs to areas that exclude external costs, and changes in production and consumption patterns with overproduction (compared to optimum) of products without external costs included in the price to underproduction (compared to optimum) of products with external costs included in the price.

Another example of a "piecemeal" problem is that many regulatory agencies are including external costs only in new resource decisions, which could bias resource efficiency through the increased use of existing resources that may have higher emissions rates.

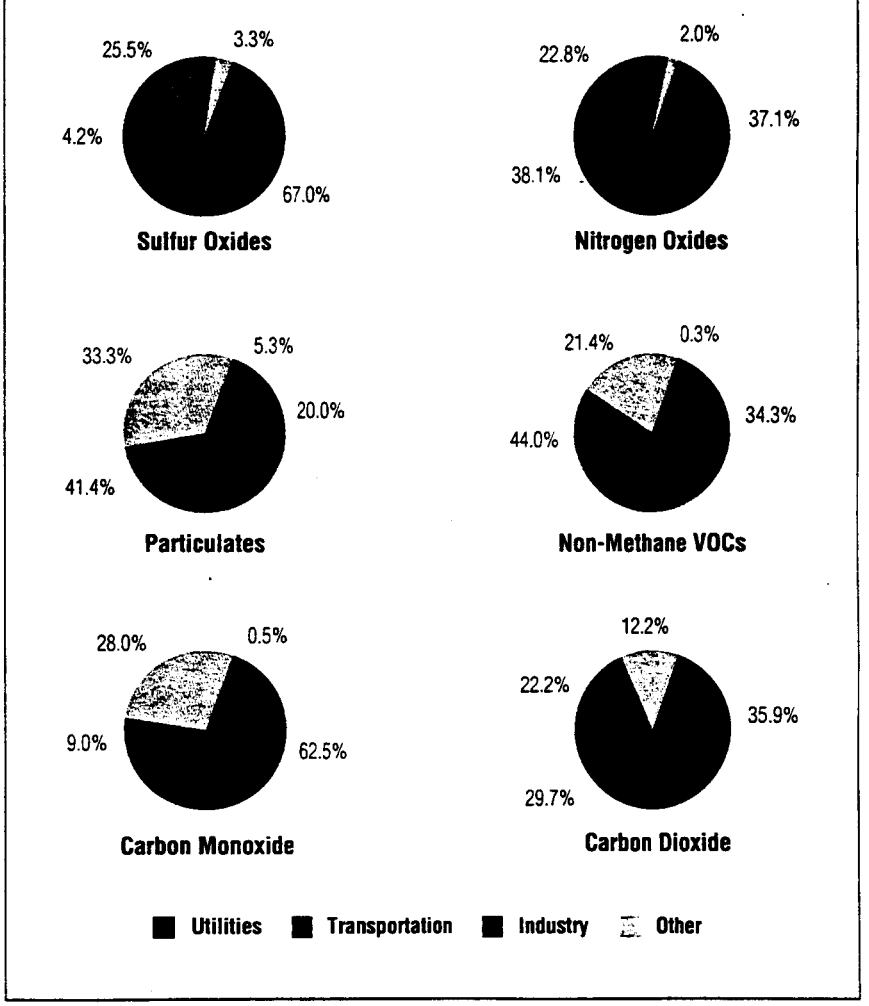
3. Current valuation methodologies are flawed.

Another common theme in opponents' arguments stems from doubts about the current methodologies used to estimate externality values. In particular, they are critical of the cost-of-control method, which they argue does not reflect a valid benefit-cost analysis because the political process that produced a given level of control reflects more than just the value of the remaining environment impacts.

4. Uncertainty exists in the quality of the damage cost estimates.

A major uncertainty is the quality of the estimates of the external cost of environmental externalities. The preferred method is to estimate the external costs based on the cost of the dam-

FIGURE T4-8. **Emissions by Sector in the United States**



age resulting from the pollutant. From an economic efficiency perspective, social costs are minimized by reducing a pollutant up to the point at which the reduction in marginal damage is equal to the marginal costs of reducing the pollutant. Emissions of sulfur dioxide may cause increased costs of health care or illness. Increased carbon dioxide emissions may result in global warming with its associated costs.

One of the major uncertainties in dealing with the externality problem is the difficulty of estimating the marginal damages from the emissions of an externality. Sulfur dioxide emissions may cause health problems with individuals, it may damage watersheds and forests, and it may affect agriculture production. Estimating the costs of these effects is extremely difficult; therefore, any resulting estimates may be highly uncertain, as previously indicated in *Figure T4-7.*

5. Some air emissions are already regulated.

Existing regulations already or soon will internalize all costs resulting in a zero value for the costs of residual emissions. For example, the Clean Air Act provisions for the regulations of sulfur dioxide permit the trading of allowances for emissions below the regulated limits. The value for allowances is an estimate of the external cost of residual emissions. Thus, further monetization of externalities is not necessary.

TVA's Approach to Environmental Externalities

Given the many difficulties of monetizing externalities and the lack of coherent position within the electric utility industry, TVA does not monetize externalities in the Energy Vision 2020.

Rather, TVA has addressed externalities by using several environmental measures as part of the evaluation criteria used in Energy Vision 2020. Emissions of sulfur dioxide, carbon dioxide, nitrogen oxides, and several other pollutants are measured for resource options. The environmental measures are then used in the multi-attribute trade-off analysis. In addition, externalities have been qualitatively considered through the programmatic environmental review.

In Energy Vision 2020, the potential for future environmental regulations (specifically, carbon dioxide legislation which imposes a dollars per ton tax on carbon dioxide emissions) is explicitly identified. Resource options or strategies that meet environmental future regulations are evaluated based on this evaluation criteria.

Summary of the Rationale by Public Service Commissions for Not Monetizing Externalities

A number of public utility commissions (PUCs) have offered reasons or stated a rationale for not monetizing environmental externalities. Below is a summary of those statements.

Alaska. The Alaska Public Utilities Commission said in its review of the Healy Clean Coal Project that it believes externality requirements to be beyond its current authority. (Docket #U-92-11) (EPRINET, 1994)

Colorado. The Public Utilities Commission rejected monetization of externalities in integrated resource planning. In a 1993 decision, the commissioners stated that: "...the methods for quantification of externalities are highly complex, and, at this time still speculative... Given this state of knowledge, it would be premature to mandate utilities to monetize externalities." (Docket #91R-642E) (EPRINET, 1994)

Connecticut. The Public Utilities Commission ruled in December 1993 that it will not require utilities to use monetized adders to value externalities in least cost planning. Rather, utilities will be directed to use "trade-off analysis" which involves the use of computer models to compare the external cost and benefits of power plan scenarios.[1] The process was developed by researchers at Massachusetts Institute of Technology. (EPRINET, 1994) However, the PUC accepted United Illuminating's voluntary use of a 25 percent credit for demand-side management programs without requiring the credit of other utilities.

Florida. The Department of Environmental Regulation (DER) was directed to review the state's power plant siting process to consider how externalities should be considered. Monetization of externalities was not recommended, but consideration of environmental factors in the selection and evaluation of new resources was suggested. (EPRINET, 1994)

The Public Service Commission stated that it does not believe it should consider environmental externalities when evaluating cost effectiveness in need determinations. The Public Service Commission has stated that it "...has neither the expertise, the

[1] The externalities to be modeled include EMF, economic development, electric system reliability, fuel risk, and impacts on air, land, and water. For air emissions, only NO_x and VOCs were determined not to already be fully internalized by regulatory efforts. The impacts of CO_2 were to be assessed by utilities. Other externalities determined to be fully internalized were SO_2; ash, sludge; hazardous waste disposal; nuclear waste; and noise, visual, and property impacts. (EPRINET, 1994)

personnel, nor a statutory directive to consider such environmental issues. These matters, traditionally and statutorily, have been considered by the DER and not the Public Service Commission. (EPRINET, 1994)

Idaho. The Public Utilities Commission found that the quantification method requires further exploration and environmental externalities be quantified as part of the statewide energy planning process on the basis that insufficient record evidence existed to make an informed decision. The ICC later concluded that the externalities issue requires further study, and that an adversarial approach is appropriate for determining an approach for incorporating externalities into utility planning. (EPRINET, 1994)

Maine. The Public Utilities Commission was directed by legislation to study the extent to which externalities should be included in utility planning. The subsequent Public Utilities Commission report strongly recommended against externality requirements at this time. (EPRINET, 1994)

Michigan. The Public Service Commission seems to concur with its administrative law judge, finding that "implementation of a system to evaluate environmental factors to take into account the differences between combustion and non-combustion resources bids is not appropriate at this time." (Case #U-9586) The administrative law judge also ruled that the Public Service Commission is not authorized to handicap a particular resource. (EPRINET, 1994)

In April 1992, another administrative law judge rejected the consideration of environmental externalities as a requirement on the grounds that the Public Service Commission has no specific legislative mandate to engage in environmental protection activities. The Public Service Commission staff had agreed that the Public Service Commission does have authority to address externalities, and that environmental costs can be estimated. (EPRINET, 1994)

Virginia. Although the Virginia State Corporation Commission indirectly requires utilities to consider environmental externalities, it has stated that the potentially higher rates associated with a resource mix chosen with environmental externalities in mind would be speculative and thus not consistent with its legal authority. The Commission suggests that the environmental externalities are best left to U.S. Congress and the General Assembly of Virginia. (EPRINET, 1994)

Public Service Commission Testimony Regarding Monetization

In an Edison Electric Institute publication (1992), 18 testimonies from Public Service Commissions were summarized with the intent of presenting representative views on the issue of monetizing environmental externalities. Of these testimonies, eight argued against monetization as follows:

A. James Barnes[2] on behalf of Massachusetts Electric Company argued that the monetized values derived by the Tellus Institute and used by the State were based on faulty assumptions. The Tellus Institute used the marginal cost of control as the revealed preference for the cost of environmental externalities (the residual emissions). Barnes argued that existing environmental regulations have resulted in past externalities being internalized; that is, the residual emissions are not of significant value or concern (a value of zero).

Marc Goldsmith[3] on behalf of several Illinois utilities testified that the quality and quantity of available data on environmental impacts are insufficient to justify assignment of monetized values. Another opinion given was that unreliable data or incomplete methods may cause increases in the cost of electricity, but not other energy sources not subject to monetized externalities, which raises competitiveness issues, and increases potential for higher ratepayer costs by biasing supply planning toward higher cost generation.

Alfred Kahn[4] on behalf of Tampa Electric Company testified that there are possible distortions and inefficiencies in imposing additional environmental costs on only selected segments of the energy market that happens to be regulated by the Public Utilities Commission.

Lester Lave[5] on behalf of Western Massachusetts Electric Company testified that the marginal benefit of abatement rather than the marginal cost of control should be used for valuation. According to Lave, the benefits of further abatement are negligible for health for most pollutants in areas where National Ambient Air Quality Standards (NAAQS) are being met (an exception is indirect ozone formation effects). Some small benefits were assigned for visibility and "other." The resulting ranges of externality values are considerably lower (especially the low range value) than most estimates using damage costs or cost of control.

2 Dean, School of Public and Environmental Affairs, Indiana University.

3 President, Energy Research Group, Inc.

4 Special Consultant, National Economic Research Associates.

5 Professor of Economics and Professor of Engineering and Public Policy, Carnegie-Mellon University.

Richard Lester[6] on behalf of the National Independent Energy Producers recommended suspension of Massachusetts' environmental externalities policy until negative environmental, economic, and public policy consequences are addressed. Specifically, he stated that as a policy option, monetized externalities appear to fail in meeting three objectives: (1) efficacy–because emission reductions are not effective since only new resource decisions are affected, (2) cost effectiveness–minimization of mitigation costs are not achieved, and (3) increased costs are passed directly to the consumer. The Massachusetts policy of using externalities only for evaluation of new resources excluded the source of most pollution, the existing power plants. Also, it was asserted that the remaining sulfur dioxide externality was zero and that the cost of control cannot be applied for carbon dioxide since without regulation there was no basis for choosing a control technology. On the topic of fuel switching, it was pointed out that if monetized externalities cause a significant rate increase, the end-use switching to non-electric fuels may result in an increase in pollution. The use of state-imposed regulations to solve regional or global problems may cause competitive disadvantages within the state unless uniform policies are adopted in neighboring states.

Larry Ruff[7] on behalf of Delaware Power and Light Company recommended that the Public Utilities Commission not adopt monetized environmental externalities using a cost of control methodology. He suggested that further study be conducted on society's willingness to pay and that the environmental and regulatory situation in Delaware be reviewed. Ruff argued that a system-wide approach to utilizing existing capacity, not the modification of new resource decisions, is the key to cost-effective emissions reductions. He also contends that an inaccurate estimate of an externality improperly applied can easily be worse than assuming a value of zero. Also, he believes externalities is not a policy that can be applied on a piecemeal basis, if no evaluation of existing capacity or competitive energy resources.

Richard Schmalensee[8] on behalf of Massachusetts Electric Company presented three conclusions regarding the development, application, and role of externality values in IRP: (1) the marginal cost of control used by the Tellus Institute and adopted by the Public Utilities Commission is incorrect in principle; (2) if values are to be calculated, they should be based on non-internalized residual damages and applied only to net incremental emissions after offsets; and (3) in lieu of a piecemeal approach to environmental protection, the Public Utilities Commission should address broader environmental concerns by promoting least-cost control strategies. In regard to conclusion 1, Schmalensee contends that there is no support for the view that Congress or state legislators have "revealed" through their actions that residual damages have the values calculated by Tellus. Concerning the use of residual damages to determine externality values, the values must be applied to all sources, not just electric utilities, to avoid a piecemeal approach to environmental protection. And because residual damages may differ, dependent on the location of emissions, the values from other states or regions should not necessarily be used, should differ with location of each power plant, and should take into account environmental regulations already in place. Schmalensee also argued that an sulfur dioxide externality had no economic meaning in light of the 1990 Clean Air Act and that it would not change the overall level of sulfur dioxide in the U.S. He also said that it made no environmental or economic sense to impose a "large" carbon dioxide emissions value.

Department of Energy comments to the Texas Public Service Commission made the following points: (1) Department of Energy prefers damage-based values since other proxy measures such as the highest marginal cost of control are unlikely to have any relationship to damages. Department of Energy pointed out serious flaws in both the Tellus and Pace University studies and that values from these studies differed by as much as a factor of 16; (2) net system impacts of all alternatives (DSM and generation) should be considered before applying externalities (for example, an alternative with the highest capacity factor will displace more existing generating capacity, and therefore emissions, than an alternative with a lower capacity factor, where the net system impact is the increase in pollution from the new alternative minus the decrease in pollution from existing generation, which will operate less often because of the new alternative); (3) sulfur dioxide will be fully internalized after the year 2000 and should have a value of zero, and it is premature to assign a value to carbon dioxide because of uncertainty in damage costs; and (4) Department of Energy advises against a cost penalty for other criteria pollutants unless it is clear that existing programs have not fully internalized the costs.

6 Professor of Nuclear Engineering and Executive Director of the Commission on Industrial Productivity, Massachusetts Institute of Technology.

7 Director, Putnam, Hayes & Bartlett, Inc.

8 Professor of Economics and Management and Director of the MIT Center for Energy Policy Research, Massachusetts Institute of Technology.

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Energy Vision

2020

Volume 2, Technical Document

5 Load Forecast

Volume 2, Technical Document 5

Load Forecast

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This technical document has two major sections that were originally separate information items. These were the basis for various discussions on load forecast that TVA used to develop Energy Vision 2020.

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Load Forecast

ENERGY VISION 2020 LOAD FORECAST SUMMARY – 1994

Introduction

Like many utilities, TVA forecasts the long-term energy and peak demand outlook 20 to 25 years into the future. The long-term forecast is developed from individual forecasts of residential, commercial, and industrial sales. These forecasts serve as the basis for planning the TVA power system, budgeting, and financial planning. The Energy Vision 2020 forecast is based on five elements necessary for state-of-the-art forecasting:

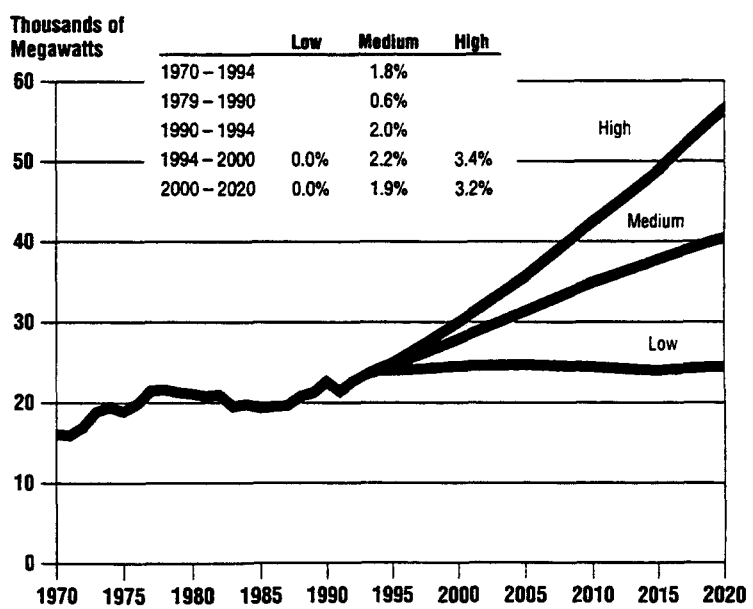
- Accuracy
- Use of best information
- Use of best methods
- Explicit treatment of uncertainty
- Continuous improvement

TVA's system energy forecast is the sum of forecasts by sector. *Figure T5-2* shows the breakdown of the medium forecast into the residential, commercial, and manufacturing sectors. Total energy requirements in 1994 were 35 percent residential, 25 percent commercial, 30 percent manufacturing, and 10 percent other sales and system losses. The commercial and manufacturing sectors are expected to increase faster than residential from 1994 to 2000. From 2000 to 2020, the directly served portion of the manufacturing sector is expected to grow less than the other sectors.

Summary of Results

The range of long-term peak load forecasts developed for Energy Vision 2020 is shown in *Figure T5-1*. For the medium forecast, peak loads are expected to increase 2.2 percent per year from 1994 to 2000 and 1.9 percent per year from 2000 to 2020. Recognizing the uncertainty in forecasting, TVA's high load forecast annual growth is approximately 3.3 percent from 1994 to 2020, and the low forecast is less than 1 percent from 1994 to 2020.

FIGURE T5-1. **System Peak Forecast**



Actual and projected growth of system peak needs are shown. High, medium, and low forecasts were developed to address uncertainties in the future. Under the medium forecast, peak demand is projected to be approximately 40,000 megawatts by 2020.

Historical Perspective—Forecast Accuracy

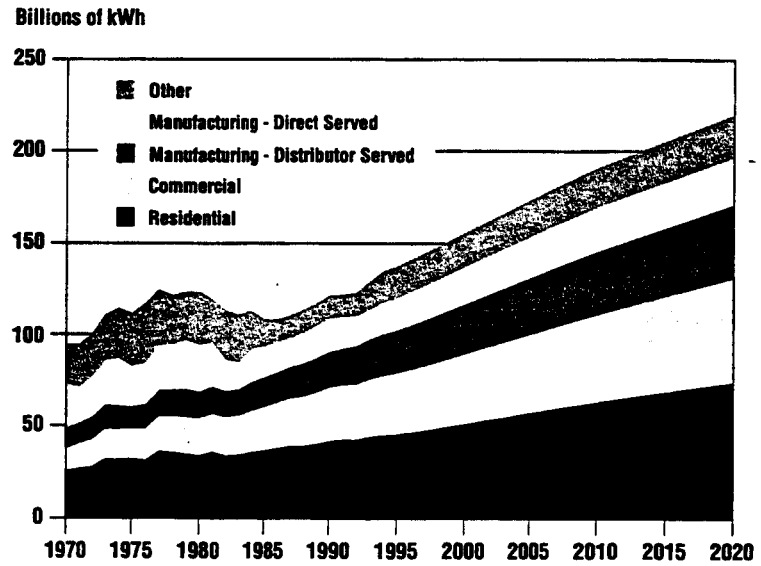
Forecasting is inherently uncertain. However, TVA's load forecast accuracy since 1985 has been within 5 percent (plus or minus) of actual loads, as shown in *Figure T5-3*. This is well within the industry standard of plus or minus 8 percent accuracy. A 1991 review of TVA forecasts by Barakat & Chamberlin, Inc. concluded that: "...on a comparative basis, TVA's forecasting procedures compare very favorably with the best-practice procedures in the United States utility industry."

FORECASTING IN THE 1970S

TVA's load forecasting has changed dramatically over the last 20 years. Until the late 1970s, forecasting at TVA consisted of examining the historical trend of energy sales and projecting future sales based on past growth. These early forecasts were based on a generally stable picture. Underlying factors such as the price of electricity and the economic situation were not considered, causing the forecasts of the 1970s to be very optimistic. TVA's 1970 and 1975 forecasts, shown in *Figure T5-4*, illustrate the error rate for these forecasts.

During and after the oil embargoes of the 1970s, the world economy experienced a long recession and steadily rising energy prices. These changes caused TVA to look to new forecasting techniques that recognized fundamental changes that were taking place in energy costs and patterns of energy use. The old methods were producing large inaccuracies and simply no longer worked.

FIGURE T5-2. **Sales by Customer Class**



ANNUAL INCREASE IN SALES %

	Residential	Commercial	Manufacturing Distributor Served	Manufacturing Direct Served	Other
1970 – 94	2.4%	4.3%	3.2%	-1.5%	-1.7%
1979 – 90	1.6%	3.6%	2.2%	-3.4%	-6.7%
1990 – 94	2.4%	3.0%	4.3%	-2.3%	4.6%
1994 – 00	1.7%	2.5%	2.8%	3.5%	4.0%
2000 – 20	1.9%	2.0%	2.0%	1.1%	1.2%

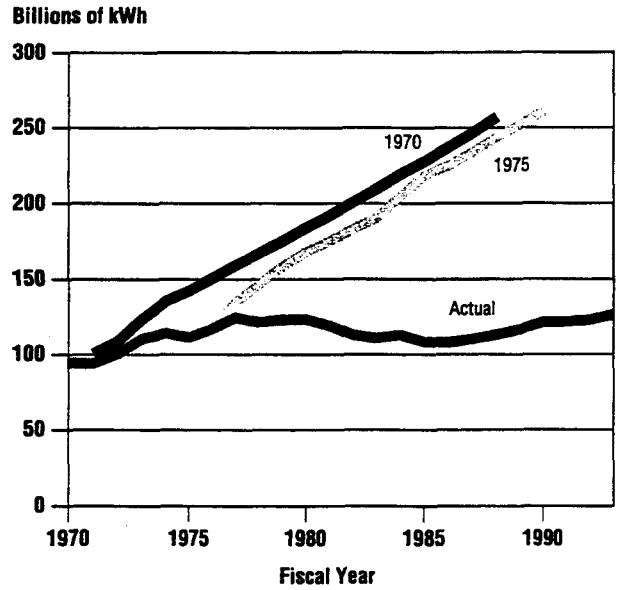
Electricity sales are shown for the customer classes of residential, commercial, and manufacturing. Electricity sales for the manufacturing customer class are divided into sales to industrial customers served by distributors and sales to industries served directly by TVA. The "other" category includes outdoor lighting sales and power sales to other federal agencies.

FIGURE T5-3. **TVA Five-Year Forecast Record**

Year Forecast Prepared	Forecast Target Year	Peak (MW)	Forecast Actual (MW)	Error (Percent)
1983	1988	22,610	20,684	9.3
1984	1989	22,546	21,149	6.6
1985	1990	21,669	21,142	2.5
1986	1991	22,348	21,810	2.5
1987	1992	21,493	22,533	-4.6
1988	1993	23,119	23,354	-1.0
Average Absolute Error				4.4

Since 1985, TVA's load forecast for five years ahead has been within 5 percent (plus or minus) of actual loads.

FIGURE T5-4. **Comparison of Historic Forecasts 1970s – System Energy**



Forecasting techniques used in the 1970s proved to be too optimistic. Earlier forecasts did not explicitly consider uncertainty in prices and economic variables.

FORECASTING IN THE 1980S AND 1990S

New approaches adopted by TVA in the late 1970s included using better quality data in the forecasts, using econometric and end-use models, and making special provisions to deal with uncertainty.

TVA's 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.

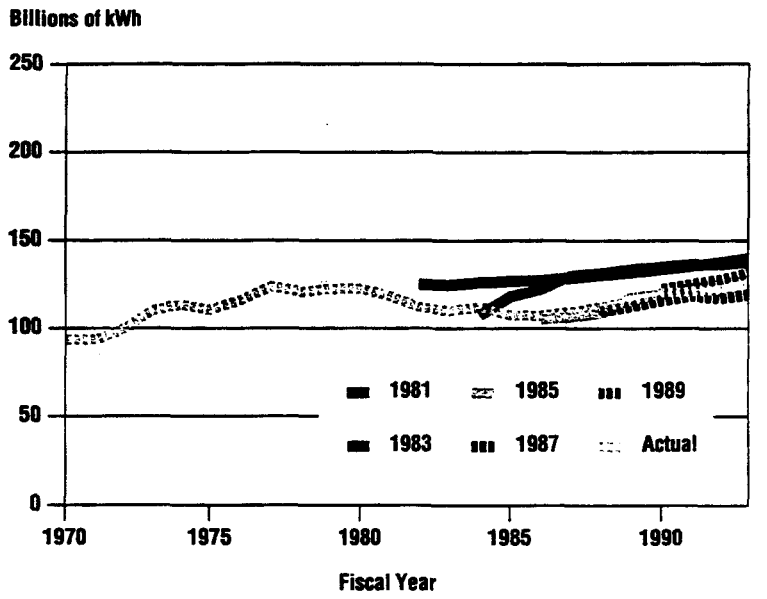
Underlying trends within each sector, such as the use of various types of equipment or processes, also play a major role in forecasting sales. To capture these trends, TVA uses a variety of state-of-the-art end-use forecasting models. For example, in the residential sector, sales are forecast for space heating, air conditioning, water heating, and several other uses. In the commercial sector, a number of end-use categories including lighting, cooling, refrigeration, and space heating are examined.

End-use and econometric models have vastly increased the amount of data used in TVA forecasting. TVA uses a cutting-edge Regional Economic Simulation Model (RESM) to forecast regional economic activity. The regional economic forecasts are based on national economic forecasts provided by DRI/McGraw-Hill.

Forecasts of the price of electricity are provided from TVA's financial modeling. In addition, during the 1980s, TVA began conducting numerous surveys of its residential and business customers. This continuing survey effort provides valuable information on TVA customer market shares, the kinds of electric equipment used, and equipment efficiency. Finally, the inaccurate forecasts of the 1970s demonstrated to utility planners that there is much uncertainty in even the best forecast. In the 1980s, TVA began to deal with this uncertainty by using high and low forecasts to bracket the medium forecast.

Figure T5-5 shows the improved accuracy of TVA forecasts developed in the 1980s. While the 1981 and 1983 forecasts had errors relating to large declines in Department of Energy (DOE) contracts, they are still more accurate than their predecessors. Since 1985—when most of the improvements were fully implemented—every load forecast has been within plus or minus 5 percent accuracy.

FIGURE T5-5. **Comparison of Historic Forecasts 1980s – System Energy**



Forecasting techniques were improved in the 1980s, resulting in a more accurate forecast. Since 1985, TVA's load forecast has been within plus or minus 5 percent accuracy.

Key Variables Affecting the Forecast

Four key variables are used in the load forecasts and in each of the residential, commercial, and industrial sectors.

- Economic activity
- Price of electricity
- TVA's level of competitive success
- Price of substitute fuels

The impact of these variables on the use of electricity is not measured by a single value. Instead, a range of values is developed from which a range of load forecasts is derived. The uncertainties section of this technical document discusses how the range of load forecasts is developed. The key variables are discussed in greater detail below.

ECONOMIC ACTIVITY

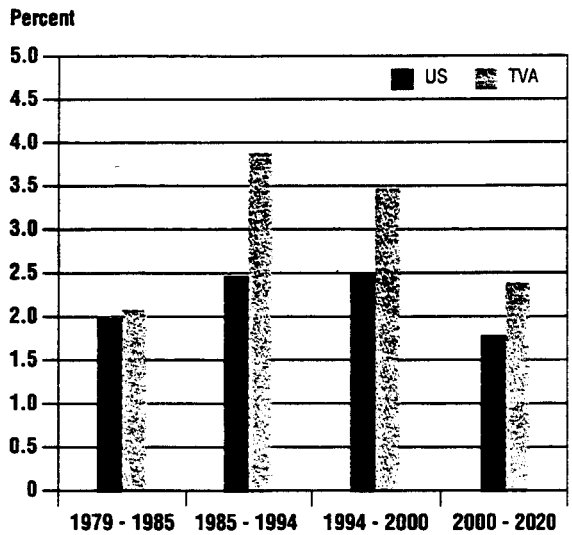
TVA produces its own forecasts of regional economic activity using a Regional Economic Simulation Model (RESM), an econometric model of the TVA region's economy. TVA's forecasts are based on forecasts of the national economy by DRI/McGraw-Hill, an internationally recognized forecasting service. However, RESM does not blindly attribute national trends to the TVA region. Instead, it recognizes differences inherent in the region's economic structure that cause it to perform differently than the United States.

The most likely outlook is for the region to continue to outperform the nation *(Figure T5-6)*. Gross Regional Product (GRP) is forecast to grow 3.5 percent annually from 1994 to 2000 and 2.4 percent from 2000 to 2020, while national Gross Domestic Product (GDP) is expected to grow at 2.5 and 1.8 percent for the respective periods. This compares favorably with the historical performance of GRP and GDP shown in *Figure T5-6*.

The region's economy is expected to grow faster than the rest of the nation's, largely due to the region's advantages in manufacturing. In 1994, about 29 percent of total product in the region was in manufacturing, as opposed to 19 percent for the United States. Manufacturing's predominance in the regional economy is due to several factors:

- A location in the South between the markets of the Northeast, Midwest, Southwest, and Florida
- A good transportation system allowing goods to be shipped to these markets by interstate, rail, and barge
- A good, low wage (for the United States) workforce
- Relatively low-cost, abundant resources including water, electricity, and land

FIGURE T5-6. **Gross Product Comparison – TVA vs. U.S. Average Annual Growth Rates**



This figure shows the most likely outlook is for the Tennessee Valley to continue to outperform the nation. This is largely due to the region's advantages in manufacturing. Manufacturing output in the Tennessee Valley is expected to surpass national average growth rates, continuing the trend since 1985.

Because of these advantages, the regional economic model forecasts manufacturing in the region to outperform manufacturing in the United States, continuing the trend since 1985. Before 1985, manufacturing was adversely affected by exceptionally high oil and energy prices, high interest rates, and the high value of the dollar compared to other currencies. These factors have returned to relatively low levels and are expected to remain relatively low in the future. Given the region's dependence on manufacturing, this sets up favorable conditions for the region's economic growth.

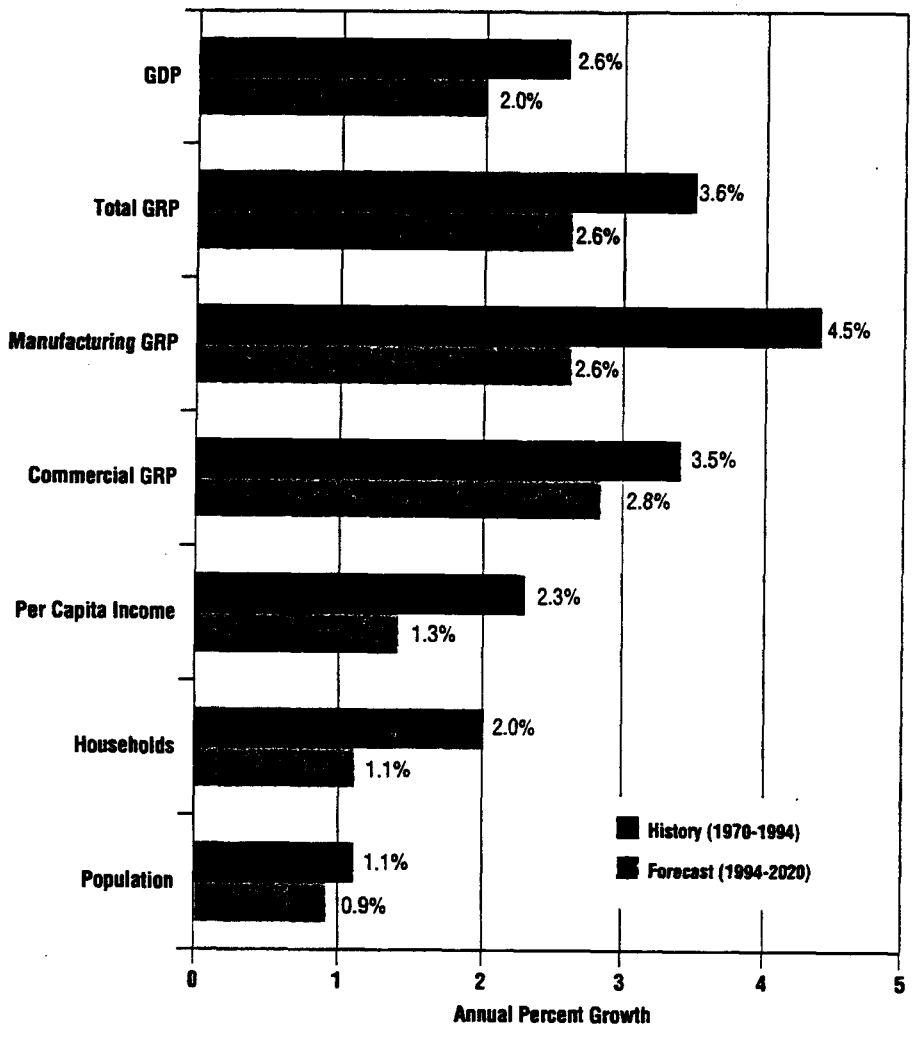
Within the manufacturing sector of the regional economy, several industries are showing favorable growth trends. Durable goods production has expanded while, at the same time, nondurables have held up better than in the rest of the United States. Although there are several examples of newer durable industries growing in the TVA region, such as machinery and furniture, the prime example is motor vehicles. Employment in the motor vehicle industry has grown much faster in the region than the nation, with considerable potential for continuing expansion.

Over the rest of the decade, the region's performance is expected to be similar to that of the 1985-1994 period as newer manufacturing industries continue to expand and national economic conditions remain favorable. Beyond the year 2000, manufacturing is expected to continue to provide enough impetus for the region to expand at a somewhat faster rate than the United States, but the region's growth is expected to be slower than before 2000 as the region's newer manufacturing industries reach maturity. The region does not have particular advantages in the commercial sector as it does for manufacturing. Thus, with the slowing of manufacturing growth, the overall regional economy is expected to grow at a rate closer to the nation's economic growth.

From the economic forecast, several variables are used as drivers to the load forecasts. For the residential sector, population, households, and per capita income drive the load forecast in the Valley. For the commercial and industrial sector, output or Gross Regional Product are key drivers. The historical and predicted growth rates for the medium forecast of the economic variables are shown in *Figure T5-7.*

To account for uncertainty, high and low regional economic forecasts are derived by using corresponding national forecasts and the TVA low and high electricity price forecasts. In addition,

FIGURE T5-7. **Economic Outlook – History and Forecast**



Economic forecasts for the TVA region are developed as part of the load forecast process. Historical and predicted growth rates for economic variables are shown for the medium regional economic forecast. Economic growth is expected to slow from the 1970-1994 rates.

explicit assumptions are made concerning national and international developments. The high scenario assumes that the region will develop a commercial sector that more closely matches that of the nation. On the other hand, the low scenario assumes that the Valley is more affected by foreign competition and that the commercial sector does not develop further.

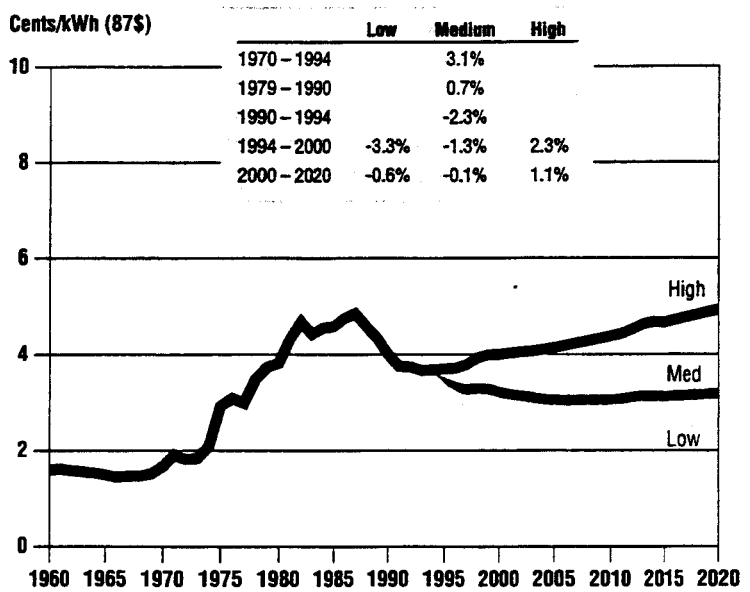
Additional information on the economic forecasts is available from TVA in a report titled "Economic Outlook."

PRICE OF ELECTRICITY

TVA has not increased electricity prices since 1987 and is committed to no rate increases through 1997. This has been achieved through a combination of efforts including controlling costs, refinancing debt, and efficiency improvements. Holding rates constant is expected to continue to have a positive impact on electricity sales.

The real wholesale price of electricity (excluding inflation) is expected to decline 1.3 percent per year from 1994 to 2000 and decline further at 0.1 percent per year from 2000 to 2020 as shown in the medium forecast in *Figure T5-8*. For the low

FIGURE T5-8. **Wholesale Price of Electricity**



The wholesale price of electricity without inflation is expected to decline through 2020 under the low and medium forecasts.

forecast, the price of electricity will decrease by 3.3 percent per year from 1994 to 2000 and 0.6 percent per year from 2000 to 2020. For the high forecast, the price of electricity will grow at 2.3 percent per year from 1994 to 2000 and 1.1 percent per year from 2000 to 2020.

Forecasts of the price of electricity are based on estimates of the total revenue required to operate and maintain the power system. Forecasts of total revenue requirements are based on estimates of key costs such as fuel, operations and maintenance, depreciation, and interest costs. Therefore, the high and low electric price forecasts are derived from variations in the same factors: fuel, operations and maintenance, depreciation, and interest costs.

TVA'S LEVEL OF COMPETITIVE SUCCESS

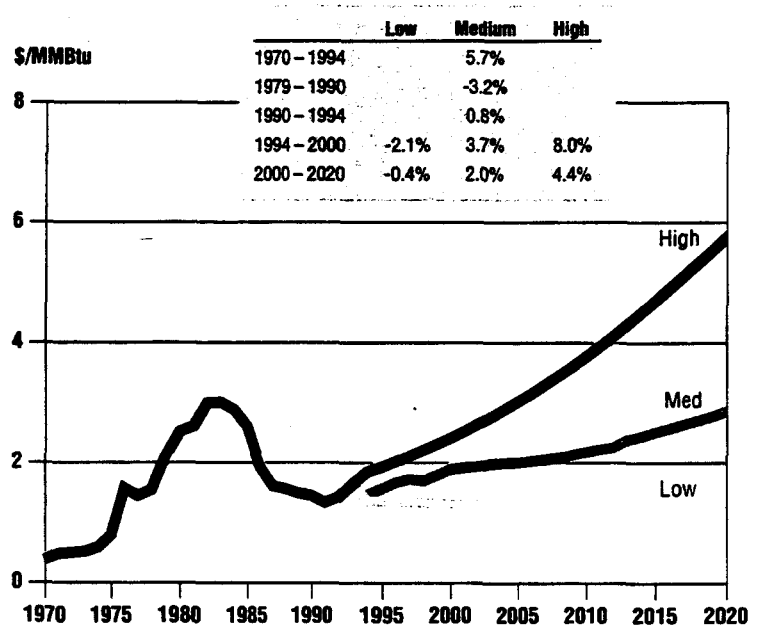
In recent years, the electric utility industry has undergone a fundamental change. The world of regulated monopoly is being replaced by a world of competitive pressures. Wholesale open access (the right of wholesale customers to buy power from generating utilities other than the one whose lines serve them) can be mandated by the Federal Energy Regulatory Commission (FERC). Retail firms, such as large industrial customers, are looking for the same privilege, and retail open access is beginning to be mandated by some state regulatory bodies. In a more competitive market, TVA's success as a generating company will be greatly affected by whether TVA is successful in being a low-cost producer.

TVA has incorporated different competitive scenarios into its forecasts. In the medium forecast, TVA's price of electricity is expected to remain competitive with other utilities. Market and regulatory changes would have less impact in the medium case than in the high or low cases. As a result, the net impact of competition in the medium forecast is that TVA will retain its current customers.

The prospect of increasingly competitive markets increases the uncertainty in the forecast. If TVA operates at lower costs than the competition and regulations permit, TVA may have opportunities to gain customers. This is termed high competitive success. Likewise, if TVA is a higher cost producer than its competitors, it is likely to lose customers—described as low competitive success. Both cases assume that deregulation of the electric market continues. The high and low forecasts recognize the risks and opportunities of increased competition.

TVA analyzed competitive impacts for all sales. The effort was aimed at looking at the market rather than specific customers. In the low competitive success case, TVA will lose customers to competing electric utilities. In order to estimate the potential for losing sales to competition, TVA's customer survey—complet-

FIGURE T5-9 **Natural Gas Acquisition Price**



	Low	Medium	High
1970 – 1994		5.7%	
1979 – 1990		-3.2%	
1990 – 1994		0.8%	
1994 – 2000	-2.1%	3.7%	8.0%
2000 – 2020	-0.4%	2.0%	4.4%

Natural gas prices without inflation are expected to increase 3.7 percent annually through 2000 and 2 percent per year from 2000 to 2020 under the medium forecast.

ed by many of TVA's distributors and directly served customers—was used to identify the amount of load that appeared to be at high risk.

In the high competitive success case, TVA will gain customers from its competition. To estimate the potential for this gain in the wholesale markets, loads of municipal and cooperative distributors in neighboring regions were used. The chance of gaining any distributor was partly influenced by the wholesale price paid by that distributor. Because a very large percentage of TVA's sales are wholesale compared to neighboring utilities, the potential gain in the wholesale market in the high competitive success case was smaller than the potential loss in the low competitive success case.

For directly served customers, less specific information on nearby opportunities was available. Because TVA is surrounded by states with large industrial loads, a judgment was made that potential gain is higher than potential loss of industrial loads.

Wholesale and retail gains in load were assigned the highest probability for the low electric price forecast, making TVA more competitive. A more complete discussion of all uncertainties in the forecast can be found in the uncertainty section.

PRICE OF SUBSTITUTE FUELS

The potential for substitution between electricity and fossil fuels, primarily oil and natural gas, will depend on relative prices and technological factors. Changes in the TVA price of electricity compared to the price of natural gas and other fuels will influence consumers' choices of appliances—either electric, gas, or other fuels. While other substitutions are possible, natural gas prices are the benchmark for determining substitution impacts in the load forecasts.

In preparing the medium natural gas price forecast, TVA relied on forecasts by Energy Ventures Analysis, Inc., Jofree Corporation, and ICF Resources. The forecast for natural gas prices is higher than for electricity. Natural gas prices in real terms are forecast to increase at 3.7 percent from 1994 to 2000 and at 2.0 percent from 2000 to 2020 as shown in *Figure T5-9*.

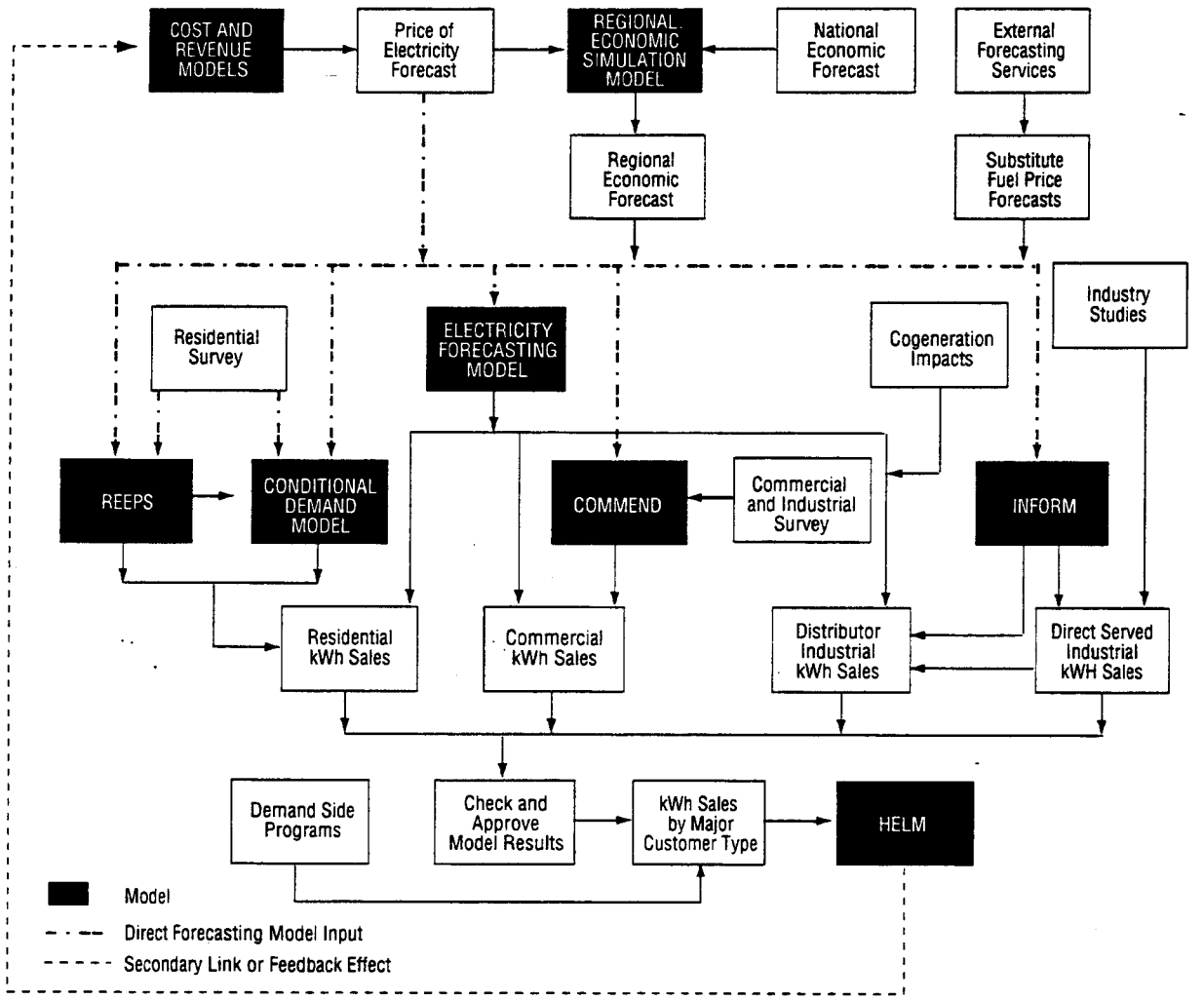
The high and low forecasts for gas prices were derived using several nationally recognized forecasters such as Gas Research Institute, American Gas Association, DRI/McGraw-Hill, and the Energy Information Administration. The high forecast is for growth rates of 8.0 percent per year from 1994 to 2000 and 4.4 percent per year from 2000 to 2020. The low is for -2.1 percent per year and -0.4 percent per year over the same periods.

TVA Uses the Best Methods Available

TVA stays abreast of issues and procedures relating to energy forecasting and continually incorporates new information into its forecasting process. The use of multiple forecasting models makes it possible to avoid blind spots that could result with a single model. At TVA, several advanced forecasting models and techniques have been incorporated to form a complete forecasting system from data collection to evaluation of forecast uncertainties. To deal with uncertainty, the forecast does not rely on a single estimate, but provides decision-makers with a range of forecasts. An overview of the TVA forecasting process is shown in *Figure T5-10*.

The system forecast is built up from its major sectors: residential, commercial, and industrial. The outputs of several models for each sector are systematically compared, and trends

FIGURE T5-10. **Overview of TVA's Load Forecasting Process**



The load forecasting process is illustrated by this flow chart which shows how information is gathered and evaluated to form the basis of the forecast. Multiple models or computer simulations are used to ensure that all possibilities and impacts are considered.

in key parameters, such as saturation rates and unit energy consumption, are examined.

Large customers that have significant electricity requirements are analyzed individually. In addition, each major industry group, such as paper or machinery, is reviewed annually for changes in technology, finances, competitive structure, etc. Ranges of values for key variables are developed in order to measure the varying impacts on TVA sales.

Econometric modeling is used extensively. The strengths of this approach include the explicit estimation of the historical response of electricity consumption to electricity prices, natural gas prices, and income. Each of TVA's primary customer sectors is considered individually in the models to allow for changing shares of energy use.

End-use models are used to measure how much energy consumption will occur from given end uses such as residential air conditioners, office lighting, and industrial motors. These models can reflect how energy use is changing within sectors. While econometric models are tied to historical data, end-use models allow forecasters to incorporate expected future events

such as the introduction of mandated efficiency standards or the arrival of new technologies.

Conditional demand and qualitative choice analysis is a hybrid of econometric and end-use modeling. TVA uses this analysis in the residential sector and is developing a commercial conditional demand model. This analysis is useful in estimating the relationship between electricity consumption and demographic characteristics. These models incorporate the best of econometric and end-use models and allow for a more detailed analysis of each sector.

Best methods available include the following models, which are used in the Energy Vision 2020 forecast:

- Residential Conditional Demand Model (RCDM)
- Residential Energy End-Use Planning System (REEPS)
- Electricity Forecasting Model (EFM)
- Commercial Energy End-Use Model (COMMEND)
- Industrial Energy End-Use Model (INFORM)
- Regional Economic Simulation Model (RESM)
- Financial Model used in price of electricity (FINESSE)
- Hourly Electric Load Model (HELM)

RESIDENTIAL SECTOR FORECASTING MODELS

Residential Conditional Demand Model (RCDM)

This model is based on econometric analysis of data from TVA's residential surveys, which is used to estimate unit energy consumption of major appliances, along with price and income elasticities. This allows individual components of the residential model to be forecast. The estimates of unit energy consumption are used in conjunction with saturation forecasts by appliance types to produce forecasts of total residential sector electricity use. The estimates of unit energy consumption are also used in calibrating Residential Energy End-Use Planning System (REEPS), using TVA service territory data.

Residential Energy End-Use Planning System (REEPS)

REEPS is an end-use econometric model of electricity consumption developed with the Electric Power Research Institute (EPRI). REEPS forecasts residential energy consumption by end-use, fuel type, and market segment in order to forecast market potential and saturation of residential end uses by fuel type and market segment. This model also analyzes the impacts of mandated or utility-sponsored demand-side management programs. REEPS generates aggregate forecasts for the entire residential sector by calculating a weighted sum of all residential market segments. Thus, TVA can evaluate forecast impacts on each market segment, rather than simply assessing behavior of the "average" household.

Electricity Forecasting Model (EFM)

This is an aggregate time series econometric model. For the residential sector, consumption per customer is the major variable. The independent variables are average real price of electricity, average real price of natural gas, and real annual per capita income. By multiplying sales per customer by the projected number of residential customers, a forecast for the total sector is derived.

COMMERCIAL SECTOR FORECASTING MODELS

Commercial Energy End-Use Model (COMMEND)

COMMEND, widely used by utilities and regulatory agencies, was developed by Electric Power Research Institute. It forecasts energy consumption by building types and end uses. COMMEND allows its user to assess the impacts of energy price changes, technology, efficiencies, and economic growth. It also identifies and evaluates demand-side management opportunities. The model allows up to 20 building types to be addressed, each with a variety of end uses.

Electricity Forecasting Model (EFM)

EFM is an econometric forecasting model for the commercial sector. EFM divides the commercial sector into six subsectors—(1) regulated industries, (2) wholesale/retail trade, (3) finance/insurance and real estate, (4) service, (5) government, and (6) unclassified. Electricity demand is derived for each sector based on Gross Regional Product, employment, the real price of electricity, and the real price of natural gas.

INDUSTRIAL SECTOR FORECASTING MODELS

Industrial Energy End-Use Model (INFORM)

INFORM is an industrial end-use model developed by the Electric Power Research Institute. TVA began using this model in 1992. The model categorizes energy sales by subsector and end use.

Electricity Forecasting Model (EFM)

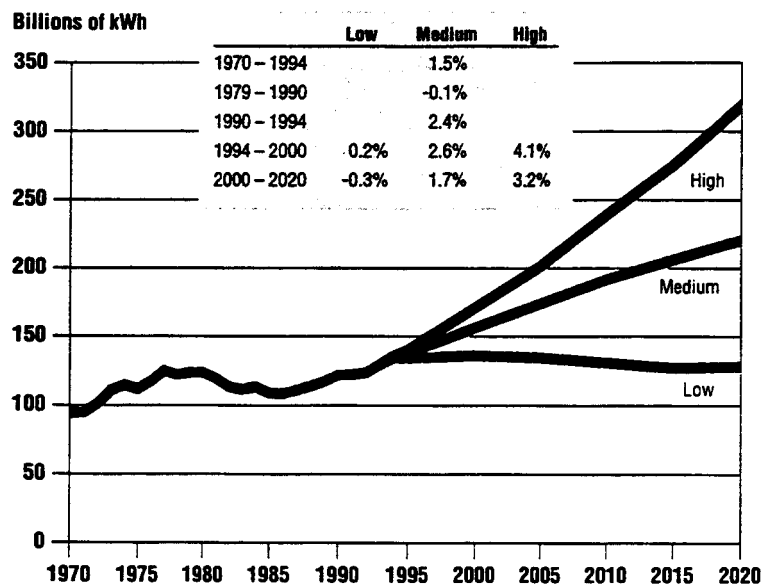
EFM is an econometric forecasting model for the industrial sector. It is divided into subsectors for food, machinery, paper, textiles, chemicals, primary metals, other nondurable goods, and other durable goods. The dependent variable is energy use, and the independent variables are Gross Regional Product, employment, the real price of electricity, and the real price of natural gas.

OTHER FORECASTING MODELS

Regional Economic Simulation Model (RESM)

RESM is an econometric model of the TVA region that maps out the regional economy with its major linkages and feedbacks and its relations to the United States economy. This model uses state-of-the-art methods comparable to those of the major nation-

FIGURE T5-11. **System Energy Requirements**



	Low	Medium	High
1970 – 1994		1.5%	
1979 – 1990		-0.1%	
1990 – 1994		2.4%	
1994 – 2000	0.2%	2.6%	4.1%
2000 – 2020	-0.3%	1.7%	3.2%

Actual and projected growth of electricity needs are shown. High, medium, and low forecasts were developed to reflect future uncertainty. Energy requirements are projected to be 219.7 billion kilowatt-hours by 2020 under the medium forecast.

Financial Model (FINESSE)

This model, developed in-house by TVA, estimates TVA's total revenue requirements over time. The forecast of revenue requirements is based on forecasts of the individual cost components. These cost components include the load forecast, capital costs, additions and improvements (A&I) costs, interest rates, fuel costs, and operating and maintenance (O&M) costs.

Hourly Electric Load Model (HELM)

HELM was developed in partnership with TVA, Electric Power Research Institute, and ICF Resources during the early 1980s. It produces an hourly load or peak load forecast based on forecasts of energy consumption. HELM analyzes the load-shape impacts of many changing conditions, including conservation and load management programs, rate design alternatives, market penetrations of new electricity-using technologies, changes in the mix of customers or end uses, and alternative weather conditions.

al forecasters. Several professional papers have been presented on the model including presentations at the Electric Power Research Institute (EPRI) forecasting conference in 1991.

The two major inputs, or key assumptions, to RESM are the national economic forecast from DRI/McGraw-Hill and industrial electricity prices.

RESM is a highly disaggregated model which uses two-digit standard industrial classification (SIC) detail. With regard to the manufacturing sector, there are equations for chemicals, apparel, primary metals, etc. For the commercial sector there are equations for eating and drinking establishments, health services, hotels, etc. This allows for linkages between industries—for instance, wholesale trade is linked to retail trade.

RESM does not simply capture trends, but rather, it captures the differences inherent in the regional economic structure that leads the region to perform differently than the nation as a whole.

Further details on the forecast methodology and accuracy may be found in "Economic Forecasting Methodology and Validation" included in this document.

Load Forecast Results

The medium forecast for total system energy for Energy Vision 2020 is 155.5 billion kilowatt-hours in 2000 and 219.6 billion kilowatt-hours in 2020, as shown in *Figure T5-11*. The medium load forecast is based on the medium forecasts of all the variables discussed in the previous section. The medium forecast assumes the TVA region will experience moderate economic growth of 2.7 percent annually through 2020. It assumes that TVA can maintain its "no rate increase" policy through 1997 and thereafter maintain competitive rates. It is also assumed TVA is able to successfully defend its current market if a less-regulated and more competitive marketplace develops, as expected. Finally, the medium forecast assumes any inroads made by natural gas are not severe, due to TVA's ability to maintain its price versus the price of natural gas.

The Energy Vision 2020 high load forecast is for 170 billion kilowatt-hours in 2000, 238 billion kilowatt-hours in 2010, and 317.5 billion kilowatt-hours in 2020. The primary factor influencing the high load forecast is high economic growth. Competitive success and continued relatively low electric prices also contribute to TVA's success in the high forecast. The

Energy Vision 2020 low load forecast is for 135.1 billion kilowatt-hours in 2000, 129.9 billion kilowatt-hours in 2010, and 126.3 billion kilowatt-hours in 2020, with growth generally less than 1 percent. Low annual economic growth is a major influence in the low load forecast. The low economic scenario can be summarized as follows: the recovery falters and, in the long term, the United States and the TVA region become less competitive globally, interest rates become unstable, and inflation rises. In short, the TVA region has manufacturing output growth of 0.2 percent and commercial output growth of 1.3 percent through 2020.

RESIDENTIAL SECTOR FORECAST

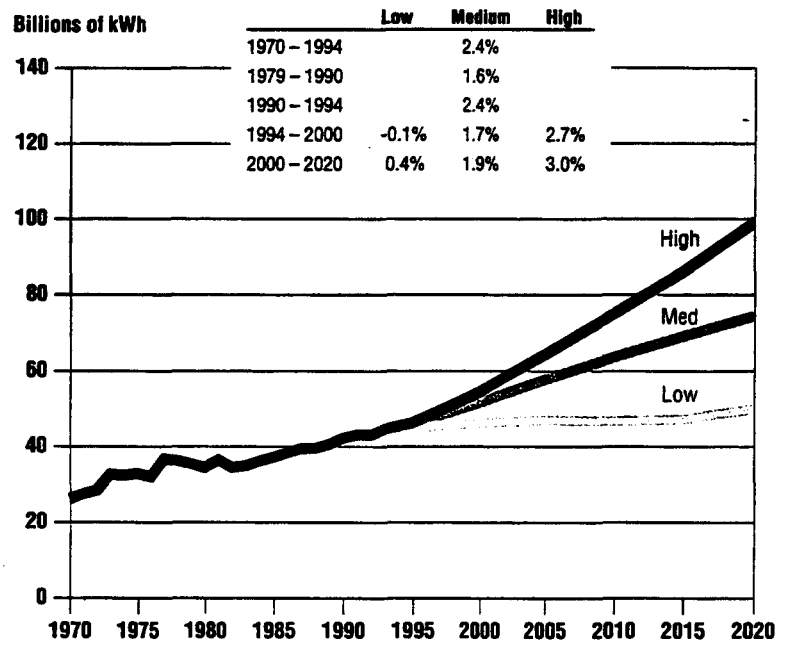
Long-term sales forecasts for the residential customer sector are shown in *Figure T5-12.* In the medium forecast, residential sales are forecast to be 51.4 billion kilowatt-hours in 2000, 63.4 billion kilowatt-hours in 2010, and 74.3 billion kilowatt-hours in 2020. Corresponding growth rates are 1.7 percent per year from 1994 to 2000 and 1.9 percent per year from 2000 to 2020. For the high residential sales forecast, the percent per year growth is 2.7 percent from 1994 to 2000 and 3.0 percent from 2000 to 2020. The low forecast is -0.1 percent from 1994 to 2000 and 0.4 percent from 2000 to 2020.

The residential forecasts are influenced by six factors: per capita income, population, residential electric prices, residential gas prices, household types, and efficiencies, as shown in *Figure T5-13.*

Residential End-Use Energy Forecast

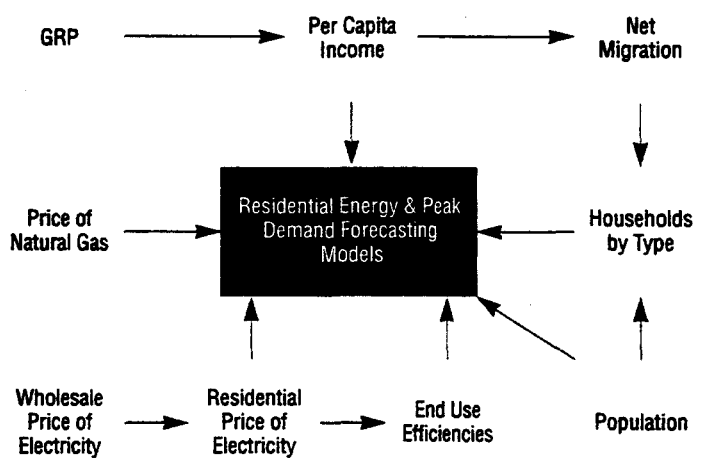
The residential forecast is developed from forecasts of end uses of electricity. Major end uses include space heating, space cooling, water heating, refrigerators, freezers, and cooking. The share of residential electricity sales attributable to each of these end uses and miscellaneous use is shown in *Figure T5-14.* The largest increase in the share of total residential electricity use is for the "other" category, which moves from 31.5 percent to 41.1 percent. The miscellaneous category includes a number of appliances, such as dishwashers,

FIGURE T5-12. **Total Residential Sales**



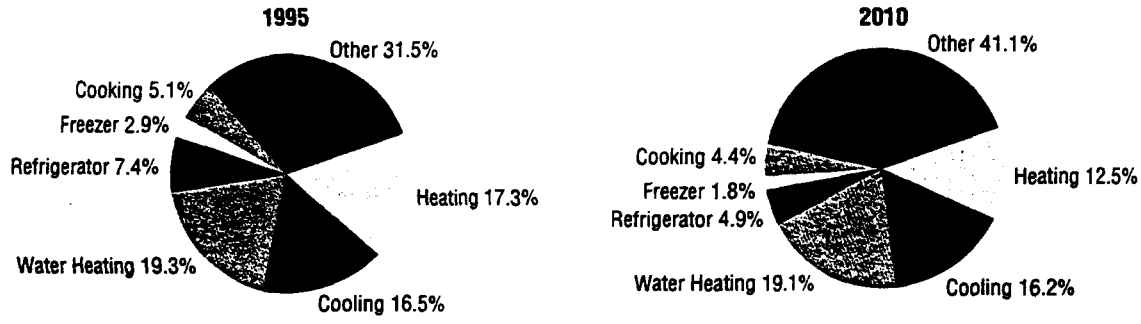
Residential sales are expected to increase to 74.3 billion kilowatt-hours by 2020 under the medium forecast.

FIGURE T5-13. **Residential Sector Influence Diagram**



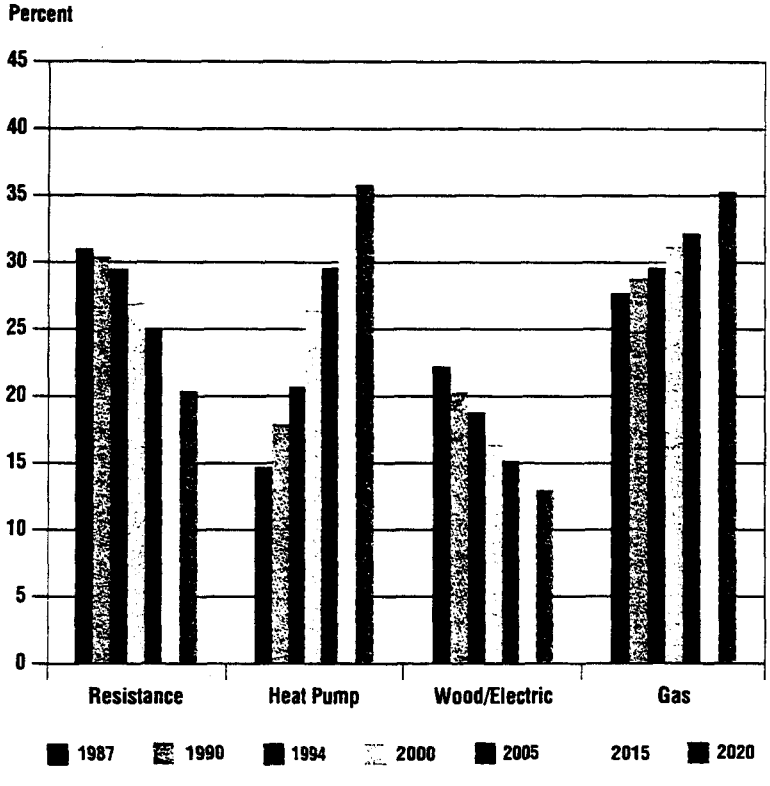
Residential forecasts are influenced by six factors: per capita income, population, residential electric prices, residential gas prices, household types, and efficiencies.

FIGURE T5-14. **Percent of Residential Sales by End Use**



TVA anticipates changes in the way residential consumers use electricity through 2010. The largest increase in the share of total residential electricity use is for the "other" category. The largest decrease in the share of total residential electricity use is for the heating category.

FIGURE T5-15. **Residential Space Heating Saturations**



Electric heat pumps and natural gas heating units are expected to continue to gain favor with consumers at the expense of resistance electric heating and wood-burning stoves.

clothes washers, clothes dryers, and the increasing use of electronic equipment in the home, for which room for growth remains as incomes increase. The heating share drops the most as total heating energy rises only slightly over the forecast period.

Residential Saturations

Major factors in the changing end-use energy forecasts are changes in the saturation of appliances. Saturation is defined as the percentage of total households that have a particular appliance. In the long term, consumers switch to more efficient end-use appliances, as well as those using fuels that are declining relatively in price. Changes in space heating saturations are shown in *Figure T5-15*. Heat pumps are substituted for resistance heat, especially in areas where natural gas is not available. Heat pumps increase in saturation from 21 percent of total households in 1994 to 26 percent in 2000 and 36 percent in 2020. These heat pumps provide both heating and cooling. Electric resistance space heat declines from 29 percent in 1994 to 27 percent in 2000 and 20 percent in 2020. Natural gas used for space heating increases from 30 percent in 1994 to 31 percent in 2000 and 35 percent in 2020. Electric backup for wood heat is expected to decline due to the decline in wood as a primary heating fuel. The gains by

both heat pumps and gas furnaces are at the expense of the dwindling wood heat market and declining resistance heat.

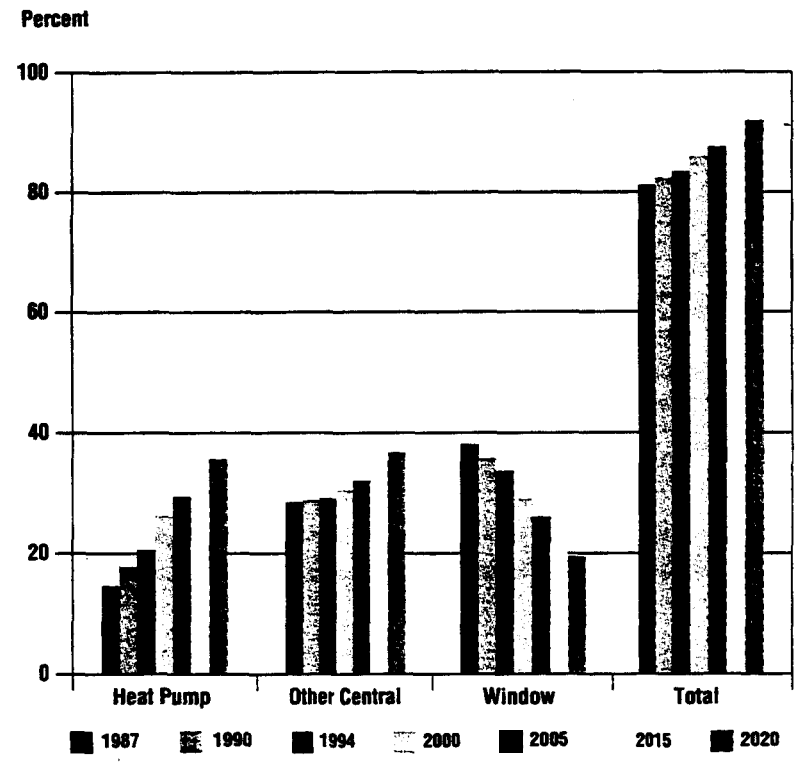
Central air conditioning other than heat pumps increases from 29 percent in 1994 to 31 percent in 2000 and 37 percent in 2020, as shown in *Figure T5-16*. Window air conditioning saturation drops from 33 percent to 20 percent by 2020. Total air conditioning saturation increases from 84 percent in 1994 to 92 percent by 2020.

Residential water heating is dominated by electricity. The saturation of electric resistance water heating decreases slightly from 77 to 75 percent. Natural gas water heating saturation increases moderately from 22 to 25 percent over the same period. Declining electricity prices support the electric water heating market share in spite of increasing competition from natural gas.

Residential Efficiency Improvements

Another major factor in changing end-use energy forecasts is improvement in efficiency of the appliances. These improvements reduce the amount of fuel needed to provide a given level of service. As a result, forecasts of efficiency improvements will reduce the forecast of electricity sales. End-use efficiency improvements for the residential customer class are shown in *Figure T5-17*. The efficiency improvements are in terms of the percentage reduction in energy use by the years 2000 and 2020. For example, heat pump efficiency increases by 12 percent over current levels by 2020, air conditioning efficiency increases by 11.2 percent, and water heating decreases by 7 percent. Efficiency improvements estimates incorporate requirements of the Energy Policy Act of 1992.

FIGURE T5-16. **Residential Space Cooling Saturations**



Air conditioning saturation is projected to increase to 92 percent by 2020.

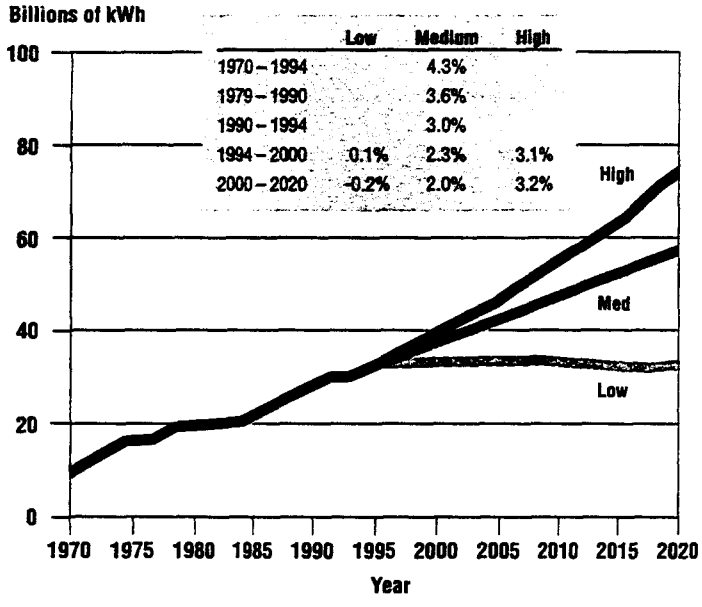
FIGURE T5-17. **Residential Efficiency Improvements 1995–2020**

Water Heating	-7.0%
Resistance Heating	0.0%
Central Air Conditioning	11.2%
Heat Pump Heating	12.0%
Heat Pump Cooling	13.6%
Freezer	20.2%
Refrigeration	59.4%

Total Residential Improvements 7.2%

Efficiency improvements in home appliances and heating and cooling equipment will affect future load by reducing the amount of energy needed to provide a given level of service. Because direct electric heating is 100 percent efficient, little opportunity exists for efficiency improvements in water heating and resistance heating. The declining efficiency for water heating is a result of consumers becoming less concerned with the insulation levels of their water heaters as electricity prices fall.

FIGURE T5-18. **Total Commercial Sales**



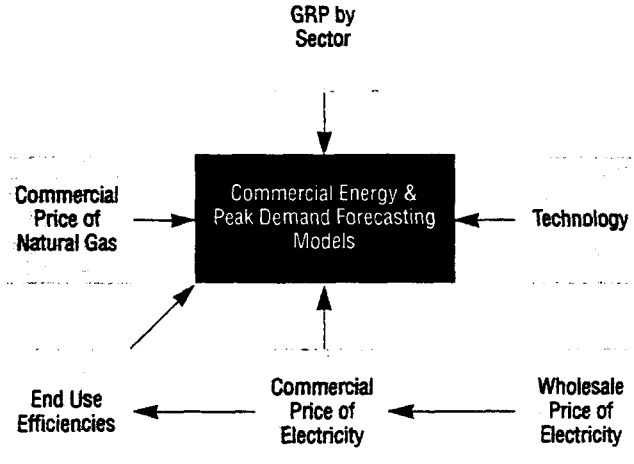
Commercial sales are expected to be 56.9 billion kilowatt-hours in 2020 for the medium forecast.

COMMERCIAL SECTOR FORECAST

Long-term sales forecasts for the commercial sector are shown in *Figure T5-18.* In the medium forecast, commercial kilowatt-hours sales are expected to be 38.2 billion kilowatt-hours in 2000 and 56.9 billion kilowatt-hours in 2020. Corresponding growth rates are 2.3 percent per year from 1994 to 2000 and 2.0 percent per year from 2000 to 2020. For the high commercial sales forecast, the growth rates are 3.1 percent from 1994 to 2000 and 3.2 percent from 2000 to 2020. The corresponding sales growth in the low forecast is 0.1 percent from 1994 to 2000 and -0.2 percent from 2000 to 2020.

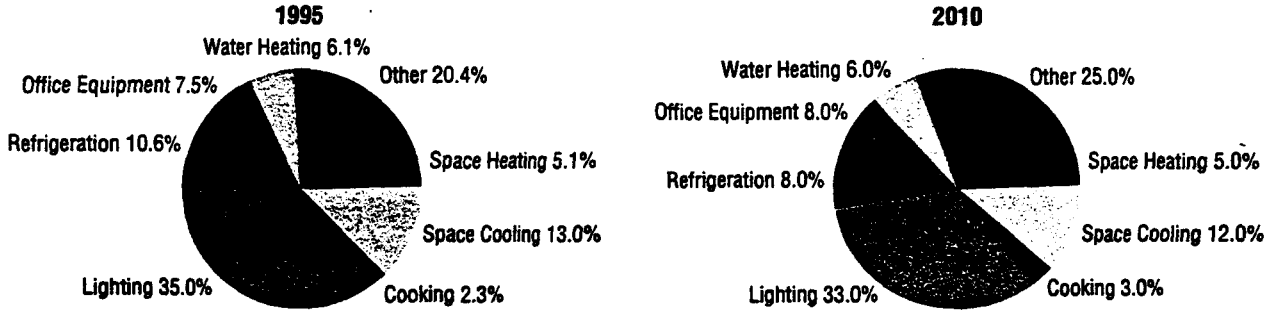
The commercial sector sales forecast is driven by economic activity, the price of electricity, the price of competing fuels, efficiency improvements, and technology, as indicated in *Figure T5-19.*

FIGURE T5-19. **Commercial Sector Influence Diagram**



The commercial sector sales forecast is driven by economic activity (in terms of GRP by sector), the price of electricity, the price of competing fuels, efficiency improvements, and technology.

FIGURE T5-20. **Percent of Commercial Sales by End Use**



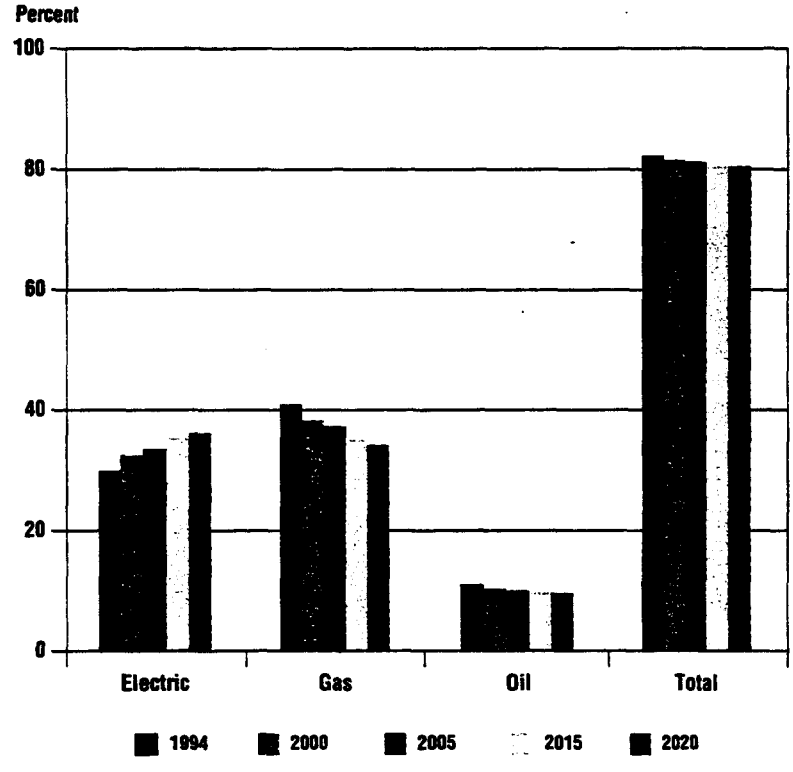
Commercial sales for cooking, office equipment, and miscellaneous uses are expected to increase through the next 15 years.

Commercial End-Use Energy Forecasts

In the commercial sector, the major end uses are space cooling, lighting, space heating, refrigeration, and office equipment. The share of commercial electricity sales attributable to each of these end uses is shown in *Figure T5-20.* Cooking, office equipment, and miscellaneous uses show increasing shares of the total energy consumption between 1994 and 2010.

As in the residential sector, end-use energy forecasts are influenced by two major factors, the saturations of each appliance and improvements in efficiency of the appliances.

FIGURE T5-21. **Commercial Space Heating Saturations**



Electric heating for commercial customers is expected to increase through 2020 at the expense of gas and oil. Rising gas and oil prices will influence this change.

Commercial Saturations

Space heating saturations by fuel type are shown for the commercial sector in *Figure T5-21.* The saturation of electric space heat increases from 30 percent in 1994 to 36 percent in 2020. Natural gas saturation declines from 41 percent in 1994 to 34 percent in 2020 as gas prices increase. Oil, liquefied petroleum (LP) gas, and other fuels used for space heating decline from 11 to 10 percent.

Other saturations also impact commercial sales. The total saturation of air conditioning increases from 66 percent in 1994 to 71 percent in 2020. The saturation of electric water heating is 43 percent in 1994 and 53 percent in 2020. Over the same period, natural gas water heating saturation declines slightly from 36 to 31 percent, and oil water heating declines from 3 to 1 percent. The saturation of electric lighting is very nearly 100 percent.

FIGURE T5-22. **Commercial Efficiency Improvements 1995–2020**

Resistance Heating	0.0%
Space Cooling	6.6%
Refrigeration	4.9%
Lighting	8.4%
Heat Pump Heating	12.8%
Office Equipment	22.3%

Total Commercial Improvements 9.4%

Efficiency improvements in commercial lighting and space cooling will have significant impact on commercial energy usage since lighting and cooling currently consume about half of the energy used in the commercial sector.

Commercial Efficiency Improvements

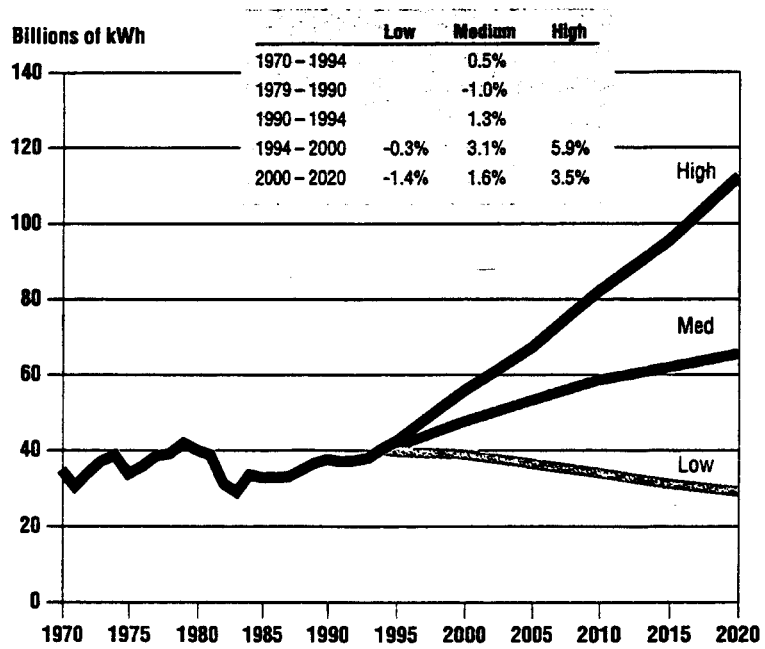
The impact of efficiency improvements and alternative technologies on the commercial long-term sales forecast is shown in *Figure T5-22*. The major impact is in the improvement in efficiency in lighting of 8.4 percent from 1995-2020 and the improvement in space cooling of 6.6 percent over the same period. Efficiency improvements in lighting and cooling have large impacts because lighting and space cooling consumed 48 percent of the energy in the commercial sector in 1994. The impact of efficient office equipment, primarily more efficient computers, is also significant. Efficient office equipment and lighting also generate less heat and reduce cooling requirements. The efficiency improvements comply with the provisions of the Energy Policy Act of 1992.

MANUFACTURING SECTOR FORECAST

The medium manufacturing sales forecast, shown in *Figure T5-23*, has growth rates of 3.1 percent per year from 1994 to 2000 and 1.6 percent per year from 2000 to 2020. The medium forecast of manufacturing kilowatt-hours sales is reasonably bounded by the high and low forecasts, which have 1994 to 2020 growth rates of 5.9 and -0.3 percent per year, respectively.

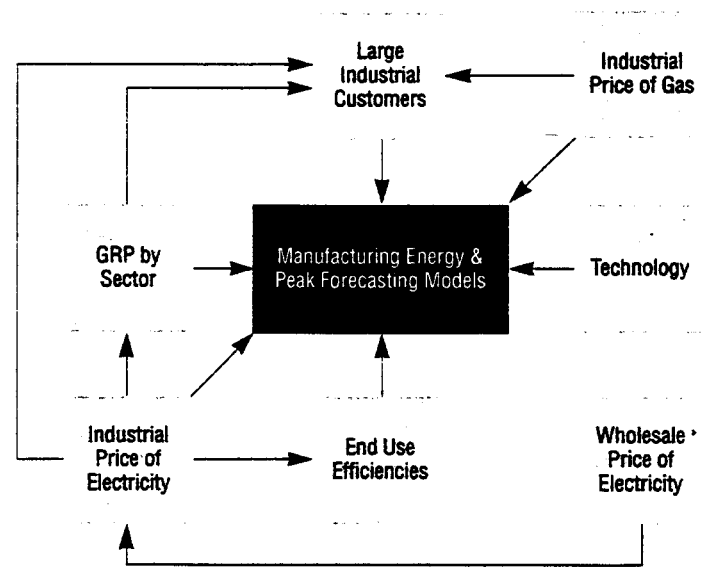
Manufacturing sales are forecast for individual industry groups or standard industrial classification (SIC) codes. In each industry group the sales are influenced by the five major factors shown

FIGURE T5-23. **Total Manufacturing Sales**



Energy sales to manufacturing customers are expected to increase to over 65 billion kilowatt-hours by 2020.

FIGURE T5-24. **Manufacturing Sector Influence Diagram**



Factors affecting sales to manufacturing customers include economic activity (in terms of GRP by sector), price of electricity, price of industrial gas, efficiency improvements, and technology.

in *Figure T5-24* economic activity, price of electricity, price of industrial gas, efficiency improvements, and technology.

These inputs are used in the industrial forecast models to forecast manufacturing sales. In addition, a general survey of business conditions is made for each major industry group. This survey includes major products, technology, and business conditions specific to an industry group. Also, each industry is considered from an international, national, and regional perspective, emphasizing the competitive situation, new products, environmental concerns, and other related issues.

The forecasts of manufacturing by industry groups are shown in *Figure T5-25*.

FIGURE T5-25. **Manufacturing Sales by Industry Group**

	Billions of kWh			Average Annual Growth Rate	
	1979	1994	2020	1979-1994	1994-2020
Food	1.5	2.8	5.7	4.3%	2.8%
Textiles & Apparel	1.9	2.4	3.3	1.6%	1.2%
Paper	2.2	4.8	8.6	5.3%	2.3%
Chemicals	11.7	9.5	11.2	-1.4%	0.6%
Primary Metals	17.1	6.4	9.1	-6.3%	1.4%
Machinery	3.0	4.4	6.9	2.6%	1.8%
Other Durables	2.8	5.6	9.1	4.7%	1.9%
Other Nondurables	1.9	3.9	11.9	4.9%	4.4%
Total Manufacturing	42.1	39.8	65.8	0.4%	2.0%

Electric sales to manufacturing customers are expected to reach 65.8 billion kilowatt-hours by 2020. Other nondurables, food processing, and paper manufacturing are expected to lead in average annual growth rates among Valley industries.

Distributor Served Industries

Manufacturing sales by the 160 power distributors within the TVA service area were 23.1 billion kilowatt-hours in 1994. These sales accounted for 58 percent of the total manufacturing sales in 1994 and are expected to increase to 61 percent in 2020. Distributor served sales have experienced 2.8 percent growth since 1979 in contrast to the -3.0 percent growth in TVA directly served sales. This trend is expected to continue with a 2.2 percent growth in distributor served industry sales through 2020. *Figure T5-26* shows the kilowatt-hours and average annual growth rates for distributor served industry sales.

FIGURE T5-26. **Distributor Served Industrial Sales**

	Billions of kWh			Average Annual Growth Rate	
	1979	1994	2020	1979-1994	1994-2020
Food	1.5	2.8	5.0	4.2%	2.3%
Textiles & Apparel	1.9	2.4	3.3	1.6%	1.2%
Paper	0.8	1.1	1.7	2.1%	1.7%
Chemicals	2.6	2.7	2.9	0.3%	0.3%
Primary Metals	1.5	2.2	2.2	2.6%	0.0%
Machinery	2.5	3.7	5.7	2.6%	1.7%
Other Durables	2.6	4.5	7.8	3.7%	2.1%
Other Nondurables	1.9	3.7	11.7	4.5%	4.5%
	15.3	23.1	40.3	2.8%	2.2%

Distributor manufacturing sales are expected to reach 40.3 billion kilowatt-hours by 2020. The growth leader is expected to be other nondurables at 4.5%.

Other nondurables are expected to be the leader in growth with 4.5 percent annual growth rate through 2020. Nondurables consist primarily of printing and publications, miscellaneous plastics, and petroleum products, among other industries. The food industries are expected to follow with 2.3 percent annual growth rate.

Directly Served Industries

The directly served industrial class consists of relatively large customers served directly by TVA. They account for 42 percent of manufacturing sales and 13 percent of total TVA sales. These sales are spread among 54 companies and are concentrated in 3 industries—primary metals, paper, and chemicals. A close look at each customer is required because these customers have a significant impact on TVA sales.

The forecast for directly served industries is built up on a company-by-company basis. The outlook for the company and the industry is developed from several sources of information. This includes specific company information, industry outlooks, and national economic industry forecasts.

Forecasts for major directly served industries are shown in *Figure T5-27*. Total energy sales for directly served industries are expected to increase from 16.8 billion kilowatt-hours in 1994 to 25.4 billion kilowatt-hours in 2020. Historically, total directly served sales have declined by 3.5 percent per year, largely based on the decline in primary metals and to a lesser degree in chemicals. From 1994 to 2020, directly served industry sales are expected to increase 1.6 percent per year.

FIGURE T5-27. **Directly Served Industrial Sales**

	Billions of kWh			Average Annual Growth Rate	
	1979	1994	2020	1979-1994	1994-2020
Primary Metals	15.6	4.2	6.9	-8.4%	1.9%
Chemicals	9.0	6.9	8.2	-1.8%	0.7%
Chlorine	3.4	4.2	4.7	1.4%	0.4%
Fibers	2.2	2.0	3.0	-0.1%	1.6%
Other Chemicals	3.4	0.7	0.5	-10.0%	-1.3%
Paper	1.4	3.7	6.9	6.7%	2.4%
Other	0.7	2.0	3.4	7.3%	2.1%
Total Direct Served	26.7	16.8	25.4	-3.0%	1.6%

Energy sales to industries served directly by TVA are expected to increase to 25.4 billion kilowatt-hours annually by 2020.

Cogeneration

Cogeneration is the production of electricity by an industry for its own use. Cogeneration by directly served industries is forecast to increase from 2.3 billion kilowatt-hours in 1994 to 3.1 billion kilowatt-hours in 2000 and to 6.1 billion kilowatt-hours by 2020. It is expected that cogeneration will continue to increase as long as it proves beneficial to industries or the environment. Presently, customers most likely to produce their own electricity are those with process steam needs, in particular, operations involving paper, chemicals, and textiles. For example, energy produced during the recovery cycle of the paper manufacturing process is often sufficient to meet the energy needs of the pulp industry. In addition, the lumber industry is becoming increasingly interested in cogeneration because landfills, in many cases, are either charging more for dumping waste sawdust or refusing to accept it.

Load Forecast Uncertainty

A load forecast is inherently uncertain for two reasons. First, there is uncertainty in the future values of the key variables that determine the level of future electricity consumption. For the Energy Vision 2020 forecast these variables are:

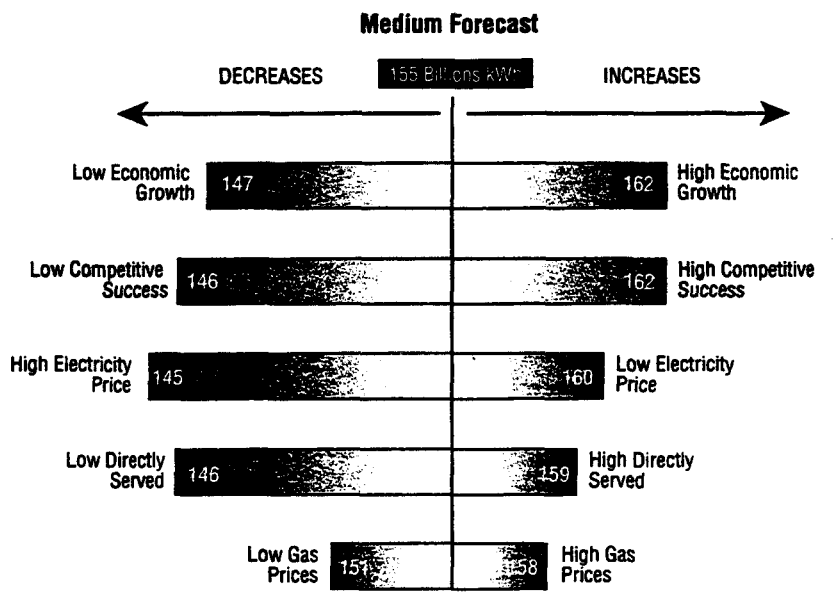
- Economic activity
- Price of electricity
- Competitive success
- Directly served load
- Price of substitute fuels

The second reason for load uncertainty is due to the relationships between the key variables and future electricity consumption. Customer preferences and behaviors will change over time. Therefore, the relationships between them and the consumption of electricity will change.

In the Energy Vision 2020 forecast, TVA has dealt with uncertainty using the following methods.

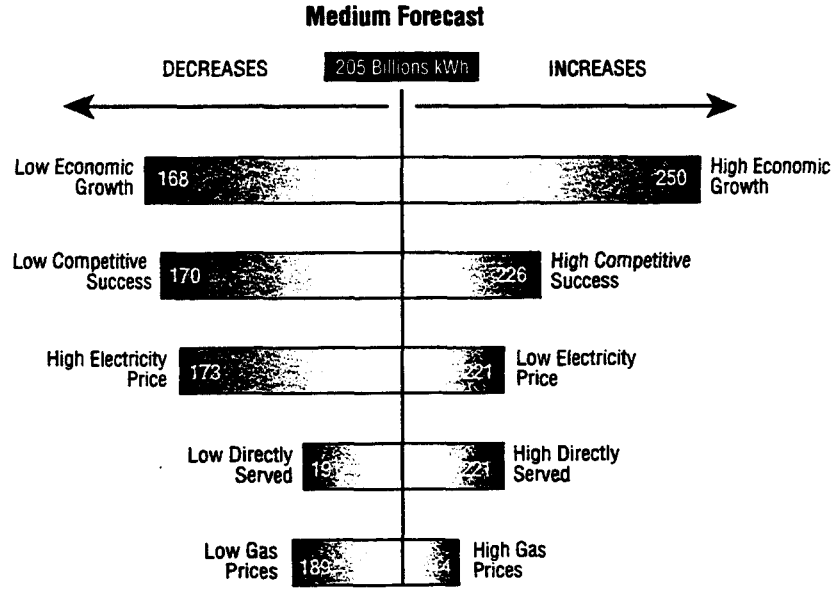
1. Evaluating alternative levels (high, medium, and low) of the key variables for their impacts on future electricity consumption. This process is based on probability and results in a wide range of alternative load forecasts.
2. Use of several quantitative models to evaluate the relationship between the major variables and their impact on future electricity consumption. Both econometric and economic end-use models are used.

FIGURE T5-28. **Variation of the System Energy Forecast Assuming High and Low Conditions for Key Uncertainties in 2000**



Uncertainty about the future requires a broad review of key variables and their impacts on system energy requirements. Load growth is most affected by economic activity, competition, and the price of electricity.

FIGURE T5-29. **Variation of the System Energy Forecast Assuming High and Low Conditions for Key Uncertainties in 2015**



Uncertainty about the future requires a broad review of key variables and their impacts on system energy requirements. Load growth is most affected by economic activity, competition, and the price of electricity.

ALTERNATIVE LEVELS OF KEY VARIABLES

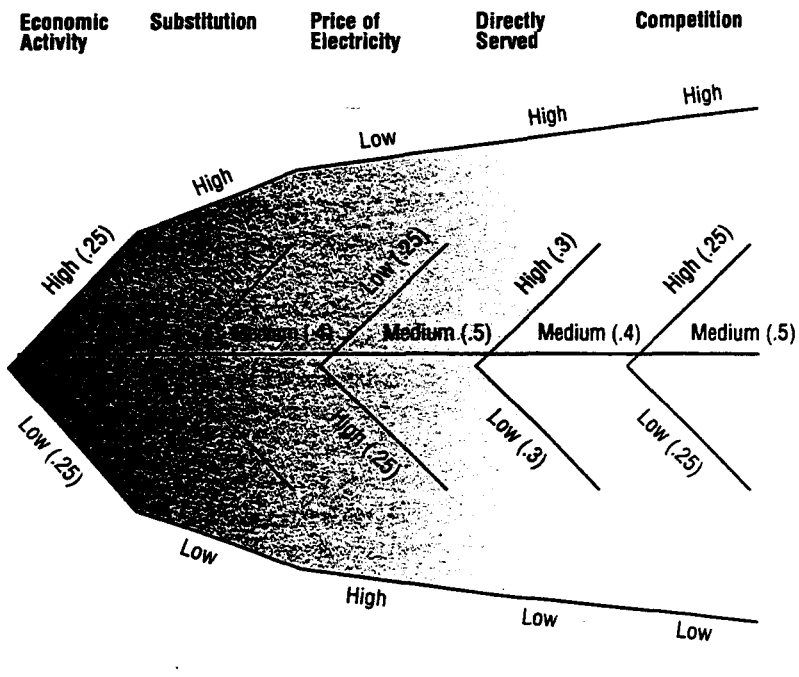
The high, medium, and low load forecasts reflect changes in the key variables which, in turn, impact load growth. The medium load forecast is based on the medium or expected level of each key variable. The high and low levels of each key variable are quantified, and models are used to determine the high and low sales levels.

The incremental impacts above or below the medium sales forecast are shown for each key variable for 2000 and 2015 in *Figures T5-28* and *T5-29*. For example, *Figure T5-28* shows that the impact on system energy requirements in the year 2000 of going from the medium to the high level of economic activity would be to increase system energy requirements by 7 billion kilowatt-hours. In 2015, as shown in *Figure T5-29*, the incremental impact of going from the medium to the high level of economic activity would be to add 45 billion kilowatt-hours—raising the forecast from 205 billion kilowatt-hours to 250 billion kilowatt-hours.

As shown in *Figures T5-28* and *T5-29*, considerable uncertainty exists in the key variables and their impacts on system energy requirements. Economic activity, competition, and the price of electricity have the greatest impact on possible changes in load growth. In 2000 the range of sales due to uncertainty in economic activity is 15 billion kilowatt-hours, increasing to 82 billion kilowatt-hours in 2015. The range on electricity price impacts is 15 billion kilowatt-hours in 2000 and 48 billion kilowatt-hours in 2015. The range on competitive success is 16 billion kilowatt-hours in 2000 and 56 billion kilowatt-hours in 2015.

The range of load growth impacts from the low to the high levels of economic activity, competition, and electricity prices does not include any impacts on the directly served sector since this sector reacts differently to changes in econom-

FIGURE T5-30 **Alternate Load Forecasts**



High and low load forecasts are developed by determining the probabilities assigned to alternative levels of the key variables, what is the likelihood that economic activity, for example, will be high or low for any given forecast period.

ic activity and electricity prices. The range of incremental impacts on net system requirements from the directly served sector is 13 billion kilowatt-hours in 2000 and 30 billion kilowatt-hours in 2020. The incremental impact of substitution of electricity for natural gas based on changes in natural gas prices has a range of 7 billion kilowatt-hours in 2000 and 25 billion in 2020.

PUTTING THE NUMBERS TOGETHER – SELECTING THE HIGH AND LOW FORECASTS

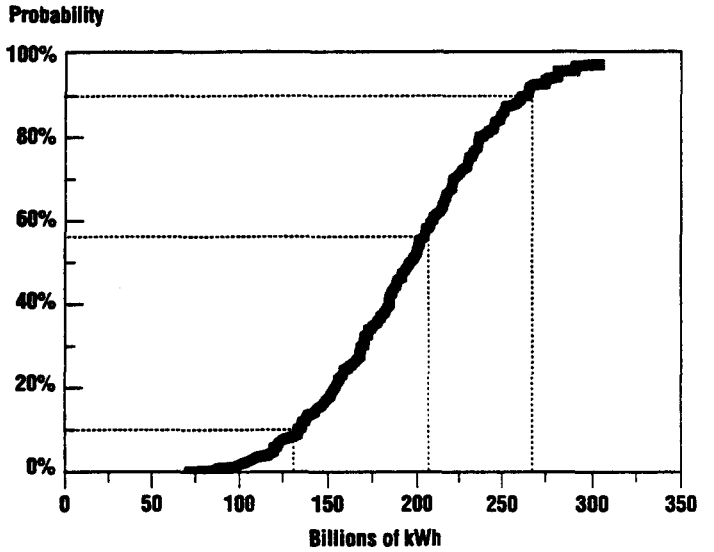
Selecting the high and low forecasts involves organizing the alternative load growth scenarios with a tree diagram *(Figure T5-30)*. There are five alternative branches in the tree—one for each of the five major determinants of load growth: economic activity, substitution (price of natural gas), price of electricity, directly served industry, and competitive success. Combinations of these five major determinants of electricity consumption produce alternative load forecasts. For example, high economic activity, high competitive success, high price of natural gas (high substitution), low price of electricity, and high directly served industry would produce the highest load forecast as represented by the top branch of the tree. Conversely, the alternative levels of the determinants of electricity consumption represented by the bottom branches of the tree would produce the lowest load forecast.

The numbers in parentheses represent the probabilities assigned to the alternative levels of the key variables. For example, high economic growth is assigned a .25 probability, medium economic growth is assigned a .50 probability, and low economic growth is assigned a .25 probability. Some of the variables are not independent. An explanation of the detailed probability assessment will be furnished upon request.

The probabilities associated with the possible forecast outcomes are used as a guideline in selecting those forecasts that will be evaluated explicitly in the decision process. A cumulative probability distribution, shown in *Figure T5-31*, indicates the distribution of probabilities associated with the entire range of possible forecasts. The cumulative probability distribution helps select a set of three forecasts that sufficiently bound the range of uncertainty. The cumulative probability distribution indicates the probability that the actual load will be less than the forecast load. TVA's high load forecast has a 90 percent probability that the actual load will be less than the forecast load. The medium forecast has a 50 percent probability that the actual load will be less than the forecast load, and the low load forecast has a 10 percent probability.

As indicated by the cumulative probability distribution, there are several potential forecasts that will be either greater than the high load forecast (90 percent) or lower than the low forecast (10 percent). Conditions that would result in load growth greater than the high load forecast, for example, are lower electricity prices. One condition that could result in load growth being lower than the low forecast would be lower natural gas prices.

FIGURE T5-31. **Forecast Probability Distribution – 2015**



High, medium, and low load forecasts have assigned probabilities that the actual load will be less than the forecast load. In the high load forecast, for example, there is a 90 percent probability that the actual load will be lower than projected.

Continuous Improvement

TVA recognizes that the world is rapidly changing and its processes and products must continually be assessed to maintain credible load forecasts. TVA therefore contracted with Barakat & Chamberlin, Inc., to evaluate the TVA load forecasting system in 1991. Barakat & Chamberlin, Inc., concluded that, "on a comparative basis, TVA's forecasting procedures compare very favorably with the best-practice procedures in the United States utility industry." Several of Barakat & Chamberlin's recommendations have been incorporated into the TVA load forecast:

- In 1992 TVA began using an industrial end-use model.
- A commercial conditional demand model is being developed.
- TVA is updating residential conditional demand studies.
- The uncertainty analysis has been expanded to include additional factors.
- Industry surveys are made continually to monitor closely the important industrial sectors of the TVA market.

ECONOMIC FORECASTING METHODOLOGY AND VALIDATION

TVA produces its own forecasts of regional economic activity. These forecasts are based on forecasts of the national economy developed by an internationally recognized forecasting service, DRI/McGraw Hill. TVA uses its regional economic forecasts for budget planning, the planning of locks and other navigation facilities, and economic development activities. These forecasts are publicly distributed throughout the Tennessee Valley and are used by four regional universities as the basis for their own publicly released economic forecasts of their local areas. (The regional universities that use the TVA forecasts as the driver in their own local area economic model forecasts are: Eastern Kentucky University, Mississippi State University, the University of Alabama in Huntsville, and Western Carolina University.) The regional economic forecasts are also the major "key assumption" to TVA's load forecasts.

These forecasts are based on five elements necessary for state-of-the-art forecasting: accuracy, use of best information, use of best methods, explicit treatment of uncertainty, and continuous improvement.

Accuracy

Figure T5-32 summarizes the accuracy of TVA's five-year forecast for Gross Regional Product (the sum of the value in dollars of all final goods and services produced) and DRI's forecasts for Gross National Product. (DRI has been used for national forecasts since 1988. Prior to that, the WEFA Group forecasts were used. However, both companies' long-term forecasts of gross national product have been very similar over the years.) These forecasts were made annually during the 1980s. For example, a regional and a national forecast for 1985 (the target year in *Figure T5-32*) were done at the start of 1981, with 1980 as the latest his-

FIGURE T5-32. **TVA Economic Forecast Five–Year Forecast Error**

		Gross Product in Billions of Dollars					
		REGIONAL			NATIONAL		
Year of Forecast	Target Year	GRP Forecast	GRP Actual	Forecast Error	GNP Forecast	GNP Actual	Forecast Error
1980	1985	$105.3	$91.5	15.1%	$4,746	$4,054	17.1%
1981	1986	$114.5	$98.1	16.7%	$5,164	$4,278	20.7%
1982	1987	$114.6	$106.6	7.5%	$5,149	$4,545	13.3%
1983	1988	$117.5	$114.9	2.3%	$5,196	$4,908	5.9%
1984	1989	$124.1	$124.1	0.0%	$5,519	$5,267	4.8%
1985	1990	$127.4	$130.7	-2.5%	$5,673	$5,568	1.9%
1986	1991	$143.4	$137.6	4.2%	$6,116	$5,741	6.5%
1987	1992	$145.8	$149.1	-2.3%	$6,171	$6,026	2.4%
1988	1993	$161.7	$159.6	1.3%	$6,862	$6,348	8.1%
1989	1994	$174.7	$172.7	1.1%	$6,863	$6,727	2.0%
Average Absolute Error (1988-1994):				2.0%			4.5%
Average Absolute Error (1985-1994):				5.3%			8.3%

This chart summarizes the accuracy of TVA's five-year economic forecasts for the region and the nation.

torical year (the year of forecast in *Figure T5-32*). Likewise, forecasts for 1994 were done at the beginning of 1990, with 1989 as the latest historical year. *Figure T5-32* shows the percentage of error between the forecasted value and actual data (expressed as a positive—forecast was too high—or negative—forecast was too low—value) for both the regional and national forecasts.

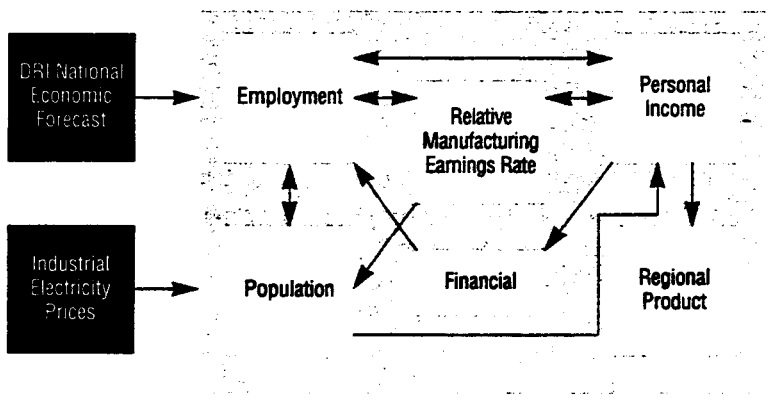
Figure T5-32 indicates that the performance of TVA regional economic forecasts has improved over time and that the performance has been favorable compared to that of the national economic forecasts. For the forecasted years of 1988 through 1994, the average error in the regional forecasts for total gross product was good, within plus or minus 2 percent.

The regional economic forecast performance has improved due to the better performance of the national forecasts and to improvements in the TVA economic forecasting process, including the validation procedures. TVA does reviews of long-term forecasting performance (as per the example above), as well as annual reviews of new economic data. Economic forecasts over the historical period are also done annually to test TVA's economic model performance versus actual data.

To improve the process, TVA began a program with universities around the Valley to share economic information in 1985. Currently, there are 11 university partners: The University of Alabama in Huntsville, Eastern Kentucky University, Western Kentucky University, Mississippi State University, Western Carolina University, East Tennessee State University, Middle Tennessee State University, Tennessee State University, The University of Memphis, The University of Tennessee at Martin, and Virginia Polytechnic and State University. TVA's regional economic forecasts are allocated to economic subregions of the Valley. The universities then review both the regional forecast and the forecasts for their subregions on an annual basis. All of this information is incorporated into the economic forecasting process and used to validate the regional economic forecasts.

The TVA regional economic forecast used for the Energy Vision 2020 process has been favorably reviewed by the regional universities. Further, the latest State of Tennessee long-term economic forecast, developed by The University of Tennessee at Knoxville, is consistent with it. The University's independently forecast average annual rate of growth for Tennessee total gross product of 3.8 percent from 1993 through 2002 compares well with the TVA forecast rate for regional total gross product growth of 3.5 percent for the same period. (See Murray, Matthew N., "The Long-Term Outlook for Tennessee: Three Trends Will Determine the State's Economic Future," *Survey of Business*, Center for Business and Economic Research, The University of Tennessee, Knoxville, (Winter 1994), pg. 39, for information on the university forecast.)

FIGURE T5-33 **Regional Economic Simulation Model Flowchart**



Major inputs into the Regional Economic Simulation Model are the national economic forecast and TVA industrial electricity prices.

Use of Best Information

TVA strives to use the best information available for its economic forecasting. As stated previously, the national economic forecasts are purchased from DRI/McGraw-Hill. DRI forecasts are well recognized and widely used. Among DRI clients are a great number of utilities, federal and state agencies, universities, and Fortune 500 companies. DRI forecasts are quoted by the *Wall Street Journal* and other major business publications and used in Congressional hearings and legal cases.

The source historical economic data for the regional forecasts come from the federal government: the Bureau of Economic Analysis and the Bureau of the Census, U.S. Department of Commerce, and the Bureau of Labor Statistics, U.S. Department of Labor. The federal government has improved these data over the years. Further, TVA has improved its use of these data to get a better and more current picture of the region-

al economy. For example, by using the monthly state employment data from the Bureau of Labor Statistics, TVA can estimate regional employment in a more timely manner than by using estimates from other sources.

TVA has also improved its information by supplementing the data discussed above with information from other sources, including detailed employment and payroll data from state employment agencies, information on industry trends from trade journals and federal government publications, and information from the regional universities (discussed above) about the status of their local economies and industries.

Use of Best Methods

TVA uses its Regional Economic Simulation Model to produce its regional economic forecasts. The model uses state-of-the-art statistical methods comparable to those of the major economic forecasters in the country. TVA has been a leader in the utility industry in the use of econometric forecasting models that have now become the industry standard.

As seen in *Figure T5-33*, the two major inputs to RESM are the DRI national economic forecasts and TVA industrial electricity prices. RESM does not merely allocate national trends, but captures the differences inherent in the regional economic structure that affect regional performance. RESM is updated on an annual basis and has a high degree of industry detail (for example, chemicals, apparel, etc., in manufacturing; food stores, health services, etc., in the commercial sector). This allows for interindustry linkages—for instance, wholesale trade is linked to retail trade. (See Gonzalez, Juan E., "The TVA Regional Economic Simulation Model," *Proceedings: Eighth Electric Utility Forecasting Symposium*, (EPRI TR-100396), Electric Power Research Institute, Palo Alto, California, April 1992, pp. 39-1 to 39-11, for a more detailed discussion of RESM.)

Explicit Treatment of Uncertainty

Forecasting is inherently uncertain. First, there is uncertainty in the major inputs to the regional forecast. Many events, especially those that are not economic in nature, such as the Gulf War or the breakup of the Soviet Union, may throw the national economy from its expected growth path. Likewise, there is uncertainty related to the TVA electricity price forecasts. In addition, there is uncertainty as to how the regional economic structure will change over time.

To deal with uncertainty, TVA supplements its modeling with industry analyses and studies of specific major issues such as the effects of changes in the value of the dollar or interest rates on the Valley economy. This is an effort to continually improve TVA's understanding of the Valley economy and its ability to produce accurate economic forecasts.

Further, TVA deals with uncertainty by producing high and low regional economic forecasts that provide a range of possible future economic outcomes. These are derived by using DRI national high and low economic forecasts and TVA low and high electricity price forecasts, respectively. Also, explicit assumptions are made as to possible events that are not considered most likely, but are feasible developments from emerging historical events. Thus, in the current high economic forecast, the assumption is made that the region will develop a commercial sector that more closely matches that of the nation. Likewise in the low forecast, the assumption is made that several of the Valley's manufacturing industries experience large negative effects due to foreign competition.

Continuous Improvement

TVA is continuously improving its economic forecasting process. Specific efforts have been discussed previously for accuracy, use of best information, use of best methods, and explicit treatment of uncertainty. For example, TVA has made efforts to improve accuracy by working with regional universities. Efforts to improve information include supplementing data from various sources. In using the best methods, the Regional Economic Simulation Model is updated on an annual basis to improve estimates. Finally, to improve the treatment of uncertainty, TVA supplements its modeling with industry analyses and studies of specific major issues.

Energy Vision

2020

Volume 2, Technical Document

5 Supply-Side Options

Volume 2, Technical Document 6

Supply-Side Options

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Supply-Side Options

Over 100 different supply-side options were identified during the course of Energy Vision 2020. These options represent a broad spectrum of options—both in terms of fuel source and operating characteristics. While the full range of supply-side options is nearly unlimited, this set provides a reasonable representation of the options that are available. In some cases, two or more similar options were defined in order to better evaluate specific differences. In most cases, however, the options represent a "typical" configuration and not necessarily the only design that could be considered. This document provides additional descriptions and characterizations of each of the options that have been identified.

Figure T6-1 shows performance, cost, and environmental characteristics for the conventional TVA supply-side options. *Figure T6-2* shows additional characteristics for the flexible TVA supply-side options.

FIGURE T6-1. **Conventional TVA Supply-Side Options**

Number	Option ID	Option Name	Status	Duty Cycle	PERFORMANCE CHARACTERISTICS: Net Full Load Capacity (MW)	Net Full Load Heat Rate (Btu/kWh)	Fuel	Total Schedule (Yr)	Coproducts	Base Capital Cost ($/kW)
1	1.1.1.1	Supercritical Pulverized Coal-Fired Plant (1x300 MW)	Mature Commercial	Base	300	9,522	High Sulfur Coal	7	None	$1,614
2	1.1.1.2	Supercritical Pulverized Coal-Fired Plant (4x300 MW)	Mature Commercial	Base	1,200	9,522	High Sulfur Coal	8	None	$1,345
3	1.1.1.3	Atmospheric Fluidized Bed Combustion Repowering, Generic (1x125 MW)	Initial Commercial	Base	125	10,600	High Sulfur Coal	6	None	$1,119
4	1.1.1.4	Circulating Atmospheric Fluidized Bed Combustion Plant (1x200 MW)	Initial Commercial	Base	200	9,830	High Sulfur Coal	8	None	$1,486
5	1.1.1.5	Subcritical Pulverized Coal-Fired Plant (4x300 MW)	Mature Commercial	Base	1,200	10,000	High Sulfur Coal	8	None	$1,413
6	1.1.2.1	Simple Cycle Combustion Turbine Plant (1x150 MW)	Mature Commercial	Peaking	150	10,500	Natural Gas	5	None	$360
7	1.1.2.2	Natural Gas-Fired Combined Cycle Plant (1x470 MW)	Mature Commercial	Intermediate	470	7,000	Natural Gas	5	None	$655
8	1.1.2.3	Combined Cycle Repowering, Generic (1x425 MW)	Initial Commercial	Intermediate	425	7,900	Natural Gas	4	None	$487
9	1.1.2.4	Small Cogeneration Combined Cycle Plant (3x10 MW)	Mature Commercial	Base	30	12,000	Natural Gas	4	Steam	$1,120
10	1.1.2.5	Small Combined Cycle Plant (1x42 MW)	Mature Commercial	Peaking / Intermediate	42	8,600	Natural Gas	4.5	None	$800
11	1.1.3.1	Refuse-Derived Fuel-Fired Stoker (1x40 MW)	Mature Commercial	Base	40	16,464	Refuse-Derived Fuel	8	None	$5,740
12	1.1.5.1	Lead Acid Battery Energy Storage (1x20 MW)	Mature Commercial	Peaking	20	NA	NA	3	None	$578
13	1.2.1.1	State-of-the-Art Pulverized Coal-Fired Plant (1x400 MW)	Large Scale Demo	Base	400	8,110	High Sulfur Coal	7	None	$1,417
14	1.2.2.1	Compressed Air Energy Storage with Humidification (3x337 MW)	Initial Commercial	Peaking	1,011	5,874	Natural Gas	7	None	$315
15	1.2.2.2	Compressed Air Energy Storage with Recuperation (3x337 MW)	Initial Commercial	Peaking	1,011	4,509	Natural Gas	7	None	$338
16	1.2.3.1	Biomass Whole Tree Energy Boiler Power Plant (1x100 MW)	Large Scale Demo	Base	100	10,654	Biomass	8	None	$1,512
17	1.3.1.1	First Generation Pressurized Fluidized Bed Combustion Repowering, Generic (1x156 MW)	Large Scale Demo	Base	156	8,830	High Sulfur Coal	6	None	$1,167
18	1.3.1.2	First Generation Pressurized Fluidized Bed Combustion (1x340 MW)	Large Scale Demo	Base	340	8,200	High Sulfur Coal	8	None	$1,281
19	1.3.1.3	Integrated Gasification Compressed Air Storage with Humidification (1x410 MW)	Large Scale Demo	Intermediate	410	10,020	High Sulfur Coal	8	Sulfur	$1,492
20	1.3.1.4	Integrated Gasification Combined Cycle with Fertilizer Coproduction (3x227 MW)	Initial Commercial	Base	682	9,860	High Sulfur Coal	8	Urea	$2,241
21	1.3.1.5	Integrated Gasification Combined Cycle (3x245 MW)	Initial Commercial	Base	740	7,230	High Sulfur Coal	8	Sulfur	$1[illegible]
22	1.3.1.6	Compressed Air Storage with Humidification with Integrated Gasification & Natural Gas Peaking (1x850 MW)	Large Scale Demo	Intermediate/ Peaking	850	4,700	Natural Gas and Coal	8	Sulfur	$872

COST CHARACTERISTICS					ENVIRONMENTAL AND OTHER CHARACTERISTICS					
Fuel Cost ($/MMBtu)	Base Fixed Operating & Maintenance ($/kW-Yr)	Base Variable Operating & Maintenance (Mills/kWh)	Base Fixed Additions & Improvements ($/kW-Yr)	Base Decommissioning Cost ($ Million)	Sulfur Dioxide (lb/MMBtu)	Nitrogen Oxides (lb/MMBtu)	Carbon Dioxide (lb/MMBtu)	Thermal Discharge (MMBtu/MWh)	Solid Waste (lb/MMBtu)	Economic Development [1] (Annual Average Employment)
$1.00	$21.80	1.3	$13.60	$0	0.3	0.1	210	0	24.02	NA
$1.00	$20.00	1.3	$13.60	$0	0.3	0.1	210	0	24.02	918
$1.00	$21.20	1.4	$14.70	$0	0.25	0.1	210	6.02	31.74	NA
$1.00	$21.00	1.4	$14.70	$0	0.25	0.1	210	0	31.74	NA
$1.00	$20.00	1.3	$13.60	$0	0.3	0.15	210	0	24.02	NA
$2.48	$2.00	2.6	$0.00	$0	0	0.08	115	0	0	20
$2.48	$4.70	1.3	$4.50	$0	0	0.08	115	0	0	128
$2.48	$4.60	1.3	$4.50	$0	0	0.08	115	0.82	0	96
$2.48	$18.30	3.2	$0.00	$0	0	0.16	115	0	0	NA
$2.48	$13.10	4.3	$0.00	$0	0	0.16	115	0	0	NA
($1.54)	$84.00	1.8	$58.00	$0	0.07	0.06	0	0	21.43	128
NA	$2.50	7.7	$7.10	$0	0	0	0	0	0	4
$1.00	$19.90	1.6	$16.00	$0	0.1	0.06	210	0	24.02	NA
$2.48	$2.20	2.5	$0.00	$0	0	0.03	115	0	0	130
$2.48	$2.20	2.6	$0.00	$0	0	0.03	115	0	0	NA
$1.87	$33.50	7	$12.50	$0	0.002	0.1	-267	0	0.57	190
$1.00	$18.70	4	$16.90	$0	0.25	0.1	210	3.33	30.14	NA
$1.00	$29.00	1.3	$27.80	$0	0.25	0.1	210	0	30.14	NA
$1.00	$20.50	0.4	$15.00	$0	0.05	0.03	210	0	9.48	NA
$1.00	$22.50	1.2	$13.20	$0	0.035	0.029	159	0	9.48	NA
$1.00	$20.80	1.2	$12.00	$0	0.05	0.035	205	0	9.48	610
$2.48 & $1.00	$20.50	0.4	$15.00	$0	0.025	0.03	180	0	7.22	NA

[1] Calculated for selected options only

FIGURE T6-1 **Conventional TVA Supply-Side Options** *CONTINUED*

Number	Option ID	Option Name	Status	Duty Cycle	PERFORMANCE CHARACTERISTICS Net Full Load Capacity (MW)	Net Full Load Heat Rate (Btu/kWh)	Fuel	Total Schedule (Yr)	Coproducts	Base Capital Cost ($/kW)
23	1.3.1.7	Advanced Pressurized Fluidized Bed Combustor with Development Cost (1x300 MW)	Initial Commercial	Base	300	7,400	High Sulfur Coal	8	0	$1,518
24	1.3.1.8	Advanced Pressurized Fluidized Bed Combustor with No Development Cost (1x300 MW)	Initial Commercial	Base	300	7,400	High Sulfur Coal	8	0	$1,246
25	1.3.1.9	Partnered IGCC with Coproduction, Greenfield Site (1x530 MW)	CC-Mature Commercial	Base	530	7,200	Syngas	8	None	$581
26	1.3.1.10	IGCC with Coproduction, Greenfield Site (1x498 MW)	Initial Commercial	Base	498	11,140	High Sulfur Coal	8	Methanol	$2,325
27	1.3.1.11	Integrated Gasification Cascaded Humidified Advanced Turbine (IGCHAT) with Coproduction, Greenfield Site (1x598 MW)	Initial Commercial	Base	598	10,515	High Sulfur Coal	8	Methanol	$1,930
28	1.3.1.12	Coal Refinery/IGCC, Greenfield Site (1x530 MW)	Initial Commercial	Base	530	17,000	High Sulfur Coal	8	Naphtha, Benzene	$2,590
29	1.3.1.13	Coal Refinery/IGCHAT, Greenfield Site (1x530 MW)	Initial Commercial	Base	530	17,000	High Sulfur Coal	8	Naphtha, Benzene	$2,325
30	1.3.1.14	Coal Refinery/IGCHAT with Coproduction, Greenfield Site (1x180 MW)	Initial Commercial	Base	180	43,250	High Sulfur Coal	8	Methanol	$7,100
31	1.3.2.1	Fuel Cell - Molten Carbonate or Solid Oxide (1x2 MW)	Large Scale Demo	Base	2	6,450	Natural Gas	4	Waste Heat, Steam	$1,034
32	1.3.2.2	Intercooled Aeroderivative Combustion Turbine (1x125 MW)	Large Scale Demo	Intermediate/ Peaking	125	8,100	Natural Gas	5	None	$467
33	1.3.2.3	Cascaded Humidified Advanced Turbine (F Series CT) (1x288 MW)	Large Scale Demo	Intermediate	288	7,315	Natural Gas	6	None	$503
34	1.3.2.4	Integrated Gasification Cascaded Humidified Advanced Turbine with Coproduction (F Series CT) (2x303 MW)	Large Scale Demo	Base	606	12,485	High Sulfur Coal	8	Urea, MTBE, Methanol	$1,739
35	1.3.2.5	Integrated Gasification Cascaded Humidified Advanced Turbine (F Series CT) (2x303 MW)	Large Scale Demo	Base	606	8,750	High Sulfur Coal	8	None	$1,243
36	1.3.2.6	Cascaded Humidified Advanced Turbine (G Series CT) (1x400 MW)	Large Scale Demo	Intermediate	400	6,920	Natural Gas	6	None	$477
37	1.3.2.7	Integrated Gasification Cascaded Humidified Advanced Turbine with Coproduction (G Series CT) (2x420 MW)	Large Scale Demo	Base	840	10,660	High Sulfur Coal	8	Urea, MTBE, Methanol	$1,622
38	1.3.2.8	Integrated Gasification Cascaded Humidified Advanced Turbine (G Series CT) (2x420 MW)	Large Scale Demo	Base	840	8,200	High Sulfur Coal	8	None	$1,126
39	1.3.2.9	Integrated Fuel Cell/Combustion Turbine (1x2.5 MW)	Large Scale Demo	Base	2.5	5,250	Natural Gas	4	None	$1,240
40	1.3.3.1	Large Solar-Photovoltaic - Fixed Flat Plate (1x50 MW)	Pilot Scale	Intermediate	50	NA	Solar	7	None	$3,032
41	1.3.3.2	Landfill Methane (1x2 MW)	Pilot Scale	Intermediate	2	6,450	Landfill Gas (Methane)	3	Waste Heat, Steam	$1,034
42	1.3.3.3	Coalbed Methane (1x2 MW)	Pilot Scale	Intermediate	2	6,450	Coalbed Methane	3	Waste Heat, Steam	$1,034
43	1.3.3.4	Biorefinery - Coproduction of Electricity and Chemicals (1x100 MW)	Demo	Base	100	18,000	Biomass	5	Multiproducts	$4,000

COST CHARACTERISTICS					ENVIRONMENTAL AND OTHER CHARACTERISTICS					
Fuel Cost ($/MMBtu)	Base Fixed Operating & Maintenance ($/kW-Yr)	Base Variable Operating & Maintenance (Mills/kWh)	Base Fixed Additions & Improvements ($/kW-Yr)	Base Decommissioning Cost ($ Million)	Sulfur Dioxide (lb/MMBtu)	Nitrogen Oxides (lb/MMBtu)	Carbon Dioxide (lb/MMBtu)	Thermal Discharge (MMBtu/MWh)	Solid Waste (lb/MMBtu)	Economic Development 1 (Annual Average Employment)
$1.00	$36.00	1.3	$6.50	$0	0.4	0.1	210	0	30.14	NA
$1.00	$36.00	1.3	$6.50	$0	0.4	0.1	210	0	30.14	NA
$1.00	$4.20	1.2	$4.00	$0	0.03	0.08	131	0	0	NA
$1.00	$57.00	2.5	$0.00	$0	0.03	0.08	173	0	0	NA
$1.00	$54.00	2.5	$0.00	$0	0.03	0.08	173	0	0	NA
$1.00	$55.00	2.6	$0.00	$0	0.03	0.08	173	0	0	NA
$1.00	$50.00	2.6	$0.00	$0	0.03	0.08	173	0	0	NA
$1.00	$275.00	20	$5.00	$0	0.03	0.08	173	0	0	NA
$2.48	$10.00	1.7	$105.00	$0	0	0.16	115	0	0	1
$2.48	$3.50	3.7	$0.00	$0	0	0.08	115	0	0	NA
$2.48	$4.50	1.3	$3.50	$0	0	0.005	115	0	0	65
$1.00	$20.80	1.7	$13.20	$0	0.035	0.01	205	0	9.48	NA
$1.00	$18.60	0.9	$13.20	$0	0.05	0.01	205	0	9.48	NA
$2.48	$4.50	1.3	$3.50	$0	0	0.005	110	0	0	NA
$1.00	$20.80	1.7	$13.20	$0	0.035	0.01	205	0	9.48	NA
$1.00	$18.60	0.9	$13.20	$0	0.05	0.01	205	0	9.48	569
$2.48	$0.60	12	$70.00	$0	0	0.005	110	0	0	NA
NA	$5.00	0	$1.30	$0	0	0	0	0	0	44
$1.29	$9.80	1.7	$40.00	$0	0	0.16	-798	0	0	1
$1.80	$9.80	1.7	$40.00	$0	0	0.16	115	0	0	1
$3.00	$200.00	40.0	$0.00	$0	0.05	0.1	0	0	1.0	NA

[1] Calculated for selected options only

FIGURE T6-1. **Conventional TVA Supply-Side Options** *CONTINUED*

Number	Option ID	Option Name	Status	Duty Cycle	PERFORMANCE CHARACTERISTICS Net Full Load Capacity (MW)	Net Full Load Heat Rate (Btu/kWh)	Fuel	Total Schedule (Yr)	Coproducts	Base Capital Cost ($/kW)
44	1.3.5.1	Advanced Battery Energy Storage (1x20 MW)	Pilot Scale	Peaking	20	NA	NA	3	None	$491
45	1.3.5.2	Superconducting Magnetic Energy Storage (1x500 MW)	Pilot Scale	Peaking	500	NA	NA	8	None	$1,235
46	2.1.3.1	Additional Hydro Generation at Existing Nonpower Projects (1x10 MW)	Mature Commercial	Peaking	10	NA	NA	5	None	$2,460
47	2.1.3.2	Additional Hydro Generation at Existing Projects (1x24 MW)	Mature Commercial	Peaking	24	NA	NA	6	None	$4,288
48	2.1.3.3	Additional Hydro Generation-New Conventional Projects (1x65 MW)	Mature Commercial	Peaking	65	NA	NA	9	None	$8,753
49	2.1.3.4	Hydro Modernization at Existing Projects	Mature Commercial	Peaking	3,864	NA	NA	11	None	$52
50	3.3.1.1	Generic Pressurized Fluidized Bed Combustion Cogeneration (1x70 MW)	Large Scale Demo	Base	70	7,700	High Sulfur Coal	6	Steam	$0
51	4.1.1.1	Lignite-Fired Circulating Fluidized Bed Combustion Plant (1x200 MW)	Initial Commercial	Base	200	10,777	Lignite	7	None	$1,600
52	5.1.1.1	NUG - Generic IPP Lignite Circulating Fluidized Combustion Plant (1x300 MW)	Mature Commercial	Base	300	10,500	Lignite	5	None	$0
53	6.3.2.7	Gas Turbine - Modular Helium Reactor (3x289 MW)	Pilot Scale	Base	867	7,070	Nuclear	13	None	$2,273
54	6.3.4.1	Advanced Light Water Reactor (1x1300 MW)	Large Scale Demo	Base	1,300	10,200	Nuclear	10	None	$1,904
55	7.1.1.1	Bellefonte Repowering with Integrated Gasification Combined Cycle (9x250 MW)	Initial Commercial	Base	2,250	8,488	High Sulfur Coal	9	None	$1,484
56	7.1.1.2	Bellefonte Repowering with Pulverized Coal (4x616 MW)	Mature Commercial	Base	2,464	9,611	Medium Sulfur Coal	11	None	$1,263
57	7.1.1.3	Bellefonte Repowering - Phased Combined Cycle/IGCC - Phase A -Combined Cycle (9x222 MW)	Mature Commercial	Intermediate	1,997	7,367	Natural Gas	8	None	$551
58	7.1.1.4	Bellefonte Repowering - Phased Combined Cycle/IGCC - Phase B - IGCC (9x250 MW)	Initial Commercial	Base	2,250	8,463	High Sulfur Coal	7	None	$1,555
59	7.1.1.5	Bellefonte Repowering - IGCC with Coproduction (11x229 MW)	Initial Commercial	Base	2,520	12,560	High Sulfur Coal	11	Multi-products	$1,857
60	7.1.1.6	Bellefonte Repowering - IGCC with Coproduction with Partners (2x242 MW)	Initial Commercial	Base	484	7,200	Syngas	8	Multi-products	$465
61	7.1.1.7	Bellefonte Repowering - IGCC Demo with Partners (1x400 MW)	Initial Commercial	Base	400	7,200	Syngas	5	Multi-products	$600
62	7.1.2.1	Bellefonte Repowering - Natural Gas Combined Cycle (10x222 MW)	Mature Commercial	Intermediate	2,220	7,367	Natural Gas	8	None	$475
63	7.1.4.1	Completion of Bellefonte Unit 1 as Nuclear (1x1212 MW)	Mature Commercial	Base	1,212	10,204	Nuclear	5	None	$2,163
64	7.1.4.2	Completion of Bellefonte Unit 2 as Nuclear (1x1212 MW)	Mature Commercial	Base	1,212	10,204	Nuclear	6	None	$1,505

COST CHARACTERISTICS					ENVIRONMENTAL AND OTHER CHARACTERISTICS					
Fuel Cost ($/MMBtu)	Base Fixed Operating & Maintenance ($/kW-Yr)	Base Variable Operating & Maintenance (Mills/kWh)	Base Fixed Additions & Improvements ($/kW-Yr)	Base Decommissioning Cost ($ Million)	Sulfur Dioxide (lb/MMBtu)	Nitrogen Oxides (lb/MMBtu)	Carbon Dioxide (lb/MMBtu)	Thermal Discharge (MMBtu/MWh)	Solid Waste (lb/MMBtu)	Economic Development [1] (Annual Average Employment)
NA	$2.50	6.9	$1.10	$0	0	0	0	0	0	NA
NA	$4.00	4.2	$1.20	$0	0	0	0	0	0	NA
NA	$7.50	0	$11.40	$0	0	0	0	0	0	NA
NA	$7.50	0	$11.40	$0	0	0	0	0	0	NA
NA	$7.40	0	$11.40	$0	0	0	0	0	0	NA
NA	$6.90	0	$10.80	$0	0	0	0	0	0	619
NA	$150.00	40	$0.00	$0	0.25	0.1	210	0	30.14	NA
$1.40	$21.00	1.4	$18.50	$0	0.4	0.1	210	0	38.02	NA
NA	$240.80	12.9	$0.00	$0	0.6	0.27	210	0	38.02	280
$1.31	$39.60	0.3	$16.20	$300	0	0	0	0	0	NA
$0.41	$45.30	0.1	$16.20	$350	0	0	0	0	0	NA
$1.00	$20.40	1.2	$12.00	$0	0.05	0.03	205	0	9.48	NA
$1.38	$20.00	1.3	$13.60	$0	0.3	0.15	210	0	24.02	NA
$2.48	$5.00	2.8	$0.00	$0	0	0.03	115	0	0	NA
$1.00	$20.40	1.2	$12.00	$0	0.05	0.03	205	0	9.48	NA
$1.00	$27.80	2.6	$15.50	$0	0.035	0.03	173	0	9.48	NA
$3.59	$4.70	1.3	$4.50	$0	0.03	0.08	131	0	9.48	108
$3.59	$4.70	1.3	$4.50	$0	0.03	0.08	131	0	9.48	NA
$2.48	$4.70	1.3	$4.50	$0	0	0.03	115	0	0	NA
$0.41	$92.00	0	$12.40	$300	0	0	0	0	0	NA
$0.41	$46.00	0	$12.40	$300	0	0	0	0	0	NA

[1] Calculated for selected options only

FIGURE T6-1. **Conventional TVA Supply-Side Options** *CONTINUED*

Number	Option ID	Option Name	Status	Duty Cycle	Net Full Load Capacity (MW)	Net Full Load Heat Rate (Btu/kWh)	Fuel	Total Schedule (Yr)	Coproducts	Base Capital Cost ($/kW)
			PERFORMANCE CHARACTERISTICS							
65	7.1.4.3	Bellefonte Units 1&2 Cancellation	NA	NA	NA	NA	NA	NA	NA	NA
66	7.1.4.4	Bellefonte- Partnership for Completion and Operation	Mature Commercial	Base	600	NA	Nuclear	4.5	None	NA
67	8.1.4.1	Recover Browns Ferry Unit 1 (1x1065 MW)	Mature Commercial	Base	1,065	10,418	Nuclear	5	None	$2,229
68	8.1.4.2	Browns Ferry Unit 1 Cancellation	NA	NA	NA	NA	NA	NA	NA	NA
69	8.1.4.3	Browns Ferry Unit 1 Recovery with Fixed Cost to Complete (1x1065 MW)	Mature Commercial	Base	1,065	10,418	Nuclear	5	None	$1,502
70	9.1.4.1	Completion of Watts Bar Unit 2 (1x1170 MW)	Mature Commercial	Base	1,170	10,000	Nuclear	5	None	$1,875
71	9.1.4.2	Watts Bar Unit 2 Cancellation	NA	NA	NA	NA	NA	NA	NA	NA
72	10.1.2.1	Inlet Air Precooling with Storage (16x61 MW)	Mature Commercial	Summer Peaking	982	8,847	Natural Gas	3	None	$51
73	10.1.2.2	New Combustion Turbine at Johnsonville to Supply Steam to DuPont (1x174 MW)	Mature Commercial	Base	174	9,834	Natural Gas	4	None	$1,113
74	10.1.2.3	Repowering One of JOF 7-10 with Natural Gas/Combined Cycle (1x465 MW)	Initial Commercial	Intermediate	465	7,100	Natural Gas	4	None	$481
75	10.1.2.4	Water Spray Cooling of Combustion Turbine Inlet Air	Initial Commercial	Summer Peaking	97	13,230	Natural Gas	2	None	$17
76	10.3.1.1	Repowering One of JOF Units 1-6 with IGCC (1x242 MW)	Initial Commercial	Base	242	8,700	High Sulfur Coal	7	None	$1,470
77	10.3.1.2	Repowering One of JOF Units 7-10 with IGCC (1x250 MW)	Initial Commercial	Base	250	8,400	High Sulfur Coal	7	None	$1,440
78	11.1.5.1	Laurel Branch Pumped-Hydro Storage (4x386 MW)	Mature Commercial	Peaking	1,544	NA	NA	10	None	$1,120
79	12.1.2.1	Generic Combined Cycle Cogeneration (2x210 MW)	Mature Commercial	Base	420	9,045	Natural Gas	4	Steam	$0
80	13.1.2.1	NUG - Generic IPP Combined Cycle (2x260 MW)	Mature Commercial	Intermediate	520	7,200	Natural Gas	4	None	$0
81	13.1.2.2	NUG - Generic IPP Combined Cycle (1x150 MW)	Mature Commercial	Intermediate	150	7,500	Natural Gas	5	None	$0
82	14.1.3.1	Wind - 33 Meter Variable Speed Advanced Wind Turbine (285x0.35 MW)	Initial Commercial	Intermediate	100	NA	Wind	6	None	$1,056
83	14.3.3.1	Wind - 39 Meter Variable Speed Advanced Wind Turbine (444x0.45 MW)	Pilot Scale	Intermediate	200	NA	Wind	6	None	$958
84	15.1.5.1	Reynolds Creek Pumped-Hydro Storage (3x366 MW)	Mature Commercial	Peaking	1,098	NA	NA	10	None	$1,498
85	16.1.5.1	Raccoon Mountain Pumped-Hydro Energy Storage Addition (3x255 MW)	Mature Commercial	Peaking	765	NA	NA	10	None	$1,038
86	16.1.5.2	Raccoon Mountain Pumped-Storage Modernization	Mature Commercial	Peaking	1,608	NA	NA	6	None	$20
87	17.1.5.1	Rorex Creek Pumped-Hydro Storage (3x292 MW)	Mature Commercial	Peaking	876	NA	NA	10	None	$1,075
88	18.1.1.1	Shawnee Unit 11 (1x168 MW)	Mature Commercial	Base / Intermediate	168	10,241	Low Sulfur Coal	5	None	$561

COST CHARACTERISTICS					ENVIRONMENTAL AND OTHER CHARACTERISTICS					
Fuel Cost ($/MMBtu)	Base Fixed Operating & Maintenance ($/kW-Yr)	Base Variable Operating & Maintenance (Mills/kWh)	Base Fixed Additions & Improvements ($/kW-Yr)	Base Decommissioning Cost ($ Million)	Sulfur Dioxide (lb/MMBtu)	Nitrogen Oxides (lb/MMBtu)	Carbon Dioxide (lb/MMBtu)	Thermal Discharge (MMBtu/MWh)	Solid Waste (lb/MMBtu)	Economic Development [1] (Annual Average Employment)
NA	NA	NA	NA	$0	NA	NA	NA	NA	NA	NA
NA	$180.00	9.3	NA	NA	0	0	0	0	0	2,818
$0.41	$46.00	0	$14.10	$350	0	0	0	8.17	0	NA
NA	NA	NA	NA	$0	0	0	0	0	0	NA
$0.41	$46.00	0	$14.10	$350	0	0	0	0	0	NA
$0.41	$46.00	0	$12.80	$300	0	0	0	0	0	NA
NA	NA	NA	NA	$0	NA	NA	0	0	0	NA
$2.48	$2.50	2.6	$0.00	$0	0	0.16	115	0	0	NA
$2.48	$4.70	2.8	$0.00	$0	0	0.08	115	0	0	NA
$2.48	$5.30	0.9	$3.80	$0	0	0.08	115	0.39	0	110
$2.48	$4.70	2.8	$0.00	$0	0	0.08	115	3.68	0	NA
$1.00	$16.00	1.6	$18.80	$0	0.05	0.03	205	4.33	9.48	NA
$1.00	$26.30	1.6	$19.00	$0	0.05	0.03	205	4.06	9.48	NA
NA	$1.60	0	$2.50	$0	0	0	0	0	0	NA
NA	$120.00	15	$0.00	$0	0.0004	0.048	115	0	0	59
NA	$175.00	15	$0.00	$0	0.00063	0.048	115	0	0	27
NA	$86.70	17.2	$0.00	$0	0	0.08	115	0	0	15
$0.00	$25.00	0	$0.00	$0	0	0	0	0	0	76
$0.00	$15.00	0	$0.00	$0	0	0	0	0	0	108
NA	$1.80	0	$2.50	$0	0	0	0	0	0	NA
NA	$1.30	0	$2.50	$0	0	0	0	0	0	NA
NA	$1.40	0	$2.50	$0	0	0	0	0	0	NA
NA	$2.20	0	$2.50	$0	0	0	0	0	0	NA
$1.38	$19.60	0.6	$13.60	$0	1.2	0.8	205	0	0	92

[1] Calculated for selected options only

FIGURE T6-1. **Conventional TVA Supply-Side Options** *CONTINUED*

Number	Option ID	Option Name	Status	Duty Cycle	Net Full Load Capacity (MW)	Net Full Load Heat Rate (Btu/kWh)	Fuel	Total Schedule (yr)	Coproducts	Base Capital Cost ($/kW)
					PERFORMANCE CHARACTERISTICS					
89	19.3.1.1	NUG - Generic Integrated Gasification Combined Cycle (1x110 MW)	Large Scale Demo	Base	110	8,200	High Sulfur Coal	5	None	$0
90	20.1.1.1	Restart One Unit of Watts Bar Fossil Plant (1x56 MW)	Mature Base/ Commercial	Intermediate	56	12,519	Low Sulfur Coal	4	None	$575
91	20.1.3.1	RDF - Fluidized Bed Combustion Repowering of One Unit of Watts Bar Fossil Plant (1x56 MW)	Mature Commercial	Base	56	14,000	Refuse-Derived Fuel	6	RDF Credit	$2,551
92	20.1.3.2	RDF Companion Boiler at Watts Bar Fossil (1x60 MW)	Mature Commercial	Base	60	14,000	Refuse-Derived Fuel	6	RDF Credit	$2,333
93	20.3.1.1	Repowering Two Units of Watts Bar Fossil Plant with IGCC (1x242 MW)	Initial Commercial	Base	242	8,900	High Sulfur Coal	7	0	$1,541
94	21.1.3.1	RDF Companion Boiler at Kingston Fossil Plant (1x60 MW)	Mature Commercial	Base	60	14,000	Refuse-Derived Fuel	6	RDF Credit	$2,333
95	22.1.1.1	NUG - Generic IPP Pulverized Coal with Cogeneration (2x170 MW)	Mature Commercial	Base	340	9,900	Low Sulfur Coal	4	Steam	$0
96	23.1.2.1	Power Purchase - Base Load (1x300 MW)	Mature Commercial	Base	300	NA	NA	0	0	$0
97	23.1.2.2	Power Purchase - Peaking (1x300 MW)	Mature Commercial	Peaking	300	NA	NA	0	None	$0
98	23.1.3.1	NUG - Generic IPP Run of River Hydro (4x20 MW)	Mature Commercial	Base	80	N/A	NA	4	None	$0
99	24.1.1.1	Unit Power Purchase 15 Year	Mature Commercial	Base	400	NA	NA	0	None	$0
100	24.1.1.2	Partially Complete Pulverized Coal Plant (1x710 MW)	Mature Commercial	Base	710	9,600	High Sulfur Coal	5	None	$888
101	25.1.2.1	Repowering Allen Fossil Plant with Natural Gas/ Combined Cycle (1x705 MW)	Initial Commercial	Intermediate	705	7,200	Natural Gas	4	None	$449
102	25.3.1.1	Repowering Allen Fossil Plant with IGCC (1x500 MW)	Initial Commercial	Base	500	8,200	High Sulfur Coal	7	0	$1,318
103	26.1.3.1	Biomass Cofiring - Customer Service	Initial Commercial	Base	See Note 1	Same as Existing Unit	See Note 1	1	None	$0.36
104	26.2.3.1	Biomass Cofiring - Low Level	Initial Commercial	Base	See Note 2	Same as Existing Unit	See Note 2	1	None	$2.70
105	26.3.3.1	Biomass Cofiring - Emissions Reduction (<$5/Ton CO_2)	Initial Commercial	Base	See Note 3	Same as Existing Unit	See Note 3	1	None	$3.10
106	28.2.3.2	Biomass Cofiring - Moderate Level at Colbert Fossil Plant Unit 5	Initial Commercial	Base	See Note 4	Same as Existing Unit	See Note 4	2	None	$20.10
107	29.1.5.1	NUG - Generic IPP Pumped-Hydro Storage	Initial Commercial	Peaking	1,000	NA	NA	0	None	$0

Note 1: This option applies to JSF,CUF,BRF,ALF,SHF1-9. There are no capacity changes from the current units. The capital cost is to add the cofiring capability. Adjustments should be made as follows: Fuel Cost =(Current Unit Coal Cost)*(1-.0031)+$0.60*.0031. Fixed O&M Costs=Current Unit+$0.09/kW. SO_2 Emissions=Current Unit Coal Emissions*(1-.0031). CO_2 Emissions=Current Unit Emissions*(1-.0031)-322*.0031. These adjustments reflect a 0.31% biomass energy input. All other cost and performance are same as current units.

Note 2: This option applies to COF1-4,GAF,JOF,KIF,PAF. There are no capacity changes from the current units. The capital cost is to add the cofiring capability. Adjustments should be made as follows: Fuel Cost =(Current Unit Coal Cost)*(1-.012)+$0.77*.012. Fixed O&M Costs=Current Unit+$0.09/kW. SO_2 Emissions=Current Unit Coal Emissions*(1-.012). CO_2 Emissions=Current Unit Emissions*(1-.012)-322*.012. These adjustments reflect a 1.2% biomass energy input. All other cost and performance are same as current units.

COST CHARACTERISTICS					ENVIRONMENTAL AND OTHER CHARACTERISTICS					
Fuel Cost ($/MMBtu)	Base Fixed Operating & Maintenance ($/kW-Yr)	Base Variable Operating & Maintenance (Mills/kWh)	Base Fixed Additions & Improvements ($/kW-Yr)	Base Decommissioning Cost ($ Million)	Sulfur Dioxide (lb/MMBtu)	Nitrogen Oxides (lb/MMBtu)	Carbon Dioxide (lb/MMBtu)	Thermal Discharge (MMBtu/MWh)	Solid Waste (lb/MMBtu)	Economic Development 1 (Annual Average Employment)
NA	$225.00	17	$0.00	$0	0.056	0.03	205	0	9.48	NA
$1.38	$29.50	0.3	$11.20	$0	1.2	0.8	205	7.73	9.48	NA
($1.54)	$83.00	1.8	$58.00	$0	0.07	0.1	0	9.05	21.43	132
($1.54)	$90.00	5.8	$0.00	$0	0.07	0.1	0	9.05	21.43	NA
$1.00	$10.90	1.5	$19.90	$0	0.05	0.03	205	4.51	9.48	NA
($1.54)	$90.00	5.8	$0.00	$0	0.07	0.1	0	9.05	21.43	NA
NA	$200.00	12	$0.00	$0	0.24	0.1	210	0	0	NA
NA	$114.50	22	$0.00	$0	0	0.1	115	0	0	0
NA	$33.60	31.8	$0.00	$0	0	0.1	115	0	0	0
NA	$50.00	17	$0.00	$0	0	0	0	0	0	160
NA	$42.60	19.7	$0.00	$0	0.6	0.7	205	0	0	NA
$1.00	$24.00	0.6	$16.20	$0	0.3	0.15	210	0	24.02	513
$2.48	$4.00	1.3	$5.40	$0	0	0.08	115	0.45	0	144
$1.00	$15.30	0.9	$19.00	$0	0.05	0.03	205	3.89	9.48	NA
See Note 1	See Note 1	Same as Existing Unit	Same as Existing Unit	$0	See Note 1	Same as Existing Unit	See Note 1	Same as Existing Unit	Same as Existing Unit	NA
See Note 2	See Note 2	Same as Existing Unit	See Note 2	$0	See Note 2	Same as Existing Unit	See Note 2	Same as Existing Unit	Same as Existing Unit	NA
See Note 3	See Note 3	Same as Existing Unit	See Note 3	$0	See Note 3	Same as Existing Unit	See Note 3	Same as Existing Unit	Same as Existing Unit	NA
See Note 4	See Note 4	Same as Existing Unit	See Note 4	$0	See Note 4	Same as Existing Unit	See Note 4	Same as Existing Unit	Same as Existing Unit	NA
NA	$151.20	33.8	$0.00	$0	0	0	0	0	0	NA

Note 3: This option applies to all plants. There are no capacity changes from the current units. The capital cost is to add the cofiring capability. Adjustments should be made as follows: Fuel Cost =(Current Unit Coal Cost)*(1-.0125)+$0.764*.0125. Fixed O&M Costs=Current Unit+$0.09/kW. SO_2 Emissions=Current Unit Coal Emissions*(1-.0125). CO_2 Emissions=Current Unit Emissions*(1-.0125)-322*.0125. These adjustments reflect a 1.25% biomass energy input. All other cost and performance are same as current units.

Note 4: This option applies to all COF5 only. There are no capacity changes from the current units. The capital cost is to add the cofiring capability. Adjustments should be made as follows: Fuel Cost =(COF5 Coal Cost)*(1-.10)+$0.73*.10. Fixed O&M Costs=COF5 Cost+$0.13/kW. SO_2 Emissions=COF5 Emissions*(1-.10). CO_2 Emissions=COF5 Emissions*(1-.10)-322*.10. These adjustments reflect a 10% biomass energy input. All other cost and performance are same as COF5.

1 Calculated for selected options only

FIGURE T6-2. **Flexible TVA Supply-Side Options**

Number	ID Number	Option	Original Schedule (Yrs)	Accelerated Schedule (Yrs)	Cost to Obtain Accelerated Schedule ($/kW)	Cost Remaining ($/kW)
1	1.1.1.1.F	Supercritical Pulverized Coal-Fired Plant (1X300 MW)	8	3	$35	$1,579
2	1.1.1.2.F	Supercritical Pulverized Coal-Fired Plant (4X300 MW)	8	3	$10	$1,335
3	1.1.1.3.F	Atmospheric Fluidized Bed Combustion Repowering, Generic (1X125 MW)	6	3	$73	$1,046
4	1.1.1.4.F	Circulating Atmospheric Fluidized Bed Combustion Plant (1x200 MW)	8	3	$60	$1,426
5	1.1.1.5.F	Subcritical Pulverized Coal-Fired Plant (4x300 MW)	8	3	$8	$1,405
6	1.1.2.1.F	Simple Cycle Combustion Turbine Plant (1x150 MW)	5	1.5	$22	$338
7	1.1.2.2.F	Natural Gas-Fired Combined Cycle Plant (1x470 MW)	5	2	$14	$641
8	1.1.2.3.F	Combined Cycle Repowering, Generic (1x425 MW)	4	2	$14	$473
9	1.1.2.4.F	Small Cogeneration Combined Cycle Plant (3x10 MW)	4	1.5	$76	$1,044
10	1.1.2.5.F	Small Combined Cycle Plant (1X42 MW)	4.5	1.5	$59	$741
11	1.1.3.1.F	Refuse-Derived Fuel-Fired Stoker (1x40 MW)	8	3	$152	$5,588
12	1.1.5.1.F	Lead Acid Battery Energy Storage (1x20 MW)	3	1.5	$72	$506
13	1.2.1.1.F	State-of-the-Art Pulverized Coal-Fired Plant (1x400 MW)	8	4	$33	$1,384
14	1.2.2.1.F	Compressed Air Energy Storage with Humidification (3x337 MW)	7	3	$12	$303
15	1.2.2.2.F	Compressed Air Energy Storage with Recuperation (3x337 MW)	7	3	$11	$327
16	1.2.3.1.F	Biomass Whole Tree Energy Boiler Power Plant (1x100 MW)	8	3	$95	$1,417
17	1.3.1.1.F	First Generation Pressurized Fluidized Bed Combustion Repowering, Generic (1x156 MW)	6	3	$67	$1,100
18	1.3.1.2.F	First Generation Pressurized Fluidized Bed Combustion (1x340 MW)	8	3	$38	$1,243
19	1.3.1.3.F	Integrated Gasification Compressed Air Storage with Humidification (1x410 MW)	8	4	$36	$1,456
20	1.3.1.4.F	Integrated Gasification Combined Cycle with Fertilizer Coproduction (3x227 MW)	8	3.5	$23	$2,218
21	1.3.1.5.F	Integrated Gasification Combined Cycle (3x245 MW)	8	3.5	$18	$1,506
22	1.3.1.6.F	Compressed Air Storage with Humidification with Integrated Gasification & Natural Gas Peaking (1x850 MW)	8	4	$14	$858
23	1.3.1.7.F	Advanced Pressurized Fluidized Bed Combustor with Development Cost (1x300 MW)	8	3	$46	$1,472
24	1.3.1.8.F	Advanced Pressurized Fluidized Bed Combustor with No Development Cost (1x300 MW)	8	3	$42	$1,204
25	1.3.2.1.F	Fuel Cell - Molten Carbonate or Solid Oxide (1x2 MW)	4	1.5	$262	$772

FIGURE T6-2. **Flexible TVA Supply-Side Options** *CONTINUED*

Number	ID Number	Option	Original Schedule (Yrs)	Accelerated Schedule (Yrs)	Cost to Obtain Accelerated Schedule ($/kW)	Cost Remaining ($/kW)
26	1.3.2.2.F	Intercooled Aeroderivative Combustion Turbine (1x125 MW)	5	1.5	$36	$431
27	1.3.2.3.F	Cascaded Humidified Advanced Turbine (F Series CT) (1x288 MW)	6	2.5	$26	$477
28	1.3.2.4.F	Integrated Gasification Cascaded Humidified Advanced Turbine with Coproduction (F Series CT) (2x303 MW)	8	3.5	$21	$1,718
29	1.3.2.5.F	Integrated Gasification Cascaded Humidified Advanced Turbine (F Series CT) (2x303 MW)	8	3.5	$21	$1,222
30	1.3.2.6.F	Cascaded Humidified Advanced Turbine (G Series CT) (1x400 MW)	6	2.5	$20	$457
31	1.3.2.7.F	Integrated Gasification Cascaded Humidified Advanced Turbine with Coproduction (G Series CT) (2x420 MW)	8	3.5	$15	$1,607
32	1.3.2.8.F	Integrated Gasification Cascaded Humidified Advanced Turbine (G Series CT) (2x420 MW)	8	3.5	$15	$1,111
33	1.3.2.9.F	Integrated Fuel Cell/Combustion Turbine (1x2.5 MW)	4	1.5	$183	$1,057
34	1.3.3.1.F	Large Solar-Photovoltaic - Fixed Flat Plate (1x50 MW)	7	3	$111	$2,921
35	1.3.3.2.F	Landfill Methane (1x2 MW)	3	1.5	$205	$829
36	1.3.3.3.F	Coalbed Methane (1x2 MW)	3	1.5	$182	$852
37	1.3.5.1.F	Advanced Battery Energy Storage (1x20 MW)	3	1.5	$68	$423
38	1.3.5.2.F	Superconducting Magnetic Energy Storage (1x500 MW)	8	4	$26	$751
39	2.1.3.1.F	Additional Hydro Generation at Existing Nonpower Projects (1x10 MW)	5	3	$266	$2,194
40	2.1.3.2.F	Additional Hydro Generation at Existing Projects (1x24 MW)	6	3	$132	$4,156
41	2.1.3.3.F	Additional Hydro Generation - New Conventional Projects (1x65 MW)	9	5	$224	$8,529
42	4.1.1.1.F	Lignite-Fired Circulating Fluidized Bed Combustion Plant (1x200 MW)	7	3	$59	$1,541
43	6.3.2.7.F	Gas Turbine - Modular Helium Reactor (3x289 MW)	13	6	$28	$2,094
44	6.3.4.1.F	Advanced Light Water Reactor (1x1300 MW)	10	6	$18	$1,822
45	7.1.1.1.F	Bellefonte Repowering with Integrated Gasification Combined Cycle (9x250 MW)	9	3.5	$6	$1,478
46	7.1.1.2.F	Bellefonte Repowering with Pulverized Coal (4x616 MW)	11	4	$5	$1,258
47	7.1.1.3.F	Bellefonte Repowering - Phased Combined Cycle/IGCC - Phase A - Combined Cycle (9x222 MW)	8	2.5	$4	$547
48	7.1.1.4.F	Bellefonte Repowering - Phased Combined Cycle/IGCC - Phase B - IGCC (9x250 MW)	7	3	$4	$1,551
49	7.1.1.5.F	Bellefonte Repowering - IGCC with Coproduction (11x229 MW)	11	3.5	$6	$1,851
50	7.1.1.6.F	Bellefonte Repowering - IGCC with Coproduction with Partners (2x242 MW)	8	3.5	$20	$445
51	7.1.2.1.F	Bellefonte Repowering - Natural Gas Combined Cycle (10x222 MW)	8	2.5	$3	$472

FIGURE T6-2: **Flexible TVA Supply-Side Options** *CONTINUED*

Number	ID Number	Option	Original Schedule (Yrs)	Accelerated Schedule (Yrs)	Cost to Obtain Accelerated Schedule ($/kW)	Cost Remaining ($/kW)
52	10.1.2.1.F	Inlet Air Precooling with Storage (16x61 MW)	3	1	$2	$49
53	10.1.2.2.F	New Combustion Turbine at Johnsonville to Supply Steam to DuPont (1x174 MW)	4	2	$34	$1,079
54	10.1.2.3.F	Repowering One of Johnsonville Fossil (JOF) Units 7-10 with Natural Gas/Combined Cycle (1x465 MW)	4	2	$13	$468
55	10.3.1.1.F	Repowering One of JOF Units 1-6 with IGCC (1X242 MW)	7	3.5	$50	$1,420
56	10.3.1.2.F	Repowering One of JOF Units 7-10 with IGCC (1x250 MW)	7	3.5	$48	$1,392
57	11.1.5.1.F	Laurel Branch Pumped-Hydro Storage (4x386 MW)	10	7	$9	$1,111
58	14.1.3.1.F	Wind - 33 Meter Variable Speed Advanced Wind Turbine (285x0.35 MW)	6	2	$45	$1,011
59	14.3.3.1.F	Wind - 39 Meter Variable Speed Advanced Wind Turbine (444x0.45 MW)	6	2	$24	$934
60	15.1.5.1.F	Reynolds Creek Pumped-Hydro Storage (3x366 MW)	10	7	$13	$1,485
61	16.1.5.1.F	Raccoon Mountain - Pumped-Hydro Energy Storage Addition (3x255 MW)	10	7	$13	$1,025
62	16.1.5.2.F	Raccoon Mountain Pumped-Storage Modernization	6	2	$1	$19
63	17.1.5.1.F	Rorex Creek Pumped-Hydro Storage (3x292 MW)	10	7	$15	$1,060
64	18.1.1.1.F	Shawnee Unit 11 (1x168 MW)	5	2.5	$30	$531
65	20.1.1.1.F	Restart One Unit of Watts Bar Fossil Plant (1x56 MW)	6	2.5	$86	$489
66	20.1.3.1.F	RDF - Fluidized Bed Combustion Repowering of One Unit of Watts Bar Fossil Plant (1x56 MW)	6	3	$136	$2,415
67	20.3.1.1.F	Repowering Two Units of Watts Bar Fossil Plant with IGCC (1x242 MW)	7	3.5	$48	$1,492
68	25.1.2.1.F	Repowering Allen Fossil Plant with Natural Gas/Combined Cycle (1x705 MW)	4	2	$9	$440
69	25.3.1.1.F	Repowering Allen Fossil Plant with IGCC (1x500 MW)	7	3.5	$24	$1,294

Option 1.1.1.1

SUPERCRITICAL PULVERIZED COAL-FIRED PLANT (1X300 MEGAWATTS)

This option is technically similar to the subcritical pulverized coal (PC)-fired plant, option 1.1.1.5, with the exception that the supercritical boiler operates at supercritical pressures of greater than 3,200 pounds per square inch. The properties of water at supercritical pressures are such that there is no discrete phase change from liquid water to steam as the fluid temperature is raised. Therefore, there is no need for a boiler drum for steam separation to occur as there is in a subcritical boiler. The supercritical PC boiler is a once-through design. The higher pressure steam cycle provides greater efficiency. The final main steam and reheat steam temperatures are 1,000°F.

The relatively high capital cost, low fuel cost, and high efficiency of the modern supercritical PC power plant make it a promising candidate for base-load capacity additions.

The cost and performance data are based on information from Electric Power Research Institute's Technical Assessment Guide.

Option 1.1.1.2

SUPERCRITICAL PULVERIZED COAL-FIRED PLANT (4X300 MEGAWATTS)

This option is similar to the 1 X 300-megawatt supercritical pulverized coal-fired plant, option 1.1.1.1, except for the plant capacity. The 4 X 300-megawatt plant will have capital cost savings, on a dollar-per-kilowatt basis, relative to the single unit plant due to common facilities shared by each unit.

The cost and performance data are based on information from Electric Power Research Institute's Technical Assessment Guide. The Technical Assessment Guide procedures were used to determine cost adjustments for a multiple-unit plant.

Option 1.1.1.3

ATMOSPHERIC FLUIDIZED BED COMBUSTION REPOWERING, GENERIC (1X125 MEGAWATTS)

Option 1.1.1.4, which follows, describes the atmospheric fluidized bed combustion (AFBC) boiler and other systems. One or more existing coal-fired boilers could be retired and replaced with an AFBC boiler. For each retired boiler, one AFBC boiler would be installed. Steam generated in the AFBC boiler would power the existing steam turbine. The efficiency and capacity of the repowered unit would be approximately the same as the original unit.

The steam cycle systems, plant infrastructure, transmission facilities, fuel-handling facilities, and a permitted site would be reused. Therefore, the capital cost of repowering would be less than that for a greenfield AFBC unit of similar capacity. Repowering costs are very site-specific. The cost advantage of a repowering installation over a greenfield installation will depend on site characteristics.

Sulfur capture in the AFBC boiler would allow a range of fuels to be burned. High sulfur coal would be the design fuel.

Cost and performance data are based on an AFBC repowering proposal presented to TVA, with adjustments to reflect results from Electric Power Research Institute repowering studies.

Option 1.1.1.4

CIRCULATING ATMOSPHERIC FLUIDIZED BED COMBUSTION PLANT (1X200 MEGAWATTS)

Fluidized bed combustion (FBC) has attracted interest in the electric utility industry in the last decade due to its ability to meet sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions standards without the need for add-on control equipment. Atmospheric FBC is now considered a commercial technology for utility applications in unit sizes up to about 200 megawatts. The AFBC option is based on the subcritical circulating FBC concept.

Crushed coal and limestone are injected at the bottom of the FBC furnace. SO_2 released from the coal combustion reacts with the calcium in the limestone to form a solid byproduct. The amount of sulfur captured in the process depends on the amount of limestone added. The furnace temperature is maintained in the optimum range for this reaction, 1500-1600°F. This relatively low temperature, compared to a pulverized coal furnace, reduces the formation of NO_X.

Fluidizing air from the forced draft fans and air heater is introduced from below the furnace to provide combustion air and maintain the fuel/limestone mixture in a well-mixed state throughout the height of the furnace. Solids that are carried out of the furnace are captured in a cyclone separator and recycled to the furnace to maximize carbon burnout and sulfur capture. The partially cleaned flue gas exits the cyclone into a convection pass, where additional heat transfer surfaces for steam superheating and reheating are located. An economizer surface is located near the exit of the convection pass. The flue gas passes through an air heater before final particulate collection in a fabric filter. Cleaned flue gas is exhausted to the atmosphere.

Heated feedwater is pumped from the steam turbine condenser to the boiler economizer. The feedwater then enters the boiler drum from which it is distributed to the waterwall furnace enclosure in which steam generation occurs. The steam/water mixture from the waterwalls re-enters the drum, where steam separation takes place. The steam is superheated in the boiler before exiting to the turbine. The final main steam pressure and

temperature are 2,400 pounds per square inch and 1,000°F, respectively. To increase efficiency, the steam is reheated after partial expansion in the steam turbine to 1,000°F.

Energy in the steam is converted to electrical energy by the turbine-generator. The turbine exhaust steam is condensed and pumped back to the boiler through a series of feedwater heaters. Heat is rejected from the condenser cooling water to the atmosphere in a mechanical draft cooling tower.

Ash, consisting of coal ash and limestone products (including the captured sulfur), is removed from the fabric filter and the furnace bottom and disposed of on-site.

Sulfur capture in the AFBC boiler would allow a range of fuels to be burned. High sulfur coal is the design fuel for the AFBC option.

The relatively high capital cost, low fuel cost, and relatively high efficiency of the AFBC plant make it a candidate for base-load capacity additions.

The cost and performance data are based on information from Electric Power Research Institute's Technical Assessment Guide.

Option 1.1.1.5

SUBCRITICAL PULVERIZED COAL-FIRED PLANT (4X300 MEGAWATTS)

The pulverized coal (PC)-fired boiler with steam turbine power generation is currently the principal electricity generation technology in the United States.

Coal is delivered from on-site storage or receiving facilities to day bunkers in the powerhouse. From the day bunkers, coal is metered to the pulverizers, where it is ground to a very small particle size. The pulverized coal is air-conveyed to burners penetrating the walls of the furnace. This conveying air, as well as the remainder of the combustion air, is provided by the forced draft fans through an air heater. The air heater recovers heat from the flue gas exiting the boiler prior to the gas being exhausted to the atmosphere.

Heated feedwater is pumped from the turbine condenser to the boiler economizer in which energy is recovered from the flue gas prior to the gas exiting the boiler. The feedwater then enters the boiler drum from which it is distributed to the waterwall furnace enclosure in which steam generation occurs. The steam/water mixture from the waterwalls re-enters the drum, where steam separation takes place. The steam is superheated in the boiler before exiting to the turbine. Energy in the steam is converted to electrical energy by the turbine-generator. To increase efficiency, the steam is reheated after partial expansion in the steam turbine and readmitted to the turbine. The turbine exhaust steam is condensed and pumped back to the boiler as feedwater through a series of feedwater heaters. Heat is rejected from the condenser cooling water to the atmosphere in a mechanical draft cooling tower. For the subcritical PC option, the final main steam pressure, main steam temperature, and reheat temperature are 2,400 pounds per square inch, 1,000°F, and 1,000°F, respectively.

Selective catalytic reduction (SCR), located in the region of the boiler where flue gas temperature is optimal for nitrogen oxides (NO_X) reduction, is used to control NO_X emissions. A fabric filter located downstream of the air heater controls particulate emissions. Sulfur dioxide (SO_2) emissions are controlled with a limestone flue gas desulfurization (FGD) system, or scrubber. The cleaned flue gas is exhausted to the atmosphere. Ash collected in the fabric filter and gypsum from the FGD system are disposed of on-site.

This option is based on a total 1,200-megawatt capacity, four-unit plant. Each unit has a 300-megawatt capacity. Multiple-unit plants offer capital cost savings on a dollar-per-kilowatt basis compared to single-unit plants due to common facilities, such as fuel handling, transmission facilities, and others that are shared by each unit.

High sulfur coal is the design fuel for the subcritical PC option.

The relatively high capital cost, low fuel cost, and relatively high efficiency of the modern subcritical PC power plant make it a candidate for base-load capacity additions.

Cost and performance data are based on TVA estimates and historical performance.

Option 1.1.2.1

SIMPLE CYCLE COMBUSTION TURBINE PLANT (1X150 MEGAWATTS)

A simple cycle combustion turbine (CT) generator consists of an air compressor, combustor, and expansion turbine. Gaseous or liquid fuels are burned under pressure in the combustor. The hot, high pressure combustion products expand through the turbine. The turbine drives the air compressor, as well as an electric generator. The electric generator converts the mechanical energy produced by the turbine into electrical energy. Gases from the expansion turbine are exhausted to the atmosphere.

The primary fuel will be natural gas with fuel oil as the back-up fuel.

The major emissions from combustion turbines fired with natural gas are nitrogen oxides (NO_X). To reduce NO_X emissions, dry, low NO_X burners would be used. As natural gas contains negligible amounts of sulfur, sulfur dioxide (SO_2) emissions are essentially zero. Because of the higher hydrogen content of the natural gas fuel relative to coal, carbon dioxide (CO_2) emissions on an energy input basis will be lower than the emissions for coal-based technologies.

Combustion turbine efficiency is strongly affected by CT firing temperature. This option reflects the current generation of advanced CTs operating at a firing temperature of 2,350°F.

Several features of simple cycle CTs, including their relatively low capital cost, short construction times, low emissions, rapid start-up times, relatively high fuel costs (compared with coal), and relatively low efficiency (compared to combined cycle CTs and most modern coal-based technologies), make this technology attractive for peaking capacity additions.

The cost and performance data are based on information provided by a combustion turbine supplier.

Option 1.1.2.2

NATURAL GAS-FIRED COMBINED CYCLE PLANT (1X470 MEGAWATTS)

The combined cycle power plant consists of a combustion turbine (CT) generator, option 1.1.2.1, and a steam turbine-generator. The hot exhaust gases from the CT pass through a heat recovery steam generator (HRSG). The HRSG reduces the CT exhaust from about 1,100°F to about 300°F before it is exhausted to the atmosphere. Steam raised in the HRSG powers the steam turbine-generator. Steam turbine exhaust is condensed and pumped back to the HRSG as feedwater. Heat is rejected from the condenser cooling water to the atmosphere in a mechanical draft cooling tower. The CT provides about two-thirds of the generated power and the steam turbine about one-third. The heat recovery from the CT exhaust provides an efficiency improvement over the simple cycle CT.

The primary fuel will be natural gas with fuel oil as the back-up fuel.

Nitrogen oxides (NO_X) emissions from the combined cycle CT will be controlled by selective catalytic reduction (SCR). Optimal performance of the SCR requires a relatively narrow gas temperature range. The SCR will be installed in the region of the HRSG, where the gas temperature is optimum for SCR performance. Sulfur dioxide emissions from the natural gas fuel would be essentially zero. The high efficiency and natural gas fuel combine to produce relatively low carbon dioxide (CO_2) emissions.

Features of the combined cycle CT option, including its high efficiency, moderate capital cost, relatively high fuel cost, low emissions, and short construction time make this technology a candidate for intermediate capacity additions.

The cost and performance data are based on information provided by a combined cycle CT supplier.

Option 1.1.2.3

COMBINED CYCLE REPOWERING, GENERIC (1X425 MEGAWATTS)

Repowering coal-fired generating units may in some cases provide operating cost savings, emissions reductions, capacity addition, and life extension of existing power-generating facilities. TVA has several low efficiency, relatively low capacity (less than 125 megawatts), aging coal-fired generating units for which repowering may be advantageous.

For each retired coal-fired boiler, two natural gas-fired combustion turbines (CT) and heat recovery steam generators (HRSG) would be installed at the plant site. The steam raised in the HRSGs would power the existing steam turbine that was previously powered by the coal-fired boiler. The HRSGs would be designed to provide steam that matches the conditions of the steam turbine. The turbine exhaust is condensed and pumped back to the HRSG as feedwater. If the capacity of the steam turbine is maintained, the additional capacity of the CTs provides a total repowered unit capacity approximately three times that of the unit prior to repowering.

Steam cycle systems, plant infrastructure, transmission facilities, and a permitted site would be reused. Therefore, capital costs for repowering would be less than for a greenfield plant of similar capacity. Repowering costs are very site-specific. The cost advantage of a repowering installation over a greenfield installation depends on site characteristics. Combined cycle repowering would provide efficiency improvement relative to the unit prior to repowering. Efficiency would not likely be as high as for a greenfield combined cycle CT plant.

Nitrogen oxides (NO_X) emission control by selective catalytic reduction (SCR) and negligible sulfur dioxide (SO_2) emissions associated with the natural gas fuel would result in lower emissions of these gases relative to the unit prior to repowering. The fuel switch to natural gas and the higher efficiency relative to the unit prior to repowering would result in lower carbon dioxide emissions.

The cost and performance data are based on information provided by a combined cycle combustion turbine supplier. Costs were based on CT selection and HRSG design that would fully repower a specific steam turbine. Other applications of this option are considered to be similar.

Option 1.1.2.4

SMALL COGENERATION COMBINED CYCLE PLANT (3X10 MEGAWATTS)

The small cogeneration combined cycle plant consists of three small combustion turbines (approximately 10 megawatts each), with each combustion turbine exhausting flue gas into separate heat recovery steam generators. The steam conditions

from the steam generators are driven by the pressure and temperature requirements of the steam host. Either a condensing steam turbine or a backpressure steam turbine may be added to the configuration to provide low pressure steam at various pressure levels if required by the steam host. The combustion turbines can be fired by either natural gas or #2 fuel oil.

Each combustion turbine/heat recovery steam generator pair can produce 37,000 pounds of steam per hour without duct firing. Thus, the small cogeneration combined cycle plant can produce in excess of 100,000 pounds of steam per hour. The addition of duct firing can raise the amount of steam produced significantly, but at the expense of the higher steam production cost due to fuel used by the duct burners.

The cost and performance information provided are based upon data from Black & Veatch on their "Instant Power Station" joint venture with Solar Turbines. The primary advantage of this type of plant is its very short lead time.

Option 1.1.2.5

SMALL COMBINED CYCLE PLANT (1X42 MEGAWATTS)

The small combined cycle plant consists of three small combustion turbines (CT), approximately 10 megawatts each, with each combustion turbine exhausting flue gas into separate heat recovery steam generators. The steam from the three steam generators is passed to a single condensing steam turbine (ST) bottoming cycle. The steam cycle heat rejection is through cooling towers. The combustion turbines can be fired by either natural gas or #2 fuel oil.

The small combined cycle plant can produce approximately 42 megawatts of electricity at ISO (International Standards Organization) conditions. The addition of duct firing can raise the amount of steam produced significantly, thus increasing power output, but at a higher steam production cost due to fuel used by the duct burners.

The cost and performance information provided is based upon data from Black & Veatch on their "Instant Power Station" joint venture with Solar Turbines. The primary advantage of this type of plant is its very short lead time.

Option 1.1.3.1

REFUSE-DERIVED FUEL-FIRED STOKER (1X40 MEGAWATTS)

Option 20.1.3.2

REFUSE-DERIVED FUEL COMPANION BOILER AT WATTS BAR FOSSIL PLANT (1X60 MEGAWATTS)

Option 21.1.3.1

REFUSE-DERIVED FUEL COMPANION BOILER AT KINGSTON FOSSIL PLANT (1X60 MEGAWATTS)

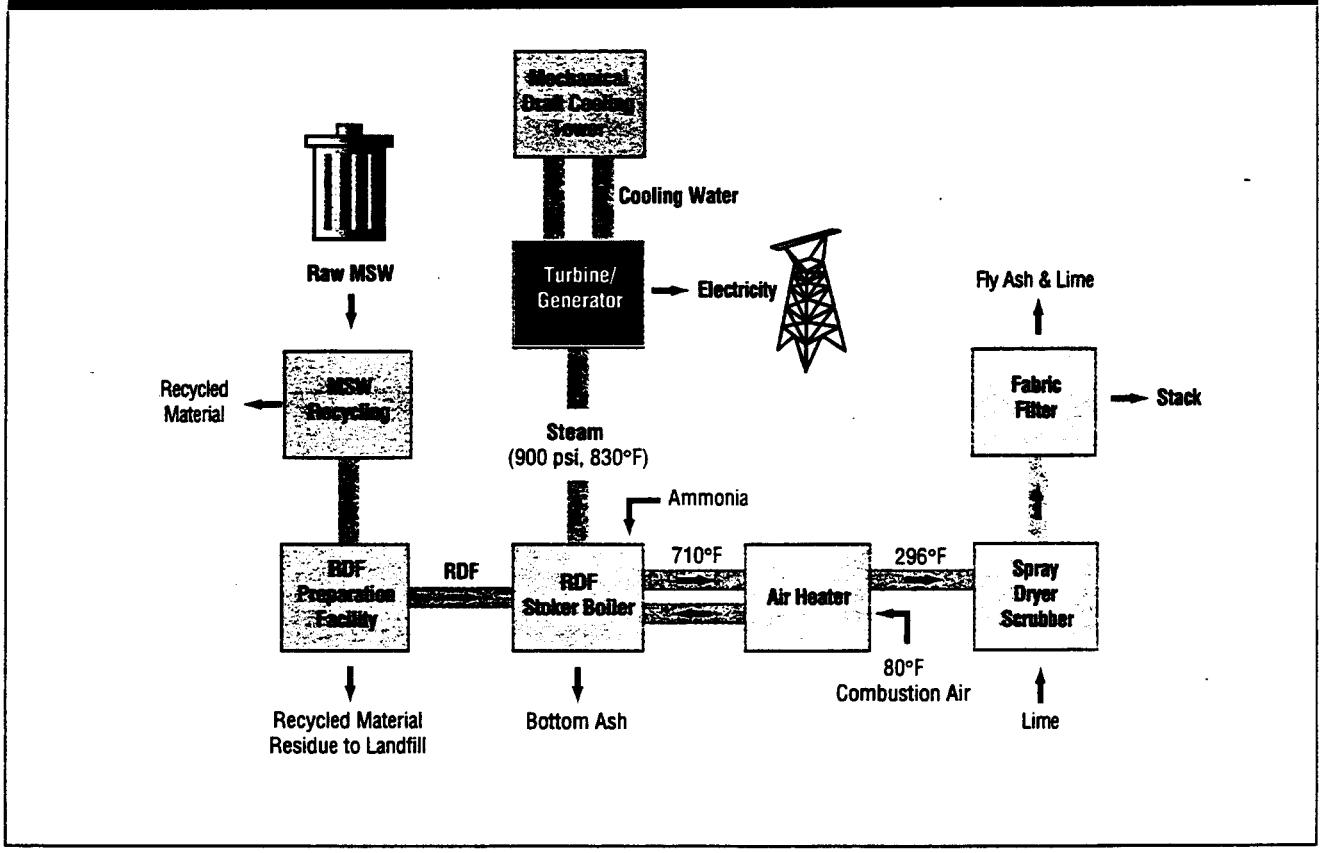
The refuse-derived fuel-fired power plant consists of both the refuse-derived fuel (RDF) preparation facility and the RDF-fired stoker boiler power plant.

After the removal and recycling of about 20 percent of the material from the raw municipal solid waste (MSW), the remaining MSW is delivered by truck to the tipping floor of the on-site RDF preparation facility. The production facility consists of three parallel trains, each sized to process about 100 tons of MSW per hour over five days per week. The waste passes through a sequence of process steps, including flail milling, trommel screening, magnetic separation, and size reduction to produce RDF containing about 12 percent ash and 5,900 Btu per pound higher heating value (HHV). The RDF is stored in a live-bottom hopper and transported by conveyor as needed to the power plant, where it is injected by spreaderstoker and burns both in suspension and on the grate. The steam conditions are 900 pounds per square inch and 830°F. The remainder of the plant includes waterwall and convective heat transfer surfaces, a steam turbine generator, a mechanical draft cooling tower, an ammonia thermal de-NO_X (nitrogen oxides) system, a lime spray dryer scrubber, a baghouse, fans, and ash disposal.

The 40-megawatt RDF preparation and stoker power plant consumes 1,736 tons of MSW per day, delivered to the plant after recycling off-site about 400 tons per day of paper, glass, metals, and other materials from 2,166 tons of raw MSW per day. The RDF preparation plant produces 1,396 tons of RDF per day, with a moisture content of 28.2 percent and 5,663 Btu per pound (HHV as received), which is consumed by the stoker boiler. The gross capacity is 46.2 megawatts, auxiliary power consumption is 6.2 megawatts, and the net plant heat rate at full load is 16,464 Btu per kilowatt-hour, based on the RDF fuel (20.7 percent thermal efficiency). *Figure T6-3* shows a diagram of an RDF preparation and stoker boiler power plant.

The companion boiler options produce steam for use in existing steam turbines. At Watts Bar, the companion boiler would displace an existing boiler to supply an existing steam turbine. At Kingston, the steam from the companion boiler would

FIGURE T6-3: **RDF Preparation and Stoker Boiler Power Plant**



increase the steam flow to existing turbines to make use of excess turbine capacity. Since these options are rated at 60 megawatts, the quantities of RDF would be proportionally higher than for the 40-megawatt stoker option. Otherwise, the companion boiler options are similar to the RDF stoker option.

The cost and performance data are based on Electric Power Research Institute's Technical Assessment Guide.

Option 1.1.5.1

LEAD ACID BATTERY ENERGY STORAGE (1X20 MEGAWATTS)

Low cost, off-peak electricity would be used to charge the lead acid battery plant. The plant has a 20-megawatt capacity and a 2-hour discharge time. The battery plant would be used for heavy duty applications such as load leveling and frequency regulation with deep discharge.

Battery plants have a very rapid response time of less than one-tenth of a second to reach full load. Another advantage of battery plants is their siting flexibility. They could be located virtually anywhere, including in urban areas.

There would be no emissions associated with the battery plant itself; however, there would be emissions from the generation sources used to charge the plant.

The cost and performance data are based on information from Electric Power Research Institute's Technical Assessment Guide.

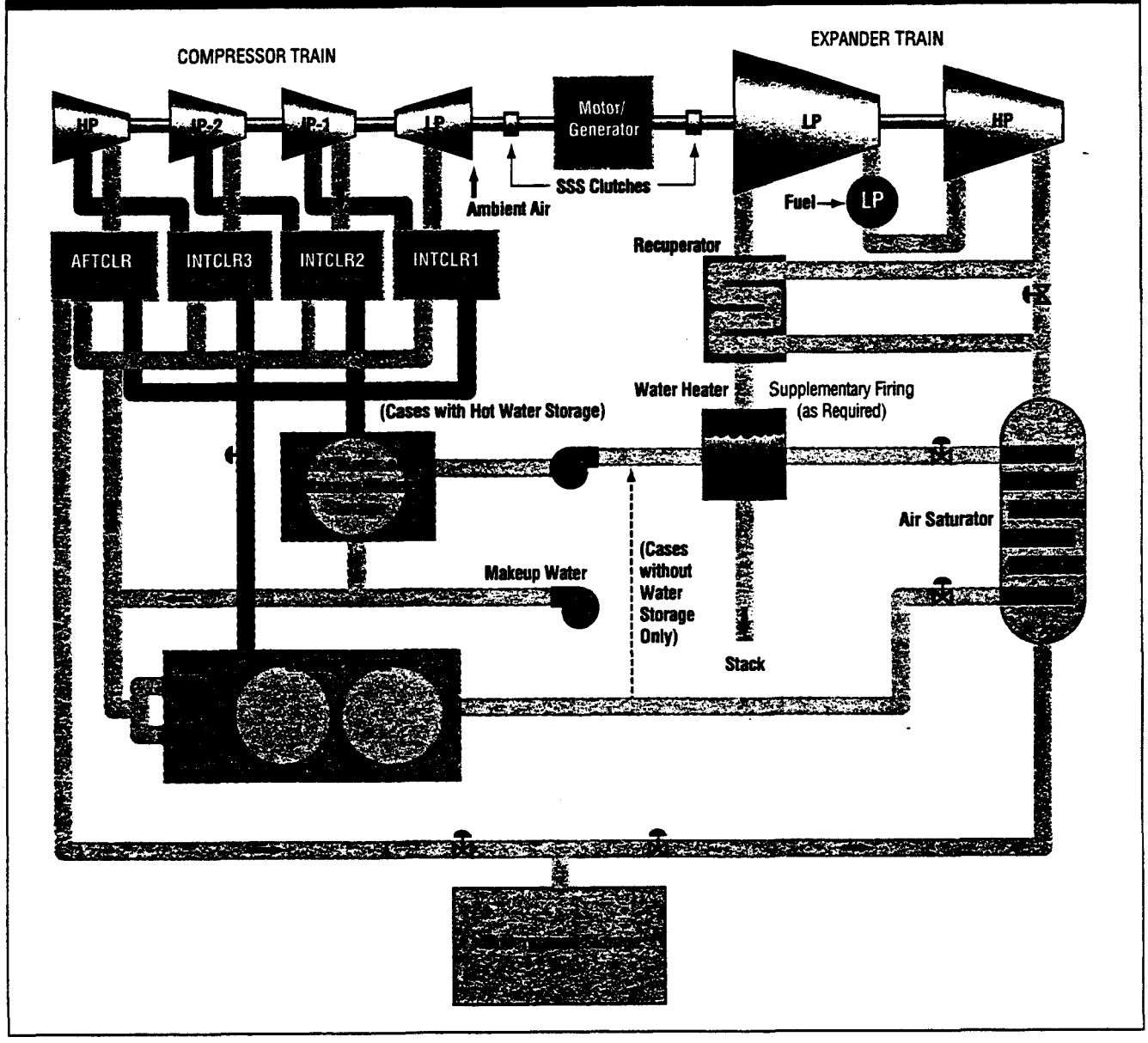
Option 1.2.1.1

STATE-OF-THE-ART PULVERIZED COAL-FIRED POWER PLANT (1X400 MEGAWATTS)

The state-of-the-art pulverized coal-fired power plant (SOAPP-PC) is a concept that is intended to be competitive with other advanced coal-fired technologies such as integrated gasification/combined cycle. Its basic performance and cost goals are to produce power at a heat rate in the low 8,000 Btu per kilowatt-hour range, have the same or lower operating and maintenance costs as a conventional pulverized coal (PC)-fired plant, and achieve this with the same or lower capital investment as a conventional PC-fired plant.

The SOAPP-PC concept is based on a supercritical double reheat steam cycle. The steam is at a 4,500 pounds per

FIGURE T6-4. **Schematic of CAES Plant with Air Humidification**



square inch gauge main steam pressure at 1,100°F. The first and final reheats are at 1,100°F. The steam generator has a spiral wound once-through design to minimize variations in heat absorption patterns. The cycle is equipped with nine stages of regenerative feedwater heating. The plant has conventional flue gas desulfurization and particulate removal, and is equipped with low nitrogen oxides (NO_X) burners and a selective catalytic reduction unit for NO_X control. Heat rejection is through a natural draft cooling tower.

The cost and performance information is obtained from Sargent & Lundy as part of their contract with Electric Power Research Institute to develop SOAPP designs for PC-fired and natural gas-fired combined cycle power plants.

Option 1.2.2.1

COMPRESSED AIR ENERGY STORAGE PLANT WITH HUMIDIFICATION (3X337 MEGAWATTS)

Option 1.2.2.2

COMPRESSED AIR ENERGY STORAGE PLANT WITH RECUPERATION (3X337 MEGAWATTS)

Compressed air energy storage (CAES) combines features from conventional combustion turbines and pumped-hydro storage.

During periods of relatively low electricity demand and, therefore, low power generation costs, air is compressed and stored in an underground reservoir. The equipment is analogous to the compressor used in a combustion turbine and the process is similar to the pumping and storing of water at a higher elevation in pumped hydro.

During periods of high electricity demand, the pressurized air from the underground reservoir is expanded through a high pressure turbine to produce power. The air enters a combustor where its temperature is raised, and then it expands through a low pressure turbine, producing additional power. The exhaust from the low pressure turbine goes to a recuperator to heat the air entering the high pressure turbine.

In CAES with humidification, the air entering the high pressure turbine is saturated with water vapor, which increases the mass flow through the turbines, and increases the amount of power produced per pound of air that has to be compressed. Again, this equipment is roughly analogous to the turbomachinery in a combustion turbine, and the process is similar to the power generation from water stored at a higher elevation in pumped hydro. *Figure T6-4* shows a schematic of a CAES plant with air humidification, and *Figure T6-5* shows a schematic of a conventional CAES plant.

Based on extensive studies of underground storage in the oil and natural gas industry, several geologies appear to be suitable for air storage: salt domes, aquifers including depleted natural gas fields, and hard rock.

The costs for this option assume storage in salt dome geology. The perfomance data are based on information from Electric Power Research Institute's Technical Assessment Guide.

Option 1.2.3.1

BIOMASS WHOLE TREE ENERGY™ BOILER POWER PLANT (1X100 MEGAWATTS)

The Whole Tree Energy™ (WTE) boiler is a new direct combustion technology being developed with support from Electric Power Research Institute and other sponsors for application in large-scale power production from energy crops. The WTE system involves the harvesting of stands of close-growing whole trees, transport by truck, tree storage, and drying using air heated by boiler flue gas, and combustion of the whole trees in a special deep bed burner at the bottom of the furnace.

FIGURE T6-5. **Schematic of Conventional CAES Plant**

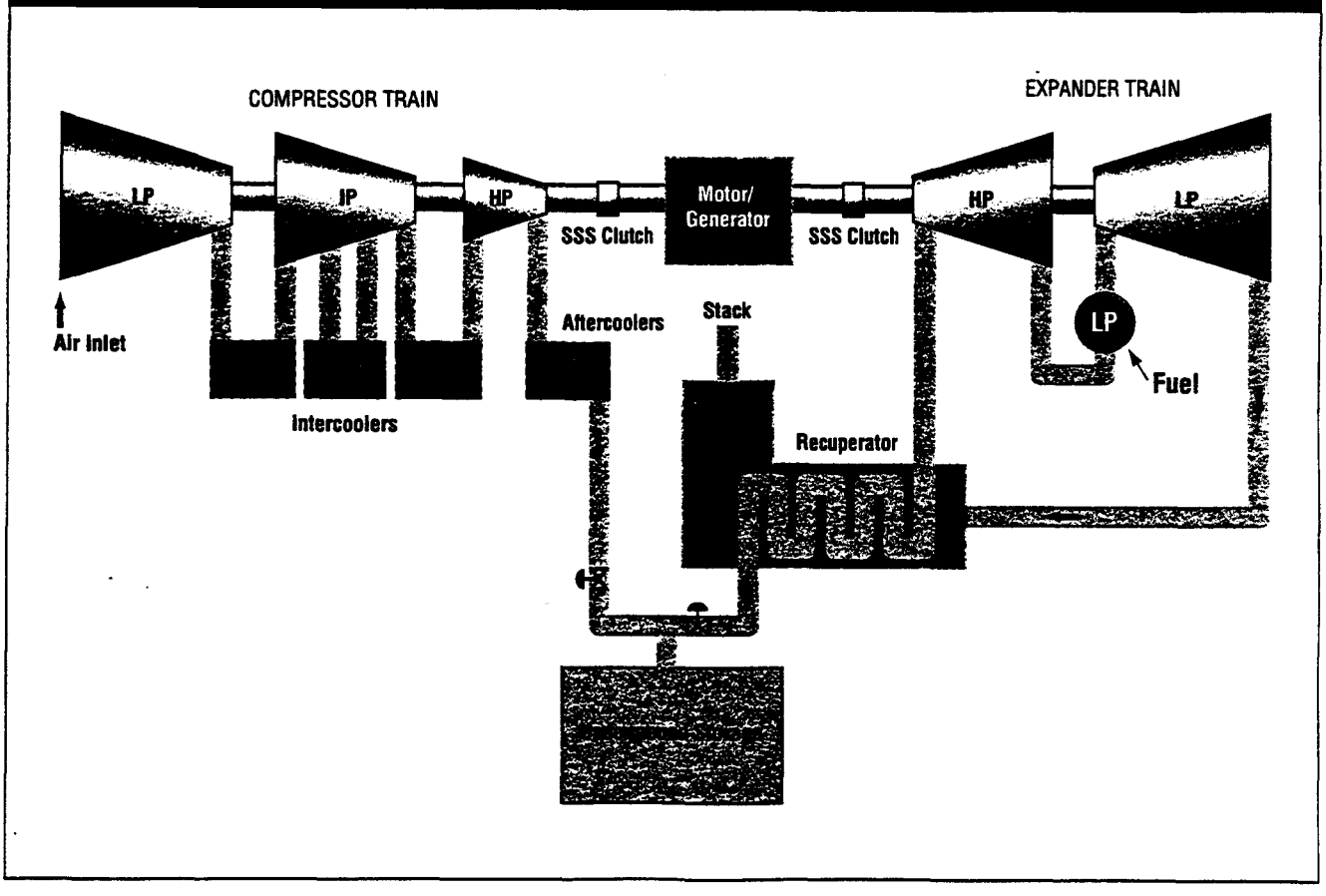
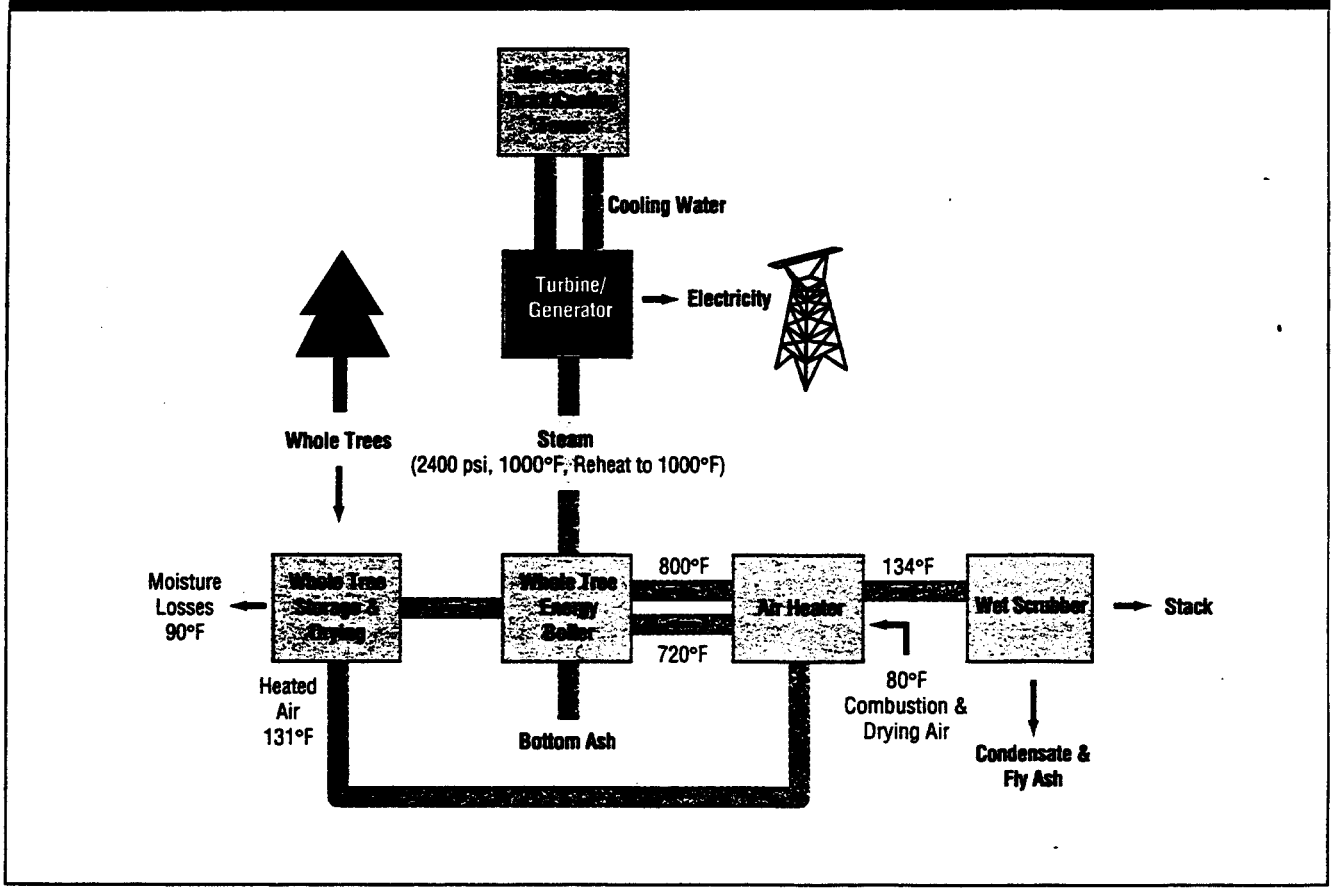


FIGURE T6-6. **Whole Tree Energy™ Boiler Power Plant**



After harvesting and delivery to the plant, the whole trees are stacked in an annular ring in the air-supported fabric dome drying building. Air heated to about 130°F in the boiler air heater is injected under the pile to dry the trees from about 45 to 25 percent moisture content. After 30 days of storage and drying, the trees are removed, cut to uniform length, and loaded through a sealing access door into the deep-bed combustor. Air injected into the bottom of the bed is sufficient to burn out the remaining char, provide heat to drive off volatiles, and gasify the whole trees in the upper bed. Overfire air is injected into the furnace above the bed to complete combustion of the volatiles. The two-stage condensing heat exchanger at the boiler exit cools the flue gases from about 800°F to 134°F, and heats the combustion air to 721°F and wood drying air to 131°F before transport to the drying building. A portion of the flue gas moisture condenses in the second stage and is collected, along with the fly ash, in a wet scrubber. The plant has main steam pressure and temperature of 2,400 pounds per square inch absolute and 1,000°F, with a reheat steam temperature of 1,000°F to achieve maximum thermal efficiency. Other plant components include the ammonia de-NO_X (nitrogen oxides) system, generator, cooling tower, and fans. Due to the relatively low gas velocity in the deep bed combustor, about 60 percent of the wood ash remains behind in the combustor, and the remainder is discharged as fly ash. *Figure T6-6* shows a diagram of a Whole Tree Energy™ boiler power plant

The 100-megawatt Whole Tree Energy™ boiler power plant receives about 2,642 tons of whole trees per day, and after the 30-day drying period, fires about 1,887 tons of dried trees per day. Gross capacity is 107.5 megawatts, auxiliary power consumption is 7.5 megawatts, and the net plant heat rate at full load is 10,654 Btu per kilowatt-hour (32 percent thermal efficiency).

The cost and performance data are based on information from Electric Power Research Institute's Technical Assessment Guide.

Option 1.3.1.1

FIRST GENERATION PRESSURIZED FLUIDIZED BED COMBUSTION REPOWERING, GENERIC (1X156 MEGAWATTS)

Option 1.3.1.2, below, describes the pressurized fluidized bed combustion (PFBC) boiler and other systems. One or more existing coal-fired boilers could be retired and replaced with a PFBC boiler. For each retired boiler, one PFBC boiler, hot gas filter, and expansion turbine would be installed. Steam generated in the PFBC boiler would power the existing steam turbine. The addition of the gas expansion turbine would result in a net capacity increase of approximately 20 percent. The repowered unit efficiency would be improved by about 20 percent. The efficiency would not likely be as high as a greenfield PFBC unit.

Steam cycle systems, plant infrastructure, transmission facilities, fuel handling facilities, and a permitted site would be reused. Therefore, the capital cost for repowering would be less than for a greenfield PFBC unit of similar capacity. Repowering costs are very site-specific. The cost advantage of a repowering installation over a greenfield installation depends on site characteristics.

Sulfur capture in the PFBC boiler would allow a range of fuels to be burned. High sulfur coal would be the design fuel.

Cost and performance data are based on information from Electric Power Research Institute's Technical Assessment Guide and other information reported from Electric Power Research Institute.

Option 1.3.1.2

FIRST GENERATION PRESSURIZED FLUIDIZED BED COMBUSTION (1X340 MEGAWATTS)

The discussion of circulating atmospheric fluidized bed combustion (AFBC), option 1.1.1.4, describes the fluidized bed combustion (FBC) boiler. In a pressurized fluidized bed combustion (PFBC) unit, the FBC boiler is enclosed in a pressure vessel. The hot (about 1,600°F), pressurized flue gas exiting the cyclone is cleaned of particulates in a ceramic filter. The cleaned gas passes through an expansion turbine that drives an electric generator, as well as an air compressor that pressurizes the PFBC pressure vessel. Energy is recovered from the expansion turbine exhaust gas by boiler feedwater in an economizer before the gas is exhausted to the atmosphere. The PFBC plant consists of four PFB boiler/gas turbine modules powering one steam turbine (ST).

Steam is generated, superheated, and reheated in the PFBC boiler to drive a conventional steam turbine-generator. About 80 percent of the net power output is from the steam turbine, and about 20 percent is from the gas expansion turbine.

The PFBC boiler has a greater energy input per unit of boiler footprint area than either the AFBC or pulverized coal (PC) boilers. Therefore, the PFBC boiler requires less area for installation. The combined cycle feature of the unit (a steam turbine and a gas expansion turbine) provides for greater efficiency than either the AFBC or PC unit.

Sulfur capture in the PFBC boiler would allow a range of fuels to be burned. High sulfur coal would be the design fuel.

PFBC technology is considered to be at the large-scale demonstration stage of development.

Cost and performance data are based on reported information from Electric Power Research Institute.

Option 1.3.1.3

INTEGRATED GASIFICATION COMPRESSED AIR STORAGE WITH HUMIDIFICATION (1X410 MEGAWATTS)

The integrated gasification compressed air storage with humidification (IGCASH) cycle combines important features from compressed air energy storage, the humid air turbine concept, and coal gasification to form a new power cycle with low capital costs and improved operating flexibility compared to other coal-fired power plants.

In an IGCASH plant, the coal gasification system operates continuously to produce syngas, which is burned in a combustion turbine to generate power. The combustion turbine uses compressed air from an underground storage reservoir (e.g., a salt dome or aquifer), which is charged by a compressor train that operates only intermittently. The compressed air from the storage reservoir is humidified in a saturator so that the required air flow is significantly reduced. Reduced air flow from humidification lowers compressor energy requirements and the underground volume required for storage. Before entering the combustion turbine, the humidified air is heated in a recuperator utilizing the hot gas from the turbine exhaust.

During periods when the demand for electricity is low, the compressor train charges the air reservoir and consumes all the power output of the combustion turbine, making the net output of the plant zero. During high load periods, the compressor is shut off and the power output of the combustion turbine is transmitted to the electric grid.

IGCASH plants have the superior environmental emissions performance characteristics of all such integrated gasification plants. Sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions are very low, while carbon dioxide (CO_2) emissions are relatively high because of the coal fuel and the heat rate, which is only average. Since the gasification plant runs 24 hours per day while the cycle is only intermediate duty, the gasification plant size is reduced and the plant capital cost is

therefore reduced. This plant should have excellent cycling characteristics since the hot components and gasification plant maintain steady operation.

One disadvantage of this cycle is the heat rate, which is not outstanding. Also, total daily generation is limited by the air stored in the underground reservoir and the amount of air injected into the reservoir by the compressor train.

Most, but not all, of the components needed for this cycle have been used in existing commercial power plants. The major exceptions are the saturator, which operates at high pressure (low pressure saturators are common in the chemical industry), and combustion with very humid air. An IGCASH plant has not yet been demonstrated, and there are no plans at this time for such a demonstration.

The cost and performance data are from Electric Power Research Institute's Technical Assessment Guide. Some performance data are inferred from other cycles.

Option 1.3.1.4
INTEGRATED GASIFICATION COMBINED CYCLE WITH FERTILIZER COPRODUCTION (3X227 MEGAWATTS)

The integrated gasification combined cycle with fertilizer coproduction (IGCC/F) option is similar to the IGCC described in option 1.3.1.5, except that a portion of the syngas is converted into chemical coproducts. A variety of coproducts can be produced from the oxygen-blown gasifier syngas. Sale of the coproduct(s) effectively reduces the cost of electricity from the IGCC/F plant. This option is based on fertilizer production.

The same gasifier capacity was considered for the IGCC option. Since a portion of the syngas is used for coproduct production and is not available for power generation, the electrical capacity of each of the 3 IGCC/F units is reduced to 227 megawatts. Similarly, the efficiency, on a kilowatt-hour basis is less than that for an IGCC plant without coproduction.

Cost and performance data are based on engineering studies performed by TVA and external architects and engineers.

Option 1.3.1.5
INTEGRATED GASIFICATION COMBINED CYCLE (3X245 MEGAWATTS)

Coal gasification is a method of producing relatively clean, burnable gas from almost any type of coal. The basic process involves crushing the coal and partially oxidizing the carbon in the coal. Partial oxidation converts the coal into a gaseous fuel composed primarily of combustible hydrogen and carbon monoxide. The gas can be piped directly into a gas turbine to generate electricity. The exhaust from the gas turbine is ducted into a heat recovery steam generator to produce steam for a conventional steam turbine generator.

The conversion of coal to gas requires more than just a gasifier to perform the gasification process. A coal gasification plant integrates a number of different technologies necessary to make gasification both environmentally safe and thermally efficient.

The integrated gasification combined cycle (IGCC) plant's major systems include fuel preparation, an air separation unit, a gasifier, acid gas removal, sulfur recovery, a combustion turbine-generator (CT), a heat recovery steam generator (HRSG), and a steam turbine-generator. Depending on the gasification technology, a wide variety of solid fuels can be used. This option is based on oxygen-blown gasifier technology with high sulfur coal as the fuel. The plant consists of 3 IGCC units, each generating 245 megawatts. *Figure T6-7* shows the major systems of the IGCC plant.

Coal is pulverized and injected into the pressurized gasifier unit. There, it is mixed with oxygen and partially oxidized at a high temperature to produce a hot, medium Btu gaseous fuel, syngas, that is composed primarily of combustible hydrogen and carbon monoxide. The oxygen is provided by the air separation unit. Coal ash is melted in the gasifier to form a slag that runs down the internal walls of the gasifier into a water bath. The molten slag solidifies in the water into a hard, inert, glassy material. It is removed from the gasifier through a lockhopper system. High pressure steam is generated in the waterwall enclosure of the gasifier.

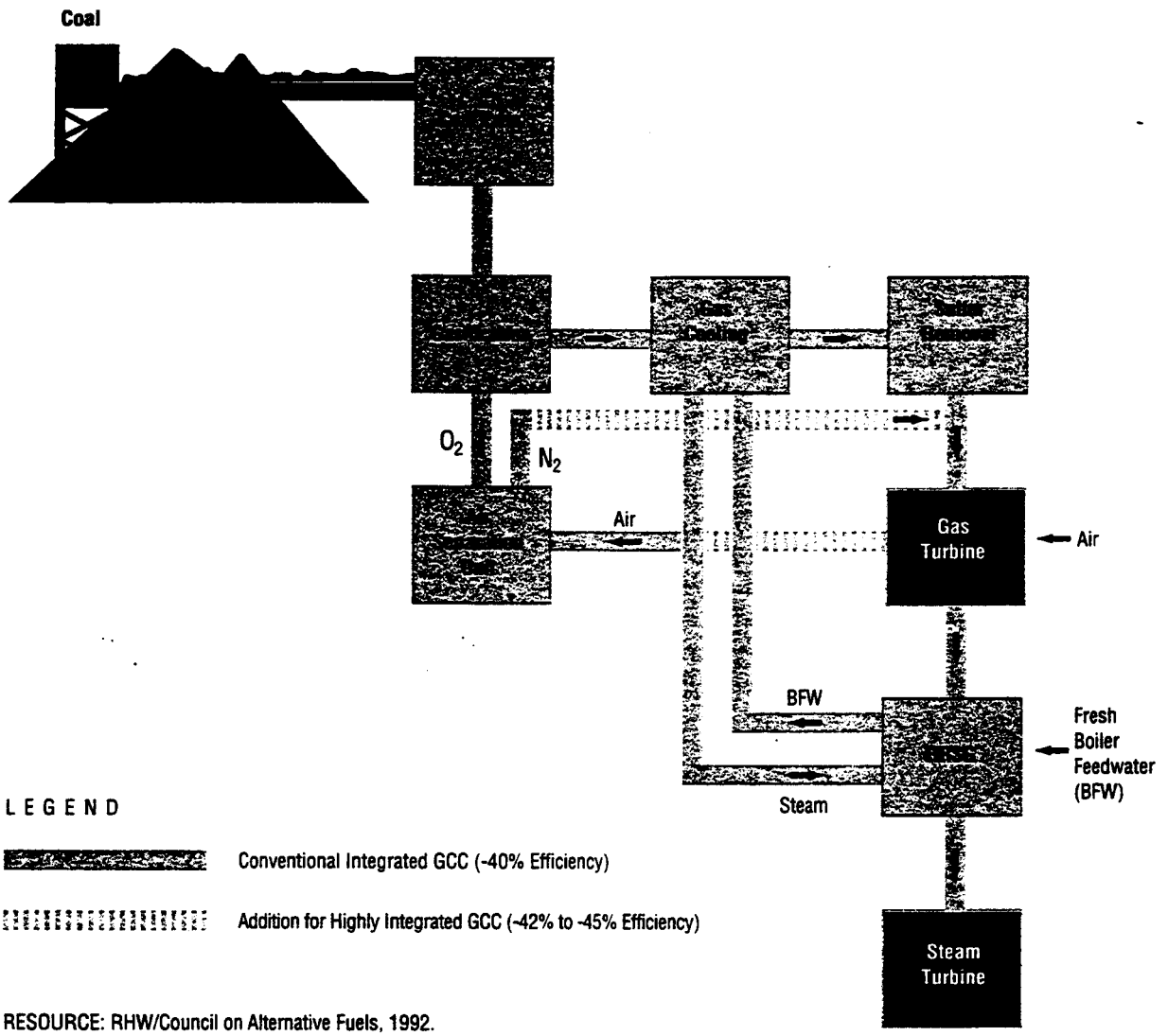
The syngas flows from the gasifier to a cooler. Medium pressure steam is generated in the syngas cooler. Particulate is removed from the cooled syngas by ceramic filters. Collected fly ash is recycled back to the gasifier.

A series of processes remove and/or convert chlorides, ammonia, and various acid gases from the syngas. Sulfur compounds are converted to marketable elemental sulfur. Sulfur recovery exceeds 99 percent.

The clean syngas is combusted with air in the CT to produce electricity. Excess nitrogen from the air separation unit is fed to the CT for power augmentation and to reduce nitrogen oxides (NO_X) emissions. The CT exhausts into the HRSG, where steam is generated to power a steam turbine-generator. The steam generated in the gasification unit and syngas cleanup processes is superheated in the HRSG and fed into the steam turbine. About two-thirds of the plant's net generation is from the CT, and one-third is from the steam turbine. Steam turbine exhaust is condensed and pumped back into the HRSG and gasification unit as feedwater. Heat is rejected from the condenser cooling water to the atmosphere in a mechanical draft cooling tower.

The combined cycle features of the IGCC plant provide a higher efficiency than either a simple cycle CT plant or a

FIGURE T6-7. **Generalized Block Flow Diagram of Coal Gasification of Production of Fuel Gas**



RESOURCE: RHW/Council on Alternative Fuels, 1992.

pulverized coal-fired plant. Higher auxiliary power consumption, primarily by the air separation unit, reduces efficiency below a natural gas-fired combined cycle plant.

Sulfur dioxide emissions are quite low due to the high sulfur recovery from the syngas in the sulfur removal process. The low nitrogen content in the syngas limits NO_X emissions to very low levels, as well.

IGCC plants are currently considered at the initial stage of commercial development. The relatively high capital cost, high efficiency, low emissions, and low fuel cost of the IGCC make it a candidate for future base-load capacity additions.

Cost and performance data are based on engineering studies performed by TVA and external architects and engineers.

Option 1.3.1.6

COMPRESSED AIR STORAGE WITH HUMIDIFICATION WITH INTEGRATED GASIFICATION AND NATURAL GAS PEAKING (1X850 MEGAWATTS)

A compressed air storage with humidification with integrated gasification and natural gas (CASHING) plant is an integrated gasification compressed air storage with humidification (IGCASH) plant with additional natural gas-fired expander trains. The CASHING cycle combines important features from compressed

air energy storage, the humid air turbine concept, coal gasification, and simple cycle combustion turbines to form a new power cycle with low capital costs and improved operating flexibility compared to other coal-fired power plants.

In a CASHING plant, the coal gasification system operates continuously to produce syngas, which is burned in a combustion turbine to generate power. The combustion turbine uses compressed air from an underground storage reservoir (e.g., a salt dome or aquifer), which is charged by a compressor train that operates intermittently. The compressed air from the storage reservoir is humidified in a saturator so that the required air flow is significantly reduced. Reduced air flow from humidification lowers compressor energy and underground volume requirements. Before entering the combustion turbine, the humidified air is heated in a recuperator utilizing the hot gas from the turbine exhaust.

During periods when the demand for electricity is low, the compressor train charges the air reservoir and consumes all the power output of the combustion turbine, making the net output of the plant zero. During high load periods, the compressor is shut off and the power output of the combustion turbine goes to the electric grid. The CASHING cycle differs from the IGCASH cycle in that natural gas-fired expander trains are added. When loads are very high, these natural gas-fired expander trains can be used for additional power generation.

CASHING will have the superior environmental emissions performance of all integrated gasification plants. Sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions from the gasification plant would be very low, while carbon dioxide (CO_2) emissions from the overall plant would be somewhat less than those from a pulverized coal plant because of the low CO_2 emissions of the natural gas fuel. However, some consideration may have to be given to NO_X emissions from the additional natural gas-fired expander trains.

The CASHING plant has a much lower capital cost than the IGCASH plant, and one that approaches that of a natural gas-fired combined cycle. Due to the majority of heat input being supplied by coal, it is much less sensitive to the price of natural gas. The plant capital cost is reduced because of two factors. The gasification plant is smaller, since it runs 24 hours per day, while the cycle is only intermediate duty. Also, the natural gas-fired expander trains can be added for a very low incremental cost.

A CASHING plant should have excellent cycling characteristics since most of the hot components and the gasification plant maintain steady operation.

Since the plant uses natural gas for a part of its heat input, it is at least somewhat sensitive to the price of natural gas. Also, total daily generation is limited by the air stored in the underground reservoir and by the amount of air injected into the reservoir by the compressor train.

Most of the components needed for this cycle are currently available. The major exceptions are a saturator, which humidifies the combustion turbine air at high pressure (low pressure saturators are common in the chemical industry), and combustion with very humid air. A CASHING plant has not yet been demonstrated, and there are no plans at this time for such a demonstration.

The cost and performance data are based on studies performed by Energy Storage and Power Consultants under contract to Electric Power Research Institute. Some performance data are inferred from other cycles.

Option 1.3.1.7

ADVANCED PRESSURIZED FLUIDIZED BED COMBUSTOR WITH DEVELOPMENT COST (1X300 MEGAWATTS)

Option 1.3.1.7 describes the pressurized fluidized bed (PFB) boiler and expansion turbine. The expansion turbine inlet temperature is limited to about 1,600°F by the operating temperature of the PFB boiler, thus limiting the cycle efficiency. The efficiency can be increased by raising the expansion turbine inlet temperature. In the advanced PFB option, a fuel gas produced from pyrolysis of coal is used to raise the turbine inlet temperature. The fuel gas from the pyrolysis is cleaned in a high temperature and pressure filtration system before being burned in the combustion turbine. Combustion of the fuel gas will raise the inlet temperature to 2,300°F. Char from the pyrolyzer is used to fuel the circulating PFB boiler in order to generate steam that powers the steam turbine.

This technology is considered to be at the pilot scale of development. Components needing further development include the pyrolyzer, the combustors for the gas turbine, the high temperature and pressure filters, and high temperature gas valves. These development costs have been captured by adding to the capital cost of this option the financial support that TVA has been asked to contribute to a project to demonstrate the advanced PFB technology.

Sulfur capture by limestone fed to the pyrolyzer and PFB boiler would allow a range of fuels to be used. High sulfur coal would be the design fuel.

Performance and cost data for this option are based on Electric Power Research Institute's Technical Assessment Guide and information provided by Air Products, Inc.

Option 1.3.1.8

ADVANCED PRESSURIZED FLUIDIZED BED COMBUSTOR WITH NO DEVELOPMENT COST (1X300 MEGAWATTS)

This option is identical to option 1.3.1.7 except that no development costs for unproved technology components have been added to the option's capital cost. The capital cost used for this option is the projected cost of a commercial 300-megawatt advanced pressurized fluidized bed (PFB) plant after all components have been successfully demonstrated.

Option 1.3.1.9

PARTNERED INTEGRATED GASIFICATION COMBINED CYCLE WITH COPRODUCTION, GREENFIELD SITE (1X530 MEGAWATTS)

This option is similar to option 1.3.1.5 except for the fact that:

- Approximately 70 percent of the synthesis gas produced is utilized for the production of chemicals. Only 30 percent of the synthesis gas is used for power production. The facility will generate approximately 480 megawatts and produce about 6,600 tons of chemicals per day.
- The facility consists of four 3,000 ton per day gasifiers, two combustion turbines with heat recovery steam generators (HRSGs), and one steam turbine, plus a chemical production plant.
- It is assumed that partners would be found to own and operate the gasification plants and the chemical production plant. TVA would own and operate the power block only.

The cost and performance data are extrapolated from information in the Black & Veatch/Bechtel Power Corporation study performed for option 7.1.1.5, the integrated gasification combined cycle with coproduction repowering of Bellefonte.

Option 1.3.1.10

INTEGRATED GASIFICATION COMBINED CYCLE WITH COPRODUCTION, GREENFIELD SITE (1X498 MEGAWATTS)

Option 1.3.1.11

INTEGRATED GASIFICATION CASCADED HUMIDIFIED ADVANCED TURBINE WITH COPRODUCTION, GREENFIELD SITE (1X598 MEGAWATTS)

The coproduction of methanol results in a lower cost of electricity than fertilizer due to the higher net capacity of each unit—250 megawatts for methanol coproduction compared to 227 megawatts for fertilizer coproduction (see option 1.3.1.4). The generic greenfield application for coproduction therefore uses methanol as the coproduct.

These two options—integrated gasification combined cycle (IGCC) and integrated gasification cascaded humidified advanced turbine (IGCHAT)—with coproduction are similar to the IGCC (option 1.3.1.5) and IGCHAT (options 1.3.2.5 and 1.3.2.8). However, for these two options, a portion of the synthesis gas is converted into chemicals through indirect liquefaction of the syngas. A variety of coproducts can be produced by indirect liquefaction, such as ammonia- and methanol-based chemicals, and transportation liquids. Only oxygen-blown gasification can produce chemicals; with air-blown gasification, the nitrogen (N_2) in the fuel gas reduces the hydrogen partial pressure.

The gasification coal feedrate of these two options is the same as both IGCC and IGCHAT. Although the combustion turbine is fully loaded, the reduced capacity is due to the use of steam in the chemical process.

The coproduction of electricity and chemicals reduces the cost of electricity due to (1) economies of scale for the gasification process units and the balance-of-plant units and (2) the anticipated real escalation of prices for natural gas-derived chemicals.

The revenues for the higher valued chemicals subsidize the cost of electricity.

Cost and performance data are based on engineering studies performed by TVA.

Option 1.3.1.12

COAL REFINERY/INTEGRATED GASIFICATION COMBINED CYCLE, GREENFIELD SITE (1X530 MEGAWATTS)

Option 1.3.1.13

COAL REFINERY/INTEGRATED GASIFICATION CASCADED HUMIDIFIED ADVANCED TURBINE, GREENFIELD SITE (1X530 MEGAWATTS)

Coal refining is another form of coproduction (see options 1.3.1.10 and 1.3.1.11). However, coal refining produces chemicals on the front end of coal gasification. Coal refining uses internally generated hydrogen (H_2) to produce coal liquids from the pyrolysis of coal. The resultant char is then used as the feedstock for integrated gasification combined cycle (IGCC) or integrated gasification cascaded humidified advanced turbine (IGCHAT) (see options 1.3.1.5, 1.3.2.5, and 1.3.2.8). The Charfuel coal refining process utilizes flash hydropyrolysis with quenching of the reaction products by H_2 and recycled liquids. Excess syngas—rich in methane (CH_4)—is converted to H_2 in a partial oxidation reactor (POX) to provide the quenching H_2. The char is separated from the syngas, and the syngas is cooled to condense liquids. The coal liquids are then hydrotreated and fractionated to produce benzene, naptha, and fuel oil.

Cost and performance data are based on engineering studies performed by TVA.

Option 1.3.1.14

COAL REFINERY/INTEGRATED GASIFICATION CASCADED HUMIDIFIED ADVANCED TURBINE WITH COPRODUCTION, GREENFIELD SITE (1X180 MEGAWATTS)

This option combines coal refining (see options 1.3.1.12 and 1.3.1.13) with option 1.3.1.11—integrated gasification cascaded humidified advanced turbine (IGCHAT) and coproduction of methanol—in a single plant. The plant consists of one coal refining unit, one char gasification unit, one cascaded humidified advanced turbine (CHAT) unit, and one methanol unit. The coal feed rate is equivalent to a two-train IGCHAT plant.

Option 1.3.2.1

FUEL CELL – MOLTEN CARBONATE OR SOLID OXIDE (1X2 MEGAWATTS)

Fuel cells are a unique advanced power generation technology because they directly convert chemical energy into electricity. All other fossil fuel-based power generation technologies require conversion of thermal energy by combustion, followed by turboexpansion or steam generation. As a result, fuel cells avoid the nitrogen oxides (NO_X) emissions and mechanical limitations of combustion and thermal conversion. This means fuel cells offer lower emissions and higher thermal efficiencies compared to any other fossil fuel-based power generation technologies.

Conceptually, fuel cells are similar to a battery with a continuous supply of chemical energy. In a fuel cell, hydrogen gas is oxidized at the anode, and the oxygen is reduced at the cathode. In this process, fuel and oxygen are supplied to cells, and the carbon dioxide and water byproducts of the reaction are removed. Since fuel cells convert the chemical energy in the fuel directly to electricity, without an intermediate thermal energy stage, theoretical energy conversion efficiencies approach 80 percent. However, practical systems are limited to efficiencies of 40-60 percent due to parasitic losses, which include the electrical resistance of the components. This potential for very high energy efficiencies, combined with relatively minor environmental impacts, makes fuel cells prime candidates for future use in electric power generating systems that must operate under the constraints of high fuel costs and minimal emissions.

Fuel cells can be assembled in building block style to make power plants of specifications tailored to the utility's load growth needs and the constraints of the site. Individual fuel cells produce less than one volt but operate at very high current densities—on the order of hundreds of amperes per square foot of electrode area. Practical output voltages are obtained by connecting many cells in series to constitute a fuel cell stack. Stacks have generating capacities ranging from a few kilowatts to several megawatts. The maximum size of a stack is dictated by engineering constraints, manufacturing technology, and cost trade-offs.

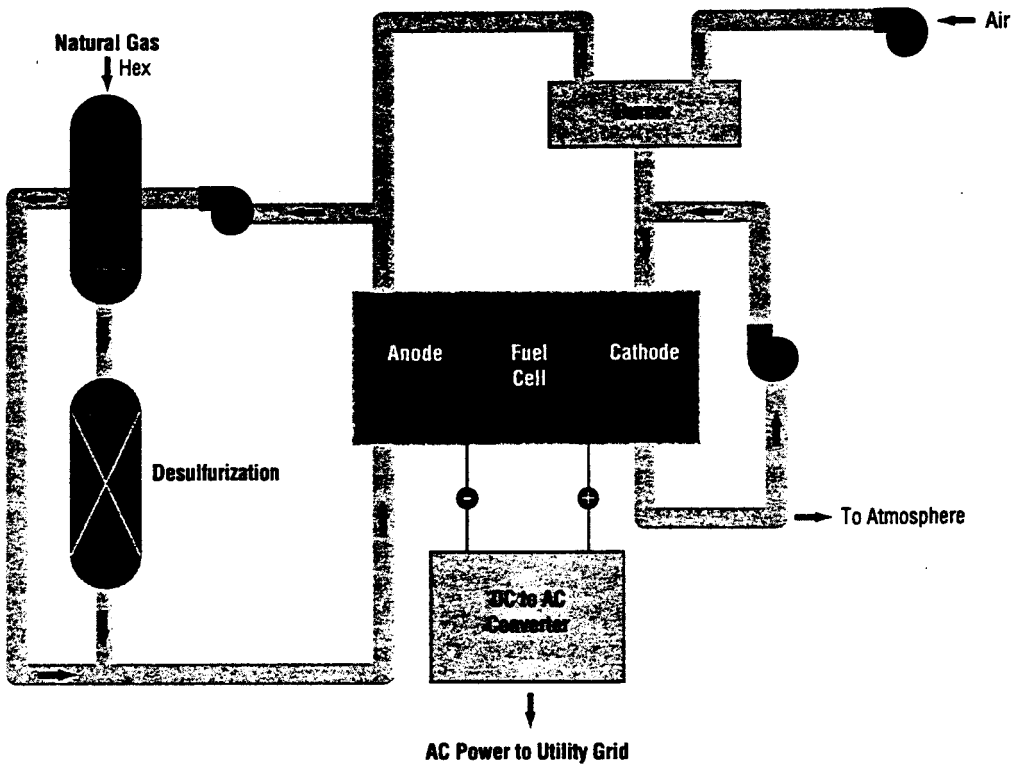
Fuel cell power plants consist of three major subsystems unique to this technology and a general balance-of-plant subsystem. The fuel processing system converts natural gas or distillate fuels to a fuel gas rich in hydrogen and carbon dioxide. Catalytic reforming processes with this capability have been in commercial use for many generations. Alternatively, a coal gasification plant can be substituted to produce the same fuel gas from coal. The fuel cell stack subsystem generates direct current power from the fuel gas while simultaneously emitting a benign exhaust gas. If desired, the system may be designed so that the exhaust gas contains economically significant quantities of thermal energy. The power conditioning subsystem converts the direct current output of the fuel cell stack to alternating current power. If a fuel cell is used for a decentralized application in small sizes, and if the customer needs direct current power, the power conditioning equipment can be removed. The balance-of-plant subsystem—including the plant control systems—provides the water and heat management, and heat recovery if desired. This subsystem also includes physical facilities such as buildings and other site-related items.

Fuel cells operate at a constant temperature and pressure regardless of load. As a result, the thermal energy liberated by the electrochemical reaction can be used in thermal bottoming cycles or for cogeneration of steam. The temperature of the waste heat varies widely with each fuel cell type, system, and design. Generally, the more advanced fuel cell systems provide the highest potential for high-quality waste heat because they operate at higher temperatures.

The commercialization of fuel cells is now targeted at factory-assembled modules. Generating capacities range from 200 kilowatts for single-stack, small-load applications to 10-25 megawatts for generating units. The primary features of these commercial concepts are:

- Modular construction, which combines the economies of mass production in a factory environment with the associated benefits of improved quality control.
- Phased construction of generating units in order to match capacity to load growth with minimal preinvestment.
- Fuel flexibility between natural gas and distillate, which may allow continued use of these fuels despite major price increases in the future.

FIGURE T6-8. **Molten Carbonate Fuel Cell Generating Unit**



- Integration with coal gasification to provide very high efficiency conversion of coal to electric power with minimal emission potential.
- Excellent capability for distributed generation applications due to quiet operation, minimal emissions, low heat rate, small operating staff, and rapid load-following capability.

The cost and performance data are based on fuel cell vendor estimates.

Molten Carbonate Fuel Cells. Molten carbonate fuel cells (MCFC) are a second-generation technology, emerging from laboratory research to engineering development at pilot-plant scale. *Figure T6-8* shows a diagram of a molten carbonate fuel cell generating unit. MCFCs operate at approximately 1,200°F. At this temperature, waste heat from MCFCs can provide the heat of reaction needed to convert light hydrocarbon fuels to synthesis gas, which can be consumed by the fuel cell. As a result, the fuel-processing system can be incorporated within the fuel cell stack. Advantages of this configuration include:

- High plant efficiency: greater than 50 percent higher heating value (HHV) with the possibility of achieving 60 percent (5,600 Btu per kilowatt-hour) on natural gas, alcohols, and light hydrocarbon fuels in small-capacity plants
- Very low emissions: 1 pound per megawatt-day combined nitrogen oxides (NO_X), sulfur oxides (SO_X), hydrocarbons, and particulates
- Low noise
- Air-cooled systems, which minimize siting problems
- A compact system, i.e., 25 megawatts per acre per vertical story

Within the next five years, the MCFC total installed capital cost is likely to be less than $1,000 per kilowatt.

Solid Oxide Fuel Cells. Westinghouse has been developing solid oxide fuel cells (SOFC) for more than 20 years, and they are the world's leader in this technology. Experimental units of 25 kilowatts have been constructed by Westinghouse for evaluation by electric and gas utilities. Westinghouse plans to commercialize a series of SOFC power plants with capacities ranging from hundreds of kilowatts to several megawatts.

The cost and performance data for this technology are under development, but the range seems to be between $750 per kilowatt and $1,000 per kilowatt.

Option 1.3.2.2

INTERCOOLED AERODERIVATIVE COMBUSTION TURBINE (1X125 MEGAWATTS)

The intercooled aeroderivative combustion turbine (ICAD) is one of the advanced combustion turbine cycles being studied in Electric Power Research Institute's Collaborative Advanced Gas Turbine program. Aeroderivative combustion turbines are now available and have excellent efficiencies because of their high pressure ratios.

However, a high pressure ratio causes excessive compressor power consumption. Compressor intercooling would decrease compressor power use, thereby increasing plant efficiency and power output. The ICAD would match intercooling with aeroderivative technology.

The ICAD cycle would be very similar to the simple cycle combustion turbine, option 1.1.2.1, except that an intercooler would be added to cool the compressed air at some point in the compression process to reduce compressor power consumption. The primary fuel would be natural gas with fuel oil as a backup. The performance for this concept is based on a nominal 2,600°F turbine inlet temperature which, because of cooler compressor air being available for turbine blade cooling, will not be technologically difficult to achieve.

The emissions characteristics of the ICAD would be similar to that of a simple cycle combustion turbine. Sulfur dioxide (SO_2) emissions would be negligible and carbon dioxide (CO_2) emissions would be roughly half of a typical pulverized coal plant. Nitrogen oxides (NO_X) emissions would also be low since dry, low NO_X combustors would be used. A selective catalytic reduction (SCR) could further lower NO_X emissions, but it is not included in this configuration.

The major potential advantages of the ICAD are its high simple-cycle efficiency for a cost which should not be much greater than that of current simple-cycle combustion turbines, and its operational flexibility. It can be used for intermediate duty, because of its high efficiency, or for peaking duty, because it appears especially promising for high-cycling use.

However, because of a lower exhaust temperature, the ICAD does not provide commensurate improvement in combined cycle efficiency. Also, because of the complexities of incorporating intercooling into the cycle, development costs are expected to be moderate.

The ICAD is one of the concepts being developed under Electric Power Research Institute's Collaborative Advanced Gas Turbine program. Electric Power Research Institute's goal is to design, build, sell, and test two ICAD units by approximately 1998.

The cost and performance data are based on information from Electric Power Research Institute's Advanced Cycle Evaluation (ACE) Group.

Option 1.3.2.3

CASCADED HUMIDIFIED ADVANCED TURBINE (F SERIES CT) (1X288 MEGAWATTS)

Option 1.3.2.6

CASCADED HUMIDIFIED ADVANCED TURBINE (G SERIES CT) (1X400 MEGAWATTS)

The cascaded humidified advanced turbine (CHAT) is an advanced Ericson cycle that employs intercooling, recuperation, reheating, and humidification of a combustion turbine with a cascaded topping turbine. Heat rates are equivalent to combined cycle plants, and capital costs are projected to be 20 to 30 percent less because the heat recovery steam generator, steam turbine, condenser, etc. are avoided. The exact arrangement of equipment and operating conditions are proprietary, but nearly all components are already available and proven, with only the high pressure combustors, saturator, and the overall integration and control of components requiring development.

The cascaded humidified advanced turbine (CHAT) adds humidification to the cascaded advanced turbine (CAT) cycle downstream of the last compressor stage. Performance improves because the water vapor expands through the turbine and reduces the amount of air which would otherwise have to be supplied by the compressor. Nitrogen oxides (NO_X) levels are thus reduced to near deminimus levels of about 1 to 2 parts per million.

The cost and performance data are based on studies performed by Energy Storage and Power Consultants under contract to Electric Power Research Institute.

Option 1.3.2.4

INTEGRATED GASIFICATION CASCADED HUMIDIFIED ADVANCED TURBINE WITH COPRODUCTION (F SERIES CT) (2X303 MEGAWATTS)

Option 1.3.2.7

INTEGRATED GASIFICATION CASCADED HUMIDIFIED ADVANCED TURBINE WITH COPRODUCTION (G SERIES CT) (2X420 MEGAWATTS)

This technology is the same as the integrated gasification cascaded humidified advanced turbine (IGCHAT) (options 1.3.2.5 and 1.3.2.8) except that the gasifier is oversized to allow for the coproduction of both electricity and chemicals such as fertilizer (urea), methanol, methyl tertiary butyl ether (MTBE), etc. Process steam requirements are produced from oversized intercoolers.

The cost and performance data are based on studies performed by Energy Storage and Power Consultants under contract to Electric Power Research Institute. TVA studies provide the basis for the information on coproduction.

Option 1.3.2.5

INTEGRATED GASIFICATION CASCADED HUMIDIFIED ADVANCED TURBINE (F SERIES CT) (2X303 MEGAWATTS)

Option 1.3.2.8

INTEGRATED GASIFICATION CASCADED HUMIDIFIED ADVANCED TURBINE (G SERIES CT) (2X420 MEGAWATTS)

The integrated gasification cascaded humidified advanced turbine (IGCHAT) integrates a coal gasification plant with the cascaded humidified advanced turbine (CHAT) cycle. The turbine is fired with clean syngas, and emissions of sulfur oxides (SO_X), nitrogen oxides (NO_X), and toxics normally associated with coal plants are extraordinarily low. Because the syngas can be humidified, a low-cost, total quench gasifier can be used, resulting in capital and operating costs that are 25 to 35 percent of those for a conventional integrated gasification combined cycle (IGCC), option 1.3.1.5.

The cost and performance data are based on studies performed by Energy Storage and Power Consultants under contract to Electric Power Research Institute.

Option 1.3.2.9

INTEGRATED FUEL CELL/COMBUSTION TURBINE (1X2.5 MEGAWATTS)

This option integrates a solid oxide fuel cell (as described in option 1.3.2.1) with a small combustion turbine. The fuel cell exhaust gas is at about 1,800°F and is pressurized. In this integrated concept, the exhaust gas is fed into a small combustion turbine to produce additional electricity (beyond the fuel cell output). The fuel cell's efficiency is already high, and integration of the combustion turbine can raise the overall efficiency to about 70 percent.

This concept is still under development. Current studies seek to determine the best overall design, taking into account several variables, such as the number of fuel cells used with a single turbine, identification of the most appropriate design and size of turbine, and variations in fuel cell operating conditions.

The overall characteristics of this option, including likely applications, are very much like the fuel cell (option 1.3.2.1). However, the combustion turbine increases overall efficiency while adding some complexity to the equipment.

The cost and performance data are based on preliminary fuel cell vendor estimates.

Option 1.3.3.1

LARGE SOLAR-PHOTOVOLTAIC – FIXED FLAT PLATE (1X50 MEGAWATTS)

Solar-photovoltaic (PV) power plants convert solar energy to electricity using a semiconductor material, usually silicon doped with phosphorus and boron, to generate a direct current. In order to increase the conversion efficiency, the principal PV technologies are thin-film, polycrystalline silicon, single-crystal silicon, and concentrator technology. Thin-film materials are typically deposited on a glass substrate and include amorphous silicon, copper-indium-diselenide (CIS), and cadmium telluride.

Except for a thin-film module, a typical solar cell produces about 2 amperes of current at 0.5 volts. Individual cells are combined together into modules and connected in series and parallel to provide higher voltage and current levels. The active areas of the modules are typically from 0.1 to 2 square meters, and the modules are typically connected together in flat arrays. Three array configurations are used: (1) fixed-tilt arrays facing south, (2) single-axis tracking of the sun from east to west, and (3) two-axis tracking of the sun to remain perpendicular to the sun's rays. The direct current power generated by the arrays is collected and converted to alternating current power by a power conditioning unit.

On a typical day, the insolation falling on a surface oriented perpendicularly to the sun's rays reaches a maximum of about 1 kilowatt per square meter at solar noon, and is lower in the morning and afternoon. Because the best commercial solar cells operate at about 12 percent conversion efficiency, the maximum power available is 120 watts per square meter. Thus, a 100-megawatt power plant would require about one square mile of land area. Since PV power output is proportional to the incident solar insolation, it is not dispatchable without energy storage.

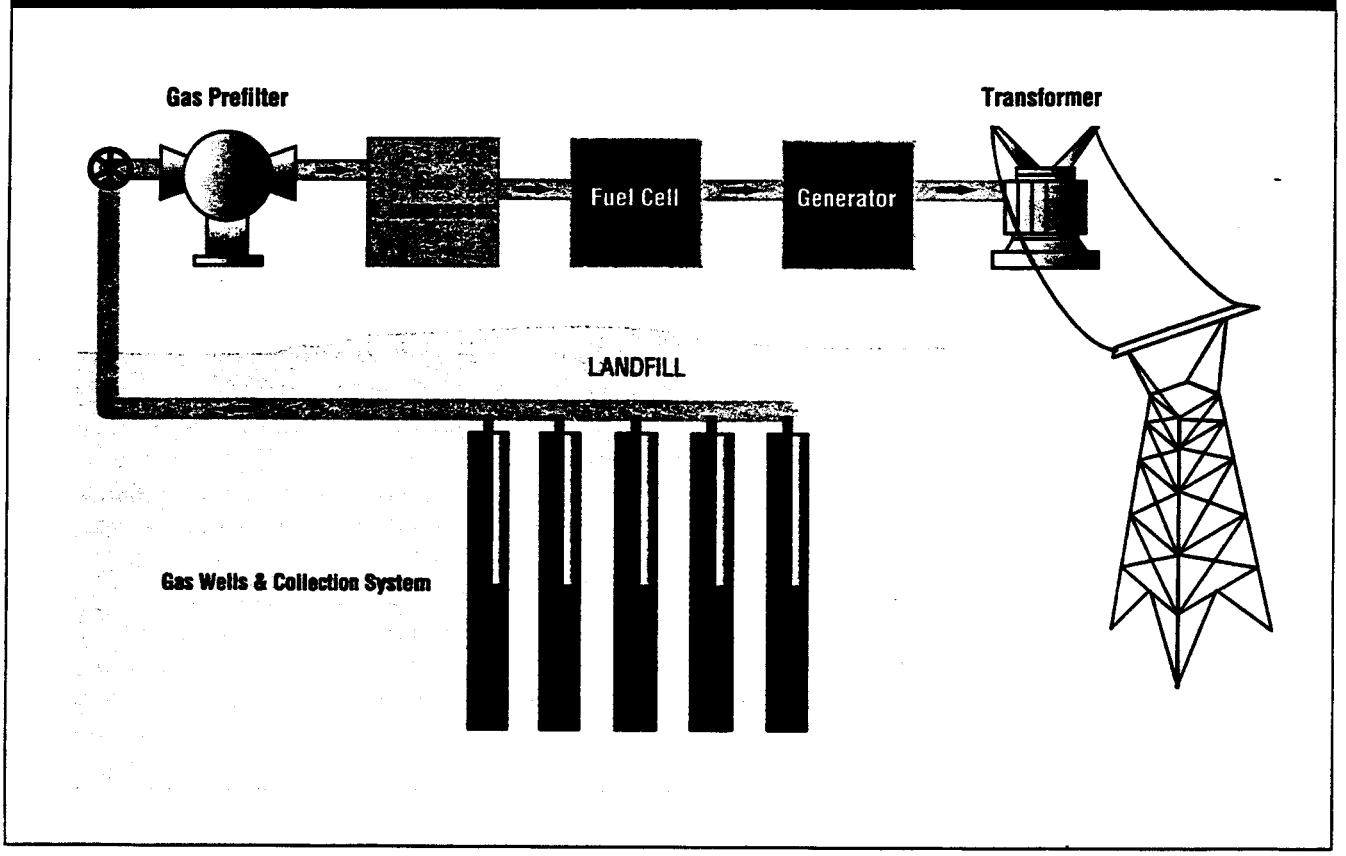
The cost and performance data are based on information from Electric Power Research Institute's Technical Assessment Guide.

Option 1.3.3.2

LANDFILL METHANE (1X2 MEGAWATTS)

The reasons for recovering landfill gas are numerous. Communities can receive revenue from a successful landfill gas project. Recovering methane helps reduce the odors produced from decomposing garbage, which can be disturbing to individuals living in the vicinity of the landfill. Also, landfill gas recovery

FIGURE T6-9. **Landfill Gas to Electricity**



reduces greenhouse gas emissions, which are potentially harmful to the environment.

As a fuel, landfill gas has a reasonably high heating value in raw form and can be upgraded to pipeline quality if desired. The landfill gas can be flared or used as a fuel on-site to produce electricity in a small combustion turbine, reciprocating engine, boiler, or eventually fuel cells. Cost and performance projections are based on use of fuel cells. Collecting landfill gas can be expensive because it is spread out over a wide area. It is difficult to predict the amount available and also to anticipate fluctuations in supply. Such information is critical to determine the economics of a landfill gas recovery project. Additional expenses are incurred in treating the gas to remove moisture, trace hydrocarbons, carbon dioxide, and especially hydrogen sulfide. A small number of landfill gas production facilities currently exist in the United States. *Figure T6-9* shows a diagram of the process for converting landfill gas to electricity.

The cost and performance data are based on vendor estimates.

Option 1.3.3.3

COALBED METHANE (1X2 MEGAWATTS)

Coalbed methane gas is present in all coal seams located throughout the United States, including the TVA region. The coalbed methane industry has grown during the recent years, powered greatly by new science and better technology. Still, major challenges remain that require research particularly in developing new basins, deeper coals, and geologically complex settings.

Numerous problem areas must be overcome before coalbed methane is accepted as a viable fuel. Estimating coalbed gas productivity and reserves remains a major problem for producers of coalbed methane. Also, the industry has yet to satisfy the financial community that it can reliably determine how much of the gas can be recovered and over what period of time. Most coal companies will find that it is not economically feasible to collect coalbed methane without a federal subsidy or tax credit. Cost and performance projections are based on use of fuel cells. At the present time, these incentive programs are not available to owners of coal mines.

A number of environmental issues, each requiring technologically innovative solutions, are of high concern to devel-

opers of coalbed methane. The most urgent are the disposal or use of coproduced water and the pending regulations on air emissions for gas compression engines. Also, the disturbance of land areas required for well sites, service roads, and gas collection systems are major concerns.

Another major obstacle to coalbed methane development is the legal question of gas ownership. This is a very complex issue and is not easily resolved. Each ownership case is usually decided on a site-specific basis, and legal rulings may vary between sites.

The cost and performance data are based on information from Electric Power Research Institute's Technical Assessment Guide.

OPTION 1.3.3.4

BIOREFINERY—COPRODUCTION OF ELECTRICITY AND CHEMICALS FROM BIOMASS (1X100 MEGAWATTS)

The biorefinery coproduces electricity and chemicals. The biomass feedstock consists of mill and wood waste, farm wastes, or dedicated crops (trees and grasses). Municipal solid waste also contains biomass material. All biomass is composed of cellulose, hemicellulose, and lignin. The cellulose and hemicellulose are converted to sugars by acid or enzymatic hydrolysis, and the sugars are fermented to chemicals (such as ethanol, organic acids, and furfural). The residual lignin is converted to electricity by either combustion or gasification. The production of higher valued chemicals significantly reduces the cost of electricity from biomass, in a dedicated biomass plant.

The biorefinery has low sulfur dioxide emissions and solid waste due to the composition of the biomass, and has a zero net production of carbon dioxide.

The cost and performance data are based on TVA internal reports on the biorefinery concept. TVA has been operating laboratory-scale units and a 2 to 10 tons per day pilot unit at the Environmental Research Center in Muscle Shoals, Alabama, for the last 10 years.

Option 1.3.5.1

ADVANCED BATTERY ENERGY STORAGE (1X20 MEGAWATTS)

The advanced energy storage battery is based on a 20-megawatt unit designed for 3-hour and 5-hour storage applications. These two duty cycles are given because for batteries, the cost for the energy component is not a linear function of duty cycle. Incremental off-peak electric energy is used to charge an advanced battery based on either the sodium-sulfur or the zinc-bromine system. The battery plant is composed of modular units. Battery capital costs are based on a production of 2,000 megawatts per year. The environmental emissions of the advanced battery plants are virtually zero. Battery plants have an extremely fast time response capability—full load can be achieved in less than 5 milliseconds.

The cost and performance data are based on information from Electric Power Research Institute's Technical Assessment Guide.

Option 1.3.5.2

SUPERCONDUCTING MAGNETIC ENERGY STORAGE (1X500 MEGAWATTS)

Superconducting magnetic energy storage (SMES) technology is applicable to all utility regions in the United States. Low-cost, off-peak energy is stored as direct current in a superconducting coil whose conductor is made of a low temperature niobium titanium alloy. Refrigeration is needed to maintain the low coil core temperature. The refrigeration costs are accounted for in the fixed costs for operating the plant, and as such, affect the plant capital cost and life-cycle cost for purchasing and operating the plant.

Since the stored energy is in the form of electricity which is not converted to some other form of energy, the round-trip efficiency of a superconducting magnetic energy storage (SMES) plant is very high, about 95 percent. The plant power conditioning system is the component that controls the plant and converts the stored direct current energy to the required utility grid alternating current requirements (which can accommodate reactive power control, black-start, and/or system frequency control, just to name a few of the possible plant applications). *Figure T6-10* shows a diagram of a superconducting magnetic energy storage plant.

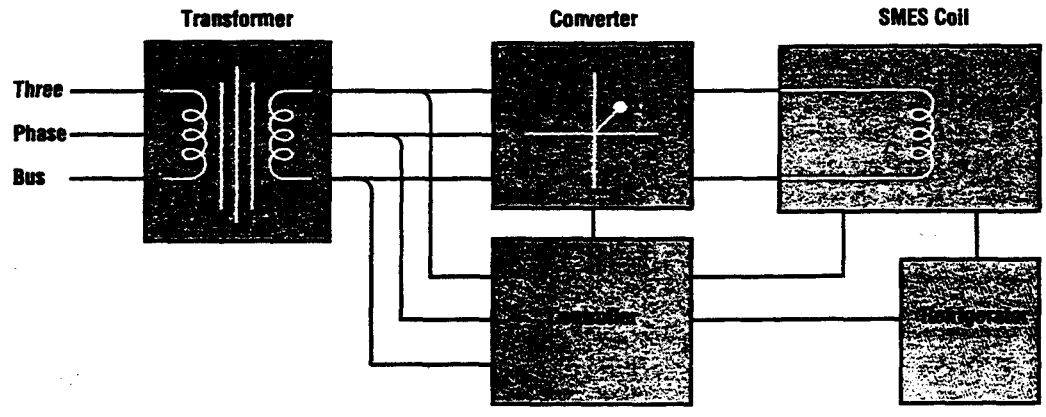
SMES plants would have a very rapid response time of less than one-tenth of a second to reach full load. As such, a major benefit of this technology is the range of dynamic, strategic, and load-leveling benefits that this plant can provide to its owner. The plant would have a 500-megawatt capacity and a two-hour storage discharge time.

There would be no emissions associated with the SMES plant other than the emissions from the generation sources used to charge the coil.

SMES technology is not yet commercially available for energy storage applications of this type but is considered a future option.

The cost and performance data are based on information from Electric Power Research Institute's Technical Assessment Guide.

FIGURE T6-10. **Superconducting Magnetic Energy Storage**



Option 2.1.3.1

ADDITIONAL HYDRO GENERATION AT EXISTING NONPOWER PROJECTS (1X10 MEGAWATTS)

Option 2.1.3.2

ADDITIONAL HYDRO GENERATION AT EXISTING PROJECTS (1X24 MEGAWATTS)

Option 2.1.3.3

ADDITIONAL HYDRO GENERATION – NEW CONVENTIONAL PROJECTS (1X65 MEGAWATTS)

This category includes three types of additional hydro generation:

1. Additional units at existing hydro power projects
2. Additional units at existing nonpower hydro projects
3. New conventional projects

These options would be similar to current TVA hydro generation facilities. A dam creates an upper and a lower water reservoir. The potential energy stored in the water in the higher reservoir is converted to electricity as it flows through a hydro turbine to the lower reservoir.

Like other hydro generation, these options would have several advantages over other generating technologies:

- Very low operating costs
- Zero emissions
- Excellent operational flexibility (e.g., low startup and shutdown costs and rapid ramp rates)

However, there are some disadvantages in these hydro options:

- Very high capital cost
- Limited energy
- Limited amount of generation
- Environmental impacts on the river
- In the case of new conventional projects, environmental impacts on the local area

This power generation technology is commercially mature. Water Resources Projects in Knoxville, Tennessee, provided the cost and generation data from studies done many years ago. The three options listed above refer to studies conducted in the years 1983, 1977, and 1965, respectively.

Option 2.1.3.4

HYDRO MODERNIZATION AT EXISTING PROJECTS

TVA's hydro system was installed in the 1940s and 1950s. Since that time, technology has advanced significantly on several fronts of hydro plant design. A modernization project is currently underway to take advantage of advances that have produced the largest benefit to the TVA hydro system, but there are still several remaining upgrades that could be performed. These remaining projects could increase the summer capability of the hydro system by over 160 megawatts.

The cost and performance information for modernization projects at existing hydro sites was provided by the TVA organization responsible for fossil and hydro projects.

Option 3.3.1.1

GENERIC PRESSURIZED FLUIDIZED BED COMBUSTION COGENERATION (1X70 MEGAWATTS)

Option 12.1.2.1

GENERIC COMBINED CYCLE COGENERATION (2X210 MEGAWATTS)

Cogeneration is defined as the sequential production of electricity and useful thermal energy (generally steam or hot water) from a single fuel source. Cogeneration utilizes the thermal energy normally discharged as waste heat in a conventional power generation process. It thus provides a higher overall efficiency (often more than double that of the conventional generation system) in fuel utilization, but often at the expense of lower electric output.

A number of different cogeneration technologies are available, including some of those already considered under the fossil and hydro options. With steam turbine technology (for example, using pulverized coal or the fluidized bed technology discussed before) steam is expanded in the turbine to the condensing pressure for pumping back to the boiler as feedwater. With an extraction turbine, steam is removed from the turbine at one or more intermediate points and used for process requirements, with the remaining steam expanded in the turbine to condensing pressure to generate power. In a backpressure turbine, the steam is expanded in the turbine to the pressure required for the process.

In gas turbine systems, the exhaust gases from the turbine are used to generate steam in a heat recovery steam generator. The steam generator may also have supplementary firing in order to increase the quantity of thermal energy without degrading the electric output.

Combined cycle systems consist of a gas turbine and steam turbine in combination. The gas turbine exhaust is used to generate steam for process heating and to generate electricity in a steam turbine. Process steam can also be extracted from the steam turbine.

Cost and performance data are based on cogeneration technology proposals presented to TVA.

Option 4.1.1.1

LIGNITE-FIRED CIRCULATING FLUIDIZED BED COMBUSTION PLANT (1X200 MEGAWATTS)

The lignite-fired circulating fluidized bed combustion (CFBC) plant is essentially the same plant as the circulating atmospheric fluidized bed combustion plant, option 1.1.1.4, described earlier, except for the fact that the fuel is lignite rather than Illinois Basin coal.

The cost and performance information for this plant were obtained primarily from Electric Power Research Institute's Technical Assessment Guide with additional information provided by various industry sources.

Option 5.1.1.1

NON-UTILITY GENERATION – GENERIC INDEPENDENT POWER PRODUCER LIGNITE CIRCULATING FLUIDIZED BED COMBUSTION PLANT (1X300 MEGAWATTS)

Option 13.1.2.1

NON-UTILITY GENERATION – GENERIC INDEPENDENT POWER PRODUCER COMBINED CYCLE (2X260 MEGAWATTS)

Option 13.1.2.2

NON-UTILITY GENERATION – GENERIC NATURAL GAS INDEPENDENT POWER PRODUCER COMBINED CYCLE (1X150 MEGAWATTS)

Option 19.3.1.1

NON-UTILITY GENERATION – GENERIC INTEGRATED GASIFICATION COMBINED CYCLE (1X110 MEGAWATTS)

Option 22.1.1.1

NON-UTILITY GENERATION – GENERIC INDEPENDENT POWER PRODUCER PULVERIZED COAL WITH COGENERATION (2X170 MEGAWATTS)

Option 23.1.3.1

NON-UTILITY GENERATION – GENERIC INDEPENDENT POWER PRODUCER RUN OF RIVER HYDRO (4X20 MEGAWATTS)

Option 29.1.5.1

NON-UTILITY GENERATION – GENERIC INDEPENDENT POWER PRODUCER PUMPED-HYDRO STORAGE

Non-utility generation (NUG) is a broad term used to designate power producing facilities that are not majority-owned by utilities.

NUG can be classified as a qualifying facility (QF) if it meets certain criteria defined in the Public Utilities Regulatory Policies Act of 1978 (PURPA) and subsequent implementation rules established by the Federal Energy Regulatory Commission (FERC). QFs are exempt from most federal and state utility regulations. Utilities are required to purchase power from a QF at less than or equal to its avoided cost and must provide standby (backup) power on a nondiscriminatory basis.

Non-QFs are the NUG facilities that do not satisfy these FERC criteria. The non-QFs that sell electricity are designated as independent power producers (IPPs). An IPP that is either partially or wholly owned by a traditional utility is defined as an affiliated power producer (APP).

The Energy Policy Act of 1992 created a new class of independent power producers called exempt wholesale generators (EWG). EWGs are exempt from the Public Utilities Holding Company Act (PUHCA) and sell electric energy at wholesale rates, either directly or through an affiliate. This allows utilities to own one or more EWGs or foreign utilities without PUHCA jurisdiction and provides expanded access to utility-owned transmission systems.

The Public Utilities Regulatory Policies Act of 1978 (PURPA) was enacted as a part of the National Energy Act of 1978 to encourage the conservation and efficient use of energy resources by electric utilities. PURPA encourages production of electric power by cogeneration and by small power producers. TVA was given regulatory responsibility for implementing PURPA in the area served with TVA power.

Cost and performance data are based on non-utility generation proposals presented to TVA.

Option 6.3.2.7
GAS TURBINE – MODULAR HELIUM REACTOR (3X289 MEGAWATTS)

This option, often called the modular helium reactor or MHR, is derived from several years of work to develop a high temperature gas-cooled reactor. Although the concept benefits greatly from prior development work, several more years of development and design work are needed before the characteristics and availability of the option can be guaranteed.

The MHR option has several distinctive characteristics. First, it extracts heat from a graphite nuclear core using helium as the coolant and working fluid. (The other nuclear options included in Energy Vision 2020 use water to remove heat from a metal-clad core.) Second, the thermal energy is converted to power by expanding helium through a closed-cycle gas turbine with intercooling, recuperation, and precooling. (Most other options in Energy Vision 2020 convert thermal energy to power by expanding steam through a closed-cycle turbine or expanding combustion gases through an open-cycle turbine.) Third, a plant would consist of at least three small modular units. The small unit size allows use of passive safety features to achieve nuclear safety. Fourth, the reactor and helium operate at high temperatures to achieve higher efficiency than conventional nuclear units (approximately 48 percent compared to 32 percent). Compared with conventional nuclear plants, the higher thermal efficiency, modular design, elimination of the steam cycle, and simpler safety systems of this option are expected to offset the lack of economy of scale associated with it.

Option 6.3.4.1
ADVANCED LIGHT WATER REACTOR (1X1300 MEGAWATTS)

U.S. and foreign utilities, reactor designers, and the U.S. Department of Energy have been developing new nuclear reactor power plant designs over the past several years for possible near-term and mid-term deployment in the United States and overseas. These reactor designs are collectively identified as advanced light water reactors (ALWR).

There are four advanced light water reactor plants under various stages of development and licensing in the U.S. The four plants include two technologies (the evolutionary designs) with a nominal power rating of approximately 1,300 megawatts, and two technologies (the passive designs) with a nominal power rating of 600 megawatts. While either the evolutionary or passive designs may ultimately emerge as a preferred design for the next generation of nuclear power plants in the United States due to performance and economic performance, both offer significantly enhanced safety performance. At the present time, the evolutionary reactors have achieved a more advanced developmental status than the passive reactors both in terms of design detail and Nuclear Regulatory Commission review. Consequently, the advanced light water reactor option considered in Energy Vision 2020 is primarily based on the evolutionary design, but this is not intended to preclude consideration of a passive design, as well.

The two evolutionary designs (advanced boiling water reactor (ABWR) and System 80+) are extensions of current technology and experience that employ advanced design features compared to existing nuclear power plants. For example, the System 80+ utilizes a large spherical containment with a wrap-around auxiliary building. The ABWR eliminates recirculation piping by using wet motor glandless pumps located in the reactor vessel bottom head.

The evolutionary ALWR designs are expected to be commercially available by the year 2000. These designs are being guided by Volumes I (Top Tier Requirements) and II (Evolutionary Plant) of the Utility Requirements Document (URD), which have been developed jointly by domestic and foreign industry and the U.S. government. The Final Safety Evaluation Report has been issued for Volume II. Volume I does not require a Safety Evaluation Report.

Both of the evolutionary reactor designs have recently been granted final design approval (FDA) by NRC under 10CFR Part 52. Each design must now undergo a final evaluation that is

open to the public in a rule-making process known as design certification. Design certification is expected in 1995. First-of-a-kind-engineering (FOAKE) for both evolutionary designs was initiated in 1993, and is expected to be completed by 1996. Separate programs for site selection and site characterization are being funded by domestic industry. When the design certification, FOAKE, and site programs are completed, pre-approved sites and designs will be available to support restoration of the nuclear option as a safe and economic alternative power source.

The cost and performance data are based on information from Electric Power Research Institute's Technical Assessment Guide.

Option 7.1.1.1

BELLEFONTE REPOWERING WITH INTEGRATED GASIFICATION COMBINED CYCLE (9X250 MEGAWATTS)

The two units at TVA's Bellefonte Nuclear Plant (BLN) have been identified as two of four nuclear units whose disposition is being determined in Energy Vision 2020. In order to properly evaluate all of the options for BLN, it is necessary to include a conversion option of the facility to utilize other fuels. The integrated gasification combined cycle (IGCC) repowering option has been conceived to provide essentially the same station generation capability, using coal gasification technology, as would be provided by the nuclear plant.

The IGCC option for BLN consists of 9 modules, each consisting of 1 gasifier plant, 1 combustion turbine rated at about 190 megawatts, and a heat recovery steam generator (HRSG). The steam produced by the nine HRSGs is collected and routed to the BLN Unit 1 steam turbine. The current BLN high pressure turbine is replaced by a turbine designed to receive steam at 1,250 pounds per square inch absolute and 990°F, and to discharge steam to the existing BLN low pressure turbine. Approximately 1,030 megawatts would be generated by the modified BLN Unit 1 steam turbine. The gasification plant air separation units and other users of station service power consume approximately 500 megawatts, thus reducing the overall plant output to 2,250 megawatts.

The repowered facility utilizes existing BLN equipment such as:

- BLN Unit 1 steam turbine and condenser
- natural draft cooling towers
- station auxiliaries (compressed air and service water)
- switchyard and transmission system
- office and service buildings

New equipment added consists of items such as:

- gasification plant modules
- syngas-fired combustion turbines and heat recovery steam generators
- coal and combustion waste handling and storage equipment
- coal receiving equipment for coal received by barge
- upgraded railroad for receiving coal by rail

The cost and performance data provided are based upon data from a study performed by an external architect and engineer under contract to TVA.

Option 7.1.1.2

BELLEFONTE REPOWERING WITH PULVERIZED COAL (4X616 MEGAWATTS)

The two units at TVA's Bellefonte Nuclear Plant (BLN) have been identified as two of four nuclear units whose disposition is being determined in Energy Vision 2020. In order to properly evaluate all of the options for BLN, it is necessary to include a conversion option of the facility to utilize other fuels. The pulverized coal (PC) repowering option has been conceived to provide essentially the same station generation capability, using conventional PC-firing technology, as would be provided by the nuclear plant.

The PC option for BLN consists of four modules, each comprising one subcritical PC-fired boiler and one high pressure (HP) turbine. Each HP turbine generates about 200 megawatts. The steam leaving each HP turbine is returned to the boiler associated with the HP turbine for reheating. The hot reheat steam from the first pair of boilers is collected and routed to the BLN Unit 1 steam turbine. The current BLN high pressure turbine is replaced by an intermediate pressure (IP) turbine designed to receive steam at 500 pounds per square inch gauge and 950°F and to discharge steam to the existing BLN low pressure turbine. Approximately 930 megawatts would be generated by the modified BLN Unit 1 steam turbine. The hot reheat steam from the second pair of boilers is collected and routed to the BLN Unit 2 steam turbine. It has a configuration similar to the BLN Unit 1 steam turbine and would also produce about 930 megawatts. The users of station service power consume approximately 200 megawatts, thus reducing the overall plant output to about 2,450 megawatts.

The repowered facility utilizes existing BLN equipment such as:

- BLN Units 1 and 2 steam turbines and condensers
- natural draft cooling towers
- station auxiliaries (compressed air and service water)
- switchyard and transmission system
- office and service buildings

New equipment added consists of items such as:

- PC-fired boilers with emissions control equipment
- HP topping turbines and modified BLN steam turbine
- coal and combustion waste handling and storage equipment
- coal receiving equipment for coal received by barge
- upgraded railroad for receiving coal and limestone by rail

The cost and performance data provided are based upon data from a study performed by an external architect and engineer under contract to TVA.

Option 7.1.1.3

BELLEFONTE REPOWERING – PHASED COMBINED CYCLE/INTEGRATED GASIFICATION COMBINED CYCLE – PHASE A – COMBINED CYCLE (9X222 MEGAWATTS)

Option 7.1.1.4

BELLEFONTE REPOWERING – PHASED COMBINED CYCLE/INTEGRATED GASIFICATION COMBINED CYCLE – PHASE B – INTEGRATED GASIFICATION COMBINED CYCLE (9X250 MEGAWATTS)

The phased integrated gasification combined cycle (IGCC) repowering of Bellefonte Nuclear Plant is essentially a combination of the natural gas-fired combined cycle (NGCC) repowering, option 1.1.2.3, followed by an IGCC repowering. The primary differences lie in the number of combustion turbines initially installed and the layout of the facility. Phase A of the phased IGCC repowering would utilize nine advanced combustion turbines arranged so as to accommodate the future integration of gasification plant modules on site. Phase A would also include the construction of a natural gas pipeline for fuel supply to the facility.

Phase B of the phased IGCC repowering would consist of constructing the gasification plant modules, along with the necessary material handling systems and connections necessary for integration of the gasification modules into the overall plant heat cycle. It should be noted that the total plant generating capability would be marginally greater due to optimization for NGCC in the beginning followed by IGCC operation.

The cost and performance data provided are based upon data from a study performed by an external architect and engineer under contract to TVA.

Option 7.1.1.5

BELLEFONTE REPOWERING – INTEGRATED GASIFICATION COMBINED CYCLE WITH COPRODUCTION (11X229 MEGAWATTS)

The two units at TVA's Bellefonte Nuclear Plant (BLN) have been identified as two of four nuclear units whose disposition is being determined in Energy Vision 2020. In order to properly evaluate all of the options for BLN, it is necessary to include a conversion option of the facility to utilize other fuels. The integrated gasification combined cycle (IGCC) with coproduction repowering option has been conceived to provide essentially the same station generation capability as would be provided by the nuclear plant using coal gasification technology, along with coproduction of chemicals to reduce electricity production costs through the sale of chemicals. Methanol and several of its derivatives were chosen for economic evaluation.

The IGCC with coproduction option for BLN consists of 10 modules, each consisting of 1 gasifier plant, 1 combustion turbine rated at about 190 megawatts, and a heat recovery steam generator (HRSG). The steam produced by the 10 HRSGs is collected and routed to the BLN Unit 1 steam turbine. The current BLN high pressure turbine is replaced by a turbine designed to receive steam at 1,215 pounds per square inch absolute and 1,000°F, and to discharge steam to the existing BLN low pressure turbine. Approximately 1,240 megawatts are generated by the modified BLN Unit 1 steam turbine. The gasification plant air separation units and other users of station service power consume approximately 720 megawatts, thus reducing the overall plant output to 2,420 megawatts. The gasification modules produce excess syngas, which is transported to the chemical production unit, along with some steam. Total chemical production would be about 6,600 tons per day. A single biomass gasifier with gas turbine and HRSG is also included in the design. This facility would produce approximately 100 megawatts, increasing the total net output of the facility to 2,520 megawatts.

The repowered facility utilizes existing BLN equipment such as:

- BLN Unit 1 steam turbine and condenser
- natural draft cooling towers
- station auxiliaries (compressed air and service water)
- switchyard and transmission system
- office and service buildings

New equipment added consists of items such as:

- gasification plant modules
- syngas-fired combustion turbines and heat recovery steam generators
- chemical production unit

- coal and combustion waste handling and storage equipment
- coal receiving equipment for coal received by barge
- upgraded railroad for receiving coal by rail
- facilities for shipping chemicals

The cost and performance data provided are based upon data from a study performed by Black & Veatch and Bechtel Power Corporation.

Option 7.1.1.6

BELLEFONTE REPOWERING – INTEGRATED GASIFICATION COMBINED CYCLE WITH COPRODUCTION WITH PARTNERS (2X242 MEGAWATTS)

This option is very similar to option 7.1.1.5, integrated gasification combined cycle repowering, except for the fact that:

- It is assumed that partners would be found to own and operate the gasification plant and the chemical production plant. TVA would own and operate the power block only.
- Seventy percent of the synthesis gas is allocated for coproduction instead of 30 percent, as in option 7.1.1.5. As a result, the power output is reduced to approximately 480 megawatts, while producing the same amount of chemicals as for option 7.1.1.5.
- Only four gasifiers and two combustion turbines/heat recovery steam generators are included rather than 10 each, as included in option 7.1.1.5. To maintain chemical production, the chemical plant is essentially the same as for option 7.1.1.5.

The cost estimate and performance data are extrapolated from information in the Black & Veatch/Bechtel Power Corporation study performed for option 7.1.1.5.

Option 7.1.1.7

BELLEFONTE REPOWERING – INTEGRATED GASIFICATION COMBINED CYCLE DEMONSTRATION WITH PARTNERS (1X400 MEGAWATTS)

This option is similar to option 7.1.1.6 except that it is smaller, has no coproduction, and could be a first module of option 7.1.1.6. It is predicated on receiving funding from the Department of Energy (DOE) through the Clean Coal Technology program. The facility would generate approximately 400 megawatts. No coproduction is assumed with the first module.

As with option 7.1.1.6, the cost and performance data are extrapolated from information in the Black & Veatch/Bechtel Power Corporation study performed for option 7.1.1.5.

Option 7.1.2.1

BELLEFONTE REPOWERING – NATURAL GAS COMBINED CYCLE (10X222 MEGAWATTS)

The two units at TVA's Bellefonte Nuclear Plant (BLN) have been identified as two of four nuclear units whose disposition is being determined by TVA's integrated resource planning process. In order to properly evaluate all of the options for BLN, it is necessary to include a conversion option of the facility to utilize other fuels. The natural gas-fired combined cycle (NGCC) repowering option has been conceived to provide essentially the same station generation capability as would be provided by the nuclear plant using conventional gas-fired combined cycle technology.

The NGCC option for BLN consists of 10 modules, each comprising 1 advanced technology combustion turbine and 1 heat recovery steam generator (HRSG). Each combustion turbine generates about 150 megawatts. The steam leaving each HRSG is collected and routed to the BLN Unit 1 steam turbine. The current BLN high pressure turbine is replaced by a new HP turbine designed to receive steam at 900 pounds per square inch gauge and 1,000°F, and to discharge steam to the existing BLN low pressure turbine. Approximately 750 megawatts are generated by the modified BLN Unit 1 steam turbine. The users of station service power consume approximately 50 megawatts, thus reducing the overall plant output to about 2,220 megawatts.

The repowered facility utilizes existing BLN equipment such as:

- BLN Unit 1 steam turbine and condenser
- natural draft cooling towers
- station auxiliaries (compressed air and service water)
- switchyard and transmission system
- office and service buildings

New equipment added consists of items such as:

- advanced technology combustion turbines with HRSGs
- modified BLN steam turbine
- natural gas pipeline

The cost and performance data provided are based upon data from a study performed by an external architect and engineer under contract to TVA.

Options 7.1.4.1 and 7.1.4.2

COMPLETION OF BELLEFONTE UNITS 1 AND 2 AS NUCLEAR (1X1212 MEGAWATTS)

The Bellefonte Nuclear Plant is located in Jackson County, Alabama, on a peninsula at Tennessee River mile 392. The site

is on the west shore of Guntersville Lake about seven miles east-northeast of Scottsboro, Alabama.

Preliminary construction on the Bellefonte site was started in 1974. In 1985, the pace of construction was slowed due to forecasts which showed that generation would not be required until the late 1990s. In 1988, construction activities were deferred, with plant systems being maintained to allow reactivation on a schedule to meet future power requirements. The units were officially returned to construction status in 1993, but engineering and construction activities remained at a very low level of activity. At the current time, all construction work on the units is suspended pending the outcome of Energy Vision 2020. The Bellefonte Nuclear Plant Units 1 and 2 are approximately 90 percent and 58 percent complete, respectively.

The decision regarding the completion and commercial operation dates for the two-unit Bellefonte Nuclear Plant is being evaluated as part of Energy Vision 2020.

The Bellefonte supply-side option is whether each of the units will be completed as nuclear units. Each of the two Babcock and Wilcox pressurized water reactors (PWRs) has a net capacity of 1,212 megawatts, for a total generating capacity of 2,424 megawatts.

The nuclear fuel is contained inside each of the reactor pressure vessels. The fuel is in sealed metal tubes and consists of slightly enriched uranium dioxide pellets. The fission process in the fuel produces heat. Water serves as both the moderator of the fission process and the coolant. The primary coolant water is pumped through the reactor from below the fuel and is heated by contact with the fuel element tubes. The reactor power is controlled by control rods, lumped burnable poison rods, and a neutron-absorbing boric acid solution. The heated coolant flows in two closed-loop circuits through tubes in steam generators and is then pumped back into the reactor. In each steam generator, a separate body of water flows in contact with the outside surfaces of the tubes and absorbs heat from the reactor coolant, producing steam to power the turbine generator. Once the steam has passed through the turbines, it is exhausted to a condenser, where the steam is condensed back into a liquid to be pumped back to the steam generators to begin the process over again. The condenser has tubes through which raw water is circulated in order to condense the steam. The raw water is then pumped to the cooling towers, where the waste heat is emitted. The waste heat is emitted into the atmosphere through two natural-draft hyperbolic cooling towers. The electrical power thus produced by the turbine generator is fed through the switchyard and transmission line connections into the TVA system to meet system power needs.

The cost and performance data are based on site business plans and completion studies performed by a series of external architect and engineering firms under contract to TVA. Sources for other site information are final safety analysis reports (FSARs) for the project, TVA informational brochures, and TVA Nuclear Power Licensing/Engineering.

Option 7.1.4.3

BELLEFONTE UNITS 1 AND 2 CANCELLATION

A decision to cancel the Bellefonte Nuclear Plant Units 1 and 2 would entail selling to the extent possible the equipment, material, and supplies that currently exist as part of the project. Any remaining investment not recovered through these sales would have to be written off by TVA.

Based on previous TVA and industry experience with nuclear plant cancellations, it appears that the majority of such endeavors result in essentially breaking even (i.e., the costs incurred in selling the assets are offset by the receipts from the sales with little or no net profit). This is due to several considerations including the limited market for nuclear-grade materials, the vintage of nuclear technology, and the uncertainty in nuclear market conditions.

The undepreciated investment in the Bellefonte project is approximately $3,762 million for Unit 1 and $793 million for Unit 2.

The source for this information is TVA Nuclear Power Licensing/Project Engineering.

Option 7.1.4.4

BELLEFONTE NUCLEAR PLANT – PARTNERSHIP FOR COMPLETION AND OPERATION

The Bellefonte Nuclear Plant Units 1 and 2 are approximately 90 percent and 58 percent complete, respectively. These units have been placed in a protective lay up status since 1985. TVA has invested approximately $4.5 billion for the completion of these units. Repeated external reviews of the Bellefonte Construction Program indicate that the work quality is sound, and that the remaining completion scope is well defined. Several external groups have expressed interest in participating in the completion of the Bellefonte Nuclear Project.

Under the partnership, TVA and the partner would form a separate corporate entity to complete, operate, and ultimately decommission the Bellefonte Nuclear Plant. TVA would contribute the equity invested in the plant to date; the partner would contribute the remaining completion cost. TVA and the partner would have access to the capacity and energy output of the plant, and share the net revenues and cash flows of sales from the plant. Sharing arrangements have yet to be negotiated, and general estimates are used for the ranking studies

for Energy Vision 2020. Revenues from the plant would cover operating costs, taxes, decommissioning costs, coverage of additional debt and principle, the partner's return on equity, and provide a return on TVA's sunk cost.

The completed plant would have operating characteristics similar to a TVA completion of Bellefonte Units 1 and 2 as nuclear (options 7.1.4.1 and 7.1.4.2). For purposes of evaluating this option in Energy Vision 2020, the Bellefonte partnership option is modeled in a manner similar to a non-utility generator (see option 13.1.2.1 for example). In this evaluation, it is assumed that TVA receives no net revenue from the partnership. The exact amount of capacity that this option would provide TVA would be negotiated with the other partners and could range anywhere from none to the full 2,412 megawatts represented by both units. Energy Vision 2020 considers a capacity addition of 600 megawatts to represent the option.

Option 8.1.4.1

RECOVER BROWNS FERRY UNIT 1 (1X1065 MEGAWATTS)

The Browns Ferry Nuclear Plant is located in Limestone County, Alabama, on the Tennessee River 10 miles southwest of Athens, Alabama. It is on the north shore of Wheeler Reservoir, 19 miles upstream from Wheeler Dam.

Preliminary construction on the Browns Ferry Nuclear Plant started in 1966. The first of the plant's three units was placed in commercial operation on August 1, 1974, about eight years after construction began. The second unit went into commercial operation in March 1, 1975. The third unit went into commercial operation in March 1977. TVA shut down the plant in March 1985 as part of a review of its nuclear power program. At the present time, Units 1 and 3 at Browns Ferry are not operational. Unit 3 has undergone extensive rework and is scheduled to resume commercial operation in the spring of 1996. Unit 1 is presently idle. The decision regarding the rework and commercial operation of the unit is being evaluated in TVA's integrated resource planning process.

The Browns Ferry supply-side option is whether to complete Browns Ferry Unit 1 as a nuclear unit. Unit 1 of the Browns Ferry facility is a General Electric boiling water reactor (BWR) capable of generating 1,065 megawatts of net electrical capacity.

During operation, nuclear fuel is contained inside the reactor pressure vessel of Unit 1. The fuel is sealed in zircalloy tubes, and consists of slightly enriched uranium dioxide pellets. The fission process in the fuel produces heat. The reactor power level is regulated primarily by control rods. Boron, a chemical element that absorbs neutrons and thereby retards nuclear fission, is sealed within the control rods. The power of the reactor, therefore, can be controlled by positioning the control rods in the core. The power is increased by slowly withdrawing the control rods from the core. The power level may also be controlled, but to a lesser extent, by regulating the flow of the water that is circulated through the reactor core.

Water enters the pressure vessel below the fuel and moves through the assembly of fuel tubes called the reactor core. As the water passes through the core, the heat converts it to steam. The steam leaves the reactor through pipes near the top of the reactor, then passes through the turbogenerator, which generates electricity. The steam is then condensed into water and returned to the reactor, where the cycle is repeated. Waste heat is emitted in the atmosphere through a series of mechanical draft cooling towers. The electrical power thus produced by the turbogenerator is fed through the switchyard and transmission line connections into the TVA system to meet system power needs. *Figure T6-11* shows a diagram of the Browns Ferry Plant simplified steam cycle.

The sources for this information are the site business plans, site Public Relations/Engineering, and Tennessee Valley Authority Environmental Statement, Browns Ferry Nuclear Plant – Units 1, 2, and 3, July 1971.

Option 8.1.4.2

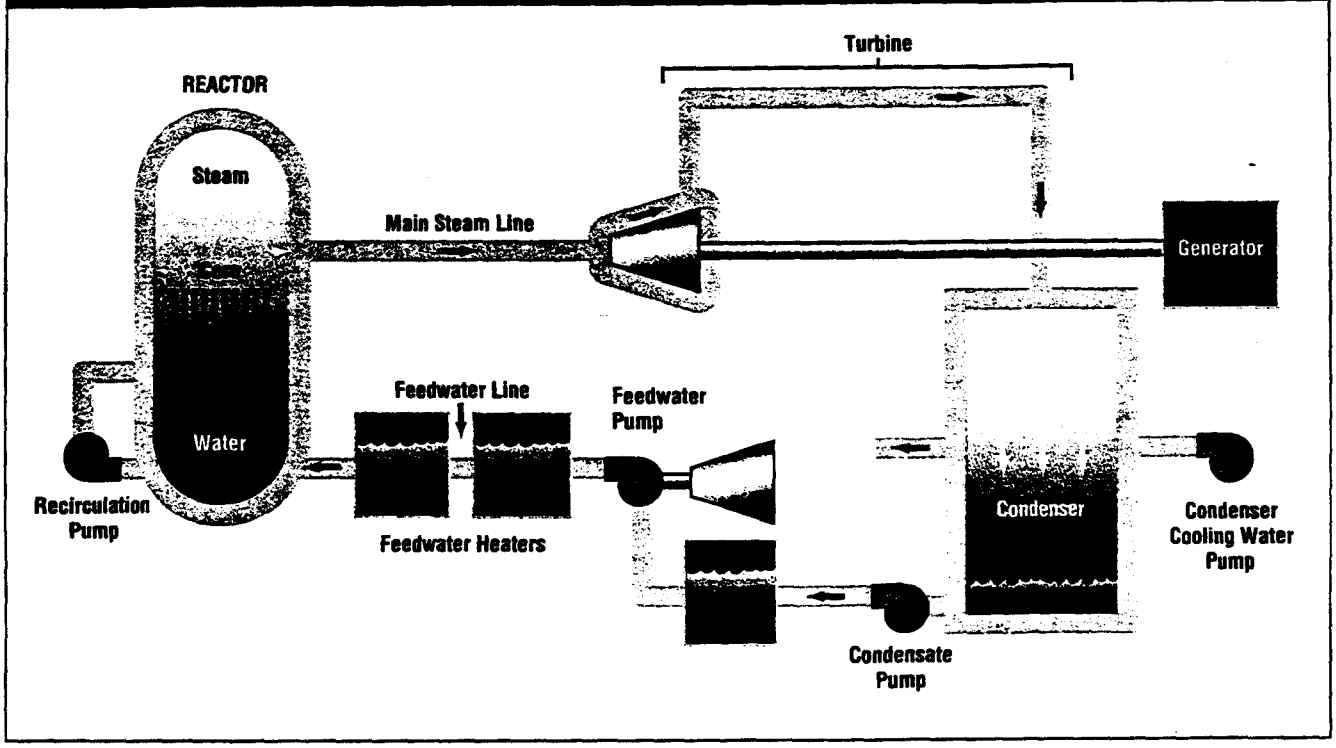
BROWNS FERRY UNIT 1 CANCELLATION

A decision to cancel the Browns Ferry Nuclear Plant Unit 1 is simply a decision not to complete the unit now or in the future. Unit 1 at Browns Ferry is an integral part of the Browns Ferry site, which also includes the operating Unit 2 and soon to be restored Unit 3. This complexity, along with the fact that Browns Ferry Unit 1 has operated in the past, makes it impossible to cancel this project in the same manner as was described for Bellefonte in option 7.1.4.3.

While some surplus equipment from Browns Ferry Unit 1 could be sold, previous TVA and industry experience with nuclear plant cancellations suggests that this would most likely be a break-even proposition (i.e., the cost incurred in selling the assets are offset by the receipts from the sales with little or no net profit). This is due to several considerations including the limited market for nuclear-grade materials, the vintage of nuclear technology, and the uncertainty in the nuclear market conditions.

The undepreciated investment in the Browns Ferry Unit 1 is approximately $708 million. A portion of the plant represented by this investment will remain useful to support operation of Units 2 and 3 even if Unit 1 is cancelled. The fraction of the investment that would be useful has not yet been determined, and has been assumed to be zero in the Energy Vision 2020 evaluation.

FIGURE T6-11. **Browns Ferry Simplified Steam Cycle**



The source for this information is TVA Nuclear Power Licensing/Project Engineering.

Option 8.1.4.3

BROWNS FERRY UNIT 1 RECOVERY WITH FIXED COST TO COMPLETE (1X1065 MEGAWATTS)

One option for Browns Ferry Nuclear Plant Unit 1 is to contract with an outside engineering firm to recover the unit for a fixed cost and operation date. This would remove TVA's exposure to the schedule and completion cost risk. TVA would operate the unit once it had been recovered. All characteristics and costs, except for the capital costs for recovery, would be the same as those for option 8.1.4.1.

Option 9.1.4.1

COMPLETION OF WATTS BAR UNIT 2 (1X1170 MEGAWATTS)

The Watts Bar Nuclear Plant is located in Rhea County, Tennessee, adjacent to the TVA Watts Bar Dam Reservation at Tennessee River mile 528. The plant is on the west shore of Chickamauga Lake about 8 miles southeast of Spring City, Tennessee, and 50 miles northeast of Chattanooga, Tennessee.

Preliminary construction on the Watts Bar Nuclear Plant started in December, 1972. The major construction elements were largely completed by 1985. Since 1985, Watts Bar has been undergoing extensive reviews and modifications. Construction work at Watts Bar was put on hold in December 1990. Work resumed in November 1991, and after extensive site review in May of 1992, the Nuclear Regulatory Commission (NRC) gave the site the go-ahead to resume full construction activities. The first of the plant's two units is scheduled for commercial operation in 1996. The decision regarding completion of the plant's second unit is being evaluated as part of Energy Vision 2020.

The Watts Bar supply-side option is whether to complete the second nuclear unit. Watts Bar Unit 2 is a Westinghouse pressurized water reactor (PWR). The Westinghouse reactor is capable of producing 1,170 MW net of electrical capacity.

During operation, the nuclear fuel is contained inside the Unit 2 reactor pressure vessel. The fuel is in sealed metal tubes and consists of slightly enriched uranium dioxide pellets. The fission process in the fuel produces heat. Water serves as both the moderator of the fission process and the coolant. The primary coolant water is pumped through the reactor from below the fuel and is heated by contact with the fuel element tubes. The heated coolant flows in four closed-loop circuits through tubes in steam generators, and is then pumped back into the reactor. In the steam generator, a separate body of water flows in contact with the outside surfaces of the tubes and absorbs heat from the reactor coolant, producing steam to power the

turbine generator. The reactor power is controlled by control rods and a neutron-absorbing boric acid solution.

The nuclear steam supply system is housed in an individual containment structure. The primary containment consists of a free-standing steel structure with an ice condenser. A separate reinforced reactor shield building encloses the primary containment. The steam power conversion system is designed to remove heat energy from the reactor coolant in the four steam generators and to convert it to electrical energy. The waste heat is emitted in the atmosphere through two natural-draft hyperbolic cooling towers.

The sources for this information are the site business plan, site Public Relations/Engineering, and Tennessee Valley Authority Environmental Report, Watts Bar Nuclear Plant, November 1972.

Option 9.1.4.2

WATTS BAR UNIT 2 CANCELLATION

A decision to cancel the Watts Bar Nuclear Plant Unit 2 would create the need for additional decisions concerning the utilization and/or disposition of the investment to date. The decisions would be to cancel the project and either sell the surplus equipment, material, and supplies, or convert the unfinished nuclear plant to a fossil-fired facility. Finally, any remaining investment not recouped through either the sale of assets or its conversion would have to be written off by TVA.

If the cancel-and-sell decision were made, materials and equipment would be sold to recoup as much of the total investment to date as possible from the project. Based on TVA's experience with nuclear plant cancel-and-sell programs and industry experience, it appears that the majority of such operations result in breaking even (i.e., it costs a dollar to recoup a dollar investment).

This is due to several considerations including the limited market for nuclear-grade materials, the vintage of nuclear technology, and the uncertainty in nuclear market conditions.

The conversion of Watts Bar Unit 2 to a fossil-fired facility is a very difficult option. The major constraints to the conversion option at Watts Bar are:

- Engineering and operational interface problems associated with Units 1 and 2 of the nuclear plant.
- Operational incompatibilities associated with a nuclear and fossil-fired unit at the same site.
- Nuclear Regulatory Commission licensing constraints that would be applied to the fossil-fired unit.

The sunk cost to date in the Watts Bar Unit 2 project is approximately $1,651 million.

The source of this information is TVA Nuclear Power Licensing/Project Engineering.

Option 10.1.2.1

INLET AIR PRECOOLING WITH STORAGE (16X61 MEGAWATTS)

Option 10.1.2.4

WATER SPRAY COOLING OF COMBUSTION TURBINE INLET AIR

Inlet air precooling with ice storage is a technology that allows combustion turbines (CTs) to operate at higher output levels during hot weather than would normally be possible. Combustion turbine performance decreases significantly as the air temperature at the compressor inlet increases. Inlet air precooling provides a mechanism to cool the air entering the compressor inlet to approximately 40°F, thus increasing the turbine output to the levels normally achievable in cool weather. This is achieved by producing and storing ice during off-peak conditions using excess system generation to operate industrial-sized chillers. When the additional combustion turbine output is required during warm weather, water is circulated through the ice storage and routed to fin coils located in the compressor inlet ducting to cool the compressor inlet air. Thus, inlet air precooling is an energy storage technology that is applicable for peaking usage during hot weather. It provides no system benefits during the rest of the year.

Water spray cooling is similar to inlet air precooling with ice storage, except for the method and extent of precooling. A fine mist of water is sprayed into the inlet air stream during hot weather operation. Evaporation of the water reduces the air temperature by 10 to 20 degrees, depending upon ambient conditions. This can increase the turbine output by 5 to 10 percent, depending upon ambient conditions. Spray cooling is more effective in conditions of lower relative humidity and higher dry bulb temperature. Compared to precooling with ice storage, water spray cooling is much simpler and less expensive to install, but provides a smaller gain in turbine output.

Cost and performance data were obtained from Electric Power Research Institute studies and from industry reports on newly installed and operational inlet air precooling systems, with calculations performed by TVA to adjust the performance to the environmental conditions found in the TVA region.

Option 10.1.2.2

NEW COMBUSTION TURBINE AT JOHNSONVILLE TO SUPPLY STEAM TO DUPONT (1X174 MEGAWATTS)

TVA has contracted with DuPont to supply process steam from TVA's Johnsonville coal-fired plant to their New Johnsonville, Tennessee, industrial plant. Currently the steam is extracted from the boilers of Units 1-4.

This supply-side option is an alternative method of supplying this steam while at the same time adding capacity to the power system. In this concept, a new high-efficiency combustion turbine is installed at Johnsonville, and the exhaust gases are routed to a heat recovery steam generator to produce steam for a steam turbine and for extraction to supply DuPont's needs. The steam turbine can increase its generation during those periods when DuPont's steam demand decreases. A backup natural gas-fired boiler provides the reliability required by DuPont.

By providing steam from the combustion turbine, the fossil Units 1-4 would no longer have to provide steam; therefore, the capacity of the station would increase by about 50 megawatts. In addition, Units 1-4 could then be dispatched according to power system needs.

If a natural gas "connector" pipeline was constructed from an interstate pipeline to the plant for this option, it would probably be very inexpensive to increase the capacity of the connector pipeline to convert the existing Johnsonville combustion turbines to natural gas, thereby lowering their fuel cost.

The technologies required for this option are commercially mature.

The source for the cost and performance data is an internal TVA study performed in fiscal year 1994.

Option 10.1.2.3

REPOWERING ONE OF JOHNSONVILLE FOSSIL UNITS 7-10 WITH NATURAL GAS/COMBINED CYCLE (1X465 MEGAWATTS)

Option 25.1.2.1

REPOWERING ALLEN FOSSIL PLANT WITH NATURAL GAS/COMBINED CYCLE (1X705 MEGAWATTS)

Repowering is defined as the reuse of the existing site infrastructure and major power generation equipment to convert an existing fossil fuel unit to a new power generation technology. In most repowering applications, the boiler is replaced, while major equipment, such as the turbine generator, feedwater system, and condenser, is reused in the new plant. Some of the advantages of repowering are:

- Extension of plant life
- Increase in generating capacity
- Improvement in unit efficiency
- Decrease in emissions

Repowering does have some disadvantages. Space availability at the existing plant can be a problem since most plants are fairly "tight." Also, the cost for additional generating capacity is relatively high when compared to a greenfield or new site.

In this particular application of repowering, the boiler and coal handling facilities would be retired while the steam turbine generator, feedwater system, and condenser would be reused. A combustion turbine(s) (CT) and a heat recovery steam generator (HRSG) would be added. The CT's hot exhaust gases generate steam in the HRSG for the existing steam turbine. The steam turbine would generate a significant amount of power (although usually less than before) and the CTs add a large amount of generation.

The unit efficiency and emission characteristics of this option appear very attractive, the capital cost and operation and maintenance costs are relatively low, and the technology is commercially mature. However, the cost of fuel (natural gas) is significantly higher than coal.

The cost and performance data are based on a study conducted by Stone & Webster Engineering Corporation for TVA in 1994.

Option 10.3.1.1

REPOWERING ONE OF JOHNSONVILLE FOSSIL UNITS 1-6 WITH INTEGRATED GASIFICATION COMBINED CYCLE (1X242 MEGAWATTS)

Option 10.3.1.2

REPOWERING ONE OF JOHNSONVILLE FOSSIL UNITS 7-10 WITH INTEGRATED GASIFICATION COMBINED CYCLE (1X250 MEGAWATTS)

Option 20.3.1.1

REPOWERING TWO UNITS OF WATTS BAR FOSSIL PLANT WITH INTEGRATED GASIFICATION COMBINED CYCLE (1X242 MEGAWATTS)

Option 25.3.1.1

REPOWERING ALLEN FOSSIL PLANT WITH INTEGRATED GASIFICATION COMBINED CYCLE (1X500 MEGAWATTS)

Repowering is defined as the reuse of the existing site infrastructure and major power generation equipment to convert an existing fossil fuel unit to a new power generation technology. In most repowering applications, the boiler is replaced, while major equipment such as the turbine-generator, feedwater system, and condenser, is reused in the new plant. Some of the advantages of repowering are:

- Extension of plant life
- Increase in generating capacity
- Improvement in unit efficiency
- Decrease in emissions

Repowering does have some disadvantages. Space availability at the existing plant can be a problem since most plants are fairly "tight." Also, the cost for additional generating capacity is relatively high compared to a greenfield or new site.

In this particular application of repowering, the boiler and coal handling facilities would be retired while the steam turbine-generator, feedwater system, and condenser would be reused. An integrated gasification combined cycle (IGCC) system is added. The major components of the IGCC plant are the gasification plant, the combustion turbine(s) (CT), and a heat recovery steam generator (HRSG). The gasifier would use coal to produce a medium syngas, which is burned to produce power in the CTs. The CT's hot exhaust gases generate steam in the HRSG for the existing steam turbine. The steam turbine would generate a significant amount of power (although usually less than before) and the CTs would add a large amount of generation.

The unit efficiency and emission characteristics of this option appear very attractive, the fuel cost (coal) is very low since high sulfur coal can be used, and the technology is quite close to being commercially mature. However, the capital cost of IGCC repowering is quite high.

The cost and performance data are based on a study conducted by Stone & Webster Engineering Corporation for TVA in 1994.

Option 11.1.5.1

LAUREL BRANCH PUMPED-HYDRO STORAGE (4X386 MEGAWATTS)

Option 15.1.5.1

REYNOLDS CREEK PUMPED-HYDRO STORAGE (3X366 MEGAWATTS)

Option 17.1.5.1

ROREX CREEK PUMPED-HYDRO STORAGE (3X292 MEGAWATTS)

The benefit of energy storage facilities is in the ability to store low-cost, off-peak energy and to discharge it during high peak demand periods. Energy storage facilities can also provide spinning reserve capacity and contribute to solving minimum overnight turndown problems.

In pumped-hydro storage, water is pumped from a lower reservoir to the upper reservoir using off-peak power. During the generating cycle, water is discharged from the upper reservoir through the reversible pump/turbine-generators located in an underground powerhouse. Pumped-hydro storage facilities have relatively long storage times of 10 to 20 hours, relative to other storage technologies.

The emissions from a pumped-hydro plant are essentially zero. There are emissions associated with the source of the power used during the pumping cycle.

Limited sites can be considered for conventional pumped-hydro installations because of the required elevation difference between the two reservoirs. Several sites have been identified in the TVA region, and preliminary engineering studies on these sites have been made.

The cost and performance data are based on a TVA study completed in November 1994.

Option 14.1.3.1

WIND – 33 METER VARIABLE SPEED ADVANCED WIND TURBINE (285X0.35 MEGAWATTS)

Option 14.3.3.1

WIND – 39 METER VARIABLE SPEED ADVANCED WIND TURBINE (444X0.45 MEGAWATTS)

Wind turbines capture the wind's energy with blades that operate as airfoils. Current commercial wind turbine designs produce electrical power at wind speeds exceeding about 10 miles per hour. The energy extractable from the wind is proportional to the cube of the wind speed; if the wind speed doubles, eight times as much power is available.

The most common turbine configuration is a horizontal axis design. A gearbox is used to step up the low hub speed to the generator's nearly synchronous speed of 1,800 revolutions per minute. Most generators now in service are squirrel cage induction generators, although some synchronous machines have been tested. A variable speed turbine using modern power electronics has been developed. This turbine, first offered commercially in 1992, is expected to be widely used during the mid- to late 1990s.

Wind turbine control options include active or passive yawing to track wind direction and stall regulation or blade pitch regulation to control power output. Both stall- and pitch-regulated turbines start turning and generating electricity at a particular wind speed, called "cut-in," and the output power increases as the wind speed increases, up to the wind speed for which it is rated. The turbine will produce its rated output at speeds between the rated wind speed and the "cut-out" speed, the speed at which the turbine stops. Stall-regulated airfoils lose their lifts at high wind speed and are therefore self-regulating. When pitch-regulated turbines are in the presence of wind speeds at or above the turbine's rated wind speed, the pitch of the blade is changed to hold the power at a given level. If the wind speed rises to a cut-out value, the blade feathers and the turbine stops to avoid excessive loads. A number of vertical axis

machines have also been deployed. They have the advantage that all of their heavy components are essentially on the ground. However, as of 1992, no commercial units were being manufactured.

The turbine ratings of state-of-the-art utility-grade turbines have increased from an average of about 50 kilowatts in 1981 to over 300 kilowatts by 1992. Well-designed machines with good maintenance service have all-wind-condition availabilities of 96 to 98 percent.

Each wind turbine has a unique transfer function (power curve) that relates a given wind speed condition to the nominal electrical output of the turbine. This curve is a function of the area swept by the rotor, the capacity of the turbine's generator(s), and the unit's energy conversion efficiency. In general, a variable-pitch turbine is more efficient than a fixed-pitch turbine, but it may also have more moving parts, and thus a higher initial cost. Variable-speed turbines can convert more of the energy in higher speed winds to electrical output. Modern power electronics are required to convert the generator's variable frequency power to constant 60 hertz power.

A wind power plant is composed of a number of wind turbines connected to the utility grid system through one or more interconnections. Typically the turbines are arranged in rows perpendicular to the prevailing wind direction. Turbines are at least 10 rotor-diameters apart in the downwind direction and about 3 diameters apart in the crosswind direction.

When the wind speeds are in the proper range, the turbines operate automatically under the control of their on-board processors. A modern power plant is monitored and controlled by means of telecommunication to a remote computer terminal located at a utility control facility. The operational status of each unit is known at all times and can be changed to meet the required operating conditions. Alarms are identified and diagnosed at the remote facility, and maintenance crews are dispatched as needed.

The cost and performance data are based on information from Electric Power Research Institute's Technical Assessment Guide.

Option 16.1.5.1

RACCOON MOUNTAIN PUMPED-HYDRO ENERGY STORAGE ADDITION (3X255 MEGAWATTS)

The TVA Raccoon Mountain pumped-hydro energy storage facility is a four-unit plant. Three additional generation/pumping units could be added to the facility to increase the total power output. Since the size of the upper storage reservoir would not be increased, the duration of full-load generation at the new, higher power output would be decreased.

The cost and performance information is extrapolated from recent TVA cost studies for new pumped-storage sites (options 11.1.5.1, 15.1.5.1, and 17.1.5.1).

Option 16.1.5.2

RACCOON MOUNTAIN PUMPED-STORAGE MODERNIZATION

TVA's Raccoon Mountain pumped-hydro plant was designed and installed in the 1970s. Since that time, technology has advanced significantly on several fronts of pumped-storage plant design. A modernization project has been identified that will increase the capacity and efficiency of the plant. This project would increase the plant output by approximately 76 megawatts.

The cost and performance information for modernization projects at existing hydro sites was provided by the Fossil and Hydro Projects organization.

Option 18.1.1.1

SHAWNEE UNIT 11 (1X168 MEGAWATTS)

Since 1988, the TVA Shawnee Fossil Plant Unit 10 turbine-generator has been powered by a new atmospheric fluidized bed combustion boiler. The original Unit 10 pulverized coal boiler is idle. A new steam turbine-generator and associated auxiliary systems could be installed as Unit 11. The original Unit 10 boiler could be refurbished to supply steam to the new Unit 11 turbine-generator. This option includes a mechanical draft cooling tower for condenser heat rejection. The other 10 units have no cooling towers.

The original Unit 10 boiler has no flue gas desulfurization (FGD) system, or scrubber capabilities. No new FGD facilities would be installed. Consequently, the fuel would be low sulfur coal.

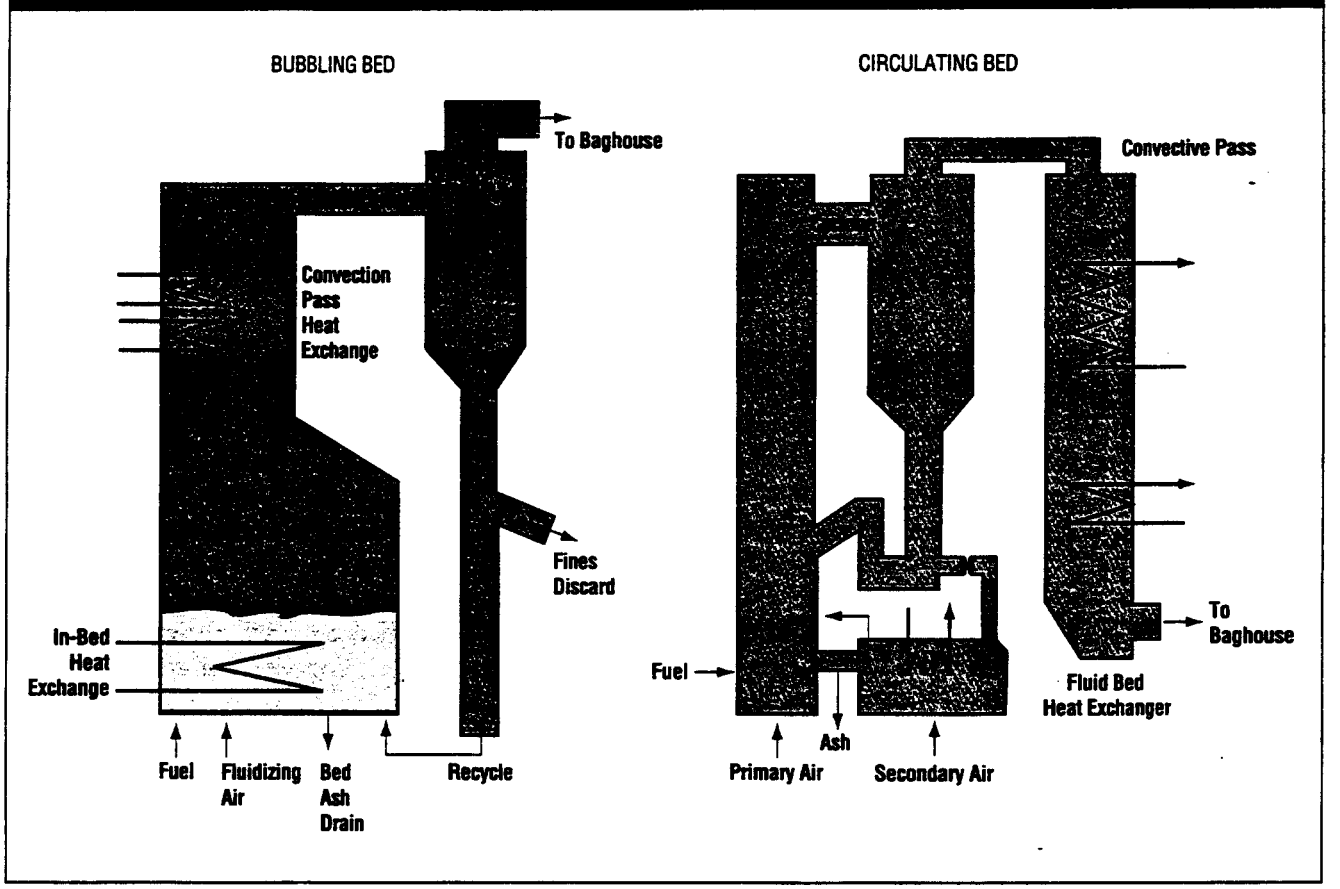
The cost data are based on results from an engineering study performed by an external architect and engineer.

Option 20.1.1.1

RESTART ONE UNIT OF WATTS BAR FOSSIL PLANT (1X56 MEGAWATTS)

TVA's Watts Bar Fossil Plant was initially placed in service in 1945. It was operated until the 1960s, when it was placed in storage status in anticipation of new nuclear capacity coming on line. It was reactivated in the mid-1970s and operated until 1982, when it was again placed in storage status. Except for some particulate collection equipment added in the 1970s, the plant is still in essentially the same configuration as when initially placed in service. Several modifications that have been identified must be performed before the plant can be returned to service. These modifications range from replacement of

FIGURE T6-12. **Atmospheric Fluidized Bed Combustion Boiler Types**



equipment that is no longer functional to modifications required to meet new emissions requirements.

The cost and performance information was taken from a study performed by an external architect and engineer with some adjustments by TVA.

Option 20:1.3.1
REFUSE-DERIVED FUEL – FLUIDIZED BED COMBUSTION REPOWERING OF ONE UNIT OF WATTS BAR FOSSIL PLANT (1X56 MEGAWATTS)

Fluidized bed combustion burns fuel that is suspended in a moving air stream. An atmospheric fluidized bed combustion (AFBC) generating unit is similar to a conventional pulverized coal unit and includes fuel receiving and handling, an air heater, a steam turbine generator and auxiliaries, particulate removal, ash handling, plant cooling, and other balance-of-plant equipment. In bubbling bed AFBC generating units, the heat transfer surface is located both in the bed and in the convection pass above the bed.

In some circulating bed AFBC generating units, the heat transfer surface is located downstream of the cyclone separators, and in a separate fluidized bed heat exchanger that recovers heat from the cyclone catch before the solids are reinjected into the furnace. Other circulating fluidized bed designs locate the superheater surface at the top of the furnace shaft and do not use the separate fluidized bed heat exchanger. *Figure T6-12* shows a diagram of two atmospheric fluidized bed combustor boiler types (the bubbling bed and the circulating bed).

Nitrogen oxides (NO_X) emissions are inherently low. With staged combustion, they can be easily limited to 0.2-0.3 pounds of NO_X per million Btu for bubbling bed units, and to 0.1-0.2 pounds of NO_X per million Btu for circulating bed units. Particulate emissions can be reduced to less than 0.03 pounds per million Btu using a fabric filter.

Due to its fuel flexibility, the AFBC boiler design is only moderately affected by fuel properties, and the boiler size is mostly dependent on flue gas volume. Thus, it could economically burn low-cost high-sulfur petroleum coke (50 cents per million Btu to 70 cents per million Btu) and coal fines, or blends of pet coke and coal fines.

The cost and performance data are based on information from Electric Power Research Institute's Technical Assessment Guide.

Option 23.1.2.1

POWER PURCHASE – BASE LOAD (1X300 MEGAWATTS)

Option 23.1.2.2

POWER PURCHASE – PEAKING (1X300 MEGAWATTS)

TVA considers the market clearing price for power purchases to be related to the technology that is available to generate this power. The peaking power purchase option is based on existing simple cycle combustion turbine technology dispatched as a peaking unit. The operation and maintenance costs reflect the production cost and capital recovery incurred by the owner of this unit. The performance and emission characteristics are similar to those for option 1.1.2.1. The basis for the base-load power purchase option is existing gas-fired combined cycle technology dispatched as a base unit. These operation and maintenance costs reflect the production cost and capital recovery incurred by the owner of this unit. The performance and emission characteristics are similar to those for option 1.1.2.2.

Option 24.1.1.1

UNIT POWER PURCHASE 15 YEAR

A neighboring utility has offered TVA the option to purchase power from one of its existing coal-fired units. The operation and maintenance costs reflect the production cost and capital recovery incurred by the owner of this unit. The performance and emission characteristics reflect those of the coal-fired unit.

Option 24.1.1.2

PARTIALLY COMPLETE PULVERIZED COAL PLANT (1X710 MEGAWATTS)

A neighboring utility has purchased the major capital equipment and completed the siting work and final design of a 710-megawatt pulverized coal (PC) plant. This utility has since deferred the completion of the plant. The plant equipment remains warehoused. The utility has offered to sell the equipment site and design. The capital cost is very competitive as compared to current market prices.

This pulverized coal plant would use midwest 5 pound per million Btu sulfur coal and a wet scrubber sulfur dioxide removal system. The utility is contiguous with the TVA service area and thus no wheeling charges were included in the option. The plant description is similar to that of the subcritical pulverized coal-fired plant, option 1.1.1.5.

Option 26.1.3.1

BIOMASS COFIRING – CUSTOMER SERVICE

The cofiring of biomass with coal in pulverized coal and cyclone-fired units at relatively low biomass percentages has been demonstrated to be a technically feasible and cost-effective method to reduce emissions from coal-fired plants, and in many cases to reduce fuel costs. The level of biomass cofiring, expressed as a percentage of the total fuel energy input to the unit, determines the capital cost of modifications required for a plant to continuously cofire biomass.

The only biomass considered for cofiring is untreated, unpainted wood waste from wood products industries. No trees would be cut to supply biomass for cofiring projects.

The customer service cofiring option would be implemented at plants in the vicinity of wood products industries that are actively seeking cost-effective alternate means of disposing of their wood wastes. TVA has had discussions with several of the industries that have indicated that costs of current disposal methods, typically landfill, have increased to the point that these costs are impacting their competitiveness.

The level of biomass cofiring for the customer service option would be low—less than 0.5 percent. The capital cost would also be low and the cost to TVA of the wood waste, expected to be only transportation cost, would be significantly lower than coal on a Btu basis.

The capital cost estimates are based on conceptual designs and cost estimates made by Ensearch Environmental Corporation in 1994. The fuel cost estimates are based on the report "Biomass Resource Assessment for Twelve TVA Plants" prepared jointly by the University of Tennessee, Oak Ridge National Laboratory, and TVA in 1994.

Option 26.2.3.1

BIOMASS COFIRING – LOW LEVEL

This biomass cofiring option is similar to option 26.1.3.1 except for the level of cofiring. In this option, wood waste would be cofired up to about 1.3 percent at various plants. The level for each plant would depend on the wood cost and supply in the vicinity of the plant. The wood waste cost would be higher than that for the biomass cofiring customer service option and would include transportation and energy costs, but would still be lower than coal costs on a Btu basis. Capital costs would be higher than for the biomass cofiring customer service option, as well.

The capital cost estimates are based on conceptual designs and cost estimates made by Ensearch Environmental Corporation in 1994. The fuel cost estimates are based on the report "Biomass Resource Assessment for Twelve TVA Plants" prepared jointly by the University of Tennessee, Oak Ridge National Laboratory, and TVA in 1994.

Option 26.3.3.1

BIOMASS COFIRING – LESS THAN $5.00 PER TON OF CARBON DIOXIDE EMISSIONS REDUCTION

One of the benefits of biomass cofiring is the reduction of greenhouse gas emissions, i.e., carbon dioxide (CO_2). The reduction is the result of fossil fuel being displaced by biomass. When the wood waste is the biomass, methane emissions are also reduced due to the avoidance of wood conversion to methane in decomposition. Methane is a more potent greenhouse gas than CO_2 (by about 20 times).

This option includes cofiring wood waste in various plants up to the level at which the cost of greenhouse gas emission reductions, expressed in terms of CO_2 equivalents, is less than $5.00 per ton. Costs include the capital cost of plant modifications, additional plant operation and maintenance costs, and increased (or reduced) fuel costs relative to the cost of coal. The level of wood waste cofiring at a particular plant would depend on the wood cost and supply in the vicinity of the plant.

The capital cost estimates are based on conceptual designs and cost estimates made by Ensearch Environmental Corporation in 1994. The fuel cost estimates are based on the report "Biomass Resource Assessment for Twelve TVA Plants" prepared jointly by the University of Tennessee, Oak Ridge National Laboratory, and TVA in 1994.

Option 28.2.3.2

BIOMASS COFIRING – MODERATE LEVEL AT COLBERT FOSSIL PLANT UNIT 5

Resource assessments indicate there are large amounts of favorably priced wood waste available in the vicinity of the Colbert Fossil Plant (COF). The amounts are such that they could potentially support moderate level, up to 10 percent energy input, at COF Unit 5. The capacity of COF Unit 5 is about 500 megawatts. At this level of cofiring in a pulverized coal-fired unit, a dedicated wood waste preparation and feed system would be required. Consequently, the capital cost of this option is higher than that of other cofiring options. Wood waste costs would remain lower than coal costs on a Btu basis.

The capital cost estimates are based on conceptual designs and cost estimates done by Ensearch Environmental Corporation in 1994. The fuel cost estimates are based on the report "Biomass Resource Assessment for Twelve TVA Plants" prepared jointly by the University of Tennessee, Oak Ridge National Laboratory, and TVA in 1994.

Energy Vision

2020

Volume 2, Technical Document

7 Customer Service Options

Volume 2, Technical Document 7

Customer Service Options

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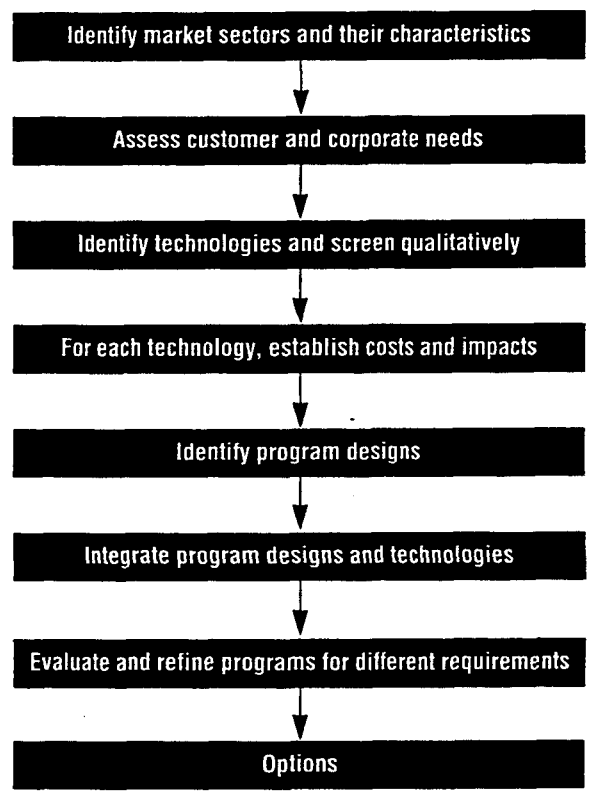
Customer Service Options

INTRODUCTION

TVA has developed more than 60 customer service options for consideration in Energy Vision 2020. Options were developed for all of the sectors and many of the end uses in the Valley economy. TVA developed options that impact the system load shape in a variety of ways, including energy efficiency, load management, self-generation, beneficial electrification, and rate options. The options include many different technologies that can be used to achieve a significant improvement in the efficiency of electricity use and deliver value to the residences and businesses throughout the Valley.

Technical Document 7, Customer Service Options, describes the methodology and data used for development of the options. This technical document contains a description of how customer service options were evaluated both at the program level and in the resource integration process. The criteria for ranking the technologies for inclusion in the options and prioritizing the options for inclusion in the different resource strategies are also discussed. Descriptions of all the customer service options are provided and include detailed impact and cost information. The last section of this technical document records the development of the technology data base and the technology screening process.

FIGURE T7-1. **Process for Development of Customer Service Options**



Methodology for Option Development

A seven-step process was used to develop and evaluate the initial set of customer service options. *Figure T7-1* illustrates the process used to develop customer service options, including energy efficiency, load management, self-generation, beneficial electrification, and to a limited extent, rate options.

IDENTIFICATION OF MARKET SECTORS AND ASSESSMENT OF CUSTOMER NEEDS

TVA identified different market sectors and their characteristics to assess customer needs and to better understand the kinds of technologies and programs that would be most beneficial. TVA also met with distributors of its power to obtain their input for promoting energy-efficient technologies to end-use customers.

IDENTIFICATION AND QUALITATIVE SCREEN OF THE TECHNOLOGIES

To ensure that a wide range of options was developed for analysis in Energy Vision 2020, TVA identified a wide variety of efficient technologies. TVA received assistance in developing technology data from several organizations that are particularly qualified to provide technology information: E-Source, Tellus Institute, the National Renewable Energy Laboratory, Barakat & Chamberlin, Inc., Synergic Resources Incorporated, and Unimar, as well as TVA sources and the Energy Vision 2020 Review Group.

Technologies were qualitatively screened to ensure their appropriateness and applicability for the region. For example, evaporative air conditioners were dismissed because they are not compatible with the Valley's humid climate. An emerging technology could be discarded if adequate data to assess its costs and impacts were unavailable or could not be estimated. Considerable care was taken not to eliminate technologies prematurely and to carry forward as many technologies as possible to the next stage of the analysis.

ESTABLISH AND RANK TECHNOLOGY COSTS AND IMPACTS

For all selected technologies, TVA gathered information on costs, energy requirements, and impacts on its capacity. This information was stored in a detailed database. Engineering simulations, as well as data from other utilities, technology vendors, and TVA field tests all contributed information to the database. Once the database was developed, it was reviewed by a number of technology experts, including the companies and agencies identified above.

For each market segment, TVA ranked energy efficiency technologies from a total resource cost perspective. To ensure that TVA would have a comprehensive set of options, some technologies with benefits less than the costs of the technology were included in one or more program options. Beneficial electrification measures were ranked according to their impact on electricity prices. This ranking identified the technologies to be included in one or more of the beneficial electrification options.

IDENTIFICATION OF PROGRAM DESIGNS

A critical step in the option development process was the design of programs that would encourage customer acceptance, meet economic and financial objectives, and provide options for all customer classes. TVA reviewed other programs to identify good strategies that would meet TVA, distributor, and customer objectives. Past and present TVA programs, other integrated resource plans, and other utility programs were examined to find best practices and program characteristics providing the greatest chance for success. Programs included in TVA's customer service options were designed to:

- Increase energy efficiency by overcoming obstacles to the adoption of a new technology
- Provide customer value
- Promote market changes

Programs providing customer value, such as microwave heating or laser cutting options, address environmental concerns and increase productivity. These factors often have a greater impact on business profits than do energy costs.

INTEGRATION OF PROGRAM DESIGNS AND TECHNOLOGIES

For customer service options, TVA combined technologies with delivery strategies to provide economical and efficient services to customers. Technologies were integrated with program designs based on likely distribution channels, customer needs, and the characteristics and economics of the different technologies.

EVALUATION AND REFINEMENT OF OPTIONS TO MEET DIFFERENT REQUIREMENTS

The customer service options were checked for completeness and correctness, and to ensure a sufficient number of options were available for the construction of a wide range of strategies. TVA looked for a wide variety of different options to ensure diversity and comprehensiveness. TVA evaluated each option to determine its likely impact on the utility, its customers, and society. Delivery of technologies through a variety of program designs ensures that different customer needs are met.

Program Designs Used to Deliver Technologies and Meet Customer Objective Needs

Figure T7-2 lists the program designs or delivery mechanisms that were used to develop the customer service options and shows the customer objectives that can be satisfied by these program designs. Some program designs are more technology-specific, while others are designed to assist customers in identifying efficiency opportunities unique to their homes or businesses. These program designs provide value to the customer by making technologies more accessible to them and by overcoming obstacles that prevent customers from adopting energy efficiency measures on their own.

The obstacles to adopting energy-efficient technologies, often referred to as market barriers, can be classified into five types:

- Inadequate information
- Inconvenience and hassle
- Excessive risk
- Financial barriers
- Equipment availability

Figure T7-3 shows how different program designs can overcome the market barriers identified above. Some program designs are more technology-specific than others.

Programs such as the following can be used to overcome these market barriers:

Financing/Leasing. Financing is offered to utility customers or the utility owns the technology itself and leases it to customers.

Technical Assistance. Architectural and engineering firms, utility personnel, equipment vendors, or manufacturers assist customers with the new technologies.

Operating and Maintenance Assistance. Customers receive ongoing assistance in operating and maintaining equipment.

Rebates. Customers, equipment installers, or manufacturers receive monetary incentives for high-efficiency energy systems.

Direct Install. Customers receive high-efficiency equipment and direct installation at no charge or at reduced charge.

Audit. Customers are offered help to determine the most cost-effective energy efficiency options for their homes or businesses. Tools and information also may be given to facilitate a self-audit.

Mail Order. Catalogs are promoted as a source of appliances that are not widely available, in order to discount cost and provide information for customers. Catalogs are most appropriate for smaller, easily installed items. This program is particularly attractive for people in rural or remote areas and for the elderly.

Rates. Customers get a special electricity rate that encourages use of various equipment or influences energy use patterns.

Custom Programs. Customers receive site-specific assistance to identify and install energy efficiency measures or make changes that will save energy.

Shared Savings. Utilities provide financing and assistance in implementing an efficiency program and share the savings with the customer.

Market Transformation. Programs designed to increase the supply and demand of efficient technologies through manufacturer alliances, customer education, and establishment of new standards and building codes.

FIGURE T7-2. **Objectives Satisfied by Program Designs**

	PROGRAM OBJECTIVES					
Program Concepts	Minimum Rates	Low Cost	Large Impact	Diversity	Customer Service	Social Equity
Financing/Leasing	●			●	●	
Technical Assistance					●	
Assistance with O & M					●	
Rebates			●	●		●
Direct Install			●		●	●
Audit	●	●		●	●	
Mail Order		●	●			●
Rates	●	●		●		
Custom Programs			●	●	●	
Shared Savings	●	●		●	●	
Market Transformation			●			

Option Evaluation

DSMANAGER & MIDAS

All of the customer service options developed for consideration in Energy Vision 2020 have been evaluated to determine option benefits and costs. DSManager, Version 2.5, was used to develop and evaluate all the customer service options. DSManager is software developed by the Electric Power Research Institute (EPRI) to analyze demand-side management (DSM) programs. The information from DSManager was then fed into MIDAS (Multiobjective Integrated Decision Analysis System, software devel-

FIGURE T7-3. **Market Barriers Overcome by Program Designs**

	MARKET BARRIERS				
Program Designs	Information	Inconvenience & Hassle	Risk	Financial	Availability
Financing/Leasing		●	●	●	
Technical Assistance	●		●		
O & M Assistance	●	●	●		
Rebates			●	●	
Direct Install	●	●	●	●	●
Audit	●				
Mail Order	●	●	●	●	●
Rates				●	
Custom Programs	●		●	●	
Shared Savings			●	●	
Market Transformation	●	●			●

oped by EPRI) to integrate and evaluate both demand-side (customer service) and supply-side options.

Customer service options change the way that customers use energy. DSManager traces these changes to quantify the change in electricity used by the customer over time. DSManager calculates the monetary impact of customer service options using data that describe how these changes in electricity use affect customer costs, as well as detailed descriptions of the production costs and rates (prices) for energy. DSManager calculates the costs and benefits of the customer service options for end-use customers, distributors, and the TVA system.

Once the customer service options had been defined and evaluated using DSManager, their impact and cost data were transferred to MIDAS. MIDAS was used to study and compare the system load impacts and rate impacts of different resource options. MIDAS performs a variety of calculations, including load analysis, capacity planning, production costing, financial projections, and rate calculations. Although available from DSManager, the demand and energy impacts shown in this technical document are from MIDAS. MIDAS provides a more dynamic description of the power system and takes into account the interactions between options and other resources in determining option impacts. Also, the supply costs avoided by implementing customer service options are determined in MIDAS, based on the alternative resource options considered.

CUSTOMER SERVICE OPTION BLOCKS

The customer service options were grouped into four blocks to be combined with supply-side options to create resource strategies. Each block is approximately the size of a generating unit, between 1,000 megawatts and 1,500 megawatts. The different resource strategies were then analyzed at the integration level using MIDAS. The options were divided into the blocks shown below based on the following criteria: (1) option cost; (2) impact on rates; (3) customer value and competitiveness (e.g., long-term customer relationships); and (4) equity (i.e., whether customers have opportunities to participate in programs).

Options in Block 1 provide energy savings at the lowest average total resource cost (described in the next section) of any block, or 2.7 cents per kilowatt-hour. Block 1 also has a minimal impact on average rates or does not cause rates to increase. The average total resource cost of Block 2 options is 2.8 cents per kilowatt-hour, but Block 2 options have a greater impact on average rates than the Block 1 options. The average total resource cost of the options in Block 3 is 3.9 cents per kilowatt-hour and in Block 4 is 5.2 cents per kilowatt-hour. The peak demand savings potential in year 2010 from Blocks 1 and 2 represents 8.7 percent of the forecast summer peak demand, and energy savings constitute 6.3 percent of the total projected system sales in the same year. *Figure T7-4* shows how the customer service options are divided into the four blocks considered in Energy Vision 2020.

BENEFIT/COST TESTS

The outputs from DSManager and MIDAS can be expressed in the terms of the cost-effectiveness tests used to examine the relative benefits and costs of the customer service options from several perspectives. The standard cost-effectiveness tests (Participant Test, Rate Impact Measure Test, and Total Resource Cost Test) measure whether particular customer service options achieve their intended goals.

The Participant Test examines the benefits and costs of the options from the perspective of end-use customers participating in a customer service option. The Rate Impact Measure (RIM) Test takes the perspective of non-participants and quantifies the change in rates due to options. Thus, a program that passes the RIM Test will cause overall system rates to decrease. The Total Resource Cost (TRC) Test looks at options from the perspective of both participants and non-participants and measures the achievement of a goal of providing energy services at the lowest resource cost.

TVA also evaluated the customer service options using the Customer Value Test. This test combines both the RIM Test and the TRC Test, as well as other factors, such as external benefits, quality gains, and long-run rate impacts resulting from customer service options. The Customer Value Test allows comparison of both energy efficiency programs and programs designed to promote new beneficial uses of electricity with supply-side resource options. The results of all the cost-effectiveness tests were considered when options were placed in the blocks to be included in the different resource strategies in Energy Vision 2020.

Option Descriptions

For each of the customer service options, information documenting the program costs and impacts has been provided. There is a written description of each option, typically discussing the applicable target market, implementation strategy, incentive strategy, and the monitoring and evaluation approach to be used to verify program benefits and costs.

The descriptions are intended to give a feel for how an option would be implemented if it were chosen as a viable resource option in the Energy Vision 2020. The option descriptions are intended to identify the appropriate delivery mechanisms for the measures involved and also to quantify the costs and impacts of these measures. Once an option has been selected, a detailed

FIGURE T7-4. **Customer Service Option Blocks**

Block 1

Commercial Cool Storage
Rooftop Cool Storage
Commercial Group Load Curtailment
Residential Load Management—Air Conditioning
Residential Existing Load Management—Air Conditioning
Residential Existing Load Management—Water Heaters
Residential Heat Pump Leasing/Financing Program
Residential Efficiency Products Catalog
Industrial Technology Rebates—High-Efficiency Motors
Residential Lighting Products—Retail Component
Comprehensive Measure Financing
Residential Ground-Source Heat Pump Leasing

Block 2

Residential Self-Audit
Residential New Homes
Commercial Lighting Technology Rebates
Residential Low Income Program
Residential Load Management—Water Heaters
Commercial New Construction
Commercial Technology Rebates—Other
Refrigerator Turn-In
Residential Student Self-Audit
Small Commercial Retrofit

Block 3

Residential Load Management—SCADA
Comprehensive Measure Rebates
Industrial Process Energy Efficiency—Distributor Served
Industrial Process Energy Efficiency—Direct Served
Industrial Technology Rebates—Adjustable Speed Drives
"Opt-Out" or Energy-Efficient Rates
Residential Heat Pump Water Heating Leasing
Residential Direct Install
Commercial HVAC Technology Rebates
Residential Manufactured Housing Program

Block 4

Residential Load Management—New Technology
Commercial HVAC Maintenance Program
Residential Heat Pump Loans
Residential Efficient Air Conditioning
Residential Heat Pump Rebates
Residential Load Management—Storage Water Heaters
Industrial Technology Rebates—Compressed Air Efficiency
Residential Appliance Rebates Program
Residential Low Income Weatherization Program
Residential Solar Water Heater Program
Commercial New Construction—Renewables

program implementation plan must be developed before the program can commence. The detailed development of all DSM programs is done in cooperation with the power distributors, as is their implementation.

PROGRAM ASSUMPTIONS

The option descriptions are followed by the Program assumptions data. This data is divided into three sections. The top section provides some important facts about each option. The second section or table shows option participation by year. Finally, the third section shows program cost data. Each of the sections and variables contained within are discussed in more detail below.

Program Constants

Package Measure Life. This is the average life of the measures installed in a program. For programs with multiple measures, the life is a weighted average of the life of the constituent measures.

Free-Rider Rate. The percentage of customers who would have adopted recommended program actions even without its existence, but who also participate directly in the program (e.g., they do claim rebates).

Free-Driver Rate. The percentage of customers who take program recommended actions because of the program, but who do not participate directly in the program (e.g., they do not claim rebates).

Dropouts. The percentage of program participants who drop out before the equipment or measure in a particular program reaches the end of its life.

Take-Back Percentage. The percentage of a measure's energy savings taken back by the program participant. Energy savings in some end-use technologies will affect a participant's bill significantly enough to influence the participant's energy usage. For example, a weatherization program may lower homeowners' heating bills such that they adjust their thermostat to achieve a more comfortable temperature, thereby "taking back" some of the energy savings to increase comfort. This variable is used only for calculations involving the Customer Value Test.

Free-Rider Market Barrier Costs Eliminated. The percentage of transaction costs, hidden costs, or other market barrier costs eliminated from free riders in the program. This variable is used in Customer Value Test calculations.

Non-Free-Rider Market Barrier Costs Eliminated. The percentage of transaction costs, hidden costs, or other market barrier costs eliminated from program participants who are not free riders in the program. This variable is used in Customer Value Test calculations.

Annual Energy Impact (kWh). The change in average annual energy usage resulting from the measures installed in the program. For programs with multiple measures, the energy impact is a weighted average of all program measures. This value is utilized to scale overall program impacts. Load management programs may not have significant energy impacts relative to their demand impacts. For program analysis, an appropriate load shape (a unitized hourly electrical demand profile) was used to determine the hourly demand impacts corresponding to the annual energy impact.

Participation Data

Year. The option start date is flexible for the Energy Vision 2020 analysis so actual dates are not shown. Participation and costs are shown for the year of the program life. Up to 12 years of program data is shown regardless of the actual length of the program.

Annual Eligible Population. The number of eligible participants determined by the program target market (all customers or annual equipment failures), market segmentation (end use, building type, SIC code), and other factors including the percentage of distributors expected to participate in the program.

New Participants. The estimated number of new program participants by year. For different program sectors, the definition of participant varies. For the residential sector, one participant refers to one unit or one home. In the commercial sector, participation is measured by each thousand square-foot area. In the industrial sector, participation is measured in terms of each one million kilowatt-hours of electric usage.

Total Participants. The cumulative participation in the program from its first year, not accounting for free riders, free drivers, or dropouts.

Cumulative Participation Rate. The ratio of total program participants to cumulative eligible participation.

Cost Data

Fixed Administrative Cost. The program costs not directly proportional to the number of participants are shown in this column. Typical items would include some staff or contract labor costs, training costs, database or software development costs, program design costs, marketing and advertising costs, and monitoring and evaluation costs.

Variable Administrative Cost. The single value indicates the per participant variable administrative cost per participant, and the table shows the annual total for these costs for all participants. Typical items included are inspection fees, program paperwork costs, survey costs, technical assistance costs, billing fees, and financing initiation fees.

Participant Measure Cost. The incremental installed cost of the program measures. This cost is the incremental cost above the base or equivalent technology. The single value shows the cost per participant, and the table shows the annual totals for all participants in a given year. In many cases a portion of this cost will be offset by participant incentives, which are shown separately.

Participant Incentives. Any incentive provided to the participant is indicated here. The single value shows the incentive per participant, and the table shows the annual totals for all participants in a given year. Incentives include one-time rebates, equipment maintenance, price buy-downs arranged with wholesale equipment dealers, or installation of equipment free of charge for some programs.

OPTION-SPECIFIC CALCULATIONS

Following the basic program assumptions in the case of most options, there is an additional table of calculations or details pertinent to the option's costs or impacts. Most options promote more than one technology or measure. A mix of these measures is utilized to determine the average weighted impacts and costs for the measures. For the beneficial electrification options, the determination of the estimated quality gain is also provided.

Many of the values shown in the detailed option descriptions have been calculated. Due to rounding, some values may not be exactly reproduced using the numbers shown.

RESIDENTIAL ENERGY EFFICIENCY OPTIONS

SUMMARY OF PROJECTED IMPACTS IN YEAR 2010

Residential Energy Efficiency	Winter MW	Summer MW	Million kWh	Thousands of Units	TRC ¢/kWh
Heat Pump Loans	433	469	1,347	254	5.0
Heat Pump Leasing	581	518	1,688	266	1.6
Heat Pump Rebates	627	527	1,787	375	3.3
Ground-Source Heat Pump Leasing	58	62	179	26	8.1
Efficient Air Conditioning	0	133	233	124	7.6
New Homes	402	184	1,142	118	3.0
Manufactured Housing	164	53	358	131	4.4
Direct Install	845	386	2,399	1,163	2.3
Low Income	165	75	467	251	2.8
Low Income Weatherization	12	6	36	10	12.9
Heat Pump Water Heater Leasing	262	103	995	452	3.2
Solar Water Heater	11	4	41	15	22.1
Efficiency Products Catalog	234	107	665	714	1.4
Lighting Products Retail Component	225	103	639	687	2.5
Appliance Rebates	39	41	304	1,518	9.1
Refrigerator Turn-In & Recycling	10	13	93	91	3.5
Student Self-Audit	53	23	150	1,235	4.3
Self-Audit	42	19	120	102	2.6
Residential Load Management					**$/kW**
Load Management—Air Conditioners	0	53	21	39	58
Load Management—Water Heaters	212	84	0	158	55
Load Management—Storage Water Heaters	100	39	0	75	934
Load Management w/SCADA	0	0	0	67	140
Load Management—New Technology	0	0	0	276	2,039

Values are the impacts occuring only in the year 2010 for the cumulative participation in the program to that date.

TVA developed 23 residential options for evaluation in Energy Vision 2020 with applications for all major end uses of electricity and for all types of housing.

HEAT PUMP LOANS PROGRAM

Overview

The Heat Pump Loans Program promotes quality installations of higher efficiency heat pumps. The program provides financing for units that meet the minimum performance criteria. Incentives are provided for higher efficiency heat pumps. Weatherization measures can also be financed, if needed to meet minimum insulation and infiltration standards.

Target Market

All residential customers in participating power distributor areas

Implementation Strategy

The Heat Pump Loans Program is designed to promote quality installations of higher efficiency heat pumps. The program will continue the long-term financing effort already in place for heat pumps that meet a minimum SEER 12 performance criterion. In addition, cash or other financial incentives are proposed for dealers or consumers installing heat pumps that have SEERs higher than 12 and HSPFs higher than 7.5. Several levels of incentives will be offered, with greater incentives provided for units with greater performance efficiencies. To ensure optimal performance, a minimum attic insulation level of R-19 and infiltration reduction through weather-stripping and caulking are also included.

The program emphasizes the responsibility of the dealer to provide a quality installation. The Quality Contractor Network provides training for dealers, execution of post-inspection checklists, and awards for maintaining high installation standards. Standards will be established for all program installations to ensure the satisfaction of the consumer and the efficient operation of the system.

Incentives

- Financing of the heat pump and installation costs
- Financing of needed weatherization measures
- Rebates for high-efficiency heat pumps

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	15%
Free-Driver Rate	0%
Dropouts	2%
Take-Back Percentage	5%
Free-Rider Market Barrier Costs Eliminated	60%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	4,630

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	57,300	11,200	11,200	20%
2	58,200	12,600	23,800	21%
3	59,100	13,500	37,300	21%
4	60,100	14,500	51,800	22%
5	61,000	15,500	67,300	23%
6	62,000	16,600	83,900	23%
7	62,900	17,000	100,900	24%
8	63,800	17,200	118,100	24%
9	64,800	17,500	135,600	25%
10	65,700	17,700	153,300	25%
11	66,700	17,000	171,300	25%
12	67,600	18,300	189,600	25%

		Per Participant Variable Administrative Costs	Per Participant Measure Cost	Per Participant Incentive
		$324	$1,048	$0
Year	Fixed Administrative Cost	Total Variable Admin. Cost	Total Part. Measure Cost	Total Part. Incentive
1	$1,286,000	$3,628,800	$11,737,600	$0
2	$1,286,000	$4,082,400	$13,204,800	$0
3	$1,286,000	$4,374,000	$14,148,000	$0
4	$1,286,000	$4,689,000	$15,196,000	$0
5	$1,286,000	$5,022,000	$16,224,000	$0
6	$1,286,000	$5,378,400	$17,396,800	$0
7	$1,286,000	$5,508,000	$17,816,000	$0
8	$1,286,000	$5,572,800	$18,025,600	$0
9	$1,286,000	$5,670,000	$18,340,000	$0
10	$1,286,000	$5,734,800	$18,549,600	$0
11	$1,286,000	$5,832,000	$18,864,000	$0
12	$1,286,000	$5,929,200	$19,178,400	$0

Monitoring and Evaluation

Program impacts will be evaluated through pre- and post-billing analysis of homes that have not changed their level of insulation. Adjustment factors will be calculated for homes that have upgraded insulation as part of the program. Quality assurance inspections are performed for 100 percent of program installations. Inspections will verify appropriate equipment sizing, air flow and balance, and duct insulation and sealing.

Measure	Incremental Energy (kWh/yr)	Incremental Cost ($)	# /home	Weighted Energy (kWh/yr)	Weighted Cost ($)
Base ASHP10 to ASHP12	3,489	590	0.78	2,721	460
Base ASHP10 to ASHP14	6,989	708	0.14	978	99
Base ASHP10 to GSHP	5,035	2,250	0.08	403	180
Attic Insulation	683	650	0.40	273	260
Programmable Thermostat	637	122	0.40	255	49
			Total	**4,630**	**1,048**

#/home: Based on current program experience

HEAT PUMP LEASING/FINANCING PROGRAM

Overview

The Heat Pump Leasing Program allows for certain technologies to be selected by a customer and installed by the utility, with the customer paying a monthly "service charge" or loan payment on their electric bill. This program is designed to promote efficient electrical products where first cost is a significant barrier to customer participation. Additionally, this program simplifies maintenance and service of complicated equipment by moving the risk to the utility.

Target Market

This program targets residential customers who own or are purchasing their dwelling.

Implementation Strategy

The program works in conjunction with local equipment retailers as a financing program. The customer selects the contractor, eligible equipment, and contacts the utility for an installation inspection and to complete the necessary paperwork. Two payment options are offered. The first is a continual monthly charge with the utility maintaining ownership of the equipment and providing all necessary maintenance and repair of the equipment for as long as the customer is in the program. Early termination (before the customer has repaid his/her debt) requires the customer to settle for the remaining debt.

The second option is a larger monthly payment designed to pay back the debt. During the repayment period, the utility maintains and repairs the equipment free of charge. At the end of the repayment period, the customer can change to a maintenance/replacement contract payment if so desired.

The specified lease equipment must meet applicable SEER and HSPF efficiency levels. The heat pump installation will include an adaptive recovery programmable thermostat and must meet specific installation requirements.

Repair and replacement work will be performed by local contractors. A local phone number with answering service will be available 24 hours per day, 365 days per year. The customer is guaranteed replacement or repair within 48 hours of the call.

Incentives

A service contract will be provided for each heat pump.

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	15%
Free-Driver Rate	0%
Dropouts	2%
Take-Back Percentage	5%
Free-Rider Market Barrier Costs Eliminated	60%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	5,478

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	57,300	11,220	11,220	20%
2	58,200	12,600	23,820	21%
3	59,100	13,500	37,320	21%
4	60,100	14,500	51,800	22%
5	61,000	15,500	67,300	23%
6	62,000	16,600	83,900	23%
7	62,900	17,000	100,900	24%
8	63,800	17,200	118,100	24%
9	64,800	17,500	135,600	25%
10	65,700	17,700	153,300	25%
11	66,700	18,000	171,300	25%
12	67,600	18,300	189,600	25%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $125 Total Variable Admin. Cost	Per Participant Measure Cost $848 Total Part. Measure Cost	Per Participant Incentive $242 Total Part. Incentive
1	$750,000	$1,400,000	$9,497,600	$2,710,400
2	$700,000	$1,575,000	$10,684,800	$3,049,200
3	$700,000	$1,687,500	$11,448,000	$3,267,000
4	$700,000	$1,812,500	$12,296,000	$3,509,000
5	$700,000	$1,937,500	$13,114,000	$3,751,000
6	$700,000	$2,075,000	$14,076,800	$4,017,200
7	$700,000	$2,125,000	$14,416,000	$4,114,000
8	$700,000	$2,150,000	$14,585,600	$4,162,400
9	$700,000	$2,187,500	$14,840,000	$4,235,000
10	$700,000	$2,212,500	$15,009,600	$4,283,400
11	$700,000	$2,250,000	$15,264,000	$4,356,000
12	$700,000	$2,287,500	$15,518,400	$4,428,600

Monitoring and Evaluation

Some equipment monitoring is required for program analysis purposes. Inspections will be performed on 100 percent of program installations for QA purposes. HVAC inspections will verify appropriate equipment sizing, equipment charge, airflow and balance, and duct insulation and sealing. A complaint phone number also listed on the appliance will provide significant feedback on the equipment and its timely repair.

Measure	Incremental Energy (kWh/yr)	Incremental Cost ($)	# /home	Weighted Energy (kWh/yr)	Weighted Cost ($)
Base ASHP 10 to ASHP 12	3,489	590	0.75	2,617	443
Base ASHP 10 to ASHP 14	6,989	708	0.25	1,747	177
Programmable Thermostat	637	122	1.00	637	122
Maintain ASHP	477	106	1.00	477	106
			Total	**5,478**	**848**

HEAT PUMP REBATES PROGRAM

Overview

The Heat Pump Rebates Program will promote efficient heat pumps using rebates and point-of-sale displays. The rebate structure is tiered corresponding to equipment efficiency levels and is designed to offset the majority of the incremental cost of the more efficient heat pumps. This program would be implemented in cooperation with heat pump manufacturers, distributors, dealers, and installers to promote the rebates to all applicable customers. Contractor/dealer training would be provided to increase understanding of the benefits and fuel cost savings for the more efficient equipment, as well as proper installation and maintenance practices.

Target Market

The program targets the two-thirds of residential heat pumps that are not installed through the TVA Heat Pump Loan Program.

Implementation Strategy

Rebate coupons, point-of-sale displays, and appliance labeling are utilized to promote efficient appliances. Utility representatives will work with manufacturers, dealers, and contractors to distribute displays and coupons. Additionally, coupons will be distributed through other compatible DSM programs, power distributor offices, and upon phone request.

Incentives

Rebate coupons will be provided.

Monitoring and Evaluation

Rebate coupons will provide initial information on replacement and usage patterns. A database will be completed from returned rebate coupons. Follow-up surveys of equipment installed and usage patterns will be conducted.

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	25%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	20%
Free-Rider Market Barrier Costs Eliminated	50%
Non-Free-Rider Market Barrier Costs Eliminated	30%
Annual Energy Impact (kWh)	4,103

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	36,600	5,500	5,500	15%
2	38,400	7,700	13,200	18%
3	40,400	10,100	23,300	20%
4	42,400	14,800	38,100	24%
5	44,500	20,000	58,100	29%
6	46,700	23,400	81,500	33%
7	49,100	24,500	106,000	36%
8	51,500	25,800	131,800	38%
9	54,100	27,000	158,800	39%
10	56,800	28,400	187,200	41%
11	59,600	29,800	217,000	42%
12	62,600	31,300	248,300	43%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $25 Total Variable Admin. Cost	Per Participant Measure Cost $739 Total Part. Measure Cost	Per Participant Incentive $568 Total Part. Incentive
1	$1,500,000	$137,500	$4,064,500	$3,124,000
2	$1,200,000	$192,500	$5,690,300	$4,373,600
3	$1,200,000	$252,500	$7,463,900	$5,736,800
4	$1,200,000	$370,000	$10,937,200	$8,406,400
5	$1,200,000	$500,000	$14,780,000	$11,360,000
6	$1,200,000	$585,000	$17,292,600	$13,291,200
7	$1,200,000	$612,500	$18,105,500	$13,916,000
8	$1,200,000	$645,000	$19,066,200	$14,654,400
9	$1,200,000	$675,000	$19,953,000	$15,336,000
10	$1,200,000	$710,000	$20,987,600	$16,131,200
11	$1,200,000	$745,000	$22,022,200	$16,926,400
12	$1,200,000	$782,500	$23,130,700	$17,778,400

GROUND SOURCE HEAT PUMP LEASING PROGRAM

Overview

The Ground Source Heat Pump Leasing Program allows for certain technologies to be selected by a customer and installed by the utility, with the customer paying a monthly "service charge" on his/her electric bill. This program is designed to promote ground source heat pumps, for which initial cost is a significant barrier to customer participation. Additionally, this program simplifies maintenance and service of complicated equipment by moving the risk to the utility.

Target Market

This program targets residential customers who own or are purchasing their dwelling.

Implementation Strategy

The program works in conjunction with local equipment retailers similar to a financing program. The customer selects the contractor, eligible equipment, and contacts the utility for an installation inspection and to complete the necessary paperwork. Two payment options are offered. The first is a continual monthly charge with the utility maintaining ownership of the equipment and providing all necessary maintenance and repair of the equipment for as long as the customer is in the program. Early termination (before the customer has repaid his/her debt) requires the customer to settle for the remaining debt.

The second option is a larger monthly payment designed to pay back the debt. Once the debt has been fully repaid, ownership of the equipment is transferred to the homeowner. During the repayment period, the utility maintains and repairs the equipment free of charge. At the end of the repayment period, the customer can change to a maintenance/replacement contract payment if so desired.

The specified lease equipment must meet applicable SEER and HSPF efficiency levels. The heat pump installation will include an adaptive recovery programmable thermostat, and must meet specific installation requirements.

Repair and replacement work will be performed by local contractors. A local phone number with answering service will be available 24 hours per day, 365 days per year. The customer is guaranteed replacement or repair within 48 hours of the call.

Incentives

A service contract will be provided for each ground source heat pump.

Monitoring and Evaluation

Some equipment monitoring is required for program analysis purposes. Inspections will be performed for 100 percent of program installations for QA purposes. The heat pump inspection will verify appropriate equipment sizing, equipment charge, air flow and balance, and duct insulation and sealing. A complaint phone number also listed on the appliance will provide significant feedback on the equipment and its timely repair.

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	1%
Free-Driver Rate	0%
Dropouts	2%
Take-Back Percentage	5%
Free-Rider Market Barrier Costs Eliminated	40%
Non-Free-Rider Market Barrier Costs Eliminated	50%
Annual Energy Impact (kWh)	6,046

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	79,700	100	100	0%
2	79,700	200	300	0%
3	79,700	300	600	0%
4	79,700	400	1,000	0%
5	79,700	500	1,500	0%
6	79,700	700	2,200	0%
7	79,700	800	3,000	1%
8	79,700	1,000	4,000	1%
9	79,700	1,200	5,200	1%
10	79,700	1,400	6,600	1%
11	79,700	1,500	8,100	1%
12	79,700	1,700	9,800	1%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $75 Total Variable Admin. Cost	Per Participant Measure Cost $2,250 Total Part. Measure Cost	Per Participant Incentive $242 Total Part. Incentive
1	$300,000	$7,500	$225,000	$24,200
2	$200,000	$15,000	$450,000	$48,400
3	$150,000	$22,500	$675,000	$72,600
4	$150,000	$30,000	$900,000	$96,800
5	$150,000	$37,500	$1,125,000	$121,000
6	$150,000	$52,500	$1,575,000	$169,400
7	$150,000	$60,000	$1,800,000	$193,600
8	$150,000	$75,000	$2,250,000	$242,000
9	$150,000	$90,000	$2,700,000	$290,400
10	$150,000	$105,000	$3,150,000	$338,800
11	$150,000	$112,500	$3,375,000	$363,000
12	$150,000	$127,500	$3,825,000	$411,400

EFFICIENT AIR CONDITIONING PROGRAM

Overview

This program will promote efficient central air conditioners using rebates. Utility representatives will work with HVAC contractors, HVAC distributors, and trade associations to promote applicable appliances and to distribute displays and coupons.

Target Market

All residential customers with central air conditioning in participating power distributor areas are targeted.

Implementation Strategy

Rebate coupons, point-of-sale displays, and appliance labeling are utilized to promote efficient appliances. Utility representatives will work with HVAC contractors, HVAC distributors, and trade associations to promote applicable appliances and to distribute displays and coupons. Additionally, coupons will be distributed through other compatible DSM programs, power distributor offices, and upon phone request.

Incentives

Rebate coupons will be provided.

Monitoring and Evaluation

Program impacts will be evaluated through pre- and post-billing analysis. Quality assurance inspections are performed for approximately 10 percent of program installations, with emphasis on new dealers and problem dealers. Inspections will verify appropriate equipment sizing, air flow and balance, and duct insulation and sealing.

Rebate coupons will provide initial information on replacement and usage patterns. A database will be completed from returned rebate coupons. Follow-up surveys of equipment installed and usage patterns will be conducted.

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	15%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	20%
Free-Rider Market Barrier Costs Eliminated	50%
Non-Free-Rider Market Barrier Costs Eliminated	30%
Annual Energy Impact (kWh)	1,632

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	19,300	2,900	2,900	15%
2	19,300	3,900	6,800	18%
3	19,300	4,800	11,600	20%
4	19,300	5,800	17,400	23%
5	19,300	6,700	24,100	25%
6	19,300	7,700	31,800	28%
7	19,300	8,700	40,500	30%
8	19,300	9,600	50,100	33%
9	19,300	9,600	59,700	34%
10	19,300	9,600	69,300	36%
11	19,300	9,600	78,900	37%
12	19,300	9,600	88,500	38%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $25 Total Variable Admin. Cost	Per Participant Measure Cost $708 Total Part. Measure Cost	Per Participant Incentive $500 Total Part. Incentive
1	$700,000	$72,500	$2,053,200	$1,450,000
2	$500,000	$97,500	$2,761,200	$1,950,000
3	$500,000	$120,000	$3,398,400	$2,400,000
4	$500,000	$145,000	$4,106,400	$2,900,000
5	$500,000	$167,500	$4,743,600	$3,350,000
6	$500,000	$192,500	$5,451,600	$3,850,000
7	$500,000	$217,500	$6,159,600	$4,350,000
8	$500,000	$240,000	$6,796,800	$4,800,000
9	$500,000	$240,000	$6,796,800	$4,800,000
10	$500,000	$240,000	$6,796,800	$4,800,000
11	$500,000	$240,000	$6,796,800	$4,800,000
12	$500,000	$240,000	$6,796,800	$4,800,000

NEW HOMES PROGRAM

Overview

The New Homes Program promotes higher efficiency standards and quality construction in new homes. Incentives are provided for homebuilders who meet the weatherization and equipment efficiency requirements of a basic package, with additional incentives for specific thermal envelope and equipment upgrades beyond the basic package.

Target Market

This program targets homebuyers in participating power distributor areas.

Implementation Strategy

The New Homes Program will promote higher efficiency standards and quality construction in new homes. Incentives are proposed for homebuilders who meet the weatherization and equipment efficiency requirements of a basic package, and additional incentives will be available for specific thermal envelope and equipment upgrades beyond the levels of the basic package. The thermal performance requirements of the basic package will exceed the standards of the Model Energy Code. The proposed minimum performance requirements for equipment are SEER 12/HSPF 7.5 or SEER 12/AFUE 90. Trade-offs will be allowed for some measures.

The program will provide training for homebuilders and trade allies to ensure the proper installation of efficiency measures. Technical requirements with an emphasis on quality installation should produce significant improvement in the energy efficiency of new homes.

The program will emphasize the responsibility of the dealer to provide a quality installation. A Quality Contractor Network provides training for dealers, execution of post-inspection checklists, and awards for maintaining high installation standards. Standards will be established for all program installations to ensure the satisfaction of the consumer and the proper operation of the system. Inspections during the building process will ensure adherence to program standards.

Incentives

- Builder incentives are provided for meeting the base program standards.
- Builder incentives are provided for additional measures that exceed the base standard.

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	15%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	5%
Free-Rider Market Barrier Costs Eliminated	60%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	4,187

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	17,500	3,000	3,000	17%
2	17,500	3,800	6,800	19%
3	17,500	5,000	11,800	22%
4	17,500	6,000	17,800	25%
5	17,500	7,200	25,000	29%
6	17,500	8,600	33,600	32%
7	17,500	8,800	42,400	35%
8	17,500	8,800	51,200	37%
9	17,500	8,800	60,000	38%
10	17,500	8,800	68,800	39%
11	17,500	8,800	77,600	40%
12	17,500	8,800	86,400	41%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $25 Total Variable Admin. Cost	Per Participant Measure Cost $627 Total Part. Measure Cost	Per Participant Incentive $723 Total Part. Incentive
1	$1,070,000	$75,000	$1,881,000	$2,169,000
2	$1,070,000	$95,000	$2,382,600	$2,747,400
3	$1,070,000	$125,000	$3,135,000	$3,615,000
4	$1,070,000	$150,000	$3,762,000	$4,338,000
5	$1,070,000	$180,000	$4,514,400	$5,205,600
6	$1,070,000	$215,000	$5,392,200	$6,217,800
7	$1,070,000	$220,000	$5,517,600	$6,362,400
8	$1,070,000	$220,000	$5,517,600	$6,362,400
9	$1,070,000	$220,000	$5,517,600	$6,362,400
10	$1,070,000	$220,000	$5,517,600	$6,362,400
11	$1,070,000	$220,000	$5,517,600	$6,362,400
12	$1,070,000	$220,000	$5,517,600	$6,362,400

Monitoring and Evaluation

For impact evaluation estimates, state energy codes will be assumed as the baseline for new construction. Prototype simulation models will be developed to determine the impacts of both the base package and the additional measures package. Additionally, billing analysis will be performed on a sample of participants for comparison with non-participating homes. QA inspections are performed to verify measures in 10 percent of program homes.

Measure	Incremental Energy (kWh/yr)	Incremental Cost ($)	Incentive ($)	# /home	Weighted Energy (kWh/yr)	Weighted Cost ($)	Weighted Incentive ($)
Compact Fluorescent Light	57	13	3	8.00	456	102	20
DHW Pipe Insulation	78	20	—	1.00	78	20	—
Programmable Thermostat	1,057	122	31	0.25	264	31	7
Ceiling Insulation—New	1,995	266	640	1.00	1,995	266	640
Bottom Board	75	3	3	1.00	75	3	3
Low Flow Showerhead	271	20	—	2.50	677	50	—
Base ASHP 12 to ASHP 14	3,500	118	63	0.14	490	17	9
Base ASHP 12 to GSHP	1,546	1,660	500	0.08	124	133	40
Efficient Dishwasher	111	20	15	0.25	28	5	4
				Total	**4,187**	**626**	**723**

MANUFACTURED HOUSING – NEW CONSTRUCTION PROGRAM

Overview

This program will promote the installation of efficient HVAC and water heating equipment by the manufacturer during the construction process. The program also promotes improved methods of connecting and sealing ductwork when the home is readied for occupancy. New HUD standards have increased the building shell requirements to optimal cost-effective levels for new construction, so the program will not address them. This program is simiilar to TVA's Energy Efficient New Manufactured Home Plan.

Target Market

Buyers of residential new construction manufactured housing including single- and double-wide mobile homes, as well as slab-sited pre-manufactured housing are targeted.

Implementation Strategy

TVA will work with stakeholders in the manufactured housing industry to ensure comprehensive coverage of the market. For manufacturers, training classes will explain the benefits of heat pumps and proper installation practices for water heaters and HVAC systems, including pipe insulation and ductwork.

Dealers will receive information, promotional materials, and financial incentives to promote the use of heat pumps in homes. Customer education materials will detail the energy and economic benefits of heat pumps and other retrofit measures, including insulated skirting. Additional educational materials including lesson plans and handouts will be provided to high school teachers in areas of high manufactured housing growth.

Related efforts for this program include lobbying lenders to consider the implications of lower utility bills from heat pumps on the financing process. Additionally, participating power distributors will be encouraged to waive or reduce hook-up charges for program housing as an additional participation incentive.

Incentives

The cost of pipe insulation in the water heater compartment and reduced duct leakage measures are paid by TVA. Four compact fluorescent light bulbs are installed in each program home. Seventeen percent of the estimated cost of the heat pump will be paid to the manufacturer. Dealers will be paid $100 for each qualifying home sold, and an additional $150 will be provided for up to two homes ordered for stock on the dealer's lots.

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	5%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	5%
Free-Rider Market Barrier Costs Eliminated	70%
Non-Free-Rider Market Barrier Costs Eliminated	90%
Annual Energy Impact (kWh)	2,366

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	8,000	2,400	2,400	30%
2	8,200	4,900	7,300	45%
3	8,300	7,500	14,800	60%
4	8,500	8,100	22,900	69%
5	8,700	8,200	31,100	75%
6	8,800	8,400	39,500	78%
7	9,000	8,600	48,100	81%
8	9,200	8,700	56,800	83%
9	9,400	8,900	65,700	84%
10	9,600	9,100	74,800	85%
11	9,800	9,300	84,100	86%
12	9,900	9,400	93,500	87%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $20 Total Variable Admin. Cost	Per Participant Measure Cost $615 Total Part. Measure Cost	Per Participant Incentive $381 Total Part. Incentive
1	$575,000	$48,000	$1,476,000	$914,400
2	$500,000	$98,000	$3,013,500	$1,866,900
3	$500,000	$150,000	$4,612,500	$2,857,500
4	$500,000	$162,000	$4,981,500	$3,086,100
5	$500,000	$164,000	$5,043,000	$3,124,200
6	$500,000	$168,000	$5,166,000	$3,200,400
7	$500,000	$172,000	$5,289,000	$3,276,600
8	$500,000	$174,000	$5,350,500	$3,314,700
9	$500,000	$178,000	$5,473,500	$3,390,900
10	$500,000	$182,000	$5,596,500	$3,467,100
11	$500,000	$186,000	$5,719,500	$3,543,300
12	$500,000	$188,000	$5,781,000	$3,581,400

Monitoring and Evaluation

A database will be developed to track the incentives paid to manufacturers and dealers; another will contain information on customers buying program homes. Program impacts will be estimated with engineering calculations representing average savings per home. The engineering assumptions will be compared and calibrated to monitored field data after the first year of the program. A process evaluation will also be conducted after the first year of the program to improve the administrative processes and customer, dealer, and manufacturer satisfaction.

Approximately 25 percent of heat pumps installed will be inspected, with particular focus on new manufacturers.

Measure	Incremental Energy (kWh/yr)	Incremental Cost ($)	Incentive ($)	# /home	Weighted Energy (kWh/yr)	Weighted Cost ($)	Weighted Incentive ($)
Compact Fluorescent Light	57	13	13	4.00	228	51	51
DHW Pipe Insulation	78	8	8	1.00	78	8	8
Reduced Duct Leakage	1,905	275	275	1.00	1,905	275	275
High Efficiency Heat Pump	2,133	4,865	811	0.03	64	146	24
Insider Heat Pump	1,517	2,250	375	0.06	91	135	23
				Total	**2,366**	**615**	**381**

DIRECT INSTALL PROGRAM—SITE VISIT

Overview

This is a direct install program. A neighborhood is targeted and a contractor goes door-to-door. In a single visit, installation crews install energy efficient lighting, attic insulation, water heater tank wraps, pipe insulation, faucet aerators, low-flow shower heads, caulking, and clean equipment coils and filters.

Target Market

This program targets all residential customers in selected neighborhoods.

Implementation Strategy

All residents in a neighborhood, including single-family homes and individually metered multi-family homes are eligible to participate. The installation crew will spend from one to two weeks in a target neighborhood, depending on the size of the area. Initial contact is made through a postcard or brochure mailed to each home. A canvasser will precede the crews, going door-to-door to make installation appointments, if possible on the same day. Installers will be radio-dispatched to the appointment. Advertisements on the installation crews' program vans will also promote the program.

One crew member will perform a quick site survey and provide a computerized printout of recommended improvements to the homeowner. The installation crew then installs appropriate measures and performs a walk-through with the customer to explain what they have done and how this benefits the customer. This educational portion of the program is extremely important in ensuring energy savings.

TVA and its distributors will work with community-based organizations to coordinate the program. Neighborhood and community groups will be recruited to assist in advertising the program.

Incentives

The measures are provided and installed free of charge.

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	20%
Free-Driver Rate	0%
Dropouts	2%
Take-Back Percentage	10%
Free-Rider Market Barrier Costs Eliminated	70%
Non-Free-Rider Market Barrier Costs Eliminated	90%
Annual Energy Impact (kWh)	1,803

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	2,510,000	25,100	25,100	1%
2	2,513,900	75,400	100,500	4%
3	2,467,500	123,400	223,900	9%
4	2,373,100	142,400	366,300	15%
5	2,259,700	135,600	501,900	20%
6	2,153,100	129,200	631,100	25%
7	2,053,000	123,200	754,300	30%
8	1,958,800	117,500	871,800	35%
9	1,870,200	112,200	984,000	39%
10	1,787,000	89,400	1,073,400	43%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $40 Total Variable Admin. Cost	Per Participant Measure Cost $295 Total Part. Measure Cost	Per Participant Incentive $295 Total Part. Incentive
1	$1,650,000	$1,004,000	$7,404,500	$7,404,500
2	$1,550,000	$3,016,000	$22,243,000	$22,243,000
3	$1,300,000	$4,936,000	$36,403,000	$36,403,000
4	$1,300,000	$5,696,000	$42,008,000	$42,008,000
5	$1,300,000	$5,424,000	$40,002,000	$40,002,000
6	$1,300,000	$5,168,000	$38,114,000	$38,114,000
7	$1,300,000	$4,928,000	$36,344,000	$36,344,000
8	$1,300,000	$4,700,000	$34,662,500	$34,662,500
9	$1,300,000	$4,488,000	$33,099,000	$33,099,000
10	$1,300,000	$3,576,000	$26,373,000	$26,373,000

Monitoring and Evaluation

Engineering estimates calibrated with information on hours of use and consumption patterns gathered for each participant will be used to estimate program savings. Spot inspections will be done on homes receiving attic insulation.

Measure	Incremental Energy (kWh/yr)	Incremental Cost ($)	# /home	Weighted Energy (kWh/yr)	Weighted Cost ($)
Compact Fluorescent Light	57	13	6.00	342	77
DHW Pipe Insulation	78	20	1.00	78	20
DHW Tank Wrap	271	35	0.50	136	18
Attic Insulation R0-R30 ASHP	2,042	590	0.03	61	17
Attic Insulation R0-R30 ER/AC	2,544	590	0.04	110	25
Attic Insulation R11-R30 ASHP	1,480	393	0.04	65	17
Attic Insulation R11-R30 ER/AC	1,842	393	0.06	117	25
Low Flow Showerhead/Aerator	271	20	2.50	678	50
Maintain ASHP	477	106	0.18	84	19
Maintain ER/AC	520	106	0.25	132	27
			Total	**1,803**	**295**

#/home: in some cases reflects market share
Homes will receive all applicable measures

LOW INCOME PROGRAM—SITE VISIT

Overview

This is a direct install program for targeted low-income neighborhoods. The program uses a contractor to perform the site visits. The installation crew, in a single visit, installs energy efficient lighting, attic insulation, water heater tank wraps, pipe insulation, faucet aerators, low-flow shower heads, caulking, and cleans equipment coils and filters.

Target Market

This program targets residential low-income customers.

Implementation Strategy

All residents in a neighborhood, including single-family homes and individually metered multi-family homes, are eligible to participate. The installation crew will spend from one to two weeks in a target neighborhood, depending on the size of the area. Initial contact is made through a postcard or brochure mailed to each home. A canvasser will precede the crews, going door-to-door to make installation appointments, if possible on the same day. Installers will be radio-dispatched to the appointment. Advertisements on the installation crews' program vans will also promote the program.

One crew member will perform a quick site survey and provide a computerized printout of recommended improvements to the homeowner. Most of the program measures will be cost-effective for almost every home. The installation crew then installs appropriate measures and performs a walk-through with the customer to explain what they have done and how this benefits the customer. This educational portion of the program is extremely important in ensuring energy savings.

TVA and its distributors will work with community-based organizations to coordinate the program. This program can leverage federal low income weatherization efforts, as well as state and local low income programs, to increase the energy efficiency services provided to these customers. Neighborhood and community groups will be recruited to assist in advertising the program, and program displays will be provided for community centers.

Incentives

The measures are provided and installed free of charge.

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	5%
Free-Driver Rate	0%
Dropouts	2%
Take-Back Percentage	15%
Free-Rider Market Barrier Costs Eliminated	70%
Non-Free-Rider Market Barrier Costs Eliminated	90%
Annual Energy Impact (kWh)	1,638

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	475,000	4800	4,800	1%
2	475,900	14,300	19,100	4%
3	467,200	23,400	42,500	9%
4	449,400	27,000	69,500	15%
5	428,100	25,700	95,200	20%
6	408,000	24,500	119,700	25%
7	389,100	23,300	143,000	30%
8	371,300	22,300	165,300	35%
9	354,700	21,300	186,600	39%
10	339,000	16,900	203,500	43%
11	327,600	16,400	219,900	46%
12	316,900	15,800	235,700	50%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $40 Total Variable Admin. Cost	Per Participant Measure Cost $304 Total Part. Measure Cost	Per Participant Incentive $304 Total Part. Incentive
1	$300,000	$192,000	$1,459,200	$1,459,200
2	$250,000	$572,000	$4,347,200	$4,347,200
3	$250,000	$936,000	$7,113,600	$7,113,600
4	$250,000	$1,080,000	$8,208,000	$8,208,000
5	$250,000	$1,028,000	$7,812,800	$7,812,800
6	$250,000	$980,000	$7,448,000	$7,448,000
7	$250,000	$932,000	$7,083,200	$7,083,200
8	$250,000	$892,000	$6,779,200	$6,779,200
9	$250,000	$852,000	$6,475,200	$6,475,200
10	$250,000	$676,000	$5,137,600	$5,137,600
11	$250,000	$656,000	$4,985,600	$4,985,600
12	$250,000	$632,000	$4,803,200	$4,803,200

Monitoring and Evaluation

Engineering estimates calibrated with information on hours of use and consumption patterns gathered for each participant will be used to estimate program savings. Spot inspections will be done on homes receiving attic insulation.

Measure	Incremental Energy (kWh/yr)	Incremental Cost ($)	# /home	Weighted Energy (kWh/yr)	Weighted Cost ($)
Compact Fluorescent Light	57	13	4.00	228	51
DHW Pipe Insulation	78	20	1.00	78	20
DHW Tank Wrap	271	35	0.50	136	18
Attic Insulation R0-R30 ASHP	2,042	590	0.06	119	34
Attic Insulation R0-R30 ER/AC	2,544	590	0.08	213	49
Attic Insulation R11-R30 ASHP	1,480	393	0.06	86	23
Attic Insulation R11-R30 ER/AC	1,842	393	0.08	155	33
Low Flow Showerhead	271	20	1.50	407	30
Maintain ASHP	477	106	0.18	84	19
Maintain ER/AC	520	106	0.25	132	27
			Total	**1,638**	**304**

#/home: in some cases reflects market share
Homes will receive all applicable measures

LOW INCOME WEATHERIZATION PROGRAM

Overview

This program complements the Low Income Program by providing for more extensive home repairs identified during the direct install site visit. The program is coordinated with state and local agencies to leverage existing low income efforts.

Target Market

This program targets residential low-income customers.

Implementation Strategy

During the Low Income Program site survey, homes needing significant improvements are identified. These homes may need insulation, infiltration reduction or significant HVAC equipment improvements. The necessary measures will be provided and installed free of charge. The weatherized structure will provide a more comfortable living space for tenants, and will increase property value and lower electric bills as a result of the efficiency improvements.

TVA and its distributors will work with community-based organizations to coordinate the program. This program can leverage federal low income weatherization efforts, as well as state and local low income programs, to increase the energy efficiency services provided to these customers. Neighborhood and community groups will be recruited to assist in advertising the program, and program displays will be provided in community centers.

Incentives

The measures are provided and installed free of charge.

Monitoring and Evaluation

Both engineering estimates calibrated with information on hours of use and consumption patterns gathered for each participant will be used to estimate program savings. Spot inspections will be done on homes receiving attic insulation.

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	5%
Free-Driver Rate	0%
Dropouts	2%
Take-Back Percentage	25%
Free-Rider Market Barrier Costs Eliminated	70%
Non-Free-Rider Market Barrier Costs Eliminated	90%
Annual Energy Impact (kWh)	3,100

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	356,300	400	400	0%
2	360,200	700	1,100	0%
3	363,800	1,000	2,100	1%
4	367,300	1,000	3,100	1%
5	370,700	1,000	4,100	1%
6	374,200	1,000	5,100	1%
7	377,600	1,000	6,100	2%
8	381,100	1,000	7,100	2%
9	384,500	1,000	8,100	2%
10	388,000	1,000	9,100	3%
11	391,400	1,000	10,100	3%
12	394,900	1,000	11,100	3%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $1,000 Total Variable Admin. Cost	Per Participant Measure Cost $2,000 Total Part. Measure Cost	Per Participant Incentive $2,000 Total Part. Incentive
1	$300,000	$400,000	$800,000	$800,000
2	$250,000	$700,000	$1,400,000	$1,400,000
3	$250,000	$1,000,000	$2,000,000	$2,000,000
4	$250,000	$1,000,000	$2,000,000	$2,000,000
5	$250,000	$1,000,000	$2,000,000	$2,000,000
6	$250,000	$1,000,000	$2,000,000	$2,000,000
7	$250,000	$1,000,000	$2,000,000	$2,000,000
8	$250,000	$1,000,000	$2,000,000	$2,000,000
9	$250,000	$1,000,000	$2,000,000	$2,000,000
10	$250,000	$1,000,000	$2,000,000	$2,000,000
11	$250,000	$1,000,000	$2,000,000	$2,000,000
12	$250,000	$1,000,000	$2,000,000	$2,000,000

HEAT PUMP WATER HEATER LEASING PROGRAM

Overview

The Heat Pump Water Heater Leasing Program allows for a qualified heat pump water heater to be selected by a customer and installed by the utility, with the customer paying a monthly "service charge" on his electric bill. This program is designed to promote efficient heat pump water heaters which have an initial cost that is a significant barrier to customer participation. Additionally, this program simplifies the maintenance and service of complicated equipment by moving the risk to the utility.

Target Market

This program targets residential customers who own or are purchasing their dwelling.

Implementation Strategy

The program works in conjunction with local equipment retailers similar to a financing program. The customer selects the contractor and appropriate equipment and contacts the utility for an installation inspection and to complete the necessary paperwork. Two payment options are offered. The first is a continual monthly charge with the utility maintaining ownership of the equipment and providing all necessary maintenance and repair of the equipment for as long as the customer is in the program. Early termination (before the customer has repaid the debt) requires the customer to settle for the remaining debt.

The second option is a larger monthly payment designed to pay back the debt. Once the debt has been repaid, ownership of the equipment is transferred to the homeowner. During the repayment period, the utility maintains and repairs the equipment free of charge. At the end of the repayment period, the customer can change to a maintenance/replacement contract payment if so desired.

The specified lease equipment must meet minimum Energy Factor (EF) levels.

Repair and replacement work will be performed by local contractors. A local phone number with answering service will be available 24 hours per day, 365 days per year. The customer is guaranteed replacement or repair within 48 hours of the call.

Incentives

A service contract will be provided for each heat pump water heater.

Monitoring and Evaluation

Some equipment monitoring is required for program analysis purposes. Inspections will be performed for 100 percent of program installations for QA purposes. Inspections will verify appropriate equipment sizing, equipment charge, air flow, and location. A complaint phone number also listed on the appliance will provide significant feedback on the equipment and its timely repair.

Program Assumptions

Package Measure Life (Years)	10
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	2%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	40%
Non-Free-Rider Market Barrier Costs Eliminated	50%
Annual Energy Impact (kWh)	1,990

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	198,000	9,900	9,900	5%
2	198,000	19,800	29,700	8%
3	198,000	29,700	59,400	10%
4	198,000	33,700	93,100	12%
5	198,000	37,600	130,700	13%
6	198,000	41,600	172,300	15%
7	198,000	43,600	215,900	16%
8	198,000	44,600	260,500	16%
9	198,000	45,500	306,000	17%
10	198,000	45,500	351,500	18%
11	198,000	45,500	397,000	18%
12	198,000	45,500	442,500	19%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $10 Total Variable Admin. Cost	Per Participant Measure Cost $500 Total Part. Measure Cost	Per Participant Incentive $192 Total Part. Incentive
1	$850,000	$99,000	$4,950,000	$1,900,800
2	$800,000	$198,000	$9,900,000	$3,801,600
3	$800,000	$297,000	$14,850,000	$5,702,400
4	$800,000	$337,000	$16,850,000	$6,470,400
5	$800,000	$376,000	$18,800,000	$7,219,200
6	$800,000	$416,000	$20,800,000	$7,987,200
7	$800,000	$436,000	$21,800,000	$8,371,200
8	$800,000	$446,000	$22,300,000	$8,563,200
9	$800,000	$455,000	$22,750,000	$8,736,000
10	$800,000	$455,000	$22,750,000	$8,736,000
11	$800,000	$455,000	$22,750,000	$8,736,000
12	$800,000	$455,000	$22,750,000	$8,736,000

SOLAR WATER HEATER PROGRAM

Overview

This program will promote solar water heaters through the use of a significant upfront rebate and an equipment lease. The lease includes a maintenance contract for the equipment. These incentives are designed to offset two significant market barriers to solar water heating: initial cost and maintenance.

Target Market

All residential customers in participating power distributor areas are targeted.

Implementation Strategy

The program works in conjunction with local equipment retailers similar to a financing program. The customer selects the contractor and appropriate equipment and contacts the utility for an installation inspection and to complete the necessary paperwork. Two payment options are offered. The first is a continual monthly charge with the utility maintaining ownership of the equipment and providing all necessary maintenance and repair of the equipment for as long as the customer is in the program. Early termination (before the customer the repaid his debt) requires the customer to settle for the remaining debt.

The second option is a larger monthly payment designed to pay back the debt. Once the debt has been repaid, ownership of the equipment is transferred to the homeowner. During the repayment period, the utility maintains and repairs the equipment free of charge. At the end of the repayment period, the customer can change to a maintenance/replacement contract payment if so desired.

Repair and replacement work will be performed by local contractors. A local phone number with answering service will be available 24 hours per day, 365 days per year. The customer is guaranteed replacement or repair within 48 hours of the call.

Incentives

- First cost buy-down will be offered.
- Equipment maintenance will be provided.

Monitoring and Evaluation

Program impacts will be evaluated through pre- and post-billing analysis of program homes. Quality assurance inspections are performed for approximately 25 percent of program installations, with emphasis on new installers and problem installers. Inspections will verify appropriate equipment sizing, orientation, tank and pipe insulation, controls, and freeze protection. A complaint phone number provided to the participant will provide significant feedback on the equipment and its timely repair. Follow-up surveys of equipment operation and usage patterns will also be conducted.

Program Assumptions

Package Measure Life (Years)	20
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	2%
Take-Back Percentage	20%
Free-Rider Market Barrier Costs Eliminated	40%
Non-Free-Rider Market Barrier Costs Eliminated	50%
Annual Energy Impact (kWh)	2,500

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	50,300	200	200	0%
2	50,300	600	800	1%
3	50,300	1,000	1,800	1%
4	50,300	1,000	2,800	1%
5	50,300	1,000	3,800	2%
6	50,300	1,000	4,800	2%
7	50,300	1,000	5,800	2%
8	50,300	1,000	6,800	2%
9	50,300	1,000	7,800	2%
10	50,300	1,000	8,800	2%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $10 Total Variable Admin. Cost	Per Participant Measure Cost $3,000 Total Part. Measure Cost	Per Participant Incentive $1,956 Total Part. Incentive
1	$550,000	$2,000	$600,000	$391,200
2	$500,000	$6,000	$1,800,000	$1,173,600
3	$500,000	$10,000	$3,000,000	$1,956,000
4	$400,000	$10,000	$3,000,000	$1,956,000
5	$400,000	$10,000	$3,000,000	$1,956,000
6	$400,000	$10,000	$3,000,000	$1,956,000
7	$400,000	$10,000	$3,000,000	$1,956,000
8	$400,000	$10,000	$3,000,000	$1,956,000
9	$400,000	$10,000	$3,000,000	$1,956,000
10	$400,000	$10,000	$3,000,000	$1,956,000

EFFICIENCY PRODUCTS CATALOG—MAIL ORDER

Overview

This program makes it easy for customers to purchase smaller, easily installed technologies that are not readily available in the marketplace. The product descriptions in the catalog will also educate customers about the benefits of each technology. For many products, TVA will "buy down" the cost to encourage people to adopt unfamiliar technologies. Promoted products could include efficient lighting, motion sensors, flow restricters, pipe insulation, and outlet insulation.

Target Market

This program targets all residential customers.

Implementation Strategy

Through the services of a professional fulfillment company, TVA will offer a catalog featuring a variety of shippable, easily installed energy efficiency technologies. Quantity limits may be imposed on certain products. The catalog will offer information on applications and how to select the appropriate models for various uses.

Consumers will obtain the catalog through a 1-800 number and may place their orders via the same number or by mail. A retail component will also be developed to provide local shopping options after the catalog effort is launched. By educating Valley consumers on the benefits and applications of energy-efficient products and offering them the opportunity to purchase these products conveniently at a reduced price, the catalog should stimulate the development of a retail infrastructure through increased demand for the products.

Incentives

- Specific measures have discounted purchase prices in the catalog.
- Overhead and administrative costs for the fulfillment contractor are paid by TVA.

Program Assumptions

Package Measure Life (Years)	7
Free-Rider Rate	15%
Free-Driver Rate	0%
Dropouts	5%
Take-Back Percentage	10%
Free-Rider Market Barrier Costs Eliminated	65%
Non-Free-Rider Market Barrier Costs Eliminated	80%
Annual Energy Impact (kWh)	823

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	2,985,000	35,800	35,800	1%
2	3,020,000	67,000	102,800	3%
3	3,055,000	73,300	176,100	6%
4	3,090,000	74,200	250,300	8%
5	3,125,000	83,400	333,700	11%
6	3,160,000	88,500	422,200	13%
7	3,195,000	95,900	518,100	16%
8	3,230,000	96,900	615,000	19%
9	3,265,000	98,000	713,000	22%
10	3,300,000	99,000	812,000	25%
11	3,335,000	100,100	912,100	27%
12	3,370,000	101,100	1,013,200	30%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $17 Total Variable Admin. Cost	Per Participant Measure Cost $70 Total Part. Measure Cost	Per Participant Incentive $9 Total Part. Incentive
1	$430,000	$608,600	$2,506,000	$322,200
2	$430,000	$1,139,000	$4,690,000	$603,000
3	$430,000	$1,246,100	$5,131,000	$659,700
4	$430,000	$1,261,400	$5,194,000	$667,800
5	$430,000	$1,417,800	$5,838,000	$750,600
6	$430,000	$1,504,500	$6,195,000	$796,500
7	$430,000	$1,630,300	$6,713,000	$863,100
8	$430,000	$1,647,300	$6,783,000	$872,100
9	$430,000	$1,666,000	$6,860,000	$882,000
10	$430,000	$1,683,000	$6,930,000	$891,000
11	$430,000	$1,701,700	$7,007,000	$901,000
12	$430,000	$1,718,700	$7,077,000	$910,000

Monitoring and Evaluation

Phone surveys of program participants will provide feedback on the equipment installed and its hours of use. This information will be incorporated into engineering impacts developed for each measure to estimate program-wide energy benefits.

Measure	Incremental Energy (kWh/yr)	Wholesale Cost ($)	Incentive ($)	# /home	Weighted Energy (kWh/yr)	Weighted Cost ($)	Weighted Incentive ($)
Compact Fluorescent Light	57	13	2.05	4.00	228	51	8
Motion Detectors (Outdoor)	53	10	1.60	0.25	13	3	0
High Pressure Sodium Light	1,604	34	5.37	0.05	80	2	0
DHW Pipe Insulation	78	10	1.00	0.25	20	3	0
DHW Tank Wrap	271	10	1.00	0.50	136	5	1
Low Flow Showerhead	271	10	1.00	1.50	407	15	2
Programmable Thermostat	1,273	92	9.15	0.18	224	16	2
		Weighted Total For 5 Products			**823**	**70**	**9**

Wholesale cost is known for lighting, calculated at 75 percent of retail for thermostats, calculated at 50 percent of retail for other measures.
Incentive is buy-down of wholesale cost.

LIGHTING PRODUCTS RETAIL COMPONENT

Overview

This program augments the Efficiency Products Catalog, which makes it easy for customers to purchase smaller, easily-installed technologies that are not readily available in the marketplace. This program works by influencing customers to purchase additional quantities of the same efficient products from their local retailers. This market transformation will help to encourage people to adopt unfamiliar technologies. Promoted products could include efficient lighting, motion sensors, flow restricters, pipe insulation, and outlet insulation.

Target Market

This program targets all residential customers.

Implementation Strategy

TVA will offer a catalog featuring a variety of energy efficiency technologies. Coupons in the catalog will be redeemable in local retail outlets to purchase the same efficiency technologies at discounted prices. The coupons can also be distributed through other complimentary DSM programs, power distributor displays, direct mail, or by customer request.

By working with manufacturers and distributors of these products, TVA will encourage local retailers to participate in the program. The coupon booklet will educate Valley consumers on the benefits and applications of energy-efficient products and will offer them the opportunity to purchase these products at a reduced price. Customer information completed on the coupon will provide feedback on customer purchases and utilization of the efficient products.

Incentives

Retail rebate coupons will be provided.

Monitoring and Evaluation

The rebate coupon will provide information on participant usage. Additionally, phone surveys of program participants will provide feedback on the equipment installed and its hours of use. This information will be incorporated into engineering impacts developed for each measure to estimate program-wide energy benefits.

Program Assumptions

Package Measure Life (Years)	7
Free-Rider Rate	15%
Free-Driver Rate	0%
Dropouts	5%
Take-Back Percentage	5%
Free-Rider Market Barrier Costs Eliminated	60%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	823

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	2,985,000	7,500	7,500	0%
2	3,020,000	15,100	22,600	1%
3	3,055,000	22,900	45,500	1%
4	3,090,000	30,900	76,400	2%
5	3,125,000	37,500	113,900	4%
6	3,160,000	44,200	158,100	5%
7	3,195,000	54,300	212,400	7%
8	3,230,000	64,600	277,000	9%
9	3,265,000	71,800	348,800	11%
10	3,300,000	79,200	428,000	13%
11	3,335,000	86,700	514,700	15%
12	3,370,000	101,100	615,800	18%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $10 Total Variable Admin. Cost	Per Participant Measure Cost $102 Total Part. Measure Cost	Per Participant Incentive $26 Total Part. Incentive
1	$900,000	$75,000	$765,000	$195,000
2	$850,000	$151,000	$1,540,200	$392,600
3	$850,000	$229,000	$2,335,800	$595,400
4	$850,000	$309,000	$3,151,800	$803,400
5	$850,000	$375,000	$3,825,000	$975,000
6	$850,000	$442,000	$4,508,400	$1,149,200
7	$850,000	$543,000	$5,538,600	$1,411,800
8	$850,000	$646,000	$6,589,200	$1,679,600
9	$850,000	$718,000	$7,323,600	$1,866,800
10	$850,000	$792,000	$8,078,400	$2,059,200
11	$850,000	$867,000	$8,843,400	$2,254,200
12	$850,000	$1,011,000	$10,312,200	$2,628,600

APPLIANCE REBATES PROGRAM

Overview

This program will promote efficient appliances using rebates and point-of-sale displays. Appliances will include high efficiency dishwashers, heat pump clothes dryers, clothes dryers with moisture sensors, horizontal axis clothes washers, high efficiency room air-conditioners, high efficiency freezers, high efficiency refrigerators, and high efficiency pool pumps.

Target Market

All residential customers in participating power distributor areas are targeted.

Implementation Strategy

Rebate coupons, point-of-sale displays, and appliance labeling are utilized to promote efficient appliances. Utility representatives will work with retail outlets to label applicable appliances and to distribute displays and coupons. Additionally, coupons will be distributed through other compatible DSM programs, power distributor offices, and upon phone request.

Incentives

Rebate coupons will be provided.

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	15%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	5%
Free-Rider Market Barrier Costs Eliminated	60%
Non-Free-Rider Market Barrier Costs Eliminated	80%
Annual Energy Impact (kWh)	181

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	573,500	13,800	13,800	2%
2	573,500	27,600	41,400	4%
3	573,500	55,200	96,600	6%
4	573,500	110,400	207,000	9%
5	573,500	110,400	317,400	11%
6	573,500	110,400	427,800	12%
7	573,500	110,400	538,200	13%
8	573,500	110,400	648,600	14%
9	573,500	110,400	759,000	15%
10	573,500	110,400	869,400	15%
11	573,500	110,400	979,800	16%
12	573,500	110,400	1,090,200	16%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $7 Total Variable Admin. Cost	Per Participant Measure Cost $90 Total Part. Measure Cost	Per Participant Incentive $71 Total Part. Incentive
1	$530,000	$96,600	$1,242,000	$979,800
2	$430,000	$193,200	$2,484,000	$1,959,600
3	$430,000	$386,400	$4,968,000	$3,919,200
4	$430,000	$772,800	$9,936,000	$7,838,400
5	$430,000	$772,800	$9,936,000	$7,838,400
6	$430,000	$772,800	$9,936,000	$7,838,400
7	$430,000	$772,800	$9,936,000	$7,838,400
8	$430,000	$772,800	$9,936,000	$7,838,400
9	$430,000	$772,800	$9,936,000	$7,838,400
10	$430,000	$772,800	$9,936,000	$7,838,400
11	$430,000	$772,800	$9,936,000	$7,838,400
12	$430,000	$772,800	$9,936,000	$7,838,400

Monitoring and Evaluation

Rebate coupons will provide initial information on replacement and usage patterns. A database will be completed from returned rebate coupons. Follow-up surveys of equipment installed and usage patterns will be conducted.

Measure	Incremental Energy (kWh/yr)	Incremental Cost ($)	Incentive ($)	Appliance Saturation Weighting	Long-Term Penetration Weighting
High-Efficiency dishwasher	130	20	20	41%	20%
High-Efficiency Pool Pump	281	39	39	4%	10%
Heat Pump Clothes Dryer	661	301	200	78%	2%
Best Current Freezer	152	68	68	48%	30%
Best Current Refrigerator	119	85	54	99%	30%
High-Efficiency Room A/C	414	142	142	40%	30%
Dryer with Moisture Sensor	122	75	56	78%	30%
Horizontal Axis Clothes Washer	450	350	200	85%	2%

Incentive based on incremental energy times average $/annual kWh, capped at full incremental cost, or capped at $200
Appliance saturation weighting based on TVA 1992 appliance survey.
Long-term penetration weighting based on information from BCI 08/03/94.

REFRIGERATOR TURN-IN AND RECYCLING PROGRAM

Overview

This is a second refrigerator and freezer pick-up program. The utility will remove unwanted refrigerators and freezers and ensure that they are disposed of properly in accordance with applicable environmental regulations. The appliance must be in working condition. The customer is given a $50 U.S. savings bond incentive for participation.

Target Market

All residential customers with second refrigerators or freezers are targeted.

Implementation Strategy

A turn-key contractor will administer and implement the program. The contractor sets up telephone lines to take customer phone calls. The call is screened to eliminate free ridership in the program. Then, an appointment is made to pick up the applicable device. The pick-up crew verifies that the equipment is operable and removes it, leaving the incentive with the customer. The equipment is taken to the contractor's warehouse/processing facility where the refrigerant is removed and recycled, and other components are disassembled and recycled.

The contractor handles administrative aspects of the program, providing monthly reports of removals, energy consumption of removed equipment and participants' names and addresses. Utility involvement is limited to contract administration and QA control over contract performance.

Incentives

A $50 U.S. savings bond is given to the customer when the operating appliance is picked up.

Monitoring and Evaluation

Reporting by turn-key contractor provides energy measurement and customer account information. Contractor performance and customer satisfaction data will be collected as part of a process evaluation.

Program Assumptions

Package Measure Life (Years)	7
Free-Rider Rate	34%
Free-Driver Rate	0%
Dropouts	25%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	60%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	929

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	298,500	12,900	12,900	1%
2	298,500	18,700	31,600	3%
3	298,500	30,200	61,800	6%
4	298,500	30,200	92,000	9%
5	298,500	24,400	116,400	11%
6	298,500	18,700	135,100	13%
7	298,500	18,700	153,800	15%
8	298,500	18,700	172,500	17%
9	298,500	18,700	191,200	19%
10	298,500	12,900	204,100	20%
11	298,500	12,900	217,000	21%
12	298,500	12,900	229,900	23%

		Per Participant Variable Administrative Costs	Per Participant Measure Cost	Per Participant Incentive
		$0	$110	$25
Year	Fixed Administrative Cost	Total Variable Admin. Cost	Total Part. Measure Cost	Total Part. Incentive
1	$275,000	$0	$1,419,000	$322,500
2	$200,000	$0	$2,057,000	$467,500
3	$200,000	$0	$3,322,000	$755,000
4	$200,000	$0	$3,322,000	$755,000
5	$200,000	$0	$2,684,000	$610,000
6	$200,000	$0	$2,057,000	$467,500
7	$200,000	$0	$2,057,000	$467,500
8	$200,000	$0	$2,057,000	$467,500
9	$200,000	$0	$2,057,000	$467,500
10	$200,000	$0	$1,419,000	$322,500
11	$200,000	$0	$1,419,000	$322,500
12	$200,000	$0	$1,419,000	$322,500

STUDENT SELF-AUDIT—SCHOOLS ENVIRONMENTAL PROGRAM

Overview

This program builds upon the energy information materials TVA already provides to Valley teachers. In addition to general information, a self-audit package will be presented to students who will be required to conduct a home audit, fill out an audit form, and return it to school, where it will be analyzed by an audit software program. The software will analyze the audit form and recommend cost-effective environmental and energy efficiency measures that the students and their families can implement. Many materials recommended in the audit report will be available through the catalog mail program. Discount coupons for catalog materials may be provided to students. This audit report will also provide coordinated promotion of other TVA and distributor energy efficiency programs.

Target Market

High school students in participating power distributor areas are targeted.

Implementation Strategy

Lesson plans on energy and environment, audit forms, and a computer with audit analysis software will be provided to each school. TVA will provide training on all materials for teachers. Audit data collected by the students is entered on the computer and a custom audit report is generated. The survey data is also compiled for teacher and utility use.

Incentives

- TVA will pay for substitute teachers during the training.
- Class materials and audit materials will be provided.

Program Assumptions

Package Measure Life (Years)	10
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	5%
Free-Rider Market Barrier Costs Eliminated	60%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	102

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	3,900	3,700	3,700	95%
2	32,500	30,900	34,600	95%
3	130,000	123,500	158,100	95%
4	130,000	123,500	281,600	95%
5	130,000	123,500	405,100	95%
6	130,000	123,500	528,600	95%
7	130,000	123,500	652,100	95%
8	130,000	123,500	775,600	95%
9	130,000	123,500	899,100	95%
10	130,000	123,500	1,022,600	95%
11	130,000	123,500	1,146,100	95%
12	130,000	123,500	1,269,600	95%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $5 Total Variable Admin. Cost	Per Participant Measure Cost $19 Total Part. Measure Cost	Per Participant Incentive $0 Total Part. Incentive
1	$1,432,000	$18,500	$70,300	$0
2	$982,000	$154,500	$587,100	$0
3	$796,400	$617,500	$2,346,500	$0
4	$796,400	$617,500	$2,346,500	$0
5	$796,400	$617,500	$2,346,500	$0
6	$796,400	$617,500	$2,346,500	$0
7	$796,400	$617,500	$2,346,500	$0
8	$796,400	$617,500	$2,346,500	$0
9	$796,400	$617,500	$2,346,500	$0
10	$796,400	$617,500	$2,346,500	$0
11	$796,400	$617,500	$2,346,500	$0
12	$796,400	$617,500	$2,346,500	$0

Monitoring and Evaluation

Follow-up phone surveys of students will determine which measures were installed and allow estimation of the energy savings attributable to the program. Savings for the first year of the program will be estimated as a small fraction of the measures expected to be recommended on the audit reports.

Measure	Incremental Energy (kWh/yr)	Incremental Cost ($)	Unitized Weighting	Weighted Energy (kWh/yr)	Weighted Cost ($)
NEW MH Motion Detectors—Outdoor Lighting	52.50	2.45	0.03	1.83	0.09
Existing AC/HP Maintenance	52.50	2.45	0.03	1.83	0.09
NEW MF Motion Detectors—Outdoor Lighting	60.00	2.80	0.03	2.09	0.10
NEW MH High Pressure Sodium (Outdoor)	60.00	2.80	0.03	2.09	0.10
Existing Ceiling Insulation (R11-R30)	130.02	20.00	0.03	4.50	0.69
Existing Reduced Duct Leakage	110.22	20.00	0.03	3.82	0.69
Existing Ceiling Insulation (R0-R19)	110.88	20.00	0.03	3.84	0.69
Existing DHW Heater Tank Insulation	77.56	20.00	0.03	2.69	0.69
NEW MH Efficient Incandescent	271.46	20.00	0.03	9.40	0.69
Existing Ceiling Fans	193.90	28.00	0.03	6.69	0.97
NEW MH Motion Detectors (Outdoor)	271.46	35.00	0.03	9.34	1.20
Existing MH High-Efficiency Dishwasher	477.45	105.88	0.03	15.90	3.53
Existing Ceiling Fans	1,119.10	105.88	0.03	37.26	3.53
Existing Programmable Thermostat (HP)	519.76	105.88	0.03	17.31	3.53
Existing Programmable Thermostat	1,011.26	105.88	0.03	33.67	3.53
Existing High-Efficiency Heat Pump	1,666.29	122.00	0.03	55.06	4.03
NEW MF Efficient Incandescent	1,272.99	122.00	0.03	42.07	4.03
Existing MF High-Efficiency Dishwasher	935.29	146.00	0.03	30.56	4.77
Existing Ground-Source Heat Pump	960.59	146.00	0.03	31.38	4.77
Existing SF High-Efficiency Dishwasher	1,905.06	275.00	0.03	58.40	8.43
NEW MF High Pressure Sodium (Outdoor)	1,133.22	275.00	0.03	34.74	8.43
NEW MF Efficient Incandescent	1,302.48	392.92	0.03	37.53	11.32
NEW MH High Pressure Sodium (Outdoor)	1,480.48	392.92	0.03	42.65	11.32
NEW MH Efficient Incandescent	1,623.30	392.92	0.03	46.77	11.32
NEW SF High Pressure Sodium (Outdoor)	1,842.03	392.92	0.03	53.07	11.32
NEW SF Motion Detectors for Outdoor Lighting	1,835.07	425.00	0.03	51.95	12.03
NEW MF Motion Detectors for Outdoor Lighting	3,488.64	590.00	0.03	89.77	15.18
NEW SF High Pressure Sodium (Outdoor)	1,366.27	650.32	0.02	33.87	16.12
Existing Low Flow Showerhead	4,655.83	650.32	0.02	115.42	16.12
Existing DHW Heat Trap	1,542.13	650.32	0.02	38.23	16.12
Existing DHW Pipe Insulation	4,069.82	650.32	0.02	100.89	16.12
Existing Reduced Duct Leakage	6,968.22	708.00	0.01	0.70	0.07
Wood Furnace w/Wood Cost	7,902.00	2,237.00	0.01	0.79	0.22
		Total	**1**	**1,016**	**192**

Same measure mix as Self-Audit Program, assumed 10 percent of homes will implement.

SELF-AUDIT PROGRAM

Overview

Customers will conduct home audits using materials provided by TVA. TVA will analyze the audits and provide recommendations for cost-effective energy and environmental conservation measures applicable to the customer's home.

Target Market

Residential customers in participating power distributor areas are targeted.

Implementation Strategy

Home audit forms and instructions will be available at mall kiosks and participating distributors' offices. Customers completing the audit form will take it to their distributor or mail it to TVA, and receive a customized computer-generated report recommending the implementation of specific environmental and energy efficiency measures. The custom printout will be coordinated with other programs and will provide referrals to other existing distributor DSM programs.

Incentives

No incentives will be provided.

Program Assumptions

Package Measure Life (Years)	10
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	5%
Free-Rider Market Barrier Costs Eliminated	50%
Non-Free-Rider Market Barrier Costs Eliminated	60%
Annual Energy Impact (kWh)	1,016

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	481,000	4,800	4,800	1%
2	478,600	19,100	23,900	5%
3	469,000	14,100	38,000	8%
4	462,000	11,100	49,100	11%
5	456,400	11,000	60,100	13%
6	451,000	10,800	70,900	16%
7	445,600	10,700	81,600	18%
8	440,200	10,600	92,200	21%
9	434,900	10,400	102,600	24%
10	429,700	10,300	112,900	26%
11	424,600	10,200	123,100	29%
12	419,500	10,100	133,200	32%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $5 Total Variable Admin. Cost	Per Participant Measure Cost $192 Total Part. Measure Cost	Per Participant Incentive $0 Total Part. Incentive
1	$437,500	$24,000	$921,600	$0
2	$187,500	$95,500	$3,667,200	$0
3	$187,500	$70,500	$2,707,200	$0
4	$187,500	$55,500	$2,131,200	$0
5	$187,500	$55,000	$2,112,000	$0
6	$187,500	$54,000	$2,073,600	$0
7	$187,500	$53,500	$2,054,400	$0
8	$187,500	$53,000	$2,035,200	$0
9	$187,500	$52,000	$1,996,800	$0
10	$187,500	$51,500	$1,977,600	$0
11	$187,500	$51,000	$1,958,400	$0
12	$187,500	$50,500	$1,939,200	$0

Monitoring and Evaluation

Follow-up phone surveys of participating customers will determine the number of installed measures, and allow estimation of the energy savings attributable to the program. Savings for the first year of the program will be estimated as a small fraction of the measures expected to be recommended on the audit reports.

Measure	Incremental Energy (kWh/yr)	Incremental Cost ($)	Unitized Weighting	Weighted Energy (kWh/yr)	Weighted Cost ($)
NEW MH Motion Detectors—Outdoor Lighting	52.50	2.45	0.03	1.83	0.09
Existing AC/HP Maintenance	52.50	2.45	0.03	1.83	0.09
NEW MF Motion Detectors—Outdoor Lighting	60.00	2.80	0.03	2.09	0.10
NEW MH High Pressure Sodium (Outdoor)	60.00	2.80	0.03	2.09	0.10
Existing Ceiling Insulation (R11-R30)	130.02	20.00	0.03	4.50	0.69
Existing Reduced Duct Leakage	110.22	20.00	0.03	3.82	0.69
Existing Ceiling Insulation (R0-R19)	110.88	20.00	0.03	3.84	0.69
Existing DHW Heater Tank Insulation	77.56	20.00	0.03	2.69	0.69
NEW MH Efficient Incandescent	271.46	20.00	0.03	9.40	0.69
Existing Ceiling Fans	193.90	28.00	0.03	6.69	0.97
NEW MH Motion Detectors (Outdoor)	271.46	35.00	0.03	9.34	1.20
Existing MH High-Efficiency Dishwasher	477.45	105.88	0.03	15.90	3.53
Existing Ceiling Fans	1,119.10	105.88	0.03	37.26	3.53
Existing Programmable Thermostat (HP)	519.76	105.88	0.03	17.31	3.53
Existing Programmable Thermostat	1,011.26	105.88	0.03	33.67	3.53
Existing High-Efficiency Heat Pump	1,666.29	122.00	0.03	55.06	4.03
NEW MF Efficient Incandescent	1,272.99	122.00	0.03	42.07	4.03
Existing MF High-Efficiency Dishwasher	935.29	146.00	0.03	30.56	4.77
Existing Ground-Source Heat Pump	960.59	146.00	0.03	31.38	4.77
Existing SF High-Efficiency Dishwasher	1,905.06	275.00	0.03	58.40	8.43
NEW MF High Pressure Sodium (Outdoor)	1,133.22	275.00	0.03	34.74	8.43
NEW MF Efficient Incandescent	1,302.48	392.92	0.03	37.53	11.32
NEW MH High Pressure Sodium (Outdoor)	1,480.48	392.92	0.03	42.65	11.32
NEW MH Efficient Incandescent	1,623.30	392.92	0.03	46.77	11.32
NEW SF High Pressure Sodium (Outdoor)	1,842.03	392.92	0.03	53.07	11.32
NEW SF Motion Detectors for Outdoor Lighting	1,835.07	425.00	0.03	51.95	12.03
NEW MF Motion Detectors for Outdoor Lighting	3,488.64	590.00	0.03	89.77	15.18
NEW SF High Pressure Sodium (Outdoor)	1,366.27	650.32	0.02	33.87	16.12
Existing Low Flow Showerhead	4,655.83	650.32	0.02	115.42	16.12
Existing DHW Heat Trap	1,542.13	650.32	0.02	38.23	16.12
Existing DHW Pipe Insulation	4,069.82	650.32	0.02	100.89	16.12
Existing Reduced Duct Leakage	6,968.22	708.00	0.01	0.70	0.07
Wood Furnace w/Wood Cost	7,902.00	2,237.00	0.01	0.79	0.22
		Total	**1**	**1,016**	**192**

LOAD MANAGEMENT PROGRAM—AIR CONDITIONERS

Overview

TVA presently has a radio control system that cycles water heaters and air-conditioning load to reduce power demand during hours of peak electrical usage. This program expands participation in the coverage area of the TVA-owned and -maintained radio control system.

Target Market

Residential customers with central air conditioners or heat pumps in participating power distributor areas are targeted.

Implementation Strategy

In participating power distributors' areas, the load management program will be promoted to encourage additional load management installations. Free maintenance of the load-controlled HVAC is used as an incentive. This provides multiple benefits including increased HVAC efficiency, increased QA inspections at no cost, and enhanced HVAC contractor buy-in to the program.

Incentives

TVA will pay the full cost of the switch and its installation. An incentive to the distributor is included and can be used to pay employees to sign up participants and/or part or all of the incentive can be passed on to participants. Free maintenance contracts are provided for central air conditioners and heat pumps participating in the program.

Monitoring and Evaluation

QA inspections of program switches and their operation are performed by the contractor during an annual maintenance inspection. Some spot checking of maintenance procedures and switch operation will be required.

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	2%
Take-Back Percentage	5%
Free-Rider Market Barrier Costs Eliminated	0%
Non-Free-Rider Market Barrier Costs Eliminated	100%
Annual Energy Impact (kWh)	520

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	52,900	1,100	1,100	2%
2	52,900	3,200	4,300	8%
3	52,900	4,200	8,500	16%
4	52,900	5,300	13,800	26%
5	52,900	6,300	20,100	38%
6	52,900	6,300	26,400	50%
7	52,900	5,300	31,700	60%
8	52,900	4,200	35,900	68%
9	52,900	3,200	39,100	74%
10	52,900	500	39,600	75%

		Per Participant Variable Administrative Costs	Per Participant Measure Cost	Annual Per Participant Incentive
		$225	$0	$65
Year	Fixed Administrative Cost	Total Variable Admin. Cost	Total Part. Measure Cost	Total Part. Incentive
1	$100,000	$247,500	$0	$71,500
2	$100,000	$720,000	$0	$279,500
3	$100,000	$945,000	$0	$552,500
4	$100,000	$1,192,500	$0	$897,000
5	$100,000	$1,417,500	$0	$1,306,500
6	$100,000	$1,417,500	$0	$1,716,000
7	$100,000	$1,192,500	$0	$2,060,500
8	$100,000	$945,000	$0	$2,333,500
9	$100,000	$720,000	$0	$2,541,500
10	$100,000	$112,500	$0	$2,574,000

LOAD MANAGEMENT PROGRAM—WATER HEATERS

Overview

TVA presently has a radio control system that cycles water heaters and air-conditioning load to reduce power demand during hours of peak electrical usage. This program expands participation in the coverage area of the TVA-owned and -maintained radio control system.

Target Market

Residential customers with electric water heaters in participating power distributor areas are targeted.

Implementation Strategy

In participating power distributors' areas, the load management program will be promoted to encourage additional load management installations. For water heater control, direct incentives can be paid to the homeowner for participating in the program.

Incentives

TVA will pay the full cost of the switch and its installation. An incentive to the distributor is included, which can be used to pay employees to sign up participants and/or part or all of the incentive can be passed on to participants.

Monitoring and Evaluation

QA inspections of program switches and their operation are performed by the contractor during an annual maintenance inspection. Some spot checking of maintenance procedures and switch operation will be required.

Program Assumptions

Package Measure Life (Years)	10
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	2%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	0%
Non-Free-Rider Market Barrier Costs Eliminated	100%
Annual Energy Impact (kWh)	—

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	215,900	4,300	4,300	2%
2	215,900	13,000	17,300	8%
3	215,900	19,400	36,700	17%
4	215,900	25,900	62,600	29%
5	215,900	25,900	88,500	41%
6	215,900	25,900	114,400	53%
7	215,900	21,600	136,000	63%
8	215,900	17,300	153,300	71%
9	215,900	8,600	161,900	75%
10	215,900	—	161,900	75%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $554 Total Variable Admin. Cost	Per Participant Measure Cost $0 Total Part. Measure Cost	Annual Per Participant Incentive $24 Total Part. Incentive
1	$100,000	$2,382,200	$0	$103,200
2	$100,000	$7,202,000	$0	$415,200
3	$100,000	$10,747,600	$0	$880,800
4	$100,000	$14,348,600	$0	$1,502,400
5	$100,000	$14,348,600	$0	$2,124,000
6	$100,000	$14,348,600	$0	$2,745,600
7	$100,000	$11,966,400	$0	$3,264,000
8	$100,000	$9,584,200	$0	$3,679,200
9	$100,000	$4,764,400	$0	$3,885,600
10	$100,000	$0	$0	$3,885,600

LOAD MANAGEMENT PROGRAM—STORAGE WATER HEATERS

Overview

TVA presently has a radio control system that cycles water heaters and air-conditioning load to reduce power demand during hours of peak electrical usage. This program prolongs cycling by using larger storage water heaters. Participation is limited to the coverage area of the TVA-owned and -maintained radio control system. The program also provides for a free water heater, installation, and free maintenance of the water heater as an incentive for program participation.

Target Market

Residential customers with electric water heaters in participating power distributor areas are targeted.

Implementation Strategy

In participating power distributors' areas, the load management program will be promoted to encourage additional load management installations. The homeowner will have a storage water heater installed free of charge, with free maintenance as an additional incentive. The storage water heater allows TVA to cycle the water heater for longer periods of time in order to minimize payback spikes at the end of a typical control period.

The specified storage water heater must meet specific efficiency requirements (Energy Factor) corresponding to the tank size. The water heater will be sized to accommodate the water heating needs of the home and to minimize hot water outages.

Repair and replacement work will be performed by local contractors. A local phone number with answering service will be available 24 hours per day, 365 days per year. The customer is guaranteed replacement or repair within 48 hours of the call.

Incentives

TVA will pay the full cost of the storage water heater, the control switch, and its installation. Also a free maintenance contract is provided for the storage water heater.

Monitoring and Evaluation

QA inspections of program switches and their operation are performed by the contractor during an annual maintenance inspection. Some spot checking of maintenance procedures and switch operation will be required.

Program Assumptions

Package Measure Life (Years)	10
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	2%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	0%
Non-Free-Rider Market Barrier Costs Eliminated	100%
Annual Energy Impact (kWh)	—

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	108,000	2,200	2,200	2%
2	108,000	6,500	8,700	8%
3	108,000	9,700	18,400	17%
4	108,000	10,800	29,200	27%
5	108,000	10,800	40,000	37%
6	108,000	10,800	50,800	47%
7	108,000	10,800	61,600	57%
8	108,000	8,600	70,200	65%
9	108,000	4,300	74,500	69%
10	108,000	2,200	76,700	71%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $600 Total Variable Admin. Cost	Per Participant Measure Cost $400 Total Part. Measure Cost	Per Participant Incentive $460 Total Part. Incentive
1	$350,000	$1,320,000	$880,000	$1,012,000
2	$350,000	$3,900,000	$2,600,000	$2,990,000
3	$350,000	$5,820,000	$3,880,000	$4,462,000
4	$350,000	$6,480,000	$4,320,000	$4,968,000
5	$350,000	$6,480,000	$4,320,000	$4,968,000
6	$350,000	$6,480,000	$4,320,000	$4,968,000
7	$350,000	$6,480,000	$4,320,000	$4,968,000
8	$350,000	$5,160,000	$3,440,000	$3,956,000
9	$350,000	$2,580,000	$1,720,000	$1,978,000
10	$350,000	$1,320,000	$880,000	$1,012,000

LOAD MANAGEMENT PROGRAM—DIRECT CONTROL WITH SCADA

Overview

Many TVA distributors presently have a Supervisory Control and Data Acquisition system. These SCADA systems can be upgraded to allow direct load control of water heaters in order to reduce power demand during hours of peak electrical usage. Through incentives, homeowners will be encouraged to have a load management device installed on their water heaters. This program expands load management participation from the coverage area of the TVA-owned and -maintained radio control system.

Target Market

Eligible residential customers have electric water heaters in participating power distributor areas that have SCADA systems and do not participate in the existing load management program using radio control.

Implementation Strategy

In participating power distributors' areas, the SCADA system will be upgraded to allow the direct load control of residential water heaters. Promotion of the load management program will encourage homeowners to have a load management device installed on their existing water heaters.

Incentives

TVA will pay the full cost of the switch and its installation. An incentive to the distributor is included and can be used to pay employees to sign up participants and/or part or all of the incentive can be passed on to participants.

Monitoring and Evaluation

QA inspections of program switches and their operation are performed by the contractor during an annual maintenance inspection. Some spot checking of maintenance procedures and switch operation will be required.

Program Assumptions

Package Measure Life (Years)	10
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	2%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	0%
Non-Free-Rider Market Barrier Costs Eliminated	100%
Annual Energy Impact (kWh)	—

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	793,000	7,900	7,900	1%
2	793,000	15,900	23,800	3%
3	793,000	23,800	47,600	6%
4	793,000	19,800	67,400	9%
5	793,000	—	67,400	9%
6	793,000	—	67,400	9%
7	793,000	—	67,400	9%
8	793,000	—	67,400	9%
9	793,000	—	67,400	9%
10	793,000	—	67,400	9%
11	793,000	—	67,400	9%
12	793,000	—	67,400	9%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $125 Total Variable Admin. Cost	Per Participant Measure Cost $0 Total Part. Measure Cost	Annual Per Participant Incentive $24 Total Part. Incentive
1	$1,911,000	$987,500	$0	$189,600
2	$1,811,000	$1,987,500	$0	$571,200
3	$1,711,000	$2,975,000	$0	$1,142,400
4	$410,000	$2,475,000	$0	$1,617,600
5	$335,000	$0	$0	$1,617,600
6	$335,000	$0	$0	$1,617,600
7	$335,000	$0	$0	$1,617,600
8	$335,000	$0	$0	$1,617,600
9	$335,000	$0	$0	$1,617,600
10	$335,000	$0	$0	$1,617,600
11	$335,000	$0	$0	$1,617,600
12	$335,000	$0	$0	$1,617,600

LOAD MANAGEMENT PROGRAM—NEW TECHNOLOGY

Overview

This program utilizes a two-way communication network to provide a combination of benefits to the consumer, increased efficiency for utility operations, and possibly profitable side businesses. The main focus for the utility is direct load control of applicable residential appliances, and real-time-pricing or time-of-use pricing for the customer. The rate options provide for additional customer load management control of other appliances, and open the door for home automation and energy storage appliances.

Target Market

All residential customers in participating power distributor areas are targeted.

Implementation Strategy

The direct load control aspect of the information superhighway allows the utility to control air conditioners, water heaters, storage water heaters, and pool pumps when required. In return the customer receives a monthly or seasonal incentive for this control. Different control levels and incentive levels are available.

The utility can also improve operations through remote meter reading, remote connection and disconnection of electrical service, and easier bill payment methods.

The real-time-pricing and time-of-use rate options provide the customer with the ability to perform load management based on price signals from the utility. The customer maintains control and has the ability to lower costs.

The information superhighway or equivalent two-way communication network provides many benefits to the customer. They will be able to have competitive cable TV service, competitive telephone service, home security system monitoring, home automation, real-time electricity pricing, itemized utility bills, and remote bill payment, all from their home.

Incentives

- The real-time pricing provides a rate incentive to the customer.
- The time-of-use rate option is another rate incentive for the customer.
- For direct load control, a comparable incentive to the rate incentives can be provided to the customer in the form of a monthly incentive on their power bill.

Monitoring and Evaluation

The two-way communications network provides real-time feedback of loads shed and the impacts on their utility system.

Program Assumptions

Package Measure Life (Years)	10
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	2%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	0%
Non-Free-Rider Market Barrier Costs Eliminated	100%
Annual Energy Impact (kWh)	—

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	1,621,300	32,400	32,400	2%
2	1,621,300	64,900	97,300	6%
3	1,621,300	97,300	194,600	12%
4	1,621,300	81,100	275,700	17%
5	1,621,300	—	275,700	17%
6	1,621,300	—	275,700	17%
7	1,621,300	—	275,700	17%
8	1,621,300	—	275,700	17%
9	1,621,300	—	275,700	17%
10	1,621,300	—	275,700	17%
11	1,621,300	—	275,700	17%
12	1,621,300	—	275,700	17%

Year	Fixed Administrative Cost and New Business Revenue	Per Participant Variable Administrative Costs $25 Total Variable Admin. Cost	Per Participant Measure Cost $500 Total Part. Measure Cost	Per Participant Incentive $500 Total Part. Incentive
1	$150,056,000	$810,000	$16,200,000	$16,200,000
2	$146,795,000	$1,622,500	$32,450,000	$32,450,000
3	$143,633,000	$2,432,500	$48,650,000	$48,650,000
4	($12,095,000)	$2,027,500	$40,550,000	$40,550,000
5	($12,095,000)	$0	$0	$0
6	($12,095,000)	$0	$0	$0
7	($12,095,000)	$0	$0	$0
8	($12,095,000)	$0	$0	$0
9	($12,095,000)	$0	$0	$0
10	($12,095,000)	$0	$0	$0
11	($12,095,000)	$0	$0	$0
12	($12,095,000)	$0	$0	$0

COMMERCIAL AND INDUSTRIAL ENERGY EFFICIENCY OPTIONS

SUMMARY OF PROJECTED IMPACTS IN YEAR 2010

Option Name	2010 Winter MW	2010 Summer MW	GWh	Units Million (sq. ft)	¢kWh TRC
COMMERCIAL TECHNOLOGY REBATES					
Lighting Rebates	265	511	2,845	1,626	2.0
HVAC & Building Shell Rebates	255	223	670	630	7.7
Appliance Rebates	40	69	364	501	3.2
New Construction	124	188	762	360	4.4
New Construction—Renewables	30	40	159	30	7.4
SMALL COMMERCIAL SECTOR					
Retrofit - Direct Install	65	98	465	315	3.1
HVAC Maintenance Program	38	26	87	236	13.7
LARGE COMMERCIAL SECTOR					
Comprehensive Measures Financing	120	170	713	284	4.9
Comprehensive Measures Rebates	242	311	1,278	449	4.9
COMMERCIAL LOAD MANAGEMENT					
Commercial Cool Storage	0	120	13	59	453 [1]
Rooftop Cool Storage	0	93	3	44	167 [1]
Commercial Group Load Curtailment	244	242	227	2,240 [2]	169 [1]
INDUSTRIAL PROGRAMS					
Industrial Technology Rebates	21	24	167	2,100 [2]	3.2
Industrial Process EE—Distributor Served	149	169	1,057	11,226 [3]	4.1
Industrial Process EE—Direct Served	167	190	1,325	8,420 [3]	4.0
Energy-Efficient Rates (opt-out)	50	56	394	2,504 [3]	3.2

[1] Cost in $/kW
[2] Number of participants
[3] Participant defined as industrial customer with one million kWh of energy use.

Values are the impacts occuring only in the year 2010 for the cumulative participation in the program to that date.

TVA developed commercial and industrial options for evaluation in Energy Vision 2020 with applications for all major uses of electricity and for all types of building. Some of the options are designed to promote specific technologies and some options address the financial, environmental, or productivity needs of end-use customers. Detailed descriptions of the options follow.

COMMERCIAL TECHNOLOGY REBATES—LIGHTING/HVAC & BUILDING SHELL/APPLIANCES

Overview

The installation of energy-efficient equipment can help commercial and industrial customers cut energy costs and enhance competitiveness and viability. Many energy-efficient technologies have widespread applicability in the commercial sector. This program provides pre-determined rebates to encourage installation of specified energy-efficient equipment.

Target Market

This program targets all commercial and industrial customers, representing over three billion square feet of floorspace in the Tennessee Valley region, interested in replacing or upgrading HVAC, lighting, water heating, or other electrical equipment. In addition to providing services for customers replacing a single technology, this program provides prescriptive rebates to customers who are not eligible for or for whom it would not be cost-effective to provide comprehensive design assistance or analysis.

Implementation Strategy

This program will be promoted to commercial and industrial customers through direct advertising, through trade allies, and at the point of purchase. The benefits of increased energy efficiency to a customer's operations will be promoted. By providing easily understandable information about these benefits, along with the rebates, customers are encouraged to select more efficient technologies. Technical assistance, such as lighting design assistance, will be available to ensure customer satisfaction and maximize the savings from the energy- efficient technologies.

Trade allies, such as equipment dealers, will receive incentives to stock and promote the energy efficient technologies included in the program to their commercial customers.

Incentives

This program targets customers at the time of natural equipment replacement and reflects a market-driven, lost opportunity resource. Once a customer has replaced equipment, the efficiency improvement may not be cost-effective until the end of the equipment's lifetime. Therefore, under this program, customers will be offered rebates equal to 75 percent of the incremental cost to achieve the desired level of participation and to make energy-efficient technologies more widely available across the Valley.

Commercial Technology Rebates—Lighting

Program Assumptions

Package Measure Life (Years)	12
Free-Rider Rate	15%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	5%
Free-Rider Market Barrier Costs Eliminated	50%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	1,650

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	271,040	54,210	54,210	20%
2	271,040	81,310	135,520	25%
3	271,040	108,420	243,940	30%
4	271,040	135,520	379,460	35%
5	271,040	135,520	514,980	38%
6	271,040	135,520	650,500	40%
7	271,040	135,520	786,020	41%
8	271,040	135,520	921,540	43%
9	271,040	135,520	1,057,060	43%
10	271,040	135,520	1,192,580	44%
11	271,040	135,520	1,328,100	49%
12	271,040	135,520	1,463,620	54%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $20 Total Variable Admin. Cost	Per Participant Measure Cost $200 Total Part. Measure Cost	Per Participant Incentive $150 Total Part. Incentive
1	$575,000	$1,084,200	$10,842,000	$8,131,500
2	$575,000	$1,626,200	$16,262,000	$12,196,500
3	$575,000	$2,168,400	$21,684,000	$16,263,000
4	$575,000	$2,710,400	$27,104,000	$20,328,000
5	$575,000	$2,710,400	$27,104,000	$20,328,000
6	$575,000	$2,710,400	$27,104,000	$20,328,000
7	$575,000	$2,710,400	$27,104,000	$20,328,000
8	$575,000	$2,710,400	$27,104,000	$20,328,000
9	$575,000	$2,710,400	$27,104,000	$20,328,000
10	$575,000	$2,710,400	$27,104,000	$20,328,000
11	$575,000	$2,710,400	$27,104,000	$20,328,000
12	$575,000	$2,710,400	$27,104,000	$20,328,000

Monitoring and Evaluation

Process evaluation will be conducted to compare the cost and effectiveness of the delivery strategy. Impact evaluation will be conducted to determine the program benefits.

COMMERCIAL TECHNOLOGY REBATES—LIGHTING

Per Participant Costs and Impacts Based on:

Efficient Measures	Base Measures	Annual Energy Impact	Cost ($)	Measure Penetration	Weighted Energy Impact	Weighted Cost ($)
T-8/Electronic Ballasts	4' - 40W Fluor. Lamps/EE Ballasts	631	62	75%	473	47
Refl/Delamp: 4' - 40W/Elec. Ballasts	4' - 40W Fluor. Lamps/EE Ballasts	1,998	185	5%	100	9
Refl/Delamp 8' - 75W/EE Ballasts	8' - 75W Fluor. Lamps/EE Ballasts	1,442	103	2%	29	2
Compact Fluorescent	Incandescent Lamps	8,480	179	3%	254	5
Occupancy Sensors	All Interior Fluorescent Lighting	847	135	25%	212	34
Photoelectric Control	Existing Lighting - Outdoor	232	6	10%	23	1
Fluorescent Exit Signs	Incandescent Exit Signs	88	28	10%	9	3
LED Exit Signs	Incandescent Exit Signs	289	103	30%	87	31
Electroluminescent Exit Signs	Incandescent Exit Signs	342	118	10%	34	12
Daylighting Design	4' - 40W Fluor. Lamps/EE Ballasts	1,760	250	10%	176	25
High Pressure Sodium	Mercury Vapor Fixtures	1,544	184	2%	31	4
High Pressure Sodium (35W)	Incandescent Lamps (150W)	11,967	1,559	2%	239	31
		Total			**1,667**	**204**

The penetration of a measure is based on its cost-effectiveness, potential net benefits, persistence of energy savings over time, technical feasibility, and the current penetration of the base and efficient technologies.

Commercial Technology Rebates—HVAC & Building Shell

Program Assumptions

Package Measure Life (Years)	20
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	5%
Free-Rider Market Barrier Costs Eliminated	50%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	950

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	101,640	20,330	20,330	20%
2	101,640	20,330	40,660	20%
3	101,640	20,330	60,990	20%
4	101,640	30,490	91,480	23%
5	101,640	30,490	121,970	24%
6	101,640	30,490	152,460	25%
7	101,640	40,660	193,120	27%
8	101,640	40,660	233,780	29%
9	101,640	40,660	274,440	30%
10	101,640	50,820	325,260	32%
11	101,640	50,820	376,080	34%
12	101,640	50,820	426,900	35%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $40 Total Variable Admin. Cost	Per Participant Measure Cost $350 Total Part. Measure Cost	Per Participant Incentive $265 Total Part. Incentive
1	$325,000	$813,200	$7,115,500	$5,387,450
2	$325,000	$813,200	$7,115,500	$5,387,450
3	$325,000	$813,200	$7,115,500	$5,387,450
4	$325,000	$1,219,600	$10,671,500	$8,079,850
5	$325,000	$1,219,600	$10,671,500	$8,079,850
6	$325,000	$1,219,600	$10,671,500	$8,079,850
7	$325,000	$1,626,400	$14,231,000	$10,774,900
8	$325,000	$1,626,400	$14,231,000	$10,774,900
9	$325,000	$1,626,400	$14,231,000	$10,774,900
10	$325,000	$2,032,800	$17,787,000	$13,467,300
11	$325,000	$2,032,800	$17,787,000	$13,467,300
12	$325,000	$2,032,800	$17,787,000	$13,467,300

COMMERCIAL TECHNOLOGY REBATES—HVAC

Per Participant Costs and Impacts Based on:

Efficient Measures	Base Measures	Annual Energy Impact	Cost ($)	Measure Penetration	Weighted Energy Impact	Weighted Cost ($)
High-Efficiency Chiller	Standard Eff. Chiller	28	12	60%	17	7
Speed Control for Cooling Tower	Standard Cooling Tower	70	6	60%	42	4
High-Efficiency A/C DX	Standard Eff. A/C DX	500	225	30%	150	68
High-Efficiency Room A/C	Standard Efficiency Room A/C	464	289	10%	46	29
High-Efficiency Heat Pump	Standard Eff. Heat Pump	300	464	20%	60	93
Ground-Source Heat Pump	Standard Eff. Heat Pump	1,167	2,680	1%	12	27
High-Efficiency Ventilation Motors	Stan. Eff. Constant Speed Motors	38	11	25%	10	3
ASD Ventilation Controls w/VAV	Stan. Eff. Constant Speed Motors	95	66	30%	29	20
Timer/Programmable Vent. Cont.	Stan. Eff. Constant Speed Motors	128	119	5%	6	6
Roof Insulation	All Heating, Cooling, Ventilation	2,458	228	15%	369	34
Wall Insulation	All Heating, Cooling, Ventilation	285	334	5%	14	17
Window Film	Standard Windows	570	65	15%	86	10
Leak-Free Ducts	All Heating, Cooling, Ventilation	256	127	15%	38	19
HVAC Air Duct/Water Pipe Insul.	All Heating, Cooling, Ventilation	173	79	15%	26	12
Temperature Setback/Setup	All Heating, Cooling, Ventilation	246	22	25%	62	6
		Total			**967**	**355**

- *High Efficiency Chillers and Speed Control for Cooling Towers Applicable in Large Office and Hospital Buildings*
- *ASD Ventilation Controls w/VAV Applicable in University Buildings*

The penetration of a measure is based on its cost-effectiveness, potential net benefits, persistence of energy savings over time, technical feasibility, and the current penetration of the base and efficient technologies.

Commercial Technology Rebates—Appliances

Program Assumptions

Package Measure Life (Years)	10
Free-Rider Rate	10%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	10%
Free-Rider Market Barrier Costs Eliminated	50%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	600

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	102,995	20,600	20,600	20%
2	102,995	20,600	41,200	20%
3	102,995	30,900	72,100	23%
4	102,995	30,900	103,000	25%
5	102,995	41,200	144,200	28%
6	102,995	41,200	185,400	30%
7	102,995	51,500	236,900	33%
8	102,995	51,500	288,400	35%
9	102,995	51,500	339,900	37%
10	102,995	51,500	391,400	38%
11	102,995	51,500	442,900	39%
12	102,995	51,500	494,400	40%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $15 Total Variable Admin. Cost	Per Participant Measure Cost $100 Total Part. Measure Cost	Per Participant Incentive $75 Total Part. Incentive
1	$165,000	$309,000	$2,060,000	$1,545,000
2	$165,000	$309,000	$2,060,000	$1,545,000
3	$165,000	$463,500	$3,090,000	$2,317,500
4	$165,000	$463,500	$3,090,000	$2,317,500
5	$165,000	$618,000	$4,120,000	$3,090,000
6	$165,000	$618,000	$4,120,000	$3,090,000
7	$165,000	$772,500	$5,150,000	$3,862,500
8	$165,000	$772,500	$5,150,000	$3,862,500
9	$165,000	$772,500	$5,150,000	$3,862,500
10	$165,000	$772,500	$5,150,000	$3,862,500
11	$165,000	$772,500	$5,150,000	$3,862,500
12	$165,000	$772,500	$5,150,000	$3,862,500

COMMERCIAL TECHNOLOGY REBATES—APPLIANCES

Per Participant Costs and Impacts Based on:

Efficient Measures	Base Measures	Annual Energy Impact	Cost ($)	Measure Penetration	Weighted Energy Impact	Weighted Cost ($)
WATER HEATING						
Heat Pump Water Heater	Electric Water Heater—Standard	494	81	50%	247	40
Heat Recovery Water Heaters	Electric Water Heater—Standard	247	19	35%	86	6
Solar Water Heaters	Electric Water Heater—Standard	638	520	5%	32	26
Low Flow Showerheads	Electric Water Heater—Standard	148	1	15%	22	1
DHW Heat Trap/Pipe Insulation	Electric Water Heater—Standard	99	1	10%	10	1
DHW Heater Insulation	Electric Water Heater—Standard	49	1	5%	3	1
DWH Recirculation Pumps	Electric Water Heater—Standard	592	4	5%	30	1
	Water Heating Total				**430**	**76**
REFRIGERATION						
Ref./Ambient Subcooling	Conv. Ref./No Subcooling	22	17	20%	4	3
High R-Value Glass Doors	Conventional Refrigeration System	283	20	40%	113	8
Anti-Condensate Heater Control	Conventional Refrigeration System	47	3	25%	12	1
Dual-Path Ref. System	Conventional Refrigeration System	68	10	20%	14	2
	Refrigeration Total				**143**	**14**
COOKING						
Energy-Efficient Electric Fryers	Standard Eff. Electric Fryers	52	5	40%	21	2
Electric Forced Convection Oven	Electric Nat. Convection Oven	47	16	20%	9	3
	Cooking Total				**30**	**5**
	Total				**603**	**95**

- *Ref./Ambient Subcooling Applicable in Restaurant, Grocery, Warehouse, and Hospital Buildings.*
- *High-R Value Glass Doors and Anti-Condensate Heater Controls Applicable in Restaurant, Retail, Grocery, School, College, Hospital, and Lodging Buildings*
- *Dual-Path Supermarket Air Conditioning Applicable in Grocery Buildings*
- *Energy-Efficient Fryers and Forced Convection Ovens Applicable in Restaurant, Grocery, School, Hospital, and Lodging Buildings*

The penetration of a measure is based on its cost-effectiveness, potential net benefits, persistence of energy savings over time, technical feasibility, and the current penetration of the base and efficient technologies.

COMMERCIAL NEW CONSTRUCTION/COMMERCIAL NEW CONSTRUCTION – RENEWABLES

Overview

This program will encourage the design and construction of energy-efficient new commercial buildings that exceed existing energy and building codes. Buildings undergoing major renovations would also be eligible to participate in this program. The program will have the goal of increasing the market acceptance of energy-efficient and renewable building technologies. This program will offer both a prescriptive path and a comprehensive path. For those customers choosing the comprehensive path, TVA will provide technical assistance to builders, architects, developers, and building owners from the early planning and design stages to the commissioning of the finished building. The prescriptive path would apply to smaller buildings or buildings too far along in their construction to participate in the comprehensive path.

Target Market

This program targets owners and developers of new commercial buildings and building undergoing major renovation. The forecast estimates that Valley commercial floorspace will grow by approximately 60 million square feet per year through 2010.

Implementation Strategy

The Commercial New Construction option will provide design assistance through provision of education and incentives to architects and engineers. Incentives provided to architects and engineers will be based on the energy efficiency performance of the building. The goal will be to make the design of energy-efficient electric buildings standard practice in the Valley. Additional design assistance will be provided to participants choosing the New Construction—Renewables option, which calls for the adoption of passive solar design.

Building commissioning services will be offered to ensure that installed efficiency measures operate as designed. Building commissioning includes balancing HVAC systems, setting controls on energy management systems, and fine tuning other equipment. Contractors will be trained to install equipment properly and building commissioning will enhance the reliability and cost-effectiveness of energy efficiency measures.

TVA will partner with trade allies in the design community in marketing the Commercial New Construction Program. Coordination with architects, engineers, and others will result in the most rapid adoption and acceptance of more energy efficient building design and construction.

Monitoring and Evaluation

Process evaluation will be conducted to compare the cost and the effectiveness of the different delivery strategies. Impact evaluation will be conducted to determine the program benefits.

Commercial New Construction

Program Assumptions

Package Measure Life (Years)	20
Free-Rider Rate	10%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	5%
Free-Rider Market Barrier Costs Eliminated	50%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	2,050

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	46,650	9,330	9,330	20%
2	46,650	13,995	23,325	25%
3	46,650	18,660	41,985	30%
4	46,650	23,325	65,310	35%
5	46,650	23,325	88,635	38%
6	48,450	24,225	112,860	40%
7	48,450	24,225	137,085	42%
8	48,450	24,225	161,310	43%
9	48,450	24,225	185,535	43%
10	48,450	24,225	209,760	44%
11	49,350	24,675	234,435	45%
12	49,350	24,675	259,110	45%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $75 Total Variable Admin. Cost	Per Participant Measure Cost $500 Total Part. Measure Cost	Per Participant Incentive $375 Total Part. Incentive
1	$475,000	$699,750	$4,665,000	$3,498,750
2	$475,000	$1,049,625	$6,997,500	$5,248,125
3	$475,000	$1,399,500	$9,330,000	$6,997,500
4	$475,000	$1,749,375	$11,662,500	$8,746,875
5	$475,000	$1,749,375	$11,662,500	$8,746,875
6	$475,000	$1,816,875	$12,112,500	$9,084,375
7	$475,000	$1,816,875	$12,112,500	$9,084,375
8	$475,000	$1,816,875	$12,112,500	$9,084,375
9	$475,000	$1,816,875	$12,112,500	$9,084,375
10	$475,000	$1,816,875	$12,112,500	$9,084,375
11	$475,000	$1,850,625	$12,337,500	$9,253,125
12	$475,000	$1,850,625	$12,337,500	$9,253,125

Incentives

This sector is the classic example of the lost opportunity efficiency investment. It is most cost-effective to include energy efficiency measures in the design and the initial construction of a new building. To achieve the desired participation level and the market transformation goals of the program, incentives will be offered to building owners and developers. Building owners and developers will be offered rebates to cover 75 percent of the incremental cost of design and of the energy-efficient technologies specified for the new or renovated building.

COMMERCIAL NEW CONSTRUCTION

Per Participant Costs and Impacts Based on:

Efficient Measures	Base Measures	Annual Energy Impact	Cost ($)	Measure Penetration	Weighted Energy Impact	Weighted Cost ($)
LIGHTING						
T-8/Electronic Ballasts	4' - 40W Fluor. Lamps/EE Ballasts	631	62	70%	442	43
Daylighting Design	4' - 40W Fluor. Lamps/EE Ballasts	1,760	250	25%	440	63
Occupancy Sensors	All Interior Fluorescent Lighting	847	135	25%	212	34
Photoelectric Controls	Existing Lighting—Outdoor	232	6	25%	58	2
LED Exit Lights	Incandescent Exit Signs	289	103	50%	144	51
		Lighting Total			**1,296**	**193**
HVAC						
High-Efficiency Chiller	Standard Eff. Chiller	93	41	50%	46	21
Speed Control for Cooling Tower	Standard Cooling Tower	234	22	50%	117	11
High-Efficiency A/C DX	Standard Eff. A/C DX	500	225	20%	100	45
High-Efficiency Heat Pump	Standard Eff. Heat Pump	300	464	15%	45	70
Spectrally Selective Windows	Standard Windows	324	294	15%	49	44
Roof Insulation	Standard Roof Insulation	317	156	15%	48	23
Wall Insulation	All Heating, Cooling, Ventilation	395	313	15%	59	47
		HVAC Total			**464**	**261**
WATER HEATING						
Heat Pump Water Heater	Electric Water Heater—Standard	494	81	40%	198	32
Heat Recovery Water Heater	Electric Water Heater—Standard	247	19	35%	86	7
Low Flow Showerheads	Electric Water Heater—Standard	148	1	25%	37	0
		Water Heating Total			**321**	**39**
		Total			**2,081**	**493**

The penetration of a measure is based on its cost-effectiveness, potential net benefits, persistence of energy savings over time, technical feasibility, and the current penetration of the base and efficient technologies.

Commercial New Construction—Renewables

Program Assumptions

Package Measure Life (Years)	30
Free-Rider Rate	10%
Free-Driver Rate	5%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	50%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	4,900

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	46,650	933	933	2%
2	46,650	933	1,866	2%
3	46,650	933	2,799	2%
4	46,650	1,400	4,199	2%
5	46,650	1,400	5,599	2%
6	48,450	1,454	7,053	3%
7	48,450	1,938	8,991	3%
8	48,450	1,938	10,929	3%
9	48,450	1,938	12,867	3%
10	48,450	2,423	15,290	3%
11	49,350	2,468	17,758	3%
12	49,350	2,468	20,226	4%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $150 Total Variable Admin. Cost	Per Participant Measure Cost $2,150 Total Part. Measure Cost	Per Participant Incentive $1,500 Total Part. Incentive
1	$225,000	$139,950	$2,005,950	$1,399,500
2	$225,000	$139,950	$2,005,950	$1,399,500
3	$225,000	$139,950	$2,005,950	$1,399,500
4	$225,000	$210,000	$3,010,000	$2,100,000
5	$225,000	$210,000	$3,010,000	$2,100,000
6	$225,000	$218,100	$3,126,100	$2,181,000
7	$225,000	$290,700	$4,166,700	$2,907,000
8	$225,000	$290,700	$4,166,700	$2,907,000
9	$225,000	$290,700	$4,166,700	$2,907,000
10	$225,000	$363,450	$5,209,450	$3,634,500
11	$225,000	$370,200	$5,306,200	$3,702,000
12	$225,000	$370,200	$5,306,200	$3,702,000

COMMERCIAL NEW CONSTRUCTION—RENEWABLES

Per Participant Costs and Impacts Based on:

Efficient Measures	Base Measures	Annual Energy Impact	Cost ($)	Measure Penetration	Weighted Energy Impact	Weighted Cost ($)
LIGHTING						
Daylighting Design	4' - 40W Fluor. Lamps/EE Ballasts	1,760	250	100%	1,760	250
HVAC						
Passive Solar Design	All Heating, Cooling, Ventilation	2,500	1,350	100%	2,500	1,350
WATER HEATING						
Solar Water Heaters	Electric Water Heater—Standard	638	544	100%	638	544
		Total			**4,898**	**2,144**

The penetration of a measure is based on its cost-effectiveness, potential net benefits, persistence of energy savings over time, technical feasibility, and the current penetration of the base and efficient technologies.

SMALL COMMERCIAL RETROFIT—DIRECT INSTALL

Overview

The installation of energy-efficient equipment can assist small commercial and industrial customers in reducing operating costs and enhancing their competitiveness and viability. This program will focus on promoting energy efficiency and renewable technologies that benefit the local business community, the utility, and the customer by reducing costs, improving reliability, and enhancing customer satisfaction.

Target Market

This program is most applicable to existing and new small commercial and industrial companies with less than 50 kilowatts of demand. These customers, occupying about one-half of the commercial floorspace in the Valley, often do not have the staff or the capital to analyze or invest in energy efficiency improvements. This program utilizes a very aggressive delivery strategy to address the needs of these customers who are considered the most difficult commercial and industrial customers to reach.

Implementation Strategy

The Small Commercial Retrofit Program would provide participants with an on-site audit. At the time of the audit, the auditor installs cost-effective lighting, water heating, and weatherization measures. The auditor will also identify and recommend any additional cost-effective energy-efficient opportunities that may exist in the customer's facility. The auditor will refer the customer to other programs offered by TVA and/or the distributors that offer rebates or financing for energy-efficient measures that cannot be installed by the auditor (e.g., HVAC system upgrade). Customers may be asked to pay a nominal charge for this service to minimize free-ridership and program dropouts.

Incentives

Direct installation of measures at the time of site visit and audit, as well as rebates or financing for other measures installed by the customer based on audit recommendations.

Program Assumptions

Package Measure Life (Years)	7
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	10%
Free-Rider Market Barrier Costs Eliminated	60%
Non-Free-Rider Market Barrier Costs Eliminated	80%
Annual Energy Impact (kWh)	1,500

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	1,500,000	30,000	30,000	2%
2	1,500,000	45,000	75,000	5%
3	1,500,000	60,000	135,000	9%
4	1,500,000	60,000	195,000	13%
5	1,500,000	60,000	255,000	17%
6	1,500,000	60,000	315,000	21%
7	1,500,000	60,000	375,000	25%
8	1,500,000	60,000	435,000	29%
9	1,500,000	60,000	495,000	33%
10	1,500,000	45,000	540,000	36%
11	1,500,000	45,000	585,000	39%
12	1,500,000	45,000	630,000	42%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $40 Total Variable Admin. Cost	Per Participant Measure Cost $280 Total Part. Measure Cost	Per Participant Incentive $250 Total Part. Incentive
1	$375,000	$1,200,000	$8,400,000	$7,500,000
2	$375,000	$1,800,000	$12,600,000	$11,250,000
3	$375,000	$2,400,000	$16,800,000	$15,000,000
4	$375,000	$2,400,000	$16,800,000	$15,000,000
5	$375,000	$2,400,000	$16,800,000	$15,000,000
6	$375,000	$2,400,000	$16,800,000	$15,000,000
7	$375,000	$2,400,000	$16,800,000	$15,000,000
8	$375,000	$2,400,000	$16,800,000	$15,000,000
9	$375,000	$2,400,000	$16,800,000	$15,000,000
10	$375,000	$1,800,000	$12,600,000	$11,250,000
11	$375,000	$1,800,000	$12,600,000	$11,250,000
12	$375,000	$1,800,000	$12,600,000	$11,250,000

Monitoring and Evaluation

Process evaluation will be conducted to compare the cost and the effectiveness of different delivery strategies. Impact evaluation will be conducted to determine the program benefits.

SMALL COMMERCIAL RETROFIT—DIRECT INSTALL

Per Participant Costs and Impacts Based on:

Efficient Measures	Base Measures	Annual Energy Impact	Cost ($)	Measure Penetration	Weighted Energy Impact	Weighted Cost ($)
LIGHTING						
Compact Fluorescent Lighting	Incandescent Lighting	8,600	1,280	10%	860	128
LED Exit Lights	Incandescent Lighting	289	135	50%	145	68
T-8/Electronic Ballasts	4' - 40W Fluor. Lamps/EE Ballasts	1,234	230	25%	308	57
		Lighting Total			**1,313**	**253**
HVAC						
Temperature Setup/Setback	All Heating, Cooling, Ventilation	246	22	25%	61	5
Window Film	Standard Windows	570	65	10%	57	7
Leak-Free Ducts	All Heating, Cooling, Ventilation	256	127	10%	26	13
		HVAC Total			**144**	**25**
WATER HEATING						
DHW Heater Insulation	Electric Water Heater—Standard	50	5	50%	25	3
DHW Heat Trap/Pipe Insulation	Electric Water Heater—Standard	99	5	20%	20	1
		Water Heating Total			**45**	**4**
		Total			**1,502**	**282**

The penetration of a measure is based on its cost-effectiveness, potential net benefits, persistence of energy savings over time, technical feasibility, and the current penetration of the base and efficient technologies.

COMMMERCIAL HVAC MAINTENANCE PROGRAM

Overview

This program offers commercial customers maintenance contracts for their HVAC systems. A monthly charge, included on the customer's electricity bill, covers regular maintenance of the customer's HVAC equipment by TVA or a contractor. The contract also provides repairs at a reduced cost in case of failure of the HVAC system. The proper maintenance of the system will result in energy savings and improved performance for the customer.

Target Market

This program targets small to medium commercial customers without building maintenance staffs.

Implementation Strategy

TVA would contract with local dealers to provide this service to the small commercial and industrial customers. The program will be promoted directly by TVA and through its trade allies. Approved TVA contractors would be enlisted to promote this program to their commercial and industrial customers. The cost of providing this service to customers would be recovered through a small charge on the customer's monthly bill. However, the customer should see a net reduction in the total bill as a result of the energy savings realized.

This program will build TVA's long-term relationship with its customers, as well as provide an opportunity to promote other TVA programs to the customer.

Incentives

The customer receives HVAC maintenance services for a fee. The maintenance contract may provide a performance guarantee or insurance coverage to protect the customer in the case of equipment failure.

Monitoring and Evaluation

Standard monitoring and evaluation will be conducted to determine program costs and benefits. Process evaluation will be conducted to assess the value of this service to customers.

Program Assumptions

Package Measure Life (Years)	10
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	50%
Non-Free-Rider Market Barrier Costs Eliminated	70%
Annual Energy Impact (kWh)	350

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	2,250,000	5,625	5,625	0%
2	2,250,000	5,625	11,250	1%
3	2,250,000	5,625	16,875	1%
4	2,250,000	11,250	28,125	1%
5	2,250,000	11,250	39,375	2%
6	2,250,000	11,250	50,625	2%
7	2,250,000	16,875	67,500	3%
8	2,250,000	16,875	84,375	4%
9	2,250,000	16,875	101,250	5%
10	2,250,000	22,500	123,750	6%
11	2,250,000	22,500	146,250	7%
12	2,250,000	22,500	168,750	8%

Year	Fixed Administrative Cost	Per Participant Annual Variable Administrative Costs $40 Total Variable Admin. Cost	Per Participant Annual Measure Cost $50 Total Part. Measure Cost	Per Participant Incentive $0 Total Part. Incentive
1	$160,000	$225,000	$281,250	$0
2	$160,000	$450,000	$562,500	$0
3	$160,000	$675,000	$843,750	$0
4	$160,000	$1,125,000	$1,406,250	$0
5	$160,000	$1,575,000	$1,968,750	$0
6	$160,000	$2,025,000	$2,531,250	$0
7	$160,000	$2,700,000	$3,375,000	$0
8	$160,000	$3,375,000	$4,218,750	$0
9	$160,000	$4,050,000	$5,062,500	$0
10	$160,000	$4,950,000	$6,187,500	$0
11	$160,000	$5,850,000	$7,312,500	$0
12	$160,000	$6,750,000	$8,437,500	$0

COMPREHENSIVE MEASURES PROGRAM—FINANCING/REBATES

Overview

This program targets large commercial customers to encourage the installation of a comprehensive set of energy efficiency measures. Technical assistance is provided to program participants to encourage them to install a combination of lighting, HVAC, water heating, and other measures in order to achieve the maximum energy savings at the lowest cost. This program will also pursue retrofits in conjunction with market-driven investments in commercial chiller and packaged HVAC unit overhauls. The program would encourage installation of high-efficiency lighting and other cooling load reductions, such as HVAC system optimization measures that allow installation of new high-efficiency, properly sized HVAC units.

Target Market

This program targets commercial customers with a demand greater than 50 kilowatts. Customer research estimates that this reflects one-third of the approximately 3 billion square feet of commercial floor space in the Tennessee Valley.

Implementation Strategy

This program provides technical assistance, low-interest financing, and rebates to customers to encourage the installation of a comprehensive set of energy efficiency measures. This program will encourage the application of energy efficient technologies to meet customers' financial, environmental, and productivity needs. TVA will employ account representatives to promote this program to its largest customers. TVA will establish partnerships with trade allies to identify industry-specific opportunities to promote energy efficiency. TVA will work with customers to assess their needs and evaluate technology-based solutions.

Incentives

Under this program, customers will be offered low interest financing to encourage installation of energy-efficient measures. Low interest financing of the full cost of the energy-efficient investment assists customers in overcoming the initial capital expenditure barrier to investing in energy efficiency, while having a minimal effect on rates. In a more aggressive scenario, customers would be offered a rebate equal to 50 percent of the cost of energy-efficient technologies. These rebates would be offered to encourage greater participation, as well as higher energy and demand savings.

Comprehensive Measures Program—Financing

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	5%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	5%
Free-Rider Market Barrier Costs Eliminated	40%
Non-Free-Rider Market Barrier Costs Eliminated	60%
Annual Energy Impact (kWh)	2,400

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	945,923	9,460	9,460	1%
2	945,923	9,460	18,920	2%
3	945,923	9,460	28,380	3%
4	945,923	14,190	42,570	5%
5	945,923	14,190	56,760	6%
6	945,923	14,190	70,950	8%
7	945,923	18,920	89,870	10%
8	945,923	18,920	108,790	12%
9	945,923	18,920	127,710	14%
10	945,923	23,650	151,360	16%
11	945,923	23,650	175,010	19%
12	945,923	23,650	198,660	21%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $60 Total Variable Admin. Cost	Per Participant Measure Cost $600 Total Part. Measure Cost	Per Participant Incentive $75 Total Part. Incentive
1	$400,000	$567,600	$5,676,000	$709,500
2	$400,000	$567,600	$5,676,000	$709,500
3	$400,000	$567,600	$5,676,000	$709,500
4	$400,000	$851,400	$8,514,000	$1,064,250
5	$400,000	$851,400	$8,514,000	$1,064,250
6	$400,000	$851,400	$8,514,000	$1,064,250
7	$400,000	$1,135,200	$11,352,000	$1,419,000
8	$400,000	$1,135,200	$11,352,000	$1,419,000
9	$400,000	$1,135,200	$11,352,000	$1,419,000
10	$400,000	$1,419,000	$14,190,000	$1,773,750
11	$400,000	$1,419,000	$14,190,000	$1,773,750
12	$400,000	$1,419,000	$14,190,000	$1,773,750

Applicable Measures

A comprehensive set of customized measures will be identified for each participant. The measures will be selected to achieve the maximum level of energy savings at the lowest cost. While several technologies have been identified for promotion in this program, the program also allows for the identification of customized applications of energy-efficient technologies that are cost-effective on a site-specific basis.

COMPREHENSIVE MEASURES PROGRAM—FINANCING

Per Participant Costs and Impacts Based on:

Efficient Measures	Base Measures	Annual Energy Impact	Cost ($)	Measure Penetration	Weighted Energy Impact	Weighted Cost ($)
LIGHTING						
T-8/Electronic Ballasts	4' - 40W Fluor. Lamps/EE Ballasts	1,234	230	70%	864	161
Refl/Delamp: 4' - 40W/Elec. Ballast	4' - 40W Fluor. Lamps/EE Ballasts	2,184	321	10%	218	32
LED Exit Lights	Incandescent Exit Signs	289	135	50%	144	67
Occupancy Sensors	All Interior Fluorescent Lighting	911	135	25%	228	34
		Lighting Total			**1,454**	**294**
HVAC						
High-Efficiency Chiller	Standard Eff. Chiller	93	41	50%	46	21
Speed Control for Cooling Tower	Standard Cooling Tower	234	22	50%	117	11
High-Efficiency A/C DX	Standard Eff. A/C DX	500	225	20%	100	45
Chiller Downsizing						
High-Efficiency Heat Pump	Standard Eff. Heat Pump	150	232	20%	30	46
Roof Insulation	All Heating, Cooling, Ventilation	2,458	228	10%	246	23
Window Film	Standard Windows	570	65	10%	57	7
ASD Ventilation Controls w/VAV	Stan. Eff. Constant Speed Motors	690	930	10%	69	93
Leak-Free Ducts	All Heating, Cooling, Ventilation	256	127	10%	26	13
		HVAC Total			**691**	**257**
WATER HEATING						
Heat Pump Water Heater	Electric Water Heater—Standard	494	104	35%	173	36
Heat Recovery Water Heater	Electric Water Heater—Standard	247	43	30%	74	13
Low Flow Showerheads	Electric Water Heater—Standard	148	1	15%	22	0
		Water Heating Total			**269**	**49**
		Total			**2,415**	**602**

The penetration of a measure is based on its cost-effectiveness, potential net benefits, persistence of energy savings over time, technical feasibility, and the current penetration of the base and efficient technologies.

Comprehensive Measures Program—Rebates

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	10%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	8%
Free-Rider Market Barrier Costs Eliminated	45%
Non-Free-Rider Market Barrier Costs Eliminated	65%
Annual Energy Impact (kWh)	2,700

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	945,923	14,190	14,190	2%
2	945,923	14,190	28,380	3%
3	945,923	18,920	47,300	5%
4	945,923	18,920	66,220	7%
5	945,923	23,650	89,870	10%
6	945,923	23,650	113,520	12%
7	945,923	28,380	141,900	15%
8	945,923	28,380	170,280	18%
9	945,923	33,110	203,390	22%
10	945,923	33,110	236,500	25%
11	945,923	37,840	274,340	29%
12	945,923	37,840	312,180	33%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $50 Total Variable Admin. Cost	Per Participant Measure Cost $700 Total Part. Measure Cost	Per Participant Incentive $350 Total Part. Incentive
1	$500,000	$709,500	$9,933,300	$4,966,500
2	$500,000	$709,500	$9,933,300	$4,966,500
3	$500,000	$946,000	$13,244,000	$6,622,000
4	$500,000	$946,000	$13,244,000	$6,622,000
5	$500,000	$1,182,500	$16,555,000	$8,277,500
6	$500,000	$1,182,500	$16,555,000	$8,277,500
7	$500,000	$1,419,000	$19,866,000	$9,933,000
8	$500,000	$1,419,000	$19,866,000	$9,933,000
9	$500,000	$1,655,500	$23,177,000	$11,588,500
10	$500,000	$1,655,500	$23,177,000	$11,588,500
11	$500,000	$1,892,000	$26,488,000	$13,244,000
12	$500,000	$1,892,000	$26,488,000	$13,244,000

COMPREHENSIVE MEASURES PROGRAM—REBATES

Per Participant Costs and Impacts Based on:

Efficient Measures	Base Measures	Annual Energy Impact	Cost ($)	Measure Penetration	Weighted Energy Impact	Weighted Cost ($)
LIGHTING						
T-8/Electronic Ballasts	4' - 40W Fluor. Lamps/EE Ballasts	1,234	230	75%	925	173
Refl/Delamp: 4' - 40W/Elec. Ballast	4' - 40W Fluor. Lamps/EE Ballasts	2,184	321	10%	218	32
LED Exit Lights	Incandescent Exit Signs	289	135	40%	116	54
Electroluminescent Exit Signs	Incandescent Exit Signs	342	150	10%	34	15
Occupancy Sensors	All Interior Fluorescent Lighting	911	135	25%	228	34
		Lighting Total			**1,521**	**308**
HVAC						
High Efficiency Chiller	Standard Eff. Chiller	93	41	50%	46	20
Speed Control for Cooling Tower	Standard Cooling Tower	234	22	50%	117	11
High Efficiency A/C DX	Standard Eff. A/C DX	500	225	20%	100	45
Chiller Downsizing						
High Efficiency Heat Pump	Standard Eff. Heat Pump	150	232	20%	30	46
Roof Insulation	All Heating, Cooling, Ventilation	2,458	228	15%	369	34
Window Film	Standard Windows	570	65	15%	86	10
ASD Ventilation Controls w/VAV	Stan. Eff. Constant Speed Motors	690	930	15%	104	140
Leak Free Ducts	All Heating, Cooling, Ventilation	256	127	15%	38	19
		HVAC Total			**890**	**325**
WATER HEATING						
Heat Pump Water Heater	Electric Water Heater—Standard	494	104	40%	198	42
Heat Recovery Water Heater	Electric Water Heater—Standard	247	43	30%	74	13
Solar Water Heaters	Electric Water Heater—Standard	638	544	5%	32	27
Low Flow Showerheads	Electric Water Heater—Standard	148	1	15%	22	0
		Water Heating Total			**326**	**82**
		Total			**2,737**	**715**

The penetration of a measure is based on its cost-effectiveness, potential net benefits, persistence of energy savings over time, technical feasibility, and the current penetration of the base and efficient technologies.

COMMERCIAL LOAD MANAGEMENT—COOL STORAGE/ ROOFTOP COOL STORAGE

Overview

This program offers customers incentives to encourage the adoption of cool storage technologies to reduce the customer's peak billing demand and thus reduce the TVA system peak demand. By encouraging customers to utilize cool storage technologies, TVA's load factor is enhanced by shifting on-peak cooling demand to off-peak periods, which lowers generating costs. The program will also promote rooftop cool storage, an emerging technology that provides efficiency and load management opportunities for small commercial customers.

Target Markets

This program is targeted at large commercial customers, particularly large offices and hospitals, with significant year-round cooling loads. The program will also be targeted to the large percentage of commercial customers using rooftop cooling equipment. The program is open both to new and existing customers able to incorporate cool storage into their building design.

Implementation Strategy

The cool storage technology will be promoted through TVA field staff technical assistance and through trade allies, particularly HVAC contractors. Customers will be offered assistance in designing the cool storage systems and incentives to cover the additional cost of installing them.

Incentives

This program offers customers a rebate of 150 percent of the incremental cost of the cool storage equipment, or offers customers a technology-specific rate option, in order to encourage adoption of cool storage technologies and to cover increased operating costs. HVAC contractors will be offered incentives to promote cool storage technology to commercial customers.

Customers are offered an incentive of 50 percent of the incremental cost of rooftop cool storage units which offer efficiency benefits. A technology specific rate for cool storage could be offered as alternative incentive to customers.

Monitoring and Evaluation

The cool storage system will be demand-metered in order to determine the demand savings to the TVA system. Bill analyses will be conducted to determine the impact on customers.

Applicable Technologies

- Thermal Storage Systems - Ice or Water
- Rooftop Cool Storage Units

Commercial Load Management—Cool Storage

Program Assumptions

Package Measure Life (Years)	20
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	50%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	(100)
Average Demand Impacts (kW)	2

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	342,000	1,710	1,710	1%
2	342,000	1,710	3,420	1%
3	342,000	1,710	5,130	2%
4	342,000	1,710	6,840	2%
5	342,000	3,420	10,260	3%
6	342,000	3,420	13,680	4%
7	342,000	3,420	17,100	5%
8	342,000	3,420	20,520	6%
9	342,000	3,420	23,940	7%
10	342,000	3,420	27,360	8%
11	342,000	3,420	30,780	9%
12	342,000	3,420	34,200	10%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $40 Total Variable Admin. Cost	Per Participant Measure Cost $300 Total Part. Measure Cost	Per Participant Incentive $450 Total Part. Incentive
1	$175,000	$68,400	$513,000	$769,500
2	$175,000	$68,400	$513,000	$769,500
3	$175,000	$68,400	$513,000	$769,500
4	$175,000	$68,400	$513,000	$769,500
5	$175,000	$136,800	$1,026,000	$1,539,000
6	$175,000	$136,800	$1,026,000	$1,539,000
7	$175,000	$136,800	$1,026,000	$1,539,000
8	$175,000	$136,800	$1,026,000	$1,539,000
9	$175,000	$136,800	$1,026,000	$1,539,000
10	$175,000	$136,800	$1,026,000	$1,539,000
11	$175,000	$136,800	$1,026,000	$1,539,000
12	$175,000	$136,800	$1,026,000	$1,539,000

Commercial Load Management—Rooftop Cool Storage

Program Assumptions

Package Measure Life (Years)	20
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	50%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	50
Average Demand Impact (kW)	2

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	1,500,000	2,050	2,050	0%
2	1,500,000	2,050	4,010	0%
3	1,500,000	3,050	7,150	1%
4	1,500,000	3,050	10,200	1%
5	1,500,000	3,050	13,250	1%
6	1,500,000	3,050	16,300	1%
7	1,500,000	4,070	20,370	1%
8	1,500,000	4,070	24,440	2%
9	1,500,000	5,080	29,520	2%
10	1,500,000	5,080	34,600	2%
11	1,500,000	5,080	39,680	3%
12	1,500,000	5,080	44,760	3%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $25 Total Variable Admin. Cost	Per Participant Measure Cost $1,000 Total Part. Measure Cost	Per Participant Incentive $500 Total Part. Incentive
1	$131,250	$51,250	$2,050,000	$1,025,000
2	$131,250	$51,250	$2,050,000	$1,025,000
3	$131,250	$76,250	$3,050,000	$1,525,000
4	$131,250	$76,250	$3,050,000	$1,525,000
5	$131,250	$76,250	$3,050,000	$1,525,000
6	$131,250	$76,250	$3,050,000	$1,525,000
7	$131,250	$101,750	$4,070,000	$2,035,000
8	$131,250	$101,750	$4,070,000	$2,035,000
9	$131,250	$127,000	$5,080,000	$2,540,000
10	$131,250	$127,000	$5,080,000	$2,540,000
11	$131,250	$127,000	$5,080,000	$2,540,000
12	$131,250	$127,000	$5,080,000	$2,540,000

COMMERCIAL GROUP LOAD CURTAILMENT

Overview

This program is designed to reduce the electricity demand of commercial customers at the time of the system peak. Commercial customers would band together to shed 100 kilowatts blocks from the system peak. Commercial customers would select their own load reduction strategy. Customers would receive bill credits as an incentive to reduce load at the system peak.

Target Market

This program targets large commercial customers, or groups of customers that can reduce electricity demand by at least 100 kilowatts at the time of the system peak.

Implementation Strategy

TVA would employ account representatives to promote this program directly to customers. The program would provide technical assistance to customers helping them to choose the most beneficial load reduction strategy. The utility would select the method and timing for notifying the customer of the need to reduce load.

Customers will select the load reduction strategy. The utility will advise customers on appropriate technologies for accomplishing load reductions.

Incentives

Participants will be offered financial incentives or bill credits based on the level of their load reduction. The amount of the incentive or bill credit will vary based on the length and frequency of interruption and the amount of notice the participating customer(s) is given.

Monitoring and Evaluation

Monitoring and evaluation will be conducted to determine program impacts, costs, and benefits. Process evaluation will monitor customers' compliance with the terms and conditions of the load reduction contract.

Program Assumptions

Package Measure Life (Years)	10
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	20%
Non-Free-Rider Market Barrier Costs Eliminated	30%
Annual Energy Impact (kWh)	4,000
Average Demand Impact (kW)	100

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	32,039	80	80	0%
2	32,039	80	160	1%
3	32,039	80	240	1%
4	32,039	80	320	1%
5	32,039	160	480	2%
6	32,039	160	640	2%
7	32,039	160	800	3%
8	32,039	160	960	3%
9	32,039	240	1,200	4%
10	32,039	240	1,440	5%
11	32,039	160	1,600	5%
12	32,039	160	1,760	6%

Year	Fixed Administrative Cost	Annual Per Participant Variable Administrative Costs $250 Total Variable Admin. Cost	Annual Per Participant Measure Cost $4,500 Total Part. Measure Cost	Annual Per Participant Incentive $4,500 Total Part. Incentive
1	$200,000	$20,000	$360,000	$360,000
2	$200,000	$40,000	$720,000	$720,000
3	$200,000	$60,000	$1,080,000	$1,080,000
4	$200,000	$80,000	$1,440,000	$1,440,000
5	$200,000	$120,000	$2,160,000	$2,160,000
6	$200,000	$160,000	$2,880,000	$2,880,000
7	$200,000	$200,000	$3,600,000	$3,600,000
8	$200,000	$240,000	$4,320,000	$4,320,000
9	$200,000	$300,000	$5,400,000	$5,400,000
10	$200,000	$360,000	$6,480,000	$6,480,000
11	$200,000	$400,000	$7,200,000	$7,200,000
12	$200,000	$440,000	$7,920,000	$7,920,000

INDUSTRIAL TECHNOLOGY REBATES—HIGH-EFFICIENCY MOTORS/ADJUSTABLE SPEED DRIVES/ COMPRESSED AIR EFFICIENCY

Overview

More than 70 percent of the electricity consumed by TVA's industrial customers is used to power electric motors. To save energy and money, standard motors can be replaced with energy-efficient motors. Energy-efficient motors use less electricity, run cooler, often last longer, and outperform standard motors of the same size. This program would encourage the use of properly sized high-efficiency motors and variable speed motor drives in cost-effective applications. This program also promotes energy-efficient compressors and the proper maintenance of compressed air systems to reduce leaks.

Target Market

This program targets industrial customers using standard efficiency equipment in process or manufacturing applications.

Implementation Strategy

This program will address the delivery and availability of energy-efficient motors. Energy-efficient motors are very cost-effective and usually meet the strict payback requirements of commercial and industrial customers. However, customers' motor replacement patterns often prevent selection of such high-efficiency motors. Motors are most often replaced when they fail. The replacement motor comes out of the existing stock at the customer's site or from the motor distributor. The customer generally cannot wait several weeks to receive an efficient motor to replace a failed motor. In order to change current motor replacement practices, customers need education about the significant cost savings potential of high-efficiency motors. The program will work to create market acceptance and demand for high-efficiency motors through incentives. TVA will also partner with motor distributors in promoting high-efficiency motors. Motor distributors will be offered incentives to stock them and make them available to customers.

Incentives

Financial incentives will be offered, in addition to education and technical assistance, to help customers adopt the practice of replacing standard motors with high-efficiency motors, and using adjustable speed drives. Rebates will be offered to program participants to offset the incremental cost of the energy-efficient measures. In addition, incentives will be directed to motor dealers to enhance the availability of high-efficiency motors in the Tennessee Valley region. Incentives would be based on the size and efficiency of the replacement motor.

Monitoring and Evaluation

Standard monitoring and evaluation will be conducted to determine program costs and benefits. Process evaluation will be conducted to assess the market transformation effects of the program.

Industrial Technology Rebates—High-Efficiency Motors

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	20%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	50%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	40,000

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	2,369	36	36	2%
2	2,369	71	107	5%
3	2,369	107	214	9%
4	2,369	142	356	15%
5	2,369	142	498	21%
6	2,369	142	640	27%
7	2,369	142	782	33%
8	2,369	142	924	39%
9	2,369	142	1,066	45%
10	2,369	142	1,208	51%
11	2,369	142	1,350	57%
12	2,369	142	1,492	63%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $100 Total Variable Admin. Cost	Per Participant Measure Cost $2,000 Total Part. Measure Cost	Per Participant Incentive $1,500 Total Part. Incentive
1	$225,000	$3,600	$72,000	$54,000
2	$225,000	$7,100	$142,000	$106,500
3	$225,000	$10,700	$214,000	$160,500
4	$225,000	$14,200	$284,000	$213,500
5	$225,000	$14,200	$284,000	$213,500
6	$225,000	$14,200	$284,000	$213,500
7	$225,000	$14,200	$284,000	$213,500
8	$225,000	$14,200	$284,000	$213,500
9	$225,000	$14,200	$284,000	$213,500
10	$225,000	$14,200	$284,000	$213,500
11	$225,000	$14,200	$284,000	$213,500
12	$225,000	$14,200	$284,000	$213,500

Industrial Technology Rebate—Adjustable Speed Drives

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	10%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	50%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	40,000

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	2,369	24	24	1%
2	2,369	36	60	3%
3	2,369	47	107	5%
4	2,369	59	166	7%
5	2,369	59	225	10%
6	2,369	59	284	12%
7	2,369	59	343	15%
8	2,369	59	402	17%
9	2,369	59	461	20%
10	2,369	59	520	22%
11	2,369	59	579	25%
12	2,369	59	638	27%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $125 Total Variable Admin. Cost	Per Participant Measure Cost $5,000 Total Part. Measure Cost	Per Participant Incentive $3,750 Total Part. Incentive
1	$100,000	$3,000	$120,000	$90,000
2	$100,000	$4,500	$180,000	$135,000
3	$100,000	$5,875	$236,000	$176,250
4	$100,000	$7,375	$295,000	$221,250
5	$100,000	$7,375	$295,000	$221,250
6	$100,000	$7,375	$295,000	$221,250
7	$100,000	$7,375	$295,000	$221,250
8	$100,000	$7,375	$295,000	$221,250
9	$100,000	$7,375	$295,000	$221,250
10	$100,000	$7,375	$295,000	$221,250
11	$100,000	$7,375	$295,000	$221,250
12	$100,000	$7,375	$295,000	$221,250

Industrial Te ıology Rebate—Compressed Air Efficiency

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	10%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	50%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	75,000

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	2,369	12	12	1%
2	2,369	18	30	1%
3	2,369	18	48	2%
4	2,369	24	72	3%
5	2,369	24	95	4%
6	2,369	24	120	5%
7	2,369	30	150	6%
8	2,369	30	180	8%
9	2,369	30	210	9%
10	2,369	36	246	10%
11	2,369	36	282	12%
12	2,369	36	318	13%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $400 Total Variable Admin. Cost	Per Participant Measure Cost $25,000 Total Part. Measure Cost	Per Participant Incentive $18,750 Total Part. Incentive
1	$100,000	$4,800	$300,000	$225,000
2	$100,000	$7,200	$450,000	$337,500
3	$100,000	$7,200	$450,000	$337,500
4	$100,000	$9,600	$600,000	$450,000
5	$100,000	$9,600	$600,000	$450,000
6	$100,000	$9,600	$600,000	$450,000
7	$100,000	$12,000	$750,000	$562,500
8	$100,000	$12,000	$750,000	$562,500
9	$100,000	$12,000	$750,000	$562,500
10	$100,000	$14,400	$900,000	$675,000
11	$100,000	$14,400	$900,000	$675,000
12	$100,000	$14,400	$900,000	$675,000

INDUSTRIAL PROCESS ENERGY EFFICIENCY PROGRAM—DISTRIBUTOR SERVED/DIRECT SERVED

Overview

This program is designed to promote energy-efficient technologies to the industrial customers served by TVA and the distributors of TVA power. The program provides technical assistance to identify opportunities for energy efficiency improvements in industrial processes. This program will encourage applications of energy-efficient technologies to address customers' financial, environmental, and productivity needs.

Target Market

This program targets large industrial customers served by TVA and the distributors of TVA power.

Implementation Strategy

TVA will employ account representatives to promote this program directly to customers. The program would enlist trade allies and technical specialists to identify energy and demand savings opportunities. This program will help to build long-term relationships with this vulnerable customer group and establish a partnership to promote future economic development.

Incentives

Customers will be encouraged to participate with financial incentives, cost savings, and productivity improvements.

Monitoring and Evaluation

Monitoring and evaluation will be conducted to determine program impacts, costs, and benefits.

Applicable Measures

Customized energy-efficient technology applications will be identified for each participant.

Industrial Process Energy Efficiency Program— Distributor Served

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	10%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	70%
Non-Free-Rider Market Barrier Costs Eliminated	80%
Annual Energy Impact (kWh)	150,000

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	14,625	219	219	2%
2	15,000	225	444	3%
3	15,375	308	752	5%
4	15,750	315	1,067	7%
5	16,125	403	1,470	9%
6	16,500	413	1,883	11%
7	16,875	506	2,389	14%
8	17,250	518	2,907	17%
9	17,625	617	3,524	20%
10	18,000	630	4,154	23%
11	18,375	735	4,889	27%
12	18,750	750	5,639	30%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $500 Total Variable Admin. Cost	Per Participant Measure Cost $33,000 Total Part. Measure Cost	Per Participant Incentive $16,500 Total Part. Incentive
1	$187,500	$109,500	$7,227,000	$3,613,500
2	$187,500	$112,500	$7,425,000	$3,712,500
3	$187,500	$154,000	$10,164,000	$5,082,000
4	$187,500	$157,500	$10,395,000	$5,197,500
5	$187,500	$201,500	$13,299,000	$6,649,500
6	$187,500	$206,500	$13,629,000	$6,814,500
7	$187,500	$253,000	$16,698,000	$8,349,000
8	$187,500	$259,000	$17,094,000	$8,547,000
9	$187,500	$308,500	$20,361,000	$10,180,500
10	$187,500	$315,000	$20,790,000	$10,395,000
11	$187,500	$367,500	$24,255,000	$12,127,500
12	$187,500	$375,000	$24,750,000	$12,375,000

:ustrial Process Energy Efficiency Program—
:rect Served

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	10%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	70%
Non-Free-Rider Market Barrier Costs Eliminated	80%
Annual Energy Impact (kWh)	100,000

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	19,500	293	293	2%
2	20,000	300	593	3%
3	20,500	410	1,003	5%
4	21,000	420	1,423	7%
5	21,500	538	1,961	9%
6	22,000	550	2,511	11%
7	22,500	675	3,186	14%
8	23,000	690	3,876	17%
9	23,500	823	4,699	20%
10	24,000	840	5,539	23%
11	24,500	980	6,519	27%
12	25,000	1,000	7,519	30%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $500 Total Variable Admin. Cost	Per Participant Measure Cost $22,500 Total Part. Measure Cost	Per Participant Incentive $11,250 Total Part. Incentive
1	$187,500	$146,500	$6,592,500	$3,296,250
2	$187,500	$150,000	$6,750,000	$3,375,000
3	$187,500	$205,000	$9,225,000	$4,612,500
4	$187,500	$210,000	$9,450,000	$4,725,000
5	$187,500	$269,000	$12,105,000	$6,052,500
6	$187,500	$275,000	$12,375,000	$6,187,500
7	$187,500	$337,500	$15,187,500	$7,593,750
8	$187,500	$345,000	$15,525,000	$7,762,500
9	$187,500	$411,500	$18,517,500	$9,258,750
10	$187,500	$420,000	$18,900,000	$9,450,000
11	$187,500	$490,000	$22,050,000	$11,025,000
12	$187,500	$500,000	$22,500,000	$11,250,000

ENERGY-EFFICIENT RATES (OPT OUT)

Overview

Customers who have made investments in energy-efficient measures and who, therefore, cannot participate in the programs offered by TVA and its distributors would be eligible for the Energy-Efficient Rate. This program rewards customers who have taken action to use energy wisely and protect the environment. These customers are granted a rate discount for five years. The rate discount is put into effect after the customers demonstrate that they have made all cost-effective energy efficiency investments to their facilities.

In addition to the rate discount, customers will be provided with cooperative advertising materials that they can use to promote themselves as an energy-efficient supplier of goods and services. The promotional materials will emphasize the environmental benefits of energy efficiency and the wise use of resources by customers who have made investments in energy-efficient measures and processes.

This program provides in effect an opt-out option for customers who chose to make investments in energy-efficient measures themselves, without financial assistance from the utility. To qualify for the Energy-Efficient Rate, the customer must agree to a co-funded audit of its facilities. If the auditor identifies any remaining opportunities for cost-effective energy efficiency investments, the customer must agree to adopt the auditor's recommendations that meet a mutually agreed upon investment hurdle rate.

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	10%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	70%
Non-Free-Rider Market Barrier Costs Eliminated	80%
Annual Energy Impact (kWh)	150,000

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	14,625	293	293	2%
2	15,000	300	593	4%
3	15,375	308	901	6%
4	15,750	236	1,137	7%
5	16,125	242	1,379	9%
6	16,500	248	1,627	10%
7	16,875	169	1,796	11%
8	17,250	173	1,969	11%
9	17,625	176	2,145	12%
10	18,000	90	2,235	12%
11	18,375	92	2,327	13%
12	18,750	94	2,421	13%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $2,000 Total Variable Admin. Cost	Per Participant Measure Cost $35,000 Total Part. Measure Cost	Annual Per Participant Incentive $2,000 Total Part. Incentive
1	$100,000	$586,000	$10,255,000	$586,000
2	$100,000	$600,000	$10,500,000	$1,186,000
3	$100,000	$616,000	$10,780,000	$1,802,000
4	$100,000	$472,000	$8,260,000	$2,274,000
5	$100,000	$484,000	$8,470,000	$2,758,000
6	$100,000	$496,000	$8,680,000	$3,254,000
7	$100,000	$338,000	$5,915,000	$3,592,000
8	$100,000	$345,000	$6,055,000	$3,938,000
9	$100,000	$352,000	$6,160,000	$4,290,000
10	$100,000	$180,000	$3,150,000	$4,470,000
11	$100,000	$184,000	$3,220,000	$4,654,000
12	$100,000	$188,000	$3,290,000	$4,842,000

RENEWABLE/SELF-GENERATION CUSTOMER SERVICE OPTIONS

SUMMARY OF PROJECTED IMPACTS IN YEAR 2010

Option Name	2010 Winter MW	2010 Summer MW	GWh	Units (# part.)	¢/kWh TRC
RENEWABLE GENERATION PROGRAMS					
Landfill Gas/Fuel Cells	74	74	585	36	6.0
Small Head Hydro	5	5	29	5	5.9
Biomass/Wood Waste	54	54	374	62	3.6
Photovoltaics	1	1.5	5	1,975	33.0
Photovoltaics/Technology Advancement.	3	3.3	11	4,600	19.0
SELF-GENERATION					
Existing Cogeneration—Commercial	95	95	118	416	7.7
New Cogeneration—Commercial	18	18	51	84	12.1
New Cogeneration—Industrial	30	30	17	208	8.8

Values are the impacts occuring only in the year 2010 for the cumulative participation in the program to date.

TVA developed eight self-generation options, including cogeneration and options utilizing renewable fuels. The greatest potential for self-generation is from land-fill gas, wood wastes and existing commercial cogeneration. Detailed descriptions of the self-generation options follow.

RENEWABLE ENERGY GENERATION: LANDFILL GAS/FUEL CELLS, SMALL-HEAD HYDRO, BIOMASS/WOOD WASTE, PHOTOVOLTAICS, PHOTOVOLTAICS/TECHNOLOGY ADVANCEMENT

Overview

This program will encourage the development of customer-owned renewable generation resources. Renewable energy resources include generation from wood waste, biogas derived from anaerobic digestion of animal waste, and methane recovered from landfills. These fuels can be used with a number of generating technologies and fuel cells. Other renewable energy resources with cost-effective potential include small-head hydro systems and the use of photovoltaics in remote locations. This program provides annual incentives to customers to develop renewable resources to provide energy for their own use and for the benefit of the TVA system.

Target Market

This program targets customers with access to or in close proximity of renewable energy resources.

Implementation Strategy

Customers with access to renewable energy sources would be provided assistance to develop those resources. In addition to technical assistance, financial incentives would be provided to customers to improve the cost-effectiveness of renewable energy.

Incentives

Customers would be offered incentives of 2¢/kilowatt-hour for energy produced by combustion-based renewable resources. For non-combustion-based renewable resources, such as hydro resources and photovoltaics, customers would be offered an incentive of 3¢/kilowatt-hour. The incentives cover the higher costs and higher uncertainties associated with energy produced from renewable resources and reflect the environmental benefits of renewable and non-combustion-based resources. These incentives are for energy produced for the customer's own use which defers the need for TVA to add to its system resources. Excess energy produced could be sold to the TVA system at a market price.

Monitoring and Evaluation

Monitoring and evaluation will be conducted to determine program costs and benefits. Information on the cost and performance of renewable resources will be gathered and documented.

Renewable Energy Generation—Landfill Gas/Fuel Cells

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	10%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	70%
Non-Free-Rider Market Barrier Costs Eliminated	80%
Annual Energy Impact (kWh)	15,768,600
Average Demand Impact (kW)	2000

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	—	—	—	n/a
2	—	1	1	n/a
3	—	1	2	n/a
4	—	2	4	n/a
5	—	2	6	n/a
6	—	2	8	n/a
7	—	2	10	n/a
8	—	2	12	n/a
9	—	3	15	n/a
10	—	3	18	n/a
11	—	3	21	n/a
12	—	3	24	n/a

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $1,000 Total Variable Admin. Cost	Per Participant Measure Cost $3,360,000 Total Part. Measure Cost	Annual Per Participant Incentive $160/kW Total Part. Incentive
1	$50,000	$0	$0	$0
2	$50,000	$1,000	$3,360,000	$320,000
3	$50,000	$1,000	$3,360,000	$640,000
4	$50,000	$2,000	$6,720,000	$1,280,000
5	$50,000	$2,000	$6,720,000	$1,920,000
6	$50,000	$2,000	$6,720,000	$2,560,000
7	$50,000	$2,000	$6,720,000	$3,200,000
8	$50,000	$2,000	$6,720,000	$3,840,000
9	$50,000	$3,000	$10,080,000	$4,800,000
10	$50,000	$3,000	$10,080,000	$5,760,000
11	$50,000	$3,000	$10,080,000	$6,720,000
12	$50,000	$3,000	$10,080,000	$7,680,000

Renewable Energy Generation—Small-Head Hydro

Program Assumptions

Package Measure Life (Years)	30
Free-Rider Rate	10%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	70%
Non-Free-Rider Market Barrier Costs Eliminated	80%
Annual Energy Impact (kWh)	1,000,000
Average Demand Impact (kW)	163

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	—	—	—	n/a
2	—	10	10	n/a
3	—	—	10	n/a
4	—	1	10	n/a
5	—	—	10	n/a
6	—	5	15	n/a
7	—	—	15	n/a
8	—	9	25	n/a
9	—	—	25	n/a
10	—	4	29	n/a
11	—	—	29	n/a
12	—	—	29	n/a

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $0 Total Variable Admin. Cost	Per Participant Measure Cost Varies Total Part. Measure Cost	Annual Per Participant Incentive $185/kW Total Part. Incentive
1	$50,000	$0	$0	$0
2	$50,000	$0	$3,162,587	$295,519
3	$50,000	$0	$0	$295,519
4	$50,000	$0	$216,056	$313,612
5	$50,000	$0	$0	$313,612
6	$50,000	$0	$1,957,192	$461,372
7	$50,000	$0	$0	$461,372
8	$50,000	$0	$5,407,107	$738,798
9	$50,000	$0	$0	$738,798
10	$50,000	$0	$2,481,976	$862,433
11	$50,000	$0	$0	$862,433
12	$50,000	$0	$0	$862,433

Renewable Energy Generation—Biomass/Wood Waste

Program Assumptions

Package Measure Life (Years)	30
Free-Rider Rate	10%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	70%
Non-Free-Rider Market Barrier Costs Eliminated	80%
Annual Energy Impact (kWh)	5,550,000
Average Demand Impact (kW)	800

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	—	3	3	n/a
2	—	3	6	n/a
3	—	3	9	n/a
4	—	4	13	n/a
5	—	4	17	n/a
6	—	5	22	n/a
7	—	5	27	n/a
8	—	4	31	n/a
9	—	4	35	n/a
10	—	3	38	n/a
11	—	3	41	n/a
12	—	3	44	n/a

Year	Fixed Administrative Cost	Participant Variable Administrative Costs $0 Total Variable Admin. Cost	Per Participant Measure Cost $1,200,000 Total Part. Measure Cost	Per Annual Per Participant Incentive $140/kW Total Part. Incentive
1	$75,000	$3,000	$3,600,000	$336,000
2	$75,000	$3,000	$3,600,000	$672,000
3	$75,000	$3,000	$3,600,000	$1,008,000
4	$75,000	$4,000	$4,800,000	$1,456,000
5	$75,000	$4,000	$4,800,000	$1,904,000
6	$75,000	$5,000	$6,000,000	$2,464,000
7	$75,000	$5,000	$6,000,000	$3,024,000
8	$75,000	$4,000	$4,800,000	$3,472,000
9	$75,000	$4,000	$4,800,000	$3,920,000
10	$75,000	$3,000	$3,600,000	$4,256,000
11	$75,000	$3,000	$3,600,000	$4,592,000
12	$75,000	$3,000	$3,600,000	$4,928,000

Renewable Energy Generation—Photovoltaics

Program Assumptions

Package Measure Life (Years)	30
Free-Rider Rate	10%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	70%
Non-Free-Rider Market Barrier Costs Eliminated	80%
Annual Energy Impact (kWh)	2,230
Average Demand Impact (kW)	1

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	—	50	50	n/a
2	—	50	100	n/a
3	—	75	175	n/a
4	—	100	275	n/a
5	—	100	375	n/a
6	—	125	500	n/a
7	—	125	625	n/a
8	—	150	775	n/a
9	—	150	925	n/a
10	—	150	1,075	n/a
11	—	150	1,225	n/a
12	—	150	1,375	n/a

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $10 Total Variable Admin. Cost	Per Participant Measure Cost $5,000 Total Part. Measure Cost	Annual Per Participant Incentive $100/kW Total Part. Incentive
1	$50,000	$500	$250,000	$5,000
2	$50,000	$500	$250,000	$10,000
3	$50,000	$750	$375,000	$17,500
4	$50,000	$1,000	$500,000	$27,500
5	$50,000	$1,000	$500,000	$37,500
6	$50,000	$1,250	$625,000	$50,000
7	$50,000	$1,250	$625,000	$62,500
8	$50,000	$1,500	$750,000	$77,500
9	$50,000	$1,500	$750,000	$92,500
10	$50,000	$1,500	$750,000	$107,500
11	$50,000	$1,500	$750,000	$122,500
12	$50,000	$1,500	$750,000	$137,500

Renewable Energy Generation—Photovoltaics/Technology Advancement

Program Assumptions

Package Measure Life (Years)	30
Free-Rider Rate	10%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	70%
Non-Free-Rider Market Barrier Costs Eliminated	80%
Annual Energy Impact (kWh)	2,230
Average Demand Impact (kW)	1

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	—	150	150	n/a
2	—	150	300	n/a
3	—	200	500	n/a
4	—	200	700	n/a
5	—	250	950	n/a
6	—	250	1,200	n/a
7	—	300	1,500	n/a
8	—	300	1,800	n/a
9	—	350	2,150	n/a
10	—	350	2,500	n/a
11	—	350	2,850	n/a
12	—	350	3,200	n/a

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $10 Total Variable Admin. Cost	Per Participant Measure Cost $3,000 Total Part. Measure Cost	Annual Per Participant Incentive $100/kW Total Part. Incentive
1	$50,000	$1,500	$450,000	$15,000
2	$50,000	$1,500	$450,000	$30,000
3	$50,000	$2,000	$600,000	$50,000
4	$50,000	$2,000	$600,000	$70,000
5	$50,000	$2,500	$750,000	$95,000
6	$50,000	$2,500	$750,000	$120,000
7	$50,000	$3,000	$900,000	$150,000
8	$50,000	$3,000	$900,000	$180,000
9	$50,000	$3,500	$1,050,000	$215,000
10	$50,000	$3,500	$1,050,000	$250,000
11	$50,000	$3,500	$1,050,000	$285,000
12	$50,000	$3,500	$1,050,000	$320,000

EXISTING COGENERATION—COMMERCIAL

Overview

The program will promote the use of existing 150-kilowatt to 20-megawatt cogeneration installations in the commercial market sector as a means of load reduction.

Target Market

SIC codes most likely to be operating existing cogeneration systems are targeted SICs 40 - 49 (transportation), SIC 54 (supermarkets), SIC 58 (restaurants), SICs 60 - 67 (finance, insurance), SIC 70 (hotels/motels), SIC 805 (hospitals), and SIC 806 (nursing homes).

Implementation Strategy

TVA will work with commercial decision-makers in the above-mentioned SIC classifications to ensure comprehensive coverage of the market. Business decision-makers will receive information, technical studies, and/or financial incentives to promote the installation of new cogeneration technologies. The technologies are targeted to be in the 150-kilowatt to 20- megawatt range and will supply power to the business for all or part of their total load during TVA system peak loads.

Incentives

TVA will pay the customer for on-peak load reductions, acheived through self-generation, at a cost range averaging $25 per kilwatt. Excess energy produced could be sold to the TVA system at a market price.

Monitoring and Evaluation

TVA engineers will work with the on-site personnel and the vendor to ensure proper installation and synchronization with local distribution systems and the facility. Contracted payments to the company will be paid based on actual peak load demand reductions.

Applicable Technologies

- Reciprocating Engine Systems
- Gas Turbine Systems
- Coal-Fired Steam Turbine Systems

Program Assumptions

Package Measure Life (Years)	20
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	70%
Non-Free-Rider Market Barrier Costs Eliminated	80%
Annual Energy Impact (kWh)	3,423,382
Average Demand Impact (kW)	615

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	803	3	3	n/a
2	803	6	9	n/a
3	803	12	21	n/a
4	803	18	39	n/a
5	803	21	60	n/a
6	803	18	78	n/a
7	803	12	90	n/a
8	803	12	102	n/a
9	803	9	111	n/a
10	803	7	118	n/a

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $5,000 Total Variable Admin. Cost	Per Participant Measure Cost $0 Total Part. Measure Cost	Annual Per Participant Incentive $25/kW Total Part. Incentive
1	$76,000	$15,000	$0	$46,125
2	$76,000	$30,000	$0	$138,375
3	$76,000	$60,000	$0	$322,875
4	$76,000	$90,000	$0	$599,625
5	$76,000	$105,000	$0	$922,500
6	$76,000	$90,000	$0	$1,199,250
7	$76,000	$60,000	$0	$1,383,750
8	$76,000	$60,000	$0	$1,568,250
9	$76,000	$45,000	$0	$1,706,625
10	$76,000	$35,000	$0	$1,814,250

NEW COGENERATION—COMMERCIAL

Overview

The program will promote new 150-kilowatt to 20-megawatt cogeneration installations in the commercial market sector as a means of load reduction.

Target Market

SIC codes most receptive to adding new cogeneration systems are targeted SICs 40 - 49 (transportation), SIC 54 (supermarkets), SIC 58 (restaurants), SICs 60 - 67 (finance, insurance), SIC 70 (hotels/motels).

Implementation Strategy

TVA will work with commercial decision-makers in the above-mentioned SIC classifications to ensure comprehensive coverage of the market. Industry decision-makers will receive information, technical studies, and/or financial incentives to promote the installation of new cogeneration technologies. The technologies are targeted to be in the 150-kilowatt to 20- megawatt range and will supply power to the business for all or part of their total load during TVA system peak loads.

Incentives

TVA will pay the customer for on-peak load reductions, acheived through self-generation, at a cost range averaging $40 per kilowatt. Excess energy produced could be sold to the TVA system at a market price.

Monitoring and Evaluation

TVA engineers will work with on-site personnel and the vendor to ensure proper installation and synchronization with local distribution systems and the facility. Contracted payments to the company will be paid based on actual peak load demand reductions.

Applicable Technologies

- Reciprocating Engine Systems
- Gas Turbine Systems
- Coal-Fired Steam Turbine Systems

Program Assumption

Package Measure Life (Years)	20
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	70%
Non-Free-Rider Market Barrier Costs Eliminated	80%
Annual Energy Impact (kWh)	1,614,455
Average Demand Impact (kW)	328

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	12,800	1	1	n/a
2	12,800	3	4	n/a
3	12,800	5	9	n/a
4	12,800	8	17	n/a
5	12,800	9	26	n/a
6	12,800	8	34	n/a
7	12,800	5	39	n/a
8	12,800	5	44	n/a
9	12,800	4	48	n/a
10	12,800	3	51	n/a

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $7,200 Total Variable Admin. Cost	Per Participant Measure Cost $595,320 Total Part. Measure Cost	Annual Per Participant Incentive $40/kW Total Part. Incentive
1	$76,000	$7,200	$595,320	$13,120
2	$76,000	$21,600	$1,785,960	$52,480
3	$76,000	$36,000	$2,976,600	$118,080
4	$76,000	$57,600	$4,762,560	$223,040
5	$76,000	$64,800	$5,357,880	$341,120
6	$76,000	$57,600	$4,762,560	$446,080
7	$76,000	$36,000	$2,976,600	$511,680
8	$76,000	$36,000	$2,976,600	$577,280
9	$76,000	$28,800	$2,381,280	$629,760
10	$76,000	$21,600	$1,785,960	$669,120

NEW COGENERATION—INDUSTRIAL MARKET SECTOR

Overview

The program will promote new 150-kilowatt to 20-megawatt cogeneration installations in the industrial manufacturing sectors in SIC codes 20 through 39, as a means of achieving peak load reduction.

Target Market

The SIC codes in the industrial sector that are most receptive to cogeneration are the food industry (SIC 20), the wood industry (SIC 24), the pulp and paper industry (SIC 26), and the chemical industry (SIC 28). These SIC codes are targeted.

Implementation Strategy

TVA will work with industry decision-makers in the above-mentioned SIC classifications to ensure comprehensive coverage of the market. Industry decision-makers will receive information, technical studies, and/or financial incentives to promote the installation of new cogeneration technologies. The technologies are targeted to be in the 150-kilowatt to 20- megawatt range and will supply power to the plant for all or part of their total load during times of TVA system peak load.

Incentives

TVA will pay the customer for on-peak load reductions, acheived through self-generation, at a cost range averaging $35 per kilowatt. Excess energy produced could be sold to the TVA system at a market price.

Monitoring and Evaluation

TVA engineers will work with on-site plant personnel and the vendor to ensure proper installation and synchronization with local distribution systems and the facility. Contracted payments to the company will be paid based on actual peak load demand reductions.

Applicable Technologies

- Reciprocating Engine Systems
- Gas Turbine Systems
- Coal-Fired Steam Turbine Systems

Program Assumptions

Package Measure Life (Years)	20
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	70%
Non-Free-Rider Market Barrier Costs Eliminated	80%
Annual Energy Impact (kWh)	11,126,814
Average Demand Impact (kW)	1600

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	1,600	1	1	n/a
2	1,600	2	3	n/a
3	1,600	4	7	n/a
4	1,600	5	12	n/a
5	1,600	6	18	n/a
6	1,600	5	23	n/a
7	1,600	4	27	n/a
8	1,600	4	31	n/a
9	1,600	3	34	n/a
10	1,600	1	35	n/a

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $10,000 Total Variable Admin. Cost	Per Participant Measure Cost $2,640,000 Total Part. Measure Cost	Per Participant Incentive $35/kW Total Part. Incentive
1	$76,000	$10,000	$2,640,000	$56,000
2	$76,000	$20,000	$5,280,000	$168,000
3	$76,000	$40,000	$10,560,000	$392,000
4	$76,000	$50,000	$13,200,000	$672,000
5	$76,000	$60,000	$15,840,000	$1,008,000
6	$76,000	$50,000	$13,200,000	$1,288,000
7	$76,000	$40,000	$10,560,000	$1,512,000
8	$76,000	$40,000	$10,560,000	$1,736,000
9	$76,000	$30,000	$7,920,000	$1,904,000
10	$76,000	$10,000	$2,640,000	$1,960,000

BENEFICIAL ELECTRIFICATION OPTIONS

SUMMARY OF PROJECTED IMPACTS IN YEAR 2010

Option Name	MW	GWh	Units
INDUSTRIAL SECTOR			
Process Heating and Melting	-87	-609	228
Process Melting	-79	-549	29
Curing and Drying	-18	-123	425
Electrotechnologies/Food Processing	-53	-368	29
Electrotechnologies/Textiles	-3	-19	64
Electrotechnologies/Chemicals & Metals	-5	-37	49
Environmental Technologies	-33	-227	140
COMMERCIAL SECTOR			
Space Conditioning and Water Heating	-21	-294	30,300
Cooking and Security Lighting	-25	-112	10,917
RESIDENTIAL SECTOR			
HVAC and Water Heating	119	-374	101,256
Security Lighting and Lawn Mowers	0	-51	236,407
TRANSPORTATION			
Electric Buses	0	-9	259
Fleet Vehicles	0	-4	503
Electric Autos	0	-6	1,774

Values are the impacts occuring only in the year 2010 for the cumulative participation in the program to that date.

TVA developed 14 beneficial electrification options for evaluation in Energy Vision 2020 with applications in all customer sectors. The industrial sector options have the most impact. Commercial space conditioning and residential heating and cooling are also significant. Detailed descriptions of the beneficial electrification options follow.

INDUSTRIAL PROCESS HEATING AND MELTING

Overview

The Process Heating and Melting programs promote select electrotechnologies (induction, resistance, arc, plasma, and infrared) to assist industrial customers in optimizing their energy efficiency needs within process heat application. These electrotechnologies also allow customers to maintain and even enhance their competitiveness by lowering operating and maintenance costs, increasing productivity, allowing for increased operating flexibility, and by helping them to position their facilities for long-term environmental compliance.

Within this program, the customer is provided with a complete menu of technologies from which to select in order to determine the most appropriate solution. This program concept has applicability to a large part of the industrial sector, but will focus initially on key industrial segments with extensive process heating and melting requirements. A pilot program is recommended to gain experience and to allow market research to be conducted to refine estimates of market potential and cost-effectiveness.

Target Markets

Target markets for the initial pilot will include: Primary Metals (SIC 33); Fabricated Metals (SIC 34); Transportation Equipment (SIC 37); Industrial Machinery (SIC 35); Electronic Equipment (SIC 36); Stone, Clay, Glass & Concrete (SIC 32); Rubber and Plastics (SIC 30).

Implementation Strategy

TVA does not plan to use any prescriptive or customized rebates for the program. Each electrotechnology should be promoted based on its potential to offer practical solutions to each customer's problems. The program is application-specific and is targeted to large industrial customers and all industrial customers perceived at risk with regard to customer retention. The process heating and melting program should be marketed to enhance customer competitiveness. Understanding the customer's need for favorable paybacks on capital outlays, two additional offerings are considered: a customized rate and customer financing.

The program will be delivered jointly by TVA and participating power distributors. TVA will supply industrial specialists to assist distributor served industrial customers. The success of the program will depend upon TVA's ability to identify and target the most appropriate markets for this program. This effort will require open, two-way communication with distributors and trade allies.

Industrial Process Heating

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	0%
Non-Free-Rider Market Barrier Costs Eliminated	20%
Annual Energy Impact (kWh)	(2,532,323)

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	139	—	—	0%
2	139	1	1	0%
3	555	6	7	1%
4	1,106	17	24	1%
5	1,092	27	51	2%
6	1,070	27	78	2%
7	1,049	26	104	2%
8	1,028	26	130	2%
9	1,007	25	155	2%
10	987	25	180	2%
11	967	24	204	2%
12	948	24	228	2%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $0 Total Variable Admin. Cost	Per Participant Measure Cost $368,000 Total Part. Measure Cost	Per Participant Incentive $0 Total Part. Incentive
1	$138,125	$0	$0	$0
2	$138,125	$0	$368,000	$0
3	$138,125	$0	$2,208,000	$0
4	$138,125	$0	$6,256,000	$0
5	$175,938	$0	$9,936,000	$0
6	$175,938	$0	$9,936,000	$0
7	$175,938	$0	$9,568,000	$0
8	$175,938	$0	$9,568,000	$0
9	$175,938	$0	$9,200,000	$0
10	$175,938	$0	$9,200,000	$0
11	$175,938	$0	$8,932,000	$0
12	$175,938	$0	$8,832,000	$0

Promotional Strategies

The program will be marketed via a program brochure and personalized one-on-one marketing visits with potential program participants. Where possible, TVA should establish customer showcases that would allow other customers the opportunity to witness successful electrotechnology applications in operation. Technical seminars and training will be provided to promote the virtues of electrotechnologies for heating and melting applications.

QUALITY GAIN ESTIMATES FOR DSMANAGER VALUE TEST

BE-1A	New Participants	Cumulative Penetration	One-Time Benefit/ Participant	Annual Benefit/ Participant	Quality Gain
1995	0	0	$200,000	$1,963,000	$0
1996	1	1	$208,000	$2,041,520	$2,249,520
1997	6	7	$216,320	$2,123,181	$16,160,187
1998	17	24	$224,973	$2,208,108	$56,819,133
1999	27	51	$233,972	$2,296,432	$123,435,276
2000	27	78	$243,331	$2,388,290	$192,856,557
2001	26	104	$253,064	$2,483,821	$264,897,048
2002	26	130	$263,186	$2,583,174	$342,655,456
2003	25	155	$273,714	$2,686,501	$423,250,505
2004	25	180	$284,662	$2,793,961	$510,029,530
2005	24	204	$296,049	$2,905,720	$599,872,056
2006	24	228	$307,891	$3,021,948	$696,393,528

One-Time Environmental Savings	*$200,000*
Annual Productivity, O&M, Fuel Savings	*$1,963,000*
Escalation Rate	*4%*

Industrial Process Melting

Program Assumptions

Package Measure Life (Years)	20
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	0%
Non-Free-Rider Market Barrier Costs Eliminated	30%
Annual Energy Impact (kWh)	(17,950,000)

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	19	—	—	0%
2	37	1	1	1%
3	74	1	2	1%
4	147	3	5	2%
5	145	3	8	2%
6	142	3	11	2%
7	141	3	14	2%
8	138	3	17	2%
9	136	3	20	2%
10	134	3	23	2%
11	132	3	26	2%
12	130	3	29	2%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $0 Total Variable Admin. Cost	Per Participant Measure Cost $1,490,000 Total Part. Measure Cost	Per Participant Incentive $0 Total Part. Incentive
1	$138,125	$0	$0	$0
2	$138,125	$0	$1,490,000	$0
3	$138,125	$0	$1,490,000	$0
4	$138,125	$0	$4,470,000	$0
5	$138,125	$0	$4,470,000	$0
6	$138,125	$0	$4,470,000	$0
7	$138,125	$0	$4,470,000	$0
8	$138,125	$0	$4,470,000	$0
9	$138,125	$0	$4,470,000	$0
10	$138,125	$0	$4,470,000	$0
11	$138,125	$0	$4,470,000	$0
12	$138,125	$0	$4,470,000	$0

QUALITY GAIN ESTIMATES FOR DSMANAGER VALUE TEST

BE-1B	New Participants	Cumulative Penetration	One-Time Benefit/ Participant	Annual Benefit/ Participant	Quality Gain
1995	0	0	$900,000	$1,748,000	$0
1996	1	1	$936,000	$1,817,920	$2,753,920
1997	1	2	$973,440	$1,890,637	$5,754,714
1998	3	5	$1,012,378	$1,966,262	$12,868,444
1999	3	8	$1,052,873	$2,044,913	$19,517,923
2000	3	11	$1,094,988	$2,126,709	$26,678,763
2001	3	14	$1,138,787	$2,211,778	$34,381,253
2002	3	17	$1,184,339	$2,300,249	$42,657,250
2003	3	20	$1,231,712	$2,392,259	$51,540,316
2004	3	23	$1,280,981	$2,487,949	$61,065,770
2005	3	26	$1,332,220	$2,587,467	$71,270,802
2006	3	29	$1,385,509	$2,690,966	$82,194,541

One-Time Environmental Savings	*$900,000*
Annual Productivity, O&M, Fuel Savings	*$1,748,000*
Escalation Rate	*4%*

INDUSTRIAL CURING AND DRYING

Overview

The Process Curing and Drying program promotes select electrotechnologies (infrared, radio-frequency, microwave, ultraviolet, and electron beam) to assist industrial customers to optimize their energy efficiency needs within curing and drying applications. These electrotechnologies also allow customers to maintain and even enhance their competitiveness by lowering operating and maintenance costs, increasing productivity, allowing for increased operating flexibility, and by helping them to position their facilities for long-term environmental compliance.

Within this program, customers are provided a complete menu of technologies from which to select in determining the most appropriate solution to meet their needs. This program concept is applicable to a large part of the industrial sector, but will focus initially on key industrial segments with extensive process curing and drying requirements. A pilot program is recommended to gain experience and to allow market research to be conducted to refine estimates of market potential and cost-effectiveness.

Target Markets

Target markets for the initial pilot will include: Food and Kindred Products (SIC 20); Textiles (SIC 22); Lumber and Wood Products (SIC 24); Paper and Allied Products (SIC 26); Printing and Publishing (SIC 27); Chemicals and Allied Products (SIC 28); Rubber and Plastics (SIC 30); Fabricated Metals (SIC 34); and Transportation (SIC 37).

Implementation Strategy

TVA does not plan to use any prescriptive or customized rebates for the program. Each electrotechnology will be promoted based on its potential to offer practical solutions to each customer's problems. The Process Curing and Drying program should be marketed to enhance customer competitiveness. Understanding the customer's need for favorable paybacks on capital outlays, two additional offerings are considered: a customized rate and customer financing.

The program would be delivered jointly by TVA and participating power distributors. TVA would supply industrial specialists to assist distributor served industrial customers. The success of the program will depend upon TVA's ability to identify and target the most appropriate markets for this program. This effort will require open, two-way communication with distributors and trade allies.

Program Assumptions

Package Measure Life (Years)	12
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	0%
Non-Free-Rider Market Barrier Costs Eliminated	10%
Annual Energy Impact (kWh)	(273,122)

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	141	—	—	0%
2	141	3	3	1%
3	562	11	14	2%
4	1,115	33	47	2%
5	1,088	54	101	3%
6	1,045	52	153	4%
7	1,003	50	203	4%
8	963	48	251	4%
9	925	46	297	4%
10	887	44	341	4%
11	852	43	394	4%
12	818	41	425	4%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $0 Total Variable Admin. Cost	Per Participant Measure Cost $200,000 Total Part. Measure Cost	Per Participant Incentive $0 Total Part. Incentive
1	$276,250	$0	$0	$0
2	$276,250	$0	$600,000	$0
3	$276,250	$0	$2,200,000	$0
4	$276,250	$0	$6,600,000	$0
5	$351,875	$0	$10,800,000	$0
6	$351,875	$0	$10,400,000	$0
7	$351,875	$0	$10,000,000	$0
8	$351,875	$0	$9,600,000	$0
9	$351,875	$0	$9,200,000	$0
10	$351,875	$0	$8,800,000	$0
11	$351,875	$0	$8,600,000	$0
12	$351,875	$0	$8,200,000	$0

Promotional Strategies

The program will be marketed via a program brochure and personalized one-on-one marketing visits with potential program participants. Where possible, TVA should establish customer showcases that would allow other customers the opportunity to witness successful electrotechnology applications in operation. Technical seminars and training will be provided to promote the virtues of electrotechnologies for heating and melting applications.

QUALITY GAIN ESTIMATES FOR DSMANAGER VALUE TEST

BE-2	New Participants	Cumulative Penetration	One-Time Benefit/ Participant	Annual Benefit/ Participant	Quality Gain
1995	0	0	$100,000	$2,303,000	$0
1996	3	3	$104,000	$2,395,120	$7,497,360
1997	11	14	$108,160	$2,490,925	$36,062,710
1998	33	47	$112,486	$2,590,562	$125,468,452
1999	54	101	$116,986	$2,694,184	$278,429,828
2000	52	153	$121,665	$2,801,952	$435,025,236
2001	50	203	$126,532	$2,914,030	$597,874,690
2002	48	251	$131,593	$3,030,591	$766,994,805
2003	46	297	$136,857	$3,151,815	$942,384,477
2004	44	341	$142,331	$3,277,887	$1,124,022,031
2005	43	384	$148,024	$3,409,003	$1,315,422,184
2006	41	425	$153,945	$3,545,363	$1,513,091,020

One-Time Environmental Savings	*$100,000*
Annual Productivity, O&M, Fuel Savings	*$2,303,000*
Escalation Rate	*4%*

INDUSTRIAL ELECTROTECHNOLOGIES

Overview

The Process-Specific Electrification program promotes select electrotechnologies (freeze concentration, reverse osmosis, vacuum slot heating and drying, and electrolytics) that represent niche opportunities for beneficial electrification. These electrotechnologies also allow customers to maintain and even enhance their competitiveness by lowering operating and maintenance costs, increasing productivity, allowing for increased operating flexibility, and by helping them to position their facilities for long-term environmental compliance.

Within this program, the customer is provided a complete menu of technologies to select from when determining the most appropriate solution to meet their needs. This program concept has applicability to a large part of the industrial sector, but will focus initially on key industrial segments with extensive process-specific electrification requirements. A pilot program is recommended to gain experience and to conduct market research in order to refine estimates of market potential and cost-effectiveness.

Target Markets

Target markets with corresponding niche opportunities for electrotechnologies include: Food and Kindred Products (SIC 20), Freeze Concentration and Reverse Osmosis Textiles (SIC 22), Vacuum Slot Heating and Drying Chemicals (SIC 28), Primary Metals (SIC 33), and Fabricated Metals (SIC 34) for electrolytics.

Implementation Strategy

TVA does not plan to use any prescriptive or customized rebates for the program. Each electrotechnology will be promoted based on its potential to offer practical solutions to each customer's problems. The Process-Specific Electrification program should be marketed to enhance customer competitiveness. The introduction of niche technologies that allow incremental gains in overall productivity assumes an extensive screening for opportunities. Understanding the customer's need for favorable paybacks on capital outlays, TVA will consider offering a customized rate and customer financing.

The program would be delivered jointly by TVA and participating power distributors. TVA will supply industrial specialists to assist distributor served industrial customers. The success of the program will depend upon TVA's ability to identify and target the most appropriate markets for this program and will require open, two-way communication with distributors and trade allies.

Promotional Strategies

The program will be marketed via a program brochure and personalized one-on-one marketing visits with potential program participants. Where possible, TVA will establish customer showcases that allow other customers the opportunity to witness successful electrotechnology applications in operation. Technical seminars and training will be provided to promote the virtues of electrotechnologies for heating and melting applications. Presentations should be made at industry trade organizations and to trade allies to promote program awareness.

Industrial Electrotechnologies/Food Processing

Program Assumptions

Package Measure Life (Years)	18
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	0%
Non-Free-Rider Market Barrier Costs Eliminated	50%
Annual Energy Impact (kWh)	(12,044,480)

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	35	—	—	0%
2	35	1	1	1%
3	88	1	2	1%
4	175	3	5	2%
5	173	3	8	2%
6	171	3	11	2%
7	170	3	14	2%
8	168	3	17	2%
9	166	3	20	2%
10	165	3	23	2%
11	163	3	26	2%
12	161	3	29	2%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $0 Total Variable Admin. Cost	Per Participant Measure Cost $4,730,000 Total Part. Measure Cost	Per Participant Incentive $0 Total Part. Incentive
1	$102,500	$0	$0	$0
2	$102,500	$0	$4,730,000	$0
3	$102,500	$0	$4,730,000	$0
4	$102,500	$0	$14,190,000	$0
5	$102,500	$0	$14,190,000	$0
6	$102,500	$0	$14,190,000	$0
7	$102,500	$0	$14,190,000	$0
8	$102,500	$0	$14,190,000	$0
9	$102,500	$0	$14,190,000	$0
10	$102,500	$0	$14,190,000	$0
11	$102,500	$0	$14,190,000	$0
12	$102,500	$0	$14,190,000	$0

QUALITY GAIN ESTIMATES FOR DSMANAGER VALUE TEST

BE-3A	New Participants	Cumulative Penetration	One-Time Benefit/ Participant	Annual Benefit/ Participant	Quality Gain
1995	0	0	$2,400,000	$8,410,000	$0
1996	1	1	$2,496,000	$8,746,400	$11,242,400
1997	1	2	$2,595,840	$9,096,256	$20,788,352
1998	3	5	$2,699,674	$9,460,106	$55,399,552
1999	3	8	$2,807,661	$9,838,510	$87,131,063
2000	3	11	$2,919,967	$10,232,051	$121,312,462
2001	3	14	$3,036,766	$10,641,333	$158,088,960
2002	3	17	$3,158,236	$11,066,986	$197,613,470
2003	3	20	$3,284,566	$11,509,666	$240,047,018
2004	3	23	$3,415,948	$11,970,052	$285,559,040
2005	3	26	$3,552,586	$12,448,854	$334,327,962
2006	3	29	$3,694,690	$12,946,809	$386,541,531

One-Time Environmental Savings	*$2,400,000*
Annual Productivity, O&M, Fuel Savings	*$8,410,000*
Escalation Rate	*4%*

Industrial Electrotechnologies/Textiles

Program Assumptions

Package Measure Life	20
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	0%
Non-Free-Rider Market Barrier Costs Eliminated	25%
Annual Energy Impact (kWh)	(280,000)

Year	• Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	23	—	—	0%
2	23	0	0	1%
3	92	2	2	1%
4	183	3	5	2%
5	181	6	11	2%
6	176	9	20	3%
7	169	8	28	3%
8	162	8	36	4%
9	156	8	44	4%
10	150	7	51	4%
11	144	7	58	4%
12	138	7	65	4%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $0 Total Variable Admin. Cost	Per Participant Measure Cost $76,000 Total Part. Measure Cost	Per Participant Incentive $0 Total Part. Incentive
1	$102,500	$0	$0	$0
2	$102,500	$0	$0	$0
3	$102,500	$0	$152,000	$0
4	$102,500	$0	$228,000	$0
5	$102,500	$0	$456,000	$0
6	$102,500	$0	$684,000	$0
7	$102,500	$0	$608,000	$0
8	$102,500	$0	$608,000	$0
9	$102,500	$0	$608,000	$0
10	$102,500	$0	$532,000	$0
11	$102,500	$0	$532,000	$0
12	$102,500	$0	$532,000	$0

QUALITY GAIN ESTIMATES FOR DSMANAGER VALUE TEST

BE-3B	New Participants	Cumulative Penetration	One-Time Benefit/ Participant	Annual Benefit/ Participant	Quality Gain
1995	0	0	$38,000	$607,000	$0
1996	0	0	$39,520	$631,280	$0
1997	2	2	$41,101	$656,531	$1,395,264
1998	3	5	$42,745	$682,792	$3,413,960
1999	6	11	$44,455	$710,104	$7,811,144
2000	9	20	$46,233	$738,508	$15,186,257
2001	8	28	$48,082	$768,049	$21,505,372
2002	8	36	$50,005	$798,771	$28,753,596
2003	8	44	$52,006	$830,721	$36,551,724
2004	7	51	$54,086	$863,950	$44,061,450
2005	7	58	$56,249	$898,508	$52,113,464
2006	7	65	$58,499	$934,449	$61,148,678

One-Time Environmental Savings	*$38,000*
Annual Productivity, O&M, Fuel Savings	*$607,000*
Escalation Rate	*4%*

Industrial Elect··echnologies/Chemicals and Metals

Program Assumptions

Package Measure Life	20
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	0%
Non-Free-Rider Market Barrier Costs Eliminated	25%
Annual Energy Impact (kWh)	(705,536)

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	60	—	—	0%
2	60	1	1	1%
3	150	2	3	1%
4	300	4	7	1%
5	298	4	11	1%
6	295	4	15	1%
7	293	5	20	1%
8	291	6	26	2%
9	288	6	32	2%
10	285	6	38	2%
11	282	6	44	2%
12	279	6	50	2%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $0 Total Variable Admin. Cost	Per Participant Measure Cost $328,000 Total Part. Measure Cost	Per Participant Incentive $0 Total Part. Incentive
1	$102,500	$0	$0	$0
2	$102,500	$0	$328,000	$0
3	$102,500	$0	$656,000	$0
4	$102,500	$0	$1,312,000	$0
5	$102,500	$0	$1,312,000	$0
6	$102,500	$0	$1,312,000	$0
7	$102,500	$0	$1,640,000	$0
8	$102,500	$0	$1,968,000	$0
9	$102,500	$0	$1,968,000	$0
10	$102,500	$0	$1,968,000	$0
11	$102,500	$0	$1,968,000	$0
12	$102,500	$0	$1,968,000	$0

QUALITY GAIN ESTIMATES FOR DSMANAGER VALUE TEST

BE-3C	New Participants	Cumulative Penetration	One-Time Benefit/ Participant	Annual Benefit/ Participant	Quality Gain
1995	0	0	$328,299	$2,011,000	$0
1996	1	1	$341,431	$2,091,440	$2,432,871
1997	2	3	$355,088	$2,175,098	$7,235,470
1998	4	7	$369,292	$2,262,102	$17,311,882
1999	4	11	$384,063	$2,352,586	$27,414,698
2000	4	15	$399,426	$2,446,689	$38,298,039
2001	5	20	$415,403	$2,544,557	$52,968,155
2002	6	26	$432,019	$2,646,339	$68,804,814
2003	6	32	$449,300	$2,752,192	$90,765,944
2004	6	38	$467,272	$2,862,280	$111,570,272
2005	6	44	$485,963	$2,976,771	$133,893,702
2006	6	50	$505,401	$3,095,842	$157,824,506

One-Time Environmental Savings	*$328,299*
Annual Productivity, O&M, Fuel Savings	*$2,011,000*
Escalation Rate	*4%*

ENVIRONMENTAL TECHNOLOGIES

Overview

The Environmental Technology Solutions program will promote select environmental compliance technologies (ultrafiltration, nanofiltration, ozonation, and reverse osmosis) to assist industrial and commercial customers to address air and water regulation and by helping them to position their facilities for long-term environmental compliance. These electrotechnologies also allow customers to maintain and even enhance their competitiveness by reducing operating and maintenance costs and by enhancing product quality.

Within this program, the customer is provided a complete menu of technologies from which to chose in determining the most appropriate solution to meet its needs. This option concept is applicable to a large part of the industrial sector, but will focus initially on key industrial segments with extensive environmental problems. A pilot program is recommended to gain experience and to conduct market research in order to refine estimates of market potential and cost effectiveness.

Target Markets

Target markets for the initial pilot will include: Municipal Waste Water Treatment Facilities (SIC 49); Select Commercial Institutions, Food and Kindred Products (SIC 20); Textiles (SIC 22); Chemicals (SIC 28); Primary Metals (SIC 33); Fabricated Metals (SIC 34); and Electronic Equipment (SIC 36).

Implementation Strategy

TVA does not plan to use any prescriptive or customized rebates for the program. Each environmental electrotechnology will be promoted on its own merits, in terms of improving product quality and addressing long-term environmental compliance. Each technology should offer a practical long-term solution to an individual customer's problems.

It is suggested that TVA consider financing options to assist in the purchase of these technologies. TVA should also consider tailored collaboration projects with EPRI to secure leveraging of federal funds for process improvement projects.

The program would be delivered jointly by TVA and participating power distributors. TVA would supply industrial specialists to assist distributor served industrial customers. The success of the program will depend upon TVA's ability to identify and target the most appropriate markets for this program. This effort will require open, two-way communication with distributors and trade allies.

Program Assumptions

Package Measure Life (Years)	14
Free-Rider Rate	0%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	0%
Non-Free-Rider Market Barrier Costs Eliminated	50%
Annual Energy Impact (kWh)	(1,537,918)

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	144	—	—	0%
2	144	1	1	1%
3	432	6	7	1%
4	860	13	20	1%
5	852	13	33	1%
6	844	13	46	1%
7	837	13	59	1%
8	829	16	75	2%
9	820	17	92	2%
10	809	16	108	2%
11	800	16	124	2%
12	790	16	140	2%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $0 Total Variable Admin. Cost	Per Participant Measure Cost $1,560,000 Total Part. Measure Cost	Per Participant Incentive $0 Total Part. Incentive
1	$295,000	$0	$0	$0
2	$295,000	$0	$1,560,000	$0
3	$295,000	$0	$9,360,000	$0
4	$295,000	$0	$20,280,000	$0
5	$342,500	$0	$20,280,000	$0
6	$342,500	$0	$20,280,000	$0
7	$342,500	$0	$20,280,000	$0
8	$342,500	$0	$24,960,000	$0
9	$342,500	$0	$26,520,000	$0
10	$342,500	$0	$24,960,000	$0
11	$342,500	$0	$24,960,000	$0
12	$342,500	$0	$24,960,000	$0

Promotional Strategies

The program will be promoted via brochures outlining state-specific regulations/compliance issues, as well as technology solutions. TVA will take into consideration each state's specific regulations. Technical seminars and training will be provided to promote electrotechnology solutions to environmental problems.

QUALITY GAIN ESTIMATES FOR DSMANAGER VALUE TEST

BE-4	New Participants	Cumulative Penetration	One-Time Benefit/ Participant	Annual Benefit/ Participant	Quality Gain
1995	0	0	$3,100,000	$1,904,000	$0
1996	1	1	$3,224,000	$1,980,160	$5,204,160
1997	6	7	$3,352,960	$2,059,366	$34,533,322
1998	13	20	$3,487,078	$2,141,741	$88,166,834
1999	13	33	$3,626,562	$2,227,411	$120,649,869
2000	13	46	$3,771,624	$2,316,507	$155,590,434
2001	13	59	$3,922,489	$2,409,167	$193,133,210
2002	16	75	$4,079,389	$2,505,534	$259,770,197
2003	17	92	$4,242,564	$2,605,755	$307,610,484
2004	16	108	$4,412,267	$2,709,986	$363,274,760
2005	16	124	$4,588,757	$2,818,385	$422,899,852
2006	16	140	$4,772,308	$2,931,121	$486,713,868

One-Time Environmental Savings	*$3,100,000*
Annual Productivity, O&M, Fuel Savings	*$1,904,000*
Escalation Rate	*4%*

COMMERCIAL SPACE CONDITIONING AND WATER HEATING

Overview

Beneficial water heating and space conditioning electrotechnologies will be promoted to new and existing commercial customers. The Commercial Space Conditioning and Water Heating option would promote technologies which overlap with measures being offered in the commercial energy efficiency options (heat pump water heaters [15kBtuh, 50kBtuh, &100kBtuh], air-source heat pumps, and dual-fuel heat pumps). In addition, the program will promote new water chillers designed to comply with ozone depletion regulations.

The Commercial Space Conditioning and Water Heating option will be designed to avoid overt load building. For example, it would be promoted through trade allies, thereby targeting customers already considering an equipment purchase, rather than actively encouraging customers to switch fuels to electricity. In addition, this option will only promote high-efficiency equipment using the same efficiency standards as the commercial energy efficiency options.

Target Market

The program will target customers replacing failed non-electric water heaters, space conditioning equipment, and/or adding air conditioning. Some technologies will be targeted to specific business types. For example, chillers will be targeted to large office buildings, schools/colleges, hospitals, and government facilities. Heat pumps will be targeted to small office buildings, restaurants, and retail establishments.

Implementation Strategy

The program will be offered in participating distributor service areas. It will be delivered through architects and engineers, and HVAC/plumbing contractors. TVA should provide trade allies with technical materials that inform potential purchasers of the benefit of replacing non-electric equipment with high-efficiency electric alternatives. To encourage contractors to educate customers, TVA will provide incentive payments to dealers. Heat pump incentives would match those of the energy efficiency options. For chillers, TVA would also provide analysis/design incentives that would reimburse owners for the cost of economic/feasibility studies.

TVA will maintain a flexible posture concerning the level of aggressiveness with which it promotes the program. Changes in market or resource conditions may warrant revising some elements of the program or terminating it completely.

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	10%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	50%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	(8,329)

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	25,252	2,525	2,525	10%
2	25,252	2,525	5,050	10%
3	25,252	2,525	7,575	10%
4	25,252	2,525	10,100	10%
5	25,252	2,525	12,625	10%
6	25,252	2,525	15,150	10%
7	25,252	2,525	17,675	10%
8	25,252	2,525	20,200	10%
9	25,252	2,525	22,725	10%
10	25,252	2,525	25,250	10%
11	25,252	2,525	27,775	10%
12	25,252	2,525	30,300	10%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs: $1,525 Total Variable Admin. Cost	Per Participant Measure Cost: $7,920 Total Part. Measure Cost	Per Participant Incentive: $70 Total Part. Incentive
1	$624,000	$3,850,625	$19,998,000	$176,750
2	$624,000	$3,850,625	$19,998,000	$176,750
3	$624,000	$3,850,625	$19,998,000	$176,750
4	$624,000	$3,850,625	$19,998,000	$176,750
5	$624,000	$3,850,625	$19,998,000	$176,750
6	$624,000	$3,850,625	$19,998,000	$176,750
7	$624,000	$3,850,625	$19,998,000	$176,750
8	$624,000	$3,850,625	$19,998,000	$176,750
9	$624,000	$3,850,625	$19,998,000	$176,750
10	$624,000	$3,850,625	$19,998,000	$176,750
11	$624,000	$3,850,625	$19,998,000	$176,750
12	$624,000	$3,850,625	$19,998,000	$176,750

Promotional Strategies

Promotional efforts will emphasize personal contact between TVA and key equipment installers/decision-makers. The program should also be promoted through presentations and seminars to professional organizations such as the American Society of Heating, Refrigerating, and Air-Conditioning Engineers, Inc. Technical seminars and training would be provided to educate trade allies and explain program operation in detail. In addition, the program should feature cooperative advertising and point-of-purchase information and displays.

QUALITY GAIN ESTIMATES FOR DSMANAGER VALUE TEST

BE-5	New Participants	Cumulative Penetration	One-Time Benefit/ Participant	Annual Benefit/ Participant	Quality Gain
1995	2,525	2,525	$0	$3,000	$7,575,000
1996	2,525	5,050	$0	$3,120	$15,756,000
1997	2,525	7,575	$0	$3,245	$24,580,875
1998	2,525	10,100	$0	$3,375	$34,087,500
1999	2,525	12,625	$0	$3,510	$44,313,750
2000	2,525	15,150	$0	$3,650	$55,297,500
2001	2,525	17,675	$0	$3,796	$67,094,300
2002	2,525	20,200	$0	$3,948	$79,749,600
2003	2,525	22,725	$0	$4,106	$93,308,850
2004	2,525	25,250	$0	$4,270	$107,817,500
2005	2,525	27,775	$0	$4,441	$123,348,775
2006	2,525	30,300	$0	$4,618	$139,925,400

One-Time Environmental Savings	*$0*
Annual Productivity, O&M, Fuel Savings	*$3,000*
Escalation Rate	*4%*

COMMERCIAL COOKING AND SECURITY LIGHTING

Overview

Beneficial electrotechnologies addressing security lighting will be promoted among customers where appropriate. In this program the following technologies would be promoted:

- High pressure sodium (HPS) security lighting
- Cooking—convection oven
- Cooking—high-efficiency fryer

Target Markets

These technologies will be promoted among a narrow range of customers. Security lighting will be promoted among retail customers and restaurants, where the technology can provide high value to customers by improving safety in walkways and parking lots. Cooking would be promoted among restaurants and hotels. Convection ovens provide value and efficiency by distributing heat more evenly in less time. High-efficiency fryers with their better insulation reduce heat loss through the bottom of the fry pot.

Delivery Strategy

Security lighting and cooking will be delivered differently. TVA, in conjunction with power distributors, will purchase HPS lamps. Power distributors would install them in targeted geographical areas and recover costs through a leasing arrangement.

Cooking technologies would be delivered through retail vendors such as restaurant supply outlets. TVA will develop a list of qualifying equipment manufacturers and recruit vendors to participate in the program. Vendors will procure approved equipment through their own distribution channels. To encourage customers to purchase electric equipment, TVA will offer customer financing. Vendors will be expected to perform the following functions:

- Promote equipment via promotional material developed by TVA
- Maintain record of equipment sales (both electric and gas) to track participation and penetration

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	0%
Free-Driver Rate	10%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	0%
Non-Free-Rider Market Barrier Costs Eliminated	25%
Annual Energy Impact (kWh)	(9,470)

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	109,238	550	550	1%
2	109,228	550	1,100	1%
3	109,218	550	1,650	2%
4	109,208	550	2,200	2%
5	109,198	1,100	3,300	3%
6	109,188	1,100	4,400	4%
7	109,178	1,100	5,500	5%
8	109,168	1,100	6,600	6%
9	109,158	1,100	7,700	7%
10	109,148	1,100	8,800	8%
11	109,139	1,100	9,900	9%
12	109,129	1,100	11,000	10%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $13 Total Variable Admin. Cost	Per Participant Measure Cost $2,292 Total Part. Measure Cost	Per Participant Incentive $0 Total Part. Incentive
1	$410,000	$7,150	$1,260,600	$0
2	$375,000	$7,150	$1,260,600	$0
3	$350,000	$7,150	$1,260,600	$0
4	$350,000	$7,150	$1,260,600	$0
5	$350,000	$14,300	$2,521,200	$0
6	$350,000	$14,300	$2,521,200	$0
7	$350,000	$14,300	$2,521,200	$0
8	$350,000	$14,300	$2,521,200	$0
9	$350,000	$14,300	$2,521,200	$0
10	$350,000	$14,300	$2,521,200	$0
11	$350,000	$14,300	$2,521,200	$0
12	$350,000	$14,300	$2,521,200	$0

Promotional Strategies

For security lighting, TVA and power distributors will emphasize direct mail, telemarketing, and face-to-face contact in targeted areas. In addition, TVA will make presentations and provide displays to regional retail chains and to local chambers of commerce, security organizations, etc. Promotional materials would illustrate how lighting can improve customer security. Materials will also discuss the low operating costs of HPS lamps.

Cooking equipment will be marketed through direct contact with restaurants and hotels. In addition, cooking supply outlets will be provided with information and encouraged to promote electric technologies among their customers. Sample equipment used to demonstrate the quality of electric cooked food should be made available to large vendors and at trade shows. TVA will develop point-of-purchase information and displays for participating vendors.

QUALITY GAIN ESTIMATES FOR DSMANAGER VALUE TEST

BE-6	New Participants	Cumulative Penetration	One-Time Benefit/ Participant	Annual Benefit/ Participant	Quality Gain
1995	550	550	$0	$3,000	$1,650,000
1996	550	1,100	$0	$3,120	$3,432,000
1997	550	1,650	$0	$3,245	$5,354,250
1998	550	2,200	$0	$3,375	$7,425,000
1999	1,100	3,300	$0	$3,510	$11,583,000
2000	1,100	4,400	$0	$3,650	$16,060,000
2001	1,100	5,500	$0	$3,796	$20,878,000
2002	1,100	6,600	$0	$3,948	$26,056,800
2003	1,100	7,700	$0	$4,106	$31,616,200
2004	1,100	8,800	$0	$4,270	$37,576,000
2005	1,100	9,900	$0	$4,441	$43,965,900
2006	1,100	11,000	$0	$4,618	$50,798,000

One-Time Environmental Savings	*$0*
Annual Productivity, O&M, Fuel Savings	*$3,000*
Escalation Rate	*4%*

RESIDENTIAL HVAC AND WATER HEATING

Overview

This option promotes beneficial water heating and space conditioning electrotechnologies to new and existing residential customers. The Residential HVAC and Water Heating option promotes the following energy-efficient technologies: heat pump water heaters; air-source heat pumps with heat recovery; ground-source heat pumps with heat recovery; and dual-fuel heat pumps with heat recovery

Program features would be similar to the residential energy efficiency option. However, participation and impact levels would be tracked separately. Installations through this option would represent added load. Impacts among participants without air conditioning may represent the full requirements of a SEER 12 air-source heat pump. Impacts for participants that previously had air conditioning but no electric heat would represent the winter heat pump load requirements. In contrast, the energy efficiency option impacts would represent the energy and demand savings achieved by installing the high-efficiency measure rather than the standard efficiency replacement.

The Residential HVAC and Water Heating option is designed to avoid overt load building. For example, it would be promoted through trade allies to customers already considering an equipment purchase, rather than actively encouraging customers to switch from another fuel to electricity. The program will use the same efficiency standards as the related energy efficiency option, and both options will offer similar services and incentives.

Target Markets

The program would target customers replacing failed nonelectric water heaters, space conditioning equipment, and/or adding air conditioning.

Delivery Strategy

The program would be delivered through HVAC/plumbing contractors. TVA should provide trade allies with technical/educational materials that inform potential purchasers of the benefits of replacing non-electric equipment with high-efficiency electric alternatives. To encourage contractors to educate customers, TVA would provide incentive payments to dealers. Heat pump incentives will match those provided under the energy efficiency options. In addition, incentives will be provided to encourage dealers to promote heat pump water heaters.

TVA will maintain a flexible posture concerning the level of aggressiveness with which it promotes this option. Changes in market or resource conditions may warrant revising some elements of the program or terminating it completely.

Program Assumptions

Package Measure Life (Years)	15
Free-Rider Rate	10%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	50%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	(2,935)

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	84,376	8,440	8,440	10%
2	84,376	8,440	16,880	10%
3	84,376	8,440	25,320	10%
4	84,376	8,440	33,760	10%
5	84,376	8,440	42,200	10%
6	84,376	8,440	50,640	10%
7	84,376	8,440	59,080	10%
8	84,376	8,440	67,520	10%
9	84,376	8,440	75,960	10%
10	84,376	8,440	84,400	10%
11	84,376	8,440	92,840	10%
12	84,376	8,440	101,280	10%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $25 Total Variable Admin. Cost	Per Participant Measure Cost $2,900 Total Part. Measure Cost	Per Participant Incentive $230 Total Part. Incentive
1	$624,000	$211,000	$24,476,000	$1,914,200
2	$624,000	$211,000	$24,476,000	$1,914,200
3	$624,000	$211,000	$24,476,000	$1,914,200
4	$624,000	$211,000	$24,476,000	$1,914,200
5	$624,000	$211,000	$24,476,000	$1,914,200
6	$624,000	$211,000	$24,476,000	$1,914,200
7	$624,000	$211,000	$24,476,000	$1,914,200
8	$624,000	$211,000	$24,476,000	$1,914,200
9	$624,000	$211,000	$24,476,000	$1,914,200
10	$624,000	$211,000	$24,476,000	$1,914,200
11	$624,000	$211,000	$24,476,000	$1,914,200
12	$624,000	$211,000	$24,476,000	$1,914,200

Promotional Strategies

Trade allies represent a key source of program promotion. The program will feature cooperative advertising and point-of-purchase display materials. In addition, training will be provided to educate trade allies and explain program operating details.

QUALITY GAIN ESTIMATES FOR DSMANAGER VALUE TEST

BE-7	New Participants	Cumulative Penetration	One-Time Benefit/ Participant	Annual Benefit/ Participant	Quality Gain
1995	8,440	8,440	$0	$1,000	$8,440,000
1996	8,440	16,880	$0	$1,040	$17,555,200
1997	8,440	25,320	$0	$1,082	$27,376,240
1998	8,440	33,760	$0	$1,125	$37,980,000
1999	8,440	42,200	$0	$1,170	$49,374,000
2000	8,440	50,640	$0	$1,217	$61,628,880
2001	8,440	59,080	$0	$1,265	$74,736,200
2002	8,440	67,520	$0	$1,316	$88,856,320
2003	8,440	75,960	$0	$1,369	$103,989,240
2004	8,440	84,400	$0	$1,423	$120,101,200
2005	8,440	92,840	$0	$1,480	$137,403,200
2006	8,440	101,280	$0	$1,539	$155,869,920

One-Time Environmental Savings	*$0*
Annual Productivity, O&M, Fuel Savings	*$1,000*
Escalation Rate	*4%*

RESIDENTIAL SECURITY LIGHTING AND LAWN MOWERS

Overview

Beneficial electrification technologies addressing security lighting and lawn maintenance would be promoted among customers where appropriate. The following technologies would be promoted in this program: high pressure sodium (HPS) security lighting, cordless electric lawn mowers, and electric cord lawn mowers.

These technologies can provide high value to certain customers. Security lighting meets a growing concern for safety, and does it in a highly efficient manner. In the past, customers wanting to receive the benefits of security lighting had to pay relatively high operating costs associated with mercury vapor lamps.

Lawn mowing with traditional gasoline-powered engines has recently been identified by the U.S. Environmental Protection Agency as a major source of air pollution. While significant improvements have been made in reducing automobile emissions, lawn mowers remain a totally uncontrolled source.

Target Markets

These technologies would be promoted among a relatively narrow range of customers. Security lighting would be promoted in rural and high crime areas. Lawn mowers would be promoted among urban and suburban customers in the market to replace existing equipment.

Delivery Strategy

Program delivery would be handled differently for security lighting and lawn mowers. TVA and/or power distributors would purchase HPS lamps. Power distributors would install them in geographically targeted areas. Distributors would recover costs through a leasing arrangement with the customer.

The lawn mowing component would be delivered through retail vendors such as Home Depot, Sears, hardware stores, etc. TVA would provide vendors with point-of-purchase educational materials designed to persuade the customer to purchase the electric mower rather than a gasoline-powered mower. TVA should develop a list of qualifying equipment manufacturers and recruit vendors to participate in the program. Vendors will use the list to procure equipment through their own distribution channels.

Program Assumptions

Package Measure Life (Years)	8
Free-Rider Rate	0%
Free-Driver Rate	10%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	0%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	(196)

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	2,955,150	14,775	14,775	1%
2	2,955,140	14,775	29,550	1%
3	2,955,130	14,775	44,325	2%
4	2,955,120	14,775	59,100	2%
5	2,955,110	29,550	88,650	3%
6	2,955,101	29,550	118,200	4%
7	2,955,091	29,550	147,750	5%
8	2,955,081	29,550	177,300	6%
9	2,955,071	29,550	206,850	7%
10	2,955,061	29,550	236,400	8%
11	2,955,051	29,550	265,950	9%
12	2,955,041	29,550	295,500	10%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $13 Total Variable Admin. Cost	Per Participant Measure Cost $220 Total Part. Measure Cost	Per Participant Incentive $0 Total Part. Incentive
1	$410,000	$192,075	$3,250,500	$0
2	$375,000	$192,075	$3,250,500	$0
3	$350,000	$192,075	$3,250,500	$0
4	$350,000	$192,075	$3,250,500	$0
5	$350,000	$384,150	$6,501,000	$0
6	$350,000	$384,150	$6,501,000	$0
7	$350,000	$384,150	$6,501,000	$0
8	$350,000	$384,150	$6,501,000	$0
9	$350,000	$384,150	$6,501,000	$0
10	$350,000	$384,150	$6,501,000	$0
11	$350,000	$384,150	$6,501,000	$0
12	$350,000	$384,150	$6,501,000	$0

Promotional Strategies

Security lighting will be promoted through direct mail, telemarketing, and face-to-face contact. Promotional materials will illustrate how lights improve customer security. Vendors will be the key source of promotion for lawn mowers. This component of the program would feature cooperative advertising and point-of-purchase information developed by TVA. In addition, educational materials will be developed to discuss the environmental and other benefits of electric lawn mowers.

QUALITY GAIN ESTIMATES FOR DSMANAGER VALUE TEST

BE-8	New Participants	Cumulative Penetration	One-Time Benefit/ Participant	Annual Benefit/ Participant	Quality Gain
1995	14,775	14,775	$0	$0	$0
1996	14,775	29,550	$0	$0	$0
1997	14,775	44,325	$0	$0	$0
1998	14,775	59,100	$0	$0	$0
1999	29,550	88,650	$0	$0	$0
2000	29,550	118,200	$0	$0	$0
2001	29,550	147,750	$0	$0	$0
2002	29,550	177,300	$0	$0	$0
2003	29,550	206,850	$0	$0	$0
2004	29,550	236,400	$0	$0	$0
2005	29,550	265,950	$0	$0	$0
2006	29,550	295,500	$0	$0	$0

One-Time Environmental Savings	*$0*
Annual Productivity, O&M, Fuel Savings	*$0*
Escalation Rate	*4%*

ELECTRIC TRANSPORTATION

Overview

The Electric Transportation option promotes select technologies (electric bus, electric fleet van, and electric cars) to assist all customer segments in reducing emissions and improving the environment in the TVA region. These technologies offer participating customers reduced operating and maintenance costs.

There are several market barriers related to this option that must be considered. This option represents a "cutting edge" strategy in promoting and accelerating the commercialization of this technology. The electric vehicle technology has not advanced to a high confidence level; in fact, it currently has reached a plateau and a technology breakthrough is required to instill enthusiasm and confidence into the marketplace.

Within the option, customers are offered a select menu of electrotechnologies from which to choose in determining the most appropriate solution to meet their needs. Electric buses and vans will target commercial, industrial, and municipal customers. Electric cars will target residential customers in select areas. A pilot program is recommended to gain experience in administering such a program. In addition, a pilot offers minimal risks to TVA and allows the evaluation of specific technologies and development of the optimal program delivery mechanisms.

Target Markets

Target markets pursued in the initial pilot include select geographic areas and markets within the industrial, commercial, residential, and municipal sectors.

Delivery Strategy

TVA does not plan to offer rebates as part of the program. The program and its technology options will be marketed as an innovative technology. TVA may consider financing or a technology-specific rate to stimulate consumer interest.

Program delivery will be administered through TVA marketing representatives and specific in-house technical staff working with power distributors and various trade allies/professionals. TVA should hire/develop an industry expert (transportation) for technical support of the program. TVA should also consider teaming up with trade professionals (equipment sales engineers and representatives) to assist in customer education and awareness. Coordination with the listed trade professionals from initial program design through program roll-out is essential to program success.

Electric Transportation/Electric Buses

Program Assumptions

Package Measure Life (Years)	20
Free-Rider Rate	20%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	0%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	(32,500)

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	100	—	—	0%
2	500	5	5	1%
3	995	20	25	3%
4	975	29	54	6%
5	946	29	83	9%
6	917	27	110	12%
7	890	27	137	15%
8	863	26	163	19%
9	837	25	188	22%
10	812	24	212	26%
11	788	24	236	30%
12	764	23	259	34%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $0 Total Variable Admin. Cost	Per Participant Measure Cost $200,000 Total Part. Measure Cost	Per Participant Incentive $0 Total Part. Incentive
1	$88,333	$0	$0	$0
2	$88,333	$0	$1,000,000	$0
3	$88,333	$0	$4,000,000	$0
4	$88,333	$0	$5,800,000	$0
5	$117,500	$0	$5,800,000	$0
6	$117,500	$0	$5,400,000	$0
7	$117,500	$0	$5,400,000	$0
8	$117,500	$0	$5,200,000	$0
9	$117,500	$0	$5,000,000	$0
10	$117,500	$0	$4,800,000	$0
11	$117,500	$0	$4,800,000	$0
12	$117,500	$0	$4,600,000	$0

Promotional Strategies

The program will be promoted via program brochures and marketing materials to permit widespread awareness of the program and its electric technologies. Technical seminars and training will be provided to educate potential customers concerning the virtues of electric vehicles and corresponding customer benefits. Presentations will be made at various industry and general public meetings to further promote this option.

QUALITY GAIN ESTIMATES FOR DSMANAGER VALUE TEST

BE-9A	New Participants	Cumulative Penetration	One-Time Benefit/ Participant	Annual Benefit/ Participant	Quality Gain
1995	0	0	$0	$6,000	$0
1996	5	5	$0	$6,240	$31,200
1997	20	25	$0	$6,490	$162,250
1998	29	54	$0	$6,749	$364,446
1999	29	83	$0	$7,019	$582,577
2000	26	110	$0	$7,300	$803,000
2001	27	137	$0	$7,592	$1,040,104
2002	26	163	$0	$7,896	$1,287,048
2003	25	188	$0	$8,211	$1,543,688
2004	24	212	$0	$8,540	$1,810,480
2005	24	236	$0	$8,881	$2,095,916
2006	23	259	$0	$9,237	$2,392,383

One-Time Environmental Savings	*$0*
Annual Productivity, O&M, Fuel Savings	*$6,000*
Escalation Rate	*4%*

Electric Transportation/Fleet Vehicles

Program Assumptions

Package Measure Life (Years)	20
Free-Rider Rate	20%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	0%
Non-Free-Rider Market Barrier Costs Eliminated	40%
Annual Energy Impact (kWh)	(7,800)

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	500	—	—	0%
2	500	5	5	1%
3	1,998	30	35	2%
4	3,972	60	95	2%
5	3,924	82	177	5%
6	3,858	62	239	6%
7	3,809	61	300	8%
8	3,760	41	341	9%
9	3,727	41	382	10%
10	3,694	41	423	11%
11	3,662	40	463	13%
12	3,630	40	503	14%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $0 Total Variable Admin. Cost	Per Participant Measure Cost $18,000 Total Part. Measure Cost	Per Participant Incentive $0 Total Part. Incentive
1	$88,333	$0	$0	$0
2	$88,333	$0	$90,000	$0
3	$88,333	$0	$540,000	$0
4	$88,333	$0	$1,080,000	$0
5	$117,500	$0	$1,476,000	$0
6	$117,500	$0	$1,116,000	$0
7	$117,500	$0	$1,098,000	$0
8	$117,500	$0	$738,000	$0
9	$117,500	$0	$738,000	$0
10	$117,500	$0	$738,000	$0
11	$117,500	$0	$720,000	$0
12	$117,500	$0	$720,000	$0

QUALITY GAIN ESTIMATES FOR DSMANAGER VALUE TEST

BE-9B	New Participants	Cumulative Penetration	One-Time Benefit/ Participant	Annual Benefit/ Participant	Quality Gain
1995	0	0	$0	$200	$0
1996	5	5	$0	$208	$1,040
1997	30	35	$0	$216	$7,560
1998	60	95	$0	$225	$21,375
1999	82	177	$0	$234	$41,418
2000	62	239	$0	$243	$58,077
2001	61	300	$0	$253	$75,900
2002	41	341	$0	$263	$89,683
2003	41	382	$0	$274	$104,688
2004	41	423	$0	$285	$120,555
2005	40	463	$0	$296	$137,048
2006	40	503	$0	$308	$154,924

One-Time Environmental Savings	*$0*
Annual Productivity, O&M, Fuel Savings	*$200*
Escalation Rate	*4%*

Electric Transportation/Electric Autos

Program Assumptions

Package Measure Life (Years)	10
Free-Rider Rate	30%
Free-Driver Rate	0%
Dropouts	0%
Take-Back Percentage	0%
Free-Rider Market Barrier Costs Eliminated	0%
Non-Free-Rider Market Barrier Costs Eliminated	75%
Annual Energy Impact (kWh)	(3,000)

Year	Annual Eligible Population	New Participants	Total Participants	Cumulative Participation Rate
1	2,000	—	—	0%
2	2,000	10	10	1%
3	9,995	50	60	1%
4	19,940	199	259	1%
5	19,741	197	457	2%
6	19,543	195	652	3%
7	19,348	193	845	4%
8	19,154	192	1,037	5%
9	18,963	190	1,227	6%
10	18,773	188	1,415	8%
11	18,585	186	1,600	9%
12	18,400	184	1,784	10%

Year	Fixed Administrative Cost	Per Participant Variable Administrative Costs $0 Total Variable Admin. Cost	Per Participant Measure Cost $25,000 Total Part. Measure Cost	Per Participant Incentive $0 Total Part. Incentive
1	$88,333	$0	$0	$0
2	$88,333	$0	$250,000	$0
3	$88,333	$0	$1,250,000	$0
4	$88,333	$0	$4,975,000	$0
5	$117,500	$0	$4,925,000	$0
6	$117,500	$0	$4,875,000	$0
7	$117,500	$0	$4,825,000	$0
8	$117,500	$0	$4,800,000	$0
9	$117,500	$0	$4,750,000	$0
10	$117,500	$0	$4,700,000	$0
11	$117,500	$0	$4,650,000	$0
12	$117,500	$0	$4,600,000	$0

QUALITY GAIN ESTIMATES FOR DSMANAGER VALUE TEST

BE-9C	New Participants	Cumulative Penetration	One-Time Benefit/ Participant	Annual Benefit/ Participant	Quality Gain
1995	0	0	$0	$700	$0
1996	10	10	$0	$728	$7,280
1997	50	60	$0	$757	$45,427
1998	199	259	$0	$787	$203,938
1999	197	457	$0	$819	$374,283
2000	195	652	$0	$852	$555,504
2001	193	845	$0	$886	$748,670
2002	192	1,037	$0	$921	$955,077
2003	190	1,227	$0	$958	$1,175,466
2004	188	1,415	$0	$996	$1,409,340
2005	186	1,600	$0	$1,036	$1,657,874
2006	184	1,784	$0	$1,078	$1,922,470

One-Time Environmental Savings	*$0*
Annual Productivity, O&M, Fuel Savings	*$700*
Escalation Rate	*4%*

TECHNOLOGY INFORMATION

DESCRIPTION OF TECHNOLOGY DATABASE

TVA developed a technology database that includes information on energy efficiency, load management, beneficial electrification, and self/generation and renewable technologies. The data used to develop the technology database included information from several primary and secondary data sources. Hourly simulations for all building types provided data for the weather-dependent technologies.

Development of the database began with a list of technologies that was reviewed for diversity and completeness by two leading DSM consultants. TVA worked with Synergic Resources Corporation (SRC) to develop the energy efficiency portions of the database for the residential, commercial, and industrial sectors. Barakat & Chamberlin, Inc. (BCI) provided information for renewable and beneficial electrification technologies. For some technologies, estimates of costs and impacts were obtained from more than one source. Technology information on small cogeneration systems was provided by Schiller Associates and UNIMAR Group, Ltd.

Technology costs and energy and demand impacts were included for both existing structures and new construction to provide estimates for retrofit and new construction options. Technologies were matched with appropriate base technologies for each market. Base technology energy use and shares were taken from detailed forecast information contained in TVA's files for REEPS (EPRI's Residential End-Use Energy Planning System software) and COMMEND (EPRI's Commercial End-Use Planning System software). Historical residential UECs (Unit Energy Consumption, kWh/yr) are based on conditional demand models using TVA survey and billing data. Some appliance data are based on manufacturers and EPRI estimates, along with other sources. The use of REEPS and COMMEND energy use and shares helped to ensure that technology estimates were consistent with load forecast assumptions. Forecast market shares were based on residential, commercial, and industrial surveys performed by TVA.

Additions and corrections to the database were made based on comments from TVA staff and reviews by the following organizations:

- National Renewable Energy Laboratory (NREL), Golden, Colorado
- TELLUS Institute, Boston, Massachusetts
- E Source, Boulder, Colorado
- TVA Energy Vision 2020 Review Group members and their consultants:
  - —Resource Insight, Inc., Middlebury, Vermont
  - —Xenergy, Allendale, New Jersey
  - —Vermont Energy Investment Corporation, Burlington, Vermont

RESIDENTIAL

Primary data sources included existing saturation surveys, energy audits, end-use load forecasts, and institutional data. Hourly building simulations of prototypical buildings were developed using DOE-2 and TMY (Typical Meteorological Year) weather for Nashville, Tennessee, to estimate energy and demand impacts of HVAC technologies and building shell improvements. DOE-2 is public domain software developed with funding from the U.S. Department of Energy and used internationally to calculate the hourly energy use of buildings and their life cycle costs of operation, given information on building location, construction, operation, and heating and air conditioning systems.

Secondary data sources included Competitek, EPRI reports, energy journals, case studies, other utility filings, ESOURCE reports, manufacturers' literature, and previous work done by SRC and BCI. ESOURCE, formerly known as Competitek, is a proprietary information service and a subsidiary of Rocky Mountain Institute.

As much as possible, the energy impacts have been adjusted to be consistent with TVA's residential end-use forecast.

The residential technologies include electric conservation, load shifting, peak clipping, and beneficial electrification (load building) measures. A summary listing of the DSM technologies is shown in *Figure T7-5*.

The technologies were grouped by end use. The primary end-use catagories considered for the residential sector were: Space Conditioning, Water Heating, Appliance, and Lighting. For each end use, the technologies were mapped to an appropriate base technology and building type. In the residential market, three building types were included: single-family, multi-family, and manufactured homes. Following are descriptions of the technologies considered for each end use.

FIGURE T7-5. Residential Technologies

End-Use	Demand-Side Measure
Space Conditioning Cooling	High-Efficiency Room Air Conditioner
	High-Efficiency Central Air Conditioner (CAC)
	Two-Speed Central Air Conditioner
	Whole-House Fan
	Ceiling Fans
	Servicing Central Air Conditioner
	Central Air Conditioner Cycling or Direct Load Control
Space Conditioning Cool/Heat	High-Efficiency Heat Pump
	Standard Heat Pump
	Two-Speed Heat Pump
	Ground-Source Heat Pump
	Dual-Fuel Heat Pump
	Standard Add-On Heat Pump
	High-Efficiency Add-On Heat Pump
	Electric Heat Direct Load Control
	Insider Heat Pump
	Servicing Heat Pump
Space Conditioning Ducting & Controls	Ducts in Conditioned Spaces
	Reduced Duct Leakage
	Reduced Duct Heat Transfer
	Programmable Thermostat
Space Conditioning Building Shell	Wall Insulation
	Weather Stripping/Caulking
	Window Film/Reflective Glass
	Low-E Glass
	Window Shade Screens
	Reflective Roof Coating
	Attic Radiant Barrier
	Landscape Shading
	Ceiling Insulation
Water Heating	High-Efficiency Electric Resistance
	Integral Heat Pump Water Heater
	Add-On Heat Pump Water Heater
	Maintenance of Heat Pump Water Heater
	Solar Water Heater
	Heat Recovery Water Heater (Desuperheater)
	Instantaneous (Tankless) Electric Water Heater
	Water Heater Tank Wrap
	Water Heater Heat Trap
	Hot Water Pipe Insulation
	Low Flow Showerhead
	Direct Load Control of Electric Resistance
	Bottom Boards
	Standard Efficiency Gas Water Heater
	High-Efficiency Gas Water Heater
Appliances	Best Current Frost-Free Refrigerator
	Remove Second Refrigerator
	Best Current Frost-Free Freezer
	Remove Second Freezer
	Servicing Refrigerator or Freezer (Clean Coils)
	Microwave Clothes Dryer
	Electric Dryer with Moisture Sensor
	Heat Pump Clothes Dryer
	Horizontal-Axis Clothes Dryer
	High-Efficiency Dishwasher
	Induction Cooktop
	Electric Cordless Lawn Mower
	Electric Cord Lawn Mower
	Smart House (Home Automation & Real-Time Pricing)
	High-Efficiency Pool Pumps or Spa Pumps
	Downsized Pool Pumps with Oversized Piping
	Direct Load Control of Pool Pumps
	Pool Pump Timer
Lighting	Compact Fluorescent
	Efficient Incandescent
	Security Lighting
	High Pressure Sodium (Outdoor)
	Halogen Lamp (Outdoor)
	Halogen Lamp (Indoor)
	Motion Detectors for Outdoor Lighting

Residential Space Conditioning

Six prototypical buildings were simulated in DOE-2 with Nashville TMY weather data to develop some of the energy impacts for space conditioning technologies. Energy impacts from simulations of a building with and without a particular technology were combined with REEPS UECs to develop average kWh and kW demand impacts.

In the short descriptions of space conditioning technologies that follow, some abbreviations are used for ratings of equipment. The common rating terms are:

- COP—Coefficient of Performance
- HSPF—Heating Season Performance Factor
- SEER—Seasonal Energy Efficiency Ratio
- R-Value—Insulation Value

Cooling

High-Efficiency Room Air Conditioner—A high-efficiency unit with an Energy Efficiency Ratio (EER) of 11.0 replaces a standard unit with an EER of 8.8.

High-Efficiency Central Air Conditioner—A high-efficiency unit with a SEER of 13.0 and a Coefficient of Performance (COP) of 3.437 replaces a standard unit with a SEER of 10.0 and a COP of 2.570.

Two-Speed Central Air Conditioner—A two-speed unit with a SEER of 14.8 and a COP of 3.074 replaces a standard unit with a SEER of 10.0 and a COP of 2.570. The two-speed unit has better performance than the high-efficiency unit at part load, but has a lower performance at design conditions.

Whole-House Fan—A whole-house fan is installed in new and existing single-family dwellings to reduce cooling energy use. The fan will be sized to provide 20 air changes per hour and will operate when the outdoor air temperature is above 72° F and below 83° F, and when relative humidity is 60 percent or less. When the fan is running, the air conditioning system is turned off.

Ceiling Fans—Ceiling fans will allow cooling thermostat settings to be increased by 2° F in single-family and multi-family dwellings. A ceiling fan will be installed for each 250 square feet of floor area.

Servicing Central Air Conditioner—Annual air conditioner maintenance reduces cooling energy use by 10 percent.

Central Air Conditioner Cycling or Direct Load Control — This measure involves the use of remote transmitters to control residential space cooling systems to reduce peak load by load shedding (turning units off at the time of the utility peak) or cycling (periodically turning units off).

Cool/Heat

High-Efficiency Heat Pump—A high-efficiency air-source heat pump with SEER 13.0 and HSPF 8.1 replaces a standard efficiency heat pump with SEER 10.0 and HSPF 6.8 in new and existing construction. The standard unit has a cooling COP of 2.570 and a heating COP of 2.978. The high-efficiency unit has a cooling COP of 3.437 and a heating COP of 3.540.

Standard Heat Pump—The standard air-source heat pump has a SEER of 10.0 and a HSPF of 6.8 in new and existing construction. The standard unit has a cooling COP of 2.570 and a heating COP of 2.978.

Two-Speed Heat Pump—A heat pump with a two-speed compressor, a SEER of 14.8 and a HSPF of 8.45 replaces a standard heat pump. The heat pump has a cooling COP of 3.074 and a heating COP of 3.430. The primary advantage of the two-speed heat pump is better performance at part load. Part load is between no load and full load. At design conditions (full load), this heat pump is somewhat less efficient than a high-efficiency unit.

Ground-Source Heat Pump—A ground-source heat pump exchanges heat with water in thermal contact with the ground. Ground-source heat pumps can be closed-loop, where water is continuously circulated (while the heat pump is running) between the heat pump and pipes buried in the ground, or they can be open-loop, where water is extracted from a well or lake and dumped after use. A ground-source heat pump replaces a standard efficiency heat pump. For this analysis, only closed-loop systems were considered.

Dual-Fuel Heat Pump—A dual-fuel heat pump is an air-source heat pump with a fossil fuel burner system for back-up heating rather than resistance coils. Estimates were included for a SEER 12 unit.

Standard Add-On Heat Pump—This measure is promoted to households that currently have central air conditioning and gas heat and are approaching the time of replacement of their central air conditioners. In addition to providing cooling, an add-on heat pump would provide heating during the moderate heating season and gas heat would be used as a back-up. The cooling efficiency of the Central Air Conditioner (CAC) and heat pump is SEER 10.0. The gas heating efficiency is 78 percent Annual Fuel Utilization Efficiency (AFUE), and the heat pump heating efficiency is HSPF 6.8.

High-Efficiency Add-On Heat Pump—This measure is similar to the standard add-on heat pump, except a high-efficiency heat pump is promoted, having a SEER 13 and HSPF 8.1. This measure provides heating electrification and cooling conservation.

Electric Heat Direct Load Control—This measure involves the use of remote transmitters to control residential space heat-

ing systems to reduce peak load by load shedding (turning units off at the time of the utility peak) or cycling (periodically turning units off). This measure was only considered for utilities that already have load control programs, meaning the cost of the central transmitter is not included in the estimates.

Insider Heat Pump—Estimates for this particular heat pump were included for manufactured housing.

Servicing Heat Pump—Annual heat pump maintenance reduces cooling energy use by 10 percent and heating energy use by 9.2 percent.

Ducting and Controls

Ducts in Conditioned Spaces—It is common in single-family detached dwellings to have space conditioning ductwork located in unconditioned spaces (primarily the attic). For this measure, the ductwork in new single-family detached dwellings will be located in the conditioned space to eliminate losses associated with duct leakage and duct heat gain/loss.

Reduced Duct Leakage—This measure involves the sealing of space conditioning ducts to eliminate the loss of conditioned air and/or the introduction of attic air into the duct system. An equivalent conditioning system efficiency change was used in DOE-2 to simulate a 70 percent reduction in duct air losses. One-third of this improvement was on the supply-side ducts and two-thirds were on the return side ducts.

Reduced Duct Heat Transfer—This measure involves the addition of insulation to ducting in new single-family detached dwellings. For this measure, it is assumed that additional insulation would be added to increase the duct total insulation level to R-12 from R-6 required by the energy code.

Programmable Thermostat—The programmable thermostat sets the thermostat up 5° F from 9:00 AM to 5:00 PM during weekdays in the cooling season and sets the thermostat down 5° F from 11:00 PM to 6:00 AM for all days during the heating season. The thermostat is assumed to have energy management recovery that allows for early recovery from a setup and involves the automatic calculation of when to begin raising (or lowering) the space temperature to reach the programmed temperature at a preset time.

Building Shell

Wall Insulation—For this measure, wall insulation in existing frame dwellings is increased from R-0 to R-11. This measure only applies to dwellings with no wall insulation.

Weather Stripping/Caulking—Caulking and weather stripping of existing dwellings reduces air infiltration by 10 percent on average. This measure only applies to existing dwellings, as it is assumed that new construction is adequately sealed in accordance with the new construction building code.

Window Film/Reflective Glass—In existing dwellings, a reflective window film is applied to the interior surface of single-pane windows. Double-pane reflective glass is substituted for clear double-pane glass in new construction. This measure is applied to windows facing east and west because the solar gain is highest from these directions.

Low-Emissivity Glass—To represent this class of windows, double-pane glass with an argon gas fill and a low-emissivity coating on the inner surface of the outer pane replaces single- and double-pane clear glass windows. This measure reduces heat transmission through the windows.

Window Shade Screens—For this measure, shade screens that block solar gain are installed on single- and double-pane clear windows in existing and new construction. This measure is applied to windows facing east and west because solar gain is highest from these directions.

Reflective Roof Coating—This measure will involve the application of a reflective coating with an absorptivity of 0.30 to a standard roof with an absorptivity of 0.80 to reduce the cooling loads associated with roof solar gain.

Attic Radiant Barrier—This measure involves the installation of a reflective surface on the bottom of roof joists in new single-family detached construction to reduce solar gain through the roof. The reflective surface will have an emissivity of 0.08 on each side and result in an effective increase in the roof insulation of approximately R-7.

Landscape Shading—This measure involves the planting of six trees, three each on the east and west sides of new and existing single family dwellings, to provide external shading during the cooling season.

Ceiling Insulation (new construction)—This measure involves adding more ceiling insulation (from R-30 to R-38) to new dwellings.

Ceiling Insulation (R-0 to R-19)—In existing dwellings with no ceiling insulation, R-19 would be added.

Ceiling Insulation (R-11 to R-30)—In existing dwellings with R-11 ceiling insulation, R-19 would be added to achieve a total of R-30.

Ceiling Insulation (R-19 to R-30)—In existing dwellings with R-19 ceiling insulation, R-11 would be added to achieve a total of R-30.

Ceiling Insulation (R-30 to R-38)—In existing dwellings with R-30 ceiling insulation, R-8 would be added to achieve a total of R-38.

Residential Water Heating

There are four general types of electric water heating equipment for the residential market:

- Electric resistance water heater
- Heat pump water heater
- Heat recovery water heater (desuperheater)
- Solar water heater

Each type has unique operating and consumption characteristics. The UEC for electric water heating is a combination (weighted average) of these four heating types for each building type. Individual UECs for each technology type were derived by disaggregating the weighted-average UEC (from REEPS) using the relative efficiencies and shares for each technology type. Efficiencies, saturations, and UECs for water heating are shown in *Figures T7-6, T7-7,* and *T7-8.*

Brief descriptions of the residential water heating technologies follow.

High-Efficiency Electric Resistance—Electric resistance water heaters with Efficiency Factors of 0.96 are compared to models that meet federal appliance standards (EF=0.90).

Integral Heat Pump Water Heater—Heat pump water heaters could be installed either to replace electric resistance water heaters or gas water heaters. When an electric resistance water heater is replaced, the electricity used for water heating is reduced by approximately half

FIGURE T7-6. **Electric Water Heating Technologies: Relative Efficiencies**

Water Heater System Type	Annual COP	Normalized COP	Daily Use (kWh)	Percent Savings
Resistance Water Heaters	0.82	1	9.60	0%
Heat Pump Water Heaters	1.53	1.87	5.13	47%
Heat Recovery Water Heaters	1.1	1.34	7.16	25%
Solar Water Heaters	2.35	2.87	3.34	65%

SOURCE: FSEC, 1990. Florida Solar Energy Center, "Electrical Use, Efficiency, and Peak Demand of Electric Resistance, Heat Pump, Desuperheater, and Solar Hot Water Systems."

FIGURE T7-7. **Electric Water Heating: Saturations**

	EXISTING			NEW		
	Single-Family	Multi-Family	Manufactured Home	Single-Family	Multi-Family	Manufactured Home
All Electric Water Heaters [1]	75.54	78.40	84.68	75.54	78.40	84.68
Resistance Water Heaters [2]	96.00	97.00	100.00	96.00	97.00	100.00
Heat Pump Water Heaters [2]	2.00	2.00	0.00	2.00	2.00	0.00
Heat Recovery Water Heaters [2]	1.00	0.00	0.00	1.00	0.00	0.00
Solar Water Heaters	1.00	1.00	0.00	1.00	1.00	0.00

[1] Electric water heat saturations for existing households are taken directly from 1993 Residential Sales Profile. Saturations for new households are assumed to be the same as existing.

[2] Based on SRC assumptions of the distribution of electric water heating technologies.

FIGURE T7-8. **Electric Water Heating: Unit Energy Consumptions (UECs)**

	EXISTING			NEW		
	Single-Family	Multi-Family	Manufactured Home	Single-Family	Multi-Family	Manufactured Home
All Electric Water Heaters [1]	4,178	3,304	3,200	3,807	3,011	2,916
Resistance Water Heaters - STOCK [2]	4,256	3,357	3,200	3,878	3,059	2,916
Heat Pump Water Heaters [2]	2,276	1,795	1,711	2,074	1,636	1,559
Heat Recovery Water Heaters [2]	3,176	2,505	2,388	2,894	2,283	2,176
Solar Water Heaters [2]	1,483	1,170	1,115	1,351	1,066	1,016
Resistance Water Heaters- STANDARD [3]	3,878	3,059	2,916	3,878	3,059	2,916

[1] All electric water heat UEC values for existing households are directly from 1993 Residential Sales Profile and exclude energy used in conjunction with major hot water using appliances. All electric water heat UECs for new households are calculated based on the adjustment factor used for Stock to Standard.

[2] Calculated based on the shares and relative efficiencies such that the weighted average is consistent with the All Electric Water Heater UEC.

[3] Calculated based on the adjustment of STOCK consumption to account for natural increases in efficiency due to replacements. Efficiency of STOCK water heaters estimated to be EF=0.82 (average efficiency in 1986) and of STANDARD water heaters to be EF=0.90 (based on 1990 Federal Standards).

(as well as providing reduced cooling loads in some cases). A heat pump water heater utilizes a vapor compressor refrigerator cycle similar to that of an air conditioner to draw heat from the surrounding air to heat water. The heat pump water heater condenser rejects heat to the domestic water supply. An integral unit includes both the water tank and the heat pump water heater located on top of the tank.

Add-On Heat Pump Water Heater—An add-on heat pump water heater supplements the existing electric resistance hot water system at the supply to the water heater.

Maintenance of Heat Pump Water Heater—Maintenance includes replacing filters, cleaning coils, checking refrigerant charge, checking plumbing connections, and checking plumbing insulation to maintain efficiency of the heat pump water heater.

Solar Water Heater—The solar water heating system actually assists rather than replaces an electric resistance water heater. When solar radiation is available, it is absorbed by collector panels and then transferred to the domestic hot water supply. Some systems heat water directly by circulating potable water through the solar loop. Others recirculate the same absorption fluid through the collectors and transfer the heat via a heat exchanger to the potable water supply.

Heat Recovery Water Heater—Estimates for the replacement of an electric resistance water heater with a heat recovery water heater show the majority of the savings occur during summer months. These units recover superheat from the compressor discharge gas of a central air conditioner or heat pump for the purpose of heating or preheating water.

Instantaneous (Tankless) Electric Water Heater—Energy savings result primarily from the elimination of tank losses. Demand increases may result in the winter because larger heating elements are used and hot water is frequently used during winter peak times.

Water Heater Tank Wrap—This measure includes the installation of R-11 external insulation blanket onto electric resistance water heater tanks.

Water Heater Heat Trap—This measure includes the installation of external heat traps on both the inlets and outlets of electric water heaters.

Hot Water Pipe Insulation—This measure includes the installation of pipe insulation to all accessible domestic hot water piping (assumed to be 70 feet of pipe in new homes, but only 20 feet in existing homes).

Low Flow Showerhead—This measure replaces existing showerheads (3-5 gallons per minute or gpm) with high quality low flow showerheads (2-2.5 gpm). Water savings, as well as energy to heat the water, result for each shower of equivalent quality. Estimates are per household.

Direct Load Control of Electric Resistance Water Heaters—Utility-controlled radio switches installed on residential electric water heaters could shut off 100 percent of participating water heaters during utility system peak periods.

Bottom Boards—This measure involves placing a 2-inch polystyrene (R-10) board under an electric resistance water heater. Savings measurements of 53 to 75 kWh/year have been recorded. Savings of 75 kWh/year were assumed for single-families, savings and 60 kWh/year savings were assumed for multi-family and manufactured housing.

Standard Efficiency Gas Water Heater—This measure includes replacing an existing electric water heater (assumed EF=0.82) with a standard efficiency gas water heater (EF=0.54 for 40-gallon heater and 0.56 for 30-gallon heater).

High-Efficiency Gas Water Heater—This measure includes replacing an existing electric water heater (assumed EF=0.82) with a high-efficiency gas water heater (EF=0.65 for 40-gallon and EF=0.63 for 30-gallon).

Residential Appliances

The 1993 UECs and saturations (or shares) from REEPS were the basis for evaluating new appliances and are shown in *Figure T7-9* and *T7-10*.

Brief descriptions of residential appliance technologies follow.

Best Current Frost-Free Refrigerator—Estimates were included for frost-free refrigerators with efficiencies at least 16 percent better than those required by federal appliance efficiency standards.

Remove Second Refrigerator—Customers with second, older, and less efficient, yet still operating refrigerators could be encouraged to remove them. The utility would be responsible for picking up and disposing of the refrigerators.

Best Current Frost-Free Freezer—Estimates were included for frost-free freezers with efficiencies at least 22 percent better than those required by federal appliance efficiency standards.

Remove Second Freezer—Customers with second, older, and less efficient, yet still operating freezers could be encouraged to remove them. The utility would be responsible for picking up and disposing of the freezers.

Servicing Refrigerator or Freezer (Primarily Clean Coils)—This measure was included for direct-install type options (programs).

Microwave Clothes Dryer—Successful prototypes that vaporize the water in clothes rather than heating them may now have a solution to the metal button problem. Preliminary tests with a lower frequency magnetron have been successful. Energy, drying times, and drying temperatures are all reduced with this technology.

FIGURE T7-9. **Appliances: Unit Energy Consumptions (UECs)**

	EXISTING			NEW		
Appliance	**Single-Family**	**Multi-Family**	**Manufactured Home**	**Single-Family**	**Multi-Family**	**Manufactured Home**
Refrigerator - 1st	1,088	989	990	1,088	989	990
Refrigerator - 2nd	949	757	941	949	757	941
Refrigerator - Average	1,066	980	988	1,066	980	988
Freezer	989	800	815	989	800	815
Clothes Dryer	1,017	957	906	1,017	957	906
Clothes Washer	195	134	113	195	134	113
Dishwasher	394	336	334	394	336	334
Electric Cooking	994	845	746	994	845	746
Pool Pumps (from FEO)	3,117	3,117	3,117	3,117	3,117	3,117

From Tennessee Valley Authority 1993 Residential Sales Profile
FEO = Florida Energy Office

FIGURE T7-10. **Appliances: Saturations**

	EXISTING			NEW		
Appliance	**Single-Family**	**Multi-Family**	**Manufactured Home**	**Single-Family**	**Multi-Family**	**Manufactured Home**
Refrigerator - 1st	100	100	100	100	100	100
Refrigerator - 2nd	19	4	4	19	4	4
Freezer	57	16	36	57	16	36
Clothes Dryer	72	48	59	72	48	59
Clothes Washer	90	47	70	90	47	70
Dishwasher	53	51	29	53	51	29
Electric Cooking	87	89	85	87	89	85
Pool Pumps	NA	NA	NA	NA	NA	NA

From Tennessee Valley Authority 1993 Residential Sales Profile

Electric Dryer with Moisture Sensor—Most dryers utilize a temperature sensor to control the operation of the dryer. A moisture sensor in the exhaust provides more precise control for automatic shutoff of the dryer when the clothes are mostly dry.

Heat Pump Clothes Dryer—The heat pump clothes dryer (not yet commercially available) uses a refrigerant cycle to remove moisture from exhaust air. This dehumidified exhaust air is then rewarmed and recirculated into the dryer. Because the exhaust is recirculated, a vent is not needed. However, a condensate drain would be required.

Horizontal-Axis Clothes Washer—Horizontal-axis clothes washers, available overseas, use less water, energy, and detergent per cycle compared to the vertical-axis clothes washer common in the United States. Only the energy savings (from the use of less hot water) were estimated.

High-Efficiency Dishwasher—In 1994 U.S. energy efficiency standards for dishwashers improved the efficiency of dishwashers being purchased in the United States. However, models are available in the U.S. that surpass this standard by about 30 percent. Their savings may be attributed to booster water heaters, lower water use, more efficient motors, and air-drying features.

Induction Cooktop—This technology (gaining acceptance in the commercial market and available but limited for the residential market) consists of a high frequency electric coil located beneath a smooth cooking surface. The coil creates an alternating magnetic field that induces a current in ferrous metal pots, thus causing heating in the pot rather than the cooking surface. Induction cooktops have efficiency gains of 20 to 40 percent over electric resistance cooktops.

Electric Cordless Lawn Mower—A cordless lawn mower uses a rechargeable battery and an electric motor. Estimates are based on Black & Decker's 18-inch model with a 12-volt lead/acid battery.

Electric Cord Lawn Mower—Gas-powered lawn mowers have 94 percent of the market share, with the rest being accounted for by electric cord mowers. Estimates are based on Black & Decker models with 8-amp and 12-amp motors.

Smart House (Home Automation & Real-Time Pricing)—A home automation system consists of an interface node near the utility meter that communicates to a smart thermostat, as well as appliance monitoring and control modules in the home. Communication between the utility and residence goes in both directions, allowing for a wide array of advanced services. The homeowner can control appliances in response to time-of-use rates or real-time price signals from the utility or can allow for utility control of appliances.

High-Efficiency Pool Pumps—Estimates are included for replacing a standard efficiency pool pump with a high-efficiency pump.

Downsized Pool Pumps with Oversized Piping—This measure encourages the combination of (1) properly sizing pool pump motors (which are often oversized) and (2) modifying the piping to minimize losses (which includes installing larger diameter piping, eliminating sharp 90-degree elbows, and possibly installing a larger filter).

Direct Load Control of Pool Pumps—Utility-controlled radio switches could be installed on residential pool pumps, which could be controlled by the utility during times of system peak demand. During system peak periods 100 percent of participating pool pumps could be turned off.

Pool Pump Timer—Timers or adjustment of existing timers on pool pumps can be used to control the operation timing of pool pumps. The timer would be set to turn off the pool pump during expected times of system peak demand.

Residential Lighting

Brief descriptions of residential lighting technologies follow:

Compact Fluorescent—Because prices and energy savings estimates vary based on procurement method and hours of operation, estimates for a single bulb or household were developed for each option (program).

Efficient Incandescent—Efficient incandescent light bulbs provide relatively equal lighting with reduced wattage due to a more efficient filament design and a phosphorescent coating. It is assumed that 80 percent of all standard incandescent lamps (40W, 60W, 75W, 100W) can be replaced with more efficient lamps.

Residential Security Lighting—High pressure sodium lamps operating 4,000 hours/yr were used for this estimate, although other types of lamps are available, such as mercury vapor and metal halide.

High Pressure Sodium (Outdoor)—Savings estimates for high pressure sodium fixtures that may be used for outdoor floodlight fixtures are based on 1,500 hours/yr operating time. This operating schedule assumes that the lights are turned off at bedtime.

Halogen Lamp (Outdoor)—One of the most significant improvements to incandescent lamps is to surround the filament with a separate capsule containing halogen gasses that capture vaporized tungsten and redeposit it on the filament, extending its life while preventing condensed tungsten from darkening the bulb. The halogen cycle creates more light per unit of electricity and provides a better quality of light.

Halogen Lamp (Indoor)—Thick walled A-lamps can be used in many residential applications.

Motion Detectors for Outdoor Lighting—Add-on controls that exclude the combination of both a motion detector and a photocell would be installed on existing outdoor lighting fixtures. Savings estimates assume that the motion detector would be activated only 5 percent of the time.

COMMERCIAL

Primary data sources included existing saturation surveys, energy audits, end-use load forecasts, and TVA institutional data. Hourly building simulations of prototypical buildings were developed using micro-AXCESS and TMY weather for Nashville, Tennessee, to estimate the energy and demand impacts of HVAC technologies and building shell improvements. The detailed hourly building energy analysis software used for analyses of the commercial prototype buildings, micro-AXCESS, is available through EPRI's (Electric Power Research Institute) Electric Power Software Center.

Secondary data sources included Competitek, EPRI reports, energy journals, case studies, other utility filings, manufacturers' literature, E Source reports, and previous work done by SRC and BCI. ESOURCE, formerly known as Competitek, is a proprietary information service and a subsidiary of Rocky Mountain Institute.

As much as possible, the energy impacts have been adjusted to be consistent with TVA's commercial end-use forecast (i.e., COMMEND EUIs [End Use Intensities in kWh/sf/yr] and electric gas shares). For example, the lighting EUI for retail buildings for 1993 was disaggregated into different lighting categories (e.g., incandescent, fluorescent, mercury vapor, high pressure sodium, metal halide) to account for their inherent lighting efficiencies and assumed distributions. These disaggregated EUIs

FIGURE T7-11. **Commercial Technologies**

End-Use	Demand-Side Measure
Space Conditioning Equipment	High-Efficiency Chiller
	High-Efficiency Chiller w/ASD
	High-Efficiency DX A/C
	High-Efficiency Room A/C
	Cool Storage (Partial Ice)
	Rooftop Cool Storage (Partial Ice)
	Thermal Energy Storage (General)
	Heat Pipe Enhanced DX A/C
	Hotel Occupancy Sensors
	2-Speed Motor for Cooling Tower
	Speed Control for Cooling Tower
	Air Conditioning Maintenance
	HVAC Air Duct/Water Pipe Insulation
	Leak-Free Ducts
	HVAC Energy Management System
	Standard Efficiency Heat Pump (Electric Backup)
	High-Efficiency Heat Pump (Electric Backup)
	VAV System with Inlet Vanes
	ASD Ventilation Controls w/VAV
	Timer/Programmable Ventilation Control
	High-Efficiency Ventilation Motors
	Separate Makeup Air/Exhaust Hoods
	Dual-Fuel Heat Pump
	Ground-Source Water Loop Heat Pump
	Wood Furnace (Space Heating Only)
	Wood Boiler (Space and Water Heating)
	Passive Solar Space Heating and Cooling
	Temperature Setup/Setback
Space Conditioning Building Shell	Roof Insulation
	Wall Insulation
	Window Film
	Spectrally Selective Windows
	Light-Colored Roofs
Lighting	T8 Lamps / Electronic Ballasts
	Electronic Ballasts
	Refl/Delamp 4' - 40W Fluor. Lamps/ Electronic Ballasts
	Refl/Delamp 8' - 75W Fluor. Lamps/ Electronic Ballasts
	Refl/Delamp 4' - 40W Fluor. Lamps/ Hybrid Ballasts
	Refl/Delamp 8' - 75W Fluor. Lamps/ Hybrid Ballasts
	4' – 34W Lamps/Electronic Ballasts
	8' – 60W Lamps/Electronic Ballasts
	4' – 34W Fluor. Lamps / Dimming Ballasts
	Compact Fluorescent Lamps and Fixtures
	Photoelectric Control
	Energy Management System Lighting Control
	Occupancy Sensors
	Indoor HID Lamps—High Pressure Sodium
	Outdoor HID Lamps—High Pressure Sodium
	Metal Halide (32W)
	LED Exit Signs (Light-Emitting Diode)
	Fluorescent Exit Signs
	Electroluminescent Exit Signs
	Daylighting Design
	LED Traffic Signal
	Sulfur Lamp
Refrigeration	Multiplex: Air-Cooled/No Subcooling
	Multiplex: Air-Cooled/Ambient Subcooling
	Multiplex: Air-Cooled/Mechanical Subcooling
	Multiplex: Air-Cooled/Ambient & Mechanical Subcooling
	Multiplex: Air-Cooled/External Liquid Suction HX
	Open-Drive Refrigeration System (ASD)
	Anti-Condensate Heater Controls
	High R-Value Glass Doors
	Refrigeration Energy Management System (EMS)
	Dual-Path Supermarket Air Conditioning
Water Heating	Heat Pump Water Heater
	Solar-Assisted Water Heater
	Heat Recovery Water Heater
	DHW Heater Insulation
	DHW Heat Trap
	Low Flow/Variable Flow Showerhead
	DWH Recirculation Pumps
Cooking	Electric Forced Convection Oven
	Electric Natural Convection Ovens
	Energy-Efficient Electric Fryers
	Flash Bake Oven

then became the base case to which the DSM lighting technologies were compared. The use of these disaggregated EUIs helps to ensure that potential energy and demand impact estimates are consistent with the load forecast assumptions. These EUIs reflect the operating characteristics of the businesses in the TVA region, such as operating hours, lighting levels, etc.

The commercial technologies include electric conservation, load shifting, peak clipping, and beneficial electrification (load growth) measures. A listing of the commercial technologies included in the technology database is shown in *Figure T7-11.*

The technologies were grouped by end use. The primary end uses considered in the commercial sector included: Space Conditioning, Building Shell, Lighting, Refrigeration, Water Heating, and Cooking. For each end use, the technologies were mapped to an appropriate base technology and building type. In the commercial market, the following ten building types were considered:

- Office (OF)
- Restaurant, Fast Food, and Full Service (FF)
- Retail (RT)
- Grocery (GR)
- Warehouse (WH)
- School (SC)
- College or University (UN)
- Hospital (HS)
- Lodging, Hotel, or Motel (HM)
- Miscellaneous (MI)

The annual costs and energy impacts were expressed per thousand square feet for each appropriate building type. Energy-efficient office equipment was not included because often there is no incremental cost over less efficient models. Also, many of these efficient models are already the baseline in new purchases resulting from market transformation efforts such as EPA's Energy Star Program, which TVA supports.

Commercial Space Conditioning

Brief descriptions of the space conditioning or building shell technologies follow:

Space Conditioning

High-Efficiency Chiller—This measure consists of comparing standard efficiency [COMPRESSOR COP=5.0] centrifugal chillers to high-efficiency [COMPRESSOR COP=5.76] centrifugal chillers. This measure was analyzed only for hospitals and large offices and was modeled using micro-AXCESS.

High-Efficiency Chiller w/ASD—This option consists of retrofitting an adjustable speed drive (ASD) controller onto high-efficiency centrifugal chillers. The same assumptions apply here as in the high-efficiency centrifugal chillers. This measure was modeled in micro-AXCESS using an improved chiller part-load profile.

High-Efficiency Direct Expansion (DX) Air Conditioning (A/C)—The Energy Policy Act and ASHRAE figures indicate the following standards:

Cooling Capacity (kBtu/hour)	EER
65 – 135	8.9
135 – 760	8.3

An average baseline EER = 8.7 (1.38 kW/ton) is assumed. The high efficiency DX AC EER is assumed to be 9.8 (1.23 kW/ton). This measure was analyzed for all building types except hospitals.

High Efficiency Room AC Units—Federal Appliance Standards mandate the following efficiency standards for 1992:

Cooling Capacity (kBtu/hour)	EER
Less than 8,000	8.9
8,000 – 13,000	8.3
Greater than 13,000	7.9

An average baseline EER = 8.3 (1.45 kW/ton) is assumed. The high efficiency room AC EER is assumed to be 10.9. This measure applies to all building types.

Cool Storage (Partial Ice)—This load shifting measure is assumed to be specifically partial ice storage or load leveling, and is only applied to buildings with chillers. This measure was modeled using DSMSIM, an SRC Systems Software Model. The DSMSIM model uses basic algorithms to estimate the ice storage chiller and storage tank capacities based on the day with the highest accumulated cooling load (determined from base case load shapes developed by micro-AXCESS). Maximum cooling energy is shifted from on-peak to off-peak periods based on the partial ice storage capacity, using a chiller priority strategy. Ice-making capacity and efficiency derating factors are also taken into account. The capacities vary by building type and weather zone. The characteristics of the base and cool storage chillers were assumed to be the same (e.g., chiller type, COP).

Rooftop Cool Storage (Partial Ice)—Established test standards do not yet completely evaluate thermal energy storage systems; also suppliers of such systems are currently limited. The addition of thermal storage to this common A/C equipment offers humidity control, improved overall efficiency, and reduced demand during utility peak periods. Manufacturer estimates (from

Powell Energy Products, Inc.) for 5- to 20-ton rooftop thermal storage A/C equipment (The Ice Bear) were compared to standard efficiency rooftop DX A/C units. Demonstrations of this technology are underway or planned in the TVA region and throughout the United States.

Thermal Energy Storage (General)—The installation of a thermal energy storage system offers a whole range of options to permit all or part of a building's cooling or heating load to be shifted from peak to off-peak periods while still providing space conditioning.

Heat Pipe Enhanced DX A/C—Heat pipes installed upstream of the evaporator can substantially reduce the moisture content from incoming outside air, resulting in significant cooling savings. The performance of this technology was estimated using micro-AXCESS by setting up the baseline cooling setpoint by 4 degrees; this technique was suggested by experienced micro-AXCESS users. This applied only to DX AC systems. Cooling savings ranged from 0.8 to 30 percent (increases in heating and ventilation energy use were not included).

Hotel Occupancy Sensors—This measure is similar to a lighting occupancy sensor. The sensor turns off the air conditioning shortly after it detects the room is unoccupied. The option was estimated using micro-AXCESS by setting up the baseline cooling setpoint by 2 degrees during the on-peak period.

2-Speed Motor for Cooling Tower—This measure consists of replacing the single-speed motors in the cooling tower with a two-speed motor. This applied only to chiller systems. The energy savings are estimated to be 80 percent of the Speed Control for Cooling Tower measure.

Speed Control for Cooling Tower—This includes retrofitting an ASD (or VFD) to an existing cooling tower fan. This applies only to chiller systems. Load impacts from this measure were estimated from the micro-AXCESS model.

Air Conditioning Maintenance—This measure consists of annual cleaning and tuning up of DX A/C and chiller systems. The impacts of this measure were estimated using micro-AXCESS by increasing both the baseline compressor efficiency and capacity by 2 percent—suggested by experienced micro-AXCESS users.

HVAC Air Duct/Water Pipe Insulation for Chiller and DX AC—This measure consists of installing additional insulation on air ducts and additional insulation on chilled water pipes. The savings and cost estimates are based on ASHRAE methodology.

Leak-Free Ducts—This measure primarily consists of sealing all exterior ductwork for rooftop DX A/C equipment. Cooling and ventilation demand and energy savings of 7 percent for existing buildings and 3 percent for new buildings was estimated. These savings are based on a combination of estimates developed by Bosek, Gibson & Assoc. and micro-AXCESS simulation (by varying outside air percentage).

HVAC Energy Management System (EMS)—The impacts of this measure were estimated using micro-AXCESS by combining the inputs of two other simulated measures:

—Temperature Setup/Setback

—Timer/Programmable Ventilation Control

Chiller coil reset was eliminated from this combination since independent DOE 2.1 simulations of this particular measure for Florida by SRC yielded negative savings.

Standard Efficiency Heat Pump (Electric Backup)—This measure compares standard efficiency air-source heat pumps (EER=8.7, HSPF=6.8) to standard efficiency DX units (EER=8.7) with gas heat (AFUE=78 percent).

High-Efficiency Heat Pump (Electric Backup)—This measure compares a high-efficiency heat pump (EER=9.8, HSPF=7.5) to a standard efficiency DX unit (EER=8.7) with gas heat (AFUE=78 percent).

VAV System with Inlet Vanes—Micro-AXCESS was used to model ventilation fan, cooling, and heating energy and demand impacts between a constant volume system and a variable air volume system with inlet vanes for both DX A/C and chiller systems for all buildings.

ASD Ventilation Control with VAV—This measure includes an adjustable speed drive control for the ventilation fan in addition to the VAV system described above for the VAV System with Inlet Vanes. Energy and demand impacts of this combined measure were computed using micro-AXCESS. This was simulated for buildings with DX A/C and chiller systems. In addition to the cost of a VAV system, the installed capital cost for ASDs was included.

Timer/Programmable Ventilation Control—This measure was modeled using micro-AXCESS by simply shutting down the ventilation fan system one to three hours earlier (depending on the building type); consequently, the cooling and heating systems shut down (or shifted into night cycling mode), as well. This measure was not applied to the grocery, hospital, or lodging market segments.

High-Efficiency Ventilation Motors—This measure assumes the use of high-efficiency motors in place of standard efficiency motors, resulting in an average demand and energy savings of 3 percent for 1 to 25 horsepower motors.

Separate Makeup Air/Exhaust Hoods—This technology is typically installed in commercial kitchen areas to reduce the energy wasted in pre-conditioned supply air via exhaust hoods. Cooling energy and demand savings of 80 percent are estimated within the kitchen areas. This measure was applied to

the restaurant, school, college, hospital, and lodging market segments. It is assumed the kitchen areas with hoods are approximately 3 percent of school, college, and hospital; 10 percent of restaurant; and 2 percent of lodging total floorspace.

Dual-Fuel Heat Pump—A heating system which utilizes both electricity and fossil fuels. The system can be designed to minimize energy costs by economically dispatching the system based on outside temperature, system operating characteristics, and energy prices.

Ground-Source Water Loop Heat Pump—A ground-source water loop heat pump takes heat from a water source, such as a well or a surface water body, to deliver warm air to a building during the heating season and rejects heat from the indoor air to the water source to provide cooling.

Wood Furnace (Space Heating Only)—Estimates were made for a furnace which burns wood or biomass waste for space heat. In commercial buildings, this technology is appropriate for applications requiring one MBtu/hour or less.

Wood Boiler (Space and Water Heating)—Estimates were made for a boiler burning wood or biomass waste to supply space heating and water heating in commercial buildings. This technology is suitable for applications requiring more than one MBtu/hour.

Passive Solar Space Heating and Cooling—Basic passive solar applications utilize proper solar orientation, coupled with thermal mass, to heat a building in the winter and to reduce cooling load in the summer. These features provide a source of solar heat gain and a means to store heat collected.

Temperature Setup/Setback—This measure was modeled using micro-AXCESS. Based on the baseline prototype building characteristics, cooling is shut off at night, while for temperature setback, the heating setpoint was lowered to 55° F during off-peak hours. The measure is not applicable to grocery, hospital, and lodging. Modeling in micro-AXCESS did not incorporate adaptive recovery technology.

Building Shell

Roof Insulation—Additional insulation is installed, raising the R-value from 2.53 to 10.53 in existing buildings and from 10 to 20 in new buildings. The measure was simulated in micro-AXCESS to determine the energy impacts.

Wall Insulation—This measure was applied only to new buildings. The R-value of the wall was increased from 5.26 to 11.76 in the buildings simulated.

Window Film—This measure consists of installing window film on existing and new construction. The option was modeled using micro-AXCESS by decreasing the window shading coefficient and glass U-value. For existing buildings, the shading coefficient was reduced from 0.85 to 0.23, and the U-value from 1.06 to 0.69. For new buildings, the shading coefficient was not changed, but the U-value was reduced from 1.06 to 0.69.

Spectrally Selective Windows—This measure, applied only to new buildings, was modeled using micro-AXCESS by reducing the U-value from 1.06 to 0.22 and reducing the shading coefficient to 0.20. (ACEEE 1992 Proceedings)

Light-Colored Roofs—This measure consists of installing lighter colored roofs or applying a reflective coating at the time of roof replacement. The energy savings estimate of 7 percent is a conservative assumption based on a report by FSEC.

Commercial Lighting

For any lighting retrofit or new design, the entire lighting system should be considered. A lighting system might include both task and ambient lighting, lamps, ballasts, the number and location of switches, the number of lamps controlled by each switch, and the type of switch—on/off, dimming, occupancy, or timed.

The technical potential for savings available from lighting retrofits and lighting designs for new construction was determined by estimating savings for fixtures, applying a reasonable number of fixtures to each building type or activity within the building, and then multiplying those numbers by our estimate of the square footage of that type of building in the TVA service territory. Lighting technologies included in this database were selected to represent the more popular or promising ones, in terms of energy savings potential and the persistence of savings over time, from the enormous number of lighting products available.

TVA survey results were used to estimate the current penetration of some lighting technologies in the Valley. Where specific Valley information was not available, estimates for the United States were used.

Brief descriptions of the commercial lighting technologies follow:

T8 Lamps—Fluorescent lamps have three starting methods. Most lamps are only compatible with one starting method, but the T8 lamps can be rapid- or instant-started. T stands for tubular; the number describes lamp diameter in 1/8-inch increments. A T8 lamp is 8/8 inches in diameter; a T12 is 12/8 inches (or 1-1/4 inches) in diameter. Estimates considered were:

- **Existing Buildings**—Compared four 4 foot -T8 lamps with one electronic ballast to four 4 foot - 34W lamps with two magnetic ballasts that meet current standards.
- **New Construction**—Compared three 4 foot - T8 lamps with one electronic ballast to four 4 foot - 34W lamps with two magnetic ballasts that meet current standards.

Electronic Ballasts—An electronic ballast uses solid state components to provide current to a lamp at high frequency

(typically 25,000 to 60,000 cycles per second) in order to produce more light using fewer watts than magnetic ballasts.

Reflector/Delamp 4 foot - 40W Fluorescent Lamps/ Electronic Ballast—This measure (considered only for existing buildings) consists of modifying a 4 foot - 40W fixture by removing the four 40W lamps and installing an efficient reflector, along with two 34W lamps.

Reflector/Delamp 8 foot - 75W Fluorescent Lamps/ Electronic Ballast—This measure (considered only for existing buildings) consists of modifying an 8 foot - 75W fixture by removing the four 75W lamps and installing an efficient reflector, along with two 60W lamps.

Reflector/Delamp 4 foot - 40W Fluorescent Lamps/ Hybrid Ballast—This measure (considered only for existing buildings) consists of modifying a 4 foot - 40W fixture by removing the four 40W lamps and installing an efficient reflector, along with two 34W lamps. Hybrid ballasts use magnetic technology to power the lamp and electronic technology to control power to the cathodes.

Reflector/Delamp 8 foot - 75W Fluorescent Lamps/ Hybrid Ballast—This measure (considered only for existing buildings) consists of modifying an 8 foot - 75W fixture by removing the four 75W lamps and installing an efficient reflector, along with two 60W lamps.

4 foot - 34W Lamps/Electronic Ballasts—This measure compares four 4 foot - 34W lamps with one electronic ballast to four 4 foot - 40W lamps with two magnetic ballasts that meet current standards.

8 foot - 60W Lamps/Electronic Ballasts—This measure compares two 8 foot - 60W lamps with one electronic ballast to two 8 foot - 75W lamps and one magnetic ballast that meets current standards.

4 foot - 34W Lamps/Dimming Ballasts (Existing Buildings Only)—This measure compares four 4 foot - 34W lamps with the electronic dimming ballast (including daylight controls to four 4 foot - 40W lamps with two magnetic ballasts that meet current standards. The lighting energy and demand savings are based on benchmark results from DOE 2.1 simulations. The technical feasibility depends on the building type based on the percentage of perimeter floorspace (15 feet deep) to total floorspace.

Compact Fluorescent Lamps and Fixtures—This measure considers replacing a weighted mix of 60W, 75W, and 100W incandescent lamps and fixtures with the same mix of 15W, 18W, and 27W compact fluorescent lamps and fixtures in both new and existing buildings. The percentage breakdown of the mix varies by building type. The incremental installation cost is included for existing buildings. The annualized maintenance cost of replacing both incandescent and compact fluorescent lamps during the lifetime of the compact fluorescent ballast is considered.

Photoelectric Control—This measure consists of retrofitting photoelectric controls onto exterior lighting. Using micro-AXCESS, the base case exterior lighting schedule of 4:00 p.m. to 7:00 a.m. (set for most building types) was changed to automatically turn on and off relative to daylighting hours. Estimated exterior lighting energy savings ranged from 14.7 percent to 25.4 percent, depending on the base case schedule of each building type. As expected, there are no demand savings.

Energy Management System Lighting Control—This measure consists of retrofitting an energy management system (EMS) to automatically control the lighting operation. It was assumed that the EMS would save an average of 2 full load hours of lighting a day. This equates to lighting energy savings ranging from 7 percent to 16 percent relative to the operating hours for each building type. It is also assumed the lighting demand savings is 20 percent of the energy savings, thus ranging from 1 to 3 percent.

Occupancy Sensors—This measure consists of retrofitting occupancy sensors to shut off lights in unoccupied portions of a building. It is assumed that this measure saves 25 percent lighting energy and 5 percent lighting demand in both new and existing buildings.

Indoor HID Lamps - High Pressure Sodium (HPS)—This measure considers replacing one 150W incandescent lamp with one 35W HPS fixture in both new and existing buildings. Incremental installation cost is included for existing buildings. Annualized maintenance cost of replacing both incandescent and HPS lamps during the lifetime of the HPS ballast was considered.

Outdoor HID Lamps - High Pressure Sodium (HPS)—This measure considers a weighted mix of 70W, 100W, 150W, and 250W high pressure sodium lamps/fixtures replacing the same mix of 100W, 175W, 250W, and 400W mercury vapor lamps/fixtures. The percentage breakdown of the mix varies by building type.

Metal Halide (32W)—This measure considers replacing one 150W incandescent lamp with one 32W metal halide fixture in both new and existing buildings. The incremental installation cost is included for existing buildings. The annualized maintenance cost of replacing both incandescent and metal halide lamps during the lifetime of the metal halide ballast was considered.

LED Exit Signs—Light-emitting diode (LED) exit signs claim a 20-year life, are reducing in price, and have an energy consumption of less than 2 watts. This promising new product would replace exit signs now using 14 to 50 watts. If these

recommended in an option, the power factor should be considered in selecting acceptable products.

Fluorescent Exit Signs—Most new fluorescent exit signs are equipped with two 5-watt twin-tube compact fluorescents. If these are recommended in an option, the power factor should be considered in selecting acceptable products.

Electroluminescent (EL) Exit Signs—EL exit signs have the lowest power consumption, but they also have the lowest luminance, as well. The EL lamps used are flat, thin-film sources. Typically thinner than a credit card, the lamps consist of a flexible plastic laminate made up of two electrode plates sandwiching a phosphor-doped dielectric film. Light is produced when the phosphors are excited upon application of alternating current to the electrode plates. Because of their slim design, Underwriters Laboratories (UL) lists EL retrofit kits for use in many existing "Listed" single-face exit signs and will "Classify" retrofit kits for use with specific manufacturers' emergency signs.

Daylighting Design—This measure would consist of a combination of dimming ballasts, doubling the window area, installing spectrally selective glass, and downsizing the cooling capacity by 10 percent. This measure applies to new buildings and excludes warehouses and lodging. Only lighting impacts were analyzed for this measure.

LED Traffic Signal—A recent breakthrough in the development of a blue LED (light-emitting diode) may be the last technical hurdle before the marketing of energy-efficient traffic signals. Each incandescent lamp in a traffic single uses 67 to 150 watts that could be replaced by an LED unit using only 9 to 25 watts.

Sulfur Lamp—The sulfur lamp is a small, rotating, air-cooled glass sphere filled with sulfur gas. A microprocessor- controlled magnetron stimulates the sulfur atoms with microwaves, generating light in the visible range. The light produced by the sulfur lamp has a high-quality color rendering and an adjustable color temperature.

Commercial Refrigeration

Brief descriptions of the commercial refrigeration technologies follow:

Multiplex: Air-Cooled/No Subcooling—This measure considers the retrofitting of a "conventional" refrigeration system (i.e., numerous stand-alone compressor systems for each display case line-up or walk-in) with a multiplex refrigeration system. The term "multiplex refrigeration" refers to the use of multiple refrigeration compressors mounted on a rack and piped to common suction and discharge manifolds. Refrigeration to each display case lineup is provided from the rack by a pair of liquid and suction pipes. Several circuits can be connected by separate pairs of refrigerant piping. Multiplex systems commonly consist of two, three, or four compressors that are sized such that the operation of all compressors simultaneously can provide adequate capacity to meet the design refrigeration load. During off-design operation, the multiplex compressors can be cycled on or off so that the capacity of the operating compressors closely matches the refrigeration load.

Multiplex: Air-Cooled/Ambient Subcooling—Ambient subcooling is the cooling of the liquid refrigerant below the condensing temperature by heat rejection to the ambient. Some subcooling normally occurs in the condenser, and additional ambient subcooling can be obtained through the use of a separate coil, usually attached to the condenser.

Multiplex: Air-Cooled/Mechanical Subcooling—Further cooling of the liquid refrigerant can be done through the use of a vapor compression system. Liquid refrigerant associated with a refrigeration system operating with a low suction temperature is mechanically subcooled by a system operating at a higher suction temperature.

Multiplex: Air-Cooled/Ambient and Mechanical Sub-cooling—This measure combines the benefits of ambient subcooling and mechanical subcooling.

Multiplex: Air-Cooled/External Liquid Suction HX—This measure involves the installation of an externally mounted heat exchanger instead of merely soldering the liquid and suction lines together. The result is more efficient liquid-to-suction heat transfer, providing more refrigeration capacity. This measure is applicable only for the very low and low temperature refrigeration applications and is a more efficient alternative to mechanical subcooling.

Open-Drive Refrigeration System (ASD)—Open-drive systems consist of one or two open-drive compressors driven by external adjustable speed drive electric motors. The main advantage of open-drive compressors over multiplex compressors is the additional electric savings due to operating open-drive compressors at low speeds, which is intended to increase compressor efficiency. An open-drive system requires larger compressors, and thus higher compressor capital costs, but smaller remote condensers, and thus lower condenser capital costs, compared to a multiplex system of equal capacity.

Anti-Condensate Heater Controls—It is assumed that this measure saves 5 percent energy and demand, and is applied to all market segments, except office, warehouse, and miscellaneous. The cost and impact estimates are based on an assessment study done for Bonneville, 1988.

High R-Value Glass Doors—This measure consists of replacing single-glass doors or retrofitting refrigeration cases with high R-value glass doors. An average of 30 percent energy and demand

savings is assumed. This technology is applied to all market segments except office, warehouse, and miscellaneous, with various levels of technical feasibility and current penetration.

Refrigeration Energy Management System—This technology consists of strategically controlling many or all refrigeration systems in a given facility. From the EPRI Commercial TAG Volume, an energy and demand savings of 10 percent and 5 percent is assumed. It is assumed that this technology is only applicable to the grocery market segment, which has an assumed current penetration of 50 percent (SRC).

Dual-Path Supermarket Air Conditioning—Similar to Heat Pipe Enhanced Air Conditioning, this technology removes a significant amount of moisture from incoming air before passing over the evaporator. Its best application is where there are high humidity levels; therefore, the dual-path air conditioner is only analyzed for the grocery market segment. The energy and demand impacts and costs have been estimated based on a case study in Miami, Florida, presented in an EPRI brochure, *Dual-Path Supermarket HVAC Systems*, 1991 (CU.2053.10.91). Although this is an air conditioning technology, it is placed with refrigeration because its applicability is focused on high refrigeration loads. It is assumed this technology has no current penetration.

Commercial Water Heating

Brief descriptions of the commercial water heating technologies follow:

Heat Pump Water Heater—This measure consists of replacing conventional electric hot water heaters with heat pump hot water heaters. The estimated energy and demand savings are 50 percent (assuming an average seasonal COP of 2.0). This measure has significantly higher capital cost compared to conventional electric water heaters (i.e., orders of magnitude). This measure was applied to all market segments.

Solar Assisted Water Heater—The solar water heating system actually assists rather than replaces an electric resistance water heater. When solar radiation is available, it is absorbed by collector panels and then transferred to the domestic hot water supply. Some systems heat water directly by circulating potable water through the solar loop. Others recirculate the same absorption fluid through the collectors and transfer the heat via a heat exchanger to the potable water supply.

Heat Recovery Water Heater—This measure consists of an electric water heater that utilizes a supplemental heat source from the cooling system waste heat from a double bundle chiller or condenser heat exchanger. There is an assumed 25 percent energy savings based on the WAPA Guidebook of Commercial DSM Technologies, assuming a summer and winter demand savings of 35 percent and 15 percent, respectively. The current penetration is assumed to be zero.

DHW Heating Insulation—This is a retrofit measure consisting of wrapping an existing water tank with additional insulation. Energy and demand savings of 5 percent are assumed. The technical feasibility and current penetration are assumed to be 50 percent and 20 percent, respectively (SRC).

DHW Heat Trap—This retrofit measure reduces hot water energy due to backflow through the pipes from natural convection. It is analyzed for all existing market segments; it is not analyzed in the new market since the technology is a requirement for some building codes. Energy savings of 10 percent are based on the WAPA Guidebook of commercial DSM technologies, while demand savings are assumed to be 2 percent. The technical feasibility and current penetration are assumed to be 80 percent and 15 percent, respectively (SRC).

Low Flow/Variable Flow Showerhead—This retrofit measure can easily be installed in place of existing showers and faucets to reduce the flow of hot water. It is assumed that there are approximately two showerheads and four faucets per water heater. The estimated energy and demand energy savings are 15 percent. Technical feasibility varies by building type based on an assumed percentage of hot water dedicated to showers and faucets:

- 80 percent—office, retail, school, college and lodging
- 50 percent—grocery, hospital, and miscellaneous
- 20 percent—restaurant

Current penetration of this measure is assumed to be 10 percent (SRC).

DHW Recirculation Pumps—This option consists of installing timers to prevent recirculation pumps on the hot water system, which are typically integrated with a boiler, and operating during periods of no hot water use. The energy saving due to this option was estimated to be 60 percent. There are no demand savings attributed to this measure, which is more applicable to schools, colleges, and hospitals than to other building types.

Commercial Cooking

Brief descriptions of the commercial cooking technologies follow:

Electric Forced Convection Ovens—This technology was modeled as a replacement option for either electric natural convection ovens or gas-fired forced convection ovens. Electric forced convection ovens have an efficiency of 64 percent compared to the 62 percent efficiency of electric natural convection ovens. Additionally, forced convection ovens can cook three times the volume of natural convection ovens. The option was applied to restaurants, groceries, schools, hospitals, and

lodging. The cost estimates are based on two $4,285 convection ovens per 5,000 square-foot restaurant. The efficiency of gas-forced convection ovens is 46 percent, versus 64 percent for electric forced convection ovens. The costs for other building types were prorated based on energy use.

Electric Natural Convection Ovens—This electric technology was analyzed to replace gas-fired natural convection ovens (for load building). The efficiency of gas natural convection ovens is 28 percent versus 62 percent for electric natural convection ovens.

Energy-Efficient Electric Fryers—This technology was modeled as a replacement technology applicable to the same building types as the forced convection ovens. The energy and demand savings were estimated to be 10 percent. The cost estimates are based on two $2,935 efficient fryers per 5,000 square feet of restaurant, prorated to other building types based on energy use. This technology was also analyzed to replace standard efficiency gas fryers with energy-efficient electric fryers (for load building). The heating efficiency of gas fryers is 45 percent, versus 100 percent for electric fryers.

Flash Bake Oven—The flash bake lightwave oven uses a combination of intense visible light and infrared energy to cook foods almost instantly from the outside in and the inside out. Dramatically faster and better, shorter cooking times can enhance food flavor and texture. These ovens are particularly suited for cooking many fast food products.

INDUSTRIAL

A list of industrial technologies was compiled by TVA. BCI and SRC suggested additional technologies. The technologies were ranked from 1 to 7, with 1 being the most important and 7 the least. Cost and energy impacts were sought for technologies that ranked 3 or better.

Technology data were not developed for the following technologies for the reasons listed below:

- **Ultrasound Treatment of Wet Textiles**—This can be used to improve the dye uptake in fabric dyeing processes. However, no information was found on the specific characteristics of this process.
- **Advanced Hybrid Membrane/Heat Pump Systems for Municipal Water Treatment**—No information on this technology was available.
- **Electron Beam Irradiation to Sterilize Municipal Water** — No information on this technology was available. A reference was found to a test performed by Massachusetts Institute of Technology in which a Van De Graaff generator was successfully used to detoxify waste water, however, based on the test, it was determined that a full-scale facility would not be economically beneficial.
- **Ceramic Membranes to Separate Oil/Water Emulsions**—No information on this technology was identified. Several references were found that referred to the development of ceramic membranes as representing a possible improvement in membrane separation processes in the future, but no specific information was provided.
- **Industrial Lighting**—Lighting applications (particularly indoor lighting) in industrial facilities are very similar to those in commercial warehouses and offices. No technology data unique to the industrial sector were developed.

The industrial technologies for which estimates were developed are shown in *Figure T7-12.*

Process Separation

Brief descriptions of the industrial technologies follow:

Freeze Concentration—Used for the separation or concentration of components in a liquid solution, freeze concentration is a substitute for conventional distillation and evaporation. In the

FIGURE T7-12. **Industrial Technologies**

End-Use	Demand-Side Measure
Process Separation	Freeze Concentration
	Electrolytic Separation
	Membrane Separation
	Electrochemical Synthesis
Process Heating	Industrial Process Heat Pumps
	DC Electric Arc Furnace
	Plasma Processing
	Induction Heating
Manufacturing	Flexible Manufacturing Module
Drying	RF & IR Drying
Fabrication/Finishing	Laser Processing
	Electrical Discharge Machining
	Electrogalvanization
	Electrochemical Machining
	Electron Beam Processing
Water Treatment	Waste Water Ozonation
	Seawater Desalinization by Reverse Osmosis
Motors	1 Horsepower High-Efficiency Motor
	50 Horsepower High-Efficiency Motor
	200 Horsepower High-Efficiency Motor

freeze concentration process, heat is removed from a liquid mixture until one component of the mixture crystallizes and can be easily separated. The advantages of freeze concentration include improved product quality, lower energy consumption, increased product recovery/quality, reduced capital and maintenance costs, and lower product shipping costs due to product concentration.

Electrolytic Separation—Electrolytic separation results in the production of new products as a result of passing an electrical current through a conductive electrolyte. Electrolytic technologies for the separation of chemicals and metals were among the earliest commercialized applications of electricity and have been economically significant since the turn of the century.

Membrane Separation—Membrane separation uses permeable barriers to filter selected components from mixtures. Membranes may be made out of polymers, ceramics, or metals and are usually categorized by the size of the particle filtered. Alternatives to membrane separation include conventional distillation and evaporation, freeze concentration, and electroseparation.

Electrochemical Synthesis—Electrochemical Synthesis is basically a form of electrolytic separation. The difference is that in electrochemical synthesis, new compounds are introduced at the electrodes in the electrolytic cell that react with the ions attracted to the electrodes. Thus, compounds are formed at the electrodes that could not be formed from the components of the electrolyte alone.

Process Heating

Industrial Process Heat Pumps—Heat pumpsw may be used to capture industrial waste heat. Where applicable, industrial process heat pumps can be used to capture relatively low temperature waste heat that has no other use and, using a moderate amount of mechanical energy, elevate the waste heat to a temperature that can supply process energy needs.

DC Electric Arc Furnace—Interest is increasing and units are being installed in the U.S. and abroad. The major benefit of a DC furnace is reduced electrode consumption as compared to 3-phase AC arc furnaces. Other benefits include lower noise levels, reduced maintenance, and less electrical disturbance on the power system.

Plasma Processing—Plasma processing involves the electrical production of a plasma in the temperature range from 2,000° to 10,000°C for metals production. At these high temperatures, the plasma is a mixture of molecules, atoms, electrons, and ions. It is the electrons and ions that allow for the conditions of electrical current or arc between two electrodes; the current may be AC or DC. The primary uses in metals production include scrap melting, heating steel in ladles, reduction of ores, treatment of electric furnace shop dusts, ferroalloy production, and the remelting of metals.

Induction Heating—Induction heating is a way to heat electrically conductive materials, such as metals. It is commonly used in process heating prior to metalworking and in heat treating, welding, and melting. Induction heating relies on electrical currents that are induced internally in the workpiece material. These so-called eddy currents dissipate energy and bring about heating. The basic components are an induction coil, an ac power supply, and the workpiece itself.

Manufacturing

Flexible Manufacturing Module—A flexible manufacturing module can be a single machine tool with part-changing equipment. A flexible manufacturing cell includes two or more computer numerical control machine tools linked to operate sequentially. A flexible manufacturing system is a combination of modules or cells that are all controlled by a central computer. Flexible manufacturing allows a company to quickly respond to changing demand and avoid creating a large product inventory to service a fluctuating demand.

Drying

Radio Frequency and Infrared Drying—These technologies cover the electromagnetic spectrum from visible light to radio waves. When a material absorbs infrared radiation, the motion of its molecules increases and it gets hotter. This is the basis of infrared process heating. Infrared radiation is produced by heating the filament of a source or emitter. Infrared heating can be applied to both conducting and nonconducting, whereas radio frequency drying/heating can only be used for dielectric, or nonconducting, materials. Radio frequencies for heating range from 2 to 200 MHz, which is in the range used for broadcasting and communications. A triode oscillator generates power in the RF range, and the products are usually heated between plate electrodes or through a series of rods.

Fabrication/Finishing

Laser Processing—Involves cutting, drilling, welding, marking, and selectively heat-treating a variety of materials. Lasers used for metalworking either have a gas lasing material (carbon dioxide mixed with helium and nitrogen) or are solid state (yttrium-aluminum-garnet crystal). Lasers are best suited to situations that involve the need for rapid prototypes, small production runs of precise parts, and/or rapid delivery of many different kinds of parts.

Electrical Discharge Machining—Uses an arc from an electrode to remove metal from the piece being machined. The workpiece and the electrode are in a dielectric bath. In a ver-

tical EDM machine, a computer-controlled electrode can be moved in three axes of motion and can create complex parts. Wire-cut EDM acts like a band saw and uses a continuous wire electrode to cut parts. EDM can be used to create intricate and unusual parts and can be used to machine any material that is conductive.

Electrogalvanization—This involves the deposition of zinc on a steel sheet in an electrolytic cell. A continuous sheet of steel is run through the cell and can be coated on one or two sides. The conventional alternative is hot-dip galvanizing, which produces a thicker coating, but in which it is difficult to coat only one side of the steel and the coated surface, when painted, is not totally acceptable for high visibility, high gloss areas.

Electrochemical Machining (ECM)—this process can be used for sinking, cutting, deburring, and grinding. A conductive workpiece is located in an electrolytic cell containing a conductive electrolyte. A high amperage, low voltage DC current passes from the workpiece through the electrolyte to a shaped electrode. The current causes particles on the workpiece surface to dissolve by electrochemical action. The dissolved material is removed as the electrolyte is pumped through the cell. As the process continues, the workpiece becomes a mirror image of the electrode. ECM is best suited to situations that involve hard or high strength materials and/or complex shapes.

Electron Beam Processing—This technology can be used for welding or selective surface hardening. A beam of electrons from a heated emitter in an electron gun is accelerated by attraction to the positively charged anode and focused by a magnetic coil. The kinetic energy of the electrons striking the workpiece is converted to heat that vaporizes the metal directly in the path and melts the adjacent metal. If the beam is directed at a joint between two pieces of metal, a weld is formed. Depending on the metal being processed, a high, partial, or nonvacuum may be required. Electron beam processing is used when high precision parts must be welded with minimal heat effects, maximum reproducibility, and no gas contamination. Electron beam processing is also suitable when high production rates are required.

Water Treatment

Waste Water Ozonation—This process is used for iron and manganese removal, oxidation of organics, microflocculation, bacterial disinfection, and viral inactivation. Ozone is generated on-site by an electrical discharge in an air or oxygen stream.

Seawater Desalinization—This process is used to produce potable water using seawater as a feedstock. The conventional approach is to evaporate seawater and condense the vapor as pure water. Reverse osmosis (RO) is an alternative to conventional evaporation techniques. The RO process uses semipermeable membranes which allow solution permeation, but act as barriers to the passage, or transport, of dissolved and suspended substance (i.e., salts, ions, and organic compounds). The solution transport in RO is accomplished by using a pressure high enough to overcome the natural osmotic pressure in the solution. The particle size of species separated is typically between 1 to 10 angstroms with a driving pressure of 200 to 1,000 pounds per square inch.

Motors

1 HP High-Efficiency Motor—Compares the 77.8 percent baseline efficiency motor to a high-efficiency motor. The high-efficiency motor reflects NEMA Efficiency Standard definition 12-6C, having a nominal efficiency of 80.0 percent. Three different operating hours were analyzed. A load factor of 0.70 was assumed.

50 HP High-Efficiency Motor—this compares the standard 50 hp motor with an efficiency of 91.4 percent to the high-efficiency motor is defined as having 93.1 percent efficiency. Again, three different annual operating hours were analyzed. A load factor of 0.70 was assumed.

200 HP High-Efficiency Motor—Compares the standard 200 hp motor with an efficiency of 94.2 percent to the high- efficiency motor is defined as 95.0 percent efficiency. Again, three different annual operating hours were analyzed. A load factor of 0.70 was assumed.

RENEWABLE/SELF-GENERATION

Renewable Energy

Renewable energy technologies were characterized in four reports by BCI for TVA. In these reports technology information was divided into four categories: Residential, Commercial, Industrial, and Self-Generation. Both dispersed renewable technologies (e.g., solar water heating), as well as more centralized generation technologies were considered. Some renewable technologies have been mentioned in the earlier sections. Renewable energy technologies considered are listed in *Figure T7-13*. Schiller Associates, a subcontractor to BCI, provided two cost estimates for wood burning plants at a host facility.

Self-Generation

Barakat & Chamberlin, Inc. subcontracted to Schiller Associates for the cogeneration technology characterization and market analysis. The market analysis, prepared by UNIMAR, Group. Ltd., identified potential industrial and commercial SIC codes where cogeneration would most likely occur. For these customers, Schiller Associates selected four system types as typical of cogeneration

installed in the under 30-megawatt range. The number of cost estimates (for purchase, installation, operation, and maintenance) that were developed are shown below:

- 8 – Natural gas-fueled reciprocating engine systems in the 100-kilowatt to 3,000-kilowatt size range
- 9 – Natural gas-fueled simple-cycle gas turbine systems in the 3,700-kilowatt to 21,500-kilowatt range
- 3 – Natural gas-fuel, combined-cycle gas turbine systems in the 13,400-kilowatt to 28,000-kilowatt range
- 1 – Coal-fueled, steam turbine (rankine cycle) system rated at 20,000-kilowatt

BENEFICIAL ELECTRIFICATION

Beneficial electrification encompasses both electrotechnologies and economic development. Because of this connection, it was advantageous to have one team assess the market, collect technology data, and develop the options. A team from Barakat & Chamberlin, Inc. assisted TVA in developing a comprehensive list of beneficial electrification (BE) technologies and in conducting qualitative, economic, and market screens on the list. Next, nine program concepts were developed and were evaluated in DSManager in fourteen options. Some adjustments to the original estimates were made for consistency with the assumptions made in the analysis of energy efficiency options. *Figure T7-14*, a summary of the beneficial electrification options, includes four industrial programs, one program focused on environmental technologies, two commercial programs, two residential programs and one program, focused on transportation.

Figure T7-15 lists the technologies for which fact sheets containing cost, energy, and demand impacts were developed.

FIGURE T7-13. **Renewable Energy Technologies**

End-Use	Demand-Side Measure
Residential	Wood Furnace
	Passive Solar Design
	Wood Stove
	Interactive (Solar and Wood Stove)
	Solar Hot Water
	Residential Rooftop PV (4kW)
	Landscape Shading
	Ground-Source Heat Pump
Commercial	Passive Solar
	Wood Furnace (Space Heating Only)
	Wood Boiler (Space and Water Heating)
	Solar Hot Water
	Commercial Rooftop PV (4kW)
	Daylight Design
	Photoelectric Control
Industrial	Biomass Process and Drying Heat
	Solar Assisted Industrial Process Heat
	Wood Waste
Generation	Biomass Fuel - Wood Waste
	Biomass Fuel - Animal Waste
	Landfill Gas
	Fuel Cells
	Small-Head Hydro
	Wind Turbines
	Remote Photovoltaics

TECHNOLOGY LISTS

The residential technologies included in options are listed in *Figure T7-16*. *Figure T7-17* contains residential technologies that should be considered if the site-specific application promises to be cost-effective. *Figure T7-18* contains residential technologies that should not be included in options. Emerging technologies that should be considered for option implementation are listed in *Figure T7-19*.

Commercial and industrial technologies included in efficiency or load management options are listed in *Figure T7-20*. Commercial and industrial technologies that should be considered, especially in comprehensive programs that customize the set of technologies appropriate for each site, are listed in *Figure T7-21*. Technologies that were not included in options are listed in *Figure T7-22*. These technologies were either not appropriate for our climate, incentives may be unnecessary for the technology to be accepted, or were eliminated for some other reason. Emerging technologies for the commercial and industrial sectors that should be considered for option implementation are listed in *Figure T7-23*.

Technologies included in Self-Generation/Renewable Generation options are listed in *Figure T7-24*.

Figure T7-25 contains a list of technologies included in beneficial electrification options.

FIGURE T7-14. **Summary of Beneficial Electrification Programs**

Program Name	Target Market	BE Technologies
Process Heating	SICs 30, 32, 33, 34, 35, 36 & 37	Induction, Resistance, Process Heat Pumps, Microwave RF Heating
Process Heating	SIC 33	DC Arc, Plasma Arc, Induction & Vacuum Melting
Curing & Drying	SICs 20, 22, 24, 26, 27, 28 & 30	UV Curing, EB Curing, Dielectric RF & Infrared Curing
Food Processing	SIC 20	Freeze Concentration, Reverse Osmosis
Textiles SIC 20	Vacuum Slots for Drying	
Chemicals and Metals	SICs 28, 33 &34	Electrolytic Reduction, Remelting, Electrogalvanization, & Electroslag
Environmental Technology	SICs 49, 20, 22, 28, 33, 34 & 36	Ultrafiltration, Microfiltration, Nanofiltration, Ozonation, & Reverse Osmosis
Space Conditioning and Water Heating	Schools, hospitals, & government facilities	Heat Pump Water Heaters, Air-Source Heat Pumps, & Dual-Fueled Heat Pumps
Cooking and Security Lighting	Restaurants, hotels, & other establishments	Electric Cooking & Security Lighting
Residential HVAC and Water Heating	Customers replacing non-electric heating and water heating systems	Heat Pump Water Heaters, Air-Source Heat Pumps, Ground-Source Heat Pumps, & Dual-Fuel Heat Pumps
Residential Security Lighting & Lawn Mowers	Promoted among relatively narrow range of customers in non-attainment and high crime areas	Electric Lawn Mowers & Security Lighting
Transportation - Electric Buses	Municipalities	Electric Buses
Transportation - Fleet Vehicles	Corporations and municipalities	Variety of Fleet Vehicles (vans, carts, fork lifts, etc.)
Transportation - Electric Autos	Residential consumers Electric cars	

FIGURE T7-15. **Beneficial Electrification Technologies**

End-Use	Demand-Side Measure
Residential	Heat Pump Water Heater
	Air-Source Heat Pump
	Ground-Source Heat Pump
	Dual-Fuel Heat Pump
	Security Lighting
	Electric Cordless Lawn Mower
	Electric Cord Lawn Mower
Commercial	Heat Pump Water Heater
	High-Efficiency Air-Source Heat Pump
	Dual-Fuel Heat Pump
	Water Chiller
	Thermal Energy Storage
	Security Lighting
	Convection Oven
	High-Efficiency Fryer
	Solid Element Burners
	Flash Bake Oven
Industrial—Process Industries	Electrolysis
	Reverse Osmosis
	Ultrafiltration
	Microfiltration
	Freeze Concentration
	Electrochemical Synthesis
	Ozonation/Oxidation
	Ultraviolet (UV) Curing
	Electron Beam Curing
	Dielectric Curing
	Infrared (IR) Curing
	Industrial Process Heat Pumps
	Resistance Heating
	Microwave Heating
	Radio Frequency (RF) Heating
Industrial—Textiles	Nanofiltration
	Radio Frequency (RF) Drying
	Infrared (IR) Drying
	Ultrasound Drying
	Vacuum Slot Drying
Industrial—Metals Fabrication	Induction Heating
	Resistance Heating
	Electroforming
	Electrical Discharge Machining
	Electrochemical Machining
	Electrofinishing
	Electron Beam Welding
	Plasma Welding
	Direct Arc Welding
	Laser Welding
	Ultraviolet (UV) Curing
	Infrared (IR) Curing
	Electrogalvanization
	Electroslag Casting
Industrial—Primary Metals	DC Electric Arc Furnace
	Plasma Arc Furnace
	Induction Melting (Coreless Induction Furnace)
	Vacuum Melting
	Plasma Ladle Refiner
	Induction Heating
	Resistance Heating
	Electrolytic Reduction
	Electroslag Remelting
Municipal	Reverse Osmosis
	UV-Ozonation
	Plasma Arc Furnace
Transportation	Electric Car
	Electric Van
	Electric Bus (Overhead Electric Cable)
	Electric Bus (Battery-Powered)
	Electric Rail
	Electric Work Vehicle

FIGURE T7-16. Residential Technologies Included in Options

End-Use	Demand-Side Measure
Cooling	Servicing Central Air Conditioner
	High-Efficiency Room Air Conditioner
	High-Efficiency Central Air Conditioner
	Servicing Room Air Conditioner
	Central AC Cycling or Direct Load Control
	Heat Pump Cycling or Direct Load Control
Cool/Heat	High-Efficiency Air-Source Heat Pump
	Ground-Source Heat Pump
	Insider Heat Pump
	Reduced Duct Leakage
	Servicing Heat Pump (Coils, Filters, Lubrication)
	Clock/Programmable Thermostat
Building Shell	Insulation (Ceiling)
	Double- or Triple-Pane Windows
	Low-Emissivity Window
	Reflective Glass/Window Film/Solar Screen
	Caulking/Weatherstripping
	Reduced Duct Leakage
Lighting	Compact Fluorescent Lamp
	High Pressure Sodium (Outdoor)
	Motion Detectors for Outdoor Lighting
Water Heating	Faucet Aerator
	Low Flow Showerhead
	Hot Water Pipe Insulation
	Water Heater Tank Wrap
	Water Heater Bottom Board
	Heat Pump Water Heater
	Maintain Heat Pump Water Heater
	Solar-Assisted Water Heating
	Storage Water Heater Cycling or Direct Load Control
	Standard Electric Water Heater Cycling or Direct Load Control
Appliances	High-Efficiency Frost Free Refrigerator
	High-Efficiency Freezer
	Servicing Refrigerator or Freezer (Clean Coils)
	Removal of Secondary Refrigerator or Freezer
	Clothes Dryer with Moisture Sensor
	Heat Pump Clothes Dryer
	High-Efficiency Dishwasher
	Smart House (Home Automation & Real-Time Pricing)
	High-Efficiency Pool or Spa Pump
	Horizontal-Axis Clothes Washer

FIGURE T7-17. Residential Technologies Under Further Consideration

End-Use	Demand-Side Measure
Cooling	Two-Speed Central Air Conditioner
	High-Efficiency Central Air Conditioner
	Ceiling Fan
	Thermal Energy Storage (Cooling)
Heating	Wood Furnace
	Electric Thermal Storage
Cool/Heat	Dual-Fuel Heat Pump
	Two-Speed Heat Pump
	Std. Add-On Heat Pump
	High-Efficiency Add-On Heat Pump
	Ducts in Conditioned Spaces
	Reduced Duct Heat Transfer
Building Shell	Insulation (Wall, Foundation)
	Reflective Roof Coating
	Radiant Roof Barrier
	Storm or Thermal Door
Lighting	Halogen Lamp (Outdoor Applications)
	Efficient Incandescent
Water Heating	High-Efficiency Electric Water Heater
	Early Replacement of Old Water Heater
	High-Efficiency Gas Water Heater
Appliances	Best Current Refrigerator or Freezer
	Early Replacement of Old Refrigerator or Freezer
	High-Efficiency Clothes Dryer
	High-Efficiency Range and Oven
	Induction Cooktop
	Downsized Pool Pumps w/Oversized Piping
	Direct Load Control of Pool Pumps
	Green Plug Motor Control

FIGURE T7-18. **Residential Technologies Not Included in Options**

End-Use	Demand-Side Measure
Cooling	Direct Evaporative Cooler
	Indirect Evaporative Cooler
	Two-Stage Indirect Evaporative Cooler
	Removal of Second Room Air Conditioner
	Attic Fan
	Whole-House Fan
	Shade Trees
Heating	Active Solar Space Heater
	Zoned Resistance Heating
	Resistance Heat & Heat Pump Cycling
Cool/Heat	Room Heat Pump
	Multi-Zone Heat Pump
Lighting	Halogen Lamp (Indoor Applications)
Water Heating	Heat Trap
	Water Heater Timer
	Water Heater Thermostat Setback
	Tankless Water Heater (Instantaneous)
	Heat Recovery Water Heater
Appliances	Refrigerator or Freezer Anti-Sweat Switch
	Duct Heat Recovery from Clothes Dryer
	Pool Pump Timer

FIGURE T7-19. **Residential Emerging Technologies**

End-Use	Demand-Side Measure
Cool/Heat	Gas Absorption Heat Pump
	Aerosol Duct Sealing
Lighting	Hafnium Single Crystal Filaments
	Sulfur Lamp
Water Heating	Ultrasonic Faucet Control
Appliances	Microwave Clothes Dryer
	Whole-House Surge Protection
	Cordless Lawn Mowers
	High Spin Speed Clothes Washer
	Low Energy and Water Use Dishwasher
	Golden Carrot Refrigerator
	Automatic Clothes Washer Controls
	200-to 300-kWh Refrigerator/Freezer
	Low Powered Color TV
	Bubble Action Clothes Washer

FIGURE T7-20. **Commercial/Industrial Technologies Included in Options**

End-Use	Demand-Side Measure
Cooling	High-Efficiency Chiller
	Speed Control for Cooling Towers
	High-Efficiency DX A/C
	High-Efficiency Room A/C
	Thermal Energy Storage (Ice or Water)
	Rooftop Cool Storage
	HVAC Maintenance & Condenser Coil Cleaning
Cool/Heat	High-Efficiency Air-Source Heat Pump
	Ground Source Heat Pump
	Setback/Setup Thermostat
Ventilation	Adjustable Speed Ventilation Motor Drives
	Variable Air Volume Systems
	High-Efficiency Ventilation Motors
	Leak-Free Ducts
	Programmable Ventilation Control
	HVAC Air Duct/Water Pipe Insulation
Building Shell	Roof Insulation
	Wall Insulation
	High-Efficiency Windows (High R-value)
	Tinted Windows (Spectrally Selective)
	Low-Emissivity Films (Window Films)
	Passive Solar Design
Lighting	T8 Lamps
	Electronic Ballasts
	Ref./Delamp 4' - 40W Lamp/EE Ballasts
	Ref./Delamp 4' - 40W Lamp/Electronic Ballast
	Ref./Delamp 4' - 40W Lamp/Hybrid Ballast
	Ref./Delamp 8' - 75W Lamp/Electronic Ballasts
	4' - 34W Lamps/Electronic Ballasts
	8' - 60W Lamps/Electronic Ballasts
	Compact Fluorescent Lamps
	Compact Fluorescent Fixtures
	4' - 34W Fluor. Lamps/Dimming Ballasts
	Photoelectric Control
	Lighting Timers
	Occupancy Sensors
	Indoor HID Lamps - High Pressure Sodium
	Outdoor HID Lamps - High Pressure Sodium
	LED Exit Signs
	Fluorescent Exit Signs
	Electroluminescent Exit Signs
	Daylighting Design
Water Heating	Heat Pump Water Heater
	Heat Recovery Water Heater
	High-Efficiency Water Heater - Increased Insulation
	Add Heat Trap
	Low Flow Showerheads
	Pipe Insulation
	DHW Recirculation Pumps
	Solar-Assisted Water Heater
Refrigeration	Glass Doors for Refrigerated Cases (High R-Value)
	Anti-Condensate Heater Controls
	Dual-Path Supermarket Air Conditioning
	Ambient Subcooling
Appliances	Energy-Efficient Electric Fryers
	Electric Forced Convection Ovens
Miscellaneous	Interruptible Rate Option
Industrial	High-Efficiency Motor
	Motor Downsizing
	Adjustable Speed Drives
	Compressed Air Efficiency Improvements
	Process Efficiency Improvements

FIGURE T7-21. **Commercial/Industrial Technologies Under Further Consideration**

End-Use	Demand-Side Measure
Cooling	High-Efficiency Chiller w/ASD
	Heat Pipe Enhanced DX A/C
	Hotel Occupancy Sensors
	2-Speed Motor for Cooling Tower
	Heat Recovery Absorption Chiller
	Outside Air Economizer Cycle
	Hydronic Economizer Cycle
	Cooling Towers - Fans
	Chilled Water Reset
Heating	Zonal Electric Heat
Cool/Heat	Closed Water Loop Heat Pump
	Ground-Coupled Heat Pump
	Dual-Fuel (Add-On) Heat Pump
Ventilation	Reduction in Fan Flowrate
	Fan Motor Downsizing
Building Shell	Double- and Triple-Pane Windows
Lighting	Lighting Management Systems
Water Heating	Desuperheater: Refrigeration or A/C
	Storage Water Heating
Refrigeration	High-Efficiency Evaporator Fan Motors
	Condenser Coil Cleaning
	Mechanical Subcooling
	Energy-Efficient Case Lighting
	High-Efficiency Evaporator Fan Motors
Office Equipment	Personal Computers
	Computer Printers
	Copiers
Miscellaneous	Energy Management System
	Time-of-Use Metering
	Real-Time Metering
Industrial	Other High-Efficiency Motors
	Voltage Unbalance
	Efficient Motor Rewinding Techniques

FIGURE T7-22. **Commercial/Industrial Technologies Not Included in Options**

End-Use	Demand-Side Measure
Cooling	Direct & Indirect Evaporative
Heating	Active Solar Space Heater
Ventilation	Reduction of Outside Air
Building Shell	Interior Shade
	Thermal Scanning
	Vestibule/Revolving Doors
Lighting	Task Lighting
	Electrodeless Fluorescent
	Halogen Lamps
	Metal Halide
Refrigeration	Multideck Strip Curtains
	Dual Gaskets
	Liquid Pressure Amplifier
	Evaporative Pre-Cooler for Air-Cooled Condensers
	Parallel Unequal Compressor Systems
	Variable Speed Compressor Systems
Appliances	High-Efficiency Griddle
	Low Temperature Dishwasher - Stationary
	Low Temperature Dishwasher - Conveyer
	Clothes Dryer - Moisture Sensor
	Clothes Dryer - Heat Pump
	Clothes Washer - High-Efficiency Motor
Office Equipment	Fax Machines
	Telephone Systems
Miscellaneous	High-Efficiency Pool Pump
	Low Pressure Drop Pool Filters
	Time-of-Day Pool Pumps

FIGURE T7-23 Commercial/Industrial Emerging Technologies

End-Use	Demand-Side Measure
Cool/Heat	Zeotropic Refrigerants
	GAX Absorption Heat Pump
	Absorption Heat Pump
	Aerosol Duct Sealing
	Electrohydrodynamic Heat Transfer Enhancement
Lighting	Hafnium Single-Crystal Filaments
	General Service Halogen IR
	Advanced Reflector Design
	Thermal Bridging for Fluorescent Fixtures
	Lower Cost Dimmable Ballast
	Integrated Fixtures/Controls
	Architectural Daylighting Device
	Electrodeless HID
	Coated Filament Incandescent
	Fluorescent Surface Wave Lamp
	Sulfur Lamp
	DC Lighting System
	LED Traffic Signals
Water Heating	Ultrasonic Faucet Control
	Ozonated Commercial Laundering
Refrigeration	Supermarket System Integration
Appliances	Microwave Clothes Dryer
	High Spin Speed Clothes Washer
	Automatic Clothes Washer Controls
	Bubble-Action Clothes Washer
	Green Plug Motor Controller
Industrial	Switched Reluctance Drive (Improved DC Motor)
	Five-Phase Motors (Improved Perm Magnet DC Motor)

FIGURE T7-24 Renewable/Self-Generation Energy Technologies

End-Use	Demand-Side Measure
Renewables	Landfill Gas - Fuel Cells
	Small-Head Hydro
	Biomass Fuel - Wood Waste
	Photovoltaics
Self-Generation	Reciprocating Engine Systems
	Gas Turbine Systems
	Coal-Fired Steam Turbine Systems

FIGURE T7-25 **Beneficial Electrification Technologies Included in Options**

End-Use	Demand-Side Measure
Residential	Heat Pump Water Heater
	Air-Source Heat Pump
	Ground-Source Heat Pump
	Dual-Fuel Heat Pump
	Security Lighting
	Electric Cordless Lawn Mower
	Electric Cord Lawn Mower
Commercial	Heat Pump Water Heater
	High-Efficiency Air-Source Heat Pump
	Dual-Fuel Heat Pump
	Security Lighting
	Convection Oven
	High-Efficiency Fryer
Industrial – Process Industries	Reverse Osmosis
	Ultrafiltration
	Microfiltration
	Freeze Concentration
	Ozonation/Oxidation
	Ultraviolet (UV) Curing
	Electron Beam Curing
	Dielectric Curing
	Infrared (IR) Curing
	Industrial Process Heat Pumps
	Microwave Heating
	Radio Frequency (RF) Heating
Industrial – Textiles	Nanofiltration
	Vacuum Slot Drying
Industrial – Primary Metals	DC Electric Arc Furnace
	Plasma Arc Furnace
	Induction Melting (Coreless Induction Furnace)
	Vacuum Melting
	Plasma Ladle Refiner
	Induction Heating
	Resistance Heating
	Electrolytic Reduction
	Electroslag Remelting
Industrial – Metals Fabrication	Induction Heating
	Resistance Heating
	Electrogalvanization
	Electroslag Casting
Municipal	Reverse Osmosis
	Ultraviolet-Ozonation
Transportation	Electric Car
	Electric Van
	Electric Bus (Battery-Powered)
	Electric Work Vehicle

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GLOSSARY

Below are definitions of terms that will be used often in this appendix. (Terms in definitions which are themselves defined in the Glossary are printed in *italics*.)

A

AC—Air Conditioning.

Add-Ons—Purchases of new or additional equipment of a type previously not present in an existing facility, such as the purchase of a food freezer for a home that previously had none or the purchase of a second room air-conditioner.

Administrative Costs—Expenses incurred by the utility for program planning, design, management, and administration. They include labor, office supplies, data processing, etc. They exclude the costs of marketing, purchase of equipment for programs, incentives, and monitoring and evaluation.

Advanced Batteries—An advanced technology battery that has more storage capacity than a lead acid battery.

AFUE—Annual fuel utilization efficiency (AFUE) is an efficiency rating used for gas appliances based on average usage including on and off cycling described in a standardized Department of Energy test procedure. These ratings are listed in publications from the Gas Appliance Manufacturers Association (GAMA).

Agricultural Sector—The group of nonresidential customers engaged in the production of crops or livestock, forestry, fishing, hunting, or trapping.

Ambient—Surrounding.

Annual Participation—The number of customers enrolled in a particular program for a given year.

Annual Participation Rate—The ratio of the number of participating units in a particular year to the number of eligible units.

ASD—An adjustable speed drive (ASD) may be used to control the speed of an electric motor.

ASHRAE—American Society of Heating, Refrigeration, and Air-Conditioning Engineers, Inc.

Attributes—Measures or criteria used to evaluate options and strategies. For example, total TVA debt is an attribute.

Availability—The percentage of time that a TVA power plant (or generating unit in a power plant) can be called on to produce power.

Avoided Cost—The incremental cost to TVA for *capacity* or *energy* or both which, but for an acquisition from another source, the TVA would have to incur. (In other words, the cost of Plant A, which TVA would have acquired except for that fact that it was able to acquire Plant B.)

B

Base Load Capacity—Large power plants, often coal- or nuclear-fueled, which are designed to operate around the clock at high capacity factors.

Baseline—A mid-range set of assumptions on all variables, with a "business as usual" decision strategy.

Beneficial Electrification—Electricity may be used as a tool for economic development to fuel new products or replace other fuels for process improvement.

Biomass—Biomass involves the harvesting of stands of close growing whole trees, truck transport, tree storage, and drying using air heated by boiler flue gas, and combustion of the whole trees in a special deep bed burner at the bottom of the furnace.

Boiler—A component that consumes a fuel for a heat source to produce steam from water.

C

Capability—(1) With respect to *supply-side resources*, the amount of electric power that a generating unit or electric system can reliably deliver under specified conditions over a specified period of time; (2) with respect to *demand-side resources*, the ability and skills to perform *demand-side management* activities such as market research, program design, evaluation, etc.

Capacity—The amount of electric power that can be delivered by a generating unit or electric system, as determined by manufacturer's nameplate ratings or by testing. (For example, the capacity of a com-

bustion turbine power plant, based on its nameplate rating, would be stated as 225 *MW*.

Capacity Factor—A universal standard for measuring power plant performance. It compares a plant's actual output with its maximum potential output, expressed as a percentage.

CFC—*Chlorofluorocarbons.*

CH_4—*Methane.*

Chemical Coproduction—The production of a chemical product while simultaneously producing electricity.

Chlorofluoro-carbon (CFC)—A family of inert, nontoxic, and easily liquified chemicals used in refrigeration, air conditioning, packaging, and insulation or as solvents and aerosol propellants. Because CFCs are not destroyed in the lower atmosphere, they drift into the upper atmosphere, where their chlorine components destroy ozone.

Class 1 Areas—Nonattainment area—the part of a state where a state fails to attain and maintain pollutant levels below the National Ambient Air Quality Standards. States are required to impose additional control requirements on sources of ozone, carbon monoxide, particulates (PM 10), sulfur dioxide, nitrogen dioxide, and lead within the nonattainment area in order to attain the ambient standard.

Climate Challenge—The principal utility industry component of the President's Climate Change Action Plan, which provides for a voluntary reduction of greenhouse gases (primarily *CO2*).

CO—*Carbon Monoxide.*

CO_2—*Carbon Dioxide.*

Cogeneration—The use of a primary fuel, such as natural gas, to produce both electrical energy and thermal energy used as steam or process heat.

Coincident Peak—The *demand* of a TVA customer or group of customers at the time TVA's entire system is at its *peak load.*

Coincident Peak Demand—The load (in kW) of an end use, customer, or group of customers at the time the utility experiences its greatest demand for electricity.

Commercial Sector—The group of nonresidential customers that provides services, including retail, wholesale, finance, insurance, and public administration.

Conservation—A reduction in either *energy* usage or *peak demand* so as to provide the prior end-use service levels at a lower cost.

COP—Coefficient of Performance (COP) is dimensionless and defined as the useful energy effect divided by the energy from external sources.

Criteria—Measuring rods used in integrated resource planning. They are derived from issues or concerns. Examples include concerns over future rates, acceptable levels of environmental impacts, etc.

Cumulative Effects—The changes in electricity use and demand caused by all of a program's participants from the program's inception through the current year.

Cumulative Participation—The number of participating units from the start of a program through the current year.

Cumulative Participation Rate—The ratio of the number of participating units from the start of a program through the current year to the number of eligible units.

Customer Class—A group of customers with similar characteristics, such as economic activity or level of electricity use.

Customer Service Options—Actions taken to influence the nature of loads on the customer-side of the meter.

D

Decision—A choice that, although made ultimately by TVA's Board, contains input from all stakeholders.

Decision Analysis—A decision-making process that provides a mathematical framework by which a large set of resource *strategies* can be evaluated for a number of uncertain parameters. (For example, an ultimate decision might include five subdecisions, each with five key uncertain parameters, for which there are three values representing the range of likely outcomes. In this example, 1,115 scenarios would be evaluated in making the decision.)

Declining Block Rates—A utility rate where after a certain level of consumption in a period, additional consumption of energy is charged a lower rate.

Demand—The amount of electric energy used at a specific point in time, measured in watts (or multiples thereof, such as *kW, MW,* or *GW*). Demand is measured for individual customers, for groups or classes of customers. and for TVA's system as a whole.

Demand-Side Management (DSM)—Activities which influence electricity use on the customer's side of the meter. Examples include home weatherization, use of compact fluorescent lighting, etc.

Demand-Side Management Measure—A single technology, such as a compact fluorescent light bulb, which can be used to alter customer load.

Demand-Side Management Programs—Organized utility activities that are intended to affect the amount and timing of customer electricity use.

Demand-Side Management Resource—Bundles or packages of DSM activities that can be used to reduce customer energy demands, and thus be viewed in many respects like a generating source.

Diesel Generators—An electrical generator powered by a traditional diesel engine. Direct-Installation ProgramsActivities in which the utility (or its contractor) installs DSM measures in the facilities of participating customers; such programs generally cover low-cost measures, such as water-heater wraps and compact fluorescent lamps.

Dispatchable—Capable of being connected or disconnected from a utility's system as necessary for efficient operation of the system. Generally applies to generating facilities, but could also apply to a load that is interruptible when necessary.

Distributed Generation—Power generation facilities located close to energy users. These are normally small size units (i.e., less than 50 *MW*) and may include both generation and energy storage technologies.

Diversified Coincident Peak Demand Effect—The change caused by the utility's DSM program in the demand for electricity at the time the utility experiences its system peak.

Diversified Demand—The average load (in *kW*) across a group of customers or end uses.

DOE 2—A public domain building energy analysis software program developed with funding from the Department of Energy.

DX—Direct expansion (DX) refers to cooling equipment with a refrigerant to air coil and no chilled water system.

E

Early Replacement—The removal of equipment before it reaches normal retirement age and the substitution of new equipment for the old.

Eco-Efficiency—Sustainable manufacturing and pollution prevention practices.

Econometric Models—Models that use past statistical relationships between electricity sales and the major assumptions such as economic activity and prices to forecast future electricity sales.

Economic Dispatch—The hour-by-hour operation of TVA's system of generating units to meet hourly and daily load swings in a way that minimizes the cost of producing electricity.

Economic Potential—An estimate of the possible energy savings assuming that all energy-efficient options will be adopted and all existing equipment will be replaced with the most efficient whenever it is cost-effective to do so, without regard to market acceptance.

Economy Surplus Power (ESP)—A form of interruptible power sold by TVA. The price for ESP changes hourly and is based on a markup over the incremental cost of the power. There are several variations of ESP with different markups and interruption provisions.

EER—Energy efficiency ratio (EER) is a ratio calculated by dividing the cooling capacity in Btu's per hour (Btuh) by the power input in watts at any given set of rating conditions, expressed in Btuh per watt (Btuh/watt). These ratings are listed in publications by the Air-Conditioning & Refrigeration Institute (ARI).

EF—Energy Factor (EF) is a measure of the overall efficiency rating of a water heater certified by the Gas Appliance Manufacturers Association (GAMA).

Effluent—Wastewater—treated or untreated—that flows out of a treatment plant, sewer, or industrial outfall. Generally refers to wastes discharged into surface waters.

Electric and Magnetic Fields—Two types of energy fields that are emitted from any device that generates, transmits, and uses electricity.

Eligible Market—The subset of the total market that is qualified to participate in a program based on the program's participation criteria.

EMF—*Electric and Magnetic Fields.*

Emission—Pollution discharged into the atmosphere from smokestacks, other vents, and surface areas of commercial or industrial facilities; from residential chimneys; and from motor vehicle, locomotive, or aircraft exhausts.

EMS—Energy management system is a term used for automated control of *HVAC* and lighting systems in buildings.

End Use—The ultimate benefits provided by electricity. For example, commercial electric energy uses can be segmented into several end uses, such as lighting, air conditioning, ventilation, heating, cooking, refrigerating, etc.

End-Use Model—An energy forecasting approach that focuses on the end uses of electricity, and the factors that influence such end uses.

Energy—The amount of power consumed over a period of time, measured in watt hours, *kWh*, *MWh*, or *GWh*.

Energy Efficiency—(1) With regard to *supply-side resources*, reducing the amount of fuel required to produce a given amount of electric energy; (2) with regard to *demand-side management resources*, reducing the amount of electric energy used without reducing the functionality of that use—for example, by replacing a 74 watt incandescent light bulb with an 18 watt compact fluorescent light bulb delivering the same amount of lumens.

Energy Efficiency Programs—Programs (sometimes called energy-conservation programs) that are aimed at reducing the energy used by specific end-use devices and systems without degrading the services provided, thereby reducing overall electricity consumption (*kWh*), often without regard for the timing of program-induced savings. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of end-use services (e.g., lighting or warmth) with less electricity.

Energy Storage—Mechanism of utilizing during the peak load period energy that was stored during the light load period when energy production costs were relatively low. The duration of an energy storage cycle rarely exceeds one week.

Environmental Externalities—Externalities are activities which result from the production and consumption of goods and services that impose costs or benefits on society that are not reflected in the prices of those goods or services. For example, negative externalities such as pollution and sonic booms can impose costs on a society that are not reflected in the prices of those goods associated with the pollution or sonic boom. Discussions of externalities in the utility industry have generally dealt with environmental externalities arising from various forms of pollution.

Environmental Mitigation—Making environmental pollutants less severe.

Equipment Cost—The price of components that the utility purchases directly for a *DSM* program, including the cost of *DSM measures* distributed free to participants.

Evaluation Criteria—Measures to evaluate the contribution of resource options to stated objectives and values.

Existing Buildings—Structures that are in use as of the beginning of the current year.

Externalities—Consequences or impacts of resource development that are not directly accounted for in the price paid for the resource developed.

F

Feedstock—The raw materials utilized by a chemical production facility to make the final product.

Firm Capacity—(1) With regard to *supply-side resources*, a binding commitment to purchase or sell *capacity*. Purchases increase the *capability* of TVA's system; sales decrease TVA's *capability*; (2) with regard to *demand-side management resources*, the amount of *capability* that must be provided to a customer under normal conditions.

Firm Power—Power sales that do not have provisions in the contract for interruptions. (See *Interruptible Power*)

Fixed Costs—Costs associated with constructing and maintaining resources in an operable condition, including capitalized construction costs, fixed operating and maintenance costs and fuel inventory costs. These costs are recovered whether or not the resource is actually operated.

Flexibility—The degree to which resource decisions can be changed over time as events unfold, and near-term futures become more clearly known.

Free Drivers—Customers who take DSM-program-recommended actions because of the program, but who do not participate directly in the program (e.g., they do not claim rebates).

Free Riders—Customers who would have adopted program-recommended actions even without the program, but who participate directly in the program (e.g., they claim rebates).

Fuel Cells—A device capable of converting a fuel and an oxidizer directly to electricity.

Fuel Switching Programs—Programs that encourage customers to change from one fuel to another for a particular end-use.

Full-Scale Programs—Mature, system-wide programs that are available to all of the eligible customers in the utility's service area.

Future—A combination of discrete values for key uncertainties that are being treated explicitly. For example, a *future* might assume a high rate of load growth, low oil prices, low coal prices, high interest rates, and no new carbon dioxide (CO_2) regulations.

Futures (Financial Market)—The sale of a product for delivery at some time in the future for a specified price. Most major commodity markets have well-organized active futures markets. For

example, farmers will sometimes sell part of their crop for fall delivery before it is planted.

G

General Information Programs—Programs that refer to utility efforts to inform customers about *DSM* options through such mechanisms as brochures, bill stuffers, TV and radio ads, and workshops.

Global Warming—The theory that certain gases such as *carbon dioxide (CO_2)*, *methane (CH_4)*, and *chlorofluorocarbon (CFC)* in the earth's atmosphere effectively restrict radiation cooling, thus elevating the earth's ambient temperatures.

Greenhouse Effect—The build-up of carbon dioxide or other trace gases that allows light from the sun's rays to heat the Earth but prevents a counterbalancing loss of heat.

Greenhouse Gas Emissions—A gas whose presence in the upper atmosphere contributes to the greenhouse effect by allowing visible light to pass through the atmosphere while preventing heat radiating back from the Earth from escaping. Greenhouse gases from anthropogenic sources include *carbon dioxide, nitrous oxide, methane,* and *chlorofluorocarbons (CFCs)*. There also are even larger quantities of naturally occurring greenhouse gases, notably ozone and water vapor, whose concentrations may be affected by interactions with atmospheric pollutants.

GW—Gigawatt, an amount of electric power equal to 1,000 *MW* or 1 billion watts.

GWh—Gigawatt hour, an amount of energy equal to 1,000 *MWh* or 1 billion watt hours.

H

Hazardous Waste—A byproduct of society that can pose a substantial or potential hazard to human health or the environment when improperly managed. Possesses at least one of four characteristics (ignitability, corrosivity, reactivity, or toxicity) or appears on special Environmental Protection Agency lists.

HSPF—Heating Season Performance Factor (HSPF) is the total heating output of a heat pump during its normal annual usage period for heating divided by the total electric power input in watt-hours during the same period. This rating is listed in publications by the American Refrigeration Institute (ARI).

HVAC—Heating, Ventilation, and Air Conditioning

Hydro Generation—A dam creates an upper and a lower water reservoir. The height difference between the two reservoirs establishes potential energy that is used to generate electricity by allowing water from the upper reservoir to flow through a hydro turbine to the lower reservoir.

I

Incentive—An award offered to encourage participation in a DSM program and adoption of recommended measures.

Incentive Programs—Programs that offer cash or noncash awards to customers, trade allies, or employees to encourage participation in a *DSM* program and adoption of recommended measures.

Incremental Cost—The additional cost incurred because of an activity. For example, a plant sitting idle has costs associated with it such as interest on funds used to build it and basic maintenance. When started up, the plant has additional costs such as fuel, additional maintenance, and other costs. These latter costs are the incremental costs of producing the product. Similar terms are avoided cost and marginal cost.

Incremental Fuel Cost—The cost of replacing a unit of fuel in today's market.

Incremental Participation—The number of annual participants in the current year minus the annual participants in the previous year.

Industrial Sector—The group of nonresidential customers that provides products, including agriculture, construction, mining, and manufacturing.

Integrated Resource Planning—A utility planning process that evaluates *supply-side resources* and *DSM resources* on a level playing field to reliably meet the future energy needs of customers.

Internalized Costs—Costs that result from the production and consumption of goods and services that are reflected in the price of those goods and services.

Interruptible Power—A type of *demand-side management* activity in which the power contract allows TVA limited rights to turn off the power when overall demand is high in return for a lower price to the customer. Many industrial customers buy part of their power as interruptible. (See *Firm Power*)

Issue—A concern expressed regarding TVA's energy resource plan or its implementation. For example, an industrial customer may see low electricity rates as vital to its continued operation.

kW—Kilowatt, which is the amount of power equal to 1,000 watts. Common measure of demand for electricity at any moment.

kWh—Kilowatt hour, which is the amount of energy equal to 1,000 watt-hours.

Common measure for use of electricity over time.

L

Life-Cycle Costs—Method of expenditure evaluation that recognizes the sum total of all costs associated with the expenditure during the time it is in use.

Limited Interruptible Power (LIP)—A form of interruptible power sold by TVA. LIP customers get discounts from firm power rates in exchange for granting TVA limited rights to interrupt the power if necessary when the power supply situation is very tight.

Load—The amount of power that is drawn from TVA's electric system at a given point in time.

Load Factor—A measure of the variability in electric usage, defined as the ratio of energy actually consumed to the potential consumption at peak load for the period of time of interest. Load factor is usually calculated over a one year (8,760 hours) time period.

Load Management—The control of customer demand during peak periods or during periods when supplies of electricity are short. Unlike energy conservation, load management may not conserve energy.

Load Not Served—A measure of the reliability of a power system.

Load Shape—The time-of-use pattern of customer electricity use, generally a 24-hour pattern or an annual (8,760-hour) pattern.

Load-Building Programs—Programs that aim to increase electricity consumption, generally without regard to the timing of the increased usage.

Load-Shifting Programs—Programs that aim to move electricity consumption from one time to another (usually from the on-peak to off-peak periods during a single day).

M

Market Potential—An estimate of the possible energy savings that would occur because of normal market forces (i.e., likely customer adoption over time of various actions without a *DSM* program)

Methane (CH_4)—A greenhouse gas that is colorless, nonpoisonous, and flammable and is created by anaerobic decomposition of organic compounds.

micro-AXCESS—A building energy analysis software program available through EPRI.

Mitigation—Measures taken to reduce adverse impacts on the environment.

Monitoring and Evaluation Cost—Expenditures associated with the collection and analysis of data used to assess program operation and effects.

MW—Megawatt, the amount of power equal to 1,000 KW or 1,000,000 watts.

MWh—Megawatt hour, the amount of power equal to 1,000 KWh or 1,000,000 watt hours.

N

Net Effect—The change in electricity use or demand for a participating customer that can be attributed to the utility *DSM* program, expressed in *MWh*/year and *MW*.

New Construction—Buildings and facilities that are constructed during the current year; it may also include major renovations of existing facilities.

New Construction Programs—Programs that affect the design and construction of residential and commercial buildings and manufacturing facilities; such programs may also include major renovations of existing facilities.

New Participants—Customers who take part in a program during the current year and did not participate in the program during the previous year.

NIMBY—Not in my backyard.

Non-Attainment Area—A geographic area that does not meet one or more of the National Ambient Air Quality Standards for the criteria pollutants designated in the Clean Air Act.

Noncoincident Peak—The peak demand imposed on TVA by a customer, group of customers or all the customers as a whole, but not necessarily at the same time.

Normal Replacement—The removal of worn-out (and perhaps obsolete) equipment and the installation of new equipment.

O

Off-Peak—The periods of time during which energy is being delivered far below the maximum demands that could be placed.

On-Peak—The periods of time during which energy is being delivered near, or at, the maximum *coincident peak load.*

Operating and Maintenance Costs—Noncapital, equipment-related expenses that continue over the life of the equipment; they include fuel costs, as well as costs for maintaining and servicing equipment.

Option—Actions TVA can take to resolve an issue. For example, if TVA forecasts an energy deficit, it has the option to meet it with *DSM* programs or other resources.

P

Participant Costs—Those expenses associated with taking part in a *DSM* program paid by the customer and not reimbursed by the utility.

Participants—Units used by a utility to measure participation in its *DSM* programs; such units of measurement include customers or households for residentials programs and customers, floor area, or *kW*-connected for commercial and industrial customers.

Participation Rate—The ratio of the number of participants in a program to the number eligible for the program, with both the numerator and denominator defined in the same units.

Peak Demand—The maximum rate of electricity use, expressed in *kW*.

Peak Load—The maximum *load* experienced by TVA's electric system over a given period of time.

Peak-Clipping Programs—Programs that aim to reduce electricity *demand* (*kW*) at certain critical times, typically when the utility experiences system peaks.

Peaking Capacity—Capacity that is available for use and used to meet *peak load*. Such capacity, usually represented by combustion turbines, often has low capital costs and high fuel costs, and is designed to operate for relatively short periods of time.

Penetration—The ratio of the number of new units of a specific type installed to the total number of new units installed during a given time (e.g., the fraction of new air-conditioner sales that exceeds an energy-efficiency ratio of 10).

Photovoltaics—Solar-photovoltaic (PV) power plants convert solar energy to electricity using a semiconductor material, usually silicon doped with phosphorus and boron, to generate dc current.

Point Sources—A stationary location or fixed facility from which pollutants are discharged or emitted. Also, any single identifiable source of pollution, for example, a pipe, ditch, ship, ore pit, or factory smokestack.

PSD—*Prevention of Significant Deterioration.*

R

Real Prices—(Or constant dollar prices, prices excluding inflation) As applied to price changes, the rate of change in a price over time adjusted for the overall inflation rate. For example, if the price of a widget goes up 1 percent while the average price of all goods sold in the economy goes up 2 percent, the real price of the widget is said to have declined 1 percent.

Real-Time Pricing—*Energy* is priced at the cost of producing it at the time it is consumed.

Rebate—Money given to customers, contractors, homebuilders, or other trade allies who make equipment choices to help defray the incremental cost of *DSM* measures.

Reference Case—One given set of circumstances used to compare other sets of circumstances.

Reliability—The ability of TVA's electric system to deliver uninterrupted power to its customers.

Renewable Resources—Power plants or other generating devices whose fuel source is generally considered to be renewable. These include generators fueled by *biomass*, water, *photovoltaics*, solar, wave or wind energy.

Reserve Margin—The difference between the capability of TVA's electric system and expected peak load, expressed as a percentage of expected peak load.

Residential Sector—The group of customers to whom electricity is sold for household purposes, including space heating, water heating, air conditioning, lighting, and appliances in single-family, multi-family, and mobile homes.

Resources—*Supply-side* or *DSM* options that can be used by TVA to meet future customer energy needs.

Retrofit—Replacement or upgrading of equipment before it reaches normal retirement age.

Retrofit Programs—Programs that upgrade existing facilities and equipment.

Revenue Requirements—The amount that must be recovered from customers to cover a utility's fixed and variable costs.

Robustness—The degree to which an energy strategy meets an objective for most or all futures.

S

Saturation—On the demand side, the percentage of a group of customers that have a particular *end use*. For example, the residential saturation of heat pumps is 50 percent if half of residential customers have them. In the commercial sector, saturations (also know as fuel shares) are generally measured on a percentage of square footage basis.

SCADA—System Control and Data Acquisition

Scenario—The combining of one *strategy* with one *future*.

SEER—Seasonal Energy Efficiency Ratio (SEER) is the total cooling of a central unitary air conditioner or unitary heat pump in Btu's during its normal annual usage period for cooling divided by the total electric energy input in watt-hours during the same period. This rating is listed in publications by the American Refrigeration Institute (ARI).

Stranded Cost—Costs that a utility faces because of stranded investments. For example, a utility may owe money on a closed plant that is generating no income. If a stranded investment can operate and cover part of its cost, only the portion of the cost not covered would be stranded.

Stranded Investment—An investment in plant or equipment that loses its value because of competition that forces down the price of the product. In the electric utility industry, firms may have been allowed or directed by regulators to build high cost capacity to meet the obligation to serve their customers. If the market is open to competition, lower cost producers may capture these customers, causing the high cost capacity to close and become a stranded investment.

Strategy—A combination of *options* intended to fulfill a particular resource goal. For example, an energy deficiency in 2007 might be met with a combination of *supply-side resources* and *DSM resources*.

unk Cost—The sum of previous investments; monies that have already been spent.

Supply-Side Resource—Resources that meet customer needs by increased production of electricity.

Sustainable Development—Meeting the needs of the present without compromising the ability of future generations to meet their own needs.

System Energy Requirements—The total energy the generating system needs to produce to meet customer needs over some time period, generally a year. System energy requirements include all sales and *system losses*. Customer needs are measured before *load management* measures are applied.

System Losses—Difference between the energy metered at the generator and the energy recorded at the customers' meters.

T

Take-back—Changes in customer behavior resulting in greater energy use stimulated by participation in a *DSM* program.

Target Market—The group of customers (a subset of the eligible market) that is the focus of utility marketing efforts.

Total Program Costs—All expenses associated with a *DSM* program regardless of whether borne by the utility, participating customer, or trade allies. The costs paid by customers and trade allies are first adjusted for incentives from the utility to avoid double-counting costs.

Total Resource Costs (TRC) Test—A benefit-cost test that measures the net costs of a *demand-side* program as a resource option based on the total cost of the program, including both the participant and the utility's costs. The costs in this are the program costs paid by both the utility and the participants plus the increase in supply costs for any period in which load has been increased. All equipment costs are included in this test.

Total Value Test—the *Total Resource Costs* test to not only include the total cost of an *option*, but also the effects upon the benefits or "value" that participants and ratepayers receive.

Trade Allies—Organizations (e.g., architect and engineer firms, building contractors, appliance manufacturers and dealers, and banks) that affect the energy-related decisions of customers who might participate in *DSM* programs.

U

Utility Costs—All the expenses (administrative, equipment, incentives, marketing, monitoring and evaluation, etc.) incurred by a utility in a given year for operation of a *DSM* program regardless of whether the costs are capitalized or expensed.

V

Valley-Filling Programs—Programs that typically seek to increase off-peak electricity consumption (without necessarily reducing *on-peak* demands).

Variable Costs—Costs associated with the generation of electricity that vary with the utilization of the generating station, such as fuel, consumable supplies, etc.

Variable Frequency Drive (VFD)—A variable frequency drive is a type of *ASD* that varies the frequency of the electricity to an electric motor to control its speed.

VOCs—*Volatile organic compounds*.

Volatile Organic Compounds—Any organic compound that participates in atmospheric photochemical reactions except for those designated by the

Environmental Protection Agency administrator as having negligible photochemical reactivity.

W

Weather Adjusted—(Or weather normalized) Having the effects of the difference between actual and expected normal weather removed. For example, TVA forecasts summer peaks for a normally expected Valley-wide average temperature of 96 degrees. If the peak one year occurs at 100 degrees, a weather adjusted peak will be estimated by applying a per degree adjustment factor to the four-degree difference.

Energy Vision

2020

Volume 2, Technical Document

8 Resource Integration

Volume 2, Technical Document 8

Resource Integration

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This technical document has eight major sections that were originally separate information items. These were used in various discussions on the resource integration process that TVA used to develop Energy Vision 2020.

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Resource Integration

STRATEGY MATRICES

The Strategy Matrices are detailed descriptions of the supply-side, environmental, customer service, and transmission improvement options contained in each strategy. The first strategy matrix, *Figure T8-1*, depicts how the initial strategies were formed from a list of customer service, supply-side expansion, and nuclear refinement strategies. By analyzing how each strategy behaves under key uncertainties, some strategies were eliminated and some new ones were created. In the second strategy matrix, *Figure T8-2*, many new strategies were formed to provide more flexibility to Energy Vision 2020, TVA's Integrated Resource Plan (IRP). The third strategy matrix, *Figure T8-3*, represents the final strategies that were evaluated in order to develop the Energy Vision 2020 portfolio.

FIGURE T8-1. Strategy Matrix for Year 2010

18-JAN-95

Acronym Key:
BFN Browns Ferry Nuclear Plant
BLN Bellefonte Nuclear Plant
CC Natural Gas Combined Cycle
CT Combustion Turbine
IGCC Integrated Gasification Combined Cycle
IPP Independent Power Producer
WBN Watts Bar Nuclear Plant
CO2 Carbon Dioxide
SO2 Sulfur Dioxide

	SUPPLY PROFILE						ENVIRONMENT		
	Nuclear (MW)	Coal (MW)	Natural Gas (MW)	Hydro & Storage (MW)	Renewables (MW)	Purchased Power (MW)	Clean Air Strategy	Biomass Cofiring	CO_2 Dispatch
Existing System in 1996	5577	14968	2292	5498	0	2300			
Existing System in 2010	5577	14968	2292	5498	0	1100			
Changes from Existing System									
Reference CC/IPP/Coal with Low-Price DSM	0	1155	5930	0	0	1740	Reference	No	No
Customer Service Strategies									
1 CC/IPP/Coal with No DSM	0	1575	6720	0	0	1740	Reference	No	No
2 CC/IPP/Coal with Block 1 DSM	0	1890	5310	0	0	1440	Reference	No	No
3 CC/IPP/Coal with Blocks 1 & 2 DSM	0	1155	4840	0	0	720	Reference	No	No
4 CC/IPP/Coal with Blocks 1, 2, & 3 DSM	0	735	4520	0	0	0	Reference	No	No
5 CC/IPP/Coal with Low-Price DSM	0	1155	5930	0	0	1740	Reference	No	No
6 CC/IPP/Coal with Low BE	0	1890	6570	0	0	1740	Reference	No	No
7 CC/IPP/Coal with High BE	0	1890	6720	0	0	1740	Reference	No	No
Supply-Side Expansion Strategies									
1 Coal Expansion	0	5168	3600	0	0	0	Reference	No	No
2 CC/Coal Expansion	0	1890	6890	0	0	0	Reference	No	No
3 CC Renewable Expansion	0	0	7490	0	1700	0	Reference	No	No
4 CC and IPP Expansion	0	0	6250	0	0	2520	Reference	No	No
Nuclear Refinement Strategies									
1 Defer WBN/BFN and Build	2235	735	4690	0	0	1140	Reference	No	No
2 Defer WBN/BFN and Cancel	0	1890	5010	0	0	1860	Reference	No	No
3 Defer BLN and Build	2424	0	5010	0	0	1440	Reference	No	No
4 Defer BLN and Cancel	0	1155	4990	0	0	1440	Reference	No	No
5 Convert BLN to CC	0	1575	6590	0	0	720	Reference	No	No
6 Partner BLN as Nuclear	1212	1155	5610	0	0	2040	Reference	No	No
7 Partner BLN as IGCC/Coproduct	0	1890	5010	0	0	1924	Reference	No	No
8 Convert BLN to IGCC/Coproduct	0	2520	5140	0	0	1140	Reference	No	No
9 Cancel Four Nuclear Units	0	1890	5010	0	0	1860	Reference	No	No
10 Cancel Three Nuclear Units/Build WBN 2	1170	1890	5010	0	0	720	Reference	No	No
Mixed Strategies									
1 Minimum Debt, Purchases/IPP/IPP Expansion	0	24	3750	0	0	5380	Fuel Switch	No	No
7 Low-Cost Producer 1, CC/IPP/Coal Expansion	0	1890	4710	163	0	1140	Reference	No	No
8 Low-Cost Producer 2, Coal/Coal Expansion	0	4253	3800	163	0	0	Reference	No	No
10 Max "Customer Value Index" (Off-Sys Sales, High BE, Declining Blk)	0	2933	4050	163	0	0	Reference	0.3%	No
11 Low TRC, Coal Expansion, and High DSM	0	1155	3900	163	0	0	Reference	0.3%	No
12 Max. Sales, Coal and Stor. Expn, High Off-Sys Sales	0	1613	7392	668	0	0	Reference	No	No
14 Competitive 1	0	1575	4880	1	0	2460	Reference	No	No
15 Competitive 2	0	1575	7190	1	0	1560	Reference	No	No
2 Min CO_2, Natural Gas Repowering	0	-1931	8850	163	0	0	Repowering	1.3%	Yes
3 Min CO_2, Nat Gas Repowering, & Renewables	0	-1931	4665	163	2240	0	Repowering	1.3%	Yes
4 Max Conservation	0	0	3876	163	0	1200	Reference	0.3%	No
5 Green Strategy, Waste Methane, Wind, & Solar	0	-1931	4721	668	3500	0	Repowering	0.3%	Yes
6 Renew, Waste Methane, Wind, Solar, & Biomass	0	-1931	3971	668	5740	0	Repowering	0.3%	Yes
13 Distributed Generation, CC, Cogen, IPP, & Fuel Cells	0	0	6310	0	500	3300	Reference	No	No
16 Maximum Diversity	0	1155	4676	506	700	1560	Reference	1.3%	No
17 Environmental Sustainability	0	-2609	8181	1011	300	0	Repowering	1.3%	Yes

Notes:
1. The reference strategy, cancel BLN 1 & BLN 2, defer and cancel WBN 2 and BFN 1 with a CC, IPP, coal expansion with low-price DSM provides common point for trade-off plots.
2. Reference clean air strategy is scrub Paradise Unit 3 and Allen Units 1-3 with various fuel switches.
3. Repowering clean air strategy is natural gas combined cycle repowering of Johnsonville and Allen units.
4. Fuel switching clean air strategy is switch to low sulfur coal at most plants and switch to natural gas at Allen.
5. Renewables include solar, wind, short rotation woody crops (SRWC), refuse-derived fuel (RDF), and methane options.

Initial strategies were formed from a list of customer service, supply-side expansion, and nuclear refinement options.

	CUSTOMER SERVICE, PRICING/RATES				TRANSMISSION
DSM (MW)	Off Sys. Sales (MW)	Beneficial Electrification (MW)	Pricing (Time-of-Day/ Declining Block) (MW)	Price Feedback (MW)	Transmission Improvements
-1120	0	0	0	138	No
0	0	0	0	112	No
-1365	0	0	0	23	No
-2997	0	0	0	191	No
-4183	0	0	0	302	No
-1120	0	0	0	138	No
0	0	89	0	203	No
0	0	196	0	103	No
-1122	0	0	0	112	No
-1122	0	0	0	23	No
-1120	0	0	0	191	No
-1119	0	0	0	302	No
-1118	0	0	0	-160	No
-1119	0	0	0	55	No
-1118	0	0	0	-112	No
-1120	0	0	0	83	No
-1120	0	0	0	201	No
-1120	0	0	0	246	No
-1122	0	0	0	711	No
-1123	0	0	0	892	No
-1119	0	0	0	95	No
-1120	0	0	0	410	No
0	0	0	-892	-1137	No
-1118	1000	144	-892	297	No
-1120	1000	144	-892	767	No
-2930	0	196	169	670	No
-4185	0	0	0	395	No
0	2000	0	0	1007	Yes
-1118	0	0	0	-50	No
0	0	196	0	-27	No
-4180	0	0	0	35	No
-4187	0	0	0	535	Yes
-4183	0	0	0	276	Yes
-4487	0	0	0	596	No
-4468	0	0	0	256	No
0	0	0	0	-331	No
-1118	0	76	0	110	No
-4178	0	0	0	-87	No

FIGURE T8-2. Strategy Matrix for Years 2005 and 2020

09-MAR-95

Acronym Key:
BFN Browns Ferry Nuclear Plant
BLN Bellefonte Nuclear Plant
CC Natural Gas Combined Cycle
CT Combustion Turbine
IGCC Integrated Gasification Combined Cycle
IPP Independent Power Producer
WBN Watts Bar Nuclear Plant
CO2 Carbon Dioxide
SO2 Sulfur Dioxide

		SUPPLY PROFILE						ENVIRONMENT			CUSTOMER SERVICE, PRICING/RATES				
	Year	Nuclear (MW)	Coal (MW)	Natural Gas (MW)	Hydro & Storage (MW)	Renewables (MW)	Purchased Power (MW)	Clean Air Strategy	Biomass Cofiring	CO_2 Dispatch	DSM (MW)	Off Sys. Sales (MW)	Beneficial Electrification (MW)	Pricing (Time-of-Day/ Declining Block) (MW)	Price Feedback (MW)
Existing System in 2005		55[illegible]	14968	2292	5498	0	1800								
Existing System in 2020		5577	14968	2292	5498	0	1000								
Changes From Existing System															
2 Min CO_2 - (Nat Gas Repowering	2005	0	-1931	4835	0	0	0	Repowering	1.3%	Yes	-3171	0	0	0	-147
of Existing Coal)	2020	0	-1931	14300	162	0	0	Repowering	1.3%	Yes	-1480	0	0	0	-1990
3 Min CO_2 - (Nat Gas Repowering	2005	0	-1931	3765	0	740	0	Repowering	1.3%	Yes	-3172	0	0		-85
of Existing Coal & Renewables)	2020	0	-1931	11265	162	3840	0	Repowering	1.3%	Yes	-1480	0	0	0	-1347
8 Low-Cost Producer	2005	0	2378	2400	0	0	0	Reference	No	No	-999	1000	62	-796	367
(Coal-Based)	2020	0	9053	5400	162	0	0	Reference	No	No	-517	0	25	-1043	-216
9 Reference (Combined Cycle,	2005	0	0	4430	0	0	925	Reference	No	No	-997	0	0	0	57
Purchased Power, Coal)	2020	0	5775	8520	0	0	1225	Reference	No	No	-517	0	0	0	-596
10 Max "Customer Value Index" (Off-	2005	0	2978	2700	0	0	0	Reference	0.3%	No	-997	1000	180	167	242
Sys Sales, High BE, Declining Blk)	2020	0	9953	5850	162	0	0	Reference	0.3%	No	-517	0	71	169	-237
11 Low TRC/High DSM	2005	0	300	2250	0	0	0	Reference	0.3%	No	-3169	0	0	0	-268
	2020	0	7230	5550	162	1500	0	Reference	0.3%	No	-1480	0	0	0	-437
12 Maximum Sales	2005	0	878	5820	0	0	0	Reference	0.3%	No	0	1000	180	0	493
	2020	0	5078	10474	162	0	0	Reference	0.3%	No	0	0	71	0	-385
16 Maximum Capacity Diversity	2005	0	0	3902	0	0	625	Reference	1.3%	No	-999	0	62	0	122
	2020	0	5355	6122	162	1640	775	Reference	1.3%	No	-517	0	25	0	-629
18 Bellefonte Nuclear Partnership	2005	600	0	3960	0	0	775	Reference	1.3%	No	-998	0	0	0	55
	2020	600	5775	8050	0	0	1075	Reference	1.3%	No	-516	0	0	0	-542
20 Bellefonte Coproduct and	2005	0	0	2550	0	500	2284	Reference	0.3%	No	-997	0	0	0	330
Renewables	2020	0	5775	5850	162	1500	2584	Reference	0.3%	No	-517	0	0	0	184
23 Defer and Build BFN 1 and WBN 2	2005	1170	0	3510	0	0	775	Reference	No	No	-997	0	0	0	-285
with Reference Expansion	2020	2235	5355	6810	0	0	775	Reference	No	No	-517	0	0	0	-774
24 Minimize CO_2 with Less DSM	2005	0	-1931	5110	0	740	0	Repowering	1.3%	Yes	-2048	0	0	0	180
	2020	0	-1931	11735	162	3640	0	Repowering	1.3%	Yes	-958	0	0	0	-1384
28 Combined DSM and	2005	0	1778	2400	0	0	0	Reference	0.3%	No	-2047	1000	0	0	229
Off-Sys Sales	2020	0	7553	5700	162	1500	0	Reference	0.3%	No	-957	0	0	0	-274
29 Decentralized Generation	2005	0	0	4430	160	0	775	Reference	No	No	-998	0	0	0	90
with More Renewables	2020	0	0	10860	160	1900	925	Reference	No	No	-517	0	0	0	-1707
32 Bellefonte Coproduct, More DSM,	2005	0	0	2550	0	500	1384	Reference	0.3%	No	-2049	1000	0	0	454
and More Off-Sys Sales	2020	0	6510	5700	162	1500	534	Reference	0.3%	No	-958	0	0	0	275
34 Low-Cost Renewables,	2005	0	-1931	5284	1011	740	450	Repowering	0.3%	Yes	-998	0	0	0	235
Low-Price DSM, Repowering	2020	0	2307	8115	1173	3340	450	Repowering	0.3%	Yes	-517	0	0	0	-253
39 Flexible Strategy with	2005	0	0	900	0	1000	3773	Reference	0.3%	No	-999	1000	62	0	648
External Options	2020	0	7665	4800	162	1500	1973	Reference	0.3%	No	-517	0	25	0	402
40 Flexible Strategy with	2005	0	0	2570	0	1250	1973	Reference	0.3%	No	-999	1000	62	0	583
Internal Options	2020	0	7665	5720	162	1500	1673	Reference	0.3%	No	-517	0	25	0	454
41 Low Cost, Low Rates,	2005	0	0	2850	0	1250	1534	Reference	0.3%	No	-999	1000	62	0	493
Improved Environment	2020	0	6930	5850	162	1500	1534	Reference	0.3%	No	-517	0	25	0	369

Notes:
1. The reference strategy, cancel BLN 1 & BLN 2, defer and cancel WBN 2 and BFN 1 with a CC, IPP, coal expansion with low-price DSM provides common point for trade-off plots.
2. Reference clean air strategy is scrub Paradise Unit 3 and Allen Units 1-3 with various fuel switches.
3. Repowering clean air strategy is natural gas combined cycle repowering of Johnsonville and Allen units.
4. Fuel switching clean air strategy is switch to low sulfur coal at most plants and switch to natural gas at Allen.
5. Renewables include solar, wind, short rotation woody crops (SRWC), refuse-derived fuel (RDF), and methane options.
6. Off-system sales begin in 1996 and end in 2004.
7. Strategies 3 and 12 contain additional transmission system capital and efficiency improvements.

New strategies were formed to provide more flexibility to TVA's Integrated Resource Plan.

TRANSMISSION	CAPACITY AND ENERGY BY FUEL TYPE											
Transmission Improvements	Nuclear (MW)	Nuclear (GWH)	Coal (MW)	Coal (GWH)	Natural Gas (MW)	Natural Gas (GWH)	Hydro & Storage (MW)	Hydro & Storage (GWH)	Renewables (MW)	Renewables (GWH)	Purchased Power (MW)	Purchased Power (GWH)
	5577	30171	14968	96212	2292	1009	5498	19268	0	0	1800	
	5577	32414	14968	100654	2292	1403	5498	20780	740	5898.5	1000	
		(CF)		(CF)		(CF)		(CF)		(CF)		(CF)
Yes	5577	67.1%	13037	84.2%	7127	20.4%	5498	42.4%	0	0	1800	4.4%
Yes	5577	67.1%	13037	85.1%	16592	39.1%	5660	42.1%	0	0	1000	0.6%
Yes	5577	67.1%	13037	82.9%	6057	16.4%	5498	42.4%	740	91.0%	1800	4.1%
Yes	5577	67.1%	13037	84.9%	13557	34.1%	5660	42.1%	3640	62.7%	1000	1.1%
No	5577	67.1%	17346	80.5%	4692	11.7%	5498	42.4%	0	0	1800	7.5%
No	5577	67.1%	24021	79.0%	7692	9.7%	5660	42.1%	0	0	1000	1.0%
No	5577	67.1%	14968	82.8%	6722	13.2%	5498	42.4%	0	0	2725	26.0%
No	5577	67.1%	20743	82.2%	10812	11.2%	5498	43.3%	0	0	2225	35.2%
No	5577	67.1%	17946	77.8%	4992	7.9%	5498	42.4%	0	0	1800	4.7%
No	5577	67.1%	24921	75.8%	8142	6.8%	5660	42.1%	0	0	1000	1.1%
No	5577	67.1%	15268	78.5%	4542	7.5%	5498	42.4%	0	0	1800	5.3%
No	5577	67.1%	22198	75.1%	7842	8.1%	5660	42.1%	1500	94.1%	1000	0.7%
Yes	5577	67.1%	15846	83.5%	8112	19.5%	5498	42.4%	0	0	1800	4.0%
Yes	5577	67.1%	20046	83.7%	12766	21.0%	5660	42.2%	0	0	1000	0%
No	5577	67.1%	14968	83.2%	6194	18.4%	5498	42.4%	0	0	2425	24.6%
No	5577	67.1%	20323	82.4%	8414	16.0%	5660	42.2%	1640	28.6%	1775	30.3%
No	6177	67.9%	14968	81.5%	6252	11.5%	5498	42.4%	0	0	2575	41.4%
No	6177	67.9%	20743	81.4%	10342	10.5%	5498	43.3%	0	0	2075	54.4%
No	5577	67.1%	14968	81.3%	4842	6.4%	5498	42.4%	500	94.1%	4084	27.5%
No	5577	67.1%	20743	80.0%	8142	6.4%	5660	42.1%	1500	94.1%	3584	28.4%
No	6747	63.7%	14968	79.8%	5802	9.2%	5498	42.4%	0	0	2575	21.9%
No	7812	67.1%	20323	79.1%	9102	9.4%	5498	43.3%	0	0	1775	29.1%
No	5577	67.1%	13037	84.4%	7402	22.7%	5498	42.4%	740	91.0%	1800	5.2%
No	5577	67.1%	13037	85.0%	14027	35.3%	5660	42.1%	3640	62.4%	1000	1.1%
No	5577	67.1%	16746	78.0%	4692	7.3%	5498	42.4%	0	0	1800	4.7%
No	5577	67.1%	22521	75.7%	7992	6.7%	5660	42.1%	1500	94.1%	1000	0.8%
No	5577	67.1%	14968	82.7%	6722	13.4%	5658	43.0%	0	0	2575	24.4%
No	5577	67.1%	14968	84.7%	13172	29.7%	5658	44.3%	1900	59.1%	1925	28.0%
No	5577	67.1%	14968	80.5%	4842	6.9%	5498	42.4%	500	94.1%	3184	24.5%
No	5577	67.1%	21478	77.9%	7992	6.6%	5660	42.1%	1500	94.1%	2534	26.6%
No	5577	67.1%	13037	84.5%	7576	25.0%	6509	35.8%	740	91.0%	2250	22.4%
No	5577	67.1%	17275	83.6%	10407	22.9%	6671	35.7%	3340	63.3%	1450	23.3%
No	5577	67.1%	14968	81.3%	3192	5.3%	5498	42.4%	1000	94.1%	5573	22.8%
No	5577	67.1%	22633	76.3%	7092	6.7%	5660	42.1%	1500	94.1%	2973	20.0%
No	5577	67.1%	14968	80.6%	4862	7.2%	5498	42.4%	1250	94.1%	3773	24.5%
No	5577	67.1%	22633	76.4%	8012	6.4%	5660	42.1%	1500	94.1%	2673	21.6%
No	5577	67.1%	14968	80.5%	5142	7.1%	5498	42.4%	1250	94.1%	3334	25.6%
No	5577	67.1%	21898	78.0%	8142	6.8%	5660	42.1%	1500	94.1%	2534	26.9%

FIGURE T8-3. Strategy Matrix for Years 2005 and 2020

09-APRIL-95

Acronym Key:
BFN Browns Ferry Nuclear Plant
BLN Bellefonte Nuclear Plant
CC Natural Gas Combined Cycle
CT Combustion Turbine
IGCC Integrated Gasification Combined Cycle
IPP Independent Power Producer
WBN Watts Bar Nuclear Plant
CO2 Carbon Dioxide
SO2 Sulfur Dioxide

			SUPPLY PROFILE							ENVIRONMENT			CUSTOMER SERVICE, PRICING/RATES			
		Year	Nuclear (MW)	Coal (MW)	Natural Gas (MW)	Hydro & Storage (MW)	Renewables (MW)	Purchased Power (MW)	Clean Air Strategy	Biomass Cofiring	CO_2 Dispatch	DSM (MW)	Off Sys. Sales (MW)	Beneficial Electrification (MW)	Pricing (Time-of-Day/ Declining Block) (MW)	Price Feedback (MW)
Existing System in 2005			5577	14968	2292	5498	0	1800								
Existing System in 2020			5577	14968	2292	5498	0	1000								
Changes from Existing System																
A	2 Min CO_2 - (Nat Gas Repowering	2005	0	-1931	4695	0	0	0	Repowering	1.3%	Yes	-3171	0	0	0	-187
	of Existing Coal)	2020	0	-1931	14425	162	0	0	Repowering	1.3%	Yes	-1480	0	0	0	-1810
B	3 Min CO_2 - (Nat Gas Repowering	2005	0	-1931	3765	0	740	0	Repowering	1.3%	Yes	-3172	0	0	0	-126
	of Existing Coal & Renewables)	2020	0	-1931	12150	162	3040	0	Repowering	1.3%	Yes	-1480	0	0	0	-1147
C	8 Low-Cost Producer	2005	0	2378	2400	0	0	0	Reference	No	No	-999	1000	62	-796	330
	(Coal-Based)	2020	0	9053	5400	162	0	0	Reference	No	No	-517	0	25	-1043	-254
D	9 Reference (Combined Cycle,	2005	0	0	4430	0	0	925	Reference	No	No	-997	0	0	0	20
	Purchased Power, Coal)	2020	0	5775	8520	0	0	1225	Reference	No	No	-517	0	0	0	-620
E	10 Max "Customer Value Index" (Off-	2005	0	2978	2700	0	0	0	Reference	0.3%	No	-997	1000	180	167	203
	Sys Sales, High BE, Declining Blk)	2020	0	10388	5850	162	0	0	Reference	0.3%	No	-517	0	71	169	-313
F	11 Low TRC/High DSM	2005	0	300	2250	0	0	0	Reference	0.3%	No	-3169	0	0	0	-302
		2020	0	7230	5550	162	1500	0	Reference	0.3%	No	-1480	0	0	0	-468
G	12 Maximum Sales	2005	0	878	5820	0	0	0	Reference	0.3%	No	-1	1000	180	0	461
		2020	0	5498	9242	1173	0	0	Reference	0.3%	No	0	0	71	0	-341
H	16 Maximum Capacity Diversity	2005	0	0	3380	1011	60	775	Reference	1.3%	No	-999	0	62	0	95
		2020	0	4620	5410	2185	1740	925	Reference	1.3%	No	-517	0	25	0	-701
I	18 Bellefonte Nuclear Partnership	2005	600	0	3960	0	0	775	Reference	1.3%	No	-998	0	0	0	55
		2020	600	5775	8050	0	0	1075	Reference	1.3%	No	-516	0	0	0	-542
J	20 Bellefonte Coproduct and	2005	0	484	2550	0	750	1650	Reference	0.3%	No	-998	0	0	0	318
	Renewables	2020	0	6994	5850	162	1500	1950	Reference	0.3%	No	-517	0	0	0	230
K	23 Defer and Build BFN 1 & WBN 2	2005	1170	0	3510	0	0	775	Reference	No	No	-997	0	0	0	-323
	with Reference Expansion	2020	2235	5355	6810	0	0	775	Reference	No	No	-517	0	0	0	-799
L	24 Minimize CO_2 with Less DSM	2005	0	-1931	5110	0	740	0	Repowering	1.3%	Yes	-2048	0	0	0	144
		2020	0	-1931	12770	162	2840	0	Repowering	1.3%	Yes	-958	0	0	0	-1191
M	28 Combined DSM and	2005	0	1778	2400	0	0	0	Reference	0.3%	No	-2047	1000	0	0	188
	Off-Sys Sales	2020	0	7553	5550	162	1500	0	Reference	0.3%	No	-957	0	0	0	-317
N	29 Decentralized Generation with	2005	0	0	3960	160	0	775	Reference	No	No	-998	0	0	0	39
	More Renewables	2020	0	0	10860	160	1900	925	Reference	No	No	-517	0	0	0	-1596
O	32 Bellefonte Coproduct, More DSM,	2005	0	484	2550	0	500	900	Reference	0.3%	No	-2049	1000	0	0	428
	and More Off-Sys Sales	2020	0	6994	5700	162	1500	1050	Reference	0.3%	No	-958	0	0	0	263
P	34 Low-Cost Renewables,	2005	0	-1931	6105	0	740	300	Repowering	0.3%	Yes	-998	0	0	0	203
	Low-Price DSM, Repowering	2020	0	207	11025	1174	2090	450	Repowering	0.3%	Yes	-517	0	0	0	-771
Q	39 Flexible Strategy with	2005	0	484	900	0	1000	3289	Reference	0.3%	No	-999	1000	62	0	648
	External Options	2020	0	8149	4800	162	1500	1489	Reference	0.3%	No	-517	0	25	0	402
R	40 Flexible Strategy with	2005	0	484	2570	0	1000	1489	Reference	0.3%	No	-999	1000	62	0	583
	Internal Options	2020	0	8149	5420	162	1500	1489	Reference	0.3%	No	-517	0	25	0	454
S	41 Low Cost, Low Rates,	2005	0	484	2850	0	1250	1050	Reference	0.3%	No	-999	1000	62	0	493
	Improved Environment	2020	0	7414	5850	162	1500	1050	Reference	0.3%	No	-517	0	25	0	369
T	44 Low-Cost Renew, Low-Price DSM,	2005	0	-1447	6225	0	0	450	Repowering	0.3%	Yes	-998	0	0	0	390
	Repowering, BLN Coproduct Part	2020	0	691	10750	1174	2500	450	Repowering	0.3%	Yes	-517	0	0	0	-55
U	45 Low-Cost Renewables, More DSM,	2005	0	-1447	5145	0	0	300	Repowering	0.3%	Yes	-2048	0	0	0	252
	Repowering, BLN Coproduct Part	2020	0	691	10750	1174	2100	450	Repowering	0.3%	Yes	-957	0	0	0	-12

Notes:
1. The reference strategy, cancel BLN 1 & BLN 2, defer and cancel WBN 2 and BFN 1 with a CC, IPP, coal expansion with low-price DSM provides common point for trade-off plots.
2. Reference clean air strategy is scrub Paradise Unit 3 and Allen Units 1-3 with various fuel switches.
3. Repowering clean air strategy is natural gas combined cycle repowering of Johnsonville and Allen units.
4. Fuel switching clean air strategy is switch to low sulfur coal at most plants and switch to natural gas at Allen.
5. Renewables include solar, wind, short rotation woody crops (SRWC), refuse-derived fuel (RDF), and methane options.
6. Off-system sales begin in 1996 and end in 2004.
7. Strategies 3 and 12 contain additional transmission system capital and efficiency improvements.

This table details the final strategies that were evaluated to develop TVA's portfolio of resource options.

TRANSMISSION	CAPACITY AND ENERGY BY FUEL TYPE											
Transmission Improvements	Nuclear (MW)	Nuclear (GWH)	Coal (MW)	Coal (GWH)	Natural Gas (MW)	Natural Gas (GWH)	Hydro & Storage (MW)	Hydro & Storage (GWH)	Renewables (MW)	Renewables (GWH)	Purchased Power (MW)	Purchased Power (GWH)
	5577	30171	14968	96212	2292	1009	5498	19268	0	0	1800	-
	5577	32414	14968	100654	2292	1403	5498	20780	740	5898.5	1000	
		(CF)		(CF)		(CF)		(CF)		(CF)		(CF)
Yes	5577	67.1%	13037	84.2%	6987	20.7%	5498	42.4%	0	0	1800	3.4%
Yes	5577	67.1%	13037	85.1%	16717	39.5%	5660	42.1%	0	0	1000	0.7%
Yes	5577	67.1%	13037	82.9%	6057	16.1%	5498	42.4%	740	91.0%	1800	4.0
Yes	5577	67.1%	13037	85.0%	14442	34.2%	5660	42.1%	3040	69.4%	1000	0.3%
No	5577	67.1%	17346	80.4%	4692	11.5%	5498	42.4%	0	0	1800	7.5%
No	5577	67.1%	24021	78.9%	7692	9.6%	5660	42.1%	0	0	1000	1.0%
No	5577	67.1%	14968	82.7%	6722	13.0%	5498	42.4%	0	0	2725	25.8%
No	5577	67.1%	20743	82.2%	10812	11.1%	5498	43.3%	0	0	2225	35.1%
No	5577	67.1%	17946	77.8%	4992	7.7%	5498	42.4%	0	0	1800	4.7%
No	5577	67.1%	25356	74.6%	8142	5.8%	5660	42.1%	0	0	1000	0.8%
No	5577	67.1%	15268	78.4%	4542	7.4%	5498	42.4%	0	0	1800	5.2%
No	5577	67.1%	22198	75.0%	7842	6.0%	5660	42.1%	1500	94.1%	1000	0.7%
Yes	5577	67.1%	15846	83.4%	8112	19.4%	5498	42.4%	0	0	1800	3.9%
Yes	5577	67.1%	20466	83.9%	11534	17.4%	6671	42.2%	0	0	1000	0
No	5577	67.1%	14968	83.6%	5672	12.8%	6509	41.0%	60	87.7%	2575	25.6%
No	5577	67.1%	19588	84.1%	7702	11.7%	7683	41.1%	1740	28.7%	1925	32.5%
No	6177	67.9%	14968	81.5%	6252	11.5%	5498	42.4%	0	0	2575	23.8%
No	6177	67.9%	20743	81.4%	10342	10.5%	5498	43.3%	0	0	2075	32.6%
No	5577	67.1%	15452	81.3%	4842	5.9%	5498	42.4%	750	94.1%	3450	17.4%
No	5577	67.1%	21962	78.7%	8142	5.3%	5660	42.1%	1500	94.1%	2950	15.4%
No	6747	63.7%	14968	79.8%	5802	9.0%	5498	42.4%	0	0	2575	21.9%
No	7812	67.1%	20323	79.1%	9102	9.3%	5498	43.3%	0	0	1775	29.1%
No	5577	67.1%	13037	84.3%	7402	22.7%	5498	42.4%	740	91.0%	1800	5.2%
No	5577	67.1%	13037	85.0%	15062	35.3%	5660	42.1%	2840	71.9%	1000	0
No	5577	67.1%	16746	77.9%	4692	7.1%	5498	42.4%	0	0	1800	4.6%
No	5577	67.1%	22521	75.6%	7842	6.7%	5660	42.1%	1500	94.1%	1000	0.9%
No	5577	67.1%	14968	82.6%	6252	13.8%	5658	43.0%	0	0	2575	25.1%
No	5577	67.1%	14968	84.7%	13152	30.0%	5658	44.3%	1900	59.1%	1925	30.0%
No	5577	67.1%	15452	80.6%	4842	6.8%	5498	42.4%	500	94.1%	2700	13.4%
No	5577	67.1%	21962	78.1%	7992	6.5%	5660	42.1%	1500	94.1%	2050	12.7%
No	5577	67.1%	13037	84.5%	8397	24.0%	5498	42.4%	740	91.0%	2100	17.3%
No	5577	67.1%	15175	84.8%	13317	28.0%	6672	43.4%	2090	75.1%	1450	26.7%
No	5577	67.1%	15452	81.4%	3192	5.2%	5498	42.4%	1000	94.1%	5089	16.7%
No	5577	67.1%	23117	76.4%	7092	6.7%	5660	42.1%	1500	94.1%	2489	7.2%
No	5577	67.1%	15452	81.4%	4862	8.1%	5498	42.4%	1000	94.1%	3289	17.3%
No	5577	67.1%	23117	76.5%	7712	6.4%	5660	42.1%	1500	94.1%	2489	6.9%
No	5577	67.1%	15452	80.6%	5142	7.0%	5498	42.4%	1250	94.1%	2850	15.3%
No	5577	67.1%	22382	78.1%	8142	6.7%	5660	42.1%	1500	94.1%	2050	13.0%
No	5577	67.1%	13521	84.7%	8517	26.9%	5498	42.4%	0	0	2250	19.7%
No	5577	67.1%	15659	84.8%	13042	27.7%	6672	43.3%	2500	69.0%	1450	26.5%
No	5577	67.1%	13521	84.6%	7437	23.6%	5498	42.4%	0	0	2100	15.1%
No	5577	67.1%	15659	84.8%	13042	26.9%	6672	43.3%	2100	76.2%	1450	26.6%

RANKING OF OPTIONS

Following is a set of tables showing the ranking of supply-side and customer service options for Energy Vision 2020. The rankings of these options are used to help create the strategies, as shown in the Strategy Matrices *(Figures T8-1* through *T8-3)*.

Figures T8-4 through *T8-12* show supply-side options, and *Figures T8-13* through *T8-18* show customer service options. The options are ranked by several key criteria. The criteria used are total resource costs, rate impact measure (RIM), customer value, average short-term rates, average mid-term rates, debt, and environmental characteristics.

All of the options were standardized in the supply-side and customer service options ranking. In the supply-side ranking, the capacity for base and peaking options was standardized to 500 megawatts and 250 megawatts, respectively. In addition, the construction lead time, if greater than seven years, was adjusted to seven years. One unit of either base or peaking was allowed to come on-line in the year 2001. All other system expansion was completed with pulverized coal and combustion turbine plants.

Customer service options were developed in a similar manner. For purposes of ranking, all customer service blocks were standardized at 250 megawatts. Penetration of a customer service block began in the year 1995 and full penetration (250 megawatts) was completed in the year 2005.

This methodology provides a comparison of supply-side and customer service options on an equal basis. However, the ranking results are not comparable to other expansion results in Energy Vision 2020.

The boldface column on each ranking table provides a frame of reference for purposes of comparison among tables.

FIGURE T8-4. **Bellefonte Repowering Options**

Option	Fuel Type	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020 SO_2 (Tons)	NO_x (Tons)	CO_2 (KTons)
BLN Repowering - IGCC Coproduction w/ Partners (2x242 MW)	Syn-Gas	86173	51.1	1287	44.8	49.3	30864	34090	521457	437186	139332
BLN Repowering - IGCC Demo w/ Partners (1x250 MW)	Syn-Gas	86460	51.2	1063	44.7	49.3	30572	33812	522020	437360	139053
BLN Repowering - IGCC with Coproduction (11x229 MW)	Coal-Gas	87417	51.7	165	45.0	49.9	31382	34396	520462	436568	139978
BLN Repowering - CC (10x222 MW)	Natural Gas	88158	52.1	-378	44.8	50.3	30478	33326	538600	442571	138940
BLN Repowering - Phased CC/IGCC-Phase A-CC (9x222 MW)	Coal-Gas	88218	52.1	-464	44.9	50.4	30799	33548	529762	439567	138753
BLN Repowering - IGCC (9x250 MW)	Coal-Gas	88241	52.1	-508	45.0	50.4	31011	33744	520248	437839	138586
Supercritical PC Plant (4x300 MW)	**Coal**	**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
BLN Repowering - PC (4x616 MW)	Coal	88317	52.2	-569	44.9	50.4	30853	33837	523942	438145	138931

Acronym Key:

BLN Bellefonte Nuclear Plant
CC Natural Gas Combined Cycle
IGCC Integrated Gasification Combined Cycle
PC Pulverized Coal
CO_2 Carbon Dioxide
K Thousands
M Millions
MW Megawatts
MWh Megawatt-Hours
NO_X Nitrogen Oxides
RIM Rate Impact Measure
SO_2 Sulfur Dioxide

FIGURE T8-5. **Supply Option Comparison (Base Category / Coal Only)**

Option	Fuel Type	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020 SO_2 (Tons)	NO_x (Tons)	CO_2 (KTons)
Shawnee Unit 11 (1x168 MW)	Coal	88137	52.1	-363	44.8	50.3	30544	33400	538592	448260	139224
Partially Completed PC Plant (1x710 MW)	Coal	88147	52.1	-389	44.8	50.3	30732	33584	525128	437768	139082
Advanced PFBC - No Development Cost (1x300 MW)	Coal	88232	52.2	-538	44.9	50.5	30879	33682	524977	437396	138291
State-of-the-Art PC Plant (1x400 MW)	Coal	88242	52.1	-502	44.9	50.4	31029	33910	520914	436690	138526
Supercritical PC Plant (4x300 MW)	**Coal**	**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
Restart of WBF (1x56 MW)	Coal	88301	52.1	-498	44.8	50.4	30538	33425	542777	447129	139444
Supercritical PC Plant (4x300 MW)	Coal	88303	52.2	-562	44.9	50.4	30980	33874	524141	438198	139054
Advanced PFBC - w/ Development Cost (1x300 MW)	Coal	88316	52.2	-640	44.9	50.6	31030	33779	524359	437180	138198
Unit Power Purchase-15 Year	Coal	88325	52.2	-546	44.7	50.4	30220	33181	533915	443556	138952
Circulating AFBC (1x200 MW)	Coal	88331	52.2	-591	44.9	50.5	31022	33909	523172	437370	138974
First Generation PFBC (1x340 MW)	Coal	88334	52.2	-568	44.9	50.4	30915	33880	523486	437426	138487
AFBC Repowering, Generic (1x125 MW)	Coal	88344	52.2	-619	45.0	50.5	31441	34150	502340	430923	138665
Supercritical PC Plant (1x300 MW)	Coal	88360	52.2	-626	44.9	50.5	31092	33977	524220	437414	138840
First Generation PFBC Repowering (1x156 MW)	Coal	88395	52.2	-667	45.0	50.5	31471	34183	501609	430616	138078
NUG - Generic IPP Lignite CFBC (1x300 MW)	Coal	88429	52.2	-672	44.7	50.7	30182	33159	528976	440190	139098
Lignite-Fired CFBC (1x200 MW)	Coal	88513	52.3	-750	44.9	50.6	31113	34004	537571	442027	139050
NUG - Generic IPP PC w/ Cogeneration (2x170 MW)	Coal	88614	52.3	-780	44.7	50.7	30182	33080	522594	437188	138766
Generic PFBC Cogeneration (1x70 MW)	Coal	89708	52.9	-1728	44.7	51.4	29945	32688	522164	436896	137064

Acronym Key:

AFBC	Atmospheric Fluidized Bed Combustion	NUG	Non-Utility Generation	CO_2	Carbon Dioxide	MWh	Megawatt-Hours
CFBC	Circulating Fluidized Bed Combustion	PC	Pulverized Coal	K	Thousands	NO_X	Nitrogen Oxides
IPP	Independent Power Producer	PFBC	Pressurized Fluidized Bed Combustion	M	Millions	RIM	Rate Impact Measure
		WBF	Watts Bar Fossil Plant	MW	Megawatts	SO_2	Sulfur Dioxide

FIGURE T8-6. Supply Option Comparison (Base Category / Coal-Gas Only)

Option	Fuel Type	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020 SO_2 (Tons)	NO_x (Tons)	CO_2 (KTons)
Coal Refinery/ IGCHAT, Greenfield (1x530 MW)	Coal-Gas	86778	51.4	688	45.1	49.5	31822	34583	520817	437042	139173
Coal Refinery/IGCC, Greenfield (1x530 MW)	Coal-Gas	86881	51.5	581	45.1	49.6	31934	34730	520747	437046	139067
IGCC w/ Coproduction, Greenfield (1x498 MW)	Coal-Gas	87527	51.8	24	45.1	50.0	31609	34506	520424	437379	139462
IGCHAT w/ Coproduction, Greenfield (1x598 MW)	Coal-Gas	87590	51.8	0	45.0	50.0	31386	34336	520567	437361	139258
IGCHAT w/ Coproduction, F-CT (2x203 MW)	Coal-Gas	87638	51.8	25	45.0	49.9	31338	34273	520592	436206	139776
IGCHAT w/ Coproduction, G-CT (2x420 MW)	Coal-Gas	87790	51.9	-96	44.9	50.0	31211	34032	521038	436376	139672
IGCC w/ Fertilizer Coproduction (3x227 MW)	Coal-Gas	87910	52.0	-238	45.0	50.2	31454	34282	520600	436519	138632
IGCHAT, G-CT (2x420 MW)	Coal-Gas	88138	52.1	-396	44.9	50.3	30856	33679	520295	436050	138591
Coalbed Methane (1x2 MW)	Coal-Gas	88141	52.1	-355	44.7	50.3	30846	33743	518427	437149	137012
IGCHAT, F-CT (2x303 MW)	Coal-Gas	88189	52.1	-449	44.9	50.4	30922	33686	520335	436063	138708
Partnered IGCC w/Coproduction, Greenfield (1x530MW)	Coal-Gas	88193	52.1	-421	44.8	50.4	30550	33318	538769	442732	138934
IGCC (3x245 MW)	Coal-Gas	88237	52.1	-507	44.9	50.4	31023	33900	520107	436280	138182
Supercritical PC Plant (4x300 MW)	**Coal**	**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
NUG-Generic IPP IGCC (1x110 MW)	Coal-Gas	88990	52.5	-1104	44.6	50.9	29927	32988	538026	442356	138404
Coal-Gas - Repowering / Conversion Options											
Repower ALF w/ IGCC (1x500 MW)	Coal-Gas	88364	52.2	-549	44.9	50.4	30919	33749	520946	436546	138459
Repower WBF w/ IGCC (1x242 MW)	Coal-Gas	88497	52.2	-675	44.9	50.5	31039	33828	520628	436447	138561
Repower JOF 1-6 w/ IGCC (1x242 MW)	Coal-Gas	88549	52.3	-747	45.0	50.6	31312	34027	508182	432744	138203
Repower JOF 7-10 w/ IGCC (1x250 MW)	Coal-Gas	88590	52.3	-764	45.1	50.6	31262	33982	505874	432131	138026

Acronym Key:

ALF	Allen Fossil Plant	IGCC	Integrated Gasification Combined Cycle	PC	Pulverized Coal	MWh	Megawatt-Hours
CC	Natural Gas Combined Cycle	IGCHAT	Integrated Gasification Cascaded Humidified Advanced Turbine	WBF	Watts Bar Fossil Plant	NO_X	Nitrogen Oxides
CHAT	Cascaded Humidified Advanced Turbine	IPP	Independent Power Producer	CO_2	Carbon Dioxide	RIM	Rate Impact Measure
CT	Combustion Turbine	JOF	Johnsonville Fossil Plant	K	Thousands	SO_2	Sulfur Dioxide
F	F-Series	NUG	Non-Utility Generation	M	Millions		
G	G-Series			MW	Megawatts		

FIGURE T8-7. **Supply Option Comparison (Base Category / Gas Only)**

Option	Fuel Type	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020 SO_2 (Tons)	NO_x (Tons)	CO_2 (KTons)
Landfill Methane (1x2 MW)	Methane	88087	52.0	-294	44.7	50.2	30846	33787	518472	437164	127369
CHAT, F-CT (1x288 MW)	Natural Gas	88158	52.1	-377	44.8	50.3	30508	33287	538942	442617	138931
CC (1x470 MW)	Natural Gas	88204	52.1	-429	44.8	50.4	30599	33492	538341	442587	138870
CC Repowering, Generic (1x425 MW)	Natural Gas	88213	52.1	-440	44.8	50.4	30776	33561	531387	440361	138712
Supercritical PC Plant (4x300 MW)	**Coal**	**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
Repower ALF w/ CC (1x705 MW)	Natural Gas	88301	52	-507	45	50	30725	33610	531197	428773	138666
NUG - Generic IPP CC (1x150 MW)	Natural Gas	88326	52.1	-511	44.7	50.4	30182	33212	538736	442762	138787
NUG - Generic IPP CC (2x260 MW)	Natural Gas	88330	52.2	-542	44.7	50.5	30182	33212	521829	437156	137280
Small CC (1x42 MW)	Natural Gas	88339	52.2	-563	44.8	50.5	30661	33586	538189	442805	138783
Repower JOF 7-10 w/ CC (1x465 MW)	Natural Gas	88344	52.2	-608	45.0	50.5	31331	34082	514674	434521	138661
Power Purchase - Base Load (1x300 MW)	Natural Gas	88449	52.2	-633	44.7	50.5	30182	33212	537802	442431	138720
Fuel Cell - MCFC or SOFC (1x2 MW)	Natural Gas	88684	52.3	-785	44.7	50.6	30867	34064	537059	442471	138373
Small Cogeneration CC (3x10 MW)	Natural Gas	89293	52.7	-1387	44.7	51.1	30485	33491	519502	438804	137040
Generic CC Cogeneration (2x210 MW)	Natural Gas	89580	52.8	-1587	44.6	51.2	29880	32901	518960	436333	136234

Acronym Key:

ALF	Allen Fossil Plant	MCFC	Molten Carbonate Fuel Cell	K	Thousands	RIM	Rate Impact Measure
CC	Natural Gas Combined Cycle	NUG	Non-Utility Generation	M	Millions	SO_2	Sulfur Dioxide
CHAT	Cascaded Humidified Advanced Turbine	PC	Pulverized Coal	MW	Megawatts		
IPP	Independent Power Producer	SOFC	Solid Oxide Fuel Cell	MWh	Megawatt-Hours		
JOF	Johnsonville Fossil Plant	CO_2	Carbon Dioxide	NO_X	Nitrogen Oxides		

FIGURE T8-8. Supply Option Comparison (Base Category / Nuclear Only)

Option	Fuel Type	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020 SO_2 (Tons)	NO_x (Tons)	CO_2 (KTons)
BLN - Partnership	Nuclear	88135	52.1	-382	44.7	50.4	30220	33050	522617	436943	136391
ALWR (1x1300 MW)	Nuclear	88258	52.2	-533	45.0	50.4	31222	33997	518890	435684	135874
Supercritical PC Plant (4x300 MW)	**Coal**	**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
Gas Turbine - Modular Helium Reactor (3x289 MW)	Nuclear	88348	52.2	-636	45.1	50.5	31362	34241	519552	435951	135939
BFN 1 Recovery w/ Fixed Cost (1x1065 MW)	Nuclear	88380	52.2	-622	45.0	50.4	30996	33868	523209	437234	136495
Recover BFN 1 (1X1065 MW)	Nuclear	88599	52.4	-863	45.1	50.6	31390	34111	522685	437121	136299
BLN 1&2 Cancellation	Nuclear	88266	52.2	-524	44.9	50.4	30942	33845	524181	437457	138943
BFN 1 Cancellation	Nuclear	88266	52.2	-524	44.9	50.4	30942	33845	524181	437457	138943
WBN 2 Cancellation	Nuclear	88266	52.2	-524	44.9	50.4	30942	33845	524181	437457	138943
Completion of BLN 2 (1x1212 MW)	Nuclear	88338	52.2	-560	44.9	50.3	31064	33886	523272	437236	136542
Completion of WBN 2 (1x1170 MW)	Nuclear	88533	52.3	-773	45.0	50.6	31232	34134	522943	437178	136357
Completion of BLN 1 (1x1212 MW)	Nuclear	88685	52.4	-896	45.1	50.4	31347	34000	523944	437570	136205

Acronym Key:

ALWR	Advanced Light Water Reactor	WBN 2	Watts Bar Nuclear Plant Unit 2	M	Millions	NO_x	Nitrogen Oxides
BFN 1	Browns Ferry Nuclear Plant Unit 1	CO_2	Carbon Dioxide	MW	Megawatts	RIM	Rate Impact Measure
BLN 1&2	Bellefonte Nuclear Plant Units 1&2	K	Thousands	MWh	Megawatt-Hours	SO_2	Sulfur Dioxide

FIGURE T8-9. Supply Option Comparison (Base Category / Renewables Only)

Option	Fuel Type	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020 SO_2 (Tons)	NO_x (Tons)	CO_2 (KTons)
RDF Companion Boiler - WBF (1x60 MW)	RDF	87268	51.6	350	45.0	49.7	31840	34488	521935	438327	136912
RDF Companion Boiler - Kingston (1x60 MW)	RDF	87268	51.6	350	45.0	49.7	31840	34488	521935	438327	136912
RDF - FBC Repower - WBF (1x56 MW)	RDF	87426	51.7	256	45.1	49.7	31956	34799	521528	438149	136835
RDF-Fired Stoker (1x40 MW)	RDF	87514	51.8	29	45.5	49.9	33601	36182	520247	437069	136718
Wind - 39M Variable Speed A Turbine (444x.45 MW)	Renewable	88265.7	52.2	-537	44.9	50.5	31131	34011	522088	436579	138356
Supercritical PC Plant (4x300 MW)	**Coal**	**88266.5**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
Wind - 33M Variable Speed A Turbine (285x.35 MW)	Renewable	88303	52.2	-575	44.9	50.5	31159	34031	521858	436496	138318
Biomass WTE Boiler (1x100 MW)	SRWC	88619	52.4	-855	44.9	50.7	30990	33884	537493	442477	137295
Large Solar-Photo - Fixed Flat Plate (1x50 MW)	Solar	88820	52.5	-1105	44.9	51.0	31558	34415	533805	440998	137525

Acronym Key:

A	Advanced	M	Meter	WBF	Watts Bar Fossil Plant	M	Millions	RIM	Rate Impact Measure
FBC	Fluidized Bed Combustion	PC	Pulverized Coal	WTE	Whole Tree Energy	MW	Megawatts	SO_2	Sulfur Dioxide
		Photo	Photovoltaic	CO_2	Carbon Dioxide	MWh	Megawatt-Hours		
		RDF	Refuse-Derived Fuel	K	Thousands	NO_x	Nitrogen Oxides		

FIGURE T8-10. Supply Option Comparison (Base Category / Hydro Only)

Option	Fuel Type	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020 SO_2 (Tons)	NO_x (Tons)	CO_2 (KTons)
NUG - Generic IPP Run of River Hydro (4x20 MW)	Renewable	88134	52.0	-343	44.7	50.3	30220	33098	536938	441964	138416
Hydro Modernization	Renewable	88394	52.2	-641	44.9	50.5	30902	33799	530570	439794	138793
Hydro - Existing Nonpower Projects (1x10 MW)	Renewable	88522	52.3	-805	45.0	50.7	31542	34275	520160	436025	138243
Hydro - Existing Projects (1x24 MW)	Renewable	88777	52.5	-1077	45.1	50.9	31783	34670	521280	436443	137992
Hydro - New Conventional Projects (1x65 MW)	Renewable	89431	52.9	-1805	45.4	51.6	32985	35382	518447	435504	137341

Acronym Key:
IPP Independent Power Producer; NUG Non-Utility Generation; CO_2 Carbon Dioxide; K Thousands; M Millions; MW Megawatts; MWh Megawatt-Hours; NO_X Nitrogen Oxides; RIM Rate Impact Measure; SO_2 Sulfur Dioxide

FIGURE T8-11. Supply Option Comparison (Peak Category / Gas Only)

Option	Fuel Type	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020 SO_2 (Tons)	NO_x (Tons)	CO_2 (KTons)
CHAT, G-CT (1x400 MW)	Natural Gas	88141	52.1	-362	44.7	50.3	30494	33322	538715	442532	138919
Water Spray Cooling CT Inlet Air	Natural Gas	88220	52.1	-474	44.9	50.4	30847	33721	524476	437570	139003
Intercooled Aeroderivative CT (1x125 MW)	Natural Gas	88256	52.2	-519	44.9	50.4	30975	33871	524211	437446	138914
Simple Cycle CT (1x150 MW)	Natural Gas	88266	52.2	-524	44.9	50.4	30942	33845	524181	437457	138943
Power Purchase - Peaking (1x300 MW)	Natural Gas	88277	52.2	-526	44.9	50.4	30838	33765	524166	437454	138947
New CT for Steam to DuPont (Johnsonville) (1x174 MW	Natural Gas	88337	52.2	-606	44.9	50.5	31107	33973	523683	437296	138886
Integrated Fuel Cell CT (1x2.5 MW)	Natural Gas	88502	52.3	-726	44.9	50.6	31231	34205	523572	437163	138661

Acronym Key:
CHAT Cascaded Humidified Advanced Turbine; CT Combustion Turbine; G G-Series; CO_2 Carbon Dioxide; K Thousands; M Millions; MW Megawatts; MWh Megawatt-Hours; NO_X Nitrogen Oxides; RIM Rate Impact Measure; SO_2 Sulfur Dioxide

FIGURE T8-12. Supply Option Comparison (Storage Options Comparison)

Option	Fuel Type	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020 SO_2 (Tons)	NO_X (Tons)	CO_2 (KTons)
Raccoon Mountain Modernization	Electricity	87891	51.9	-165	44.9	50.1	30994	33823	514655	434026	137708
Raccoon Mountain Addition	Electricity	88030	52.0	-328	45.0	50.3	31169	33922	514987	434183	137615
Advanced Battery (1x20 MW)	Coal	88050	52.0	-333	44.9	50.3	31023	33812	514347	433925	137542
SMES (1x500 MW)	Coal	88052	52.0	-341	44.9	50.3	31092	33882	514415	433964	137567
CAES w/ Recuperation (3x337 MW)	Natural Gas	88197	52.1	-466	44.9	50.4	30956	33753	523053	436994	138930
Inlet Air Precooling w/Storage (16x61 MW)	Natural Gas	88200	52.1	-457	44.9	50.4	30891	33615	524312	437574	138988
CAES w/ Humidification (3x337 MW)	Natural Gas	88206	52.1	-471	44.9	50.4	30943	33699	523890	437252	139007
IGCASH plus NGCASH (1x850 MW)	Natural Gas	88268	52.2	-532	44.9	50.4	31087	33982	518388	435435	138397
Lead Acid Battery (1x20 MW)	Electricity	88292	52.2	-554	44.9	50.5	31011	33901	524370	437513	138933
Rorex Creek Pump-Storage (3x292 MW)	Electricity	88316	52.2	-604	45.0	50.5	31135	33989	525653	437945	139052
Laurel Branch Pump-Storage (4x386 MW)	Electricity	88323	52.2	-611	45.0	50.5	31147	33999	525611	437932	139046
Reynolds Creek Pump-Storage (3x366 MW)	Electricity	88384	52.2	-680	45.0	50.6	31252	34078	525172	437783	138983
IGCASH (1x410 MW)	Coal / Gas	88401	52.2	-676	45.0	50.5	31251	34109	517682	435197	138814
NUG - Generic IPP Pump-Storage	Electricity	88569	52.3	-786	44.9	50.6	30838	33711	523328	437020	138497

Acronym Key:

CAES	Compressed Air Energy Storage	NUG	Non-Utility Generation	MW	Megawatts
IGCASH	Integrated Gasification Compressed Air Storage with Humidification	SMES	Superconducting Magnetic Energy Storage	MWh	Megawatt-Hours
IPP	Independent Power Producer	CO_2	Carbon Dioxide	NO_X	Nitrogen Oxides
NGCASH	Natural Gas Compressed Air Storage with Humidification	K	Thousands	RIM	Rate Impact Measure
		M	Millions	SO_2	Sulfur Dioxide

FIGURE T8-13. **Customer Service Options (Beneficial Electrification)**

Option	System Peak MW Impact	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020 SO_2 (Tons)	NO_X (Tons)	CO_2 (KTons)
Supercritical PC Plant (4 X 300 MW)		**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
Residential HVAC and Water Heating	110	88780	51.9	2571	44.8	50.3	30600	33524	535702	441408	139580
Process Melting	-71	88817	51.8	-450	44.9	50.4	31336	34043	526744	438231	140179
Cooking and Security Lighting	-22	88822	52.0	3179	44.9	50.5	31304	34209	523538	437094	139696
Process Heating and Melting	-78	88872	51.8	-457	44.9	50.5	31343	34048	526517	438161	140155
Electrotechnologies/ Textiles	-2	89060	51.9	-145	45.0	50.5	31353	34189	525578	437855	140090
Security Lighting and Lawn Mowers	0	89124	51.9	-494	44.9	50.4	30983	33800	529809	439384	139651
Electrotechnologies/ Food Processing	-47	89139	51.8	-457	44.9	50.4	31337	34043	526741	438230	140179
Electrotechnologies/ Chemicals & Metals	-5	89239	51.8	-458	44.9	50.5	31348	34184	526016	437996	140141
Curing & Drying	-16	89511	51.8	-241	44.9	50.5	31347	34052	526334	438102	140130
Environmental Technologies	-29	89802	51.8	-475	44.9	50.5	31345	34049	526461	438147	140149
Fleet Vehicles	0	89933	52.0	-140	45.0	50.6	31016	33782	530207	439499	139572
Space Conditioning and Water Heating	-19	91311	51.5	14265	45.2	50.7	31258	34174	534849	440960	141249
Electric Buses	0	92036	52.0	2685	44.9	50.4	30979	33795	529656	439336	139644
Electric Autos	0	93145	52.0	6689	44.9	50.5	31010	33776	530307	439532	139593

Acronym Key:

CT	Combustion Turbine	MW	Megawatts
CO_2	Carbon Dioxide	MWh	Megawatt-Hours
HVAC	Heating, Ventilation, Air Conditioning	NO_X	Nitrogen Oxides
K	Thousands	RIM	Rate Impact Measure
M	Millions	SO_2	Sulfur Dioxide

FIGURE T8-14. Customer Service Options (Commercial Sector)

Option	System Peak MW Impact	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020 SO_2 (Tons)	NO_X (Tons)	CO_2 (KTons)
Energy Efficient Rates	53	87935	52.7	-1040	45.0	50.6	30600	33508	521306	436510	137385
Water Heating Conversion	27	87950	52.4	-645	44.8	50.4	30590	33597	527044	438430	138233
Commercial Lighting Rebates	417	87980	52.5	-698	44.9	50.5	30593	33502	524854	437685	137798
Comprehensive Measure Financing	105	88029	52.4	-638	44.8	50.4	30591	33280	527894	438762	138033
Comprehensive Appliance Rebates	57	88074	52.5	-648	44.9	50.5	30597	33506	525191	437797	137853
Comprehensive Measure Rebates	190	88109	52.4	-569	44.9	50.5	30596	[illegible]38	527913	438783	137993
Commercial New Construction	124	88130	52.5	-672	44.9	50.5	30598	33286	527515	438670	138016
Small Commercial Retrofit-Direct Install	122	88147	52.5	-695	45.0	50.5	30660	33707	525374	437805	138003
Commercial New Construction-Renewables	23	88183	52.4	-563	44.8	50.4	30595	33283	527671	438685	138000
Commercial Cool Storage	57	88238	52.1	-883	44.8	50.4	30596	33155	534000	440930	139002
Commercial HVAC Rebates	133	88256	52.4	-608	44.9	50.5	30566	33322	529300	439282	138227
Supercritical PC Plant (4 X 300 MW)		**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
Rooftop Cool Storage	70	88275	52.1	-474	44.8	50.3	30597	33156	533986	440920	138997
Small Commercial HVAC Maintenance Program	14	88395	52.3	314	44.8	50.3	30590	33002	529664	439388	138204

Acronym Key:
CT Combustion Turbine
HVAC Heating, Ventilation, Air Conditioning
CO_2 Carbon Dioxide
K Thousands
M Millions
MW Megawatts
MWh Megawatt-Hours
NO_X Nitrogen Oxides
RIM Rate Impact Measure
SO_2 Sulfur Dioxide

FIGURE T8-15. Customer Service Options (Industrial Sector)

Option	System Peak MW Impact	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020 SO_2 (Tons)	NO_X (Tons)	CO_2 (KTons)
Industrial Tech Rebates - HE Motors	11	87819	52.6	-803	44.9	50.5	30594	33361	523008	437050	137429
Industrial Tech Rebates - AS Drives	4	87969	52.7	-967	45.0	50.6	30569	33179	522697	436968	137169
Industrial Process EE - Distributor Served	110	88037	52.7	-774	44.9	50.5	30561	33171	523051	437055	137186
Industrial Process EE - Direct Served	98	88049	52.7	-776	44.9	50.5	30562	33171	523011	437043	137180
Supercritical PC Plant (4 X 300 MW)		**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
Industrial Tech Rebates - CA Efficiency	3	88356	52.7	-893	45.1	50.7	30515	33443	522273	436820	137311

Acronym Key:
AS Adjustable Speed
CA Compressed Air
CT Combustion Turbine
EE Energy Efficiency
HE High Efficiency
Tech Technology
CO_2 Carbon Dioxide
K Thousands
M Millions
MW Megawatts
MWh Megawatt-Hours
NO_X Nitrogen Oxides
RIM Rate Impact Measure
SO_2 Sulfur Dioxide

FIGURE T8-16. **Customer Service Options (Residential Sector)**

Option	System Peak MW Impact	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020		
									SO_2 (Tons)	NO_X (Tons)	CO_2 (KTons)
Res Water Heater Conversion Program	89	87725	52.8	-610	44.9	50.6	30594	33556	519719	435940	137147
Res Refrigerator Turn-in	18	87834	52.9	-828	45.2	50.6	30516	33773	521465	436542	137386
Res Heat Pump Water Heater Leasing	88	87855	52.8	-2661	44.9	50.6	30556	33313	520491	436216	136960
Res Efficiency Products Catalog	99	87864	52.6	-582	44.9	50.5	30590	33596	523229	437142	137720
Res New Homes	121	87889	52.6	-649	44.9	50.5	30594	33283	524254	437503	137494
Res Lighting Retail Component	75	87892	52.5	-659	44.8	50.5	30592	33359	524547	437571	137621
Res Heat Pump Leasing	334	87931	52.3	-735	44.8	50.4	30590	33358	528759	439077	138249
Res Low Income	66	87935	52.6	-593	45.0	50.6	30596	33505	523160	437136	137608
Res Direct Install	386	87937	52.6	-585	45.0	50.6	30595	33649	522999	437069	137746
Res Heat Pump Rebates	305	87969	52.4	-415	44.8	50.4	30592	33134	528956	439143	138159
Res Self-Audit	22	87995	52.5	-988	44.9	50.5	30593	33646	523753	437296	137905
Res Student Self-Audit	22	88042	52.6	-1010	44.9	50.5	30606	33515	524314	437524	137691
Res Ground Source Heat Pump Leasing	19	88061	52.3	-1934	44.8	50.3	30558	32618	531340	440046	137928
Res Heat Pump Loans	317	88079	52.3	-477	44.8	50.4	30592	33229	529434	439304	138353
Res Efficient Air Conditioning	85	88131	52.2	-436	44.8	50.4	30595	33283	530994	439848	138588
Res Appliance Rebates	26	88230	52.9	-999	45.2	50.9	30560	33338	522149	436717	136873
Supercritical PC Plant (4 X 300 MW)		**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**

Acronym Key:

CT	Combustion Turbine	K	Thousands	MWh	Megawatt-Hours	SO_2	Sulfur Dioxide
Res	Residential	M	Millions	NO_X	Nitrogen Oxides		
CO_2	Carbon Dioxide	MW	Megawatts	RIM	Rate Impact Measure		

FIGURE T8-17. Customer Service Options (Load Management Programs)

Option	System Peak MW Impact	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020 SO_2 (Tons)	NO_X (Tons)	CO_2 (KTons)
Commercial Group Load Curtailment	173	88096	52.2	-446	44.8	50.4	30589	33226	532452	440356	138799
Res Load Management - Air Conditioners	54	88179	52.2	-539	44.8	50.4	30591	33645	530137	439487	138812
Supercritical PC Plant (4 X 300 MW)		**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
Res Load Management w/ SCADA	32	88294	52.2	-681	44.9	50.6	30746	34077	527879	438532	138745
Res Load Management - Water Heaters	86	88328	52.2	-674	44.9	50.5	30592	33555	530515	439642	138780
Flexible Load Managed Water Heater Program	86	88378	52.2	-656	44.9	50.5	30622	33581	531283	439866	138780
Res Load Management - Storage Water Heaters	41	88463	52.3	-791	45.0	50.6	30631	33590	530444	439604	138687
Res Load Management - New Technology	64	88474	52.3	-806	45.2	50.5	30840	34169	527053	438305	138691

Acronym Key:

CT	Combustion Turbine	CO_2	Carbon Dioxide	MWh	Megawatt-Hours
Res	Residential	K	Thousands	NO_X	Nitrogen Oxides
SCADA	Supervisory Control and Data Acquisition Systems	M	Millions	RIM	Rate Impact Measure
		MW	Megawatts	SO_2	Sulfur Dioxide

FIGURE T8-18. **Customer Service Options (Miscellaneous Programs)**

Option	System Peak MW Impact	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020 SO_2 (Tons)	NO_X (Tons)	CO_2 (KTons)
Landfill Gas/ Fuel Cells	43	87544	52.6	-594	44.8	50.4	30553	33310	522179	436724	137086
Small Head Hydro	5	87717	52.7	-428	44.9	50.5	30591	33554	521513	436547	137435
Existing Cogeneration - Commercial	75	87842	52.5	-557	44.8	50.4	30588	33642	524667	437629	137965
Commercial Flexible Lighting Options	570	87963	52.5	-603	44.9	50.5	30592	33462	524997	437715	137862
New Cogeneration - Industrial	30	88031	52.6	-622	44.9	50.5	30588	33642	521910	436688	137596
Flexible Comprehensive Financing	224	88044	52.4	-536	44.8	50.4	30591	33279	527532	438632	137963
Flexible Group Load Curtailment	275	88161	52.2	-507	44.8	50.4	30589	33643	529877	439360	138792
New Cogeneration - Commercial	17	88193	52.4	-541	44.8	50.4	30589	33643	525770	438011	138129
Supercritical PC Plant (4 X 300 MW)		**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
Photovoltaics/ Technology Advancement	2	88610	52.3	378	44.8	50.4	30594	33152	530673	439760	138431
Photovoltaics	1	89099	52.3	1631	44.9	50.4	30603	33292	529929	439503	138375

Acronym Key:

CT	Combustion Turbine	M	Millions	NO_X	Nitrogen Oxides
CO_2	Carbon Dioxide	MW	Megawatts	RIM	Rate Impact Measure
K	Thousands	MWh	Megawatt-Hours	SO_2	Sulfur Dioxide

UNCERTAINTY IN THE RESOURCE PLAN

Summary

Energy resource plans being made today must account for the undeniable fact that the future will be unlike expectations of the future. If TVA knew the future state of the energy world, resource plans could be made simply to best meet various planning criteria. However, the future is uncertain. Resource plans must account for a range of possible future events. Plans must be flexible enough to change as certain key parameters change; also, they should be able to withstand shifts in the long-term parameters that drive electric utility operation.

UNCERTAINTY TREATMENT PROCESS

An exhaustive list of parameters that could vary in the future was identified through discussions in the Energy Vision 2020 Building Block teams, the Energy Vision 2020 Review Group, the Forecast Review Board, the Tennessee Valley Industrial Committee, Tennessee Valley Public Power Association, and environmental review groups; as well as reviews of other utility resource plans. Almost 50 individual items were identified as uncertain items to be explored in Energy Vision 2020.

Each uncertain item is described and a range of possible outcomes identified for the future. Since in Energy Vision 2020, TVA is evaluating its resource options for a number of planning criteria, variations in the item are needed for the different criteria. Four planning criteria are being used to represent the more extensive list. These are total resource costs, electric rates, carbon dioxide output, and debt.

RESULTS OF THE UNCERTAINTY REVIEW PROCESS

The evaluation of each uncertain item for the four planning criteria shows items that are most critical in future resource planning. They result in the largest variation from the mid-range forecast and thus should be considered further in the next, more detailed phase of the evaluation.

Issues that were found to be most sensitive include the following;

- Load Growth
- Nuclear Issues
  - Capacity Factor
  - Operations and Maintenance Cost
  - Capital Cost
- Environmental Issues
  - Carbon Dioxide Compliance
  - Air and Water Environmental Controls
- Price
  - Natural Gas
  - Revenue from Coproducts (Combined Cycle)

Issues for which selected sensitivity evaluation can be performed include the nuclear moratorium and the inability to site central station generating capacity.

Process to Represent Uncertainty in the Resource Plan

As stated previously, if TVA knew the future state of the energy world, resource plans could be made simply. Alternative actions would be chosen to meet the various planning criteria without risk.

The real world is, however, highly uncertain. When energy resource plans were being made for 1995 twenty years ago, innumerable factors about the energy world in 1995 were not known. Load growth was projected to double every seven years. Construction costs were projected to be stable with project construction lead times short; fuel prices were to remain relatively low. Of course, these projections were far from the actual experience. Neither the Public Utility Regulatory Policy Act, the National Energy Act of 1992, nor the pile of regulations brought on by such events as Three Mile Island existed. There were no regulations on sulfur dioxide emissions and other environmental issues. Forecasting twenty years into the future still remains highly speculative, yet planning resource capabilities requires a long-term outlook.

Resource plans must account for a range of possible future events. Plans should be sufficiently flexible to change as key parameters change, and they should, once implemented, be capable of withstanding shifts in the long-term parameters that drive electric utility operation (robustness).

FIGURE T8-19.
Normal Distribution

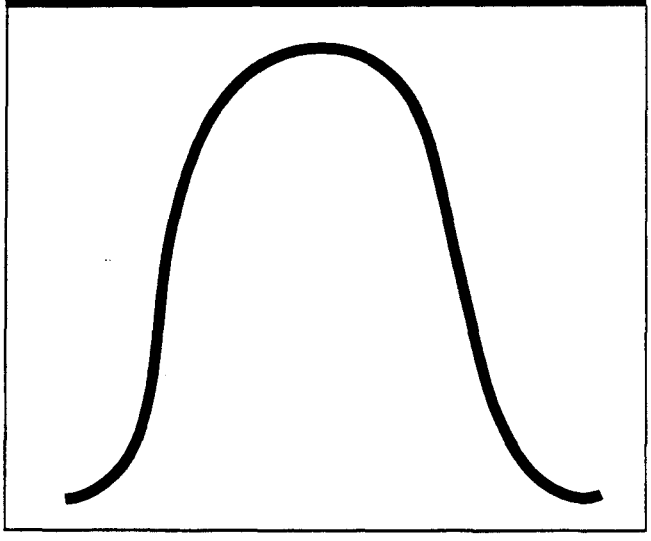
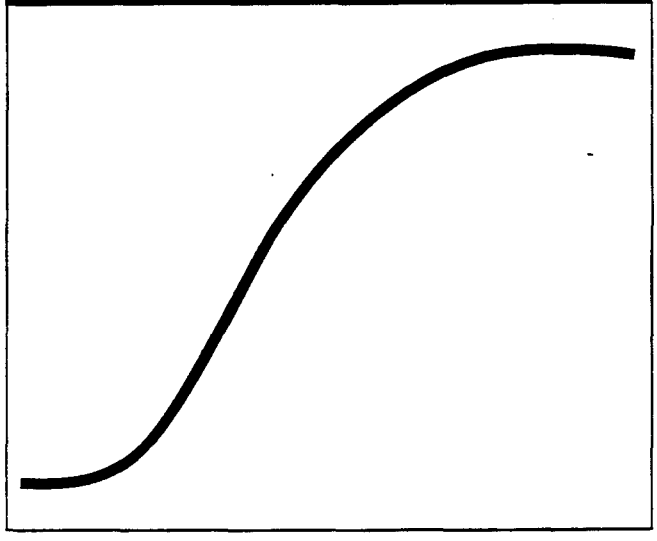


FIGURE T8-20.
Cumulative Distribution



Two important questions are: "What future events should be considered when making resource plans?" and "What future events, if known today, would change the plan significantly?" In the planning process, it is desirable to ensure that all parameters that can impact resource plan selection are sufficiently represented and considered.

Identification of numerous parameters that could vary in the future is the first step in the representation of uncertainty. An exhaustive list of parameters has been developed through discussions by the Energy Vision 2020 Building Block teams, the Forecast Review Board, and Energy Vision 2020 Review Group and in analyzing resource plans from many other utilities.

Each issue or parameter must be quantified so that its impact on resource plans can be evaluated. A wide range of future possibilities of the parameter was developed that typically is represented by a probability distribution as described in the following section.

An exhaustive resource evaluation would include every parameter that has been identified as an issue. This list of anywhere from 20 to 100 issues would be explored fully and all evaluations would consider their impacts.

Realistically and computationally, the number of parameters must be reduced to those that are significant to the decision at hand. In order to determine those uncertain parameters that can significantly impact a resource planning decision or actually change a decision, a sensitivity evaluation is performed on each parameter.

These sensitivity diagrams, sometimes referred to as "tornado" diagrams because of their shape, help to narrow the large number of uncertain issues to a much smaller, more manageable list.

Issues that can cause significant impacts on resource plan results are then used in the complete, detailed evaluation and integration of supply- and demand-side alternatives.

A Quantifiable Description of the Future

Given that the future is so uncertain, how can it be considered? In general, parameters can be described mathematically by a probability distribution. A probability distribution describes the likelihood of the value of a parameter. Typically, a "normal" distribution can be used to describe most uncertain parameters. *Figure T8-19* shows a normal distribution where the y-axis indicates the probability of the value that occurs on the x-axis.

A cumulative distribution can then be constructed that accumulates the probabilities and the values sum so that *Figure T8-19* becomes as shown in Figure *T8-20*. The y-axis accumulates to 1.0 (or 100 percent). The accumulated level represents that percentage of the values that are at least that large.

In order to utilize this information in a resource plan, it is necessary to determine discrete values that can be used to represent the distribution. Typically, 3 points on the cumulative probability distribution are chosen to represent the curve so that the points represent a value that has a 10 percent prob-

FIGURE T8-21. **Uncertainty Items from Sample IRPs**

Bonneville Power Administration
- Load Growth
- Salmon Migration
- System Operation
- Endangered Species Act
- Availability of Reserves
- Capacity from Neighbors (Contracted)
- Extreme Weather Impacts

Duke Power Company
- Load Growth
- Load Factor
- Coal Fuel Price Escalation
- Oil Fuel Price Escalation
- Capital Cost (Coal, Combustion Turbine, Combined Cycle)

Entergy
- Weather
- Mechanical Failures
- Customer Demand
- Inflation
- Fuel Prices (Gas & Oil)

Georgia Power Company
- Financial
- Environmental Cost
- Load Growth
- Fuel Cost
- Unit Cost

New England Electric System
- Load Growth
- Schedule Delays
- Conservation/Load Management Effectiveness
- Performance of Existing Facilities
- Schedule Delays of Cogeneration Sources
- Future Gas & Coal Prices
- Non-Utility Generator Siting/Licensing Problems
- Externalities

Niagara Mohawk Company
- Load Growth
- Economic Growth
- Fossil Fuel Prices
- Regulation
- Externalities
- Non-Utility Generators (NUGS)
- Demand-Side Management (DSM) Participation

Pacific Corporation
- Load Growth
- Electrification
- Loss of Resources
- High Gas Prices
- Carbon Dioxide Tax
- Environmental Externalities
- Renewable Resources
- Demand-Side Acquisition
- Plant Performance

Virginia Electric Power Company
- Economic Growth
- Load Growth
- Fossil Fuel Prices
- Regulation
- Price of Sulfur Allowance
- Demand-Side Effectiveness
- Plant Efficiency and Reliability

Wisconsin Power and Light Company
- Economy
- Fuel Price
- Fuel Availability
- Technologies

Uncertain parameters considered as issues by other electric utilities throughout the country are shown in this table.

ability of being that amount or less; a 50 percent probability of being that amount or less; and a 90 percent probability of being that amount or less.

These three points represent, respectively, approximately 25, 50, and 25 percent of the distribution.

There are numerous techniques available for developing these cumulative probability distributions. Such techniques include probability assessment interviews with experts, delphi techniques, and historical data.

Typical Uncertain Parameters in Integrated Resource Planning

Figure T8-21 shows parameters considered in sample integrated resource plans from electric utilities in the country over the past five years. Some issues, such as load growth and fuel cost, are fairly standard. Other issues may be regional, such as "Salmon Migration" an issue important in the Pacific Northwest. In this part of the country, it may be air quality in the Smoky Mountain National Park or mining restrictions for Appalachian coal.

FIGURE T8-22. **Example of Future Drivers in Utility Industry and How They Translate into Resource Planning Parameters**

DRIVERS (SAMPLES)	TRANSLATE INTO THIS UNCERTAIN PARAMETER
Environment	
• Continuing Increase in Controls	Cost of Existing Coal Availability of Existing Coal
• Local Requirements	Cost/Availability of Coal
Fuel Markets	
• Low-Cost Alternate Fuels	Low Fuel Price
• High Availability of Renewables	Low-Cost Renewable
• Reduced Availability of Gas/Oil	Gas Price
• Abundance of Gas/Oil	Gas Price
• Foreign Markets Develop for U.S. Coal	High Coal Price
Nuclear Industry	
• Public Acceptance, Good Performance, Relicense	Unit Availability Capacity Factor
• Increase Regulatory Requirements	Capacity Factor Schedule Delays Cost
• Moratorium on Nuclear Power	Unit Availability
Regulation	
• Fence Stays/Lose Anti-Cherry Picking	Lose Load
• Wholesale Deregulation	Gain/Lose Load
• Retail Deregulation	Gain/Lose Load
Technology	
• Breakthrough on: Fuel Cells, Combined Cycle, Fusion, Material	Capital Cost Operating Cost
• Transmission Breakthrough	Loss Reduction
• Telecommuting/Interactive Customers	Reduced Load
• Beneficial Electrification	Increased Load
• Cheap Natural Gas End Use	Reduced Load
Economic Activity	
• Cost Containment - Decentralize Work Force	Load Increase
• International Competition: Exports - Technology and Service	Load Increase
• International Competition: Imports Due to U.S. Regulation, High Wages, Declining Material Resources	Load Decrease
• Graying of Valley	Load Increase
Legislation	
• Reduce TVA Debt Ceiling to $15 Billion	Increased Rates
• TVA Chosen as Federal Showplace for Energy and Environment	Increased Load

Issues raised by various groups have been translated into quantifiable values for the resource evaluation.

Specific Uncertainty Building Block Results

The Energy Vision 2020 Uncertainty Building Block Team developed an exhaustive list of issues from previous meetings, other building blocks, and integrated resource plans. Each of these items has been described in this document and a range of outcomes developed. A set of key uncertainties is identified later in this document.

Figure T8-22 shows how the issues raised by various groups have been translated into quantifiable values for the resource evaluation. In the environmental area, for example, the continuing increase in controls on particular environmental emissions can translate into reduced availability of the generating plants, higher capital cost to continue to operate the plants, and increased operation and maintenance costs to operate the plants.

Exhaustive List of Uncertainties for Energy Vision 2020

Figure T8-23 shows the complete list of uncertain parameters that have been considered in Energy Vision 2020. These items are described briefly in the following section.

ISSUE 1: HYDROELECTRIC ENERGY

Energy supplied by the TVA-operated hydroelectric plants varies depending on weather and associated rainfall patterns in the Valley.

Historical TVA weather and rainfall data for almost 100 years has been modeled with the current TVA hydro system in place. While there are some hydro modernization projects underway, expected hydroelectric generating output is not expected to vary greatly because of it. The range of

FIGURE T8-23. Uncertainties in Resource Plan

ITEM	(UNITS)	RANGE Low	Medium	High
HYDRO ENERGY	(Billion kWh)	13	18 [1]	22
COAL				
Capital Additions & Improvements	($/kW/Year) (94$)	12.5	13.6 [1]	14.8
Operating & Maintenance Cost	($/kW/Year) (94$) (Escalation)	21.7 -2% Base	21.7 [1] -1% Base	21.7 +1% Base
Plant Life Extension	(MW)	No Retirements	No Retirements	750 MW Retired
Reliability of New Units	(Equivalent Forced Outage Rate)	6%	9% [1]	20%
Fuel Cost (5# Coal in 2000)	(¢/MBtu) (Escalation Rate)	100 2.8%	109 [1] 3.3%	121 4.0%
Fuel Cost Existing System	(¢/MBtu) (Escalation Rate)	119 3.0%	131 3.5%	146 4.1%
COMBINED CYCLE				
Market Price of Coproduct in 2000 for Integrated Gasification Combined Cycle	($/Ton)	91	262 [1]	320
Gas Cost (2000)	(¢/MBtu) (Escalation Rate)	256 2.4%	342 [1] 5.3%	418 7.9%
NUCLEAR				
Moratorium		Normal Operation	Normal Operation [1]	Units Do Not Operate after 2006
Return to Service/Commercial Operation Date		Base Schedule [1]	12-17 Month Delay	24-33 Month Delay
Capacity Factor	(%)	55	67 [1]	86
Operating Cost	($/kW/Year) (94$)	55	69 [1]	83
Fuel Cost	(¢/MBtu)	35	41 [1]	50
Spent Fuel Storage	($/MWh)	1.0	1.0 [1]	2.0
Capital - Additions & Improvements	($/kW/Year)	9	12 [1]	19
Capital Cost	(Billion $)			
	Bellefonte 1	1.3	2.6 [1]	3.5
	Bellefonte 2	0.9	1.8	2.4
	Watts Bar 2	1.2	2.4	3.2
	Browns Ferry 1	1.1	2.2	2.9
Browns Ferry License Extension		No Extension, Replace in 2013	Yes [1]	Yes
Summer Limits on Discharge Water Temperature		Lose 150 MW	No Impacts [1]	No Impacts
Decommissioning Cost	(Million $/Unit)	200	300 [1]	600
COGENERATION				
Cost	($/kW)	159	175 [1]	263
Availability	(MW)	1800	2000 [1]	N/A
TRANSMISSION				
Electromagnetic Field		No Additional Impacts [1]	+ $50 Million/Unit for New Site Central Generation	+ 50% Cost of Overall Transmission System
Transmission Limit Wheeling Requirements		Increased Reserve Margin for 1200 MW of Reduced TM Capability	Normal TM Capability [1]	Normal TM Capability

FIGURE T8-23 **Uncertainties in Resource Plan** *CONTINUED*

ITEM	(UNITS)	RANGE Low	Medium	High
PURCHASED POWER				
Quantity		1125 MW	1500 MW [1]	1875 MW
Price (2000)	(Escalation)	-2% Medium	56 $/MWh (6.5% Escalation)	+3% Medium
ENVIRONMENTAL QUALITY				
Carbon Dioxide Emission Cost		Voluntary Compliance No Additional Controls [1]	$5/Ton by 2002 above Limits	$5/Ton by 2002 and $10/Ton by 2010 above Limits
Sulfur Dioxide Allowance Price (2000)	($/Ton)	211	284 [1]	409
Air Quality Combined • Clean Air Capital Cost • Air Toxics • Visibility • Ozone		No Additional Controls [1]	• Low NO_x Controls at Cumberland and Gallatin • Reduced Hg by 2010 • SNCR by 2010	• Low NO_x Controls at Cumberland and Gallatin • Reduced Hg by 2002 • SNCR by 2002
Water Quality Combined • Thermal Plant Regulations • Aquatic Biota • Toxins • Water Flow Alteration • Toxics, Bioaccumulation, pH		No Additional Regulations [1]	• Cooling Towers at All Steam Plants in 2002 @ 130 $/kW (1994$)	• Cooling Towers and Additional Runoff Control @ 190 $/kW in 2002 (1994$)
LOAD REQUIREMENT				
Load Growth	(%) 1994-2000 2000-2020	0.0 0.0	2.2 [1] 1.9 [1]	3.4 3.2
Interruptible Load and Emergency Appeals (2000)	(MW)	700	1900 [1]	2560
Competition with Neighbors, Open Access, and Fence - Growth	(%) 1994-2000 2000-2020	0.9 1.0	2.2 [1] 1.9 [1]	2.1 2.2
SITING		No Restrictions [1]	No Central Station Options	No Central Station Options
DEMAND-SIDE MANAGEMENT EFFECTIVENESS	(MW) Savings in Year 2010	3124	5494 [1]	8219
NEW TECHNOLOGY COST		Reduce Cost 50%	Reference [1]	Reference
COMBUSTION TURBINE				
Reliability	(%)	68	84 [1]	90
Plant Life	(Years)	25 Years [1]	30 Years	30 years
Plant Efficiency	(Btu/kWh)	9,000	10,500 [1]	12,000
DISCOUNT/INTEREST RATE	(%)	6	8 [1]	12

[1] Indicates value in Energy Vision 2020 Reference

hydro generation over the 100-year period would indicate a 10 percent likelihood of the energy output being around 13 billion kilowatt-hours or less, and a 10 percent chance the energy output could be 22 billion kilowatt-hours or higher. The mid-range forecast of around 18 billion kilowatt-hours has a 50 percent chance of the output being lower or higher. While hydro variation may occur for several years at a time, it is less likely to remain consistently at a high or low level over the long term. Thus, this uncertainty is more significant to short-term plans of, say, five years or less.

Although not being treated explicitly, another scenario that could create a range of outcomes in long-term hydro generation is the TVA use and control of the Cumberland River Projects.

TVA could lose some of the Cumberland Projects due to license extension requirements. TVA could gain hydro output through negotiated control of additional segments of the river generating output operated by Southeastern Power Administration (SEPA).

ISSUE 2: COAL

Below are various uncertainties involving TVA's coal usage.

Issue 2.1: Capital Additions and Improvements for New Coal Capacity

Capital additions and improvements are betterments of plants. They are expected to have a long life and are therefore capitalized. In contrast, the cost of current repairs and minor replacement is charged to operating expense.

The medium estimate for a mature commercial supercritical pulverized coal plant (4 units of 300 megawatts each) is $13.6 per kilowatt per year. For the range of values, the low is $12.5 per kilowatt per year and the high is $14.8 per kilowatt per year (This is in 1994 dollars.)

Issue 2.2: Coal and Combined Cycle Operating and Maintenance Costs

Operating and maintenance costs for fossil units are divided into fixed and variable components. Variable operating and maintenance cost is the incremental cost of generation incurred only if the unit generates. Fixed operating and maintenance cost at an operating unit is incurred whether or not the unit operates. The mid-range of both the fixed and variable operating and maintenance costs escalate using standard TVA escalation with a 1 percent improvement (fiscal year 1999 to fiscal year 2020). The low case includes a 2 percent improvement, while the high case includes a 1 percent increase (fiscal year 1999 to fiscal year 2020). For the mid-range case, the fixed operating and maintenance cost is $21.7 per kilowatt per year of dependable capacity (in 1994 dollars) and the variable operating and maintenance cost is 0.39 mills per kilowatt-hour (based on 1994 dollars). The same base is used for both low and high, while the standard TVA escalation rate with a 2 percent annual improvement for the low, and a 1 percent annual increase in escalation is assumed for the high.

Issue 2.3: Plant Life Extension

Additions and improvements are made to the existing fossil units at a steady rate to ensure the units continue to operate into the future. One range of uncertainty would be a TVA decision to retire a coal facility that is low in the loading order. For purposes of illustration, the Widows Creek Units 1-6 were retired, representing 750 megawatts of capacity that must be replaced.

Issue 2.4: Reliability (Coal and Combined Cycle Units)

The reliability of a generating unit is a measure of the hours during a year that the unit is available to operate and includes the possible reduction in full unit output due to derating conditions. This excludes the time a unit is out for scheduled maintenance.

An unscheduled outage may be defined as a total loss of generation due to a failure of a component essential to unit operation. A derating is a failure of a component that may only reduce the amount of generation available from the unit. Reliability measure of equivalent forced outage rate is made up of these two factors.

The mid-range forecast is 9 percent; while the high is 20 percent, and the low is 6 percent.

Issue 2.5: Fuel Cost (Coal)

Fuel prices for coal facilities are based on FOB mine price projections combined with transportation rates to determine delivered price forecasts to each TVA stockpile. Delivered fuel price forecasts of three independent consultants have been averaged to obtain the TVA coal spot price forecast. These consultants are Energy Ventures Analysis, Inc., Hill and Associate, Inc., and J. D. Energy, Inc.

For a new coal facility at Tennessee River Mile 160 for a 5.0 pound sulfur dioxide per million Btu coal plant, the mid-range price projection (in 2000) is 109 cents per million Btu with a 3.3 percent escalation rate. The low forecast is projected to be 100 cents per million Btu with a 2.8 percent escalation. High projection is 121 cents per million Btu with 4.0 percent escalation.

For TVA's existing coal facilities, the mid-range price forecast is 131 cents per million Btu with a 3.5 percent escalation rate. The low forecast is 119 cents per million Btu (3.0 percent escalation), and the high forecast is 146 cents per million Btu (4.1 percent escalation).

FIGURE T8-24 **Range of Values for Coproduct**

Year	Low $/Ton	Medium $/Ton	High $/Ton
1995	82.7	237.4	290.0
1996	84.4	242.1	295.8
1997	86.0	247.0	301.8
1998	87.8	251.9	307.8
1999	89.5	256.9	314.0
2000	91.3	262.1	320.2
2001	96.0	282.3	352.9
2002	99.7	299.6	383.1
2003	103.3	318.0	416.1
2004	107.2	337.1	450.8
2005	109.0	351.4	481.0
2006	113.2	373.1	522.3
2007	116.9	394.6	564.5
2008	120.0	414.3	606.4
2009	124.4	439.2	657.6
2010	127.9	463.0	708.9
2011	133.8	495.6	775.3
2012	139.2	527.3	844.2
2013	143.3	555.2	909.0
2014	147.6	584.9	979.6
2015	151.1	613.5	1051.1
2016	155.1	643.6	1127.9
2017	158.1	673.0	1206.8
2018	161.4	702.6	1288.4
2019	163.8	729.9	1369.2
2020	166.4	758.7	1456.5

The viability of coal gasification combined cycle projects depends on the value of the coproducts. This chart shows the range of values for a byproduct of coal gasification.

Issue 2.6: Market Price of Coal Gasification – Combined Cycle Coproduct

Coal gasification technology is commercially utilized for producing synthesis gas for chemical applications including the production of ammonia, methanol, and methyl tertiary butyl ether (MTBE). The viability of coal gasification combined cycle projects depends on the value of the coproducts. Much of the gas produced is used up producing the coproduct, and the remaining low heat value gas is used to produce electricity. The following estimate in *Figure T8-24* is representative of various coproducts for screening purposes.

ISSUE 3: COMBINED CYCLE FUEL PRICE – NATURAL GAS

For the year 2000, the forecast for natural gas prices at a new combined cycle facility at Tennessee River Mile 160 is 342 cents per million Btu. This is expected to escalate at 5.3 percent per year. In preparing this medium natural gas price forecast, TVA relied on forecasts by Energy Ventures Analysis, Inc., Jofree Coporation, and ICF Resources.

The low and high values are 256 cents per million Btu with a 2.4 percent escalation and 418 cents per million Btu with an escalation rate of 7.9 percent. The high and low forecasts for gas prices were derived using several nationally recognized forecasters such as Gas Research Institute, American Gas Association, DRI/McGraw-Hill, and the Energy Information Administration.

ISSUE 4: NUCLEAR

Below are various uncertainties relative to TVA's use of its nuclear facilities.

Issue 4.1: Nuclear Moratorium

Issues that affect nuclear production include those events that alter the perception or physical capability of these facilities.

A major event either industry-wide or world-wide could cause a partial or complete shutdown of all nuclear units. Similarly, an event could create a shutdown of a specific unit type or vendor type for a period of time.

The range of outcomes assumed here are from the reference forecast to a shutdown of all nuclear units on the TVA system in fiscal year 2006.

Issue 4.2: Return to Service or Commercial Operating Dates on Nuclear Units

A range of operating dates are 12- to 36-month delays beyond the base for all the nuclear units beginning production after Watts Bar Unit 1.

Issue 4.3: Nuclear Capacity Factor

Capacity factor, the percentage of actual power generated compared to its maximum potential generation, is an uncertainty that impacts cost per kilowatt-hour of the nuclear facilities, as well as total production cost. The leading contributor to lost generation, or capacity factors less than 100 percent, for the nuclear industry as a whole is refueling, during which time the unit is unavailable for power generation. Additional lost generation may occur during operations due to testing, equipment maintenance, or other outages.

In this evaluation the mid-range capacity factor for nuclear units is 67 percent, with a low of 55 percent and a high of 86 percent based on TVA historical information and industry projections.

Issue 4.4: Nuclear Operating Cost

Operating costs cover those expenses incurred over the operating life of the unit. Nuclear costs are grouped into four categories: operating and maintenance, capital additions and improvements, fuel, and decommissioning. Operating and maintenance costs for nuclear units are projected in the medium case to be $69 per kilowatt of dependable capacity based on TVA's experience at the operating nuclear units since 1989. Nuclear operating and maintenance costs are driven by staffing levels. Typically, two-thirds of the total operating and maintenance budget goes directly to paying salaries, expenses, and benefits. Industry operating and maintenance costs escalated during the 1980s at rates in excess of general inflation as plant staff and contractors were added to respond to new regulatory requirements. The level of new regulations has dropped dramatically in the past five years, however, and the rate of operating and maintenance cost increases has likewise dropped. The nuclear industry has developed a strategic plan for reducing costs at operating units while still maintaining high levels of safety and performance. The trend in the nuclear industry is clearly toward smaller plant staffs, and a reduction in operating and maintenance cost is expected to follow. Industry targets for staffing levels at 2-unit sites like Sequoyah, Watts Bar, and Bellefonte is 0.5 persons per installed megawatt. This staffing level would result in operating and maintenance cost of about $55 per kilowatt per year, and this is used as the low value, with the high value at $83 per kilowatt per year. These estimates would escalate at 4.5 percent annually.

Issue 4.5: Nuclear Fuel Cost

TVA cost for nuclear fuel consists of two components; sunk cost and incremental fuel costs.

Sunk Cost of Fuel

TVA accumulated a uranium inventory during the 1980s of about 11 million pounds due to plant deferrals/cancellations and the 1985 extended outage. Interest on this inventory was capitalized throughout this period. The resulting high book value of uranium is driving TVA nuclear fuel costs. TVA is considering a write-off of the excess book value of uranium. This must be done if fuel costs are to be competitive before the inventory has been used. Barring write-off action, the existing inventory will affect fuel costs through 2001. Other actions have been initiated to reduce fuel costs, including renegotiation of contracts that will save approximately $70 million over the term of the contracts, loaning uranium from inventory, and utilization of fuel delivered for Watts Bar and Bellefonte in the operating plants at Browns Ferry and Sequoyah where practical, and purchasing enrichment services on the spot market at discounts of 30-35 percent relative to current term contracts. However, the effect of these other actions is small compared to the uranium book value.

Sunk cost is made up of two components: excess interest (approximately $1 billion dollars) and excess uranium inventory (approximately $400 million).

Incremental Cost

Incremental cost of nuclear fuel is the cost that TVA would pay today to replace the fuel. For Energy Vision 2020 considerations, TVA's nuclear plant fuel costs are based on an average incremental fuel cost for each of the nuclear plants. The incremental nuclear fuel costs (in 1994 dollars) are:

- Pressurized Water Reactor Fuel (Sequoyah, Watts Bar, and Bellefonte)—41.4 cents per million Btu
- Boiling Water Reactor (BWR) Fuel (Browns Ferry)—41.7 cents per million Btu

Escalation of Nuclear Fuel Cost

The nuclear fuel escalation rate may be affected by a number of factors including the general inflation rate, availability of nuclear fuel, demand for conversion, enrichment, and fabrication services, as well as spent fuel disposal costs.

For the next 30 years, abundant supplies of reasonably priced U_3O_8 will be available. The primary sources of supply will be inventories, production of existing projects, and known reserves, along with substantial quantities obtained from the nuclear weapon dismantlement program. In addition, enrichment and fabrication capacity exceeds demand. This situation is expected to continue for the foreseeable future.

Based on these considerations, nuclear fuel is expected to escalate at a rate equal to or less than general inflation during the period of 1995-2020. Energy Vision 2020 assumes escalation equal to general inflation. With a medium escalation forecast of 2.5 percent, the low is projected at 2.0 percent, with a high escalation forecast of 3.5 percent.

Issue 4.6: Spent Fuel Storage

A nuclear plant uses around 20 tons of fuel annually. A very small percentage of nuclear waste remains radioactive for thousands of years. The Nuclear Waste Policy Act of 1982 established a program to build a national underground high-level waste repository early in the next century. Currently a fee of $1 per megawatt-hour is collected to pay the Department of Energy for the disposal site. A high range is $2 per megawatt-hour.

Issue 4.7: Nuclear Additions and Improvements Costs

The cost of modifying an operating unit is a capital cost aggregated under the term additions and improvements. Modifications to nuclear facilities are driven by three causes:

- Implementation of regulation-driven modifications
- Facility improvements to increase reliability and capacity
- Routine replacement of existing capital equipment

During the 1980s, most modifications were driven by new regulations, many of which were issued following the 1979 Three Mile Island accident. A number of these regulations involved expensive modifications to plant systems and equipment. In recent years, however, new regulations have decreased, and in general, have had a lower financial impact. This trend reflects the maturing of the nuclear industry and increased knowledge about nuclear safety.

Nuclear industry additions and improvements costs dropped significantly with the completion of regulation-driven modifications. By 1990, the average rate of additions and improvements expenditure had been reduced to approximately one-quarter of the 1984 to 1986 high. While some regulation-driven changes continue to occur, utility investments are now more focused on general maintenance and performance upgrades.

TVA's additions and improvements costs are projected to be typical of the industry. Energy Vision 2020 assumes additions and improvements costs of $20 million per site per year plus $5 million per unit per year (in 1994 dollars). Additions and improvements for Bellefonte are $12 per kilowatt per year for the mid-range with a low of $9 per kilowatt per year and $19 per kilowatt per year for the high. Escalation is expected to be 4.5 percent.

Issue 4.8: Capital Cost-Bellefonte Unit 1

TVA and other nuclear engineering and construction firms (e.g., NUS Corporation, United Engineers & Constructors, Fluor-Daniel, MPR Associates, B&W Nuclear Services, and Stone and Webster Engineering Corporation) extensively reviewed the status and condition of the existing construction. Many of TVA's problems on other units were traced to the lack of good configuration control during the construction process. A detailed effort was conducted to firmly establish the licensing basis for the site. TVA then compared design records for the plant with construction records to confirm consistency. These records were then compared to actual construction, demonstrating that:

- The records existed and were retrievable.
- The records were consistent.
- The construction matched the design records.
- Design and construction were consistent with regulatory requirements.

Independent inspections performed by the Nuclear Regulatory Commission have confirmed these conclusions. Equipment and system inspections have shown that the construction quality problems encountered at other TVA facilities do not exist at Bellefonte. Agreements were reached with the Nuclear Regulatory Commission regarding the work required to resolve 14 potential regulatory concerns, representing the bulk of any remaining regulatory risk.

Consequently, the effort required at Bellefonte is largely associated with completing the remaining 12 percent of the construction work. A review of the remaining work shows that a substantial portion of remaining construction is associated with "close-out" type efforts (e.g., applying insulation and painting). Good record quality and frequent plant inspections allow this work to be estimated with a high level of confidence. In developing completion estimates, engineering firms with recent experience in completing other nuclear projects (e.g., Comanche Peak) were heavily involved to ensure that all necessary work was identified. In addition, TVA's experience in completing Watts Bar Unit 1 was fully considered. Bellefonte's completion plan utilizes the same "engineering-first" approach discussed previously.

The cost estimate to complete Bellefonte has been reviewed 21 times to date and provides a very definitive statement of the work scope required to place that unit in service. This definitive knowledge of scope positions the Bellefonte project to exercise several alternative contracting structures, including fixed price/lump sum contracting of facility completion.

More than half the cost to complete Bellefonte is not associated with construction but to put a well-trained operating staff in place for unit start-up. Because staffing and operator training have been done many times before in the industry, they can be estimated with a high level of confidence. Extensions in the start-up schedule can affect the cost to these items, in that the staff costs will continue to be carried as a capital expense until the unit enters service.

Estimates were also developed for the cost to complete Watts Bar Unit 2 and the cost to recover Browns Ferry Unit 1. These estimates were developed using a process similar to that used for Bellefonte in which a detailed examination was made of the work required and experience with previous projects fully considered.

Other Cost Uncertainty Considerations

While every effort has been made to provide the most accurate cost and schedule estimates possible, some uncertainty still remains. The process used to estimate costs captures the effect of previous contributors to cost increases by using actual experience as the estimate basis. Management representatives were involved in reviewing all cost estimates to ensure that the experience from each project was reflected in each new estimate. Work plans were reviewed in detail and the level of certainty assessed with the

FIGURE T8-25. **Cost to Complete Nuclear Units**

	Millions $			
	Bellefonte 1	Bellefonte 2	Browns Ferry 1	Watts Bar 2
Low	1311	912	1187	1097
Medium	2622	1824	2374	2194
High	3470	2420	3150	2910

This chart shows the low, medium, and high range of cost estimates to complete these nuclear generating units.

cost estimated for each line item. Management reserve requirements were determined based on results of this study and included in the base cost estimate. The management reserve requirement ranged from 10 percent to 30 percent depending on the level of risk.

To accommodate uncertainties not otherwise covered, adjustments are applied to the detailed engineering cost estimates based on the errors in past cost forecasts. The low completion cost estimates are the detailed engineering cost estimates themselves with the management reserve included.

The medium and high estimates are based on the low estimates adjusted for past errors in forecasting nuclear plant construction costs. The historical record of forecasting nuclear plant construction cost for plants in the United States and in the TVA region was reviewed for accuracy. The general conclusion of this review was that for plants 4 to 6 years from completion, the actual cost to complete was significantly greater than the forecast or estimated cost. The actual costs to complete were generally 100 to 200 percent greater than the forecast costs.

TVA's nuclear project cost estimate accuracy since 1987 was also reviewed. This review indicates that the error in forecasting future nuclear plant costs ranged from 100 percent to 230 percent. From 1987 to 1994, the average error in estimates made 4 to 6 years before completion was approximately 165 percent.

The major dilemma facing forecasters of nuclear plant completion costs is to what degree past forecast errors have been corrected in current estimates. The low forecasts assume that the latest engineering cost estimates are accurate. The high estimates, which use a multiplier of 2.65, assume that forecast errors will continue in the future at the same level experienced in the past. The mid-range or medium estimate of the cost to complete assumes that the future forecast error will be somewhat less than historical errors. Past forecast errors were due, at least in part, to rapidly changing regulations and the difficulty in managing large nuclear construction projects. Future errors could therefore be reduced if regulations were more stable and with improved construction project management. The medium forecast is based on the assumption that future forecast errors will match the minimum historical TVA error, which is approximately 100 percent. Thus, the medium forecast in *Figure T8-25* is twice the low estimate.

There is likewise a range of capital cost estimates for completion of the nuclear units. This range is shown in millions of dollars in *Figure T8-25*.

Issue 4.9: License Extension

The operating licenses for Browns Ferry Units 1, 2, and 3 currently expire in 2013, 2014, and 2016, respectively. The Nuclear Regulatory Commission, however, issued regulations establishing the requirements for obtaining an extension in the operating license for up to 20 additional years. The original rule issued by the Nuclear Regulatory Commission in 1991 is currently being revised and is expected to be finalized in mid-1995.

TVA, along with other utilities and industry organizations, has completed some preliminary review of the potential for extending operating licenses. No technical issues have been identified that would preclude license extension on Browns Ferry. In fact, Browns Ferry provides some unique benefits for license extension as a result of the extensive work being done to recover these units.

While it is difficult to accurately estimate the cost and schedule requirements for obtaining a license extension in advance of final issuance of the rule, the cost appears to be low (potentially on the order of $10 million).

Given the status of the rule, however, it is impossible to predict with certainty the success of an application for license extension at this time. Therefore, Energy Vision 2020 considers cases where license extension does not occur, as well as cases in which it does occur.

Issue 4.10: Nuclear Summer Limits – Temperature Water Discharge

Cooling towers are provided to support operation of the Sequoyah and Browns Ferry Nuclear Plants during periods of high river water temperature. Nonetheless, on rare occasions during extremely hot conditions, these units may be required to reduce generation. A loss of 150 megawatts is considered in the Energy Vision 2020 analyses.

Issue 4.11: Decommissioning Costs

At the end of facility's operating life, the reactor plant must either be dismantled or placed in a state of protective storage. A safe storage mode would be followed by removal of the reactor plant after a period of dormancy. The decision as to the mode of decommissioning will be influenced by a number of factors pertinent at the time of final plant shutdown. These factors include

FIGURE T8-26. **TVA Estimates of Nuclear Plant Decommisioning Cost [1]**

Value	Pressurized Water Reactors (PWRs)	Boiling Water Reactors (BWRs) [5]
Low [2]	$200 Million per Unit	$250 Million per Unit
Medium [3]	$300 Million per Unit	$350 Million per Unit
High [4]	$600 Million per Unit	$700 Million per Unit

1 Estimates are based on the DECON option.
2 The low values for the PWRs and BWRs are based on the Nuclear Regulatory Commission formula of $105 and $130 million (in January 1986 dollars), respectively, escalated to 1994 dollars.
3 The medium values represent the average of the industry estimates escalated to 1994 dollars.
4 The high values were calculated at twice the industry average.
5 The higher BWR cost reflects a margin for potential additional decommissioning cost associated with a BWR unit.

TVA has developed low, medium, and high estimates for decommissioning its nuclear power plants. The NRC formula for pressurized water reactors and boiling water reactors was used in developing the estimates.

potential use of the site for other purposes, cost of the alternatives, minimization of occupational radiation exposure, availability of low-level disposal space, availability of a high-level waste repository or spent fuel monitored retrievable storage facility, regulatory requirements, and public opinion.

As shown in *Figure T8-26*, TVA has developed low, medium, and high estimates for decommissioning its nuclear power plants. In developing the estimates, the Nuclear Regulatory Commission formula for Pressurized Water Reactors (PWRs) and Boiling Water Reactors (BWRs) was used to determine the low values. A medium value was determined from the range of current industry estimates to be $300 million (approximately 90 percent of the industry estimates are lower than this value). The high value was developed by doubling of the medium estimate. The high cost estimate, which is double the medium estimate, considers the uncertainties of decommissioning, including spent fuel disposal, and low-level waste disposal.

Some recent industry estimates for decommissioning are as high as a billion dollars, due primarily to high estimates for off-site storage and management of spent fuel and other high-level wastes. TVA's plan for spent nuclear fuel is to store it on-site at the plant locations where it is generated until the Department of Energy (DOE) accepts physical custody by shipment off-site to a monitored retrievable storage facility or to an underground repository for ultimate disposal by burial. TVA has sufficient outside site area at each of its nuclear facilities to store any high-level waste associated with decommissioning activities. This would be done, possibly in containers provided by the Department of Energy, until the federal government is able to fulfill its contractual obligation to move the fuel off-site.

ISSUE 5: COGENERATION

Below are uncertainties related to cogeneration.

Issue 5.1: Cost of Cogeneration

Cogeneration projects are being developed throughout the United States. As replacement power, capital cost of construction is an uncertain issue that is treated in a resource plan. In this case, the capital cost range is from a base of $175 per kilowatt for the medium with a 10 percent reduction for the low and a 50 percent increase projected for the high.

Issue 5.2: Available Amount of Cogeneration

The amount of cogeneration may be limited, especially if it is located outside the Tennessee Valley. A limit of 2,000 megawatts is placed on cogeneration capability to study the sensitivity of results of this issue.

ISSUE 6: TRANSMISSION

Below are three uncertainties that involve transmission issues.

Issue 6.1: Transmission-Related Electromagnetic Fields

Concern over possible health effects due to electromagnetic fields (EMF) could cause difficulties in siting transmission lines. To lower magnetic field levels, extensive reconstruction of existing transmission lines would be required, and new lines would be much more expensive.

Several methods that can be used to reduce EMF include:

- Building transmission lines underground with appropriate protection
- Increasing ground clearance of overhead lines
- Installing reverse-phasing (double circuit) lines
- Using photovoltaics, batteries, and other types of modular technologies at the customer level and thereby mitigating the need for transmission service

In Energy Vision 2020, the range of this uncertain parameter has been represented as follows: the low-range case is one in which no additional controls/modifications are required. The mid-range case is $50 million increase in the cost to build transmission for a greenfield site, while the high is represented by a 50 percent increase overall in transmission costs.

Issue 6.2: Wheeling Requirements

Transmission access (wheeling) involves allowing another utility company or retail customer access to the transmission system to send electricity from one utility to another utility. The rules of such access are being developed in response to the Energy Act of 1992. Wheeling requirements are subject to the availability

of the TVA system, good faith requests and responses, facilities upgrades and additions, scheduling and operations, losses, opportunity costs, etc. The wheeling rate being developed by TVA is comprised of three components: reactive power production, firm transmission service rate—base, and margin basis.

Issue 6.3: Transfer Limitations on Interconnections

Limitations on interconnections could cause two short-term responses. If Bellefonte is built, some excess energy may be available for export for a short period of time. This energy export could be limited under certain transmission scenarios. Second, reliability requirements could increase with reduced transfer capabilities, thus requiring replacement of capacity earlier if Bellefonte is canceled.

The limit on transfer capability is modeled in the uncertainty study through an increased reserve requirement.

ISSUE 7: PURCHASED POWER

Following are two uncertainties that involve purchased power.

Issue 7.1: Purchased Power Amount Available

The amount of power available from other utilities depends on the load and power supply situations of these potential suppliers and the timing of the need for TVA. While there is a mid-range of 1,500 megawatts of purchases available in the medium forecast, a range of 25 percent less or greater represents the low and high forecasts. Thus, the low range assumption is purchased power levels at 1,125 megawatts while the high range is 1,875 megawatts.

Issue 7.2: Purchased Power Price

In the year 2000, the purchased power projected prices are $56 per megawatt-hour with an escalation rate of 6.5 percent annually for the next five years. The low range is represented by a 2 percent reduction in escalation rates, while the high range is represented by a 3 percent increase in the escalation rates.

ISSUE 8: ENVIRONMENTAL QUALITY

The impact of future environmental issues is divided into several uncertainties for discussion.

Issue 8.1: Emission Caps on Carbon Dioxide

Carbon dioxide emissions are capped in the medium forecast at 1990 levels by the year 2002. The cost of additional emissions above 1990 levels of 83 million tons are priced at $5 per ton.

For the more constrained projection, in addition to the medium limits, an additional constraint by 2010 is a ceiling of 80 percent of 1990 levels. Emissions over that ceiling are priced at $10 per ton. Escalation of these values from 1994 are at 4 percent.

Issue 8.2: Sulfur Dioxide Price Allowance

The price of sulfur dioxide emission allowances on the market will vary in the future. The medium projection of $284 per ton (in 2000) is projected to range from $211 to $409 per ton. By 2010, that range is $201 to $723 per ton with a medium of $321 per ton. Escalation beyond that period is 0 percent for the medium, with a range from -1 to +3 percent.

Issue 8.3: Environmental – Air

Figure T8-27 shows the air quality components of the environmental issue. Additional information on these environmental air uncertainties can be found in the Environmental Uncertainties Appendix.

Issue 8.31: Clean Air Capital Cost

Capital costs associated with compliance with TVA's Clean Air Strategy may vary. These capital projects help control sulfur dioxide, nitrogen oxides, and other emissions. The medium forecast is $210 million, with a low of $180 and a high of $236 million in the year 2000. These include expenditures at the majority of the coal-fired power plants.

Issue 8.32: Air Toxics

Issue 8.33: Visibility

Issue 8.34: Ozone

The above-named three issues have been combined into one control scenario with a range of possible costs to control the pollutants related to these issues.

The control of mercury is the key issue in air toxics; visibility is affected by "haze," and the requirements for the ozone

FIGURE T8-27. **Environmental – Air**

	Control Issue	Assumed Control Methods
Health-Air Toxics	Mercury	• Wet Scrubbers at Selected Units • Scrubbers at Selected Units • #2 Coal at Selected Units
Visibility	Haze (Sulfate)	• Wet Precipitators at Selected Units • SNCR at Selected Units
Ozone	Non-Attainment Areas • Nashville • Smoky Mountains • Further Nitrogen Oxides Limits	• SNCR at Selected Units

This chart shows the air quality components of the environmental issue.

FIGURE T8-28 **Environmental – Water**

Control Issue	Assumed Control Methods
Thermal Existing Plant Regulations	• Cooling Towers
Aquatic - Biota	• Closed Mode Operation and/or Cooling Towers
Water Toxins	• Mixing Zone Controls • Linkage Regulations
Water Flow Alteration	• Minimum In-Stream Flows
Water Toxics, Bioaccumulation, & pH	• Surface Water • Discharge (Eliminate)

This chart shows the issues and possible controls.

controls relate to non-attainment areas in Nashville and the Smoky Mountain regions.

Mercury can be controlled through expenditures to add wet precipitators and scrubbers. In addition, an incremental operating cost of around $2.5 per megawatt-hour will occur at selected plants in 2002. Haze is controlled through expenditures of $410 million capital and an incremental operating cost of $2 per megawatt-hour at Bull Run, John Sevier, and Kingston plants by 2002; with a moderate impact having control by 2012. Ozone can be enhanced through capital expenditures of $68 million plus an added $2 per megawatt-hour operating cost at Cumberland and Gallatin by 1996. A more stringent case would also require $93 million capital and a $2 per megawatt-hour operating cost increase at Cumberland, Gallatin, Bull Run, John Sevier, Kingston, and Widows Creek plants.

Issue 8.4: Environmental – Water

Figure T8-28 shows the issues and possible controls. Additional information on these environmental water uncertainties can be found in the Environmental Uncertainties Appendix.

Issue 8.41: Thermal Plant Regulations

Issue 8.42: Aquatic Biota

Issue 8.43: Water Toxins

Issue 8.44: Water Flow Alteration

Issue 8.45: Water Toxics, Bioaccumulation, and pH

These five issues have been combined into one control scenario with a range of possible costs to control these issues.

Thermal limits at existing plants can be met by adding cooling towers. Aquatic biota concerns can be met through operating in a closed mode or by adding cooling towers.

Water toxins can be reduced by implementing mixing zone controls or linkage regulations. Minimum in-stream flows would require expenditures and additional operating and maintenance costs to stabilize water flow.

Surface water discharges can be eliminated at a substantial capital cost and added operating cost to control toxics, bioaccumulation, and potential of hydrogen (pH).

ISSUE 9: LOAD REQUIREMENTS

The load requirements issue involves several uncertainties, which are addressed individually below.

Issue 9.1: Native Load Growth

Total demand for electricity is measured in peak load requirements and in annual energy requirements. The growth rates for the medium forecast of peak loads from 1994 to 2000 is 2.2 percent per year, with a low of zero percent and a high of 3.4 percent. These rates are calculated from a 1994 base peak load of 24,400 megawatts. The growth rates for the period 2000 to 2020 are 1.9 percent for the medium, with a low of 0.0 percent and a high of 3.2 percent.

Issue 9.2: Deliverability of Interruptible Load

Issue 9.3: Customer Response to Emergency Appeal

These two items are combined in the sensitivity analysis. The medium reduction in load requirements is 1,900 megawatts (in 2000) with a low forecast of 700 and a high forecast of 2,560 megawatts. These reductions in load are equivalent to reduced capacity reserve requirements. The low scenario increases desired reserve levels by around 4 percent with the high decreasing reserves by 2.5 percent.

Limited Interruptible Power (LIP) and Economy Surplus Power (ESP) contracts allow TVA to interrupt load if needed when peak loads occur on the TVA system. The frequency and amount of actual interrupted load may vary from the contracted amount for several reasons including the fact that the load under interruptible contract may simply not be engaged at the time of the peak load. A medium value for the year 2000 is 1,765 megawatts available to be interrupted, while a low of 700 megawatts and a high of 2,160 megawatts are forecast.

Voluntary public appeals may result in peak load reductions ranging from 0 to 400 megawatts with a medium forecast of 140 megawatts. Any reduction of peak load results in a lower probability of loss of load, which makes the power system more reliable and lowers desired reserve requirements.

Issue 9.4: Competition with Neighbors and Open Access

In recent years, the electric utility industry has undergone a fundamental change. The world of regulated monopoly is being replaced by a world of competitive pressures. Wholesale open access (the right of wholesale customers to buy power from generating utilities other than the one whose lines serve them) can be mandated by the Federal Energy Regulatory Commission (FERC). Retail firms, such as large industrial customers, are looking for the same privilege, and retail open access is beginning to be mandated by some state regulatory bodies. In a more competitive market, TVA's success as a generating company will be greatly affected by whether TVA is successful in being a low-cost provider.

TVA has incorporated these competitive assumptions into its forecasts. In the medium forecast, TVA will maintain its current territory and will not gain outside customers nor lose customers inside its service territory.

TVA's forecast price of electricity, discussed earlier, is expected to remain competitive with other utilities. Market and regulatory changes would have less impact in the medium case, than in the high or low cases. As a result, the net impact of competition in the medium forecast is an even balance of gains and losses of sales.

The prospect of increasingly competitive markets increases the uncertainty in the forecast. If TVA operates at lower costs than the competition, and regulations permit, TVA may have opportunities to gain customers. This is termed high competitive success. Likewise, if TVA is a higher cost producer than its competitors, it is likely to lose customers-described as low competitive success. Both cases assume that deregulation of the electric market continues. The high and low forecasts recognize the risks and opportunities of increased competition.

TVA analyzed competitive impacts for all sales. The effort was aimed at looking at the market rather than specific customers. In the low competitive success case, TVA will lose customers to competing electric utilities. In order to estimate the potential for losing sales to competition, TVA's customer survey—completed by many of the distributors of TVA power and directly served customers—was used to identify the amount of load that appeared to be at high risk.

In the high competitive success case, TVA will gain customers from its competition. To estimate the potential for the gain in the wholesale markets, loads of municipal and cooperative distributors in neighboring regions were used. The chance of gaining any distributor was partly influenced by the wholesale price paid by that distributor. Because a very large percentage of TVA's sales are wholesale, compared to neighboring utilities, the potential gain in the wholesale market in the high competitive success case was smaller than the potential loss in the low competitive success case.

For directly served customers, less specific information on nearby opportunities was available. Because TVA is surrounded by states with large industrial loads, a judgment was made that potential gain is higher than loss of industrial loads.

Wholesale and retail gains in load were assigned the highest probability for the low electric price forecast, making TVA more competitive. A more complete discussion of all uncertainties in the forecast can be found elsewhere in the uncertainty section.

ISSUE 10: SITING

Availability of sites to use in developing new power supply alternatives is important to enable capacity to be added as required. Some additional capacity could be constructed on existing sites. However, there are other issues such as water usage and environmental output that could reduce site potential. Two levels of assumptions are being analyzed for the sensitivity of this issue. In the reference case, there are no constraints. A second scenario assumes there are no central station options built; rather, future requirements are met by fuel cells, batteries, and other distributed generation sources.

ISSUE 11: DEMAND-SIDE MANAGEMENT (DSM) EFFECTIVENESS OR MARKET PENETRATION

High and low forecasts of the impact of demand-side management programs are evaluated to determine their sensitivity. The mid-range scenario reduces the peak load by 5,494 megawatts in the year 2010, while low reduction is 3,124 megawatts, and the high reduction is 8,219 megawatts.

ISSUE 12: NEW TECHNOLOGY COST AND AVAILABILITY

The cost of power produced using new technologies could be significantly impacted by breakthroughs in theoretical concept, design, materials, and other factors. In order to consider the potential effect of improvements in new technologies, a 50 percent reduction in the capital cost for generating options using new technologies has been included.

ISSUE 13: DYNAMIC OPERATING BENEFITS

Operating flexibility is defined as the benefit of a unit's operating flexibility in responding to system load variations. The ability to "turn down," for example, from a maximum capacity level to a minimal level over the period of the day as the load requirements decrease would have some benefit. Another alternative is to make expenditure. capital to enable generating equipment to respond appropriately to instantaneous and short-term conditions. These benefits are being determined in a separate sensitivity review outside this evaluation.

the medium forecast of 109 cents per million Btu and a 3.3 percent escalation rate.

With the low coal price forecast, the total resource cost becomes $93,103 million or a reduction in total costs of $279 million. If the high coal prices are assumed, the total resource cost increases to $93,951 million, which is an added cost of $569 million.

Thus, the variation in total resource cost due to the uncertainty in coal prices ranges from a reduction of $279 million to an increase of $569 million.

Results of the sensitivity evaluations are shown in *Figures T8-30* through *T8-37*. As described above, the tornado diagram shows the impact each uncertainty has on the basic nuclear completion decision.

Figure T8-30 shows the change in long-term total resource costs for a range on 35 parameters described earlier in this paper. Using zero as the base, the increases or decreases in total resource costs are shown as bars from zero.

Figure T8-31 shows the variation in the planning criterion of electric rates. *Figure T8-32* shows the change in debt in the year 2007 due to variations in the various parameters. Change in average annual carbon dioxide emissions are shown in *Figure T8-33*.

Since some of the uncertain items only make a difference under selected expansion strategies, *Figures T8-34* through *T8-37* show the impact of these "special issues" on the selected criteria.

Natural gas prices show up in a scenario in which natural gas-based capacity is constructed, e.g., combined cycle. The effectiveness of demand-side management programs is only important in scenarios in which demand-side management options are pursued. Finally, the value received from coproducts is important in the scenarios in which integrated gasification combined cycle plants with coproduction facilities are installed.

In the *Figures T8-34* through *T8-37*, these different alternatives are evaluated for the same four criteria—total resource costs, electric rates, debt, and average annual carbon dioxide emissions.

Conclusions

Issues that were carried forward into the Energy Vision 2020 evaluation are listed below:

- Load Growth
- Nuclear Issues
  - Capacity Factor
  - Operating and Maintenance Cost
  - Capital Cost
- Environmental Issues
  - Carbon Dioxide Compliance
  - Air and Water Environmental Controls
- Price
  - Natural Gas
  - Revenue from Coproduct (Combined Cycle)
- Demand-Side Management Effectiveness

Issues for which selected sensitivity evaluation can be performed include the nuclear moratorium and the inability to site central station generating capacity.

ISSUE 14: COMBUSTION TURBINES

The uncertainties pertaining to combustion turbines have been subdivided into the issues below.

Issue 14.1: Reliability of New Combustion Turbines

Reliability of peaking capacity is critical since the periods of time the units are called on are peak load hours. The medium projection for combustion turbine reliability is 84 percent, while a low of 68 percent and a high of 90 percent are evaluated.

Issue 14.2: Plant Life of Existing Turbines

Plant life of new capacity is assumed to be 30 years in the medium forecast. The low case assumes a life of 25 years.

Issue 14.3: Efficiency of Combustion Turbines

A range of efficiency is evaluated for the combustion turbines. A medium forecast of 10,500 Btu per kilowatt-hour is forecast. A "high value" or low heat rate of 9,000 and a "low value" or high heat rate of 12,000 Btu per kilowatt-hour is used to represent the range.

ISSUE 15: DISCOUNT RATE

ISSUE 16: INTEREST RATE

The discount rate (economic evaluation rate for investments or minimum attractive rate of return) is used to perform equivalence calculations (e.g., present value) necessary for comparing investment alternatives. The discount rate includes an amount for the time value of money and contains an implicit forecast of inflation expectations. A very basic consideration in selecting a discount rate is the cost of capital. No corporation can stay in business for the long term by investing at return rates less than the rates paid for funds. Keeping this in mind and noting the need to compare options with various forms and sources of financing, TVA has chosen the long-term interest rate as the discount rate to be used in Energy Vision 2020.

The interest rate TVA pays for funds is projected to rise somewhat over the next 10 years as worldwide demand for capital increases after the European and Japanese economies begin to recover. However, the moderate rate of inflation and declining federal budget deficit will keep rate increases moderate.

Since discount and interest rates must be set consistently, a medium discount and interest rate of 8 percent is evaluated with a low range of 6 percent and a high range of 12 percent.

Sensitivity of Resource Plans to Uncertain Parameters

Tornado diagrams are useful in determining the parameters that are significant in the decision-making process. This ensures that the most important parameters continue to be considered in the evaluation and allows less important parameters to be dropped from the analysis.

Figure T8-29 shows the most significant items as identified from the tornado diagrams.

To describe the tornado diagram, the following information can be used to illustrate development of the tornado diagram. The 30-year annual resource costs (discounted to 1994 at 8 percent) for the reference set of assumptions with Bellefonte completed are $93,382 million.

To determine the sensitivity of this resource plan to coal prices, the range of coal prices is used to develop total resource costs. As described in Issue 2.5, the low forecast is projected to be 100 cents per million Btu in the year 2000 with a 2.8 percent escalation. The high coal price forecast is 121 cents per million Btu with a 4.0 percent escalation. These are ranges around

FIGURE T8-29. **Uncertainties to Consider Further**

	EVALUATION CRITERIA			
Uncertainty	Total Resource Cost	Rates	Debt in 2007	Carbon Dioxide Emissions
Nuclear Moratorium	●	●	●	●
Nuclear Capacity Factor	●	●		●
Nuclear Operating and Maintenance Cost	?	●		
Nuclear Capital Cost	?	●	●	
Carbon Dioxide Compliance	●	●		
Environmental-Air	?	?	?	
Environmental-Water			●	
Load Growth	●	●	●	●
Competitive Success	●		●	●
Sites	●			
Coproduct Revenue	●	●		
DSM Effectiveness	?	●	?	?
Natural Gas Price	?	?		

Based on the tornado diagrams which follow, the most significant uncertainty items are shown here.

FIGURE T8-30. **Change in Total Resource Costs – Existing System, Nuclear Completion, and Coal-Based Expansion**

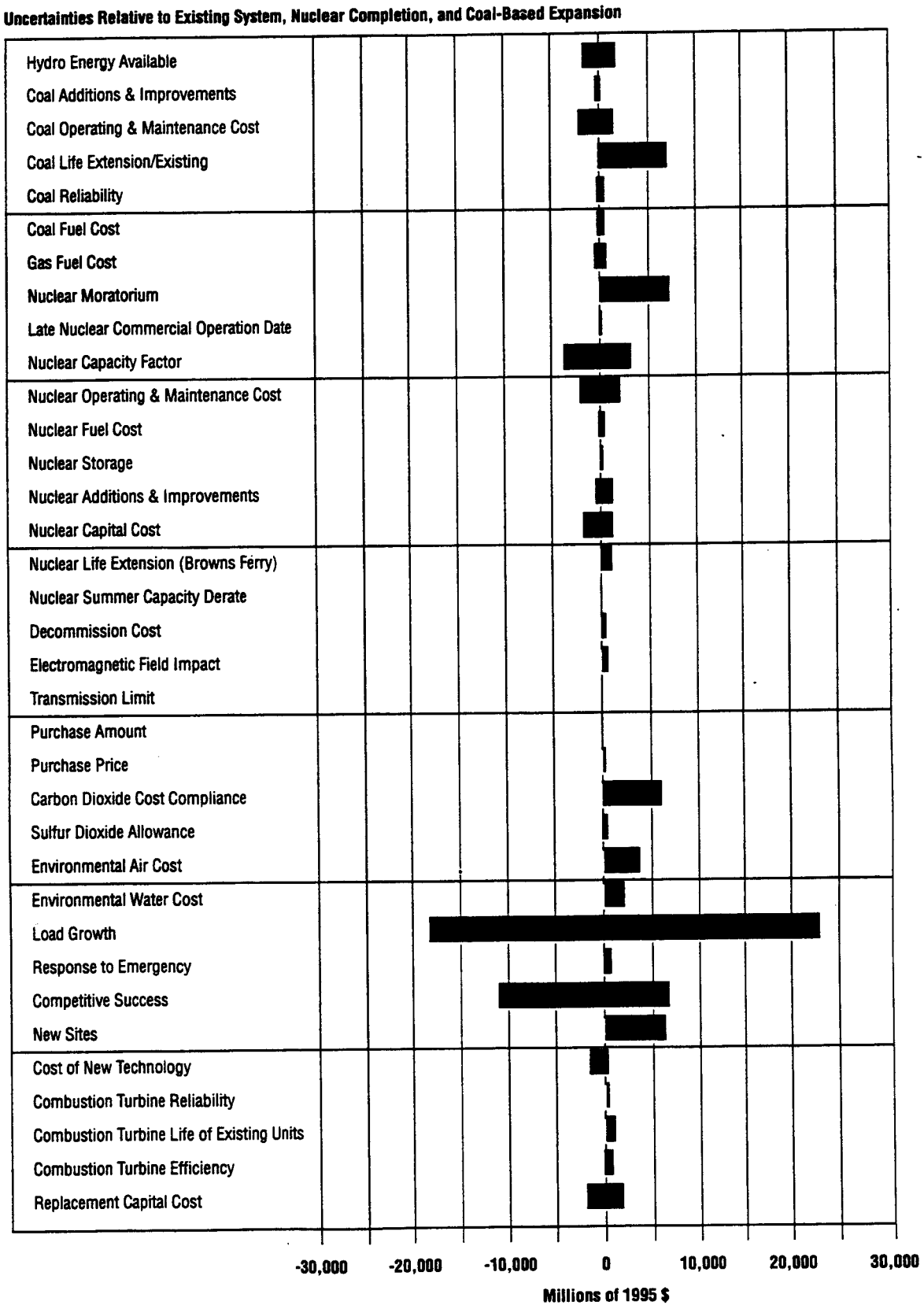


FIGURE T8-31. **Change in Electric Rates – Existing System, Nuclear Completion, and Coal-Based Expansion**

Uncertainties Relative to Existing System, Nuclear Completion, and Coal-Based Expansion

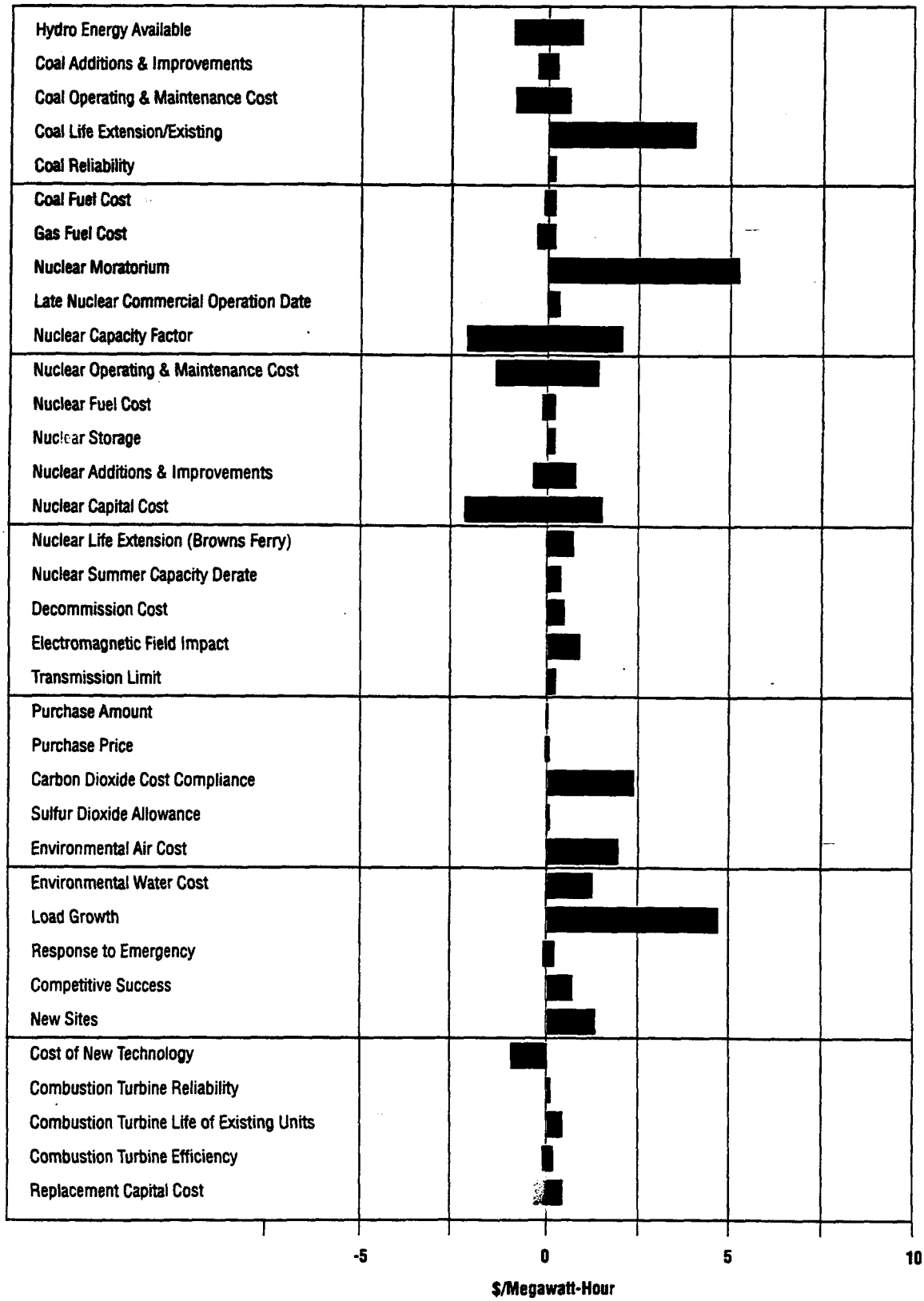


FIGURE T8-32. **Change in Debt in Year 2007 – Existing System, Nuclear Completion, and Coal-Based Expansion**

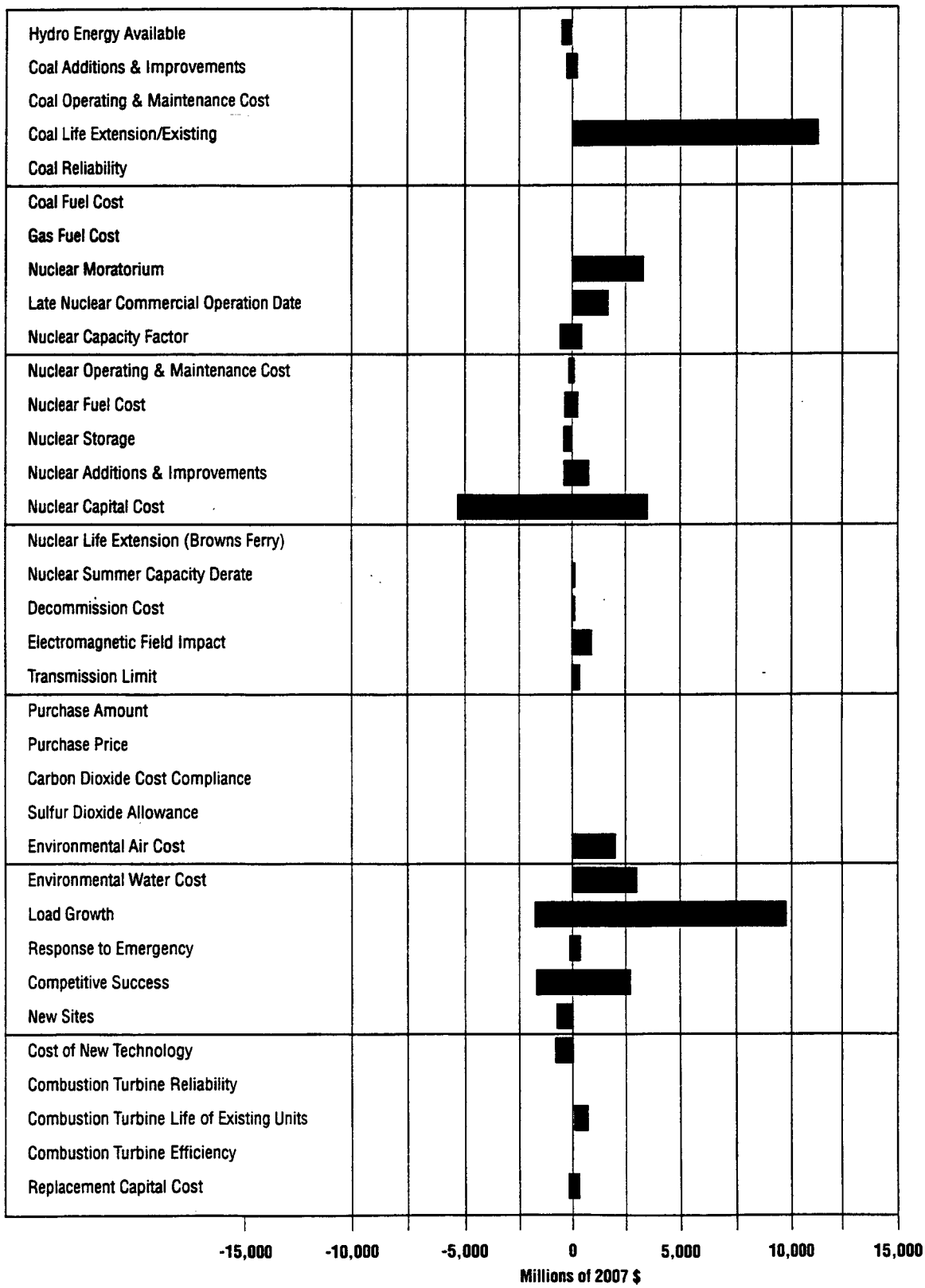


FIGURE T8-33: **Change in Average Annual Carbon Dioxide Emissions – Existing System, Nuclear Completion, and Coal-Based Expansion**

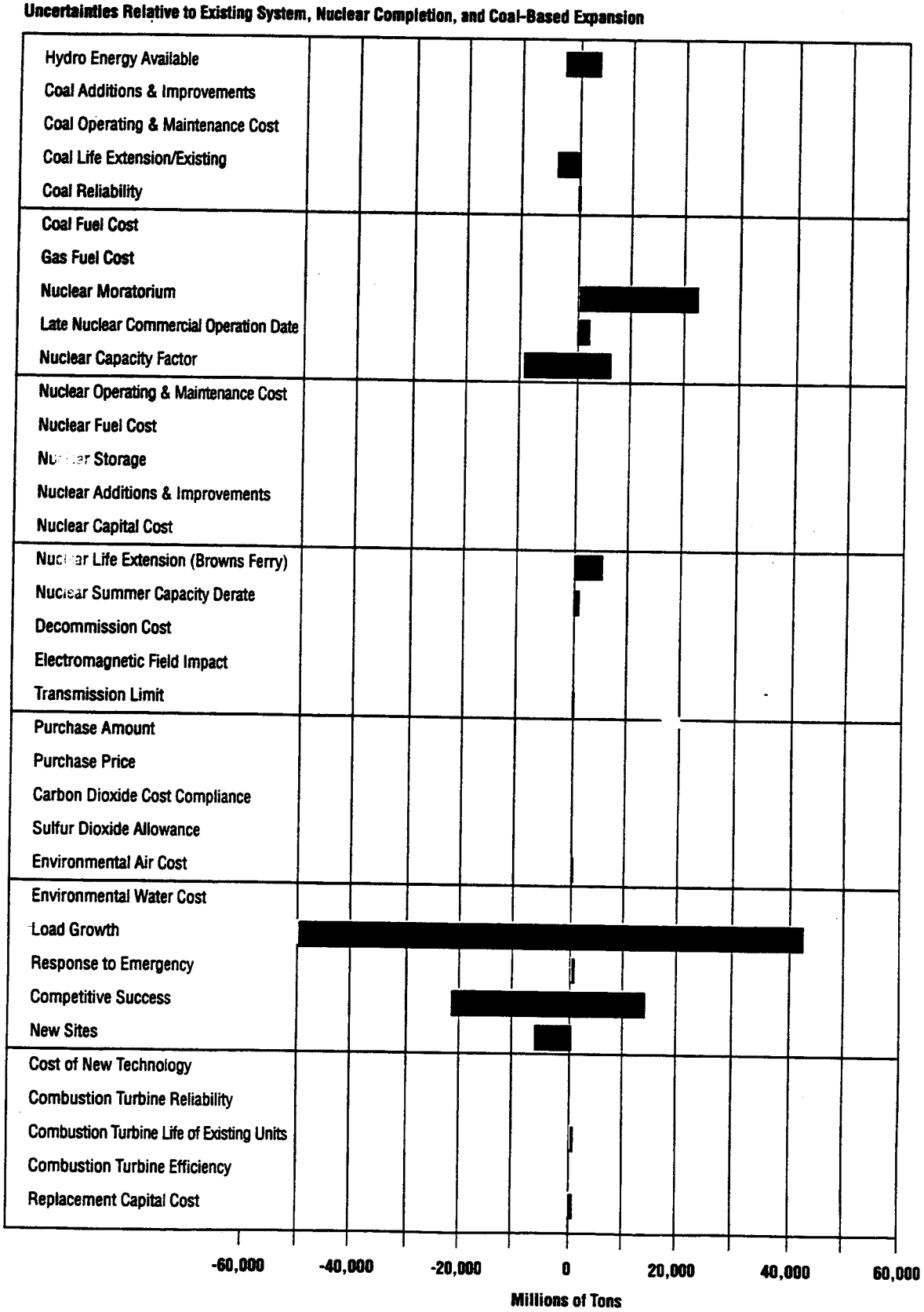


FIGURE T8-34. Change in Total Resource Costs – Other Expansion Options

Selected Uncertainties Relative to Selected Expansion Options

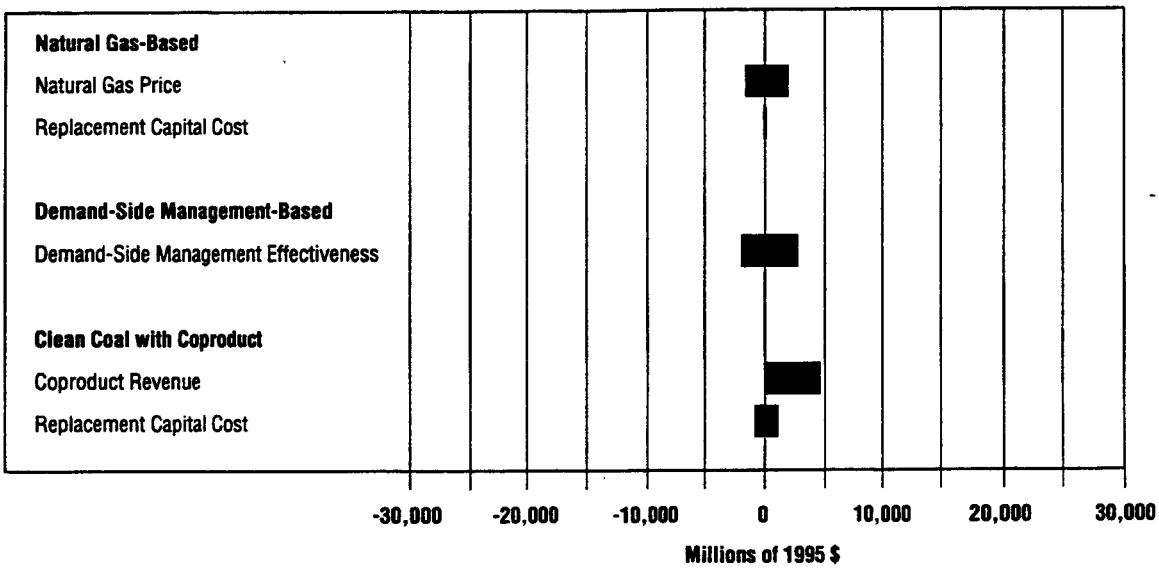


FIGURE T8-35. Change in Electric Rates – Other Expansion Options

Selected Uncertainties Relative to Selected Expansion Options

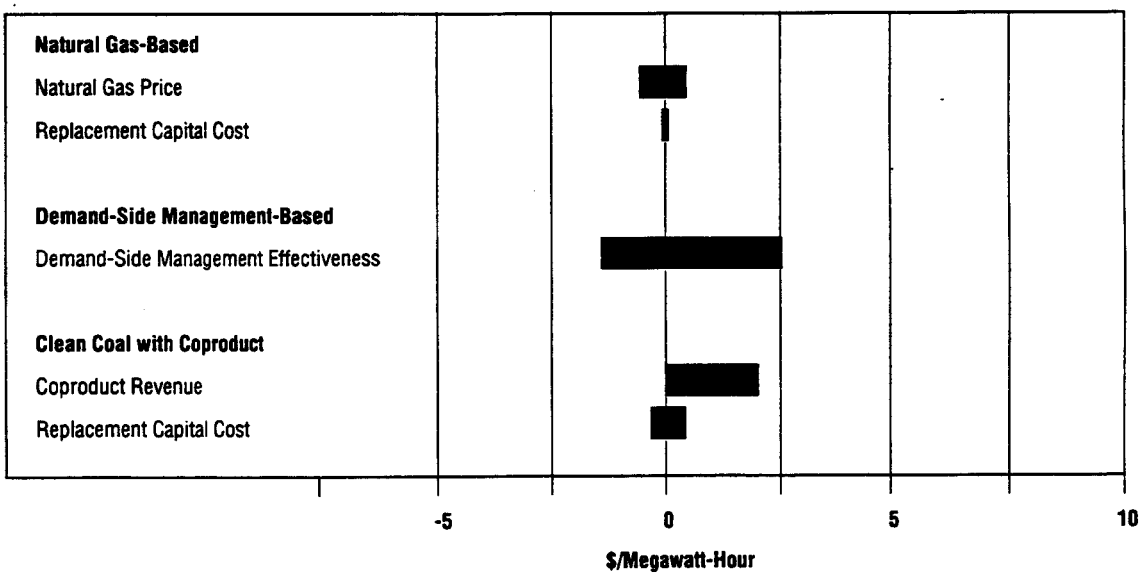


FIGURE T8-36. **Change in Debt in Year 2007 – Other Expansion Options**

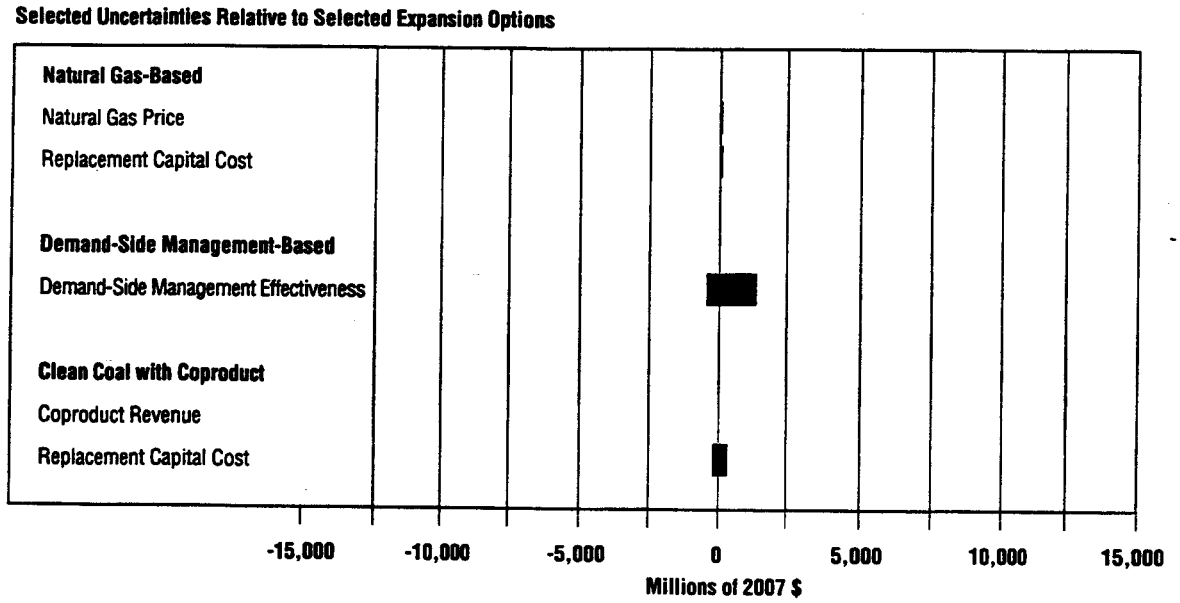
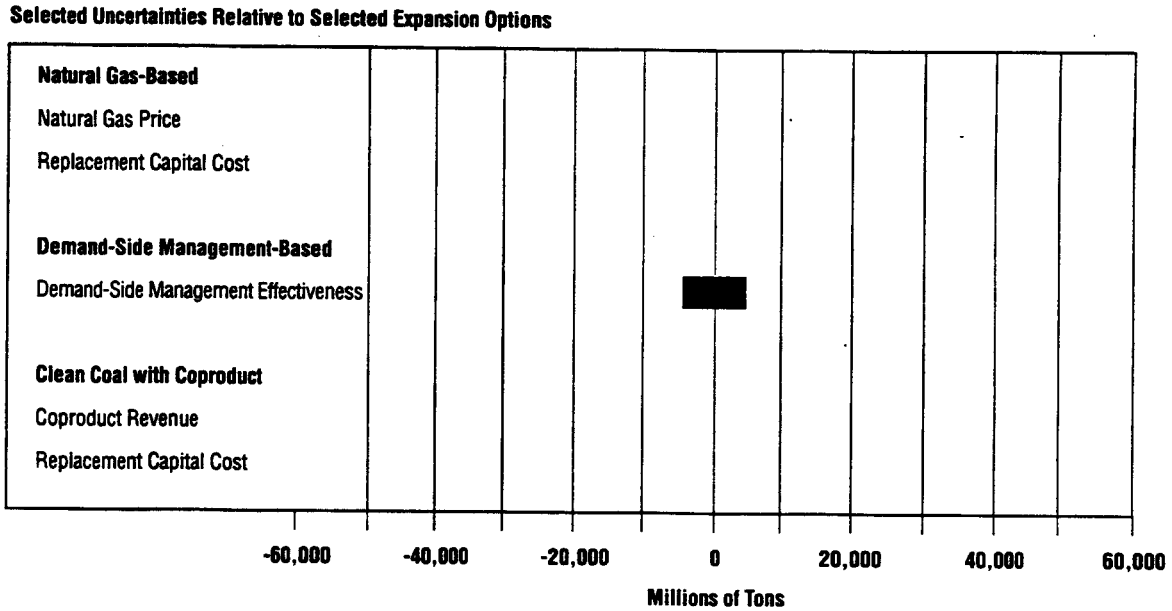


FIGURE T8-37. **Change in Average Annual Carbon Dioxide Emissions – Other Expansion Options**



ENVIRONMENTAL UNCERTAINTIES APPENDIX

Health – Air Toxics Uncertainty

Scenario 1: Utilities remain unregulated for air toxics
Impact on TVA: None
Probability of this scenario: 10 percent

Scenario 2: Environmental Protection Agency decides in 1996 to regulate air toxics from utility sources beginning in 2002. Equipment needed to control mercury will also control radioactive particulates and other heavy metals.
Impact on TVA: For Paradise 1-3, Cumberland 1-2, Widows Creek 7-8, and Allen 1-3 facilities, add wet precipitators at $50 per kilowatt. For other fossil plants, add spray dryer at $160 per kilowatt and switch to low sulfur coal of no more than 2 pounds per million Btu of sulfur dioxide emissions (some low sulfur coals are known to be low in toxic metals); add 0.4 cents per kilowatt-hour in variable operating and maintenance costs.
Probability of this scenario: 40 percent

Scenario 3: Same as scenario 2 except: Environmental Protection Agency decides in 2004 to regulate air toxics emissions beginning in 2010.
Impact on TVA: Same as scenario 2.
Probability of this scenario: 50 percent

Visibility – Acid Aerosols/Particulate Matter (PM) Uncertainty

Scenario 1: No new requirements
Impact on TVA: None
Probability of this scenario: 60 percent

Scenario 2: In 1997, visibility issues produce new regulations that require sulfate controls. TVA units put in service after 1962 are required to install Best Available Retrofit Technology (BART) by 2002. Best Available Retrofit Technology is determined to be 90 percent removal scrubbers. These are required on Bull Run, Paradise 3, and Colbert 5 plants.
Impact on TVA: Add scrubbers at capital cost of $200 per kilowatt, with increased operating and maintenance expense of 0.4 cents per kilowatt-hour.
Probability of this scenario: 30 percent

Scenario 3: In 2003, long-range transport and visibility issues produce new regulations that require sulfate and fine particulate controls by 2010. Best Available Retrofit Technology is determined to be 90 percent removal scrubbers and control of all particulates of 10 microns or less. Older units burning high or medium sulfur coal (in excess of 2.5 pounds per million Btu) are also required to reduce sulfur dioxide emissions and particulates of 10 micros or less emissions. These units add in-duct lime injection systems. (These controls will address the condensible portion of particulates of 10 micros or less. The mass portion of particulates of 10 micros or less should not affect TVA due to high efficiency of TVA's precipitators.)
Impact on TVA: Same as scenario 2. In addition, add in-duct lime injection systems at all unscrubbed units burning coal with 2.5 pounds per million Btu or greater sulfur dioxide emissions at cost of $15 per kilowatt and increased operating cost of 0.2 cents per kilowatt-hour.
Probability of this scenario: 10 percent

Health – Ozone Uncertainty

Scenario 1: No new requirements
Impact on TVA: None
Probability of this scenario: 10 percent

Scenario 2: In 1996, Nashville area is redesignated serious non-attainment for ozone, and modeling shows direct impacts due to nitrogen oxides emissions at Cumberland and Gallatin plants. Nitrogen oxides reductions are required at Cumberland and Gallatin plants by 1999. Low nitrogen oxides burners planned for installation at the Cumberland plant are judged inadequate to meet reduction requirements.
Impact on TVA: Selective non-catalytic reduction is added at Cumberland and Gallatin at cost of $20 per kilowatt. Variable operating and maintenance costs increase by 0.2 cents per kilowatt-hour at these plants.
Probability of this scenario: 30 percent

Scenario 3: In 2002, ozone non-attainment within the Great Smoky Mountains National Park forces additional nitrogen oxides reductions from sources within a 200-kilometer radius of the park. Requirements are met by adding selective non-catalytic reduc-

tion in addition to the previously installed low nitrogen oxides burners.
Impact on TVA: Additional controls are added to John Sevier, Bull Run, Kingston, and Widows Creek plants at $20 per kilowatt and 0.2 cents per kilowatt-hour variable operating and maintenance increase.
Probability of this scenario: 30 percent

Scenario 4: Combine scenarios 2 and 3
Impact on TVA: Combine impacts of scenarios 2 and 3
Probability of this scenario: 30 percent

General Air Regulation Uncertainty

Scenario 1: No new requirements that are independent of the other uncertainties described in this paper
Impact on TVA: None
Probability of this scenario: 90 percent

Scenario 2: New legislation in 2005 requires that all plants must meet all new source requirements, including new requirements for air toxics, by 2010. All plants must be equipped with 90 percent removal efficiency scrubbers and wet precipitators.
Impact on TVA: Add scrubbers to all unscrubbed units at cost of $200 per kilowatt. Add wet precipitator to all units at cost of $50 per kilowatt. Variable operating and maintenance increases at all plants by 0.4 cents per kilowatt-hour.
Probability of this scenario: 10 percent

Greenhouse Gas Emissions Uncertainty

Scenario 1: No greenhouse gas legislation
Impact on TVA: None
Probability of this scenario: 35 percent

Scenario 2: New legislation is passed in 1997 to stabilize greenhouse gas emissions at 1990 levels in the year 2002. Offsets for sequestration and "allowance trading" are allowed. Offsets are available at $3 per ton for the first million tons above 1990 levels, $5 per ton for any additional emissions.
Impact on TVA: Impose greenhouse gas emissions cap of 98 million tons of carbon dioxide equivalent beginning in 2002. Reduce value of sulfur dioxide allowances by 10 percent starting in 2002.
Probability of this scenario: 40 percent

Scenario 3: Same as scenario 2 except the emissions limit is reduced to 80 percent of 1990 levels in 2010. Needed offsets in excess of ten million tons cost $15.
Impact on TVA: Same as scenario 2 except the emissions cap drops to 80 percent of 1990 levels in 2010. The value of sulfur dioxide allowances drops 40 percent in 2010. Natural gas prices increase by 50 percent in 2010.
Probability of this scenario: 25 percent

Thermal Water Discharge Uncertainty

Scenario 1: Regulation of thermal discharges remains unchanged
Impact on TVA: None
Probability of this scenario: 80 percent

Scenario 2: All Section 316(a) variances that currently allow less stringent thermal limits are eliminated by 2002. Cooling towers operating in helper mode would be required at eight existing coal-fired plants, modifications would be required to the existing cooling towers at Sequoyah, and additional cooling towers would be required at Browns Ferry facilities.
Impact on TVA: Capital cost for cooling towers at existing coal-fired plants would be approximately $1.7 billion. Addition of cooling towers would also result in loss of 860 megawatts capacity and increased operating and maintenance cost of $3.9 million per year.
Probability of this scenario: 10 percent

Scenario 3: Mixing zones for surface water discharges are restricted to a maximum of 1,000 feet by 2002. Cooling towers operating in closed mode are required for all existing coal-fired plants and all new thermal plants to minimize mixing zone size. Modifications are required at Sequoyah and additional towers required at Browns Ferry facilities.
Impact on TVA: Capital cost for cooling towers is approximately $2.5 billion. System loses 860 megawatts capacity and annual operating and maintenance cost is increased by $13 million per year.
Probability of this scenario: 10 percent

Entrainment/Impingement Uncertainty

Scenario 1: Section 316(b) regulation, which applies to the effects of surface water intakes on aquatic biota, remains unchanged.
Impact on TVA: None
Probability of this scenario: 80 percent

Scenario 2: Section 316(b) regulations change in 1996 to require a reduction in entrainment/impingement effects at existing plants. TVA elects to comply by constructing cooling towers at existing thermal plants to reduce the volume of water taken into the plant. Towers in closed mode are added to all coal-fired plants, repairs are required at Sequoyah, and additional tower cells are required at Browns Ferry facilities.
Impact on TVA: Capital cost for cooling towers would be approximately $1.7 billion. Capacity is reduced by 860 megawatts, and operating and maintenance cost increases by $13 million per year.
Probability of this scenario: 20 percent

Toxics/Bioaccumulation Uncertainty

Scenario 1: No changes to regulations affecting surface water discharges.
Impact on TVA: None
Probability of this scenario: 75 percent

Scenario 2: Reauthorization of Clean Water Act in 2000 requires National Pollutant Discharge Elimination System permits for discharges of pollutants to groundwater which is "hydrologically connected to surface waters." TVA complies by lining all ash ponds at existing coal-fired plants. Ash in existing ash ponds is excavated and stabilized in lined areas. Metal cleaning waste ponds are lined.
Impact on TVA: Cost for existing plants will be $1.1 billion.
Probability of this scenario: 25 percent

Flow Alteration Uncertainty

Scenario 1: No new requirements (beyond TVA commitment to policy outlined in the Final Environmental Impact Statement, Tennessee River and Reservoir System Operation and Planning Review — Lake Improvement Plan).
Impact on TVA: None
Probability of this scenario: 80 percent

Scenario 2: States require additional minimum in-stream flows downstream of new and existing TVA hydro plants by 1998. Minimum in-stream flows would be maintained downstream of hydro plants by pumping water over the dam to the tailwater to supplement turbine releases.
Impact on TVA: Requires expenditure of $180 million capital and annual operating and maintenance cost increase of $11 million per year.
Probability of this scenario: 20 percent

Toxics/Bioaccumulation and pH Uncertainty

Scenario 1: No new regulation that is not covered under the Toxics/Bioaccumulation uncertainty above.
Impact on TVA: None
Probability of this scenario: 90 percent

Scenario 2: Reauthorization of Clean Water Act in 2005 requires the elimination of discharges of all pollutants by 2010. All surface water discharges, including thermal, and discharges to groundwater that are "hydrologically connected to surface water" would be eliminated. All thermal plants would operate closed cycle. Blow down and other miscellaneous wastewater are treated on-site, primarily by evaporation and constructed wetlands. All combustion byproducts and scrubber sludges are handled dry. Existing ash in ash ponds is stabilized in lined areas to eliminate discharge to groundwater. Chemical cleaning ponds are also to be lined.
Impact on TVA: Capital cost will be $11 billion and annual operating and maintenance costs increase by $14 million per year.
Probability of this scenario: 10 percent

EVALUATION CRITERIA

The Key to Criteria is a summary of the evaluation criteria that was used to evaluate each strategy. These criteria were crucial in the analysis of the strategies as shown in the various trade-off graphs. The units and a brief description of all key criteria are given in *Figure T8-38*.

FIGURE T8-38. **Key to Criteria**

Label	Description	Units
Customer Value Test	Customer Value Test	Present Value -(1996-2030)
Total Resource Costs	Total Resource Costs (TRC)	Present Value - (1996-2030)
Electric Market	Customer Value in Electric Market	Present Value - (1996-2030)
RIM Test	Rates Impact Measure (RIM) Test	$/MWh Levelized (1996-2030)
Short-Term Rates	Short-Term Rates	$/MWh Average from (1996-2000)
Mid-Term Rates	Mid-Term Rates	$/MWh Average from (1996-2005)
Long-Term Rates	Long-Term Rates	$/MWh Average from (1996-2015)
New Mid-Term Rates	Mid-Term Rates	$/MWh (2001-2005)
Debt 2001	Total Debt in Year 2001	Millions $
Debt 2007	Total Debt in Year 2007	Millions $
Total Employment	Total Employment Per Year	
Total Income	Average Annual	Thousands $
Environmental Criteria:		
CO Emissions	Carbon Monoxide (CO) Emissions	Annual Average Tons (1996-2030)
CO_2 Emissions	Carbon Dioxide (CO_2) Emissions	Annual Average Thousands of Tons (1996-2030)
NO_X Emissions	Nitrogen Oxides (NO_X) Emissions	Annual Average Tons (1996-2030)
SO_2 Emissions	Sulfur Dioxide (SO_2) Emissions	Annual Average Tons (1996-2030)
VOC Emissions	Volatile Organic Compounds (VOCs) Emissions	Annual Average Tons (1996-2030)
TSP Emissions	Total Suspended Particulates (TSPs) Emissions	Annual Average Tons (1996-2030)
Mercury Emissions	Mercury (Hg) Emissions	Annual Average Tons (1996-2030)
Solids	Solids	Annual Average Tons (1996-2030)
Thermal Discharge	Thermal Discharges	Annual Average Quadrillion BTUs (1996-2030)
Water Usage	Water Usage	Annual Average Trillions of Gallons (1996-2030)
Water Consumption	Water Consumption	Annual Average Trillions of Gallons (1996-2030)
Coal Burned	Coal Burned	Annual Average Millions of Tons (1996-2030)

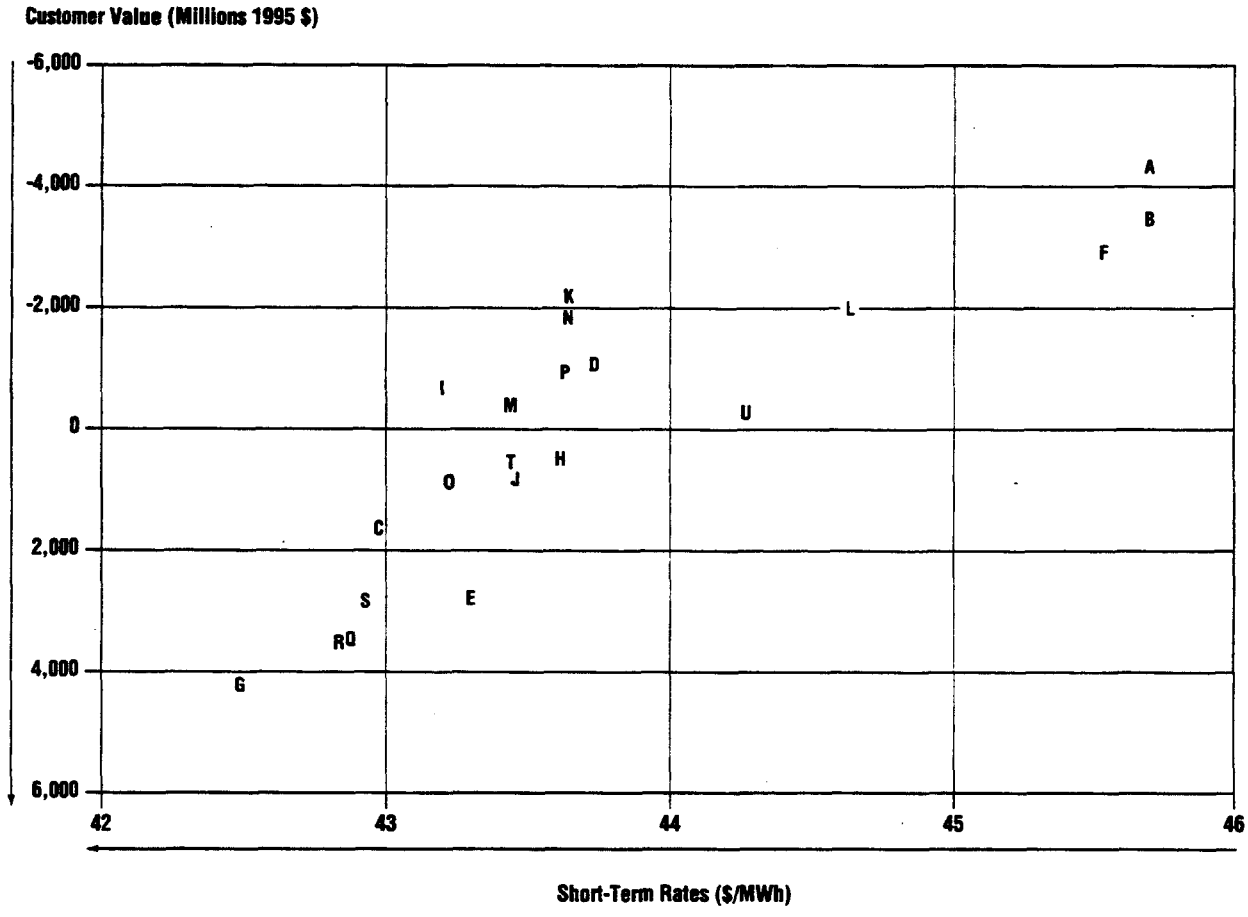
FIGURE T8-38. **Key To Criteria** *CONTINUED*

Label	Description	Units
Environmental Criteria:		
Biomass Burned	Biomass Burned	Annual Average Millions of Tons (1996-2030)
RDF Burned	Refuse-Derived Fuel (RDF) Burned	Annual Average Millions of Tons (1996-2030)
Landfill Methane Capture	Landfill Methane Capture	Annual Average Tons (1996-2030)
NG Burned	Natural Gas Burned	Millions of Standard Cubic Feet
Total Power Sales	Total Power Sales	MWh
Nuclear Power Sales	Nuclear Power Sales	MWh
Fossil Power Sales	Fossil Power Sales	MWh
Hydro Power Sales	Hydro Power Sales	MWh
Wind Capacity	Wind Capacity	MW
New Thermal Plants	New Thermal Plants	Number
Environmental Impacts:		
Air:		
Health - Inhalation	Human Health - Inhalation	Index
Visibility	Visibility	Index
Forests And Crops	Forests and Crops	Index
Materials	Materials (Structural and Cultural)	Index
Water: Health - Ingestion	Human Health - Ingestion	Index
Water Supply/ Assimilation	Water Supply/Waste Assimilation	Index
Aquatic/Biodiversity	Fish and Aquatic Life/ Biodiversity	Index
Other: Greenhouse Gases	Greenhouse Gas Emissions	Total Equivalent Carbon Dioxide (Millions of Tons)

TRADE-OFF GRAPHS

The Trade-off Graphs represent how each strategy performs given certain criteria. Specifying a particular future, some strategies were better than others for each criteria. To illustrate the evaluation of certain strategies, as well as the correlation of some of the criteria, three sets of trade-off graphs focusing on specific criteria are attached. They are cost, rates, debt, and value trade-offs, *Figures T8-39* through *T8-41*; environmental emissions trade-offs, *Figures T8-42* through *T8-48*, and environmental impacts

FIGURE T8-39. **Costs, Rates, Debt, and Value Trade-Off**
Customer Value vs. Short-Term Rates



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trade-offs, *Figures T8-49* through *T8-55*. In the environmental emissions trade-offs, there is a correlation between the emission criteria. In the environmental impacts trade-offs, there is a correlation between the environmental air impact indices. As the air quality becomes better, the attributes associated with the environmental air impacts also improve. There is no true correlation between the environmental water impact indices *(Figures T8-53* through *T8-55)*.

FIGURE T8-40. **Costs, Rates, Debt, and Value Trade-Off**
Short-Term Rates vs. Total Resource Costs

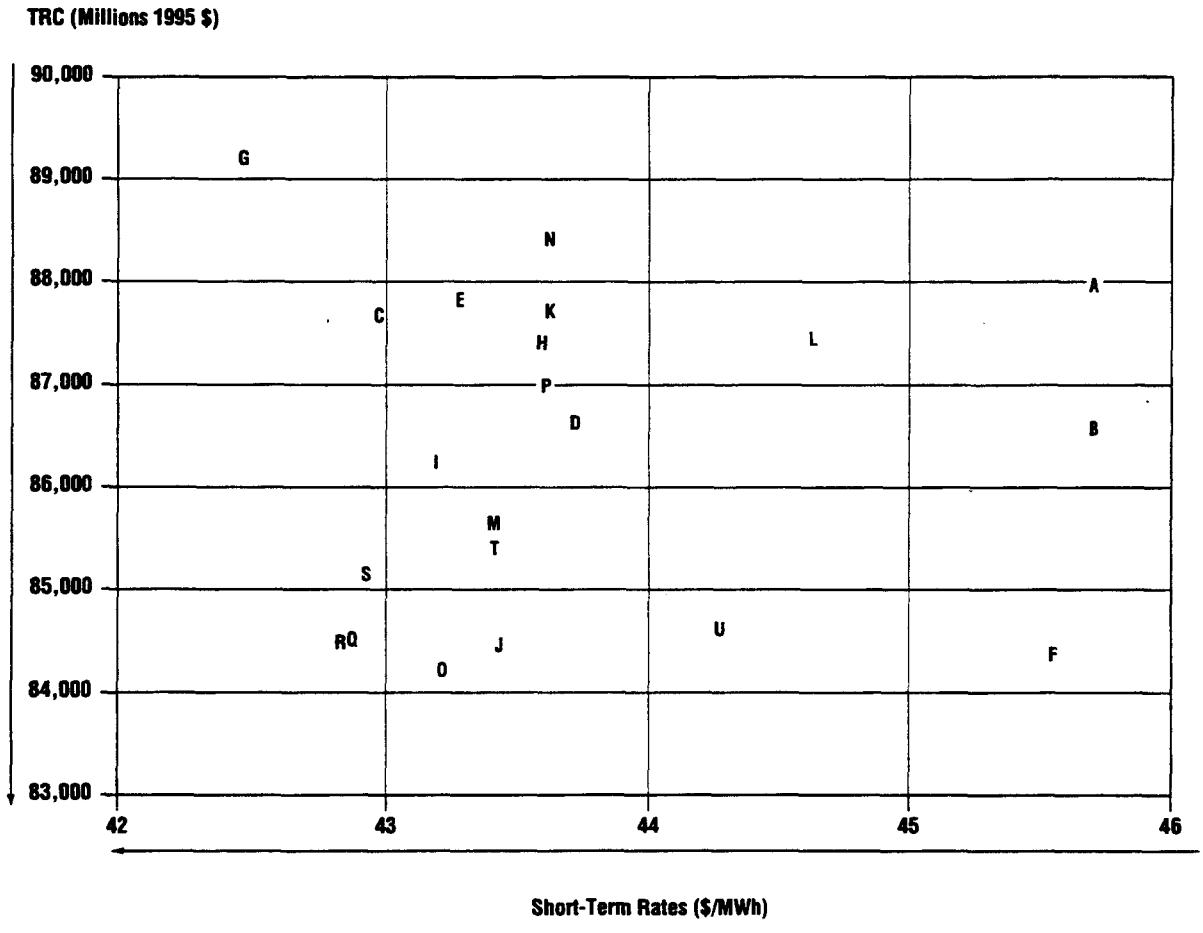

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FIGURE T8-41. **Costs, Rates, Debt, and Value Trade-Off**
Debt in Year 2001 vs. Total Resource Costs

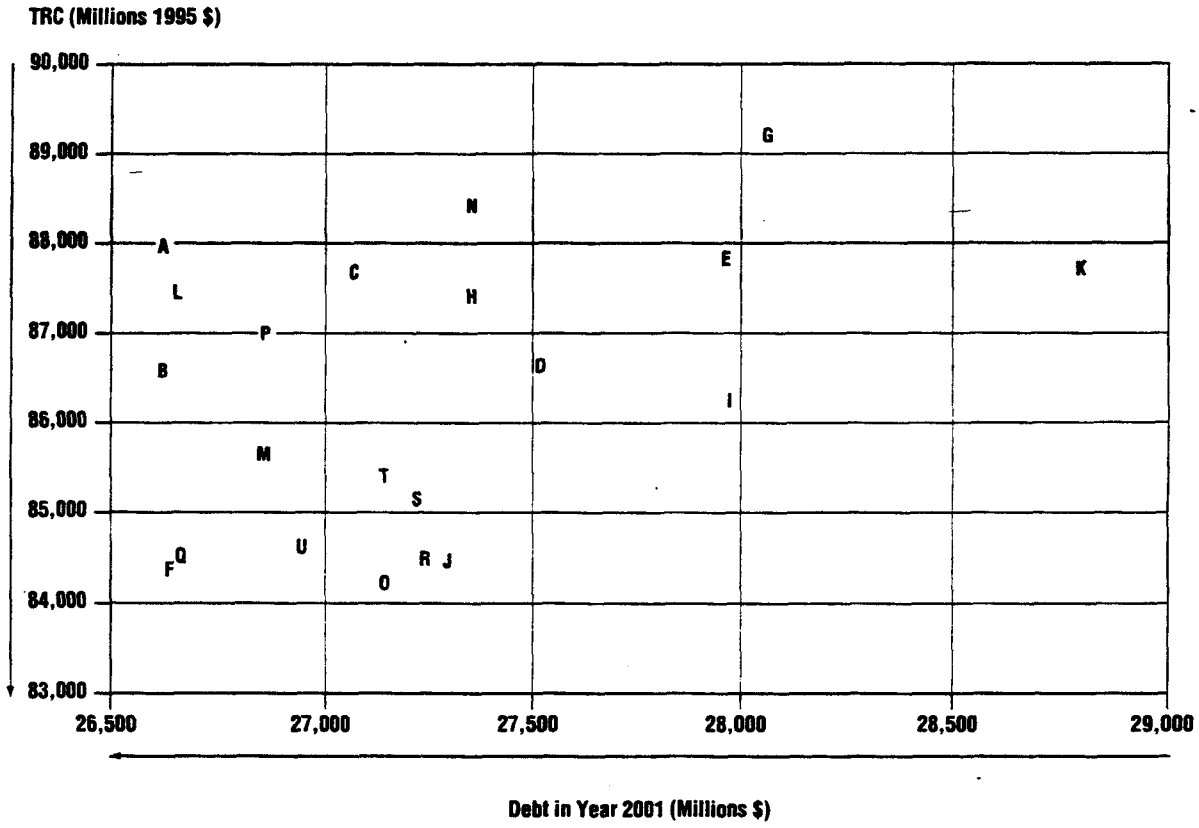

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FIGURE T8-42. Environmental Emissions Trade-Off
Average Annual Carbon Dioxide Emissions vs. Total Resource Costs

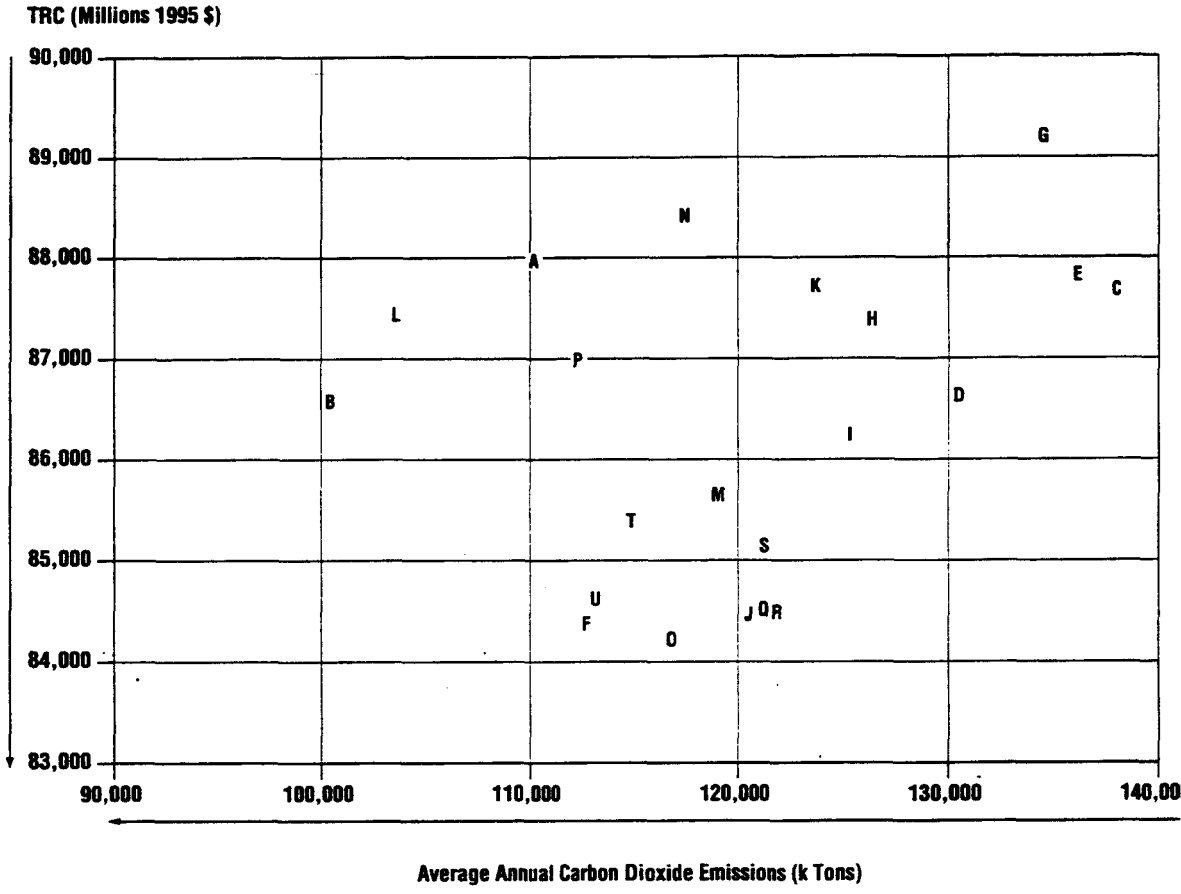

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FIGURE T8-43: Environmental Emissions Trade-Off
Average Annual Sulfur Dioxide Emissions vs. Total Resource Costs

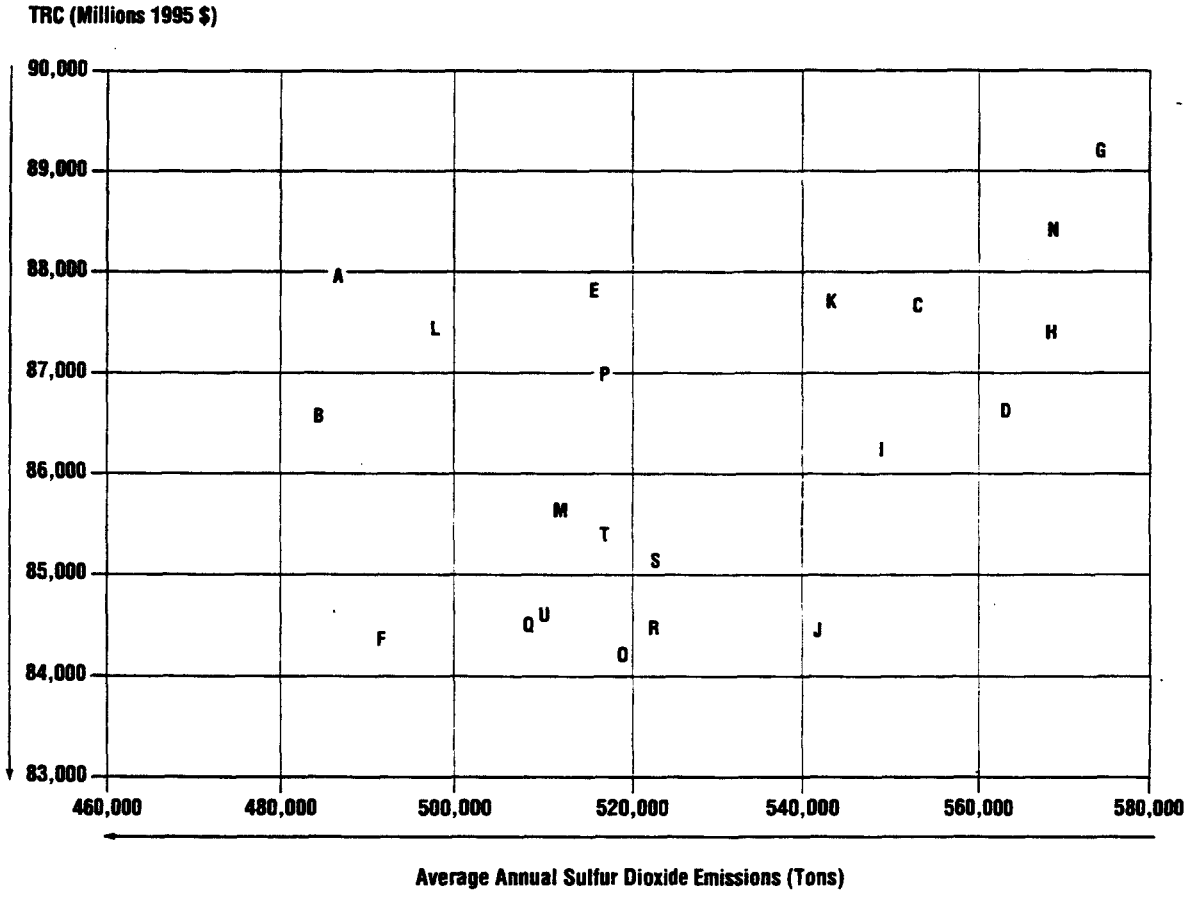

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FIGURE T8-44. **Environmental Emissions Trade-Off**
Average Annual Nitrogen Oxides Emissions vs. Total Resource Costs

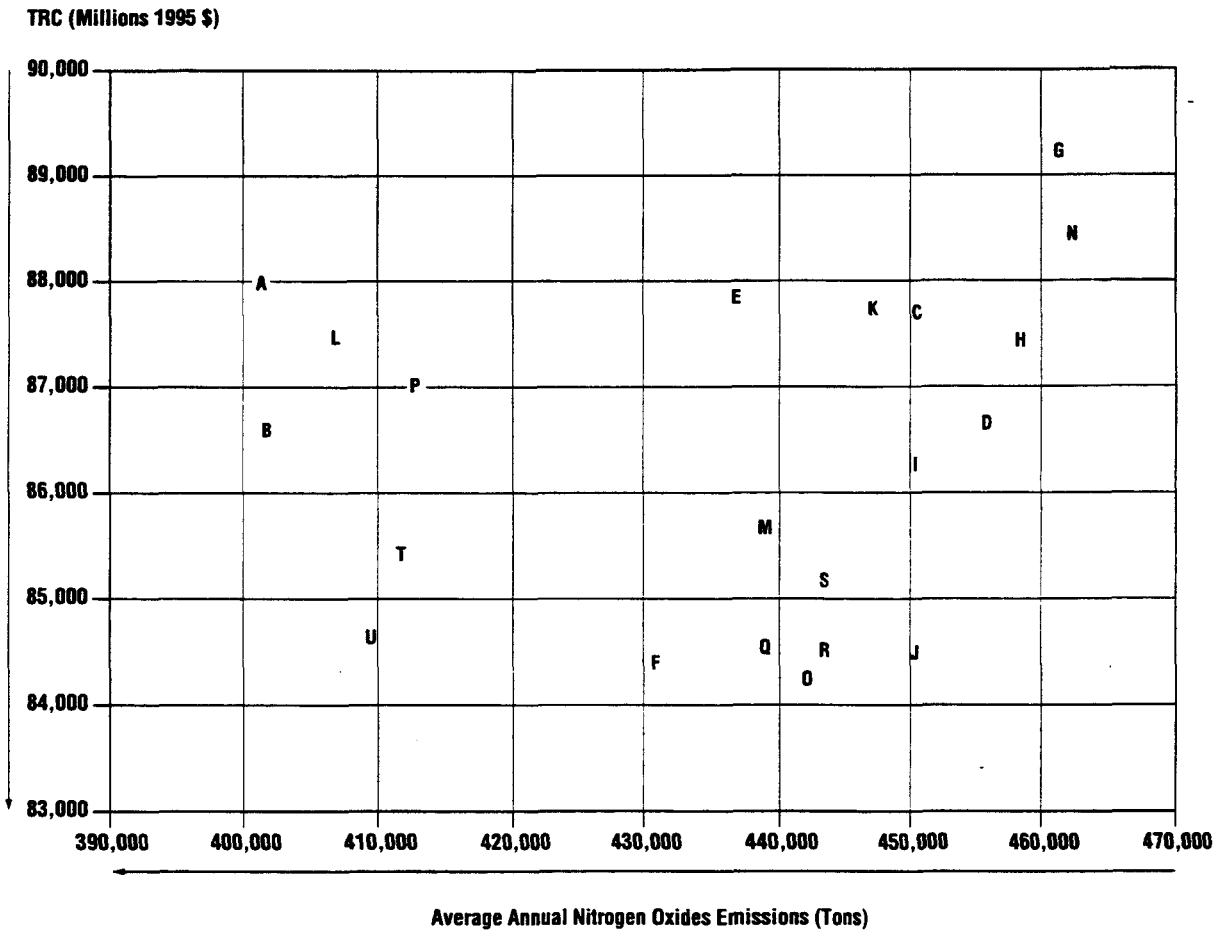

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FIGURE T8-45. **Environmental Emissions Trade-Off**
Thermal Discharge vs. Total Resource Costs

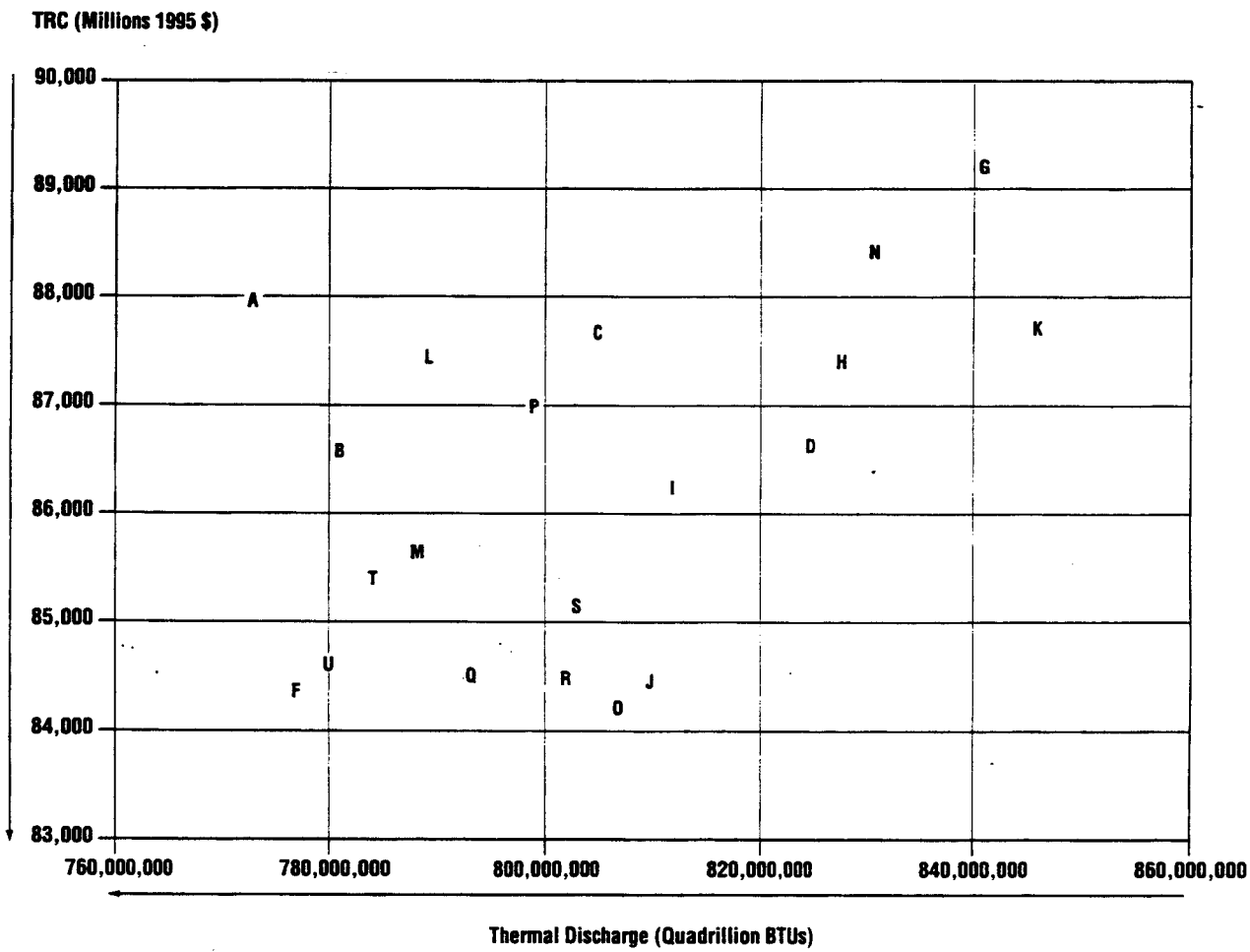

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FIGURE T8-46. **Environmental Emissions Trade-Off**
Volatile Organic Compounds vs. Average Annual Carbon Dioxide Emissions

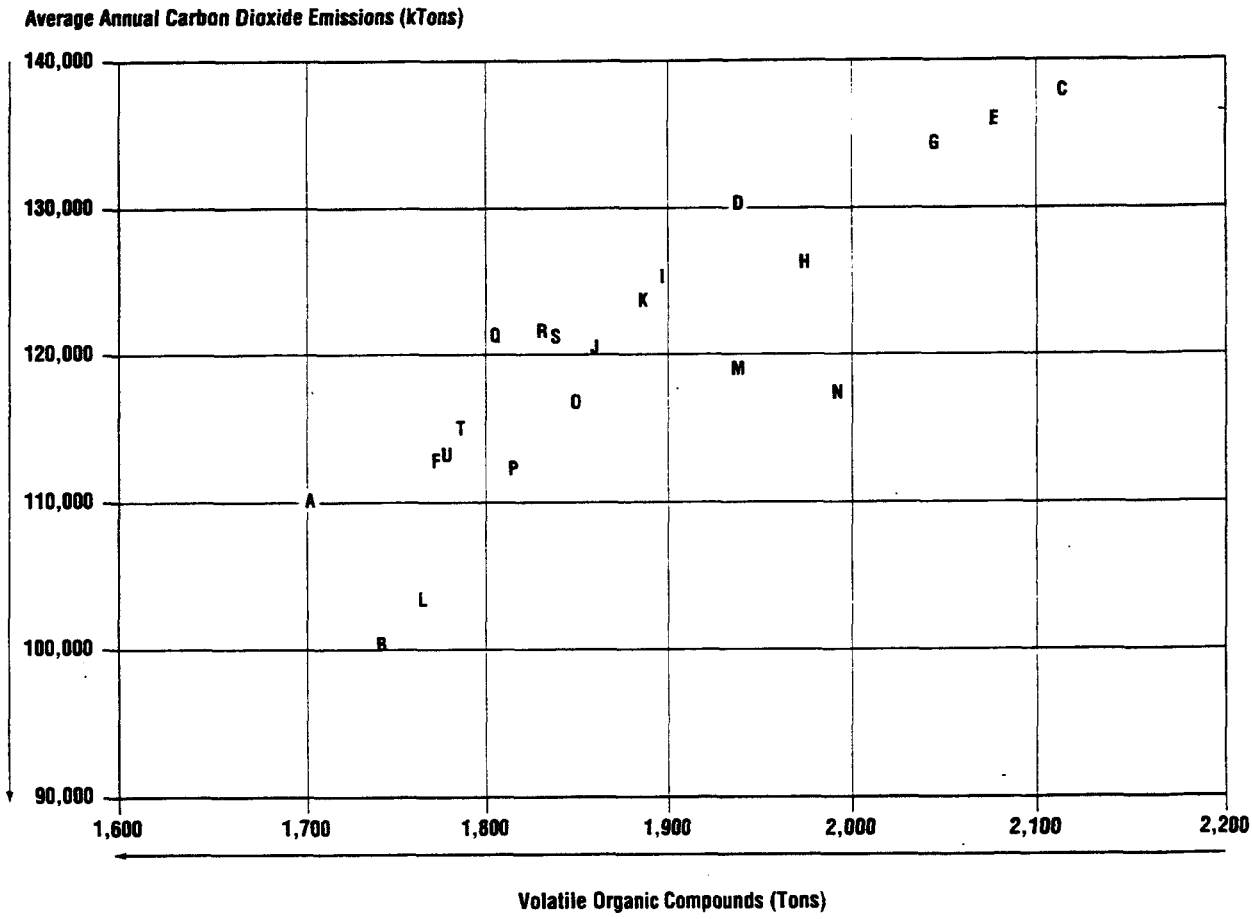

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FIGURE T8-47. **Environmental Emissions Trade-Off**
Total Suspended Particulates vs. Average Annual Carbon Dioxide Emissions

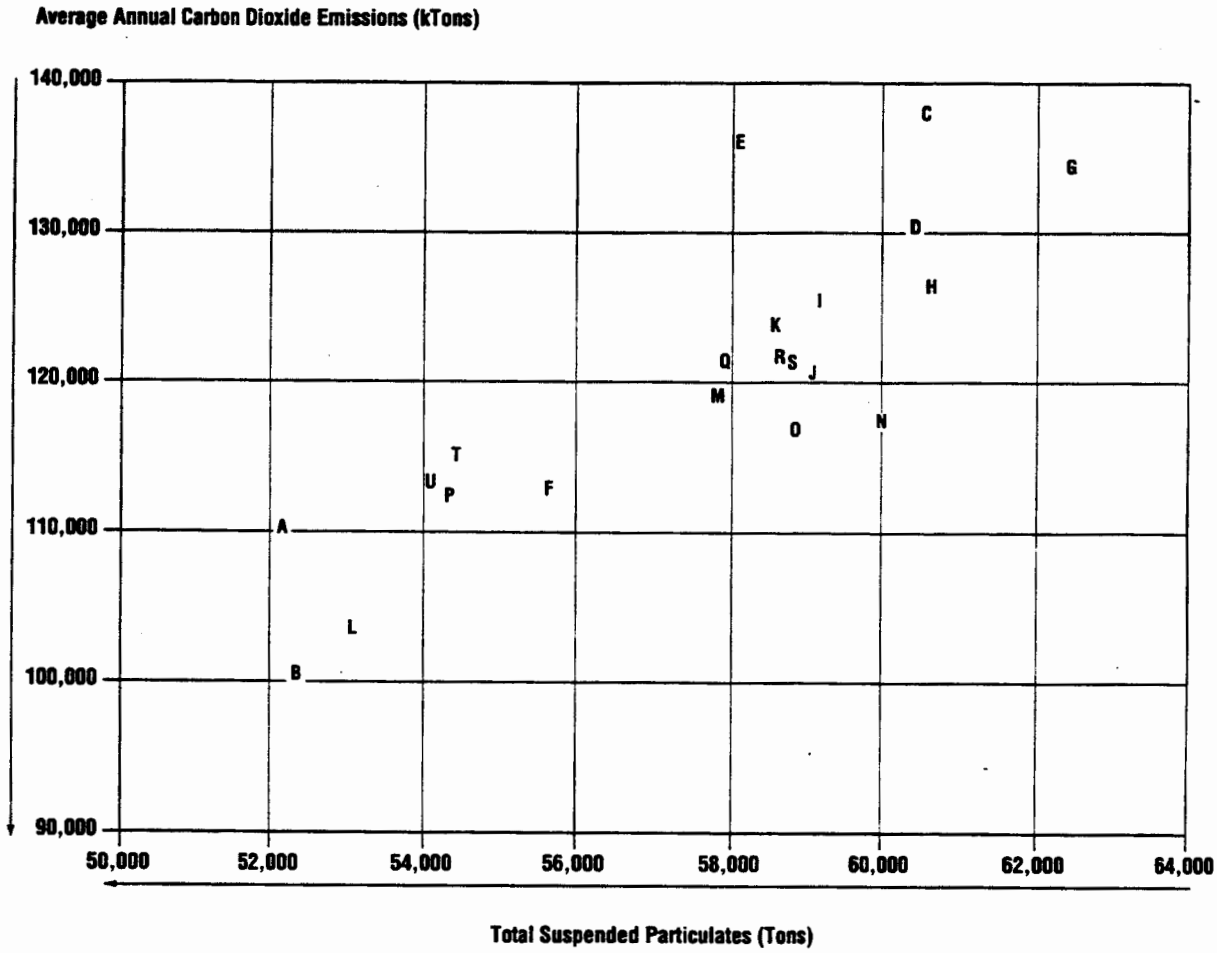

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FIGURE T8-48. **Environmental Emissions Trade-Off**
Thermal Discharge vs. Average Annual Carbon Dioxide Emissions

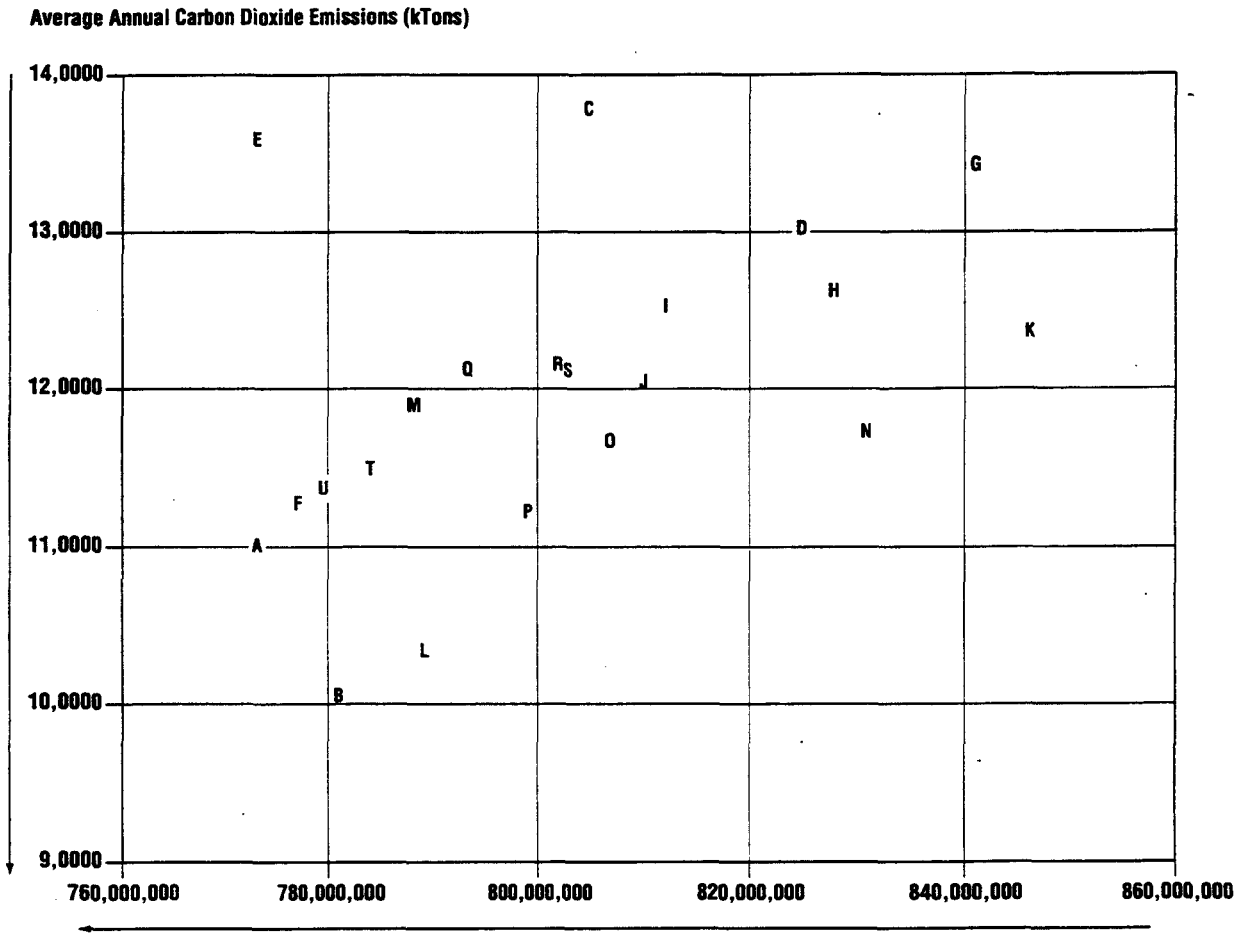

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FIGURE T8-49 **Environmental Impacts Trade-Off Greenhouse Gases vs. Health Inhalation**

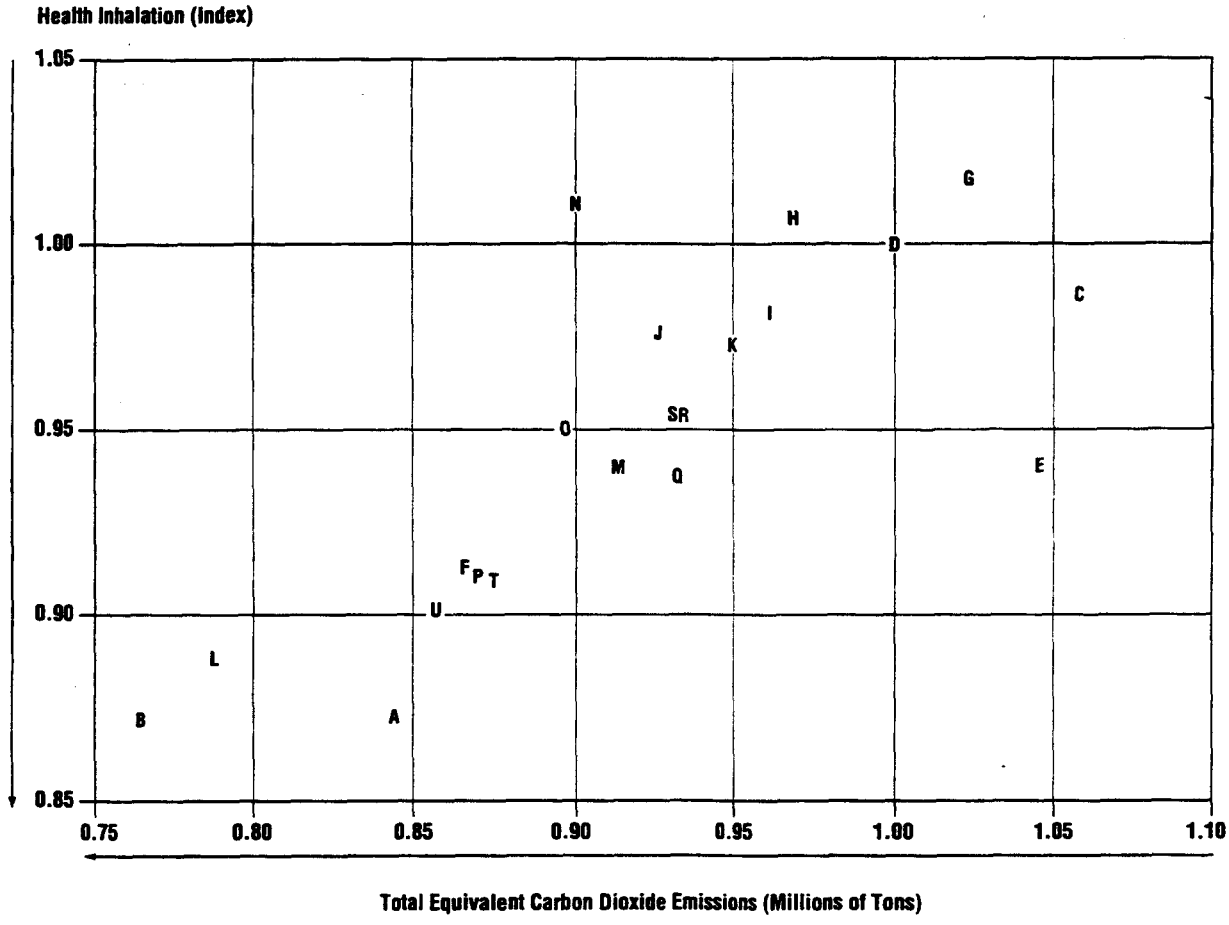

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FIGURE T8-50. **Environmental Impacts Trade-Off**
Visibility Impairment vs. Health Inhalation

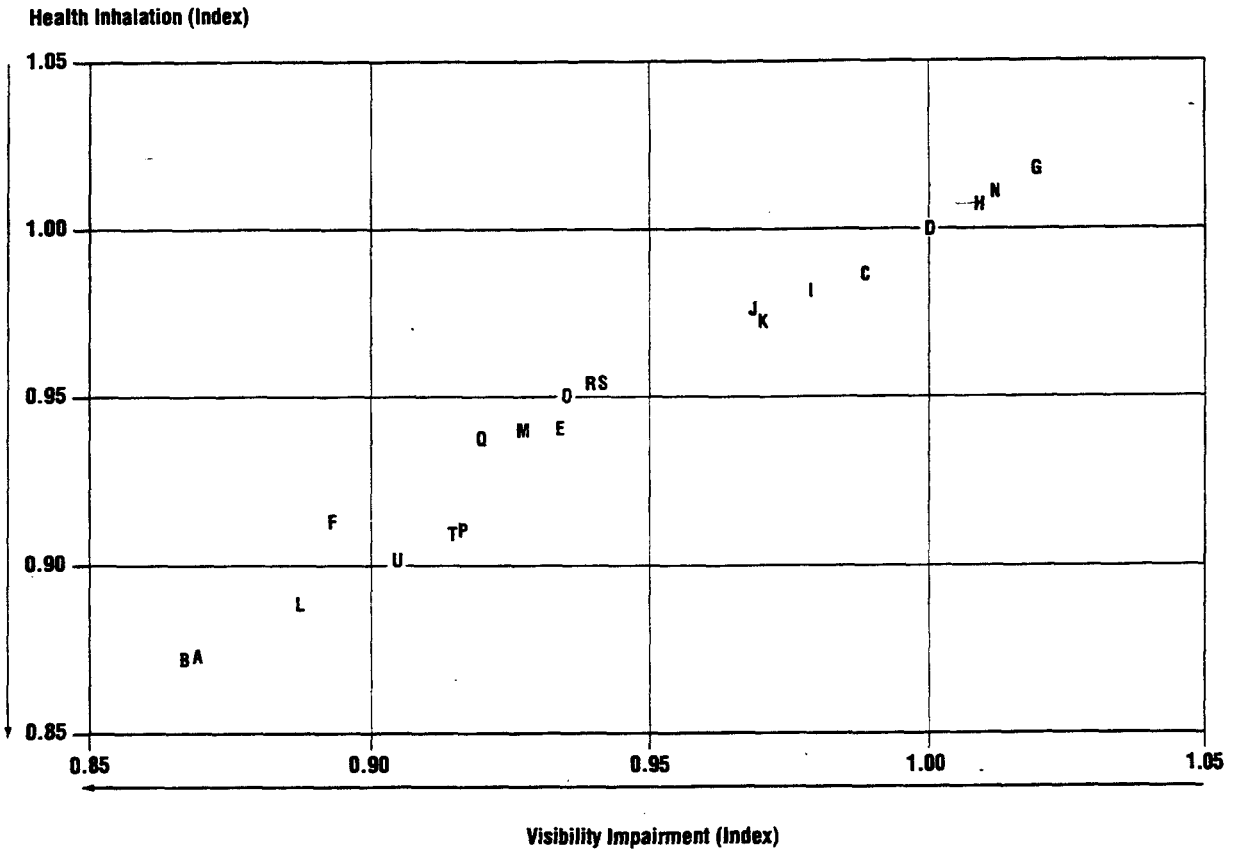

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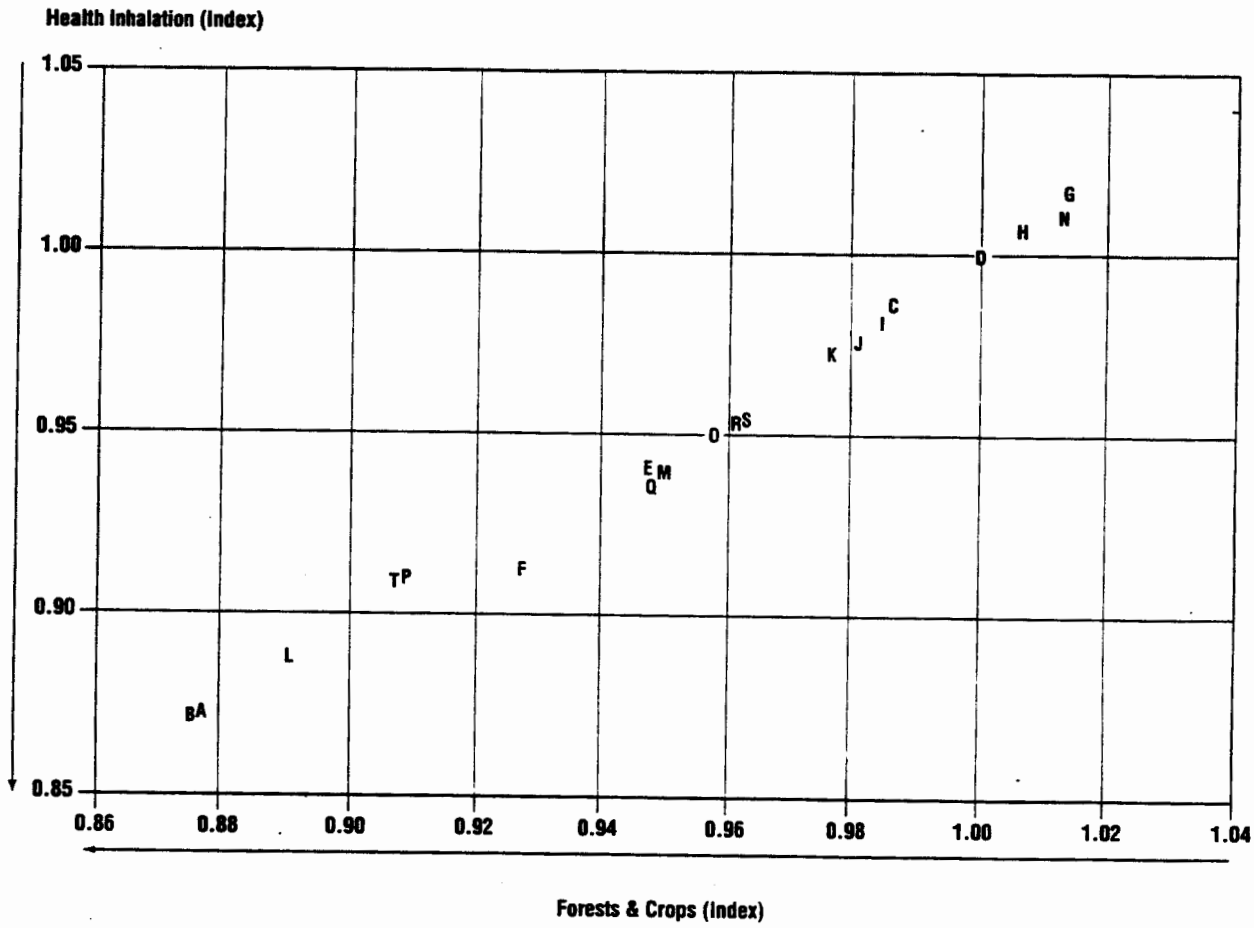
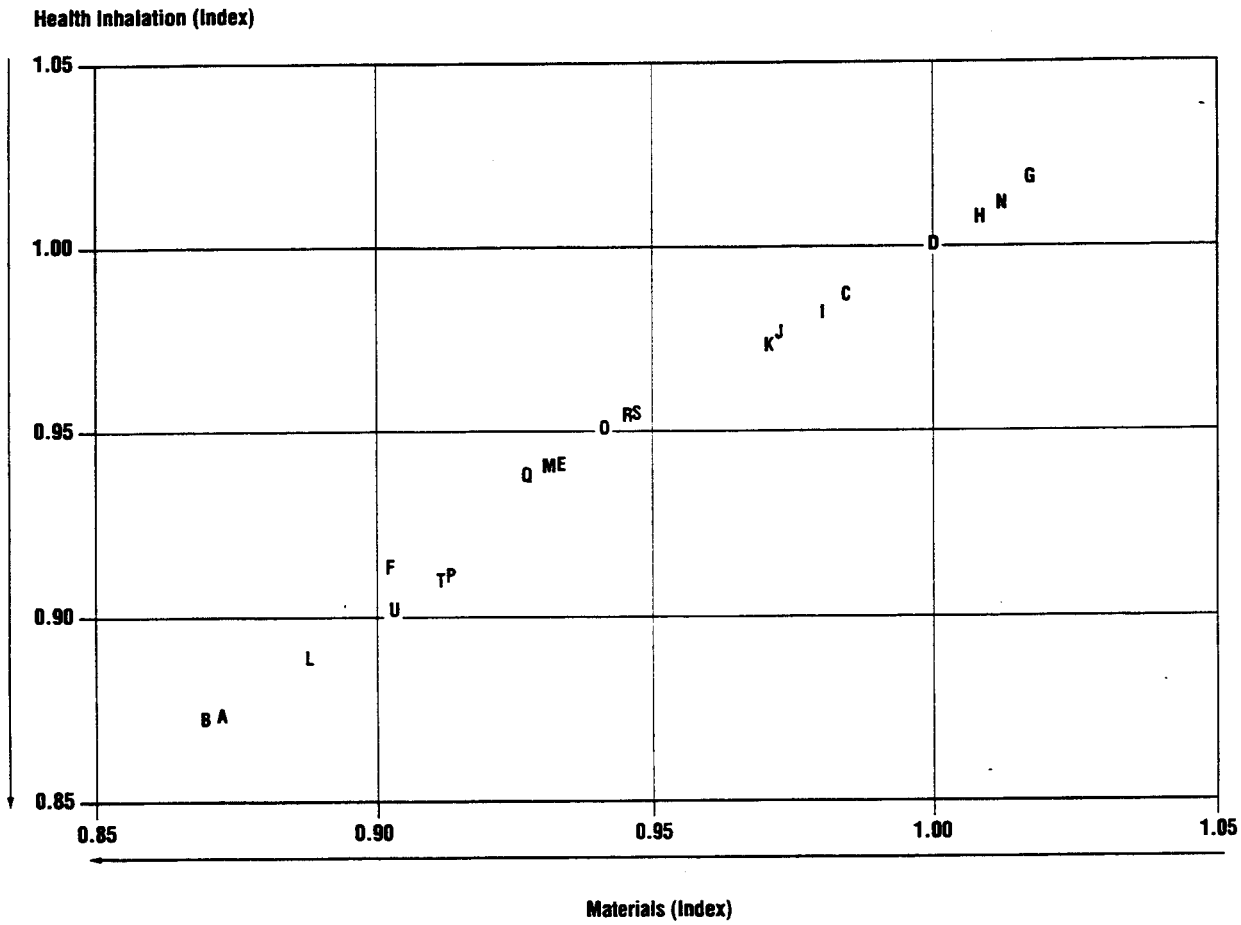
FIGURE T8-51. **Environmental Impacts Trade-Off**
Forests & Crops vs. Health Inhalation



Strategy

- **A** Minimum Carbon Dioxide—Natural Gas Repowering of Existing Coal
- **B** Minimum Carbon Dioxide—Natural Gas Repowering of Existing Coal and Renewables
- **C** Low-Cost Producer (Coal-Based)
- **D** Combined Cycle, Purchased Power, Coal (Reference)
- **E** Maximum Customer Value Index—Off-System Sales, High Beneficial Electrification, Declining Block Pricing
- **F** Low Total Resource Cost, High Demand-Side Management
- **G** Maximum Sales
- **H** Maximum Capacity Diversity
- **I** Bellefonte Nuclear Partnership
- **J** Bellefonte Coproduct, Renewables, Independent Power Producers
- **K** Defer and Build Browns Ferry 1 and Watts Bar 2 with Reference Expansion
- **L** Minimum Carbon Dioxide with Less Demand-Side Management
- **M** Combined Demand-Side Management and Off-System Sales
- **N** Decentralized Generation with More Renewables
- **O** Bellefonte Coproduct, More Demand-Side Management, More Off-System Sales
- **P** Low-Cost Renewables, Low-Price Demand-Side Management, Repowering
- **Q** Flexible with External Options
- **R** Flexible with Internal Options
- **S** Low Cost, Low Rates, Improved Environment
- **T** Low-Cost Renewables, Low-Price Demand-Side Management, Repowering, Bellefonte Coproduct Partnership
- **U** Low-Cost Renewables, More Demand-Side Management, Repowering, Bellefonte Coproduct Partnership

FIGURE T8-52. **Environmental Impacts Trade-Off**
Materials vs. Health Inhalation



Strategy

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- **B** Minimum Carbon Dioxide—Natural Gas Repowering of Existing Coal and Renewables
- **C** Low-Cost Producer (Coal-Based)
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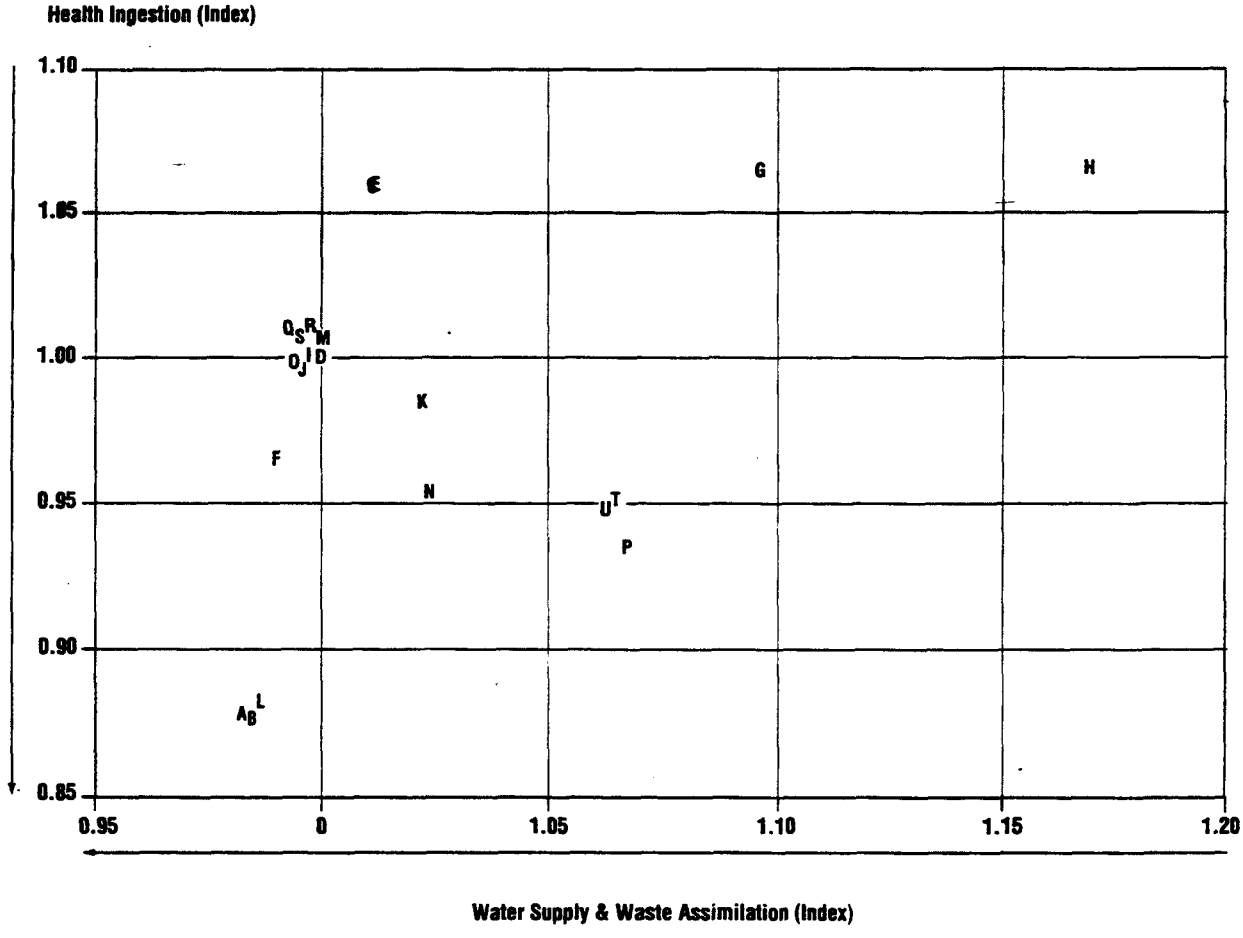
FIGURE T8-53. Environmental Impacts Trade-Off
Water Supply & Waste Assimilation vs. Health Ingestion



Strategy

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- **B** Minimum Carbon Dioxide—Natural Gas Repowering of Existing Coal and Renewables
- **C** Low-Cost Producer (Coal-Based)
- **D** Combined Cycle, Purchased Power, Coal (Reference)
- **E** Maximum Customer Value Index—Off-System Sales, High Beneficial Electrification, Declining Block Pricing
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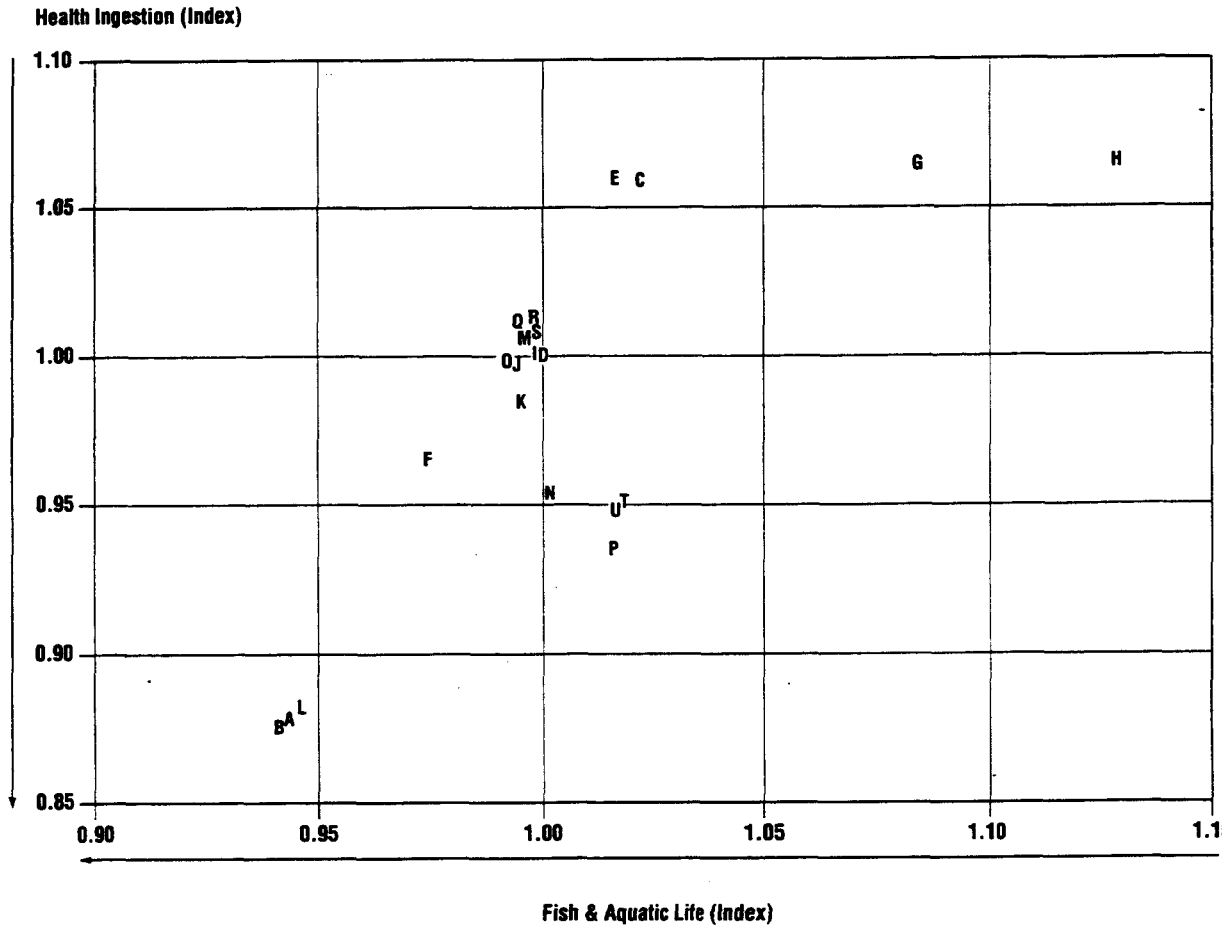
- **T** Low-Cost Renewables, Low-Price Demand-Side Management, Repowering, Bellefonte Coproduct Partnership
- **U** Low-Cost Renewables, More Demand-Side Management, Repowering, Bellefonte Coproduct Partnership

FIGURE T8-54. **Environmental Impacts Trade-Off**
Fish & Aquatic Life vs. Health Ingestion



Strategy

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- **B** Minimum Carbon Dioxide—Natural Gas Repowering of Existing Coal and Renewables
- **C** Low-Cost Producer (Coal-Based)
- **D** Combined Cycle, Purchased Power, Coal (Reference)
- **E** Maximum Customer Value Index—Off-System Sales, High Beneficial Electrification, Declining Block Pricing
- **F** Low Total Resource Cost, High Demand-Side Management
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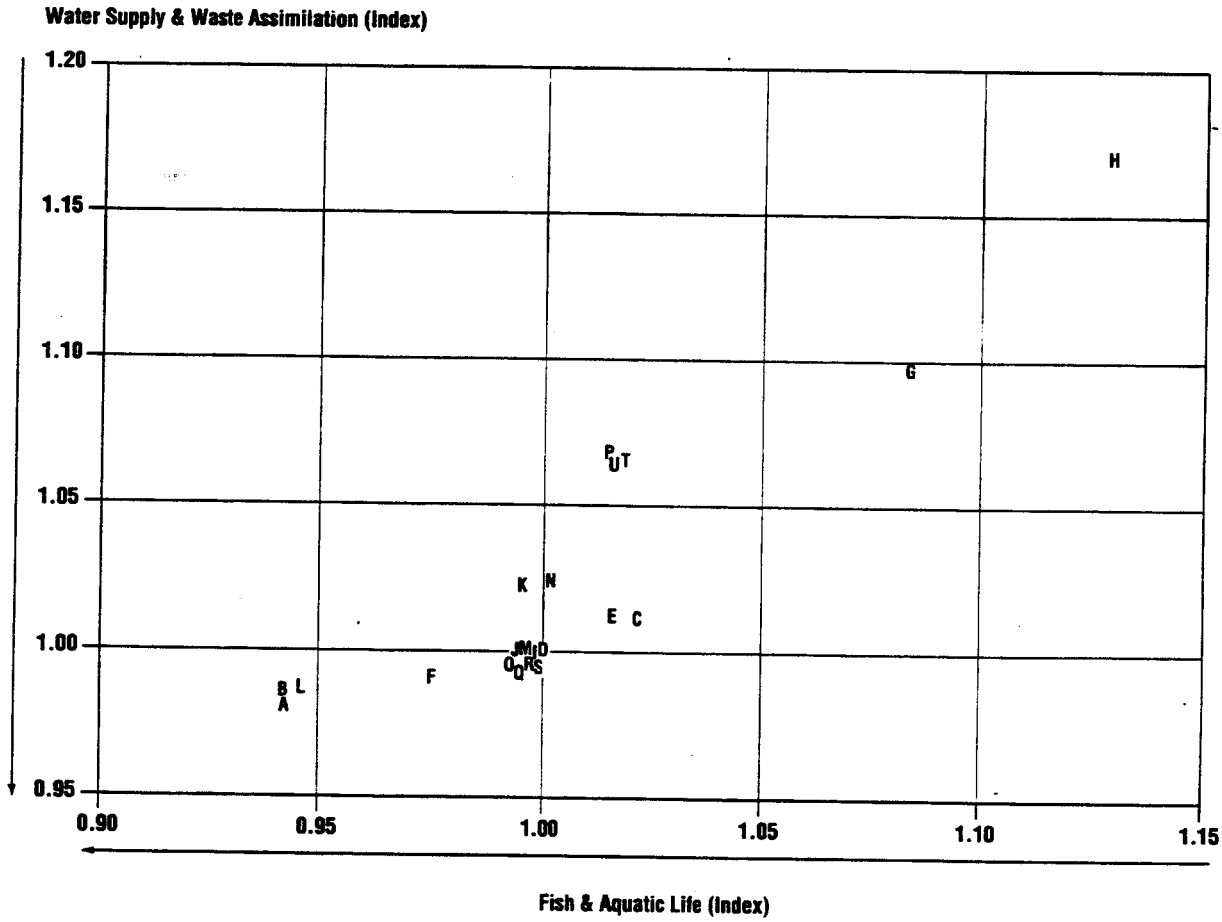
- **U** Low-Cost Renewables, More Demand-Side Management, Repowering, Bellefonte Coproduct Partnership

FIGURE T8-55 **Environmental Impacts Trade-Off**
Fish & Aquatic Life vs. Water Supply & Waste Assimilation



Strategy

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TVA'S NUCLEAR OPTIONS

This paper is from a report, "TVA's Nuclear Options, A Report on Bellefonte Units 1 and 2, Watts Bar Unit 2, and Browns Ferry Unit 1," that was issued by TVA in December 1994.

Overview

This is an interim review of issues involving four unfinished or inoperative TVA nuclear units and their impacts on rates, debt, long-term costs and flexibility for meeting future power needs. It has been developed largely in response to concerns identified through TVA's Integrated Resource Planning (IRP) process.

The three major concerns identified in TVA's IRP to date—debt, competitiveness, and nuclear power—are interrelated. In the opinion of many TVA customers and the public, high debt is generally associated with a poor competitive position. Since the large capital expenditures necessary to complete TVA's nuclear units will increase TVA's debt, completing these units contributes to a perception that TVA's competitiveness will suffer. With this in mind, the TVA Board of Directors requested the Chief Financial Officer (CFO) to initiate a study to look at the possibility of stopping the growth of debt. A summary of the conclusion of this study is:

> "The results of this review, which has encompassed the involvement of all areas of the TVA, is that TVA can limit its level of debt to $2 billion to $3 billion below the $30 billion debt ceiling and can achieve this limitation by the end of fiscal year 1997."

Additionally, the Board of Directors is requesting that the Chief Financial Officer conduct a feasibility study of reducing future levels of debt. The internal limit on debt would be formally reviewed periodically to ensure that this limitation meets TVA's continuing business needs. The debt limit will be carefully observed in the development of TVA's Integrated Resource Plan. The IRP will examine the disposition of TVA's debt in light of an increasingly competitive business environment.

TVA has three nuclear units in various stages of construction with scheduled completion dates ranging from 2003 to 2006. These units and current estimates of the costs to complete them are:

- Bellefonte Units 1 and 2, near Hollywood, Alabama—$4.4 billion
- Watts Bar Unit 2, near Spring City, Tennessee—$2.2 billion
- In addition, one TVA nuclear unit previously licensed to operate would need major modifications and is tentatively scheduled to return to service in the year 2001:
- Browns Ferry Unit 1, near Decatur, Alabama—$2.4 billion

The question of how to proceed with these four nuclear units is of critical importance to TVA and the region it serves. The total cost to complete or restore them to service as nuclear units is estimated to be about $9 billion—unquestionably a major investment by TVA customers. But in addition to these costs, TVA must consider several other factors, such as:

- The need for power in the future
- The cost of other options that could replace the nuclear units
- Prior investment in the nuclear units
- TVA's long-term costs
- TVA's rising debt
- The impact of any decision on short- and long-term rates
- The environmental effects of various options

All of these issues are currently being addressed in TVA's IRP, a comprehensive study of future power needs in the TVA region and the various ways and costs of meeting them. The IRP will not be completed until late 1995. However, several concerns regarding TVA's nuclear construction plans have already been identified through the IRP process. It is necessary, therefore, to review the current status of these units to ensure that they are being managed in the most cost-effective and beneficial manner for TVA customers.

As a result of this review, staff recommends that over the near term TVA should not fund the completion or restoration of Bellefonte Units 1 and 2, Watts Bar Unit 2, and Browns Ferry Unit 1 as nuclear units. Instead, TVA should keep open alternatives for these units that would minimize short-term rates, increase long-term flexibility, minimize long-term costs, and limit debt.

Alternatives to completing/restoring these units as nuclear units include:

- Converting them to another technology such as natural gas
- Replacing them with different types of supply- and demand-side resource options
- Completing the construction of one or more units in partnership with others

- Maintaining the nuclear units in a "mothballed" state and deciding later whether to complete or replace them

Some options could involve limited TVA investment in the future. All options will be carefully considered in the IRP process and, ultimately, the most cost-effective long-term uses for these units will be decided by the TVA Board of Directors.

Introduction

TVA formally began its IRP process in February 1994. An IRP is a process for identifying, thoroughly evaluating, and selecting a set of resource options to meet the expected future consumer demand for electricity. TVA's IRP process is called "Energy Vision 2020."

TVA is committed to developing an energy strategy for the future with considerable input from customers and stakeholders. Decisions and recommendations for meeting future energy needs will take into account the values and expectations customers have for their energy supplier for both electrical generation and demand-side options, as well as for new energy technologies. Information TVA receives from stakeholders is being incorporated into the technical analysis process for Energy Vision 2020.

A series of open meetings provided an opportunity for TVA to both inform the public about its resource planning process and collect valuable input from the public. From July to November, TVA held 12 meetings throughout the Tennessee Valley. Approximately 300 people attended to view the Energy Vision 2020 displays, talk with TVA representatives, and provide input to the planning process. After publication of the draft IRP in July 1995, there will be another round of public meetings across the Valley. These meetings will update the public on the latest findings and provide an opportunity to review and react to TVA's draft plan.

During the summer of 1994, one-on-one interviews were conducted with about 100 opinion leaders across the Tennessee Valley and in Washington, DC. The opinion leaders represented distributors of TVA power, industrial customers, environmental advocates, government, and community leaders. A questionnaire was designed to gather opinions on the issues TVA will examine in Energy Vision 2020. The questions fell into three major areas:

- General questions about the Tennessee Valley region
- Questions about economic development and the environment
- TVA-specific questions

The Energy Vision 2020 Review Group was established in June 1994 to bring key stakeholders into TVA's energy planning process. It consists of 18 representatives from various organizations outside TVA with a wide variety of views and interests. Members of the group provide input and views on TVA's planning assumptions, new options for consideration, and issues associated with long-term energy planning. To date, the Review Group has had seven intensive, full-day sessions, performing in-depth reviews of TVA's IRP planning assumptions and the overall IRP process. Four additional meetings are scheduled.

The Tennessee Valley Public Power Association, an association of the 160 distributors of TVA power, has established a Power Supply Planning Committee. This 28-member committee provides critical reviews of TVA's IRP process and of the major issues facing TVA and the distributors. Since it was formed in May 1994, TVA has met with the committee three times to discuss energy planning issues affecting TVA's wholesale customers.

Through this interactive public participation process and internal reviews, numerous concerns have been identified. Among those most frequently voiced are:

1. TVA's competitive position
2. TVA's nuclear program
3. TVA's debt

With many of the fundamental assumptions necessary for an energy strategy already in an advanced state of review in the IRP process, TVA staff has been able to perform a preliminary analysis of these three concerns. As a result, the staff has prepared this interim report to present the latest findings to the TVA Board of Directors. It should be stressed that these are only initial findings. Taking interim action on these findings would not pre-empt the ultimate decisions to be made through the IRP process. Rather, this will enhance TVA's ability to respond to the rapidly developing competitive environment of the electric utility industry.

This report examines the question of whether TVA should fund the completion or restoration of Bellefonte Units 1 and 2, Watts Bar Unit 2, and Browns Ferry Unit 1 as nuclear units. Alternatives to TVA completing these units include:

- Converting them to another technology such as natural gas
- Replacing them with different types of supply- and demand-side resource options
- Completing the construction of one or more of the units in partnership with others
- Maintaining the nuclear units in a "mothballed" state and deciding later whether to complete or replace them

A more detailed explanation of these alternatives is described in the Nuclear Options Appendix.

Each of these alternatives will affect future costs, electric rates, debt, and environmental impacts, as well as TVA's ability to respond to an ever-changing marketplace. In this paper, we will:

- Review certain key assumptions, such as the need for power,

FIGURE T8-56. **Residential Costs – CalendarYear 1993**

Kentucky Utilities	4.4 ¢/kWh
Kentucky Power	4.9
Kingsport Power	5.1
Appalachian Power (VA)	5.7
Public Service of Indiana	5.8
TVA	**5.9**
Louisville Gas & Electric	6.0
Mississippi Power	6.2
Ohio Power	6.3
East Kentucky Power	6.4 [1]
Gulf Power	6.6
Big Rivers	6.9
South Carolina Elec & Gas	7.1
Alabama Power	7.2
Duke Power	7.3
Union Electric	7.5
Georgia Power	7.8
Louisiana P&L	7.8
Florida Power	7.9
New Orleans Pub Ser	7.9
Florida P&L	8.1
Gulf States Utilities	8.2
Carolina P&L	8.3
Virginia Power	8.6
Mississippi P&L	8.6
Arkansas P&L	9.3
Illinois Power	10.2

[1] Using South Kentucky REC Corp. as representative of East Kentucky Power Coop

Source: DOE 826, REA Forms 7 & 12, and TVA Electric Sales Statistics

cost of the nuclear units, and several other key assumptions that significantly affect the alternative choices available concerning the TVA nuclear construction program.

- Evaluate the changes in costs, electric rates, and debt resulting from the different resource choices.
- Draw some preliminary conclusions upon which the TVA Board may wish to act.

TVA'S COMPETITIVE POSITION

TVA electric rates are currently competitive with other utilities. Comparisons of TVA rates with surrounding utilities for residential, commercial, and industrial customers are shown in *Figures T8-56, T8-57,* and *T8-58.*

TVA's residential electric rates are lower than most surrounding utilities. Of the 27 Southeastern utilities shown in *Figure T8-56,* TVA ranks sixth lowest. Likewise, TVA's commercial and industrial rates are below the median level of other utility rates shown in *Figures T8-57* and *T8-58.* The recommendations in this report are intended to improve TVA's competitive position into the future.

SELF-IMPOSED DEBT LIMITATION

The three major concerns identified in the IRP to date—debt, competitiveness, and the future of the four nuclear units—are interrelated. In the opinion of many TVA customers and members of the public, high debt is generally associated with a poor competitive position. Since the large capital expenditures necessary to complete TVA's nuclear units will increase TVA's debt, completing these units contributes to a perception that TVA's competitiveness will suffer. With the rapid evolution of the utility industry into a competitive environment, many utilities are improving their debt structure so that the pricing of electricity can be more flexible in response to future uncertainty. Clearly, with the increasing risk of TVA losing customers to other utilities, prudent business practices suggest that debt be carefully managed and controlled. With this in mind, the TVA Board of Directors requested the CFO to initiate a study to investigate the possibility of stopping the growth of debt. This study, "Report on Controlling the TVA Debt," was completed in December 1994. The following Introduction and Conclusion of the CFO study highlight several key points concerning TVA's debt:

FIGURE T8-57. **Commercial Costs – Calendar Year 1993**

Kentucky Utilities	4.3 ¢/kWh
Public Service of Indiana	4.6
Kingsport Power	5.1
Kentucky Power	5.2
Appalachian Power (VA)	5.3
Ohio Power	5.5
Louisville Gas & Electric	5.6
Gulf Power	5.6
South Carolina Elec. & Gas	5.6
Florida Power	5.8
TVA	**5.9**
Mississippi Power	6.0
Duke Power	6.0
Virginia Power	6.2
Union Electric	6.3
Florida P&L	6.8
East Kentucky Power	6.8 [1]
Big Rivers	6.9
Carolina P&L	6.9
Alabama Power	6.9
Gulf States Utilities	7.3
Georgia Power	7.4
Arkansas P&L	7.6
Louisiana P&L	7.8
Illinois Power	8.3
New Orleans Pub Ser	8.4
Mississippi P&L	8.6

[1] Using South Kentucky REC Corp. as representative of East Kentucky Power Coop

Source: DOE 826, REA Forms 7 & 12, and TVA Electric Sales Statistics

"At the Tennessee Valley Authority Board of Directors meeting on September 21, 1994, the Board of Directors requested that the Chief Financial Officer undertake a study to determine if it would be possible to stop the growth of debt in TVA and, in effect, impose an internal limitation on debt below TVA's statutorily mandated limit of $30 billion. If that is possible, what should that limit be and when could it be achieved.

"The results of this review, which has encompassed the involvement of all areas of the TVA, is that TVA can limit its level of debt to $2 billion to $3 billion below the $30 billion debt ceiling and can achieve this limitation by the end of fiscal year 1997."

The internal debt limit would be formally reviewed periodically to ensure that this limitation meets TVA's continuing business needs.

Additionally, the Board of Directors is requesting that the CFO conduct a feasibility study of reducing future levels of debt.

The debt limit will be carefully observed in the development of TVA's IRP. In addition, the IRP will examine the disposition of TVA's debt in light of an increasingly competitive business environment.

I. Key Assumptions for Evaluating TVA's Nuclear Construction Program

Although many assumptions about possible futures must be made to evaluate TVA's nuclear construction program, two key assumptions are both important and highly uncertain. These are the need for power, which is largely determined by the expectations of future load growth, and the cost and performance parameters for constructing and operating TVA nuclear power plants.

NEED FOR POWER

TVA will likely require additional power beginning in 1998 and increasing to several thousand megawatts (MW) by 2005. This need is shown graphically in *Figure T8-59*.

The bars in *Figure T8-59* represent TVA's long-term forecasts of peak loads plus the necessary capacity reserves to maintain a reliable power system. TVA's peak loads are approximately 24,000 MW today and are expected to increase 1.9 percent per year from 1994 to 2020. Forecasts of future load growth are particularly uncertain, and this uncertainty is represented by low

FIGURE T8-58. **Industrial Costs – Calendar Year 1993**

Big Rivers	3.0 ¢/kWh [1]
Ohio Power	3.2
Kentucky Utilities	3.3
Kentucky Power	3.3
Public Service of Indiana	3.4
Kingsport Power	3.5
Mississippi Power	3.6
Louisville Gas & Electric	3.8
Appalachian Power (VA)	3.8
South Carolina Elec. & Gas	3.9
TVA	**3.9** [2]
Louisiana P&L	4.1
Duke Power	4.3
Gulf Power	4.3
Illinois Power	4.4
Virginia Power	4.4
Alabama Power	4.5
Gulf States Utilities	4.6
Georgia Power	4.7
Florida Power	4.8
Union Electric	5.2
New Orleans Pub Ser	5.3
Florida P&L	5.4
Carolina P&L	5.5
East Kentucky Power Coop	5.5 [3]
Arkansas P&L	6.0
Mississippi P&L	6.6

1 Non-Aluminum Industrial is 3.9 cents/kWh
2 TVA's directly served industrial cost is 3.0 cents/kWh and the distributor served industrial cost is 4.6 cents/kWh
3 Using South Kentucky REC Corp. as representative of East Kentucky Power Coop

Source: DOE 826, REA Forms 7 & 12, and TVA Electric Sales Statistics

and high forecasts of peak load, which generally bound the range of uncertainty. In the low load forecast, peak loads are expected to increase by 0.1 percent per year from 1994 to 2020, and in the high forecast by 3.3 percent per year over the same period. In *Figure T8-59*, the three segments of each bar represent TVA's low, medium, and high demand requirements for that year.

TVA currently has approximately 25,500 MW of existing capacity, with a plan to add 2,235 MW upon the completion of Watts Bar Unit 1 and the return to service of Browns Ferry Unit 3. This existing and future capacity, or supply, is shown by the solid line in *Figure T8-59*.

Matching the supply with projected future demand requirements (comparing the bars to the supply line in *Figure T8-59*) indicates that TVA's need for additional capacity will increase from 700 MW in 1998 to several thousand megawatts by 2005. It must be recognized that these capacity needs are highly uncertain. With low demand requirements, there is no need for future capacity from 1996 to 2020; whereas, with high load growth, there is an almost immediate need for additional capacity.

NUCLEAR COSTS AND PERFORMANCE

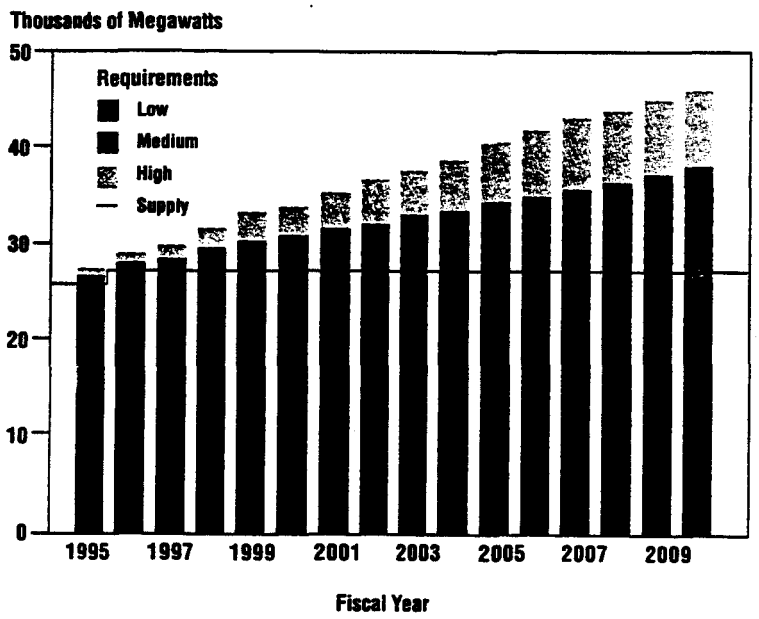
The question of whether to complete/restore the nuclear units is affected by several key assumptions about nuclear construction and operation. Most important are the cost to complete the nuclear units, the cost to operate and maintain the units, and the level of generation from the units or capacity factors. Of lesser significance are the fuel costs and costs to decommission the nuclear plants at the end of their useful lives, currently estimated to be at least 40 years. The future construction cost and operational performance of the nuclear units cannot be precisely forecast and this uncertainty in cost and performance is represented by a range of forecasts for these key assumptions.

Project Cost and Schedule Estimates

Both the expected, or medium, forecast and the low and high forecasts for the cost to complete the nuclear units are shown in *Figure T8-60*.

The medium and high-cost estimates are based on detailed engineering cost estimates plus adjustments reflecting the history of cost-estimating experience by TVA and the nuclear industry. The detailed engineering cost estimates that have

FIGURE T8-59. **Long-Term Capacity Requirements and Supply**



been developed for each of the nuclear projects serve as the "low" estimate for IRP analysis.

Capacity Factors

Capacity factor is a ratio of actual generation from a generating unit compared to its theoretical best output over a certain period of time. TVA's average annual nuclear capacity factor since restoring Sequoyah Units 1 and 2 and Browns Ferry Unit 2 to service has been 67 percent. This value is used as the medium estimate for future capacity factor for the currently operating units (Sequoyah Units 1 and 2 and Browns Ferry Unit 2), for projects under active construction or modification (Watts Bar Unit 1 and Browns Ferry Unit 3), and for the currently inactive projects (Watts Bar Unit 2, Browns Ferry Unit 1, and Bellefonte Units 1 and 2). TVA's high and low estimates for nuclear capacity factor are 86 percent and 55 percent, respectively. Industry trends have shown significant improvement in nuclear performance over the past decade.

Operating Costs

Operating costs for a nuclear unit include "operations and maintenance," "additions and improvements," and fuel. In addition, funds are accumulated for decommissioning throughout the life of the unit. These cost estimates are shown in *Figure T8-61.*

Operations and maintenance cost assumptions are based on the costs incurred by TVA for the operating units over the past five years. The range of potential costs is based on potential variations in plant staffing levels, since this is the primary driver for nuclear operations and maintenance costs.

The cost of additions and improvements has dropped significantly throughout the nuclear industry with the completion of regulation-driven modifications required after the 1979 Three Mile Island accident. TVA is assuming a level of expenditures consistent with industry experience. Replacing steam generators at Sequoyah Units 1 and 2 and Watts Bar Units 1 and 2 is an unusual addition and improvement and is considered explicitly in the IRP analysis.

Nuclear fuel costs at TVA have been higher than average because of contracts written during the 1980s. As these contracts have expired, TVA will be procuring fuel at a cost typical of the industry. Nuclear fuel is relatively abundant now, and sufficient supplies are expected to be available throughout the period of the IRP to limit cost escalation to that of general inflation.

Decommissioning costs are accrued and set aside during the operating life of the plant in accordance with rules issued by the Nuclear Regulatory Commission (NRC). Current cost estimates for decommissioning exceed these NRC requirements. TVA has identified a range of possible decommissioning costs for consideration in the IRP assumptions that use the NRC-required level as a low estimate.

FIGURE T8-60. **Nuclear Project Cost and Schedule Estimates**

Project	Cost Estimate (millions of 1994 dollars) Low	Medium	High	Nominal Schedule (months)
Bellefonte Unit 1	1311	2622	3470	67
Bellefonte Unit 2	912	1824	2420	*
Browns Ferry Unit 1	1187	2374	3150	78
Watts Bar Unit 2	1097	2194	2910	62

** Approximately 18 months after Bellefonte Unit 1 is completed*

FIGURE T8-61. **Nuclear Operating Costs (in 1994 dollars)**

	Low	Medium	High
Operations & Maintenance	$55/kW/yr	$69/kW/yr	$84/kW/yr
Additions & Improvements		Approx. $15 million/unit/yr	
Incremental Fuel		$0.42/million Btu	
Decommissioning			
• Pressurized Water Reactors	$ 200 million	$ 300 million	$ 600 million
• Boiling Water Reactors	$ 250 million	$ 350 million	$ 700 million

License Extension

Operating licenses for the Browns Ferry units expire during the time period covered by the IRP. The NRC issued regulations in 1991 that allow an operator to apply for a license extension of up to 20 years. These rules are currently being revised and are not expected to be finalized until mid-1995. Consequently, the cost and schedule for obtaining a license extension cannot be defined with certainty. Technical studies, however, have not shown any "show-stoppers" that would preclude extending the Browns Ferry licenses. To accommodate this possibility, the IRP will consider both extending the operating licenses at these units and terminating their operation at the current license expiration date.

THE CONVERSION ALTERNATIVE

Figure T8-62 provides a cost and performance summary for converting the Bellefonte nuclear units to fossil-fueled units. Four alternative conversion options are considered: coal-fired plant, natural gas combined cycle, integrated gasification combined cycle, and integrated gasification combined cycle with coproduction of a chemical product such as methanol or methyl tertiary butyl ether.

THE CANCELLATION ALTERNATIVE AND REPLACEMENT WITH SUPPLY- OR DEMAND-SIDE RESOURCES

The key assumptions for supply- and demand-side alternatives that are available to replace the nuclear units are too numerous to display in this paper. However, the cost and performance characterizations for each supply option are identified in the paper, "Energy Vision 2020 Supply-Side Options." Cost and per-

FIGURE T8-62. **Cost and Performance Summary**

	Pulverized Coal, 4x616 MW	Gas-Fired Combined Cycle 10x222 MW	IGCC, 9x250 MW	IGCC with Coproduction, 9x239 MW (feasibility only)
Capacity, MW	2,464	2,220	2,250	2,151
Heat Rate, Btu/kWh	9,611	7,367	8,488	11,761
Fuel [1]	Illinois Basin 3.0 lb SO_2 Coal	Natural Gas	Illinois Basin 7.0 lb SO_2 Coal	Illinois Basin 7.0 lb SO_2 Coal
Capital Cost, [2] $/kW (1994)	$1,263 (base) $1,158 (low) $1,325 (high)	$475 (base) $442 (low) $507 (high)	$1,484 (base) $1,327 (low) $1,650 (high)	$1,730 (base) $1,530 (low) $1,942 (high)
Total Capital Cost, MM$ (1994)	$3,112 (base) $2,853 (low) $3,265 (high)	$1,054 (base) $981 (low) $1,125 (high)	$3,339 (base) $2,986 (low) $3,712 (high)	$3,721 (base) $3,291 (low) $4,177 high)
Coproduct	none	none	none	Methyl Tertiary Butyl Ether
Coproduction Rate, Tons/Day	none	none	none	4,410 tpd
Schedule, Months First Capacity Addition [3]	90 months	66 months	66 months / 81 months [4]	66 months / 81 months [4]
Last Capacity Addition	126 months	90 months	90 months / 108 months [4]	90 months / 108 months [4]

1 Fuel SO_2 is given in terms of pounds of sulfur dioxide produced per million Btus fired.
2 Base capital cost is the expected cost. The high and low ranges define the potential range of capital costs given the uncertainties that have been identified.
3 Duration to first capacity addition assumes approximately 3 years from project initiation to start of construction for environmental permitting activities. This duration may be reduced to 18 months if credit can be taken for previously collected environmental data.
4 First duration assumes phased construction with gas-fired generation coming on-line first, followed by conversion to integrated gasification combined cycle at a later date. Second duration assumes that project proceeds directly to integrated gasification combined cycle without phased construction.

formance characteristics for the demand-side options can be found in "Energy Vision 2020 Customer Service Options."

Canceling the nuclear projects also involves liquidating the asset. Past experience with nuclear project cancellations has shown that there is essentially no net recovery from the existing equipment by the time the project is closed. The IRP, therefore, assumes no net proceeds from canceling the units.

The undepreciated value of the projects, shown in *Figure T8-63*, must also be recovered following cancellation. TVA is investigating the possibility of using recovery periods of up to 30 years.

FIGURE T8-63. **Current Undepreciated Nuclear Project Investments**

	Bellefonte Unit 1	Bellefonte Unit 2	Watts Bar Unit 2	Browns Ferry Unit 1
Current Undepreciated Investment	$ 3.7 Billion	$ 0.8 Billion	$ 1.7 Billion	$ 0.7 Billion

THE DEFERRAL OPTION

The cost of maintaining a nuclear project in a condition that would permit it to be completed at a later date is approximately $10 to $20 million per unit per year. Deferring the decision to a subsequent IRP would allow additional time to acquire information regarding nuclear unit performance and economics, TVA's need for power, and the possible role of nuclear power in minimizing total environmental impacts.

II. Evaluation of Alternatives

Based on the assumptions outlined in the previous section, the alternative nuclear strategies will be evaluated against several key criteria. These criteria (and their measurements), shown in *Figure T8-64*, were developed for the IRP process.

In the full IRP process, each nuclear strategy is evaluated against the criteria in *Figure T8-64*. For example, a strategy to complete the nuclear units is compared to a strategy to replace them with other options, such as coal-fired units. This comparison or trade-off would tell us which strategy (nuclear or coal) would have the lowest costs (total resource costs), lowest rates, least impact on debt, and most flexibility.

FIGURE T8-64. **Evaluation Criteria and Measurements**

Criteria	Measurement
Long-Run Cost and Value	Total Resource Costs Rate Impact Measure Participant Test/Electric Bill Total Value
Rates/Competitiveness	Electric Rates (Cents/kWh) 1996-2000, 1996-2005
Reliability	Reserve Margin Load Not Served
Environment	Emissions (SO_2, CO_2, NO_X, VOC, TSP, etc.) MWh Nuclear Generation
Economic Development	Jobs, Total Personal Income
Financial	Borrowings, Debt, Cash Flow, Net Income
Risk Management	Robustness, Flexibility

Not all of the IRP criteria will be used for the evaluations in this report, but some will be represented as constraints in evaluating the strategies. For example, for each strategy evaluated, the reliability of the power system will be maintained, using a 13 percent capacity reserve margin. Under the environmental criteria, all strategies are evaluated assuming compliance with Phase I and II of the acid rain provisions of the Clean Air Act and compliance with the voluntary goals for greenhouse gas emissions of the Climate Challenge Program.

The criteria for economic development will not be addressed in this report but will be addressed through the IRP.

In this report, strategies will be evaluated specifically on long-term cost (total resource cost), electric rates, and total debt, reflecting the many concerns expressed about TVA's costs and flexibility.

EVALUATING NUCLEAR STRATEGIES – THE PROCESS

Many different strategies were developed as combinations of the nuclear options, supply-side replacement options, and demand-side options. For the purposes of this report, the focus has been narrowed to a few key strategies and the resulting changes in costs, rates, debt, and flexibility. (For a complete description of all strategies and their development, see TVA's Nuclear Options Appendix.)

In evaluating the strategies, the staff looked for those that will minimize long-term costs, minimize short-term rates, minimize long-term debt, and be flexible enough to adapt to an uncertain future. In particular, the staff investigated whether there are strategies better than TVA funding the completion of the four nuclear units. In the analysis, several successive strategies were evaluated—each of which improves TVA's position in one or more of the areas of cost, rates, debt, or flexibility. These strategies are grouped as:

- Completing the nuclear units, as opposed to replacing them with alternative supply- and demand-side resource options
- Converting Bellefonte to another technology

- Completing Bellefonte as a nuclear plant, but with a partner providing funds to complete the plant
- Deferring Watts Bar Unit 2 and Browns Ferry Unit 1 to provide flexibility for an uncertain future

Each of these successive evaluations results in a potential improvement in long-term costs, short-term rates, long-term debt, and flexibility compared to TVA funding completion of the nuclear units. Exactly which strategy or strategies will be pursued as an alternative to completing the nuclear units will be determined through TVA's IRP.

Completing the Nuclear Units vs. Replacement

Five specific nuclear completion strategies are evaluated in this analysis:

1. Complete Bellefonte Units 1 and 2, Watts Bar Unit 2, and Browns Ferry Unit 1
2. Complete Bellefonte Unit 1, Watts Bar Unit 2, Browns Ferry Unit 1, and replace Bellefonte Unit 2
3. Complete Watts Bar Unit 2, Browns Ferry Unit 1, and replace both Bellefonte Units 1 and 2
4. Complete Watts Bar Unit 2 and replace Bellefonte Units 1 and 2 and Browns Ferry Unit 1
5. Replace all four units: Bellefonte Units 1 and 2, Watts Bar Unit 2, and Browns Ferry Unit 1.

Supply-Side Options: For each of these strategies, the supply-side replacement options considered were natural gas-fired combined cycle units (CC) in the short term and, for the long term, clean coal units (advanced integrated gasification combined cycle (IGCC). Peaking capacity was supplied by combustion turbines. Many different supply-side resource options were evaluated for replacement capacity. These included coal-based capacity, natural gas-based capacity, renewables, and purchases of power from cogenerators, other utilities, and independent power producers. Some of the lower-cost options in the short term were coal-fired units and combined cycle units. In the long term, natural gas-based options, renewables, and clean coal technologies such as integrated gasification combined cycle units were lower in cost. An alternative in the short term to replacing the nuclear units with combined cycle units would be to replace the units with a combination of TVA-financed combined cycle units and purchases of power from other utilities, cogenerators, or independent power producers. Such a strategy would also produce a combination of relatively low long-term costs, low short-term rates, and lower debt.

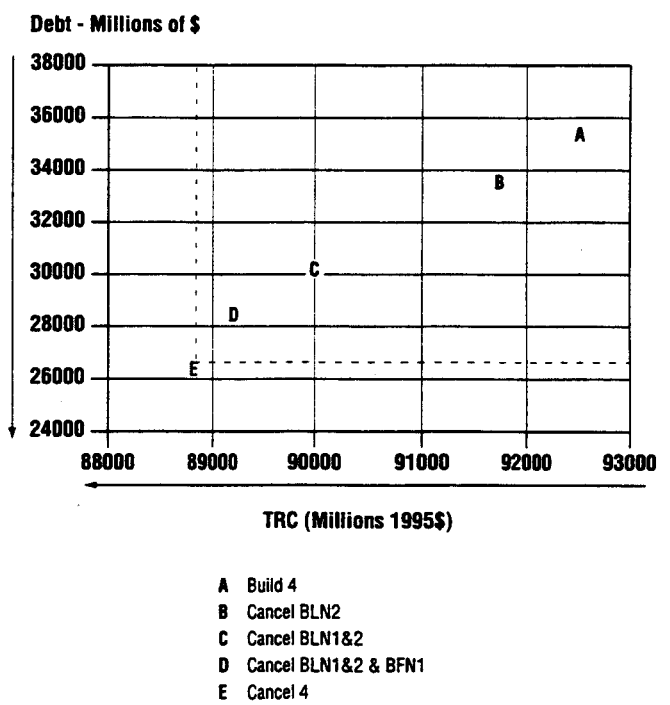
Demand-Side Options: Several combinations of demand-side options were also evaluated. For this report, the demand-side replacement option was a 700-megawatt block of programs (installed by 2005) that is both low in long-term cost and does not increase electric rates over the short term.

In all cases, the environmental strategy for compliance with Phase II acid rain regulations is based on a combination of switching to low-sulfur coal at several plants and building a scrubber at Paradise Unit 3 and the Allen Steam Plant.

The supply-side, demand-side, and environmental strategies will be thoroughly reviewed in the IRP process.

A comparison of the five nuclear completion/replacement strategies for long-term total resource costs (TRC) and total debt in the year 2007 is represented in *Figure T8-65.*

FIGURE T8-65. **Nuclear Decision Trade-Off: Low-Price DSM, Current Clean Air, CC/Coal – Total Resource Costs vs. Debt in Year 2007**

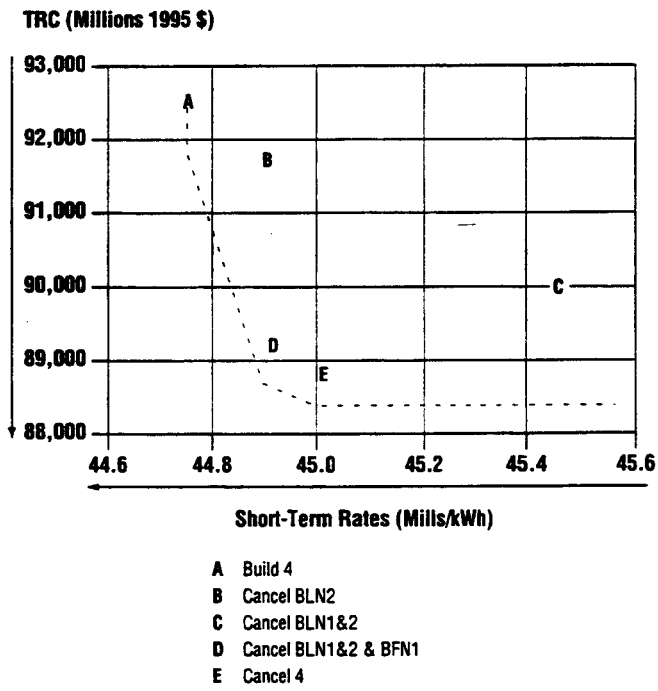


In *Figure T8-65*, the trade-off between long-term cos TRC on the horizontal axis) and debt in the year 2007 (vertical axis) is shown for the five strategies. The results indicate that completing the four nuclear units (A) has the highest debt and highest cost compared to other strategies. The strategy that results in the lowest cost and lowest debt is to replace all four nuclear units with alternative supply- and demand-side resource options. The other strategies indicate that not completing various combinations of the nuclear units and replacing them with other resource options would result in successively lower long-term cost and debt.

A comparison of these same five strategies for long-term cost and short-term electric rates (average from 1996 to 2000) is shown in *Figure T8-66*.

Long-term costs are a measure of the long-term economic efficiency of the power system and short-term rates are a measure of short-term competitiveness. Short-term viability is extremely important as the electric utility industry is deregulated and competition or competitive pressures increase. Low rates will be an important measure of success.

FIGURE T8-66. **Nuclear Decision Trade-Off: Low-Price DSM, Current Clean Air, CC/Coal – Short-Term Rates vs. Total Resource Costs**



The comparison of the five strategies indicates a trade-off between long-term TRC and short-term rates, as indicated by the dashed trade-off line. Building all four nuclear units results in the highest cost and lowest rates, whereas replacing all four units results in lower cost and a slight increase in rates. Replacing only Bellefonte Units 1 and 2 (C) results in lower costs but increased short-term rates. The short-term rate increase would result from an increase in revenue needed to write off previously spent (sunk) capital expenditures on the nuclear units if these units are replaced.

Replacing all four nuclear units has a lower effect on rates than replacing Bellefonte Units 1 and 2 only. One might expect that replacing all four units would have a greater effect on short-term rates than simply replacing two units, since the write-off of sunk cost for four units is greater. However, the short-term rate increases are less when replacing four units because of other cost savings. The lower cost-to-complete, capital additions and improvements, and operation and maintenance costs for Browns Ferry Unit 1 offset the increase in revenue needs due to write-offs.

Converting Bellefonte to Another Technology

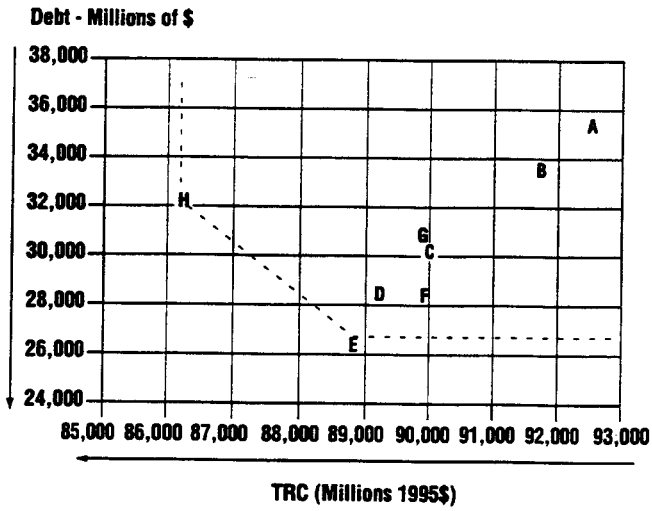
Three strategies for converting Bellefonte Units 1 and 2 to an alternative technology are:

1. Convert to a natural gas-fired combined cycle (CC)
2. Convert to an integrated gasification combined cycle unit (IGCC) in which coal is gasified and the synthesis gas is used in a combined cycle unit
3. Convert to an integrated gasification combined cycle plant where some of the synthesis gas is used to produce a chemical coproduct such as methanol (IGCC/P)

Converting Watts Bar Unit 2 or Browns Ferry Unit 1 to another technology is less feasible because there are, or will be, operating nuclear units at these sites. Although not completely infeasible, the shared systems would make conversion emely difficult from a technical viewpoint. Thus, for this report, nverting Watts Bar Unit 2 and Browns Ferry Unit 1 are not considered.

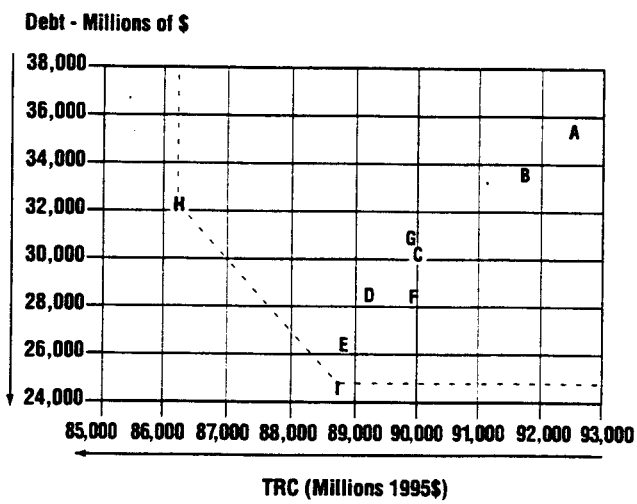
These three Bellefonte conversion strategies are compared to the completion and replacement strategies previously evaluated. For comparison purposes, all of the conversion strategies assume that Watts Bar Unit 2 and Browns Ferry Unit 1 are replaced by the same supply- and demand-side options as in the previous comparisons. The completion, replacement, and conversion strategies are shown in *Figure T8-67* for long-term costs and total debt in 2007.

FIGURE T8-67. **Nuclear Decision Trade-Off: Low-Price DSM, Current Clean Air, CC/Coal – Total Resource Costs vs. Debt in Year 2007**



A	Build 4	E	Cancel 4
B	Cancel BLN2	F	Cancel CC Conv
C	Cancel BLN1&2	G	Cancel IGCC Conv
D	Cancel BLN1&2 & BFN1	H	Cancel IGCC/P Conv

FIGURE T8-68. **Nuclear Decision Trade-Off: Low-Price DSM, Current Clean Air, CC/Coal – Total Resource Costs vs. Debt in Year 2007**



A	Build 4	F	Cancel CC Conv
B	Cancel BLN2	G	Cancel IGCC Conv
C	Cancel BLN1&2	H	Cancel IGCC/P Conv
D	Cancel BLN1&2 & BFN1	I	Defer & Partner
E	Cancel 4		

The conversion options (F,G, and H) compared to replacing all the nuclear units (E) have higher debt associated with them. The conversion to combined cycle (F) and integrated gasification combined cycle (G) also tends to increase costs by approximately $1 billion. The conversion to an integrated gasification plant with a chemical coproduct (H), although increasing debt, does lower long-term costs by approximately $3 billion compared to replacing all of the nuclear units (E).

Although not shown in *Figure T8-67*, the conversion to combined cycle or the conversion to integrated gasification combined cycle with a coproduct (IGCC/P) have about the same effect on short-term rates as replacing all of the nuclear units.

The conclusion from this comparison is that converting Bellefonte to a combined cycle (CC) plant increases long-term cost and debt slightly compared to replacement, but appears to be a viable alternative to completing Bellefonte as a nuclear plant. The conversion to integrated gasification combined cycle with a chemical coproduct (IGCC/P) can significantly reduce long-term costs but significantly increases debt. To reduce the impact on debt for the conversion to a plant that produces a coproduct, TVA is exploring an option for a partnership to build the IGCC/P plant. This option will be fully explored in the IRP process.

Bellefonte Nuclear Partnership

Another strategy currently being explored by TVA is to enter into a partnership with another firm to complete Bellefonte as a nuclear plant. In this arrangement, the partner would complete the construction of the nuclear plant and TVA would buy a part or all of the electricity produced at predetermined prices. Any profits from the sale of electricity would be returned to TVA and the partner(s). This partnership strategy is compared to the completion, replacement, and conversion strategies in *Figure T8-68*.

The Bellefonte partnership strategy is shown in *Figure T8-68* as an 'I'. Based on preliminary assessments of the potential for a partnership arrangement, this strategy could reduce long-term cost and debt compared to replacing Bellefonte with alternative supply- or demand-side resource options. Thus, a partnership for Bellefonte will be fully evaluated in TVA's IRP.

UNCERTAINTY IN KEY ASSUMPTIONS

The strategies to complete the nuclear units, replace the nuclear units, convert Bellefonte, or enter into a partnership to complete Bellefonte as a nuclear plant have been evaluated based on a mid-range set of assumptions discussed in the previous section. All of the evaluations have been based on a mid-range future that includes:

- The mid-range load forecast
- The mid-range cost and operating characteristics for the nuclear plants
- Other assumptions necessary for the evaluations

Basing the evaluations solely on the mid-range assumptions implies that we can perfectly forecast the future. Since no one has perfect foresight, it is necessary to evaluate the nuclear strategies using different assumptions about the future. Under the IRP, over 30 different parameters already have been analyzed, as well as how variations in these parameters can change the evaluations of these strategies. From these analyses, we have identified the most important parameters or uncertainties whose variation could alter the evaluations of the nuclear strategies. These uncertainties are:

- The load forecast
- The cost to complete the nuclear plants
- The operations and maintenance cost for the nuclear plants
- The capacity factor of the nuclear plants
- Whether there will be future legislation on carbon dioxide (CO_2) emissions or greenhouse gases

Further evaluations have indicated that decisions concerning completing the nuclear units versus replacing them would not be affected by possible future legislation on CO_2 emissions. In these evaluations, CO_2 was valued at $5 and $10 per ton. Before it became a significant decision factor, CO_2 would have to be valued at approximately $30 per ton.

To examine uncertainty, the nuclear strategies have been evaluated for two alternative futures as compared to the mid-range assumptions. To derive these futures, we have varied the load forecast, the cost-to-complete, the operation and maintenance cost, and the capacity factor of the nuclear units. The first future is a "low performance" future consisting of:

- Low load growth
- High cost-to-complete the nuclear units
- High operations and maintenance costs of the nuclear units
- Low nuclear capacity factor

The second "high performance" future consists of:

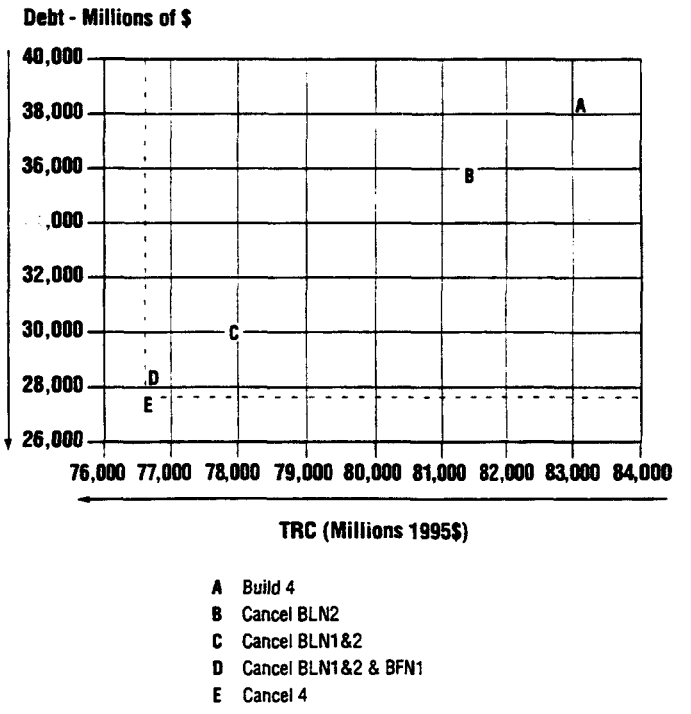
- The high load forecast
- Low cost-to-complete the nuclear units
- Low operations and maintenance costs
- High nuclear capacity factor

A Comparison of Nuclear Completion and Replacement with Alternative Futures

The effect on long-term cost and debt for the five nuclear completion and replacement strategies for the "low performance" future is shown in *Figure T8-69*.

In *Figure T8-69* the lowest cost and lowest debt option is to replace all four nuclear units with alternative supply- or demand-

FIGURE T8-69. **Nuclear Decision Trade-Off: "Low Performance" Future – Total Resource Costs vs. Debt in Year 2007**

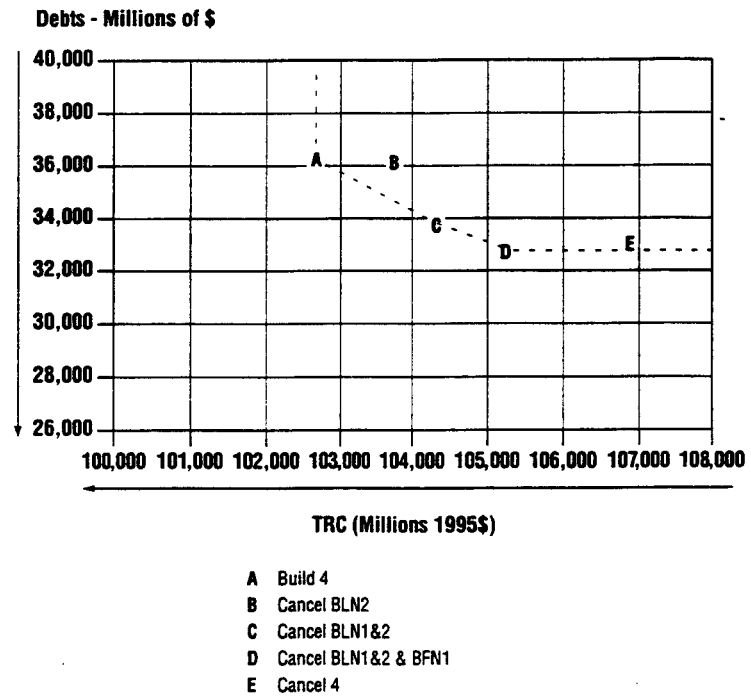


side options. This result is the same as for the "mid-range forecast" shown in *Figure T8-59* in the "Key Assumptions" section.

The same strategies evaluated with the "high performance" future are shown in *Figure T8-70*.

In *Figure T8-70*, the five nuclear completion and replacement strategies are evaluated for the "high performance" future and the resulting impacts on long-term costs and debt are represented. These results differ from previous results in that the lowest-cost option is to complete the nuclear units (A) compared to canceling the units (E). Completing the units (particularly the Bellefonte units) generally results in higher debt when compared to replacing them (A and E).

FIGURE T8-70. **Nuclear Decision Trade-Off: "High Performance" Future – Total Resource Costs vs. Debt in Year 2007**



SUMMARY OF ALTERNATIVE FUTURES

For the "mid-range" future and "low performance" future, the lowest long-term cost and debt strategy was the strategy to replace all four of the nuclear units. For the "high performance" future, the completion of Watts Bar Unit 2 and Browns Ferry Unit 1 could reduce costs compared to replacing the units and not significantly increase debt in 2007. Thus, if we could predict for certain that the "high performance" future would occur, costs could be reduced by completing Watts Bar Unit 2 and Browns Ferry Unit 1 compared to replacing the units.

An alternative that would allow TVA to gain additional information about load growth and nuclear performance would be to defer until a later time the decision to complete or replace the nuclear units. If, in the near future, the "mid-range performance" or the "low performance" future appears more likely, the nuclear units could be replaced. If the "high performance" future seems likely, then the nuclear units could be completed. The additional cost of such a strategy is the cost of keeping the nuclear units in a deferred status, or approximately $10 to $20 million per year per unit.

Deferral of the Decision on Watts Bar Unit 2 and Browns Ferry Unit 1

Since there are clearly several strategies available for the completion and conversion of the Bellefonte units, an attractive strategy may be to defer the decision to complete or replace Watts Bar Unit 2 and Browns Ferry Unit 1 for several years. An evaluation of a strategy to defer the decision on these units until the year 2000 is shown in *Figures T8-71* and *T8-72*.

Figure T8-71 indicates that deferral does not significantly raise long-term cost or debt compared to immediately replacing the nuclear units or replacing Watts Bar Unit 2 and Browns Ferry Unit 1.

Deferring the decision to either complete or replace these two units provides flexibility to adapt to significantly different futures. With the "medium or low performance" future, the decision can be made to replace these two units. With the "high performance future," the decision can be made to complete construction of the nuclear units. The value of this flexibility is estimated to be about $200 million more than the costs of keeping the nuclear units in a deferred status.

Deferring a decision on Watts Bar Unit 2 and Browns Ferry Unit 1 also has a favorable impact on short-term rates as shown in *Figure T8-72*.

In *Figure T8-72*, the continued deferral of both nuclear units is represented by 'D' if the deferred units are completed and by 'B' if the units are canceled at a later date. Comparing the deferral strategies to the replacement strategies (A and C) indicates that short-term rates are reduced by deferring the decision on Browns Ferry Unit 1 and Watts Bar Unit 2.

FIGURE T8-71. **Deferral of Watts Bar Unit 2 and Browns Ferry Unit 1 Decision Trade-Off – Total Resource Costs vs. Debt in Year 2007**

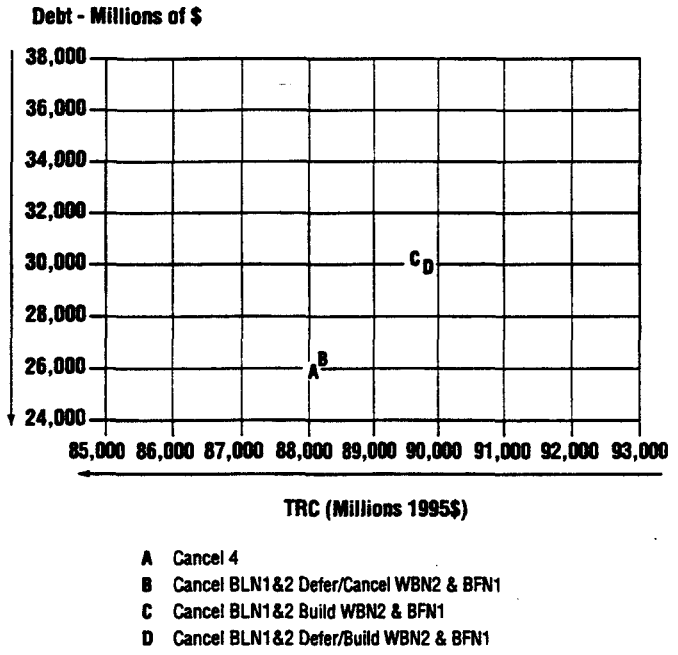
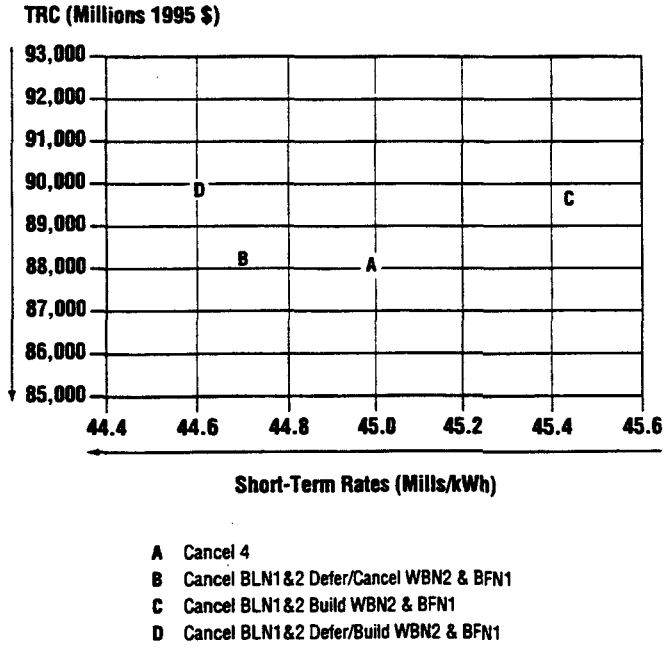


FIGURE T8-72. **Deferral of Watts Bar Unit 2 and Browns Ferry Unit 1 Decision Trade-Off – Short-Term Rates vs. Total Resource Costs**



Thus, the continued deferral of Watts Bar Unit 2 and Browns Ferry Unit 1 can provide flexibility to adapt to a highly uncertain future and reduce short-term rate changes compared to an immediate decision to either build or replace the units.

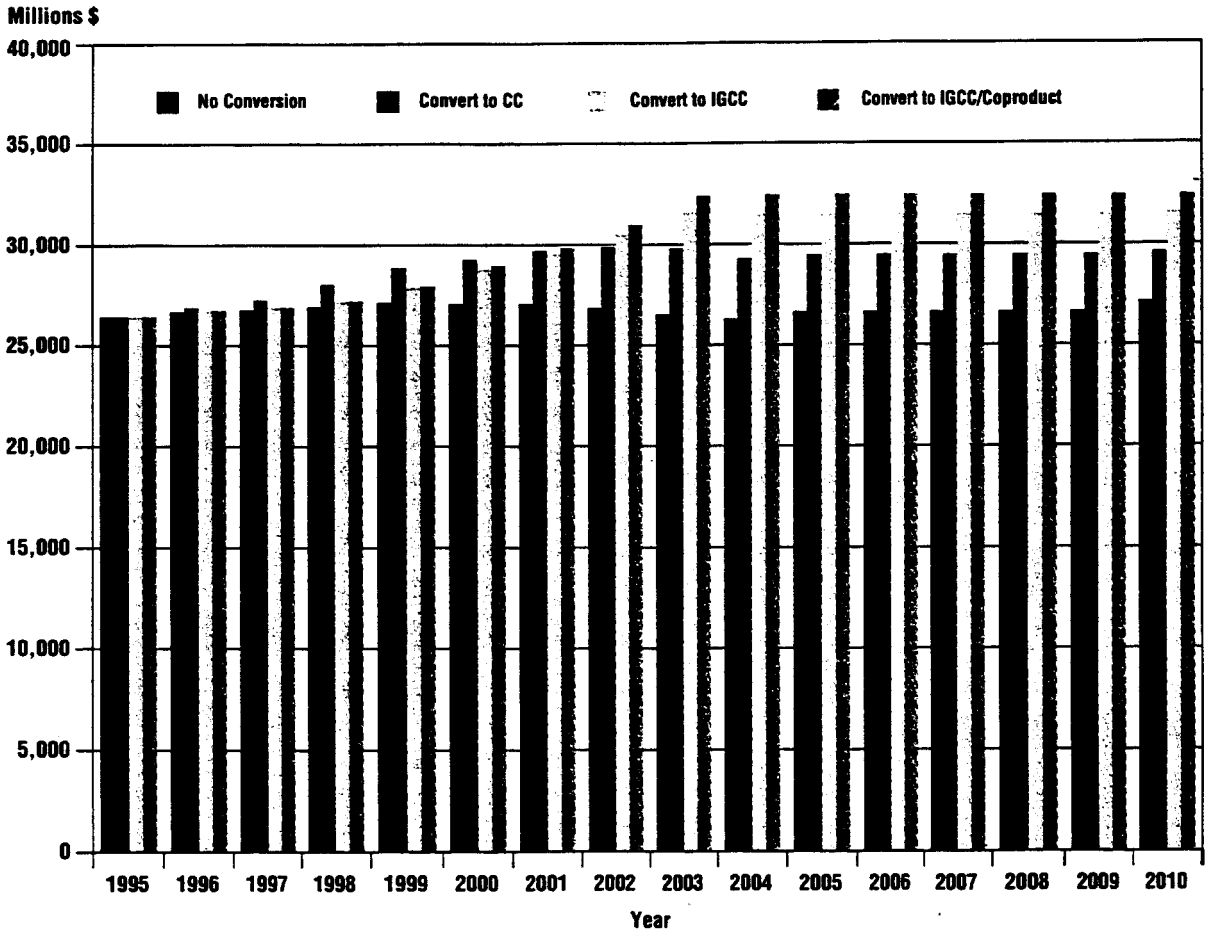
SUMMARY OF NUCLEAR STRATEGY RESULTS

Combining the different nuclear strategies is likely to produce a single strategy that minimizes debt, long-term costs, and short-term rates. Such a strategy could include:

- Completing Bellefonte as a nuclear plant with a partner
- Converting Bellefonte by TVA alone or in partnership
- Deferring a decision to complete or replace Watts Bar Unit 2 and Browns Ferry Unit 1
- Replacing capacity with combined cycle units or a combination of combined cycle units and purchases of power
- A block of demand-side management programs that minimize short-term rate changes

The change in debt from 1995 to 2010 for such a strategy is shown in *Figure T8-73*. By the end of 1995, total TVA debt will be slightly less than $27 billion. Without a conversion at Bellefonte or a conversion with a partner providing the capital funds, debt will remain slightly less than $27 billion through the year 2006. With the conversion of Bellefonte to combined cycle, debt increases to slightly less than $30 billion in the year 2002 and under the other conversion strategies, debt reaches $30 billion in the year 2002.

FIGURE T8-73. **Total Debt – Defer Browns Ferry Nuclear Unit 1 & Watts Bar Nuclear Unit 2**



Note: Expand with CC/IPP/ Coal and Low-Price DSM

III. Conclusions

Evaluations of the nuclear strategies for the long-term cost, debt, short-term rate, and flexibility criteria lead to the following conclusions:

- Continued TVA construction of Bellefonte Units 1 and 2 and Watts Bar Unit 2 as nuclear units and restoration of Browns Ferry Unit 1 lead to higher costs and prevent TVA from limiting debt.
- Alternatives which could lower costs and limit debt include:
  - Replacing the nuclear units
  - Converting Bellefonte to another technology
  - Completing or converting Bellefonte in partnership with others
- Under certain conditions in the future, nuclear generation could emerge as a low-cost option. These conditions are:
  - High load growth
  - Improved nuclear performance
- Holding the nuclear option open can lead to lower short-term rate increases and increased long-term flexibility compared to immediate decisions to either complete or replace the nuclear units. Flexibility may be enhanced by:
  - Completing Bellefonte in partnership with others ($100 million savings and reduced debt)
  - Converting Bellefonte to another technology in partnership with others
  - Deferring Watts Bar Unit 2 and Browns Ferry Unit 1 – (value of the flexibility gained by deferring these units is upwards of $200 million when compared to canceling them immediately)
- TVA should not fund the completion or restoration of Bellefonte Units 1 and 2, Watts Bar Unit 2, and Browns Ferry Unit 1 as nuclear units. Instead, TVA should keep open alternatives for these units that would minimize short-term rates, increase long-term flexibility, minimize long-term costs, and limit debt.

TVA'S NUCLEAR OPTIONS APPENDIX

Alternative Resource Strategies

Several possible strategies have been developed for the four nuclear units, Bellefonte Units 1 and 2, Watts Bar Unit 2, and Browns Ferry Unit 1. These strategies include:

1. Complete the units as nuclear units.
2. Convert them to another technology.
3. Cancel one or more of them and replace them with other supply- and demand-side technologies.
4. Defer the decision and decide at a later date either to complete, convert, or cancel the units.

Completion of the Nuclear Units

Completing the units as nuclear requires continuing the projects as currently planned with TVA performing and paying for construction. The four nuclear units are described in *Figure T8-74*.

Another option for completing the nuclear units is for TVA to enter into a partnership. Under this approach, TVA would contribute the nuclear asset as it is currently constructed to the project partnership. The other member(s) of the partnership would complete the units with non-TVA funds. The output of the plant after completion could be sold to TVA or other consumers at prearranged prices. Any profits from the sale of the electricity from the units would be shared by the partners: TVA and the other party(ies). TVA is currently exploring this type of arrangement for Bellefonte Nuclear Plant.

Conversion to Alternative Technologies

Alternatives for converting Bellefonte to a fossil-fueled facility have been considered since the late 1980s. The alternatives include converting the units to:

- Pulverized coal-fired units (PC)
- Natural gas-fired combined cycle (NGCC)
- Integrated gasification combined cycle (IGCC)
- Integrated gasification combined cycle with coproduction of a chemical byproduct

FIGURE T8-74. **Status of Nuclear Plant Construction**

	Bellefonte Unit 1	Bellefonte Unit 2	Browns Ferry Unit 1	Watts Bar Unit 2
Plant Location	Hollywood, AL	Hollywood, AL	Decatur, AL	Spring City, TN
Power Level	1212 MW	1212 MW	1065 MW	1170 MW
Reactor Type	Pressurized Water Reactor	Pressurized Water Reactor	Boiling Water Reactor	Pressurized Water Reactor
Nuclear Steam Supply System Manufacturer	Babcock & Wilcox	Babcock & Wilcox	General Electric	Westinghouse
Construction Permit Date	1974	1974	1967	1973
Construction Status	88%	5[illegible]	100%	61%
Current Undepreciated Investment	$ 3.7 Billion	$ 0.8 Billion	$ 0.7 Billion	$ 1.7 Billion

Cancel the Projects and Replace with Alternative Capacity

The four nuclear units could be replaced with many different types of supply- and demand-side resource options.

SUPPLY-SIDE OPTIONS

Supply-side options are drawn from a variety of sources. Some are traditional power supply technologies, such as the pulverized coal and natural gas-fired combined cycle options. Other supply-side options describe opportunities that are unique to TVA. Examples of this second group include completing or converting the Bellefonte Nuclear Units or increasing the capacity of the Raccoon Mountain pumped-storage facility. Still other options reflect ongoing research and development of new technologies including solar power, wind power, fuel cells, and some of the more advanced combustion technologies.

A challenge faced in developing the supply-side options catalog is to ensure that a sufficiently broad spectrum of options is identified while still keeping the total to a manageable number. Clearly the nuclear completion, conversion, and cancellation options had to be included since they represented near-term decisions that TVA needs to make. Traditional options are included to provide a comparison with previous work and because a number of these technologies are still viable options being constructed by other utilities today.

TVA also reviewed 20 other utility IRPs to determine if we had left out any important options. Comparing TVA's option list to the list extracted from the review provides some indication of reasonableness. *Figure T8-75* illustrates this comparison. With the exception of geothermal (which is not available to a significant degree in the TVA region), large solar collectors (which do not appear to be economical as compared to other solar options), and diesel generators (which are covered better as customer service options), the TVA list spans the range covered by other IRPs.

Obtaining power supply from cogenerators and independent power producers (IPPs) has become common in the utility industry. Generally, contracts for this kind of power supply are obtained through a bidding process after a utility defines its needs (in terms of capacity type, power level, and need dates). TVA has issued a request for proposals on options for future power purchases.

TVA also can buy power from other utilities. In the near term, some utilities in the region have excess generating capacity. This excess capacity is expected to be consumed by the early 2000s, however. In the longer term, power purchases from other

FIGURE T8-75. **Comparison with Options Cited in 20 Other Integrated Resource Plans**

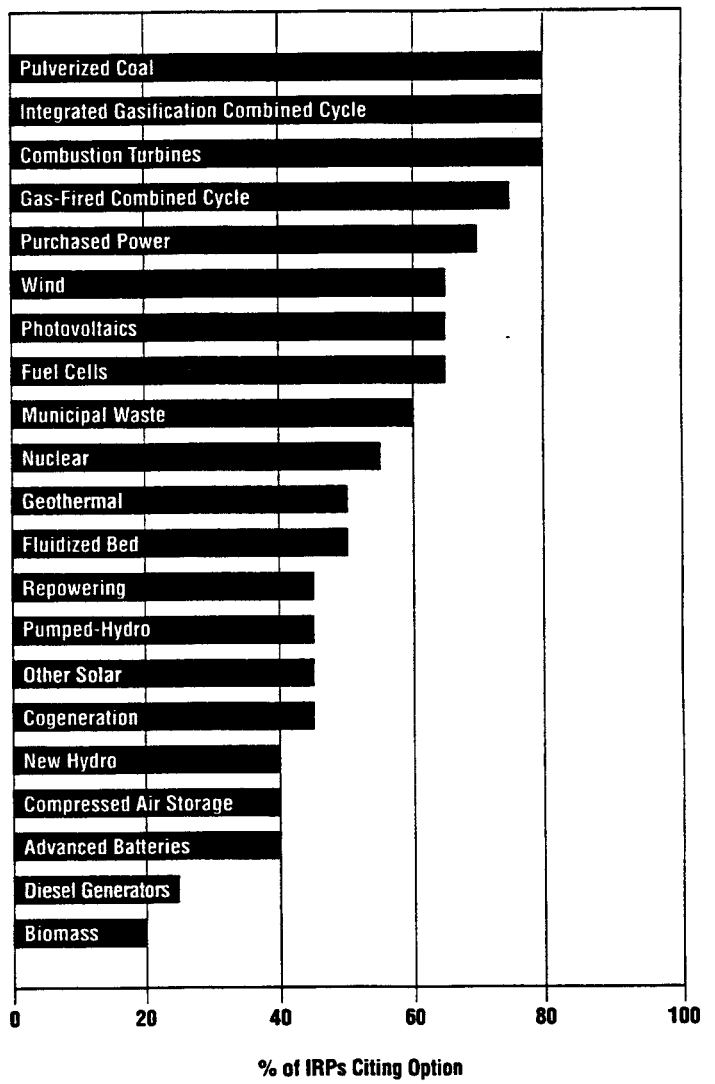


FIGURE T8-76 **Customer Service Options – Summary Impacts**

Area	Options	IMPACTS IN THE YEAR 2005 MW	GWH
Energy Efficiency	30	2,780	12,455
Self-Generation	3	146	575
Beneficial Electrification	14	-397	-1,931
Rates	3	670	-1,533

utilities will still be possible, but will likely have higher prices that reflect their cost of adding new capacity.

DEMAND-SIDE MANAGEMENT

In addition, there are over 50 different demand-side options which could be used to replace all or a part of the nuclear units. The demand-side options cover several different technologies including load management, energy efficiency, and renewables. Demand-side options have been developed for residential, commercial, and industrial customers.

TVA's customer service options were developed in four key areas:

- Energy efficiency, including conservation and load management options
- Self-generation
- Beneficial electrification
- Pricing or rate incentives

Figure T8-76 provides a summary of all options that have been developed by TVA to date for consideration in the IRP. Thirty options (17 residential and 13 commercial and industrial) have been developed in the energy efficiency classification. Three general options have been identified for the cogeneration classification. Fourteen options spanning all sectors of the economy, including the transportation sector, have been developed for beneficial electrification. These options affect both the need for new generating capacity, in terms of megawatts (MW), and the level of electricity sales, in terms of gigawatt-hours (GWH) that TVA would be required to provide. Thus, *Figure T8-76* shows that in 2005, over 2,500 megawatts of capacity savings are contained in the proposed energy efficiency options. Further, small-scale self-generation would reduce the direct demand on the TVA system by almost 150 megawatts. Time-of-day rates for the residential, commercial and industrial sectors would reduce demand by 616 MW; however, energy use would increase by 1,533 GWH. Finally, beneficial electrification options represent an increase in the demand for electric capacity by almost 400 megawatts.

FIGURE T8-77 **IRP Strategy Development – Option Choices**

Short-Term Decisions (1996-1999)	Long-Term Decisions (2000-2020)
SUPPLY	
• Build Bellefonte • Convert Bellefonte -Coal -Combined Cycle -Integrated Gasification Combined Cycle (IGCC) -IGCC w/Coproduction • Cancel Bellefonte • Cancel Bellefonte/ Browns Ferry Unit 1 • Cancel Bellefonte/ Browns Ferry Unit 1, Watts Bar Unit 2 • If Cancellation, Replace with -Combustion Turbines (CTs), Coal -CTs, Combined Cycle -CTs, IGCC with or without Coproduction -Purchased Power, Cogeneration, IPPs -Phased CT, CC, IGCC -Repower Fossil Units -Market-Based Options	• For Build, Cancel or Convert, Options Are: -CTs, Coal -Gas-Based -Clean Coal (IGCC) -Renewables
• Hydro Modernization • Storage Options	
• Defer Nuclear Units	• Then: -Build Nuclear -Cancel Nuclear -Convert Nuclear
ENVIRONMENT	
• Phase II Acid Rain -Reference Case (Low Cost) -Minimum Debt -Minimum CO_2 -Advanced Technology	• Phase II Acid Rain • CO_2 Offsets
• Wood Cofiring	

Defer the Decision to Complete the Nuclear Units

Another option is to defer the decision to either build, cancel, or convert some of the nuclear units to a later time period. This option has been specifically considered for Watts Bar Unit 2 and Browns Ferry Unit 1. For the preliminary analysis, the decision to build or cancel the nuclear units could be deferred to the year 2000. The deferral of the Bellefonte plant was not considered since the partnering option and conversion option are being considered at Bellefonte.

FIGURE T8-77 **IRP Strategy Development – Option Choices** *CONTINUED*

Short-Term Decisions (1996-1999)	Long-Term Decisions (2000-2020)
MARKETS	
• DSM -Low Rates -Low Cost -Low Penetration -High Penetration -Renewables -Low Income	• DSM • Beneficial Electrification
• Beneficial Electrification -Low Penetration -High Penetration • Off-System Sales • Distributed Generation • Fuel Switch to Natural Gas	
PRICING	
• Price Levels -Higher -Lower • Pricing Structure -Current Practice -Time-of-Day -Real Time -Block Structure	
TRANSMISSION	
• Efficiency Improvements • East-West Transmission -Capability	

Resource Strategies

The numerous nuclear, conversion, and supply- and demand-side resource options may be categorized into several different groups as outlined in *Figure T8-77*.

In *Figure T8-77*, options have been categorized according to those which can be implemented in the short term and those for the long term. The options have also been grouped by type, such as supply, environment, market, pricing, and transmission.

Strategies Evaluated

For this study, options have been chosen from *Figure T8-77* in order to develop strategies. The possible strategies are shown in *Figure T8-78*.

FIGURE T8-78 **Prospective Strategies in the IRP**

SUPPLY OPTIONS - NUCLEAR
- Build Bellefonte (BLN) Units 1 and 2, Browns Ferry (BFN) Unit 1, and Watts Bar (WBN) Unit 2
- Build BLN 1, BFN 1, WBN 2, and Cancel BLN 2
- Build BFN 1, WBN 2, and Cancel BLN 1 and 2
- Cancel All Four Units
- Convert BLN, Cancel WBN 2, BFN 1
  - -Combined Cycle (CC)
  - -Integrated Gasification Combined Cycle (IGCC)
  - -IGCC with Coproduction of Chemical Product (IGCC/P)
- Defer WBN 2, BFN 1
  - -Cancel BLN 1 and 2
  - -Convert BLN to CC
  - -Convert BLN to IGCC
  - -Convert BLN to IGCC/P
  - -Nuclear Partnership at BLN 1 and 2

OTHER SUPPLY OPTIONS

Short-Term	Long-Term
• Combined Cycle • Coal (Shawnee II) • Purchased Power, Cogeneration, Independent Power Producers (IPP)	• Clean Coal (IGCC) • Renewable (Wind,Biomass) • IPPs

DEMAND-SIDE MANAGEMENT (DSM)
- No DSM
- Low-Cost DSM Block (1000 MW)
- Low-and Medium-Cost Block (2000 MW)
- Low-Price Block (700 MW)

ENVIRONMENT
- Phase II Acid Rain Strategy
- Fuel Switch and Scrubber at Paradise Unit 3
- All Fuel Switch Strategy

Energy Vision

2020

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TVA Staff T9.1

TVA Consultants T9.12

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M.S., Industrial Organizational Psychology
Experience: 12 years of experience in oil and natural gas fuel market procurement and market analysis. Previous experience in other procurement fields.

RICHARD A. SHINN
Position: Manager, Transmission Development
Education: B.S., Electrical Engineer
Experience: 24 years of experience in TVA transmission planning and development.

JOHN W. SHIPP, JR.
Position: Manager, Environmental Services
Education: B.S., Civil Engineering
M.S., Civil Engineering
Experience: 20 years of experience in TVA environmental services, including water resources, hazardous materials handling, and emergency operations. Registered Professional Engineer. Certified Hazardous Materials Manager.

ROY E. SIEBER
Position: Project Manager
Education: Aeronautical Design
Experience: 15 years of experience in TVA industrial marketing, new product development, and demand-side planning. Previous experience includes resource planning at the New York Power Pool and Long Island Lighting Company.

R. CRAIG SMITH
Position: Manager, Conservation and Load Management
Education: B.A., Urban Studies and Planning
Experience: 3 years of experience in TVA demand-side planning and program implementation. Previous experience includes DSM program implementation at Pacific Gas and Electric and Pacific Power and Light Companies; regulatory experience at Michigan Public Service Commission.

MICHAEL CHARLES SMITH
Position: Senior Economist
Education: B.A., Mathematics
M.A., Economics
Experience: 15 years of experience in TVA economic development research and forecasting. Previous experience includes energy demand forecasting at Oak Ridge National Laboratory and teaching and research in economics at the University of Tennessee at Knoxville.

MEREDITH H. SNYDER
Position: Power Supply Analyst
Education: A.S., Mechanical Engineering
B.S., Mathematics
M.Ed., Education
Experience: 9 years of experience in load forecasting and nuclear operations. Previous experience includes teaching in Hamilton County and at Chattanooga State Technical Community College.

JOANNE V. SWANSON
Position: Decision Analysis Specialist
Education: B.S., Business Administration
M.B.A.
Experience: 20 years of experience in TVA power resource planning.

BYRON D. STEWART
Position: Manager, Bulk Transmission Planning
Education: B.S., Electrical Engineering
Experience: 24 years of experience at TVA in planning.

ROBERT E. TAYLOR
Position: Specialist, Peaking and Energy Storage
Education: B.S., Engineering Science
M.S., Aerospace Engineering
Experience: 23 years of experience in TVA power plant engineering and research and development.

R. LARRY TAYLOR
Position: Manager, Electric System Operations
Education: B.S., Electrical Engineering
M.B.A.
Experience: 2 years of experience in TVA in areas of power system operation, bulk power marketing, and interchange operations. Previous experience includes consulting for the electric power industry; Vice President, Power Delivery at Florida Power & Light Company.

J. DANIEL THOMAS
Position: Project Leader, Forest Resources Information System
Education: B.S., Forest Management
M.S., Forestry
Experience: 12 years of experience in TVA Forest Resources Inventory and Analysis Project; 2 years Forest Inventory, TVA.

TOMMY R. THOMPSON
Position: Specialist, Generation Technology
Education: B.S., Mechanical Engineering
M.S., Mechanical Engineering
Experience: 18 years of experience at TVA in fossil-fired power plant engineering, including conceptual design, detailed design, contract management, technical supervision, and project management. Previous experience includes nuclear power plant engineering. Registered Professional Engineer.

FRANK C. THORNTON
Position: Specialist, Atmospheric Sciences
Education: B.S., Environmental Sciences
M.S., Forestry
Ph.D., Forest Soils
Experience: 9 years of experience in air pollution effects at TVA. Previous experience includes post-doctoral work in mineral nutrition of woody plants and metal toxicity in United States and abroad; agricultural consultant.

CHARLES R. TICHY
Position: Historical Architect
Education: B. Architecture
M.A., Historic Preservation
Experience: 16 years of experience as TVA Historical Architect. Previous experience includes State of New Jersey Office of Historic Preservation; historic architect for Nassau County, New York.

EDDIE TRAMEL
Position: Johnson City Customer Service Center Manager
Education: B.S., Electrical Engineering
Experience: 26 years of experience in TVA working with customers and distributors in marketing, conservation, rate and contract administration, and program development and management.

RALPH J. VALENTE
Position: Project Engineer
Education: B.S., Meteorology
M.S., Engineering
Experience: 15 years of experience in TVA air quality research. Extensive experience in ground-based and air-borne monitoring and model evaluation studies.

L. CHRISTY VALERIO
Position: Economist
Education: B.S., Agricultural Economics
M.S., Agricultural Economics
M.S., Public Policy and Public Administration
Ph.D., Economics
Experience: 4 years of experience in TVA regional economic forecasting. Adjunct Professor at Tusculum College.

CAROLINE M. WALLER
Position: Computer Graphics Technician, Geographic Information and Engineering
Education: High School Diploma
Experience: 18 years of experience in graphics composition and computer graphics.

BARRY B. WALTON
Position: Assistant General Counsel, Environmental
Education: B.A., Political Science
J.D., Law
Experience: 22 years of experience in TVA's General Counsel's Office practicing environmental and natural resource law.

JOHN WATKINS
Position: Economist
Education: B.S., Math
Experience: 25 years of experience in TVA load forecasting and 15 years in revenue forecasting.

FRANCES P. WEATHERFORD
Position: Senior Environmental Scientist
Education: B.A., Biology
Experience: 20 years of experience in air quality research, monitoring, and other technical services related to air quality compliance.

KATHY S. WHITAKER
Position: Manager, Transmission, Distribution and End-Use
Education: B.S., Civil Engineering
M.S., Engineering
Experience: 12 years of experience in TVA engineering disciplines; special assignment serving as the Public Participation Manager for TVA's Integrated Resource Planning development.

JAMES O. WHITE
Position: Project Manager, Industrial Marketing, and IRP Coordinator
Education: B.S., Geography/Biology
M.S., Planning
Experience: 20 years of experience in TVA regional development studies, and project management and evaluation. Previous experience includes community land use planning.

JAMES T. WHITEHEAD
Position: Manager, Reliability Analysis
Education: B.S., Electrical Engineering
Experience: 26 years of TVA experience, primarily in planning.

DALE V. WILHELM
Position: National Environmental Policy Act Liaison
Education: B.S., Mathematics
M.S., Meteorology
Experience: 20 years of experience in interdisciplinary environmental review. Previous experience as Agency NEPA Advisor.

JAMES F. WILLIAMSON, JR.
Position: Environmental Scientist
Education: B.S., General Science/Zoology
M.S., Wildlife Ecology
Ph.D., Fisheries and Wildlife Sciences
Experience: 4 years of experience in environmental reviews and preparing environmental documentation. Previous experience in forest and wildlife-related software and database development and forest biometrics.

NEIL M. WOOMER
Position: Senior Limnologist
Education: B.A., Botany
M.S., Biology
Ph.D., Limnology
Experience: 15 years of experience in TVA aquatic monitoring and assessment. Previous experience as chief ecologist for water quality studies, Arkansas Department of Pollution Control and Ecology.

B. J. WRIGHT
Position: Manager, Customer Communications
Education: B.S., Communications
M.B.A., Marketing
Experience: 12 years of experience in TVA employee, marketing, and strategic communications; visitor relations; speechwriting; and advertising.

CASSANDRA L. WYLIE
Position: Statistician
Education: B.S., Forestry
M.S., Forest Biometry
Experience: 10 years of experience in TVA data analysis of atmospheric effects on forests.

DENNIS H. YANKEE
Position: Programmer/Analyst
Education: M.S., Geography
Experience: 7 years of experience with Geographic Information Systems.

TVA Consultants

CLINTON J. ANDREWS

Position: Assistant Professor of Public and International Affairs, Princeton University

Education: Sc.B., Mechanical Engineering
S.M., Technology and Policy
Ph.D, Regional Planning

Experience: 17 years of experience in energy sector including integrated resource planning methods. Author of more than a dozen refereed articles on IRP, contributions on related topics, including *Regulating Regional Power Systems* (Quorum/IEEE, 1995).

JOHN R. BROOKS

Position: Principal, Brooks Jenkins (Communications and Design Agency)

Education: B.A., Journalism

Experience: 25 years of experience in corporate communications and agency management. Extensive experience in the transportation and energy fields, including a ten-year assignment at the Institute of Nuclear Power Operations. Accredited by the International Association of Business Communicators.

LORI CLEGHON

Position: Art Director, Graphic Advertising, Inc.

Education: A.S., Advertising Arts

Experience: 6 years of experience in graphic design and print media.

MAXIM R. DUCKWORTH

Position: Research Analyst, Energy Group, Tellus Institute

Education: B.S., Physics
M.A., Physics

Experience: Experience in electric power system modeling and planning analysis at Tellus Institute. Involved in TVA project to investigate potential level of competition from other electricity providers over the next 25 years.

LOIS HOGAN

Position: Senior Counselor, Jackson Jackson & Wagner

Education: B.S., Journalism
M.A., Holistic Education

Experience: Specializes in organization development, group acilitation, management training, development and production management of graphic systems, and community relations and public participation groups. Contributor, *pr reporter*, the international weekly professional newsletter; Contributor, *Public Relations Practices, Managerial Case Studies and Problems*, Center and Jackson, 1989, 1995. PSRA National Conferences, Council on Advancement and Support of Education (CASE) Community Relations Conference, and American Institute of Cooperatives. Accredited by the Public Relations Society of America. Certified in Group Facilitation, Interface Foundation, Boston.

JOHN I. JAMES

Position: President, The Cube, Inc.

Education: B.F.A., Graphic Design

Experience: 5 years of experience in management; 5 years in information technology; and 10 years graphic design.

HEIDI KROLL

Position: Research Associate, Energy Group, Tellus Institute

Education: B.A., Economics

Experience: Experience in the acquisition and analysis of economic, energy use, and conservation-related data underlying integrated resource planning research in utility and regulatory settings; tracking development of TVA's first comprehensive Integrated Resource Plan, on which Tellus is advising the TVA's Board of Directors. Participated in a comprehensive survey of utility and regulatory Integrated Resource Plan practices throughout the United States and helped draft proposed Integrated Resource Plan rules for the Kansas Corporation Commission and the Colorado office of Energy Conservation.

BRUCE LANDREY
Position: Principal, Landrey & Hunt, Inc.
Education: B.S., Journalism
Experience: 20 years of experience in public relations, investor relations, advertising, media and community relations, and government affairs. Previous experience includes vice president of public relations for TVA, director of investor relations for Portland General Corporation, director of corporate communications at Portland General Electric Company, and strategy development at Edison Electric Institute, the Electric Power Research Institute, and the U.S. Committee for Energy Awareness.

CHAS LAW
Position: Owner, Chas Law Design
Education: A.A.S., Communications Graphics Technology
Experience: 4 years of experience in publication design. Previous experience includes teaching computer graphics, graphic design, and photography at Pellissippi State Technical Community College.

RICHARD B. MCLEAN
Position: Principal/NEPA Manager, PTRL Environmental Services
Education: Ph.D., Marine Biology
Experience: 21 years of experience in environmental assessment.

ISOBEL PARKE
Position: Senior Counselor, Jackson Jackson & Wagner
Education: B.A., History
M.A., History
Experience: Specializes in strategic planning, crisis communication, emerging issues, environmental and waste disposal issues, coalition and consensus building, and naming strategies and graphic concepts. President, New Hampshire Timberland Owners Association, 1986-87; President, Rockingham County Woodland Owners Association, 1987. Contributor, *Public Relations Practice, Managerial Case Studies and Problems*, Center and Jackson, 1989, 1995. Accredited by and a Fellow of the Public Relations Society of America.

GABRIELLE RATLIFF
Position: Database Administrator, Geophex Ltd.
Education: B.S., Computer Science
Experience: 2 years of experience in computer programming.

MARY REVENIG
Position: Graphic Designer, DesignWorks
Education: B.F.A., Painting and Drawing
Experience: 26 years of experience in publication design.

RICHARD A. ROSEN
Position: Executive Vice-President, Director and Senior Scientist, Energy Group, Tellus Institute
Education: B.S., Physics and Philosophy
M.A., Physics
Ph.D., Physics
Experience: Research on integrated resource planning energy conservation; electric generation planning issues; and modeling studies of long-range energy demand, utility system reliability, energy demand curtailment, and environmental externalities and energy planning. Experience in integration of supply-side and DSM options into integrated resource planning, including consideration of the costs of environmental externalities.

RICHARD M. SANDVIK
Position: Energy-Related Projects Consultant
Education: B.A., Economics
J.D.
Experience: Experience in consulting for such firms as Bonneville Power Administration, U.S. Generating Company, and TVA. Previous experience includes General Manager and Director, Legal Department and Director of Strategic Issues Management for Portland General Corporation, and Senior Assistant Attorney General for the Oregon Department of Justice.

RICHARD E. SAYLOR
Position: Program Manager, Geophex Ltd.
Education: M.S., Environmental Science
Experience: 16 years of experience in environmental and safety assessment.

KATHY L. SHASSERE
Position: Database Administrator, PTRL Environmental Services
Experience: 15 years of experience in computer science.

DALJIT SINGH

Position: Research Associate, Energy Group, Tellus Institute

Education: B.Tech, Electrical Engineering
M.S., Electrical Engineering (Power Electronics)
M.S., Electrical and Computer Engineering (Computer Systems Engineering)
M.S., Technology and Policy

Experience: Experience in electric system planning, including power plant performance assessment, evaluation of power supply technologies, transmission and distribution, cost/benefit analysis, and emission control technologies. Also worked on resource bidding and evaluation of qualifying facilities and independent power producing facilities.

STEPHEN L. THUMB

Position: Partner, Energy Ventures Analysis

Education: B.S., Chemical Engineering
M.B.A., Finance

Experience: 7 years of experience directing oil and natural gas practice. EVA senior financial analyst for natural gas procurement, natural gas/oil industry analyses, forecasting, acquisition and divesture analysis. Previous experience includes over 15 years in related industry positions.

DOUGLAS H. WALTERS

Position: Senior Consultant, Strategic Decisions, Inc.

Education: B.S., Electrical Engineering
M.S., Industrial Engineering
Ph.D., Industrial Engineering

Experience: 22 years of electric utility planning experience with TVA, primarily in economic analysis and decision and risk analysis.

CHRIS WATTS

Position: Contractor, Operations Simulation Associates, Inc. (OSA)

Education: B.S., Engineering

Experience: 9 years of experience in resource planning at a utility. Previous experience as utility consultant.

THOMAS A. WINDHAM

Position: Cartographic Design Specialist

Education: B.F.A., Graphic Arts

Experience: 5 years of experience in cartographic design and production.

Review Group Consultants

STEPHEN R. CONNORS

Position: Director, M.I.T. Electric Utility Program, Director, M.I.T. Analysis Group for Regional Electricity Alternatives

Education: B.A., Anthropology
B.S., Mechanical Engineering
S.M., Masters in Technology and Policy

Experience: Participant of the Massachusetts Institute of Technology Energy Laboratory's Analysis Group For Regional Electricity Alternatives (AREA). Worked with New England's electric utilities, regulatory agencies, and business, consumer and environmental concerns to identify long-range strategies. Experience includes a broad range of energy and environmental issues ranging from electricity planning and regulation to identification of cost-effective emissions reductions, domestic and international.

BARBARA A. MACMULLAN

Position: Senior Analyst, National Economic Research Associates, Inc.

Education: B.S., Natural Resources
M.A., Economics

Experience: Experience in research and analysis for the electric utility industry, including comparing cost of electricity from nuclear and coal plants, statistical analyses of nuclear and coal capital and operating costs and analysis of utility conservation programs. Assisted clients in all aspects of regulatory proceedings, including reviewing expert testimony, preparing cross-examination of opposing witnesses, and testifying on behalf of electric utilities in regulatory and other proceedings concerning the economics of nuclear power plants. Previous experience as a consultant evaluating economic losses in wrongful death and accident cases.

GEORGE M. MCCOLLISTER

Position: Principal, Spectrum Economics, Inc.

Education: B.A., Mathematics and Chemistry
M.A., Mathematics
Ph.D., Economics

Experience: Specializes in econometric and statistical analysis for energy supply planning and calculation of economic damages in civil litigation. Applied these skills for ten years as a consultant, and for several years as a staff economist at two large investor owned utilities. Examples of projects include energy demand forecasting, probabilistic energy supply planning, conservation and load management program savings evaluation, econometric modeling to value natural resources, statistical hypothesis testing in discrimination cases, expert testimony and management of economic experts in civil litigation.

JOHN H. WILE

Position: Vice President, R. J. Rudden Associates, Inc.

Education: B.A., Economics
Ph.D., Economics

Experience: 20 years of diversified experience in the practice areas of utility pricing, electric generation and transmission planning, financial and economic analysis, strategic and resource planning, regulatory policy analysis, and related management and organizational consulting.