SUPPLEMENT 2 TO
WATTS BAR NUCLEAR PLANT ENVIRONMENTAL INFORMATION

TENNESSEE VALLEY AUTHORITY RESPONSES
TO
NUCLEAR REGULATORY COMMISSION QUESTIONS
ON
WATTS BAR NUCLEAR PLANT
ENVIRONMENTAL INFORMATION
UNITS 1 AND 2

QUESTIONS FORWARDED BY
USNRC LETTERS FROM WM. H. REGAN, JR.
TO GODWIN WILLIAMS, JR., DATED APRIL 12 AND MAY 10, 1977

Question Number 7.1:

Provide most recent projections of energy and peak demand for the TVA system; by year from present to two years beyond the planned on-line date of Watts Bar Unit No. 2. For energy demand, provide total system energy, Federal energy component, and Non-Federal energy component separately. For peak load, provide total peak load, ERDA load, non-ERDA peak load, and non-ERDA temperature-adjusted peak load separately.

Response:

	Megawatts			Millions of Kilowatthours		
Fiscal Year	Total Peak	ERDA Peak	Non-ERDA Peak	Total Energy	Federal Energy	Non-Federal Energy
1977	22,000	3,965	19,035	130,080	26,655	103,425
1978	23,150	3,360	19,790	139,230	28,825	110,405
1979	25,100	3,900	21,200	151,310	33,285	118,025
1980	27,200	4,485	22,715	164,900	39,115	125,785
1981	28,700	4,485	24,215	172,870	40,290	132,580
1982	30,100	4,485	25,615	180,160	40,290	139,870

Non-ERDA peak load and non-ERDA temperature-adjusted peak load are the same in the forecast period. This information reflects TVA's power forecast and is similiar to information supplied to the NRC for the Yellow Creek and Phipps Bend Nuclear Plants.

Question Number 7.2:

Discuss TVA's power projection technique in general and specially for residential sector, distributor-served commercial/industrial sector, and direct-served industry sector. Provide annual projections for each of these sectors.

Response:

The Residential Sales Forecast - Residential sales now account for about 30 percent of total area energy requirements. Growth in residential customers is shown in Table 7.2-1. The number of residential customers is expected to grow more in the next decade due to the effects of the postwar baby boom and the fact that one-third of the people of the region are now below the age of 20 (Table 7.2-2).

The effect of the recession on customer growth can be seen in Table 7.2-1. The number of customers grew only 41,000 from 1974 to 1975, the smallest increment in the past decade. However, the age distribution of the population indicates rapid household formation during the next decade. Household projections are shown in Table 7.2-3.

Table 7.2-4 presents actual and adjusted average annual residential usage and heating (winter) and cooling (summer) degree days. The actual average annual use has been relatively flat since 1970. However, 1970 had the coldest winter in the last 16 years while the following 6 years were much warmer. After adjusting the average uses to normal weather, the figures in the last column show continuous growth from year to year through 1973. As Button and Burdeshaw[1] pointed out, there was no obvious response to substantial rate increases which began in 1967 through the summer of 1973.

Growth of adjusted average use is shown in the last column of Table 7.2-4 in fiscal year 1974 was negligible, declined in fiscal year 1975, and declined slightly in fiscal year 1976. These effects are primarily due to inflation, the recession, higher prices, and conservation measures associated with the oil embargo and the coal shortage. Other factors influencing the residential use per customer are the gradual shift toward fewer people per household and the greater proportion of multi- as opposed to single-family dwellings of smaller cubic footage among new dwellings. However, the outlook indicates moderating electric price increases, a return to growth in personal incomes following the recession, and considerable stabilization of oil prices and supply.

Table 7.2-5 shows on lines 1-12 appliance saturation, annual appliance kilowatthour usage, and contribution to average use by appliances in fiscal years 1975 and 1986. Saturations projected for 1986 are based upon historical trends, the fact that some appliances such as ranges and water heaters already have very high saturations, and the effect of the natural gas shortage which causes greater penetration of the space and water heating markets by electricity. Annual usages of some appliances in 1986 are adjusted judgmentally for the effect of the higher real price of electricity, conservation programs, the Energy Policy and Conservation Act of 1975, and some shift toward multifamily housing. Line 13 shows that the average use per residential customer is expected to grow at nearly 2.1 percent per year and reach about 18,800 kWh by 1986. All of this growth is due to expected increases in appliance saturations. Line 14 shows that the number of residential customers is projected to grow 2.6 percent per year on the basis of the households outlook.

Past and future growth rates of residential sales are shown in Table 7.2-6. It is important to note that over half the projected future growth of residential sales are expected to result from growth of the number of households. It is also important to note that the effect of the natural gas shortage has been included in the estimates of 1986 appliance saturations and that average use per appliance has been judgmentally modified by the changing housing mix and the price-conservation effect.

A comparison of forecasts for 1986 obtained by three methods is given below.

Appliance method	54.5 billion kWh
Trend method	54.5 billion kWh
Econometric model[2,3]	55.2 billion kWh

While each of the three methods used has important differences, the forecasts obtained for 1986 fall in a narrow band.

Forecasts of Commercial and Industrial Sales - Commercial and industrial usage by ultimate consumers (excluding directly served Federal agencies) served by distributors and TVA account for about half of all area electrical requirements.

Growth from 1975 to 1986 includes both recovery from the current recession and growth due to new consumers and expansions of existing consumers. The forecast of industrial requirements is undergirded by: (1) the fact that smaller new industries continued to come onstream in the depths of the previous recession; (2) growing use of electricity by existing and new industries in facilities to meet new environmental regulations; and (3) because about 240 megawatts of new directly served load (more than 10 percent of the allowance for growth through 1986) was considered probable or highly probable, but was not under contract when the forecast was prepared. Although the price-conservation effect is included as a depressing factor, it is partly offset by substitution of electricity for scarce and now expensive fossil fuels and by increasing use of electricity for pollution abatement. The commercial and industrial forecast is also undergirded by the fact that the TVA region has experienced faster growth than the Nation from 1955 to 1972 and even faster in relation to national growth from 1962 to 1972 as shown by State of Tennessee data* on output and employment.

Employment figures for 1973 and 1974 continue to show a higher growth rate for the state versus the national economy.

State output grew about 1.5 times as fast as U.S. output in the period 1962-72 and about 1.35 times as fast in the longer period 1955-72. State output in manufacturing grew even faster than gross state product and grew 1.7 times as fast as U.S. manufacturing output in the 1962-72 period.

The conditions and factors which caused rapid growth in the TVA region relative to the Nation are not likely to dissipate significantly in the next decade. Causal factors explaining a TVA growth rate which is faster than the U.S. growth rate include availability of reasonably priced land; ample supply of clean water for industrial uses; ample supply of skilled and unskilled labor; adequate supply of electric power; favorable tax rates; excellent transportation networks; a high degree of industrial development activity by state governments, local governments, and various quasi-public and private organizations; and proximity to raw materials and markets. The latter factor will be enhanced by the Tennessee-Tombigbee Waterway scheduled for completion in the 1980's.

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*Data on output and employment were prepared by the Center for Business and Economic Research at The University of Tennessee at Knoxville.

The forecast of the load of the quarter million distributor-served commercial and industrial loads was prepared by the use of three techniques. A comparison of the three forecasts for 1986 is shown below.

Trend Method	61.5 billion kilowatthours
Crude Linkage Method	63.6 billion kilowatthours
Econometric Equation Method	58.1 billion kilowatthours

Direct Service, Industrial - Forecasts of TVA-served large industries are based on extensive communication with existing plants including negotiations in progress; contract demands; the historical record of load factors and peak loads as a percentage of contract demand; and the behavior of various types of loads in the 1975 and prior recessions. An allowance for growth to provide for expansion of existing plants and for new plants is added after study of past growth and outlook for growth of various categories of industry. The forecast of TVA-served industry load is 40.3 billion kilowatthours in 1986, of which 27.5 is attributable to existing plants and known contract changes, and 12.8 to the allowance for growth. The growth rate from 1975 to 1986 including recovery from the current recession is 5 percent.

Forecasts of Federal Loads - ERDA loads included in the Federal and interdivisional loads account for nearly one-fifth of total area energy loads and are included at firm contract demand levels. ERDA load reductions had a depressing effect upon regional load growth in the past decade. However, ERDA-scheduled load growth in the future is a positive growth factor. ERDA firm contract loads included in the forecast are as follows:

July 1976-October 1976	2,340 MW	Present level
November 1976-March 1978	2,965 MW	Tied to Browns Ferry #3 COD
April 1978-December 1978	3,360 MW	Cascade Improvement Program
January 1979-March 1979	3,560 MW	Tied to Sequoyah #2 COD
April 1979-September 1979	3,900 MW	Cascade Uprating Program
October 1979-December 1979	4,020 MW	Cascade Uprating Program
January 1980-March 1980	4,360 MW	Cascade Uprating Program
April 1980-and beyond	4,485 MW	Cascade Uprating Program

Other Federal loads are small relative to ERDA loads. No provision for growth other than increases under contract are included in this forecast.

Forecasts of TVA load by class of service are presented in the table below.

ANNUAL PROJECTIONS OF TVA LOAD BY

CLASSES OF SERVICE IN MILLIONS OF KILOWATTHOURS

Fiscal Year	Distributor Served: Residential	Distributor Served: Commercial and Industrial	Direct Service Industrial
1977	34,604	33,058	26,705
1978	36,577	35,701	28,410
1979	38,730	38,633	30,200
1980	41,155	41,584	31,705
1981	43,332	44,146	33,150
1982	45,643	47,057	34,600
1986	54,500	61,500	40,300

Similiar information was provided for the Yellow Creek and Phipps Bend Nuclear Plants.

1. Federal Power Commission, 1970 National Power Survey, Forecasts of Electric Energy and Demand to the Year 2000, A Report by the Task Force on Forecast Review to the Technical Advisory Committee on Power Supply, July 19, 1973.

2. For a complete discussion of the residential energy model see, "The Residential Demand for Electricity in the TVA Area," prepared by Lynn C. Maxwell, Chattanooga, Tennessee; Division of Power Utilization, Tennessee Valley Authority, 1976 (Draft Paper).

3. For a complete description of the econometric model and forecasts of all exogenous variables see, "An Econometric Model of Distributor Residential Commerical and Industrial Electric Energy Sales" prepared by Lynn C. Maxwell, Chattanooga, Tennessee; Division of Power Utilization, Tennessee Valley Authority, 1976 (Draft paper).

Table 7.2-1

DISTRIBUTOR RESIDENTIAL CUSTOMERS

THOUSANDS

	Customers at End of Calendar Year	Change From Previous Year
1966	1,708	54
1967	1,750	42
1968	1,799	49
1969	1,843	44
1970	1,894	51
1971	1,955	61
1972	2,027	72
1973	2,110	83
1974	2,181	71
1975	2,222	41
1980	2,542	64*
1985	2,879	67**

*Average annual increase 1975-1980
**Average annual increase 1980-1985

Table 7.2-2

POPULATION DISTRIBUTION BY AGE GROUPS

1975

Age Group	U.S.	TVA Area
0-13	26.0%	24.3%
14-19	9.7%	10.6%
20-29	17.0%	15.2%
30-44	16.9%	18.5%
45-64	20.1%	19.0%
65 and over	10.3%	12.4%
	100.0%	100.0%

Table 7.2-3

REGIONAL ECONOMIC OUTLOOK

TVA Projections	1975	1980	1985	Average Annual Percent Change 1975-80	Average Annual Percent Change 1980-85
Gross state product (Tenn.) (millions $1958)	15,079	20,175	25,154	6.0	4.5
Manufacturing output (Tenn.) (millions $1958)	6,555	9,608	12,450	7.9	5.3
Trade & service output (Tenn.) (millions $1958)	6,355	7,784	9,200	4.1	3.4
Personal income per capita (TVA) ($1967)	2,771	3,380	3,790	4.1	2.3
Total employment (TVA) (thousands)	2,207.9	2,572.4	2,829.9	3.1	1.9
Manufacturing employment (TVA) (thousands)	677.5	841.7	925.8	4.4	1.9
Trade & service & government employment (TVA) (thousands)	1,411.4	1,615.7	1,789.1	2.7	2.1
Population (TVA) (thousands)	6,285.3	6,629.6	6,940.1	1.1	0.9
Household (TVA) (thousands)	2,033	2,265	2,550	2.2	2.4
Alternative Projections Based on Tennessee Econometric Model					
Gross state product (Tenn.) (millions $1958)	15,079	20,868		6.7	
Manufacturing output (millions $1958)	6,555	9,936		8.7	
Trade & service output (millions $1958)	6,355	8,163		5.1	

Source alternative projections:

Hui S. Chang, Tennessee Econometric Model: Phase I (Knoxville, Tenn.: Center for Business and Economic Research, The University of Tennessee, 1976), pp. 78-80.

Table 7.2-4

AVERAGE RESIDENTIAL USE IN THE TVA AREA INCLUDING MEMPHIS ALL YEARS ACTUAL AND ADJUSTED TO NORMAL WEATHER 1960-76

Ending June 30	Average Residential Use - kWh	Heating Degree Days Base=65°F	Heating Degree Days % Above Normal	Cooling Degree Days Base=75°F	Cooling Degree Days % Above Normal	Average Residential Use Adjusted To Normal Weather - kWh
1960	8,280	4,042	13.1	463	-7.4	8,025
1961	8,615	3,781	5.8	425	-15.0	8,452
1962	9,025	3,535	-1.1	454	-9.2	9,020
1963	9,849	3,962	10.8	454	-9.2	9,503
1964	10,260	3,709	3.7	415	-17.0	10,159
1965	10,655	3,553	-0.6	358	-28.4	10,649
1966	11,294	3,687	3.1	434	-23.2	11,215
1967	11,680	3,435	-3.9	435	-23.0	11,785
1968	12,668	4,048	13.2	225	-55.0	12,467
1969	13,600	3,842	7.5	501	0.2	13,285
1970	14,560	4,190	17.3	444	-11.2	13,851
1971	14,400	3,780	5.7	539	7.8	14,101
1972	14,040	3,099	-13.3	328	-34.4	14,542
1973	15,080	3,635	1.7	354	-29.2	15,238
1974	14,480	2,943	-17.7	420	-16.0	15,270
1975	14,540	3,514	-1.7	351	-29.8	14,911
1976	14,370	3,292	-7.9	364	-27.2	14,855
Normal		3,575		500		

Table 7.2-5

APPLIANCE SATURATIONS AND CONTRIBUTIONS
TO ANNUAL AVERAGE RESIDENTIAL USE
TOTAL ALL DISTRIBUTORS

	Appliance	Fiscal Year 1975 Saturation	Fiscal Year 1975 Avg. Use of Appliance	Fiscal Year 1975 Contribution to Annual Avg. Use		Fiscal Year 1986 Saturation	Fiscal Year 1986 Avg. Use of Appliance	Fiscal Year 1986 Contribution to Annual Avg. Use
1.	Lighting	100	1,070	1,070		100	1,070	1,070
2.	Television	97	400	388		100	400	400
3.	Refrigerator	99	1,170	1,158		100	1,560	1,560
4.	Range	80	1,350	1,080		85	1,210	1,029
5.	Water heater	72	5,100	3,672		84	4,980	4,183
6.	Washer	74	100	74		74	100	74
7.	Air conditioning	63	3,150	1,984		81	3,060	2,479
8.	Freezer	46	1,060	488		56	1,180	661
9.	Dryer	44	1,380	607		56	1,350	756
0.	Electric heat	43	9,400	4,042		56	8,500	4,760
1.	Dishwasher	23	350	81		40	330	132
2.	Other			267				1,709
3.	Average use			14,911	← 2.1%/yr →			18,813
4.	Average customers (000)			2,178.7	← 2.6%/yr →			2,898
5.	Energy use (millions kWh)			32,486.6	← 4.8%/yr →			54,520

Table 7.2-6

AVERAGE ANNUAL RATES OF GROWTH

TVA AREA POWER REQUIREMENTS

	1965-74	1975-80	1975-86
		Fiscal Year Energy	
Residential	7.2%	4.8%	4.8%
Commercial and industrial	6.2	7.1	6.4
Distributor served	8.0	7.8	7.2
Directly served	4.4	6.1	5.0
Federal agencies	Declining	14.5	6.6
		Fiscal Year Peaks	
Total area requirements	4.7%	7.8%	6.2%
Total area requirements less ERDA	5.8	7.0	6.2

Question Number 7.3:

Discuss the projected effect which conservation and substitution efforts are expected to have on TVA's forecasts of energy and peak system demand. Present forecasts with conservation and substitution effects considered.

Response:

Price-Conservation Effects in the Load Forecast - The consumption of electricity is expected to respond to several factors which have been quantified as the price-conservation effect in the load forecast. These factors are: (1) the price of electricity; (2) present or future legislation which affects the insulation of homes and buildings; and (3) present or future legislation which affects appliance efficiency.

Changes in the load forecast due only to price changes are quantified by the price elasticity concept. Price elasticity is defined as the percentage change in load per 1-

percent change in real price of electricity, all other factors held constant. The long-run price elasticities inherent in this forecast are presented in Table 7.3-1 for the residential sector and Table 7.3-2 for the distributor served commercial and industrial sector.

The median family income in the area served by TVA power has grown rapidly during the past 35 years and the average power bill is presently about as large a percentage of family income as it was in 1950, despite substantial rate increases beginning in 1967. The percentage of family income spent for electricity would have declined significantly after 1960 had not consumers chosen electricity over direct fossil fuels for cooking and heating and installed other appliances for which electricity is the only practical energy source such as air conditioning.

To explore business price response, a tour of selected industrial plants in the TVA area was conducted and reports of tours in other utility areas were reviewed. These tours explored the four types of possible response to electric price increases available to industry: (a) reduce output, (b) shift to other energy forms, (c) conservation, and (d) self-generation.

None of the plants toured were considering the first response (reduction of output). In fact, many surveyed plants were planning expansions despite past and certain future rate increases.

Shifts to other energy forms were found to be unlikely. Historically, electricity has been more expensive than other energy forms and plants are generally designed to use electricity to exploit advantages other than the price of energy. However, the survey did indicate a strong potential for shifts to the use of electricity in place of fossil fuels.

The potential for conservation was found to be limited because essential production uses of electricity--electric drive, electrolytic cell applications, pollution control equipment, etc.--cannot be reduced without reducing production. Such uses typically account for 95 percent or more of the industrial use of electricity. Possible conservation reductions to minimum standards for other uses--lighting, heating, air conditioning, etc.--might permit a 2- to 3-percent reduction in total industrial use during the next decade.

Economies of scale provide a large advantage to the electric utility and tend to preclude self-generation as a practical industry response to higher electric prices. Self-generation may exist where waste products can be used as a fuel or where process steam is necessary for the production process. None of the toured plants generated steam, in excess of essential process steam, for electricity production. To the extent that uncertainties in fuel supplies continue, further shifts to electric processes are likely to reduce still further the self-generation now associated as a byproduct of other process-steam needs.

The conclusion drawn from information obtained in the industry tours was that industrial response to the increase in the price of electricity is small in the short and intermediate run and that consumption of electricity varies closely with industrial output. Over the long run, changes in the price of electricity may be expected to affect technologies selected by industries and the mix of resources employed and thus the use of electricity.

Among large TVA-served electricity-intensive loads, indications from the tours and national reports suggest that increasing use of electricity for pollution control and other effects of environmental regulations will offset or more than offset price-conservation effects during the next decade.

The wholesale price of electricity is expected to increase from 1976-86 but at a slower rate than the overall rate of inflation. The wholesale price of electricity forecasts were used to project residential and distributor commercial and industrial prices of electricity in constant dollars. The long-run increase in these prices are shown in Table 7.3-3 for several alternative periods of time.

Residential Conservation - The actual price effect used in the forecast was based on the residential model. It has been estimated that the effect of prices on residential energy up through 1975 amounted to 1.9 billion kWh. The lagged effects of price increase up through 1975 adds another 3.3 billion kWh, and the price decreases from 1975-86 cause an increase in energy consumption of 2.3 billion kWh. Thus, the net effect of price changes on 1986 energy consumption is to decrease energy consumption by 2.9 billion kWh. These effects are shown in Table 7.3-4.

The insulation programs under way and proposed could result in conservation by the residential consumer of 0.7 billion kWh as shown in Table 7.3-4.

The Energy Policy and Conservation Act of 1975 requires that the Federal Energy Administration (FEA) set appliance energy efficiency targets that are economically and technologically feasible. As FEA has not yet established the targets, a study was made to determine the conservation in the residential loads resulting from an assumed 20-percent increase in appliance efficiency. This resulted in a savings of about 4.2 billion kWh. Not all appliances can reach this level of efficiency; however, about 60 percent of this value, or 2.5 billion kWh, was believed to be an attainable target as shown in Table 7.3-4.

As shown in Table 7.3-4, the total identified conservation in the 1986 forecast is 6.1 billion kWh. The actual conservation used in the forecast is 6.6 billion kWh or 0.5 billion kWh greater than conservation which has been identified. The difference between the identified conservation and the forecast conservation provides for greater energy conservation than what is currently anticipated.

Distributor Commercial and Industrial Conservation - The price effect used in the forecast was based on the distributor-served commercial and industrial model. The effect of prices on energy consumption up through 1975 has been estimated to be 4.1 billion kWh. The lagged effects of price increase up through 1975 adds another 5.3 billion kWh, and the real price decreases from 1975-86 cause an increase in energy consumption of 2.1 billion kWh. Thus, the net effect of price changes in 1986 energy consumption is 7.3 billion kWh. These effects are shown in Table 7.3-4.

The effect of price was the only portion of the conservation effect which was quantified in this sector. As indicated in Table 7.3-4, the actual conservation in the forecast is 9.2 billion. The 1.9 billion kWh excess over and above the price effect is to account for present and future legislation which would affect energy conservation in commercial and industrial building and to account for unforeseen price increases above the assumed price changes.

The magnitude of the price-conservation effect included in the forecast for 1977-86 is shown in Table 7.3-5 and Table 7.3-6.

The price-conservation effect in residential class of 6.6 billion kilowatthours included in the forecast for 1986 amounts to 12 percent of the forecast of residential sales of 54.6 billion kilowatthours in 1986. The comparable effect of 9.2 billion kWh in the distributor-served commercial and industrial sector amounts to nearly 15 percent in 1986. The total of all quantified price-conservation effects in this forecast amount to about 7.5 percent of total area energy requirements in 1986. Excluding Federal agencies and TVA-served large industries, the price-conservation effect amounts to about 12.1 percent of the remaining energy load in 1986.

Effects of Environmental Regulation - Increasingly stringent environmental regulations (Clean Air Act, Federal Water Pollution Control Act) have led to significant increases in the consumption of electricity by industry, and the outlook is for further increases in consumption.

New environmental regulations have led to electricity usage for national pollution abatement of 4 to 6 percent of total electricity consumption by industry, with prospects for further increases. These findings were published in a report prepared for the Council on Environmental Quality.[1]

Pollution regulations also affect the types of processes used by industry. For example, Corning Glass Works reportedly began switching to electric glass furnaces because of strict air pollution standards.

Tours of industrial plants in the TVA area discussed above indicated a range of the percentage of total electricity consumption planned for pollution abatement among large users of electricity as shown below.

Product	%
Titanium dioxide	22
Industrial chemicals	19
Ferroalloys	8-10
Paper	8
Industrial chemicals	8
Synthetic fibers	8
Aluminum	5

It appears that perhaps 7 percent or more of the load of large TVA-served industries will be attributable to pollution abatement by 1977. If it is conservatively assumed that the percent of load attributable to pollution abatement remains at about 7 percent to 1986, pollution-abatement load in 1986 would be nearly 3 billion kilowatthours, a substantial amount of power roughly equivalent to one-third the net output of one Yellow Creek generating unit.

It was assumed in preparing this forecast that the effect of pollution abatement and the effect of environmental regulation upon industrial processes would offset the price effect among TVA-served large industries during the next decade. The pollution abatement equipment in place and planned will require large blocks of electricity while the opportunities for conservation and price responsiveness were found to be small in the industrial tours discussed above.

On the basis of the type of industries served, it appears likely that the additional load due to pollution abatement in distributor-served commercial and industrial loads would be less than expected from the directly served industry. If a roughly estimated 2 percent of the distributor-served commercial and industrial load is used for pollution-abatement in 1986, it would amount to 1.2 billion kilowatthours.

<u>The Natural Gas Shortage and Gas Prices</u> - After decades of rapid growth of consumption and plentiful supply, a turning point came in the late 1960's when natural gas consumed began to exceed annual additions to proved reserves. The surge of demand for natural gas was reinforced in recent years by environmental regulation because gas is a clean fuel. Recent estimates of undiscovered reserves have been sharply below estimates prepared in previous years. These facts suggest that annual U.S. natural gas production has probably peaked.[2] A review of gas industry statistics reveals that proved reserves peaked in 1967 and gas utility industry sales to ultimate consumers peaked in 1972 and declined thereafter.[3]

The national shortage of natural gas and sharp rises in the cost of fossil fuels since 1973 are well known to officials and the public. Concern over reliability of energy supply has also become an important factor since the oil embargo which began in October 1973. There is widespread concern regarding domestic supplies of oil and gas in the ground heightened by recent downward revisions of undiscovered reserve estimates. Numerous studies underscore this concern.[4,13]

The development of Alaskan gas and oil supplies is an important factor in the future national energy supply. For example, the 1.3 trillion cubic feet of gas expected annually is about 6 percent of current U.S. consumption. However, it now appears that Canadian gas exports to the U.S. which presently amount to about 1 trillion cubic feet annually will be phased out as Canada grapples with the long-run Canadian energy supply and demand situation.[14] Thus, it appears that new Alaskan supplies will be largely offset by reduced Canadian exports.

Prices of natural gas have been regulated in the interstate markets. Whether rising gas prices would bring about increased production depends on the supply elasticity. In the short run, it is believed that the supply is highly inelastic,[15] but in the longer term this elasticity should increase somewhat. If the intrastate markets are any indication of what might happen on a national basis, rising prices should tend to increase domestic production. The rise of prices of gas to as high as $2.00 per million Btu in some cases in intrastate markets has been accompanied by fully adequate supply and resulted in some downward pressure on intrastate prices in 1975.

The gas shortage continues to be severe in the TVA area, with curtailments increasing in the states in which the TVA area is located.[16] The real extent of shortages for industry has been masked by reduced industrial output resulting from the recession and associated lower need for industrial gas. Surveys by the State of Tennessee Energy Office indicated that curtailments in the winter of 1976-77 were expected to exceed curtailments of the prior winter. Curtailments included up to a 45-percent curtailment of FPC priority 2 consumers by one pipeline.[17] With many firm contract industrial and commercial consumers subject to sharp curtailments, little gas for new consumers is now available. The Tennessee Energy Office survey of distribution systems confirmed that virtually no gas is available for new industry.[18] Information from other states in which the TVA area is located indicate about the same supply situation. In the fall of 1976, the outlook for gas supply for the winter of 1976-77 was less than the fall 1975 outlook for the winter of 1975-76, with the State of Tennessee among the ten most affected states.

TVA investigations through interviews with local electric systems, gas systems, and industrial development associations confirm the shortage of gas for new consumers.

Should gas prices be deregulated in the interest of conservation and increased supply, prices would be expected to increase sharply. In fact, the average wellhead price of gas increased 40 percent from 1973 to 1974[19] and prices continued to rise in 1975.[20] The average U.S. price paid by residential customers rose 14 percent in 1974.[3]

The Federal Power Commission raised the price of new gas discovered or dedicated to interstate pipelines since January 1975 from $0.52 per 1,000 cubic feet (MCF) to $1.42, with the provision that the price can be increased $0.01 quarterly. The price of intermediate gas discovered or dedicated between January 1973 and January 1975 was raised to $0.98 per MCF. New gas presently constitutes about 10 percent of the national supply; but as that share increases and as distribution costs escalate, the cost of gas to consumers can be expected to rise sharply.

A recent FPC study[15] of the costs and benefits of deregulation of natural gas prices attempted to quantify future supply shortfalls without deregulation. Using a range of forecasts of demand for gas and level production at 1973 output, the shortfall by 1985 was projected at from 20 to 33 percent of demand. The average wellhead price assumed to maintain level production was 3-1/3 times as high as the 1973 average wellhead price.

From the above figures and observations one would reasonably conclude that, even with assumed total deregulation of gas with an accompanying increase of supply, gas prices rising rapidly, and electric rate increases moderating, electric heating could easily maintain domination of the home heating market, and electricity could be more attractive in numerous other applications in the residential, commercial, and industrial markets.

Substitution Effects in the Load Forecast - The substitution effect in the forecast is defined as the increase in electricity use resulting from replacement of direct fossil fuel with electricity due to rising prices of fuels, unavailability of natural gas, and uncertainty as to supply of other fossil fuels.

The substitution effect for the residential class of customers results in increased penetration in the space and water heating markets over and above normal long-term increases. Due to substitution, the 1986 space-heating saturation is projected to be 56 percent, instead of 54 percent based on an assumption of plentiful gas supply; and the water-heating saturation is projected to be 84 percent instead of 82 percent. These higher appliance saturations result in a substitution load of one billion kilowatthours in 1986 (see Table 7.3-5).

In the distributor-served commercial and industrial sector, increased use of electricity as a replacement for natural gas is expected, especially for process steam, space heating, cooking, and paint and other drying. Already, numerous cases of substitution have been identified.

Reasons reported for substituting electricity for fossil fuels among commercial and industrial consumers in the TVA area include lower operating cost, environmental regulations, desire for an ensured energy supply, in addition to the unavailability of natural gas.

Table 7.3-7 shows the reported kilowatts of distributor-served commercial and industrial load converted due to substitution of electricity for applications which have traditionally employed fossil fuels. The figures are the result of incomplete reporting during the 22-month period ending April 1976. Many of the 160 municipal and cooperative distributors of TVA power do not report instances of substitution at all, and others do not report in a systematic manner. It is believed that only about one-fourth to one-third of the cases are reported. On the basis of reported figures and with an allowance for cases not reported, it appears that 0.3 to 0.4 billion kilowatthours of load developed annually during the worst recession in 40 years. It appears reasonable that if the recession had not depressed new commercial and industrial development and made it possible for existing plants to operate with reduced gas supplies during a period of reduced output, much more substitution load would have developed. On that basis, additional substitution load in the order of 0.6 billion kilowatthours per year during the next decade appears reasonable.

The magnitudes of the substitution effect are shown in Tables 7.3-5 and 7.3-6. The amount of substitution in the distributor-served commercial and industrial category of 6.1 billion kilowatthours in 1986 when used with a compound growth of 3 percent in real price of gas is associated with a cross price elasticity of 0.3 to 0.4. That range is consistent with the findings reported by other researchers. While the estimates of substitution in this forecast are based primarily on the unavailability of gas, the above check of the effect of gas price gives some assurance that substitution will be a significant load by 1986 even if gas supplies do increase through deregulation and sharply higher prices. The total substitution effect in the forecast for 1986 is about 3 percent of total regional load.

Similiar information was provided for Yellow Creek and Phipps Bend Nuclear Plants.

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Table 7.3-1

LONG-RUN ELASTICITIES USED

IN RESIDENTIAL ENERGY MODEL

Causal Factor	Long-Run Elasticity
Residential	
Price of electricity	-0.36
Price of electricity relative to price of gas	-0.22
Income per capita	0.68
Number of persons less than 18 years of age	0.12
Ratio of multifamily to single family households	-0.17
Ratio of rural to urban households	0.33
Population per housing unit	-1.34
Percent of housing units with head 62 years and older	-0.77

Table 7.3-2

LONG-RUN ELASTICITIES OF CAUSAL FACTORS

FOR DISTRIBUTOR COMMERCIAL AND INDUSTRIAL ENERGY MODEL FORECAST

Long-Run Elasticities:	Elasticities
Price of electricity	
Under 1,000 kW demand	-0.79
1,000-5,000 kW demand	-0.31
Over 5,000 kW demand	-0.33
Output	
Under 1,000 kW demand	1.46
1,000-5,000 kW demand	1.66
Over 5,000 kW demand	1.14

Table 7.3-3

AVERAGE ANNUAL PERCENT CHANGE IN REAL PRICE OF ELECTRICITY

Period	Residential	Distributor Commercial and Industrial
1972-1986	0.5	1.5
1973-1986	0.6	1.4
1974-1986	0.3	1.1
1975-1986	-1.5	-1.1

Table 7.3-4

RESIDENTIAL CONSERVATION

BILLIONS kWh

1.	Real price effects in calendar 1975	1.9	
2.	Effect of real price increases through 1975 on loads 1975-86	3.3	
3.	Effect of real price decreases 1976-86	-2.3	
4.	Net real price effect in calendar 1986		2.9
5.	Insulation programs (upper limit 1.5) in 1986		0.7
6.	Improved appliance efficiency (upper limit 4.2) in 1986		2.5
7.	Total identified conservation in 1986		6.1
8.	Additional unidentified conservation		0.5
9.	Conservation in forecast in 1986		6.6
10.	Conservation as percent of sales forecast (54.5) in 1986		12%

DISTRIBUTOR-SERVED COMMERCIAL AND INDUSTRIAL CONSERVATION

BILLIONS kWh

1.	Real price effect in calendar 1975	4.1
2.	Effect of real price increases through 1975 on loads 1976-86	5.3
3.	Effect of real price decreases 1976-86	-2.1
4.	Net real price effect in calendar 1986	7.3
5.	Additional unidentified conservation	1.9
6.	Conservation in forecast in 1986	9.2
7.	Conservation as percent of sales (61.5 billion kWh) in 1986	15%

Table 7.3-5

DISTRIBUTOR SERVED
CONSERVATION AND SUBSTITUTION
1976 FORECAST

	Fiscal Year Energy - Billions of kWh									
	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Residential										
Conservation (-)	3.7	4.2	4.6	5.0	5.5	5.8	6.0	6.2	6.4	6.6
Substitution (+)	.5	.7	.7	.7	.8	.8	1.0	1.0	1.0	1.0
Net	-3.2	-3.5	-3.9	-4.3	-4.7	-5.0	-5.0	-5.2	-5.4	-5.6
Total C&I										
Conservation (-)	5.2	5.7	6.2	6.7	7.2	7.6	8.0	8.4	8.8	9.2
Substitution (+)	3.0	4.0	4.8	5.0	5.2	5.4	5.6	5.8	6.0	6.1
Net	-2.2	-1.7	-1.4	-1.7	-2.0	-2.2	-2.4	-2.6	-2.8	-3.1
Total										
Conservation (-)	8.9	9.9	10.8	11.7	12.7	13.4	14.0	14.6	15.2	15.8
Substitution (+)	3.5	4.7	5.5	5.7	6.0	6.2	6.6	6.8	7.0	7.1
Net	-5.4	-5.2	-5.3	-6.0	-6.7	-7.2	-7.4	-7.8	-8.2	-8.7

Table 7.3-6

EFFECT OF CONSERVATION AND SUBSTITUTION ON DISTRIBUTOR WINTER AND SUMMER PEAKS MEGAWATTS

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Winter Peaks										
Conservation	-1,500	-1,640	-1,790	-1,930	-2,100	-2,230	-2,350	-2,450	-2,580	-2,690
Substitution	590	780	910	940	1,000	1,030	1,100	1,140	1,180	1,210
Net Effect	-910	-860	-880	-990	-1,100	-1,200	-1,250	-1,310	-1,400	-1,480
Summer Peaks										
Conservation	-1,350	-1,520	-1,650	-1,760	-1,910	-2,030	-2,130	-2,220	-2,330	-2,430
Substitution	530	720	840	860	900	940	1,000	1,040	1,070	1,090
Net Effect	-820	-800	-810	-900	-1,010	-1,090	-1,130	-1,180	-1,260	-1,340

Table 7.3-7

REPORTED COMMERCIAL AND INDUSTRIAL
SUBSTITUTION BY APPLICATION
JUNE 1974 - APRIL 1976
TVA AREA

		kW	%
1.	HVAC and water heating	51,835	50.5
2.	Food preparation and processing	1,549	1.5
3.	Electric furnaces, smelters, and forges	28,333	27.6
4.	Electric boilers	4,270	4.2
5.	Pumps, air compressors	2,250	2.2
6.	Other	14,240	14.0
		102,477	100.0

Question Number 7.4:

Discuss TVA's future outlook for pricing electricity under alternative rate structures, particularly flattening of rates, inverting rates, and various forms of peak load or time differentiated pricing techniques. Discuss projected effects on energy and peak demand, if adopted.

Response:

TVA has recently examined and discussed its policies related to the making of rates in regard to legal constraints, revenue requirements, and cost considerations which form the basis of the rate structure.[1] With regard to alternate rates, TVA has reached the following conclusions: "Major changes in rate structure, such as might be associated with adoption by TVA of one or more of the types of alternative rate structures described in section 4.0 of the draft EIS, would have a very limited effect on consumption of electricity in the short run; hence, no measurable environmental impacts. Any environmental impacts that might result from long-run changes in consumption are speculative, remote, and impossible to trace with any degree of accuracy in light of current knowledge."[1]

Since the publication of the TVA FES, several new developments have occurred. TVA is continuing intensive investigation and study of the environmental, economic, and social impacts and benefits of alternative rate structures as they might be applied to TVA's power system and to neither adopt nor reject at this time any of the alternative rate structures. For example, TVA has initiated a study of the demand for electricity by hours of the day in Knoxville, Tennessee, which will be pertinent to time-differentiated rates.

At present, much is known about the price elasticity of electricity on an annual basis but little is known about price elasticity by hours. In addition, a nationwide electric utility rate design study is being conducted by the Electric Power Research Institute, the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association for the National Association of Regulatory Utility Commissioners. The results of that study are still not known. In anticipation of the results of these studies, TVA has made no attempt to speculate on the effects of such rates on energy and peak demand.

With regard to the flattening of rates, an FPC report[2] of March 1975 concludes: "More important, there is no evidence to support the contention that flattening rate schedules will lead to drastic reductions in the use of electricity. In fact, there might be a slight expansion of consumption, which could be attributed to an increased use by customers who currently use small quantities of electricity that is sufficient to offset reductions made by large users.

"A recent investigation[2] of the effect of reducing average price differences between consumer classes reached a similar conclusion. A demand analysis similar to the one discussed in Section III was undertaken, and forecasts were made with the same price charged in all three consumer classes. Elimination of the differences between industrial, commercial, and residential rates lowered industrial demand and accelerated residential and commercial demand. Aggregate growth remained unchanged. In some circumstances rate equalization caused a slight increase in aggregate growth.

"In summary, the level of the rate schedule is a more important determinant of the quantity of electricity demanded than the shape of the rate schedule."

REFERENCES

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2. Federal Power Commission, The National Power Survey, Task Force Report: Power Generation: Conservation, Health, and Fuel Supply, Technical Advisory Committee on Conservation of Energy, March 1975. pp. 38 and 40.

Question Number 7.5:

Provide and discuss other relevant forecasts of energy and/or peak demand performed by other governmental agencies, private firms, academic institutions, etc. applicable to the TVA service area. Include forecasts which are of a regional; state; or local nature and not necessarily conforming exactly to the TVA service area.

Response:

Two forecasts of peak loads for the TVA area were prepared by NRC.[1] The first was prepared by using growth rates by categories of load from the FEA forecast of loads for the East South Central Region (Census Region 5). The second was prepared by using growth rates for Tennessee as prepared by the Center for Business and Economic Research (CBER), University of Tennessee, Knoxville. These two forecasts are shown below.

TVA PEAK LOAD PREDICTIONS

(Megawatts)

Year	FEA Regional	CBER
1977	22,373	23,035
1978	23,626	24,401
1979	24,949	25,848
1980	26,346	27,381
1981	27,821	29,004
1982	29,379	30,727

An illustrative forecast is shown below for the State of Tennessee from CBER:[2]

Year	Millions of Kilowatthours Consumption
1977	53,822
1978	60,531
1979	65,595
1980	70,844
1981	78,005
1982	85,724

Table 7.5-1 shows growth rates of major load categories and area winter peaks with and without ERDA loads for historical and forecast periods. All figures are adjusted to normal weather conditions.

Future growth rates of loads for different periods are revealing. For example, TVA loads in the period 1977-86 are expected to grow at a compound rate of 5.7 percent. The growth rate for the 1977-86 period is slower than for the period 1975-86 of 6.2 percent and for the period 1975-80 of 7.8 percent because the period 1975-77 is one of recovery from the worst recession in 40 years and because ERDA loads are scheduled to increase by more than one-quarter in that period (see answer to question 7.1). The growth rate for the period 1986-2000 is estimated to be about 4 percent. As these figures show, the outlook contained in this forecast is one of declining growth rates in the last quarter of this century in the region served with TVA power.

Future rates for the Southeastern Electric Reliability Council (SERC), of which the TVA is a part, and the U.S. as reported by the Edison Electric Institute[3] are given below for comparison. TVA growth rates are less than growth rates of SERC and the U.S.

TVA	SERC	U.S.
6.2% (1975-86)	7.2% (1975-85)	6.3% (1975-85)
5.7% (1977-86)	6.6% (1977-85)	6.0% (1977-85)

The growth rate of each of the three geographic areas is less from 1977 to 1985, than from 1975-85 or 86, indicating strong recovery from the recession in the period 1975-77 and growth rates associated with long-term growth thereafter.

A review of other recent forecasts of national sales and output available in the summer of 1976 shows a grouping of growth rates to 1985 near 6 percent per year. A Federal Power Commission staff forecast based upon figures submitted by the nine regional electric reliability councils shows a growth rate of 6.2 percent per year for electric energy requirements and 6.3 percent per year for winter and summer peaks.[4] An Arthur D. Little forecast of electricity sales reportedly showed an expected growth rate of 5.9 percent per year.[5] The recently updated Project Independence report prepared by the Federal Energy Administration reportedly projects growth at 5.7 percent per year.[5] The most recent Edison Electric Institute forecast as of August 1976 shows a growth rate of output of 6.4 percent per year.[5] The McGraw-Hill forecast published in the fall of 1975 shows growth of output at 6.4 percent per year.[6] A General Electric report[7] published in the summer of 1976 projects national growth at a rate of 6.1 percent for the period 1975-85. All of these forecasts post-date the trough of the recent severe recession, the oil embargo, and the worst of the surge of rate increases.

REFERENCES

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Table 7.5-1

AVERAGE ANNUAL RATES OF GROWTH

TVA AREA POWER REQUIREMENTS

	1965-74	1975-80	1975-86
	Fiscal Year Energy		
Residential	7.2%	4.8%	4.8%
Commercial and industrial	6.2	7.1	6.4
Distributor served	8.0	7.8	7.2
Directly served	4.4	6.1	5.0
Federal agencies	Declining	14.5	6.6
	Fiscal Year Peaks		
Total area requirements	4.7%	7.8%	6.2%
Total area requirements less ERDA	5.8	7.0	6.2

Question Number 7.6:

Provide capacity plans and on-line capacity for each year from present to beyond two years of the Watts Bar Unit No. 2 on-line date. Identify type of units and capacity of these units which make up total capacity for each year.

Response:

1977

Capacity Installation Plans	On-Line Dependable Capacity - MW Type of Units	Capacity
(N) Browns Ferry 3-3/77	Fossil	16,529
	Nuclear	3,201
	Combustion Turbine	2,484
	Hydro (Conventional)	3,882
	Year End Total	26,096

1978

Capacity Installation Plans	On-Line Dependable Capacity - MW Type of Units	Capacity
(PS) Raccoon Mountain 1-2/78	Fossil	16,529
(PS) Raccoon Mountain 2-4/78	Nuclear	4,349
(PS) Raccoon Mountain 3-6/78	Combustion Turbine	2,484
(PS) Raccoon Mountain 4-8/78	Hydro (conventional)	3,882
(N) Sequoyah 1-9/78	Hydro (Pumped Storage)	1,300
	Year End Total	28,544

1979

Capacity Installation Plans	On-Line Dependable Capacity - MW Type of Units	Capacity
(N) Sequoyah 2-5/79	Fossil	16,529
(N) Watts Bar 1-6/79	Nuclear	6,674
	Combustion Turbine	2,484
	Hydro (Conventional)	3,882
	Hydro (Pumped Storage)	1,300
	Year End Total	30,869

1980

Capacity Installation Plans	On-Line Dependable Capacity - MW: Type of Units	Capacity
(N) Watts Bar 2-3/80	Fossil	16,529
(N) Bellefonte 1-6/80	Nuclear	9,064
	Combustion Turbine	2,484
	Hydro (Conventional)	3,882
	Hydro (Pumped Storage)	1,300
	Year End Total	33,259

1981

Capacity Installation Plans	Type of Units	Capacity
(N) Bellefonte 2-3/81	Fossil	16,529
	Nuclear	10,277
	Combustion Turbine	2,484
	Hydro (Conventional)	3,882
	Hydro (Pumped Storage)	1,300
	Year End Total	34,472

1982

Capacity Installation Plans	Type of Units	Capacity
	Fossil	16,529
	Nuclear	10,277
	Combustion Turbine	2,484
	Hydro (Conventional)	3,882
	Hydro (Pumped Storage)	1,300
	Year End Total	34,472

Question Number 7.7:

Provide a summary table of forecast peaks, capacity, and reserve margins for each year from present to two years beyond Watts Bar Unit No. 2 on-line date. Discuss the methodology used to determine reserve margins. Provide criteria for determination of minimum required system reserve margins.

Response:

Period	Forecast Peak Demand-MW Total	On-TVA	Dependable Capacity-MW	Reserve Margin MW	%
Winter 1977-78	23,150	21,090	26,096 1,300 RM1-4 1,148 S1	5,006	23.7
Winter 1978-79	24,900	22,840	28,544 1,148 S2 1,177 WBN1	5,704	25.0
Winter 1979-80	27,200	25,620	30,869 1,177 WBN2 1,213 BEL1	5,249	20.5
Winter 1980-81	28,700	27,600	33,259 1,213 BEL2	5,659	20.5
Winter 1981-82	30,100	29,000	34,472	5,472	18.9
Winter 1982-83	31,550	30,450	34,472	4,022	13.2

TVA uses the "loss of load" method as a means to determine generating capacity to supply load requirements plus reserves. The method, a probability technique, is well documented in the literature and is widely used throughout the electric utility industry for capacity planning. TVA has described this method previously for the Yellow Creek and Phipps Bend Nuclear Plants.

TVA's generation planning criterion and method determines the amount of capacity required to provide a reasonable assurance that sufficient capacity will be available at the time of future system peaks so that the probability of risk will not be greater than the acceptable index of reliability (0.1 day per year) for a reliable supply of bulk power.

Generation planning on the TVA system is made on a month-by-month basis and is based on the expectation that no maintenance will be scheduled during the winter and summer peak months of January and August, respectively. For present TVA system characteristics, planning sufficient capacity to meet the load plus reserve requirements for the peak months at the same time provides load plus reserve requirements with sufficient margin to perform maintenance in the off-peak months. Seasonal capacity exchange under contract is reflected in TVA planning studies as an adjustment to the system load model. The reserve requirements for the exchanged capacity are provided by the supplying system. Similar information on TVA's planning criteria was supplied for the Yellow Creek and Phipps Bend Nuclear Plants.

Question Number 7.8:

Discuss effects of delays of one and two years in the planned operating dates of Watts Bar Unit Nos. 1 and 2 on reserve margins and power supply of the TVA system.

Response:

Based on current projections, the power supply situation for the period during which the Watts Bar Nuclear units are scheduled to become commercial is expected to be adequate if the current projected schedules of capacity addition are achieved. Delays in operation of the Watts Bar units could result in the inability of the TVA system to adequately meet its load obligations and jeopardize the reliability of TVA's bulk power supply.

The following tabulation indicates the amounts by which reserves on the TVA system will be inadequate during the peak load seasons, postulating a delay of 1 and 2 years for each of the Watts Bar Nuclear units (a delay in unit 1 results in an equal delay in the other unit) and assumes no delay in the Bellefonte Nuclear Unit schedule.

Megawatt Deficiencies in TVA System Reserve Due to Delays

Period	1-Year	2-Years
Winter 1979-80	-2,000	-2,000
Winter 1980-81	-2,114	-3,236
Winter 1981-82	-	-2,607

Delays in Watts Bar units can result in deficiencies in margins available for maintenance, and if the delays are sufficiently long, will result in an inadequate level of system reliability. If no action is taken to increase capacity and if the projected loads materialize, TVA will be unable to meet its load obligations.

Question Number 7.9:

In terms of operating costs (i.e., fuel costs plus operation and maintenance costs), provide a listing of those plants, if any, which would cost less to operate than Watts Bar Unit Nos. 1 and 2 (at the planned on-line dates for each unit). Provide generating capacity, annual energy output, and capacity factors for each of these plants in the first full year of Watts Bar Unit Nos. 1 and 2 operation.

Response:

Plants with lower operating cost than Watts Bar units 1 and 2:

Browns Ferry, unit 1
Browns Ferry, unit 2
Hydro

Fiscal Year 1981

Plant	Capacity (MW)	Current Estimate of Annual Energy Output (GWh)	Capacity Factor
Browns Ferry			
Unit 1	1,067	6,543	70.0
Unit 2	1,067	6,543	70.0
Hydro Units	3,982	18,276	52.4

Question Number 7.10:

Assuming no load growth (zero growth) after 1976, compare operating costs for the overall TVA system with and without Watts Bar Unit Nos. 1 and 2. Provide the same calculations and data assuming projected load growth is realized.

Response:

The following tabulation shows the estimated operating costs of the overall TVA system with and without Watts Bar assuming zero load growth from fiscal year 1976 and assuming the projected load growth is realized. The total operating costs shown are the variable costs of operating the system and consist of fuel and O&M expenses.

Zero load growth case comparing cost with and without Watts Bar Nuclear Plant units 1 and 2 for fiscal year 1981.

	With Watts Bar, units 1 & 2 (Millions)	Without Watts Bar, units 1 & 2 (Millions)
Estimated System Operating Cost	$780	$925

Projected growth case comparing operating cost with and without Watts Bar Nuclear Plant units 1 and 2 for fiscal year 1981.

	With Watts Bar, units 1 & 2 (Millions)	Without* Watts Bar, units 1 & 2 (Millions)
Estimated System Operating Cost	$1,545	$1,770

*Assumes optimistic coal-fired generation level. If assumed generation is not achieved, TVA would have to increase its reliance on purchased power to meet system energy requirements.

Question Number 7.11:

Provide most recent projected fuel costs for Watts Bar Unit Nos. 1 and 2 for the first full year of operation; state in mills/kWh and dollars per year.

Response:

Fuel Cost in First Full Year of Operation of Each Unit

Plant	Mills/kWh	Dollars (Millions)
Watts Bar		
Unit 1	3.8	28
Unit 2	3.9	30

Question Number 7.12:

Provide mix of fuels which would be used to generate electricity during the first full year of operation if Watts Bar Unit No. 1 were not on-line. Provide same for first full year of operation if unit No. 2 were not on-line. Also provide forecasted cost of that fuel in terms of mills/kWh and millions of dollars per year. If purchased power were necessary and available, provide its estimated cost.

Response:

With Watts Bar unit 1 not on-line during first full year of operation, energy make up by:

Type	Percent	Mills/kWh	Dollars Per Year (Millions)
Coal*	43	12.3	38
Combustion Turbines	5	35.0	11
Purchases**	52	25.0	95
			144

With Watts Bar unit 2 not on-line (Watts Bar unit 1 on-line) during first full year of operation, energy make up by:

Type	Percent	Mills/kWh	Dollars Per Year (Millions)
Coal*	67	12.9	62
Combustion Turbines	11	38	30
Purchases**	22	25	40
			132

*Assumes optimistic coal-fired generation level. If assigned generation is not achieved, TVA would have to increase its reliance on purchased power to meet system energy requirements.

**Assumes purchase power available at cost levels indicated in this time period.

Question Number 7.13:

Provide most recent estimate of total capital cost for completion of Watts Bar unit Nos. 1 and 2.

Response:

$985,000,000

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