Mr. Sawyer
~~15678~~
~~15684~~
113988

UNITED STATES GENERAL ACCOUNTING OFFICE

WASHINGTON, D.C.

FOR RELEASE ON DELIVERY
EXPECTED AT 10:00 AM
DECEMBER 11, 1980

STATEMENT OF
J. DEXTER PEACH
DIRECTOR, ENERGY AND MINERALS DIVISION
BEFORE THE
COMMITTEE ON APPROPRIATIONS
U.S. SENATE

113988

Senator Sasser: James R.

We appreciate your invitation to discuss our recent work at the Tennessee Valley Authority AGC00108 concerning TVA's latest demand forecast and its current analysis of alternatives for responding to the latest demand forecast. Specifically, you asked that we address the following questions.

--What is the history of TVA's demand forecasting?

--What improvements has TVA made in demand forecasting?

--What additional improvements should TVA make?

--What will be the magnitude of TVA's surplus capacity based on its most recent demand forecast?

--How long is the surplus expected to last?

--What effect has the surplus capacity had to date on the costs of TVA operations?

--What effect will the surplus capacity have on future electric rates?

--What effect will the surplus capacity have on the economic benefits of TVA's conservation programs?

013662

[Forecast of Future Demand for Electricity by TVA]

In February 1979, the Tennessee Valley Authority (TVA) testified before the Senate Committee on the Budget. In that testimony, TVA presented its 1978 forecast of future demand for electricity in the Valley. Since that time, TVA has prepared its 1979, 1980, and 1981 forecasts of future demand. In general, each successive forecast has predicted lower demand growth rates for the period 1980 to 2000.

As a result of the 1979 forecast, TVA announced in May 1979 that it planned to defer completion of four nuclear units--one at Phipps Bend, one at Yellow Creek, and two at Hartsville. (See exhibit 1.) The purpose was to create a better fit between the completion of new nuclear units and the Valley's estimated demand for additional power. Through this action, the construction program's completion date was deferred until 1990.

Subsequently, TVA prepared its 1980 forecast which was lower than the previous forecast, and consequently TVA decided in May 1980 to further defer completion of the four already delayed nuclear units. That deferral resulted in the current construction schedule which has a final completion date of 1996.

But, after the May 1980 deferral decision, TVA prepared another demand forecast that is referred to as the 1981 forecast. It was even lower than the previous forecast, and TVA is now in the midst of analyzing the economic effects of the various options for responding to this lower forecast. TVA plans to complete its analysis in December 1980 or January 1981.

DEMAND FORECASTING

In November 1978, GAO reported a number of demand forecasting weaknesses that were noted during our review of TVA's 1977 demand forecast.

Our conclusions and recommendations included the following:

- --The end-use data on which TVA based its demand forecast was incomplete and inadequate. We recommended that TVA collect detailed data on the users and uses of electricity. For example, we said TVA should survey residential customers to determine patterns of ownership for household equipment, appliances, and housing units.

- --TVA prepared only one demand forecast that was based primarily on a combination of trends and extrapolations of historic trends. We recommended that TVA prepare several electricity demand forecasts.

Since our report, TVA has made significant improvements in the methodology and approach used in demand forecasting. The major improvements since 1977 in TVA's forecasting system are as follows:

- --TVA uses a sophisticated set of models that permits the factors which TVA believes influence demand growth to be explicitly identified rather than relying on a trend forecast. These models include three econometric models and two end use models.

- --TVA incorporates the results of a residential appliance survey of 9,400 customers completed in January 1980. The results include data on: appliance saturation; type, age, and size of living quarters; implemented conservation measures; social and economic characteristics of households, such as, family size, age distribution, and income levels. TVA plans to update the residential survey periodically and is now preparing to do a commercial and industrial end-use survey.

--TVA deals with uncertainty by producing a range of forecasts based on alternative levels of five explicitly identified factors which TVA believes drives its load growth. The more important factors are economic growth and the price of electricity. The other three factors are price of substitutes, conservation programs, and the Department of Energy's (DOE) demand for electricity to enrich uranium.

--For each of the five factors that drive load growth, TVA prepares a low, medium, and high forecast, with the exception of the DOE demand which has two alternative levels. In total, this procedure will yield 162 alternative forecasts. Because of analytical constraints and for practical reasons, only a limited number of forecasts are selected for analysis in great detail. Using various combinations of the five factors, TVA finally produces three basic planning demand forecasts that are referred to as the low, medium, and high demand forecasts. (See exhibit 2.)

In short, TVA has made significant improvements to its demand forecasting system along the lines that we recommended in our 1978 report. Nevertheless, I do have some observations to make about several assumptions related to the major factors which drive the forecasting system.

Economic growth assumptions

The demand forecast is driven directly by both national and regional forecasts of the level of economic activity. Before 1973, the TVA region grew significantly faster than the Nation. (See exhibit 3.) However, during 1973-1979, the TVA region's growth rate lagged the Nation's growth rate.

Until the 1981 forecast, TVA assumed that the pre-1973 relationship between regional and national growth rates would prevail in the long term. However, based on TVA's own forecast of regional economic growth, TVA changed the assumptions in its 1981 forecast to reflect to some extent the lower regional growth rates experienced during 1973-1979. For example, in the 1981 medium forecast, TVA assumed that the regional growth rate would be slightly less than the national rate during 1980-1990 but slightly higher during 1990-2000. For the total 20 year period 1980-2000, TVA assumed the region's annual growth rate would be 2.7 percent versus 2.8 percent for the Nation. In the high forecast, TVA assumed an annual growth rate of 3.5 percent, and in the low forecast, 2.2 percent.

TVA is now in the process of trying to determine why the TVA region grew slower than the Nation during 1973-1979. The results of this study may shed some light on what assumptions should be made for economic growth. Should the study reveal underlying structural changes that indicate the region may continue to grow slower than the Nation, then TVA's forecasts of demand for electricity would tend to be lower. For example, according to a TVA sensitivity analysis, switching from the medium to the low economic growth rate assumption would reduce the medium demand forecast by 5.5 percent in 1990 and by 7.7 percent in the year 2000.

Uncertainty about price elasticity of demand for electricity

One of the five major factors that drive the demand forecast is price of electricity. TVA's latest forecasts assumed average annual residential real price growth rates during 1980 to 1990 of 0.03, 1.9, and 3.5 percent in the low, medium, and high forecasts, respectively. The assumed commercial and industrial price growth rates were -0.03, 1.9, and 3.5 percent. (See exhibit 4.) Interestingly, the bulk of the rate increases occur during 1981 and 1982 and taper off for several years and then pick up again toward the end of the decade. In any event, TVA's assumptions about the price elasticity of demand for electricity will need continued scrutiny in the years ahead.

In general, as the price of electricity rises, consumers will tend to use less electricity. In economics, such consumer behavior demonstrates the concept of price elasticity of demand.

Specifically, the price elasticity of demand for electricity measures the percentage change in electricity consumption relative to a percentage change in electricity price. For example, an elasticity coefficient of -0.5 would indicate that a 1 percent increase in price would lead to a 0.5 percent decrease in consumption.

Estimates of elasticity for a given commodity are generally based on historical data. But whenever structural changes occur in the basic relationship between the price of the commodity and the prices of other commodities, problems may arise in estimating elasticity because historical data may not be representative of future consumption patterns.

The TVA demand forecasting staff believes that since the time of the Arab oil embargo structural changes have taken place in the relationship between the price of electricity and the rest of the economy, and they surmise that the current estimates of price elasticity may be too low. However, sufficient historical data on new consumption patterns is not yet available to reestimate the long term price elasticity of demand for electricity with a high degree of certainty. The staff believes that the next 3 or 4 years may provide sufficient data to reestimate price elasticity with a higher degree of certainty.

<u>DOE uranium enrichment demand assumptions</u>

In TVA's view, DOE's demand for electricity to enrich uranium has two alternative levels. The first demand level is based on amounts of power under contract. The alternative level is the level that TVA expects DOE to demand. TVA used the expected demand in the three 1981 basic planning forecasts.

DOE's expected demand is determined from an analysis of expected requirements of enriched uranium for nuclear power plants, national defense needs, and foreign exports. Since nuclear power plant completions and operations are uncertain, estimation of the expected DOE demand concentrates on an analysis of construction schedules, probable plant completions, and expected plant operating characteristics. As a result, the expected DOE demand is significantly lower than the load currently under contract. (See exhibit 5.)

Since the 1981 demand forecast was prepared, TVA has re-estimated the expected DOE demand and preliminary results show that TVA now expects that DOE's average demand through 1992 may be even less than previously estimated. To the extent the new estimate is on target, surplus capacity under the current construction schedule would tend to increase.

SURPLUS CAPACITY BASED ON RECENT FORECASTS

Let me turn to the topic of surplus capacity. Exhibits 6 through 8 show TVA's forecasted winter and summer peak demand capacity requirements versus dependable capacity during the years 1981 through 2010. Dependable capacity through about the year 2000 is based on the current nuclear construction program. Growth in dependable capacity after the year 2000 is based on expected additional capacity that would be necessary to meet demand growth beyond the year 2000. It should be noted that capacity requirements are not identical with the forecast of demand that the TVA power system must supply. Capacity requirements are made up of the forecasted peak demand plus the desired reserve margin.

The desired reserve margin is the additional capacity above expected peak demand that is necessary to provide for scheduled maintenance, emergency outages, and deviations from average weather conditions. TVA's desired reserve margin is currently based on a standard designed to limit disconnection of firm loads to no more than 168 hours annually. This standard of 168 hours was selected in mid-1979 based on a cost-benefit study that indicated this was the least-cost option, taking into account TVA's variable and fixed costs and the cost of outages to TVA customers.

Any amount of available capacity over and above the desired reserves is surplus to TVA's needs. Exhibits 9 through 14 show TVA's desired reserves, available reserves, and surplus capacity (available reserves minus desired reserves) under the three planning forecasts and the current construction schedule.

As shown in exhibits 9 and 10, the medium forecast and current construction schedule would result in surplus capacity during 1981 to 2000 ranging from about 4 to 12 percent in terms of summer peak demand and from about 8 to 22 percent for winter peaks. Exhibits 11 and 12 show that under the low forecast and the current construction schedule, surplus capacity during 1981 to 2000 would range from about 4 to 34 percent in the summer and from about 9 to 54 percent in the winter. In comparison, exhibits 13 and 14 show that under the high forecast summer and winter peaks, TVA would have relatively little or no surplus capacity.

One observation I would like to make is that, as mentioned before, TVA's desired reserve margin is based on a standard that was selected in mid-1979 as the least-cost option. But since that time, the estimated costs of constructing new capacity have risen sharply, and as new capacity costs rise, the optimum reserve margin may be lower. In other words, the least-cost option based on the higher expected costs of new capacity may dictate that TVA be willing to disconnect firm loads more than 168 hours each year. This would tend to lower capacity requirements.

EFFECT OF POTENTIAL SURPLUS CAPACITY ON RATES TO DATE

As pointed out above, TVA would have relatively little or no surplus capacity under the high forecast. However, based on the low forecast summer peaks, TVA would have surplus capacity equivalent to about six nuclear units by the early to mid-1990s. Therefore, to address the question of the effect that potential surplus capacity has had on rates to date, we obtained the estimated revenue requirements that have been generated by the construction of the last six units due to go into operation under the current construction schedule.

As shown in exhibit 15, the cumulative revenue requirements for these 6 units have been about $215.9 million in fiscal years 1974 through 1980. (On a per kilowatt hour basis, the largest yearly increase in revenue requirements due to these units was only about 0.5 mills.)

EFFECT OF TVA'S OPTIONS ON POWER RATES

Just what options is TVA considering to respond to the potential overcapacity situation? As I mentioned earlier, TVA will not complete its analysis until December 1980 or January 1981. Thus, we have not had time to assess in any detail the options that TVA is now analyzing, but I can make several observations about the basic options and their potential effect on rates. Our observations are based on unaudited data provided to us by TVA. My remarks will be confined to four basic options that describe the general parameters within which TVA's decision will likely be made.

Option A--Continue the current construction schedule with four units deferred: Yellow Creek 2, Phipps Bend 2, Hartsville B-1, and Hartsville B-2. Resume construction of the deferred units in 1984.

Option B--Defer six units: Yellow Creek 1 and 2, Phipps Bend 1 and 2, and Hartsville B-1 and B-2. Resume construction of Yellow Creek 1 and 2 in 1984 and cancel the other four units in 1984.

Option C--Immediately cancel four units: Phipps Bend 1 and 2 and Hartsville B-1 and B-2. Defer Yellow Creek 1 and 2 and resume construction in 1984.

Option D--Complete all units at Yellow Creek, Phipps Bend, and Hartsville B. Transfer surplus power to oil-dependent utilities under long term exchange agreements, which are defined by TVA as 10 years or more.

Short term effects

Exhibit 16 compares the deferral versus cancellation revenue requirements of options A, B, and C during the years

1981 through 1987. The exhibit shows the additional revenue requirements of each option over and above the revenue requirement associated with borrowings for construction during prior years. As shown, by 1987 the total additional annual revenue requirement associated solely with the continued deferral of 4 units (option A) is about $586 million; the total additional annual revenue requirement associated with deferring six units now and cancelling four in 1984 (option B) is about $359 million; and the total additional revenue requirement associated with deferring 2 units and immediately cancelling four units (option C) is about $287 million. As shown in exhibit 16, the additional annual revenue requirements for options A, B, and C are relatively small in terms of their year-to-year impact on power rates.

Under option D, TVA would complete all nuclear units and transfer excess power under long term exchange agreements to utilities that are dependent on oil-fired generating capacity. Under this option, TVA could either maintain the current construction schedule and transfer surplus power as it becomes available, or TVA could speed up the construction schedule in accordance with the earliest dates that the other utilities would want to take the power. The utilities that TVA has contacted about taking surplus power are located in Arkansas, Louisiana, Oklahoma, Florida, Virginia, New York, and New Jersey.

The attractiveness of this option is that it would have the potential to relieve TVA ratepayers of the financial burden of surplus capacity after the plants were built and the transfer of power begun. But until the plants were completed and the transfer of power begun, (TVA ratepayers ~~would~~ continue to bear the financing costs associated with construction of the surplus capacity.) (If the construction schedule were advanced to sell power earlier, rates could rise faster because financing costs would rise more rapidly.)

Long term effects

In addition to looking at the short term effects of options A, B, and C, we believe it is also useful to look at the estimated long-term effects of these options.

Exhibits 17, 18, and 19 compare revenue requirements under options A, B, and C. As shown from 1980 to about 1997, option A is slightly more expensive than options B or C. Then in about 1997, the revenue requirements for options B and C overtake those of option A and become slightly larger. But it should be noted that no appreciable difference in revenue requirements occurs until after the year 2000.

The basic reason that there is little difference between the revenue requirements of options A, B, and C, is that under each scenario TVA must continue expanding its borrowings, which results in rising interest charges. (See exhibit 20.) If option B or C, both of which would cancel some of the units in the current schedule, were chosen, TVA would still have to greatly expand its borrowings to complete the Sequoyah, Watts Bar, Bellefonte, and Hartsville-A nuclear plants and to meet the costs of other items such as additions and improvements to existing generating facilities, new transmission facilities, and general facilities.

Then, under either of the three options, TVA would begin a new construction program in the early 1990s to replace coal-fired plants which are assumed to be retired after 50 years of service and to meet expected demand growth beyond the year 2000. (See exhibit 21.)

Because of the necessity to finance the expanded capital requirements, interest charges are expected to increase greatly from 1980 to 2000. For example, under option A, interest charges would increase from about $848 million to about $6.6 billion (unadjusted for inflation).

EFFECT OF POTENTIAL SURPLUS CAPACITY ON ECONOMIC BENEFIT OF TVA's CONSERVATION PROGRAMS

TVA has implemented a range of conservation programs during the past several years. Original estimates of the programs' cost effectiveness indicated that conservation programs as a whole offered potentially lower rate increases to TVA ratepayers because the relatively low cost programs would enable TVA to defer some expansion of more expensive generating capacity. However, as described earlier, TVA, with its current nuclear construction program, potentially faces substantial amounts of excess capacity under its medium and low demand forecasts. When a utility is in an overcapacity situation, the utility can produce additional energy without having to add new capacity. Therefore, the marginal costs of producing additional energy are relatively low because the only costs involved are the variable costs; no additional fixed costs are required. In such a situation, if consumers conserve energy, the average cost per kilowatt hour consumed will actually rise because the fixed costs will have to be spread over fewer kilowatt hours. In addition, if the utility spends money to promote conservation, these additional expenditures will also increase average costs per kilowatt hour. Consequently, one must wonder how TVA's potential overcapacity situation would affect the cost effectiveness of spending power funds on conservation programs.

In essence, the question that must be answered is whether spending power funds on conservation programs would increase the average total costs per kilowatt hour. If such expenditures increase average costs, then the expenditures are not to the benefit of ratepayers as a whole. Only the ratepayers who enjoy lower electric bills because of their participation in the conservation programs would benefit from the programs, but ratepayers as a whole would not benefit.

In general, our comments on the cost effectiveness of conservation programs are based on TVA's most recent marginal cost study. That study was based on TVA's 1980 demand forecasts. As already noted, TVA's 1981 forecasts were lower than the 1980 forecasts. Therefore, the 1981 forecasts would tend to make conservation programs look economically less attractive than indicated by the most recent marginal cost study.

Exhibit 23 depicts the cost effectiveness of conservation programs under the 1980 low forecast. The cost curves are based on the assumption that four nuclear units are cancelled and not completed. Even with those cancellations, TVA would have enough surplus capacity that, without conservation programs, TVA could produce the additional required electric energy past the year 2000 at a total marginal cost per kwh that would be less than the average total cost per kwh. Not until about the year 2002 would the capacity situation get tight enough that conservation programs could actually defer construction of more expensive new generating capacity. At that time, the marginal costs to produce energy not conserved would be greater than the average production costs. Until that time, expenditures of power funds on conservation programs would raise the average cost per kwh.

Exhibit 24 depicts the cost effectiveness of conservation programs under the 1980 medium forecast. The cost curves are based on the assumption that the current construction schedule (with four units deferred) will be completed. Under this scenario, TVA would have enough surplus capacity that conservation programs would offer little or no cost effectiveness until about the year 1993 when marginal costs consistently begin to exceed average costs.

However, it should be noted that, under this scenario, the benefits from 1993 forward may be sufficiently large to justify investing power funds in conservation programs in earlier years even when they are not cost effective on a year-to-year basis. It should also be noted that TVA must spend some level of power funds on conservation programs in years when the programs are not cost effective if the programs are to be in place and operational when they are needed in the future.

In its study, TVA also combined the marginal cost results of the 1980 medium and low forecasts on a weighted basis. (See exhibit 25.) The weighted results indicated that conservation programs would offer no cost benefit until about the year 1993 when total marginal costs begin to exceed average total costs.

As mentioned earlier, if expenditures of power funds on conservation programs are not cost effective, ratepayers as a whole do not benefit from the programs. The only ratepayers who benefit from the programs are those whose electric bills are lower because of their participation in the programs. However, TVA has recently taken actions that offset this situation to some extent. For example, effective November 1, 1980, TVA made the following changes to some of its conservation programs.

--To reflect the increasing cost of money to TVA, the interest rate was raised from 8.5 to 10.5 percent for the Heat Pump Financing Program and from 6.5 to 10.5 percent for the Solar Nashville and Solar Middle Tennessee solar water heating programs. However, TVA will continue to provide energy surveys to residential consumers at no charge.

--In the Commercial and Industrial Energy Conservation Program, loans to implement energy conservation opportunities will continue to be made at TVA's cost of money plus 1 percent. TVA will begin charging for comprehensive energy surveys an amount that reflects TVA's cost for performing the survey. However, the comprehensive survey charges will be rebated to those customers who implement sufficient conservation measures to achieve 75 percent of the recommended energy savings. TVA will continue to offer free walk-through surveys to spot easily identifiable energy conservation opportunities and provide a cost estimate for a comprehensive survey at a later date.

IMPLICATIONS

Based on the options we examined concerning the suspension or cancellation of four nuclear units, we noted that none of the options in themselves offers the hope of significantly lower annual rate increases during the next decade. While an individual option may offer dollar savings that seem large in an absolute sense, the potential annual savings are relatively small in relation to total revenues and to the new revenue requirements added each year to complete the other nuclear plants under construction and to meet the costs of other items such as additions and improvements to existing facilities and new transmission facilities.

As described in our discussion of demand forecasting, TVA now faces a great amount of uncertainty about future demand because of uncertainty about factors such as economic growth and price elasticity of demand for electrictiy. It appears that within the next 4 years TVA should have enough time to collect the information it needs to predict these factors with greater certainty. During this period, TVA needs to maintain sufficient flexibility to respond in a reasonable fashion to the high, medium, or low forecast, whichever of them appears to be the most probable forecast of demand after obtaining new data on economic growth and price elasticity.

In our minds, the preliminary data we have examined indicates that TVA should neither cancel any nuclear units immediately nor forge ahead with completion of any deferred units immediately. But, it should continue along a path of deferring four, or perhaps even six, nuclear units and hold expenditures on them to the bare minimum required to restart construction if necessary. Based on the options we have examined, this path would not add unreasonable amounts to rates on a yearly basis, and these relatively small amounts of revenues would buy the time and information TVA needs to decide with more certainty whether to cancel or complete deferred nuclear units.

The aspect of buying time at a reasonable cost is also important from the standpoint of being in a position to take advantage of technological advances, if any, in the generation of electricity. For example, TVA may find in 4 to 5 years that its demand forecasts require the deferred nuclear units to be restarted. But another possibility is that technological breakthroughs may have occurred that offer significantly reduced capital costs, operating costs and/or reduced construction lead times. By having deferred the units and spent a bare minimum on them, TVA could possibly cancel the nuclear units and replace them with lower cost, technologically advanced new capacity, if it exists.

One further point. Conservation programs can also play a part in buying time. The longer TVA can delay decisions about starting new plants in the 1990s to replace retired coal-fired plants and to meet projected demand growth beyond the year 2000, the greater the likelihood there will be new generating technologies that may offer lower costs to ratepayers. Therefore, even if expenditures on conservation programs during the next decade cannot be shown to be cost effective based on today's data, expenditures on these programs possibly could prove to be cost effective investments that buy time TVA needs to be in a position to take advantage of technological breakthroughs 5, 10, or 15 years from now.

 EXHIBIT 1

CHANGES IN TVA'S NUCLEAR PROGRAM CONSTRUCTION SCHEDULE IN RESPONSE TO CHANGES IN DEMAND FORECASTS

	Commercial operating date		
Unit	Before May 1979 deferral	After May 1979 deferral (note a)	After May 1980 deferral (note a)
Sequoyah 1	01/80	06/80	11/80
Sequoyah 2	09/80	06/81	07/82
Watts Bar 1	12/80	09/81	11/82
Watts Bar 2	09/81	06/82	08/83
Bellefonte 1	03/83	09/83	12/85
Bellefonte 2	12/83	06/84	09/86
Hartsville A1	12/84	07/86	07/88
Hartsville A2	12/85	07/87	04/89
Hartsville B1	06/85	06/89	04/95
Hartsville B2	06/86	06/90	04/96
Yellow Creek 1	11/85	11/85	04/88
Yellow Creek 2	11/86	04/88	04/93
Phipps Bend 1	09/85	03/87	02/89
Phipps Bend 2	09/86	08/89	04/94

a/The only units that TVA specifically deferred were the two Hartsville-B units, Yellow Creek 2, and Phipps Bend 2. According to TVA, changes in the schedule for other plants were due to unplanned delays.

EXHIBIT 2

COMPARISON OF TVA LOAD FORECASTS

Year	Alternate forecasts	Assumptions about five major driving factors in the load forecasts (note a): Economic growth	Substitution	Electricity price	Conservation programs	DOE load	Electricity consumption growth rates (note b): 1980-1990	1990-2000
							--------Percent--------	
1978 (note c)	1	H	M	L	H	-	4.60	3.80
	2	H	M	M	H	-	4.10	3.00
	3	M	M	L	H	-	3.90	3.20
	4	L	M	L	L	-	3.70	2.80
	5	L	M	M	L	-	3.20	2.00
1979	1	H	M	L	H	-	4.60	3.50
	2	M	H	L	L	-	4.30	3.20
	3	M	M	M	L	-	3.60	2.10
	4	M	M	H	H	-	2.80	1.20
	5	L	M	H	H	-	2.40	0.70
1980 (prepared April 1980)	High	H	H	L	M	E	4.52	3.71
	Medium	M	M	M	M	E	3.33	2.12
	Low	L	L	H	M	E	2.31	-0.03
1981 (prepared August 1980)	High	H	M	M	M	E	3.26	2.30
	Medium	M	M	M	M	E	2.45	1.54
	Low	L	M	H	M	E	1.41	0.51

a/H = High
M = Medium
L = Low
E = Expected

b/The "1980-1990" growth rates column for the 1978 and 1979 forecasts represents growth rates for 1978-1990.

c/This is the forecast presented by TVA before the Senate Committee on the Budget in February 1979 hearing.

 EXHIBIT 3

TVA ECONOMIC GROWTH ASSUMPTIONS USED IN 1981 FORECASTS (Constant 1972 Dollars)

Year	Gross national product (note a)	Gross regional product High	Gross regional product Medium	Gross regional product Low
	-----Percentage growth rates-----			
Actual				
1970-1973	4.7	7.1	7.1	7.1
1970-1980	2.8	3.3	3.3	3.3
1973-1979	2.5	2.0	2.0	2.0
Forecast				
1980	-1.2	-0.1	-0.1	-0.1
1981	0.8	1.6	0.3	0.3
1982	4.2	4.0	3.6	2.1
1983	3.2	4.0	3.7	1.9
1984	3.2	3.9	3.2	1.5
1985	1.8	3.3	2.5	1.2
1980-1990	2.8	3.5	2.5	1.7
1990-2000	2.8	3.5	2.9	2.7
1980-2000	2.8	3.5	2.7	2.2

a/TVA's source for this data is the Wharton Economic Forecasting Associates.

 EXHIBIT 4

TVA ELECTRICITY PRICE GROWTH ASSUMPTIONS USED IN 1981 FORECASTS (Constant 1972 Dollars)

Year	Residential price growth			Commercial and industrial price growth		
	High	Medium	Low	High	Medium	Low
	Percentage growth rate					
Actual						
1960-1970	-1.6	-1.6	-1.6	0.3	0.3	0.3
1970-1980	4.5	4.5	4.5	7.5	7.5	7.5
Forecast						
1981	10.0	8.4	6.3	9.0	7.4	5.3
1982	7.2	5.8	4.0	7.3	5.9	4.0
1983	2.2	0.9	-1.0	2.3	0.5	-1.0
1984	3.1	1.4	-0.5	3.1	1.4	-0.5
1985	3.4	2.2	0.5	3.4	2.8	0.5
1986	1.6	0.0	-1.9	1.7	0.0	-2.0
1987	2.0	0.4	-1.5	2.0	0.0	-1.5
1988	4.7	3.5	1.5	4.8	4.0	1.5
1980-1990	3.8	2.3	0.4	3.8	2.3	0.4
1990-2000	3.1	1.6	-0.4	3.2	1.6	-0.4
1980-2000	3.5	1.9	0.03	3.5	1.9	-0.03

 EXHIBIT 5

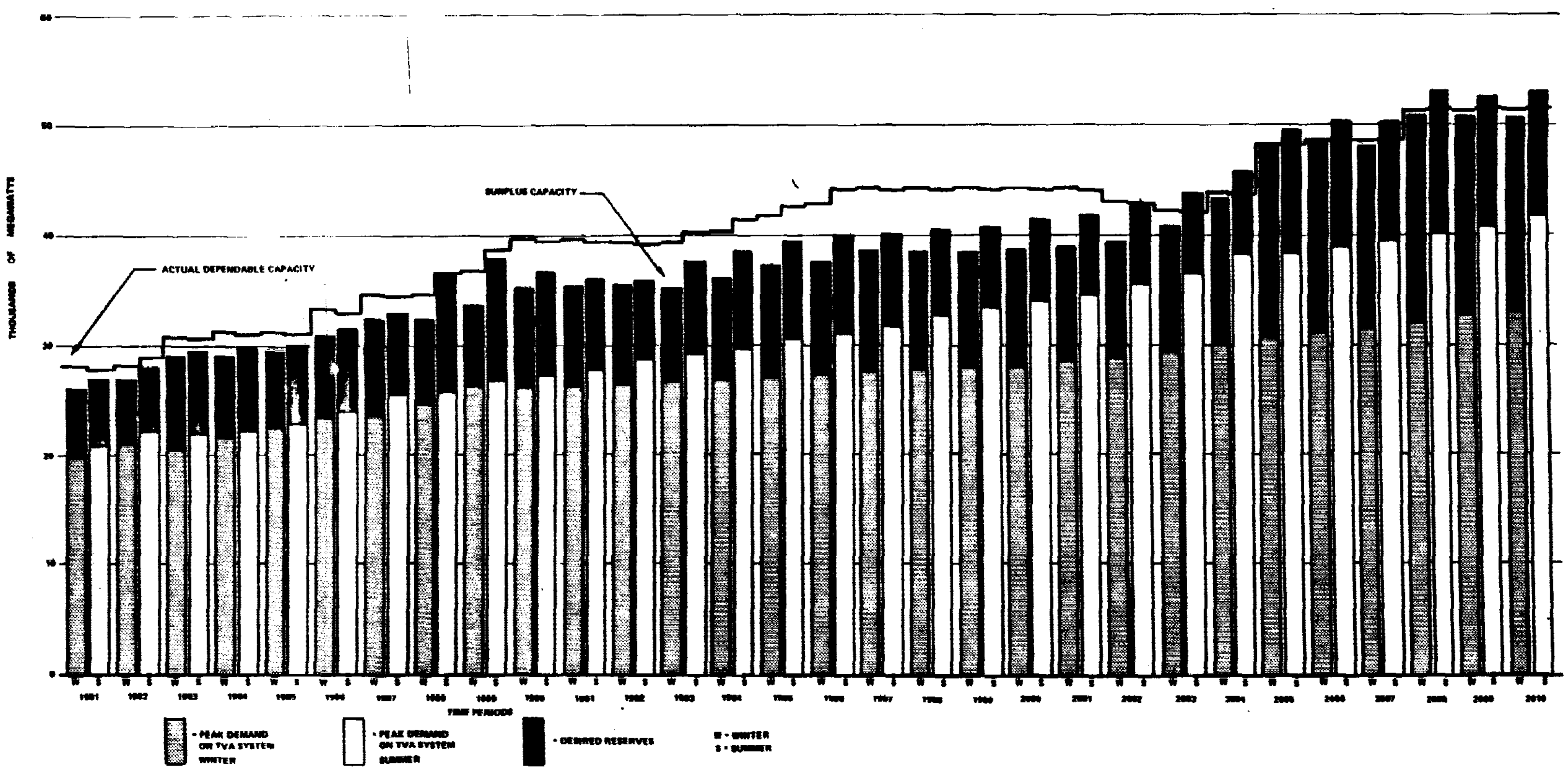
TVA ESTIMATES OF
ENRICHMENT POWER SUPPLY TO DOE
FOR 1981 DEMAND FORECASTS

	Demand in megawatts	
Fiscal year	Contract	Expected
1981	2,340	2,340
1982	3,165	2,000
1983	3,165	2,000
1984	3,560	2,000
1985	4,485	2,314
1986	4,485	2,628
1987	4,485	3,383
1988	4,485	3,383
1989	4,485	3,326
1990	4,485	3,326
1995	a/4,485	3,182
2000	4,485	2,480
2020	4,485	2,116

a/All current DOE contracts will expire by 1995. TVA assumed the contracts would be renewed at the same level.

EXHIBIT 6

PEAK LOAD CAPACITY REQUIREMENTS VS ACTUAL DEPENDABLE CAPACITY
(Medium Forecast and Current Construction Schedule)



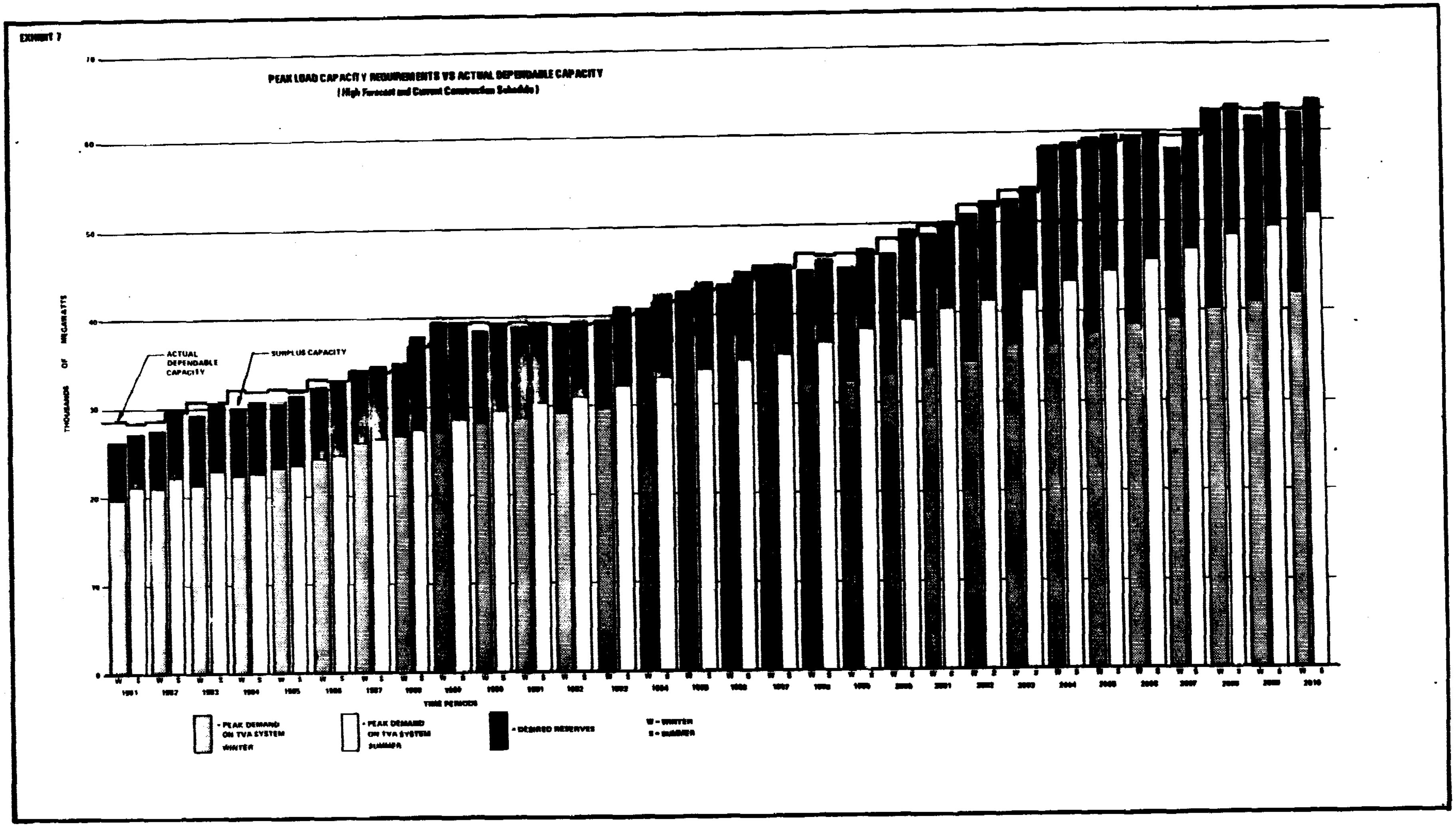


EXHIBIT 7
PEAK LOAD CAPACITY REQUIREMENTS VS ACTUAL DEPENDABLE CAPACITY
(High Forecast and Current Construction Schedule)
THOUSANDS OF MEGAWATTS
0
10
20
30
40
50
60
70
ACTUAL DEPENDABLE CAPACITY
SURPLUS CAPACITY
TIME PERIODS
= PEAK DEMAND ON TVA SYSTEM WINTER
= PEAK DEMAND ON TVA SYSTEM SUMMER
= DESIRED RESERVES
W = WINTER
S = SUMMER

EXHIBIT 8

PEAK LOAD CAPACITY REQUIREMENTS VS ACTUAL DEPENDABLE CAPACITY

(Low Forecast and Current Construction Schedule)

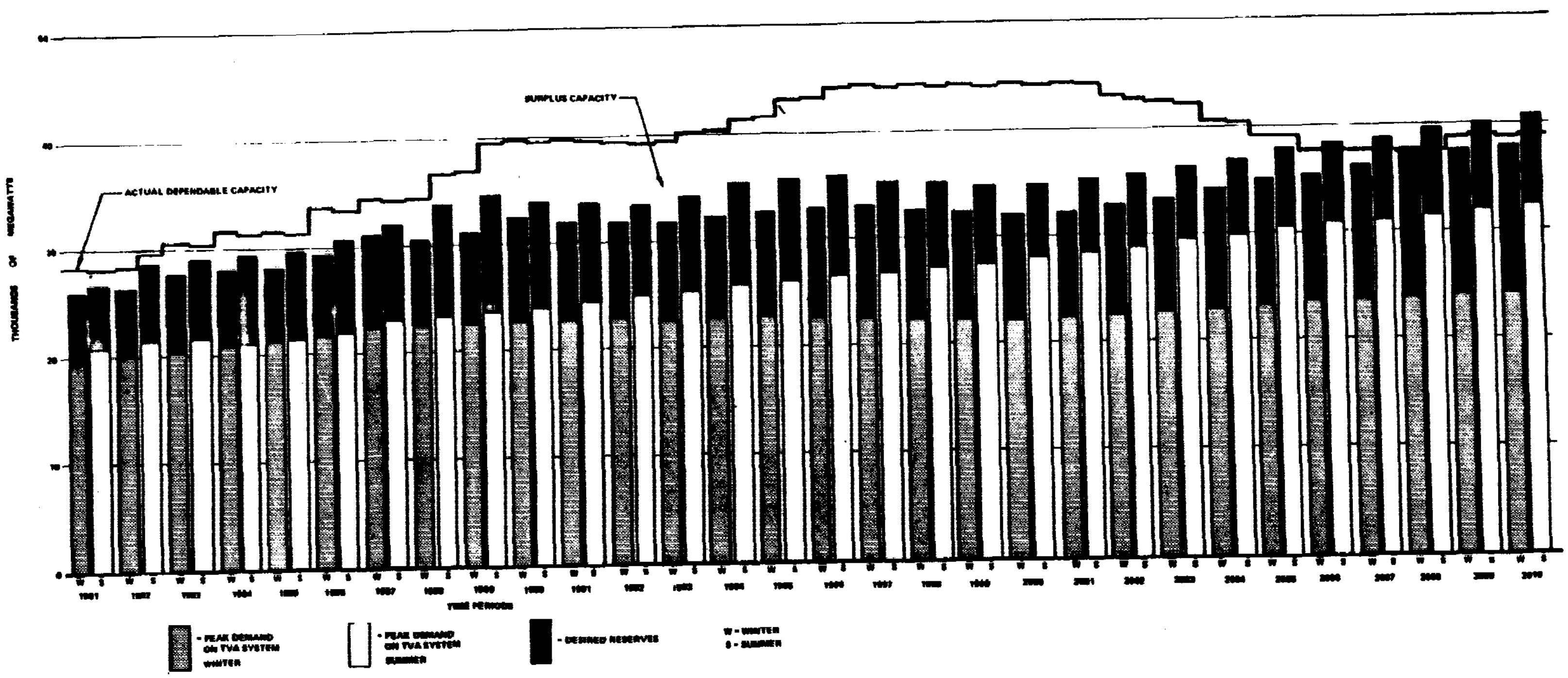


 EXHIBIT 9

TVA ESTIMATES OF SUMMER PEAK DEMAND RESERVE MARGINS
MEDIUM FORCAST AND CURRENT CONSTRUCTION SCHEDULE

	Reserve margins					
	Desired		Available		Surplus	
Year	MW	Percent	MW	Percent	MW	Percent
1981	6063	28.9	7421	35.3	1358	6.4
1982	6568	29.8	7511	34.0	943	4.2
1983	6825	30.3	8260	36.7	1435	6.4
1984	7551	33.8	9591	42.9	2040	9.1
1985	7247	31.7	9092	39.8	1845	8.1
1986	7831	32.9	9361	39.4	1530	6.5
1987	8072	32.1	9186	36.5	1114	4.4
1988	9770	37.9	11076	42.9	1306	5.0
1989	10413	39.4	12900	48.8	2487	9.4
1990	9229	34.0	12198	44.9	2969	10.9
1991	8368	30.2	11630	42.0	3262	11.8
1992	7679	27.1	10747	37.9	3068	10.8
1993	8647	29.8	11336	39.0	2689	9.2
1994	8647	29.0	11843	39.8	3196	10.8
1995	8955	29.3	12287	40.2	3332	10.9
1996	9089	29.1	12909	41.4	3820	12.3
1997	8514	26.7	12226	38.4	3712	11.7
1998	8103	24.9	11521	35.4	3418	10.5
1999	7838	23.5	10768	32.3	2930	8.8
2000	7678	22.5	9997	29.3	2319	6.8
2001	7584	21.8	9285	26.7	1701	4.9
2002	7616	21.4	7796	21.9	180	.5
2003	7715	21.2	6229	17.1	-1486	-4.1
2004	8820	23.7	6869	18.5	-1951	-5.2
2005	11948	31.4	10357	27.3	-1591	-4.1
2006	11769	30.4	9998	25.8	-1771	-4.6
2007	10993	27.8	9210	23.3	-1783	-4.5
2008	13087	32.4	11512	28.5	-1575	-3.9
2009	11991	29.1	10679	25.9	-1312	-3.2
2010	11269	26.8	9812	23.3	-1457	-3.5

 EXHIBIT 10

TVA ESTIMATES OF WINTER PEAK DEMAND RESERVE MARGINS
MEDIUM FORECAST AND CURRENT CONSTRUCTION SCHEDULE

	Reserve margins					
	Desired		Available		Surplus	
Year	MW	Percent	MW	Percent	MW	Percent
1981	6222	31.3	8692	43.8	2470	12.5
1982	6443	31.5	8076	39.5	1633	8.0
1983	7670	36.9	10072	48.4	2402	11.5
1984	7160	32.9	10310	47.4	3150	14.5
1985	6772	30.1	9526	42.3	2754	12.2
1986	7654	33.0	10096	43.6	2442	10.6
1987	8326	34.3	10190	42.0	1864	7.7
1988	7871	31.8	9743	39.4	1872	7.6
1989	8506	33.8	11854	47.2	3348	13.4
1990	9587	37.5	13875	54.2	4288	16.7
1991	9454	36.6	13636	52.8	4182	16.2
1992	9370	35.9	13116	50.2	3746	14.3
1993	8941	33.9	12833	48.6	3892	14.7
1994	9559	35.8	13841	51.9	4282	16.1
1995	10467	38.8	14741	54.6	4274	15.8
1996	10565	38.8	15744	57.8	5179	19.0
1997	11113	40.6	16812	61.3	5699	20.7
1998	10776	39.1	16622	60.2	5846	22.1
1999	10506	37.7	16376	58.8	5870	21.1
2000	10596	37.7	16095	57.2	5499	19.5
2001	10622	37.1	15598	54.5	4976	17.4
2002	10694	36.7	14339	49.2	3645	12.5
2003	11439	38.7	13090	44.2	1651	5.5
2004	13219	43.8	13906	46.1	687	2.3
2005	17369	56.6	17639	57.5	270	.9
2006	17306	55.3	17448	55.8	142	.5
2007	16584	52.2	16978	53.5	394	1.3
2008	19126	59.2	19499	60.3	373	1.1
2009	18020	54.9	18985	57.8	965	2.9
2010	17312	51.8	18431	55.2	1119	3.4

 EXHIBIT 11

TVA ESTIMATES OF SUMMER PEAK DEMAND RESERVE MARGINS LOW FORECAST AND CURRENT CONSTRUCTION SCHEDULE

	Reserve margins					
	Desired		Available		Surplus	
Year	MW	Percent	MW	Percent	MW	Percent
1981	6030	29.0	7626	36.7	1596	7.7
1982	7045	32.6	7950	36.8	905	4.2
1983	7283	33.4	8937	41.0	1654	7.6
1984	7980	37.3	10519	49.1	2539	11.8
1985	7966	36.8	10286	47.5	2320	10.7
1986	8210	36.8	10828	48.5	2618	11.7
1987	8486	36.3	10951	46.8	2465	10.5
1988	10104	42.6	13156	55.5	3052	12.9
1989	10676	44.5	15321	63.8	4645	19.3
1990	9515	39.1	14981	61.5	5466	22.4
1991	9064	36.7	14667	59.5	5603	22.8
1992	8379	33.4	14049	56.1	5670	22.7
1993	8866	34.8	14915	58.5	6049	23.7
1994	9168	35.3	15641	60.2	6473	24.9
1995	8943	33.7	16342	61.6	7399	27.9
1996	9017	33.7	17314	64.6	8297	30.9
1997	8042	29.7	17005	62.8	8963	33.1
1998	7640	27.9	16695	60.9	9055	33.0
1999	6941	25.0	16360	59.0	9419	34.0
2000	6759	24.1	16024	57.1	9265	33.0
2001	6665	23.4	15619	54.8	8954	31.4
2002	6686	23.1	14457	50.0	7771	26.9
2003	6768	23.0	13231	45.0	6463	22.0
2004	7034	23.6	10715	35.9	3681	12.3
2005	7352	24.3	8467	28.0	1115	3.7
2006	7438	24.2	7264	23.7	-174	-.5
2007	7440	23.9	6851	22.0	-589	-1.9
2008	8174	25.9	6043	19.2	-2131	-6.7
2009	8000	25.0	6614	20.7	-1386	-4.3
2010	7949	24.5	6170	19.0	-1779	-5.5

 EXHIBIT 12

TVA ESTIMATES OF WINTER PEAK DEMAND RESERVE MARGINS
LOW FORECAST AND CURRENT CONSTRUCTION SCHEDULE

Year	Reserve margins: Desired MW	Desired Percent	Available MW	Available Percent	Surplus MW	Surplus Percent
1981	6413	32.9	9062	46.5	2649	13.6
1982	6509	32.2	8351	41.4	1842	9.2
1983	7606	37.5	10582	52.2	2976	14.7
1984	7218	34.4	11063	52.7	3845	18.3
1985	6772	31.5	10545	49.0	3773	17.5
1986	7261	33.2	11363	51.9	4102	18.7
1987	8172	36.0	11740	51.6	3568	15.6
1988	7358	32.1	11577	50.6	4219	18.5
1989	8124	35.3	13988	60.8	5864	25.5
1990	9334	40.4	16331	70.6	6997	30.2
1991	8795	38.0	16340	70.7	7545	32.7
1992	8655	37.4	16077	69.4	7422	32.0
1993	8619	37.2	16061	69.3	7442	32.1
1994	9131	39.4	17367	75.0	8236	35.6
1995	9452	40.8	18560	80.0	9108	39.2
1996	9752	42.2	19862	85.9	10110	43.7
1997	10082	43.9	21249	92.5	11167	48.6
1998	9666	42.4	21427	94.0	11761	51.6
1999	9760	43.1	21558	95.1	11798	52.0
2000	9397	41.6	21649	95.9	12252	54.3
2001	9371	41.2	21451	94.2	12080	53.0
2002	9838	42.8	20478	89.1	10640	46.3
2003	9991	43.1	19527	84.3	9536	41.2
2004	10899	46.6	17145	73.2	6246	26.6
2005	11295	47.8	15113	64.0	3818	16.2
2006	11420	47.9	14069	59.0	2649	11.1
2007	12010	50.1	13939	58.1	1929	8.0
2008	13175	54.4	13330	55.1	155	.7
2009	12927	53.1	14180	58.2	1253	5.1
2010	12971	52.9	14008	57.1	1037	4.2

 EXHIBIT 13

TVA ESTIMATES OF SUMMER PEAK DEMAND RESERVE MARGINS
HIGH FORECAST AND CURRENT CONSTRUCTION SCHEDULE

	Reserve margins					
	Desired		Available		Surplus	
Year	MW	Percent	MW	Percent	MW	Percent
1981	6076	28.8	7309	34.6	1233	5.8
1982	7156	32.1	7274	32.6	118	.5
1983	7464	32.7	7894	34.5	430	1.8
1984	7945	34.8	9086	39.8	1141	5.0
1985	7985	34.0	8440	35.9	455	1.9
1986	8297	33.6	8416	34.0	119	.4
1987	8604	32.6	7920	30.0	-684	-2.6
1988	10477	38.2	9477	34.6	-1000	-3.6
1989	11252	39.6	10953	38.6	-299	-1.0
1990	9606	32.6	9881	33.5	275	.9
1991	9155	30.2	9036	29.8	-119	-.4
1992	8448	27.0	7869	25.2	-579	-1.8
1993	9110	28.3	8186	25.4	-924	-2.9
1994	9158	27.5	8376	25.2	-782	-2.3
1995	9521	27.7	8487	24.7	-1034	-3.0
1996	9795	27.8	8890	25.3	-905	-2.5
1997	9563	26.5	9266	25.6	-297	-.9
1998	9016	24.3	9263	24.9	247	.6
1999	8757	22.9	8169	21.4	-588	-1.5
2000	9244	23.5	8240	20.9	-1004	-2.6
2001	9603	23.8	8419	20.9	-1184	-2.9
2002	10998	26.5	10305	24.8	-693	-1.7
2003	11754	27.6	10801	25.3	-953	-2.3
2004	14215	32.5	13593	31.1	-622	-1.4
2005	14913	33.2	14214	31.6	-699	-1.6
2006	14102	30.6	13498	29.3	-604	-1.3
2007	12997	27.5	12333	26.1	-664	-1.4
2008	14796	30.5	14244	29.4	-552	-1.1
2009	13661	27.5	13006	26.2	-655	-1.3
2010	12924	25.4	11721	23.0	-1203	-2.4

 EXHIBIT 14

TVA ESTIMATES OF WINTER PEAK DEMAND RESERVE MARGINS
HIGH FORECAST AND CURRENT CONSTRUCTION SCHEDULE

	Reserve margins					
	Desired		Available		Surplus	
Year	MW	Percent	MW	Percent	MW	Percent
1981	6473	32.7	8742	44.1	2269	11.4
1982	6689	32.0	7651	36.6	962	4.6
1983	7930	37.1	9492	44.4	1562	7.3
1984	7626	33.9	9581	42.6	1955	8.7
1985	7255	31.0	8649	37.0	1394	6.0
1986	7920	32.5	8917	36.6	997	4.1
1987	9010	35.0	8701	33.8	-309	-1.2
1988	8647	32.6	7921	29.8	-726	-2.8
1989	9273	33.9	9673	35.4	400	1.5
1990	10391	36.9	11330	40.3	939	3.4
1991	10398	36.3	10843	37.9	445	1.6
1992	10053	34.4	10047	34.4	-6	0.0
1993	9938	33.4	9484	31.9	-454	-1.5
1994	10726	35.4	10205	33.7	-521	-1.7
1995	11806	38.1	10788	34.8	-1018	-3.3
1996	12141	38.6	11507	36.6	-634	-2.0
1997	13279	41.6	13622	42.7	343	1.1
1998	12682	39.3	14220	44.0	1538	4.7
1999	12415	37.9	13725	41.9	1310	4.0
2000	13235	39.6	14337	43.0	1102	3.4
2001	13798	40.4	14724	43.1	926	2.7
2002	15874	45.3	16846	48.1	972	2.8
2003	16887	47.2	17691	49.4	804	2.2
2004	20866	56.8	20650	56.3	-216	-.5
2005	21863	58.1	21536	57.3	-327	-.8
2006	20912	54.2	20963	54.4	51	.2
2007	19009	48.3	20173	51.3	1164	3.0
2008	22078	54.8	22316	55.4	238	.6
2009	20856	50.6	21414	52.0	558	1.4
2010	20169	47.9	20493	48.6	324	.7

EXHIBIT 15

REVENUE REQUIREMENTS ASSOCIATED WITH
LAST SIX NUCLEAR UNITS (Note a)

Fiscal year	Additional annual revenue requirements: Phipps Bend Unit 1	Phipps Bend Unit 2	Yellow Creek Unit 1	Yellow Creek Unit 2	Hartsville B Unit 1	Hartsville B Unit 2	Total Amount	Total Mills/kwh	Total annual revenue requirement
	---$ millions---								($ millions)
1974	-	-	-	-	0.1	-	0.1	0.0	0.1
1975	0.1	-	0.1	-	0.2	0.1	0.5	0.0	0.6
1976	0.3	0.2	0.3	0.1	0.4	0.3	1.6	0.0	2.2
TQ	0.3	0.2	0.2	0.1	0.3	0.2	1.3	0.0	3.5
1977	0.8	0.5	0.8	0.3	1.3	0.8	4.5	0.0	8.0
1978	2.9	1.9	3.5	1.5	4.1	2.7	16.6	0.1	24.6
1979	7.0	4.5	8.4	3.6	7.4	4.9	35.8	0.3	60.4
1980	12.1	7.7	13.6	6.0	9.9	6.8	56.1	0.5	116.5
Total									215.9

a/Based on unaudited data furnished by TVA.

EXHIBIT 16

COMPARISON OF ANNUAL ADDITIONAL REVENUE
REQUIREMENTS UNDER OPTIONS A, B, AND C (note a)

Fiscal year	Option A		Option B		Option C		Differences between: Options A and B		Options A and C		Options B and C	
	Dollars (millions)	Mills/ kwh	Dollars (millions)	Mills/ kwh	Dollars (millions)	Mills/ kwh	Dollars (millions)	Mills/ kwh	Dollars (millions)	Mills/ kwh	Dollars (millions)	Mills/ kwh
1981	86.5	0.73	75.3	0.64	82.6	0.70	11.2	0.09	3.9	0.03	-7.3	-0.06
1982	78.2	0.63	43.5	0.35	55.3	0.45	34.7	0.28	22.9	0.18	-11.8	-0.10
1983	73.6	0.58	22.5	0.18	12.9	0.10	51.1	0.40	60.7	0.48	9.6	0.08
1984	72.7	0.57	32.4	0.25	15.2	0.12	40.3	0.32	57.5	0.45	17.2	0.13
1985	77.5	0.59	55.1	0.42	23.0	0.17	22.4	0.17	54.5	0.42	32.1	0.25
1986	92.6	0.67	72.1	0.52	40.2	0.29	20.5	0.15	52.4	0.38	31.9	0.23
1987	104.4	0.71	57.6	0.39	57.6	0.39	46.8	0.32	46.8	0.32	0.0	0.00
Totals	585.5	4.48	358.5	2.75	286.8	2.22	227.0	1.73	298.7	2.26	71.7	0.53

a/TVA furnished GAO this unaudited data which assumes 100 percent debt financing and a 1.1 interest coverage ratio.

EXHIBIT 17

REVENUE REQUIREMENTS
OPTIONS A & B MEDIUM FORECAST
(NOT ADJUSTED FOR INFLATION)

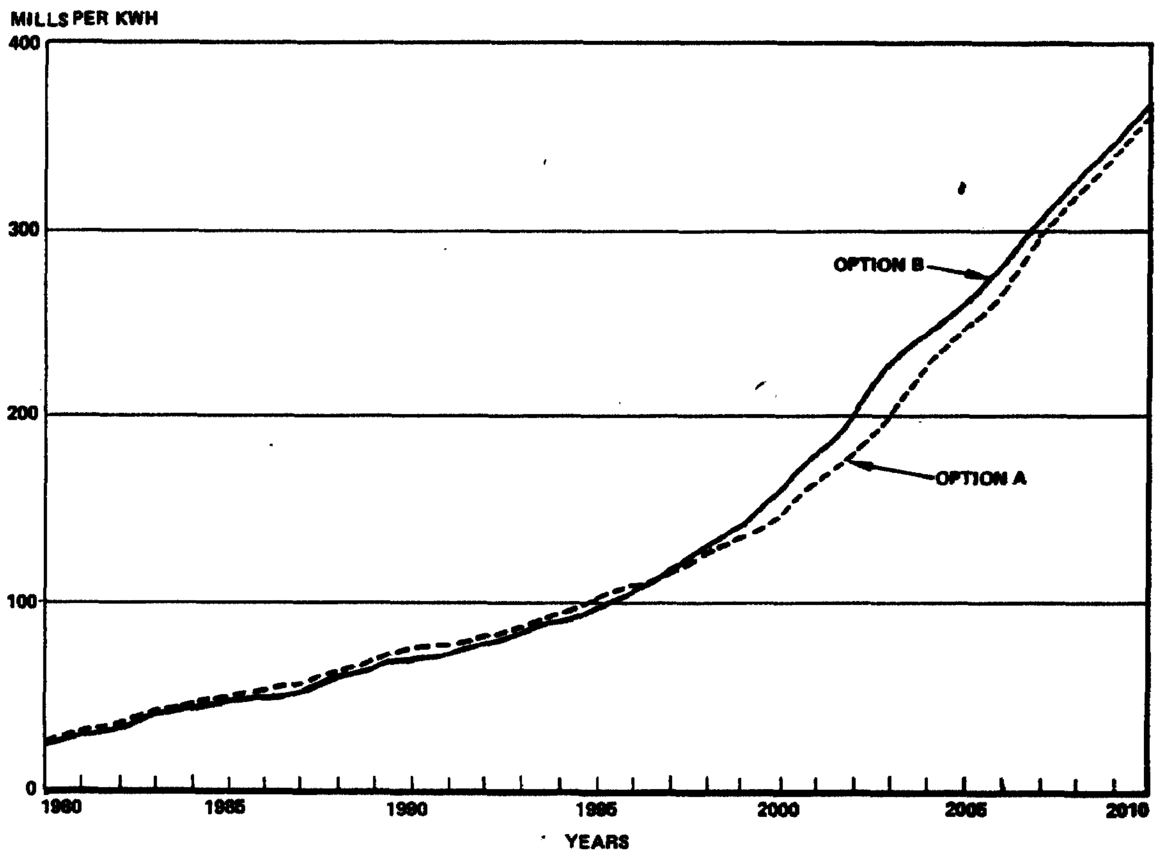


EXHIBIT 18

REVENUE REQUIREMENTS
OPTIONS A & C MEDIUM FORECAST
(NOT ADJUSTED FOR INFLATION)

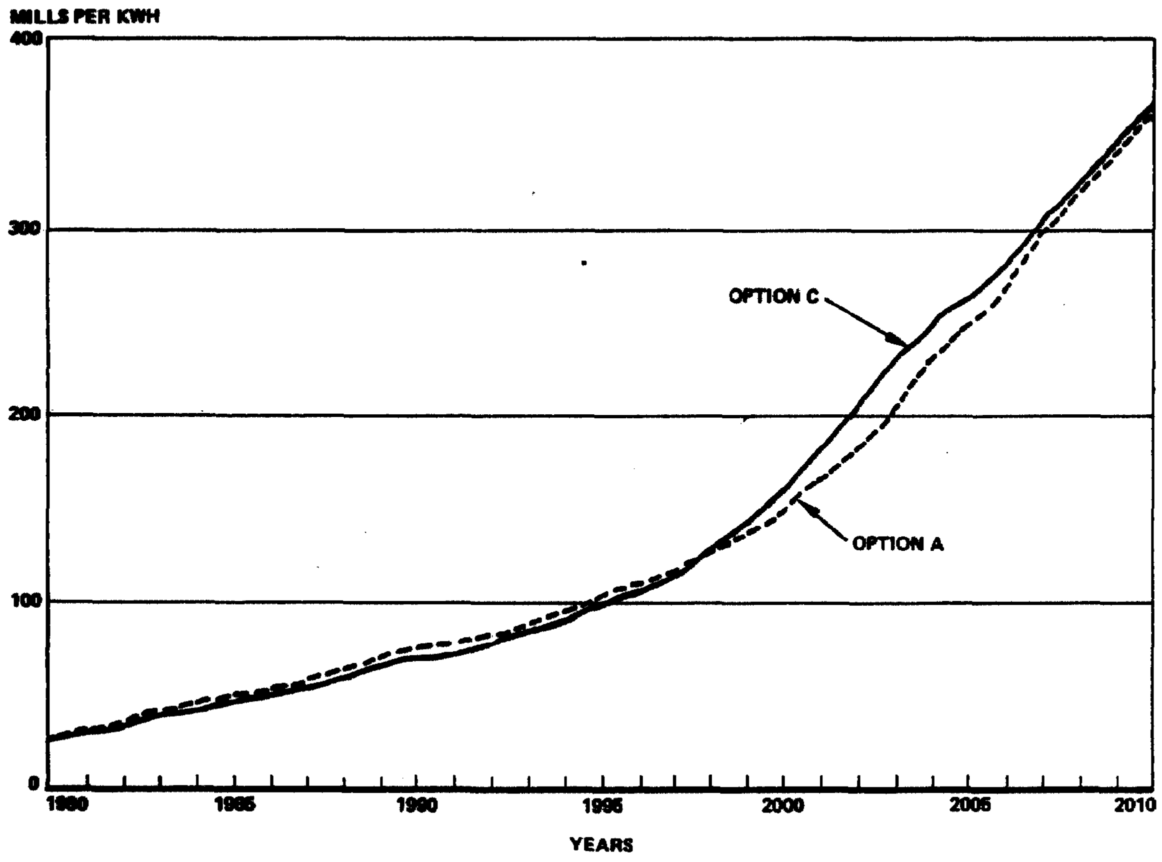


EXHIBIT 19

COMPARISON OF TOTAL REVENUE REQUIREMENTS
UNDER ALTERNATE CONSTRUCTION SCENARIOS (note a)

	Revenue requirement (note b)					
	Option A		Option B		Option C	
Year	Mills/ kwh	Percent increase	Mills/ kwh	Percent increase	Mills/ kwh	Percent increase
1980	26.6	-	26.6	-	26.6	-
1981	32.9	23.7	32.8	23.3	32.9	23.7
1982	38.6	17.3	38.2	16.5	38.4	16.7
1983	42.4	9.8	41.6	8.9	41.8	8.9
1984	46.4	9.4	45.3	8.9	45.3	8.4
1985	51.6	11.2	50.3	11.0	50.1	10.6
1986	55.2	7.0	53.8	7.0	53.4	6.6
1987	57.7	4.5	56.2	4.5	55.7	4.3
1988	65.0	12.7	62.2	10.7	61.7	10.8
1989	69.8	7.4	66.5	6.9	66.0	7.0
1990	74.0	6.0	71.1	6.9	70.7	7.1
1991	77.6	4.9	74.8	5.2	74.4	5.2
1992	81.8	5.4	79.9	6.8	79.5	6.9
1993	87.8	7.3	86.2	7.9	85.7	7.8
1994	94.5	7.6	92.1	6.8	91.7	7.0
1995	102.2	8.1	99.7	8.3	99.3	8.3
1996	110.9	8.5	108.8	9.1	108.3	9.1
1997	118.9	7.2	119.2	9.6	118.8	9.7
1998	128.2	7.8	131.0	9.9	130.6	9.9
1999	139.6	8.9	144.9	10.6	144.4	10.6
2000	152.4	9.2	162.0	11.8	161.6	11.9
2001	168.2	10.4	181.8	12.2	181.5	12.3
2002	183.3	9.0	204.0	12.2	203.6	12.2
2003	201.7	10.0	229.5	12.5	229.1	12.5
2004	227.0	12.5	247.5	7.8	247.2	7.9
2005	249.7	10.0	264.4	6.8	264.1	6.8
2006	270.4	8.3	282.3	6.8	281.9	6.7
2007	299.6	10.8	307.4	8.9	307.1	8.9
2008	320.0	6.8	326.3	6.1	325.9	6.1
2009	341.1	6.6	347.2	6.4	346.9	6.4
2010	360.3	5.6	366.3	5.5	365.9	5.5

a/Based on unaudited data from TVA financial projections which assume that the 1981 medium demand forecast will become an actuality.

b/Not adjusted for inflation.

 EXHIBIT 20

ESTIMATED ANNUAL BORROWINGS BY TVA
UNDER OPTIONS A, B, AND C (note a)

Year	Sequoyah, Watts Bar, Bellefonte, and Hartville A (note a)	Other (note b)	Phipps Bend, Yellow Creek, and Hartsville B (note c) Option A	Option B	Option C	TVA total borrowing Option A	Option B	Option C
	$ millions							
1981	697	742	526	377	474	1965	1816	1913
1982	814	746	555	216	280	2115	1776	1840
1983	794	710	515	112	73	2019	1616	1577
1984	513	782	538	343	139	1833	1638	1434
1985	279	893	589	471	202	1761	1643	1374
1986	180	1054	755	576	382	1989	1810	1616
1987	109	1178	759	454	454	2046	1741	1741
1988	85	1450	775	480	480	2310	2015	2015
1989	92	1611	783	458	458	2486	2161	2161
1990	45	1870	689	331	331	2604	2246	2246

a/Based on unaudited TVA projections of future borrowings.

b/The "other" category includes items such as additions and improvements to existing generating facilities, new transmission facilities, and general facilities. Estimated borrowings are based on unaudited TVA cost data, assuming 20 percent internal financing. See table below for breakout of total "other" costs from 1981-1985.

c/Based on unaudited TVA cost data, assuming 20 percent internal financing.

	Estimated "other" costs 1981	1982	1983	1984	1985
	$ millions				
Additions and improvements to existing generating facilities	704	493	430	340	275
Transmission facilities	123	115	97	78	100
General facilities	9	31	50	33	17
Contingencies	92	294	310	527	724
Totals	928	933	887	978	1116

 EXHIBIT 21

TVA'S TENTATIVE GENERATING UNIT SCHEDULE BEYOND CURRENTLY COMMITTED UNITS BASED ON 1981 FORECASTS

	On-line dates required by 1981 forecasts		
Type unit	High	Medium	Low
Energy storage	10/1996	10/2003	10/2003
Peaking	10/1997	10/2003	10/2003
Baseload	10/1999	10/2003	10/2004
Baseload	10/2000	10/2004	10/2004
Baseload	10/2001	10/2004	10/2004
Energy storage	10/2001	10/2004	10/2004
Baseload	10/2001	10/2004	10/2004
Baseload	10/2002	10/2004	10/2007
Baselaod	10/2002	10/2005	10/2007
Baseload	10/2003	10/2007	10/2007
Baseload	10/2003	10/2007	10/2012
Baseload	10/2003	10/2007	10/2012
Baseload	10/2003	10/2007	10/2014
Baseload	10/2003	10/2011	10/2014
Baseload	10/2004	10/2012	10/2014
Baseload	10/2004	10/2012	10/2019
Baseload	10/2004	10/2012	10/2019
Baseload	10/2005	10/2014	
Baseload	10/2007	10/2014	
Baseload	10/2007	10/2014	
Baseload	10/2007	10/2014	
Baseload	10/2007	10/2017	
Baseload	10/2110	10/2019	
Baseload	10/2010	10/2019	
Baseload	10/2011	10/2019	
Baseload	10/2012		
Baseload	10/2012		
Baseload	10/2012		
Baseload	10/2014		
Baseload	10/2014		
Baseload	10/2014		
Baseload	10/2014		
Baseload	10/2014		
Baseload	10/2016		
Baseload	10/2016		
Baseload	10/2018		
Baseload	10/2018		
Baseload	10/2019		
Baseload	10/2019		

EXHIBIT 22

TVA ESTIMATES OF TOTAL OUTSTANDING DEBT
UNDER THE CURRENT CONSTRUCTION SCHEDULE
AND THE 1981 DEMAND FORECASTS (Note a)

Fiscal year	Low forecast	Medium forecast	High forecast
	-----------------$ billions-----------------		
1981	12.9	12.9	12.9
1982	15.3	15.3	15.3
1983	17.5	17.5	17.5
1984	19.4	19.4	19.4
1985	21.2	21.2	21.2
1986	23.1	23.1	23.1
1987	24.9	24.9	24.9
1988	26.9	26.9	26.9
1989	28.8	28.8	28.8
1990	30.6	30.6	30.7
1991	32.5	32.5	32.8
1992	34.5	34.5	35.8
1993	36.6	36.6	39.0
1994	38.7	38.8	43.7
1995	40.8	41.4	50.3
1996	43.0	45.1	58.7
1997	45.6	50.3	70.0
1998	48.5	56.7	82.5
1999	51.7	64.8	97.2
2000	55.2	74.8	113.6
2001	59.1	86.5	131.2
2002	63.7	99.6	150.0
2003	69.0	116.0	168.5
2004	75.6	133.2	185.7
2005	83.5	149.5	202.8
2006	93.9	166.6	221.9
2007	105.9	185.7	242.1
2008	121.3	202.4	264.1
2009	136.6	219.8	287.9
2010	153.5	238.8	314.7

a/The debt level for each year assumes that 20 percent of construction costs will be financed from internal funds.

EXHIBIT 23

AVERAGE TOTAL COSTS VS TOTAL MARGINAL COSTS
1980 LOW FORECAST

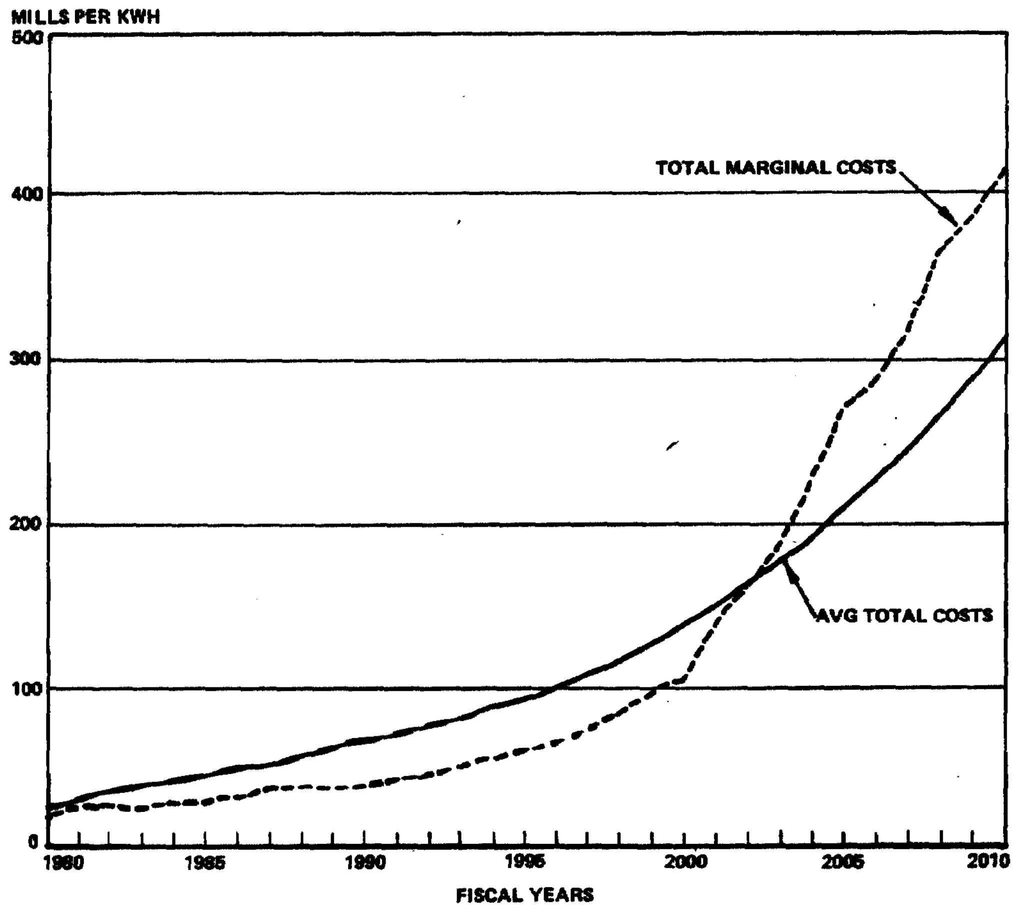


EXHIBIT 24

AVERAGE TOTAL COSTS VS TOTAL MARGINAL COSTS

1980 MEDIUM FORECAST

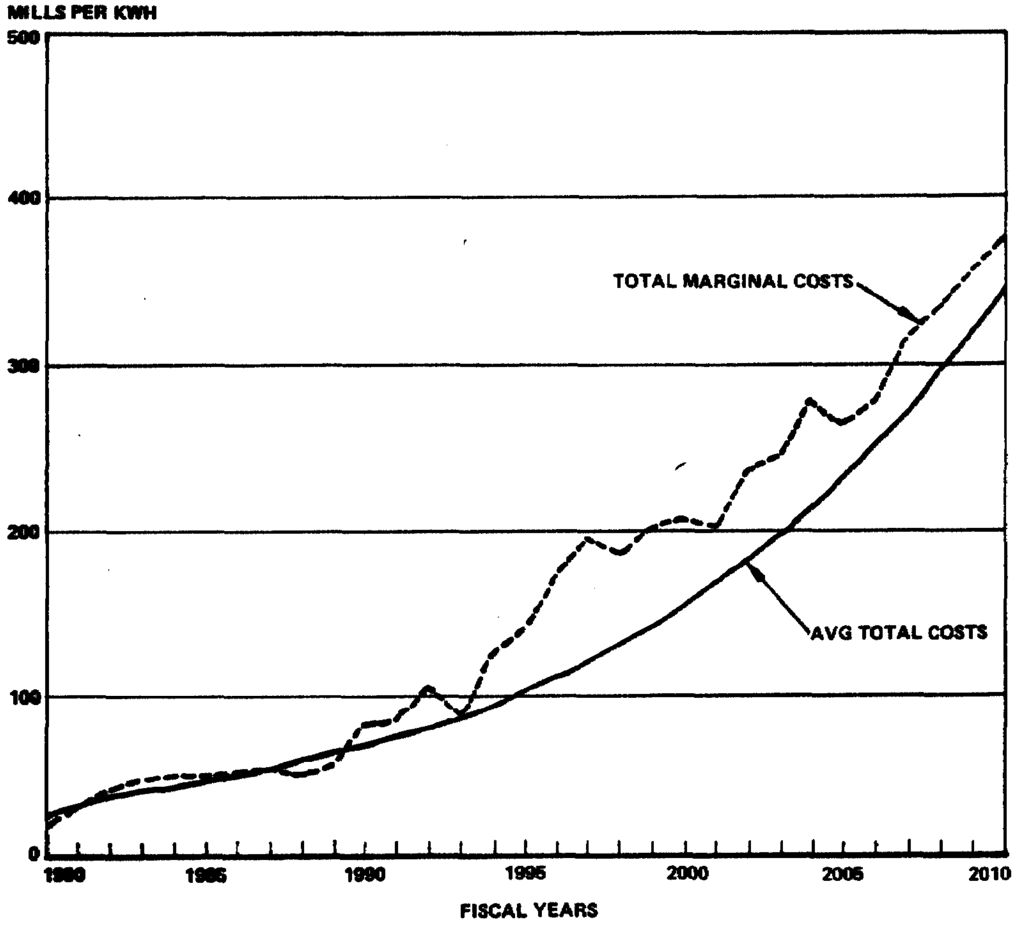
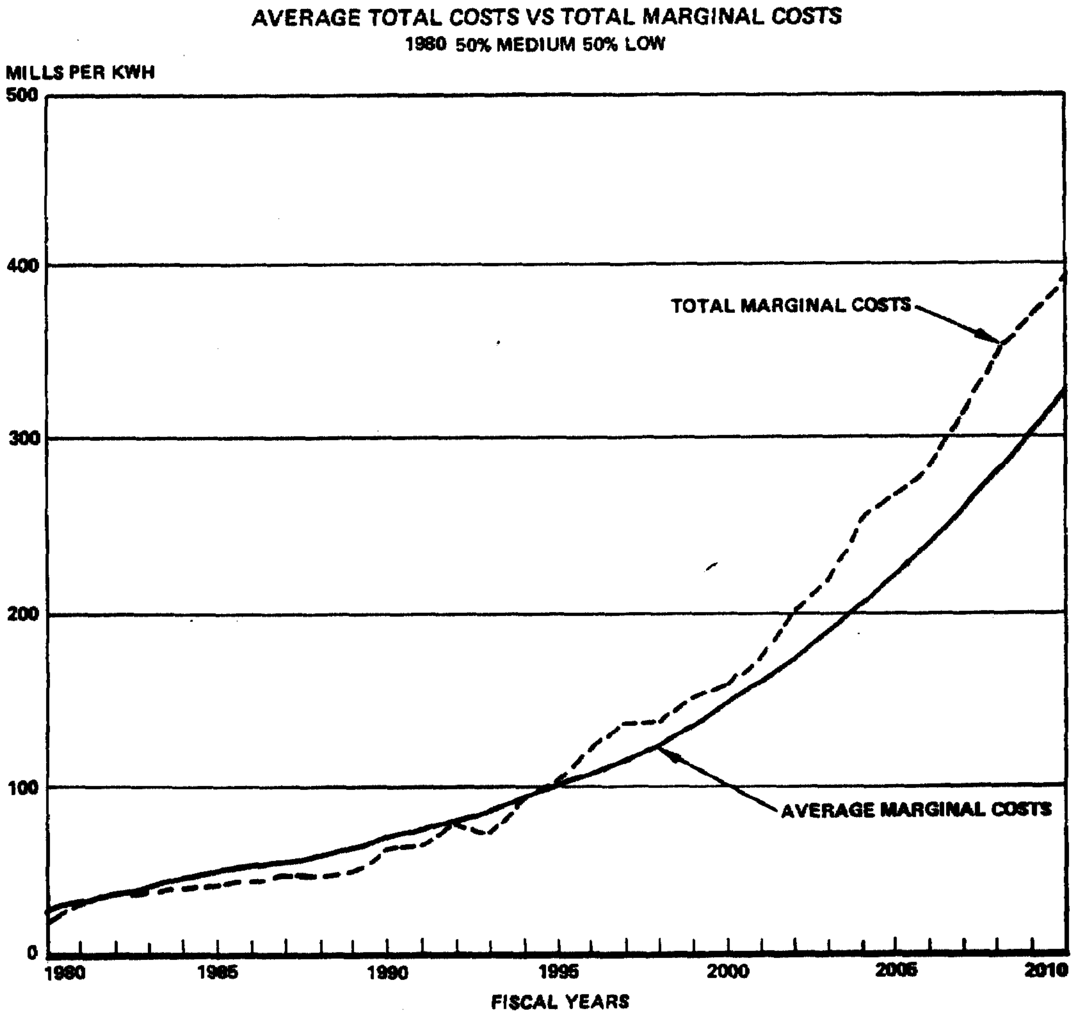


EXHIBIT 25


AVERAGE TOTAL COSTS VS TOTAL MARGINAL COSTS
1980 50% MEDIUM 50% LOW
MILLS PER KWH
500
400
300
200
100
0
TOTAL MARGINAL COSTS
AVERAGE MARGINAL COSTS
1980
1985
1990
1995
2000
2005
2010
FISCAL YEARS