EXHIBIT JC-400

JERSEY CENTRAL POWER & LIGHT COMPANY

DOCKET NO. 804-285

TESTIMONY OF MARVIN RABER

My name is Marvin Raber. I am employed by GPU Service Corporation (hereafter referred to as "Service Corp." or the "GPUSC") located at 100 Interpace Parkway, Parsippany, New Jersey, as Manager of Forecasting and Supply Planning. The forecast for this proceeding was prepared under my direction.

I am testifying on behalf of Jersey Central Power and Light Company (hereafter referred to as "Jersey Central" or the "Company") in the following areas: (1) The support for the sales forecast which has been used as a basis for current rate proceedings; (2) a description of how the short term sales forecast was determined; and, (3) a comparison of the present forecast and forecasts presented in other recent Jersey Central rate proceedings, notably the forecast entitled "October 1979 Forecast" or "Original 1980 Budget" and which, with adjustments derived from the March 1980 LEAC proceeding, was used as a basis for the original filing in this proceeding.

Exhibit JC-401, entitled "Jersey Central Power and Light Company Short Term Sales Forecast Summary - July 1980," provides a summary of the latest short term sales forecast, which was prepared in July of this year. The sales forecast covers the calendar years 1980 through 1982. In addition

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to recent historical sales data, Exhibit JC-401 shows forecast sales by customer class for these three calendar years, the upcoming LEAC period Sept. 1980 - Aug. 1981, and the normalized test year for the subject base rate case July 1980 - June 1981.

The July 1980 Forecast incorporates the following key elements:

- Loss of sales to New Jersey Steel
- Recession during 1980, with slow recovery in 1981
- Slowdown in housing construction in 1980 and early 1981
- Effects of conservation and recent price increases

Each of these elements significantly reduces forecast sales for 1980-1982 relative to sales projections made in 1979.

Page three of Exhibit JC-401 presents a summary by customer class of 1979 actual and weather adjusted sales and the corresponding forecasts of sales for 1980 to 1982. The tabulation on page four of Exhibit JC-401 provides a comparison between the July 1980 Forecast and the October 1979 Forecast for 1980 to 1982. For calendar year 1980, the current sales forecast is 5.4% lower than the October 1979 Forecast. For calendar year 1981, it is 7.0% lower. Pages five and six present tabulations similar to that on page three, but for the upcoming LEAC period (Sept. 1980 - Aug. 1981) and for the normalized test year (July 1980 - June 1981). Comparisons are made to comparable historical periods. Pages seven through fourteen of Exhibit JC-401 present graphical displays of historical and forecast trends for key economic variables and for sales to each major customer class, along with historical information and forecasts of the number of residential customers and use per customer.

The methodology used to produce short term sales forecasts has two major features; a quantitative projection of recent historical sales trends into the future, and adjustments to these projected trends for specific, identified forces that are expected to cause deflections from recent history. These adjustments are derived via a combination of quantitative and qualitative (judgmental) means, including aggregate econometric relationships between Jersey Central sales and selected economic indicators for which forecasts are obtainable from our economic consultants, customer services information, and other factors that may be appropriate. Quantitative projections of historical trends are based on twelve month rolling average projections of weather adjusted historical sales data by customer class.

The forecast process involves three major steps: (1) For each customer class or group of customers, historical monthly sales data are adjusted to standard weather conditions and further adjusted, if necessary, for customer reclassifications and gains or losses of large customers, (2) Twelve month rolling average projections are then developed. In the residential classes these projections are based on number of customers and usage per customer, and sales are then developed from the product of the two individual forecasts. In the commercial and industrial classes, twelve month rolling averages are developed for aggregate sales. Finally, (3) Sales developed from the twelve month rolling average projections are then adjusted for the most current economic outlook and, if appropriate, other structural effects.

The basic objective of the short term sales forecast is to produce an estimate of Gwh sales for use in revenue projections for financial planning and related regulatory proceedings. Our intent is to make these forecasts as accurate as possible on a twelve month basis, biased neither high or low, while recognizing that forecasts for individual months may be less accurate than forecasts for the aggregate twelve month period.

In developing the July 1980 Forecast, the following factors were considered explicitly. (1) The substantial loss of sales to New Jersey Steel as of the third quarter of 1979. This amounts to approximately 90 GWH per year of sales reduction. To the best of our knowledge today, the status of New Jersey Steel remains unchanged and that level of sales loss has been incorporated into the forecast for the entire forecast period. (2) The outlook for the economy as projected in July of 1980, primarily by Data Resources, Inc. (DRI). In addition to these explicit factors, three factors have been implicitly considered in that they are an integral part of the recent historical sales trends that form a major basis for the July 1980 Forecast. (1) Continuation of conservation trends promoted by company sponsored programs. (2) Continuation of conservation trends driven by increases in the price of electricity, assuming that future price increases will be comparable in magnitude to those experienced in the recent past. (3) Continuation of conservation trends promoted by other factors such as mandated limits to thermostat settings in commercial buildings, better insulation levels and more energy efficient appliances.

The economic outlook projections of Data Resources, Inc. (DRI) as published in its July 1980 report were the primary input in establishing the economic basis for the July 1980 Forecast. Pages seven and eight of Exhibit JC-401 characterize this outlook in terms of gross national product, industrial production index, and disposable personal income. The production index is a key characterization of industrial activity and therefore a significant driving variable for industrial sales of electricity. Similarly, disposable personal income is a key driving variable for electricity sales in the commercial and residential sectors.

In addition to income, another factor that was considered in the residential area was the sharp decline in residential housing starts. Residential housing starts were considered by conducting a survey in six benchmark counties in the Jersey Central service area to determine the short term trend in residential building permits. The trend, thus determined, was projected through 1981 based upon an evaluation of DRI's national housing start forecast and an analysis of Jersey Central's historical building permit trend. The trend of new residential customer additions was then evaluated based upon the building permit trend and on the historical trend of new customer projections as developed with the rolling average methodology.

As a result of the above evaluation, the number of new residential customers is expected to increase by 1.7%, representing 10,600 new customers, over the 1979 level (this compares to the 2.1% growt , representing 12,800 new customers, experienced from 1978 to 1979). The forecast for 1981 is for an increase of 1.6%, representing 10,300 new residential customers, over the 1980 level. The decreased growth in 1981, as compared to 1980, can be attributed, in part, to the six to nine month lag from the time a building permit is issued to the time the customer is connected. It should be noted that during the severe recession of 1974/75, the number of residential customers increased by about 10,500 per year - approximately the same as the current forecast for 1980 and 1981.

It is of importance to note that a modest deviation between the actual number of new residential customers and the forecast number is not very significant in the short-term in terms of total sales. For example, if the new customer forecast for 1980 turns out to be off by ± 1,000 customers, the impact on total company sales is only ± 8 Gwh, or ± 0.06%.

The short term sales forecast implicitly captures the effects of customer conservation that may be driven by increases in the price of electricity over the last several years. This type of conservation is captured in the twelve month rolling average procedure used to forecast short term sales. It is assumed that electric price increases in the short term will be comparable in magnitude to those experienced in the recent past.

The sales forecast presented in JC-401 is not identical to the filing basis presented by Mr. Paul Preis in JC-100 and JC-201. As stated by Mr. Preis, the filing basis was derived from the March 1980 LEAC stipulation. At that time, updating of the forecast was in progress, and preliminary results were close to those derived from the LEAC stipulation. A comparison is shown in the following table:

TOTAL SALES FOR NORMALIZED TEST YEAR JULY 1980 - JUNE 1981

		Comparison to Filing Basis	
	GWH	GWH	%
October 1979 Forecast	13552	527	4.0
Filing Basis (JC-201)	13025	Base Case	
July 1980 Forecast	12657	(368)	(2.8)

JERSEY CENTRAL POWER & LIGHT COMPANY

SHORT TERM SALES FORECAST SUMMARY

JULY 1980

GPUSC Forecasting Department

JCP&L Forecasting Department

JERSEY CENTRAL POWER & LIGHT COMPANY

SHORT TERM SALES FORECAST

BASES AND RESULTS

JULY 1980

INTRODUCTION

The Jersey Central short term (1980-1982) electric sales forecast has been updated to:

1. Firm up the bases for revenue projections for 1980-1982, taking into account actual sales trends through June, 1980.

2. Provide input to upcoming rate filings.

This report presents the bases and results of the updated forecast. The new forecast presented here incorporates the following key elements:

1. Loss of sales to New Jersey Steel.

2. Recession during 1980, with slow recovery in 1981.

3. Slowdown in housing construction in 1980 and early 1981.

4. Effects of conservation and recent price increases.

SUMMARY

Total Jersey Central electric sales for 1980 is projected to decrease 1.6 percent compared to 1979 sales. Total sales for 1981 and 1982 are forecast to grow at 2.0 and 4.0 percent, respectively, relative to the prior year. The table below provides a breakdown of projected sales levels through 1982 for each of the major customer classes.

This forecast reflects the loss of New Jersey Steel, an expected recession during 1980, a housing construction slowdown which reduces the number of new residential customers and continued conservation efforts.

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SHORT TERM SALES FORECAST SUMMARY BY CALENDAR YEAR

GWH SALES AND PERCENT CHANGE FROM PERVIOUS YEAR

	1979 Actuals	1979 Weather Adjusted	1979 %Δ	JULY 1980 FORECAST 1980*	%Δ	1981	%Δ	1982	%Δ
Residential									
NTE	3805	3817	3.4	3776	(1.1)	3815	1.0	3891	2.0
TE	1333	1344	9.9	1296	(3.6)	1326	2.3	1392	5.0
TOTAL	5138	5161	5.0	5072	(1.7)	5141	1.4	5283	2.8
Commercial	3495	3497	5.4	3555	1.7	3645	2.5	3820	4.8
Industrial	3762	3762	3.4	3593	(4.5)	3670	2.1	3854	5.0
Other	378	378	3.3	372	(1.6)	389	4.6	406	4.4
Totals:	12773**	12798	4.6	12592	(1.6)	12845	2.0	13363	4.0

* 6 + 6; January to June weather adjusted actual sales are included

** Total sales shown are 6 GWH less than booked sales. The 6 GWH were sold in 1978 but booked in 1979.

SUMMARY (Continued)

A comparison of forecasts reveals that this forecast for total company sales for 1980 is 717 GWh or 5.4 percent lower than the October 1979 Forecast. The major contributing factors are:

- Loss of New Jersey Steel
- Economic recession
- Effects of conservation and recent price increases

The following table provides a comparison of the July 1980 Forecast with the October 1979 Forecast.

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JULY 1980 FORECAST COMPARED TO OCTOBER 1979 FORECAST

CALENDAR YEAR BASIS - GWh SALES

	1980			1981			1982		
	7/80 Forecast	10/79 Forecast	% Δ	7/80 Forecast	10/79 Forecast	% Δ	7/80 Forecast	10/79 Forecast	% Δ
Residential									
NTE	3776	3864	(2.3)	3815	3938	(3.1)	3891	4008	(2.9)
TE	1296	1363	(4.9)	1326	1425	(6.9)	1392	1489	(6.5)
Total	5072	5227	(3.0)	5141	5363	(4.1)	5283	5497	(3.9)
Commercial	3555	3716	(4.3)	3645	3894	(6.4)	3820	4057	(5.8)
Industrial	3593	3967	(9.4)	3670	4138	(11.3)	3854	4286	(10.1)
Other	372	399	(6.8)	389	417	(6.7)	406	436	(6.9)
Totals	12592	13309	(5.4)	12845	13812	(7.0)	13363	14276	(6.4)

The July 1980 forecast for industrial and total sales reflects the loss of N.J. Steel (90 GWh per year)

LEAC PERIOD

The table below provides a comparison of sales for each class for the LEAC period September through August. Sales are expected to increase slightly, 0.5 percent, in the twelve month period ending August 1981, as compared to the previous period.

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SHORT TERM SALES FORECAST SUMMARY BY LEAC PERIOD

SEPTEMBER THROUGH AUGUST

GWH Sales and Percent Change From Previous Period

	1978		1979		1980		1981	
	GWH	%Δ	GWH	%Δ	GWH	%Δ	GWH	%Δ
Residential								
NTE	3674	1.5	3798	3.4	3782	(0.4)	3799	0.5
TE	1202	4.0	1329	10.6	1301	(2.1)	1315	1.1
Total	4876	2.1	5127	5.1	5083	(0.9)	5114	0.6
Commercial	3270	4.6	3467	6.0	3535	2.0	3611	2.1
Industrial	3554	4.7	3763	5.9	3654	(2.9)	3608	(1.3)
PSHL	87	1.9	88	1.2	89	1.6	91	2.3
Resale	278	2.6	287	3.3	285	(0.8)	291	2.2
Total:	12082	3.5	12742	5.5	12646	(0.8)	12715	0.5

Note: Weather adjusted actual sales through June 1980.

NORMALIZED PERIOD

Provided below is a comparison of sales for each class for the normalized period July through June. The forecast of sales for the normalized period ending June 1981 is

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SHORT TERM FORECAST SUMMARY BY PERIOD JULY - JUNE

(Normalized)

GWH Sales and Percent Change From Previous Period

	1978		1979		1980		1981	
	GWH	%Δ	GWH	%Δ	GWH	%Δ	GWH	%Δ
Residential								
NTE	3690	3.0	3768	2.1	3794	0.7	3791	(0.1)
TE	1198	4.9	1318	10.0	1300	(1.4)	1311	0.9
Total	4888	3.5	5086	4.0	5094	0.2	5102	0.2
Commercial	3255	5.4	3445	5.9	3524	2.3	3594	2.0
Industrial	3511	3.5	3739	6.5	3696	(1.2)	3584	(3.0)
PSHL	87	1.8	88	1.1	89	1.3	90	1.2
Resale	276	2.6	285	3.3	291	2.0	287	(1.3)
Total	12034	4.0	12655	5.2	12693	0.3	12657	(0.3)

Note: Weather adjusted actual sales through June 1980.

ECONOMIC OUTLOOK

The economic outlook incorporated into the July 1980 sales forecast is for a recession to develop during the second quarter of 1980 and continue through the last quarter.

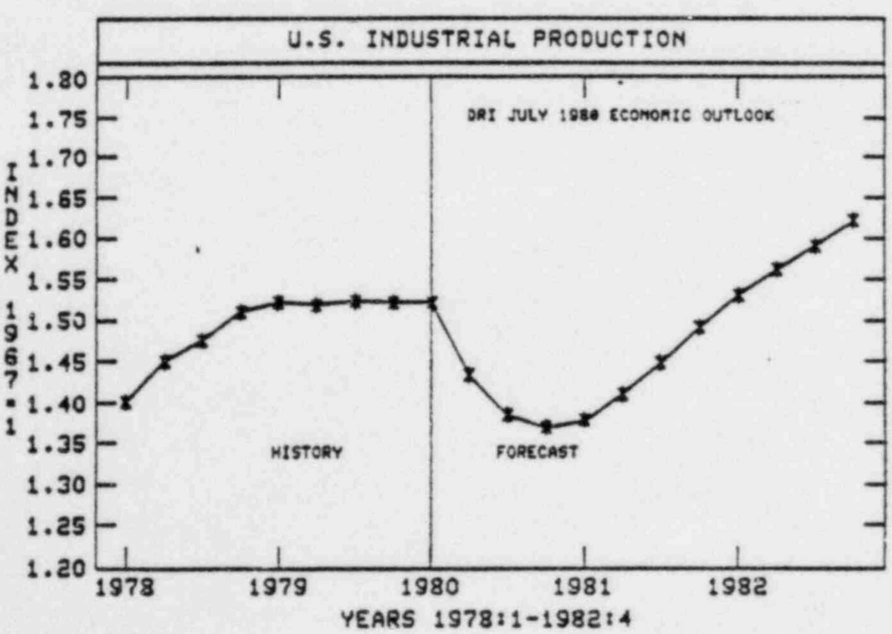
The economy is expected to recover in 1981. During 1980 high mortgage rates and a general unavailability of mortgage funds is expected to persist.

Following is the quarterly outlook for real gross national product based on the Data Resources Inc. (DRI) July 1980 forecast of the economy.

Real GNP Change From Previous Quarter

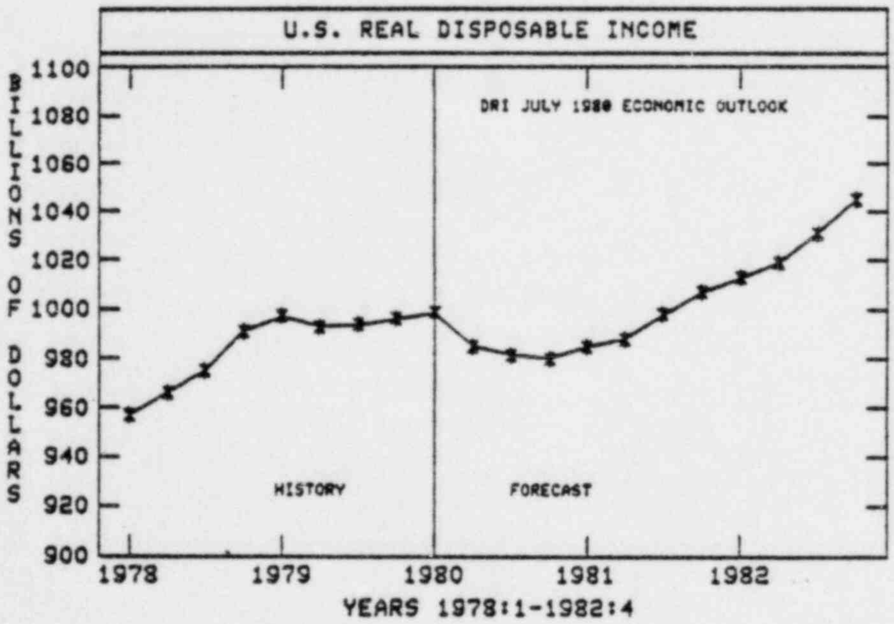
Actual		Annual Rates (%)						
1979	1980	1980			1981			
IV	I	II	III	IV	I	II	III	IV
2.0	1.2	(8.9)	(6.0)	(1.8)	3.3	4.0	5.2	5.2

Industrial production, which measures the level of physical industrial output, was used to estimate the impact of the expected recession on industrial electric sales. The graph below shows the quarterly production index, which reflects a downturn during 1980 and a modest recovery in 1981, resulting in annual changes of (6.2) and 0.3 percent, respectively.



ECONOMIC OUTLOOK (Continued)

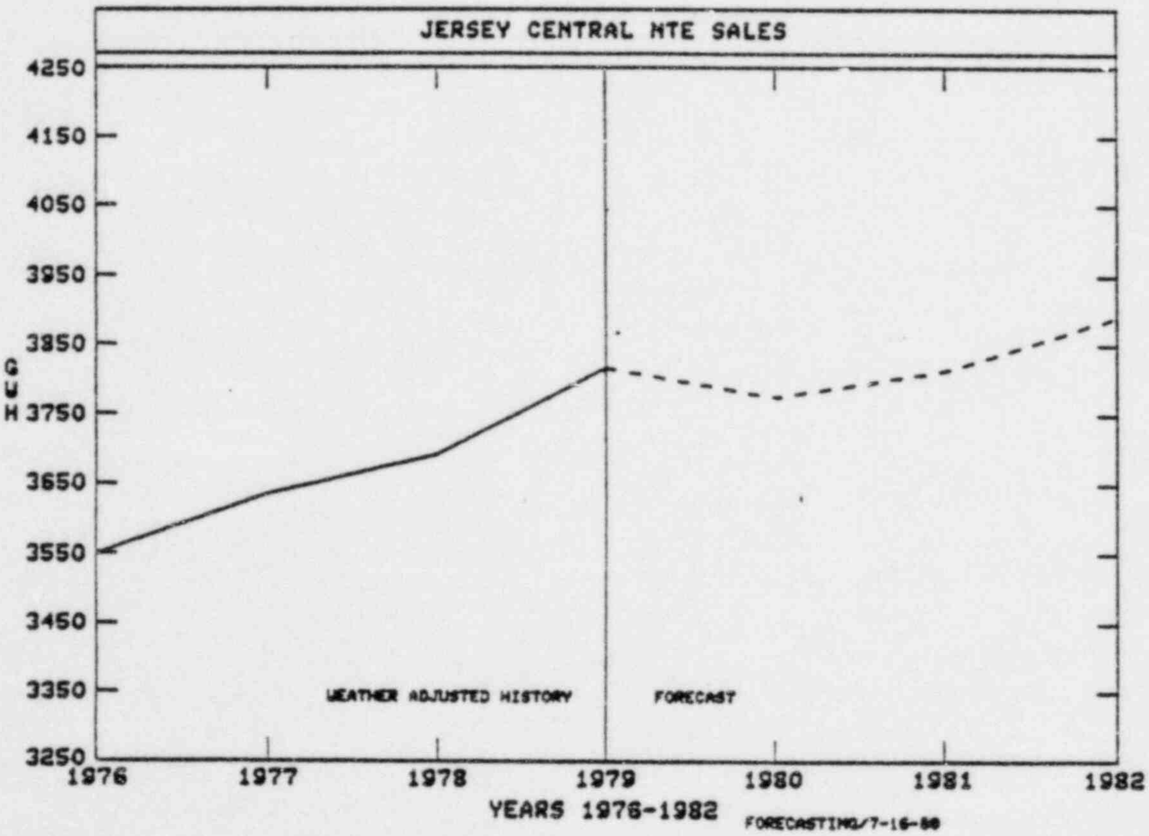
Real disposable income on a quarterly basis was used to model the recessionary impact on commercial sales. As shown on the chart below, real disposable income for 1980 is expected to decline 0.9% from the 1979 level, and for 1981 an increase of 0.8 percent is projected.



RESIDENTIAL NON-TOTAL ELECTRIC SALES (NTE)

Residential NTE sales for 1980 are forecast to decrease 1.1 percent over 1979. Use per customer for 1980 is 138 kWh lower than in the previous (October 1979) forecast. However, the number of new customers is forecast to be 1700 less, as a result of the deteriorated housing market. In terms of sales for 1980, the July 1980 forecast is lower than the old forecast by 2.3 percent.

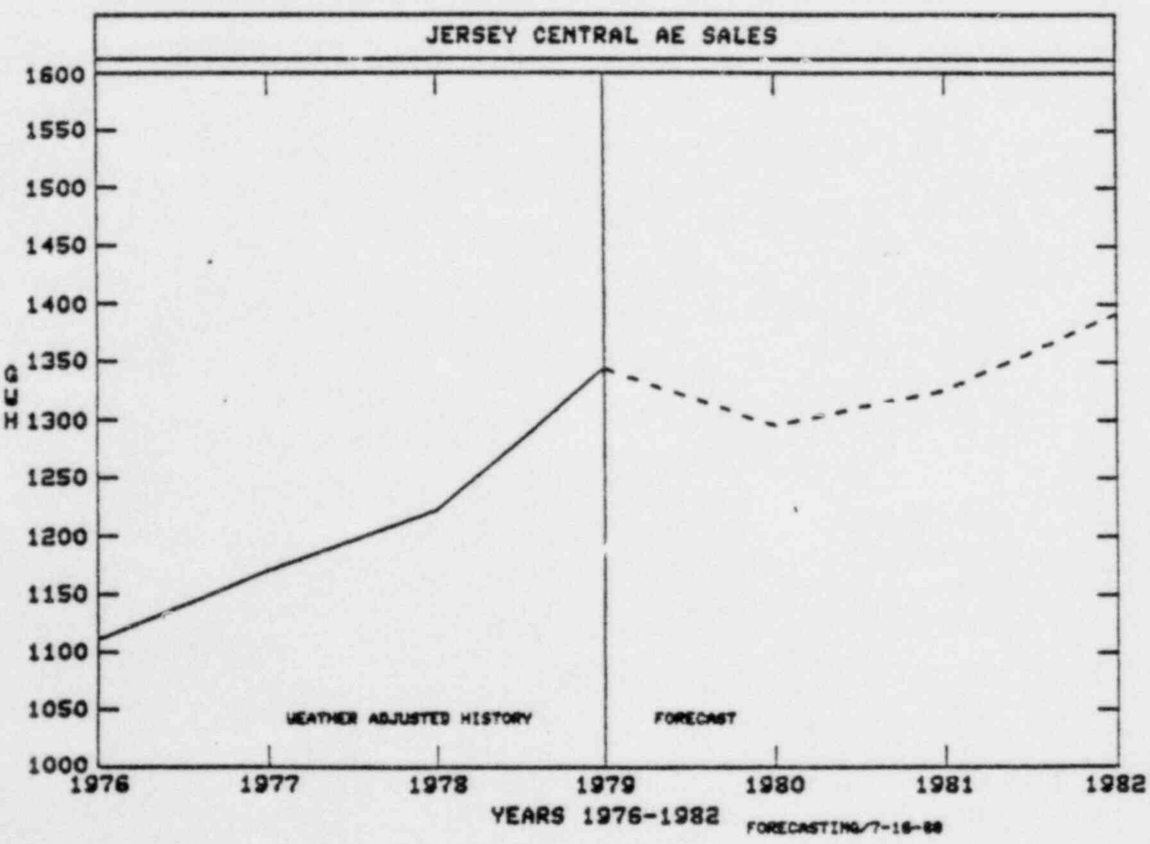
	Use Per Customer-kWh	Average Number of Customers	Sales GWh	Yearly Change in Sales - %
1977	6853	530631	3636	1.7
1978	6868	537713	3693	1.6
1979	7004	544889	3817	3.4
1980	6841	551954	3776	(1.1)
1981	6834	558200	3815	1.0
1982	6865	566800	3891	2.0



RESIDENTIAL TOTAL ELECTRIC SALES (TE)

Residential TE sales for 1980 is projected to decline 3.6 percent from 1979. Use per customer in 1979 was up from 1978 after having declined during the previous several years. In-depth analysis leads us to conclude that the trend in use per customer is still downward as the TE customers are expected to continue to conserve, especially on electric space heating. As with the NTE class, the slowdown in housing construction should reduce the number of new TE customers in 1980 by about 500 compared to the old forecast.

	Use Per Customer-kWh	Average Number of Customers	Sales GWh	Yearly Change in Sales - %
1977	18673	62703	1171	6.0
1978	18061	67726	1223	4.4
1979	18504	72625	1344	9.9
1980	16927	76562	1296	(3.6)
1981	16523	80252	1326	2.3
1982	16436	84692	1392	5.0

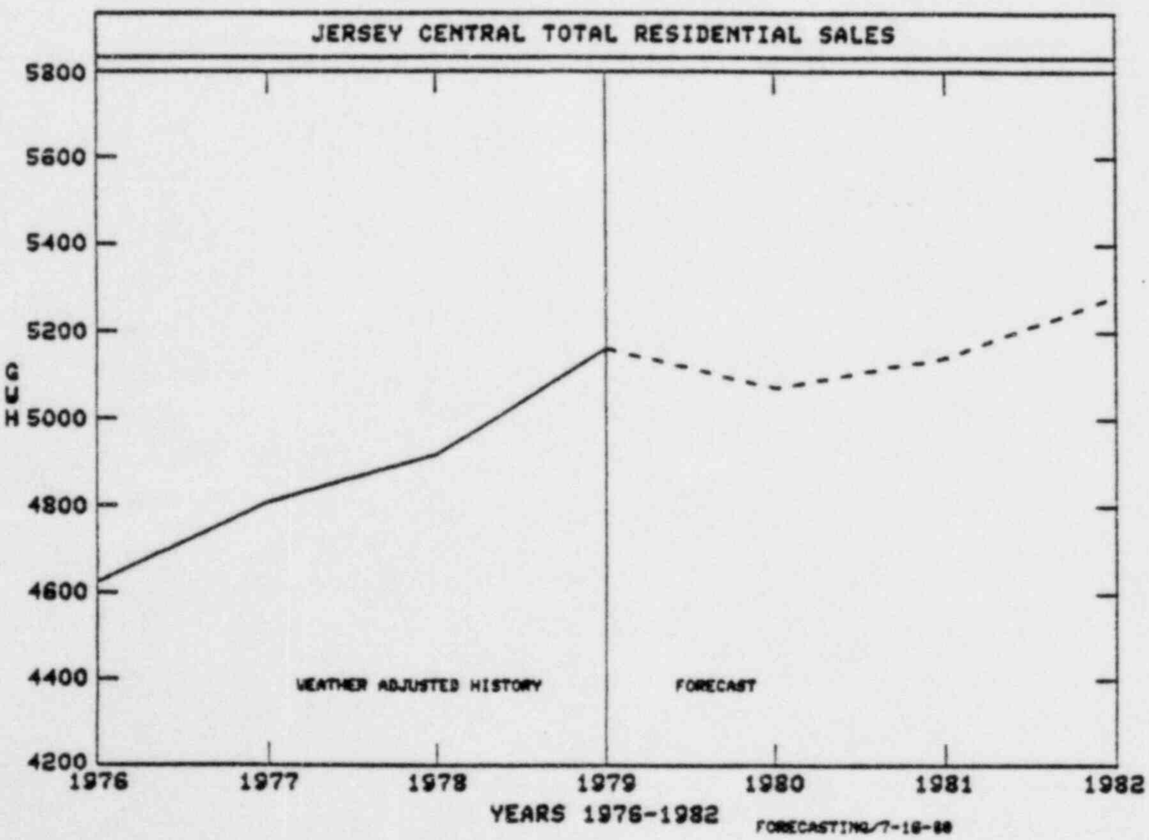


TOTAL RESIDENTIAL SALES

Total residential sales for 1980 is expected to decrease 1.7 percent over 1979. That compares with percent increases of 5.0 in 1979, 2.3 in 1978 and 2.7 in 1977. The significant rise in sales for 1979 was mostly due to higher than expected use per customer. Use per customer for 1980 is projected to decline approximately 300 kWh from the abnormally high level of 1979, and the number of new customers is estimated to be less than the old forecast due to the decline in housing construction.

The total electric (TE) share of total residential sales has been increasing. This trend is expected to remain flat thru 1982 due primarily to increased conservation on the part of the TE customer.

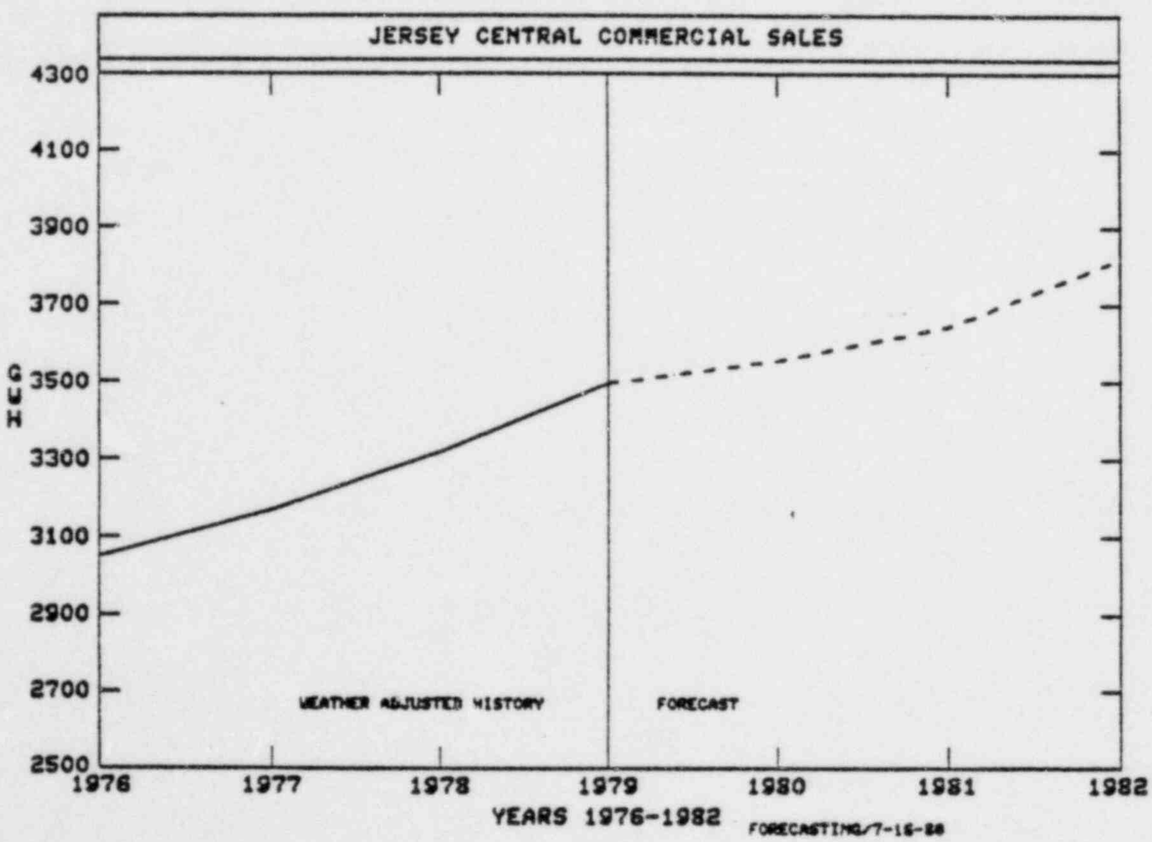
	Total Residential GWh	NTE GWh	NTE Percent of Total	TE GWh	TE Percent of Total
1977	4807	3636	76	1171	24
1978	4916	3693	75	1223	25
1979	5161	3817	74	1344	26
1980	5072	3776	74	1296	26
1981	5141	3815	74	1326	26
1982	5283	3891	74	1392	26



COMMERCIAL SALES

Commercial sales, which accounted for 27 percent of 1979 total company sales, is forecast to increase 58 GWh or 1.7 percent in 1980 compared to 1979. The projected level of sales for 1980 has been reduced to reflect the impact of an expected economic recession during the last three quarters of 1980. Real disposable personal income, which is a significant explanatory variable for commercial sales, was used to estimate the effect of the expected recession on sales.

	Commercial Sales-GWh	Annual Growth GWh	%
1977	3168	137	4.5
1978	3318	150	4.7
1979	3497	179	5.4
1980	3555	58	1.7
1981	3645	90	2.5
1982	3820	175	4.8



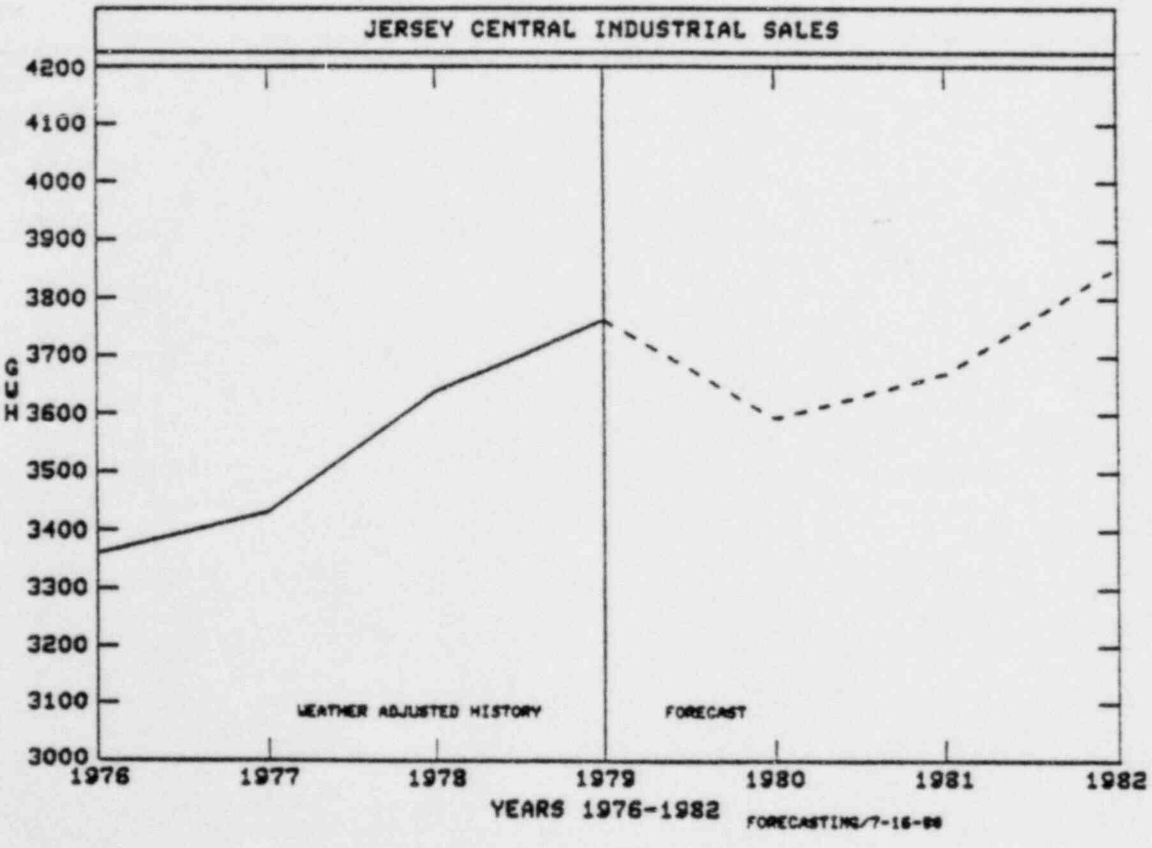
INDUSTRIAL SALES

Industrial sales, which have increased each year since the downturn in 1975 resulting from the 1974/75 recession, are forecast to decline by 169 GWh or 4.5 percent in 1980 from the 1979 sales level.

The reasons for the projected drop in industrial sales during 1980 are the loss of New Jersey Steel (90 GWh) and the impact of a recession in the last three quarters of 1980. Industrial sales should recover in 1981 along with the economy.

Data Resources, Inc. July 1980 forecast of industrial production, which measures physical output by manufacturers, was used to calculate the recessionary impact on industrial sales.

	Industrial Sales-GWh	Annual Growth	
		GWh	%
1977	3434	78	2.3
1978	3639	204	5.9
1979	3762	123	3.4
1980	3593	(169)	(4.5)
1981	3670	77	2.1
1982	3854	184	5.0



TOTAL COMPANY SALES

Total company sales for 1980 is forecast to decrease 206 GWh or 1.6 percent relative to 1979. Total sales are forecast to recover in 1981 from the slowdown in 1980, resulting in growth of 2.0 percent.

The sales contribution of each major class to total company sales is not expected to change significantly during the period of this forecast, as shown below:

	Total Sales		Percent Contribution to Total Sales			
	GWh	% Growth	Residential	Commercial	Industrial	Other
1977	11764	3.0	41	27	29	3
1978	12239	4.0	40	27	30	3
1979	12798	4.6	40	27	30	3
1980	12592	(1.6)	40	28	29	3
1981	12845	2.0	40	28	29	3
1982	13363	4.0	40	28	29	3

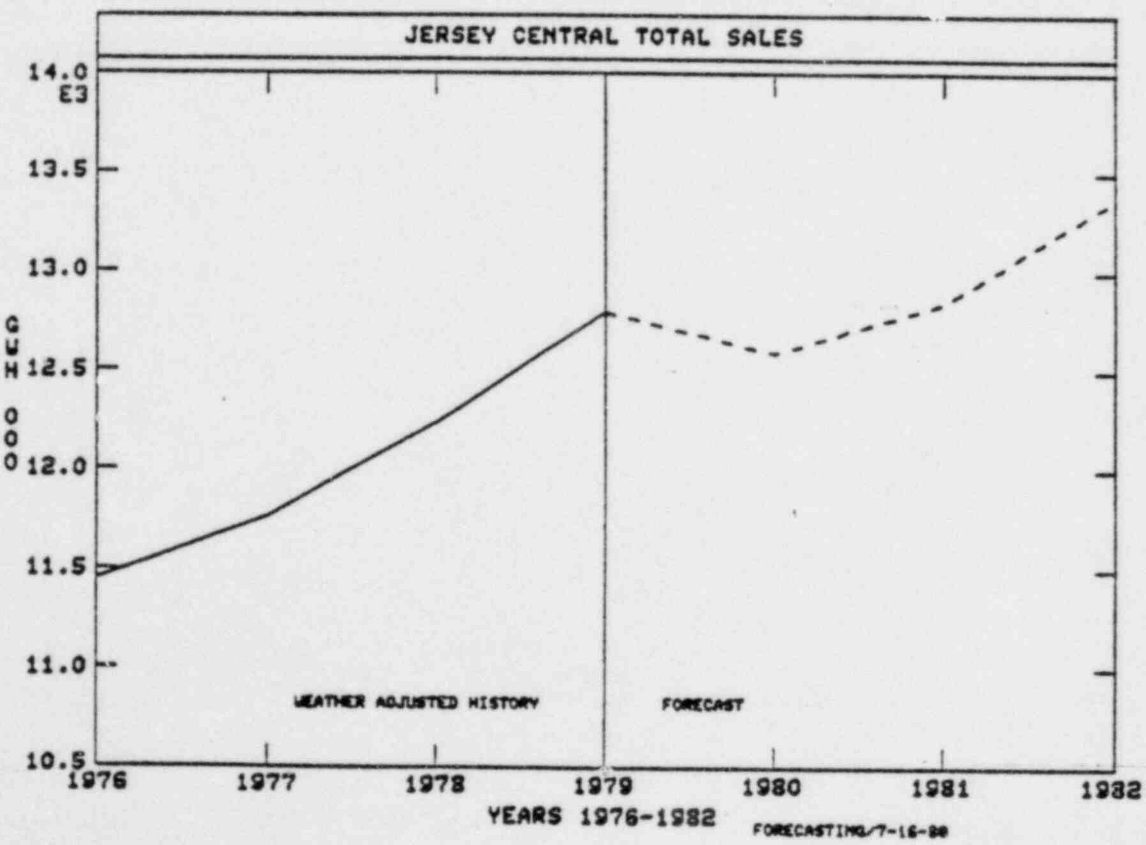


Exhibit JC-503

THREE MILE ISLAND #2

MAJOR COMMITMENT REVIEW

June 2, 1980

I. SUMMARY

This Major Commitment Review will identify and evaluate the alternative courses of action available to GPU regarding the disposition of TMI-2 and select the course of action which best meets the needs of our customers and the corporation.

FINDINGS

1) Present and future needs for supplying our customers' demand for electricity require the restoration or replacement of TMI-2.

2) No known technical factors have been identified which would foreclose restoring TMI-2 to service. However, the technical feasibility of restoration will not be known with confidence until after a first hand inspection has been made inside the reactor building and the pressure vessel.

3) The alternatives evaluated by GPU are:

	Net Capital Cost as Incurred	Earliest Startup
a) Restore TMI-2 (880 MW)	$ 100 Million	1/1/84
& build 472 MW Coal Plant*	$ 645 Million	1/1/87
b) Convert TMI-2 to a Coal-fired Plant (1352 MW)	$1377 Million	1/1/87

* The 472 MW coal plant size was selected for consistency with the other options. In fact, a 625 MW plant would be built. The cost used is the same as for a 625 MW plant on a $/Kw basis.

c) Convert TMI-2 to a gas-fired plant (1375 MW), run for 5 years, then convert to coal (1352 MW)	$1658 Million	10/1/86
d) Replace TMI-2 with two offsite coal plants (1352 MW)	$1846 Million	1/1/87

(These cases were designed to achieve identical capacity levels and supply the same annual quantities of electricity for 1984-1996.)

4) The average estimated cost of electricity supplied, either by generation or purchases of electricity, under each of the four alternative cases for 1984-96 are:

	¢/KWH
a) Restore plus coal	7.60
b) Convert-Coal	11.15
c) Convert-Gas/Coal	10.60
d) Replace-Offsite Coal	11.25

Using the restore option as a benchmark, the <u>average monthly cost penalty</u> to a typical residential customer (500 KWH's/month usage) over the 13 year period would be:

	Met-Ed	Jersey Central	Penelec
Convert-Coal	$5.04	$1.60	$1.89
Convert-Gas/Coal	$4.23	$1.34	$1.58
Replace-Offsite Coal	$5.19	$1.65	$1.94

The actual monthly penalty is less in early years and grows with time, continuing past the 1996 end-date used in this evaluation.

5) The earliest and least expensive option from the customers' and corporation's viewpoint is restoring TMI-2 to service. There is a large margin for error in meeting cost and schedule targets before the benefits of this option would be eliminated. For the restore option to have the same average cost of electricity as the nearest competitor (gas/coal), the following conditions would be necessary:

   a) TMI-2 Restored 1/1/84; Cost overrun - $1250 Million

   b) TMI-2 Restoration delayed to 1/1/87; Cost overrun - $1100 Million

6) All the non-nuclear alternatives have comparable economic consequences. While costs are similar, the risk and uncertainties are not. The conversion options have a number of issues not shared by the offsite coal alternative which could undermine their practicality. In addition, the reliability of

operation for a converted unit is a major unknown, since it would be a "first of a kind" on such a large scale.

7) The decision on the restart of TMI-1, expected in early 1981, will help to establish whether restoring TMI-2 is a feasible option. If the undamaged TMI-1 is not allowed to restart, then assuming TMI-2 can be restored and allowed to operate is unrealistic. The TMI-1 licensing process now underway will help define the technical changes that would be required of TMI-2. It also provides a forum for airing the views of GPU, Federal, state and local governments, and the public on this controversial issue.

8) Ideally, GPU could keep two or more of the options on track, however, GPU's current financial condition may preclude this approach.

CONCLUSION

In light of these findings, the following strategy is recommended as the course of action which best fulfills GPU's responsibilities to its customers and stockholders:

1) Commit to restoring TMI-2 to service as the best option, even with its considerable risks and uncertainties. This commitment would be reinforced by a favorable decision on restarting TMI-1. Under these circumstances, the primary condition which would reverse this commitment is if restoration is found to be technically infeasible.

2) If TMI-1 is not allowed to restart or restoring TMI-2 is found to be impractical for other reasons, then redirect GPU's resources, to the extent possible, to building off-site coal plants to replace TMI-2 (and TMI-1, if necessary) as the next best course of action. Continue with the clean-up and decontamination of TMI-2. At the same time, retain the conversion option for possible future use. Attempt to reduce or eliminate the present uncertainties associated with conversion, especially the initial gas-fired approach.

The selection of the offsite coal option as the second best choice is supported by an additional strategic advantage. If difficulties in financing both plant arise, at least one plant might be completed on schedule. Financing limitations would force the delay of all of the capacity represented by the conversion option if that were the selected approach.

II. Background

Since the accident at Three Mile Island a year ago, GPU has devoted substantial resources to the safe cleanup and decontamination of the damaged nuclear reactor (TMI-2). We are in the initial stages of the cleanup program, which must be completed before taking any action to restore the unit to service. No known technical factors have been identified which would prevent eventual restoration. Current information, obtained from remote television scanning of limited portions of the reactor building interior and analyses of radioactive air and water samples obtained from within, indicates that conditions during the accident and the resulting damage may have been less severe than originally thought. However, the full extent of damage will remain uncertain until a first hand inspection can be achieved, after entry into the reactor containment building.

Since the ability to return the nuclear unit to service cannot be considered a certainty, GPU has utilized several consultants and in-house personnel to investigate the three possible courses of action regarding the unit:

1) Restoring TMI-2 to service as a nuclear unit.

In July, 1979, the Bechtel Corp. completed a preliminary assessment of the potential cost and schedule for decontaminating and restoring the unit to service.

2) Converting TMI-2 to a fossil-fueled plant.

Gilbert Associates, Inc., investigated this approach in two steps. In October, 1979, a report describing the results of the Phase I effort concluded that this option was technically feasible and identified several variations for further study. The Phase II report completed in February, 1980, provided plant layouts, schedules and project cost estimates for the selected alternatives. GPU developed corresponding fuel, operating, and maintenance costs.

3) Not reactivating TMI-2 and replacing it with capacity at other sites.

GPU personnel evaluated the acceleration of coal-fired plants already planned for construction in western Pennsylvania in the mid 1980's and beyond.

The necessity for taking one of these courses of action is clear. Prior to the accident, capacity installed throughout the GPU System was sufficient to match supply and our customers' demand for electricity with an adequate reserve margin to assure supply reliability. TMI-1, the sister unit to the damaged reactor, was shut down for refueling at the time of the accident and has yet to receive approval from the Nuclear Regulatory Commission (NRC) to restart. We now anticipate return of TMI-1 to service in early 1981. These two units represent 1650 MW, or over 20%, of GPU's current capacity. The cost of power purchased to replace the output of these units has been averaging over $25 million a month. As a consequence of the cash drain caused by the need to purchase replacement power, all non-critical construction expenditures have been eliminated, causing delays in planned future additions to the GPU system.

At the same time, the most recent GPU forecast estimates electrical demand will increase by over 3% per year, on the average, through 1990. This level of growth would require adding another 2350 MW of capacity to the GPU system, in addition to TMI-1 restart and the return or replacement of the 880 MW TMI-2, to achieve a supply/demand balance in 1990. To reduce this need, GPU has developed a comprehensive Conservation/Load Management Master Plan intended to cut the growth rate in the peak demand for electricity in half. Even under these circumstances and with TMI-1 restart and TMI-2 returned or replaced, new capacity requirements would still exceed 1000 MW by 1990. Implementing the Master Plan, restarting TMI-1, returning or replacing TMI-2, and building new capacity in the future will reduce significantly the need to purchase expensive replacement power, with the added benefit of curtailing oil usage for electricity production.

PURPOSE

In keeping with our corporate objective to provide a safe and reliable supply of electricity to our customers at reasonable cost, the purpose of this Major Commitment Review is to determine the preferred course of action regarding TMI-2. The three alternatives open to us will be evaluated and compared, making extensive use of the individual investigations mentioned earlier. This evaluation and comparison will identify potential cost impacts to our customers, investment and replacement power requirements and their implications, and the uncertainties and risks associated with each approach. While the major emphasis will be given to the customer cost impact, the cash drain caused by the purchase of replacement power: a) puts a high premium on keeping new investment requirements to a minimum;

and b) underlines the importance of making a timely and prudent decision on which course of action to follow.

APPROACH

The balance of this paper consists of three chapters:

1) The Options - the restore, convert, and replace alternatives will be briefly described, including corresponding project costs and schedules, licensing and approval requirements, and a brief summary of major risks and uncertainties.

2) The Comparison - the options will be compared in the frame-work of the cost of electricity generated under each and the corresponding cost implications to our customers. Project costs will be combined with estimates of fuel, operating and maintenance (O&M), and replacement power costs for each case to determine electricity cost impacts. The effect of potential delays and cost overruns on the comparisons also will be summarized.

3) The Strategy - using the economic results and an evaluation of the relative impact and importance of risks and uncertainties associated with each course of action, an overall strategy will be developed which best meets the needs of our customers and the corporation.

III. THE OPTIONS

A. Restore TMI-2 to Service as a Nuclear Unit

Shortly after the accident, GPU commissioned the Bechtel Corporation to investigate what would be involved in returning TMI-2 to service. Under the assumption that restoring TMI-2 as a nuclear unit was feasible, Bechtel developed the tasks, project costs, and corresponding schedules for the cleanup, decontamination, and restoration efforts, as summarized in Table III-1. The time required to achieve restoration is estimated to be 42 months from the time of entry into the reactor building. Assuming containment entry in the summer of this year, TMI-2 could be returned to service by the beginning of 1984.

Of the total estimate of $315 million, $263 million is related to cleanup and decontamination, necessary tasks under any course of action (restore, convert, or replace). Potential costs items not included in the estimate are given in Table III-2. An additional $85 million would be needed to replace the fuel in the reactor core, increasing the total cost to $400 million; however, insurance reimbursements up to a $300 million maximum would make the net project cost of this option equal to

$100 million. The expenditure, insurance recovery, and net cash flows for returning the unit to service are listed in Table III-3. No attempt has yet been made to estimate the cost of system modifications that might be required to comply with possible revisions in NRC regulations. (A summary of the Bechtel study is provided in Appendix A.)

The Nuclear Regulatory Commission must give its approval, after extensive public hearings, to restore the plant to service. The licensing process is the main source of uncertainty for this option <u>if</u> restoration is found to be technically feasible. In addition, resolution of two related licensing matters, before an NRC decision on return of TMI-2, is critical. The first concerns the approval of an acceptable means for removing the radioactive Krypton gas from the reactor building so that entry and decontamination can proceed. The second centers on NRC approval of the return to service of the undamaged sister unit, TMI-1. Overlaying all of these factors is the issue of public acceptance, a particularly important consideration in the licensing process. The determinations made during licensing can affect: costs, through revised regulatory requirements; schedules, depending on the licensing timetable and the resolution of the radioactive gas removal issue; and feasibility, if for some reason TMI-1 is not allowed to restart.

B. Convert TMI-2 to a Fossil-Fueled Plant

In July, 1979, GPU directed Gilbert Associates to examine the feasibility of converting TMI-2 to a fossil-fired power plant. This approach would make use of portions of the plant not closely associated with the reactor itself (the cooling towers, the turbine-generator, the switchyard, and the transmission lines) so that the cost would be less than building the same size plant from scratch. Fossil-fired boilers would replace the nuclear reactor as the source of steam for running the turbine-generator.

The Phase I report issued in October, 1979, concluded that conversion was technically feasible and identified a number of alternatives for further consideration. The alternatives identified were combinations of the following:

a) fueling the plant with anthracite coal, bituminous coal, and/or natural gas;

b) matching the steam conditions of a nuclear plant <u>or</u> producing the higher pressure steam typical of fossil plants. The latter involves building additional steam turbines to take advantage of the greater energy content of the higher pressure steam before sending it to the TMI-2 turbine.

On the basis of cost comparisons, the higher pressure system was selected for further study with two fuel variations. Anthracite coal was dropped as a potential fuel since its estimated cost was about twice that of bituminous coal and the production increase necessary to supply TMI-2 would require a doubling of the Penn. anthracite coal industry's supply capability. Federal law bars the use of natural gas in new power plants over their total life but allows, under certain circumstances, up to a five year exemption from this ban. Therefore, the two alternatives selected for further study during Phase II were a bituminous coal-fired unit and a plant initially fueled by natural gas and converted to bituminous coal firing after 5 years of operation. With the additional steam turbines included in these designs, the capacity of the converted unit would be greater than the original 880 MW TMI-2 by 470-495 MW or over 50%.

A Gilbert report issued in February, 1980, summarized the Phase II analysis. Plant layouts, licensing requirements, costs, and schedules were developed for the two selected options. The costs and schedules are provided in Table III-4. The estimates range from $1365 million for the coal option to a total of $1640 for the gas/coal approach, with over $800 million of the latter estimate to be spent in 1987-91. An additional $12 million would be necessary to develop the site for disposal of the ash and sludge recovered during coal combustion. The cash flows for these options are shown in Table III-5 and III-6, including estimates for escalation and Allowance for Funds used During Construction (AFDC).

Assuming a project start date of July, 1980, the coal option could be operational by the end of 1986 while the gas/coal plant could start-up 3 months earlier. (A summary of the Phase II report is provided in Appendix B; the analysis of the anthracite option in Appendix C.)

Either the coal or gas/coal plant requires a number of licenses, as described in more detail in the Gilbert Phase II report. Of particular concern are:

a) the need for a waiver by the Federal Aviation Administration, because of the Harrisburg airport nearby, allowing a smoke stack higher than 360 feet;

b) if "offsets" to coal combustion particulate emmissions are needed to comply with EPA air quality standards. This depends on whether the Harrisburg air basis continues to be classified as a "nonattainment" area;

c) the selection and approval of a site for disposal of ash and sludge produced during coal combustion;

d) the reversal of the Federal Energy Regulatory Commission designation of part of Three Mile Island as a recreational area, since the land would be needed for plant construction and coal storage; and

e) the resolution of any interface/security issues with the Nuclear Regulatory Commission related to the plant's proximity to the remaining nuclear unit, TMI-1.

A number of additional state and local permits are necessary to complete construction.

In addition to licensing requirements and their risks, there are three other areas of potential uncertainty. The sizable investment requirements raise questions about GPU's ability to finance such a large undertaking. Second, the plant arrangement is the first of its kind on such a large scale, causing concern about meeting schedule and cost targets and, when completed, achieving reliable operation. Finally, the issue of public acceptance is critical in that any number of required licenses could be contested or delayed. Potential public issues are coal burning (pollution), coal transportation and storage (traffic and land use), and ash and sludge disposal (traffic and land use).

C. Replace TMI-2 with Capacity Elsewhere

The two means for replacing TMI-2 with capacity at other sites are purchasing capacity (or electricity) from other utilities or building our own plants. GPU is agressively pursuing purchase possibilities and has successfully negotiated a number of arrangements recently that reduce today's cost of replacement power. This approach, however, is not a permanent solution since surpluses are temporary and difficult to confidently predict for the future. The only permanent approach to replacing TMI-2 is building new capacity.

The earliest alternative available to us is the acceleration of coal plants already planned for startup in the mid to late 1980's. In particular, GPU looked at speeding up the construction of Seward 7 and Cono 1, two 625 MW coal plants in western Pennsylvania scheduled for operation in 1987 and 1989. Though the schedules would be tight, we concluded that it was feasible to complete both plants by the end of 1986, the same target startup date as the coal conversion option. The cash flow and total project costs for these two plants are summarized in Table III-7.

Permit and licensing requirements are similar to those mentioned for TMI-2 conversion to coal; however, proximity to a nuclear plant is not an issue. The major sources of uncertainty for this option are the risk of not meeting the accelerated schedule and GPU's financing ability, uncertainties which also apply to conversion. The public acceptance issue may not be as controversial as with the restore and convert options.

SUMMARY

The cash flows and net project costs for the restore, convert, and replace options are contrasted in Table III-8. In all cases, 1981 is the year when large capital expenditures begin. While the table highlights the differences in the timing and amount of capital investment, it does not convey the differences in the total costs of electricity. To do this, fuel, O&M, and replacement power costs must be taken into account.

TABLE III-1 BECHTEL PROJECT COST ESTIMATE

SUMMARY OF COST AND SCHEDULE FOR RESTORATION

NOTE: The preliminary assessment of potential cost and schedule for the TMI-2 recommissioning is summarized below. This specifically relates to the assumptions and qualifications stated in the Bechtel Report. As knowledge of the containment status improves, the cost and schedule assessment is subject to change.

Cost Estimate

		(Dollars in Millions)
A.	Clean-up and Radwaste Processing	33
B.	Re-entry and Hands-on Containment Decontamination	41
C.	Shielding, Rigging and Vessel Head Removal	5
D.	Core Inspection	2
E.	Fuel Removal and Disposition	23
F.	Vessel Internals Removal and RCS* Decontamination	9
G.	Requalification and In-Service Inspection (ISI)	5
H.	Reconstruction	26
I.	Refurbishment or Replacement of Major Equipment	15
J.	System/Component/Structure Modifications	Not Incl.**
K.	Analysis, Safety Assessment, Licensing and Other Services	40
L.	Miscellaneous and Radwaste Disposal	37
	Subtotal	236
	Contingency (33%)	79
	Total Containment Recovery Costs	315

Schedule Milestones

		Months From Containment Entry
o	Containment Re-Entry	0
o	Vessel Head Removal	11
o	Fuel Removal	20
o	RCS Decontamination	26
o	ISI Complete	32
o	Fuel Load	37
o	Commercial Operation	42

* Reactor Cooling System
** Depends on NRC licensing requirements

TABLE III-2 POTENTIAL COST ITEMS NOT INCLUDED IN BECHTEL ESTIMATE

Owner's costs, or those costs which are not associated with contracts and procurement of goods and services directly related to the TMI-2 recommissioning activities, are not included in this report. Examples of owner's costs (and potential credits) are:

- Replacement fuel costs are excluded.
- All Metropolitan Edison and GPU operating expenses (e.g., engineering, administration, overhead, etc.), except health physics and security, are excluded.
- Cost of federal, state or local permits and licenses are excluded.
- Cost of replacement power is excluded.
- Financing costs are excluded.
- Professional services such as legal, financial, etc., are excluded.
- Potential insurance reimbursements are not considered.
- No credit has been taken for unburned energy in the spent fuel.
- Although many items procurred for the TMI-2 recommissioning could have significant salvage value, no credit for temporary equipment is assumed.

TABLE III-3 TMI-2 CASH FLOWS (as incurred)

a. TMI-2 Returned to Service as Nuclear Unit (880 MW)

YEAR	EXPENDITURE	INSURANCE RECOVERY	NET COST
1979	$ 95	$ 36	$ 59
1980	130	121	9
1981	100	71	29
1982	60	72	(12)
1983	10	-	10
1984	5	-	5
	$400	$300	$100

b. TMI-2 Cleanup & Decontamination Portion

YEAR	EXPENDITURE	INSURANCE RECOVERY	NET COST
1979	$ 95	$ 36	$ 59
1980	130	121	9
1981	30	71	(41)
1982	8	35	(27)
	$263	$263	0

c. TMI-2 Restoration Portion

YEAR	EXPENDITURE	INSURANCE RECOVERY	NET COST
1979	$ 0	$ 0	$ 0
1980	0	0	0
1981	70	0	70
1982	52	37	15
1983	10	0	10
1984	5	0	5
	$137	$ 37	$100

TABLE III-4 GILBERT PROJECT COST ESTIMATE

TMI-2 FOSSIL FUELED STEAM SUPPLY CONVERSION

	Base Case Coal Firing	Alternative Case Gas Firing Initial 5 yrs.	Alternative Case Coal Firing After 5 yrs
Net Capacity MW	1352	1375	1352
Commercial Operation Date for Project Start July, 1980	1/87	10/86	1/92
(1) Installed Cost (Millions) Including Escalation and AFDC	1,365	833	1,640
(1) Installed Cost ($/kW) Including Escalation and AFDC	1,010	606	1,213

NOTES:

(1) All costs are escalated and include AFDC to the commercial operation date. The costs for the alternative case with later coal firing include a 5 year delay in the construction of the coal firing facilities outside the boiler house.

(2) Does not include $12 million necessary for development of ash and sludge disposal site.

TABLE III-5 CASH FLOW OF TMI-2 CONVERSION
CAPITAL COSTS (COAL FIRED ONLY)

($ Millions)

YEAR	1/80 COSTS	ESCALATION*	AFDC**	TOTAL FLOW
1980	4.9	0.2	0.2	5.3
1981	22.1	2.7	1.3	26.1
1982	69.5	14.8	5.5	89.8
1983	167.3	51.8	17.2	236.3
1984	238.6	99.0	39.3	376.9
1985	191.3	101.0	65.9	358.2
1986	116.3	74.4	81.7	272.4
TOTALS	810.0	343.9	211.1	1365.0

* Calculated from 1/80 to mid point of year at 8% per year, compounded annually.

** Calculated from mid point of year to the end of the year for current year's costs (or the start of current year to end of current year for all prior years' total flow) at 7.4% per year, compounded semi-annually.

TABLE III-6 CASH FLOW OF TMI-2 CONVERSION CAPITAL COSTS (GAS-FUTURE COAL)

($ Millions)

YEAR	1/80 COSTS	ESCALATION*	AFDC**	TOTAL FLOW
1980	4.7	0.2	0.2	5.1
1981	15.6	1.9	1.0	18.5
1982	43.3	9.2	3.7	56.2
1983	99.5	30.8	10.8	141.1
1984	147.7	61.3	24.4	233.4
1985	109.0	57.6	40.4	207.0
1986	75.2	46.6	49.9	171.7
TOTALS	495.0	207.6	130.4	833.0

CASH FLOW OF CAPITAL COSTS (CONVERT GAS TO COAL)

YEAR	1/80 COSTS	ESCALATION*	AFDC**	TOTAL FLOW
1987	3.0	2.3	0.2	5.5
1988	12.1	11.2	1.3	24.6
1989	41.8	45.1	5.5	92.4
1990	189.7	236.2	25.0	450.9
1991	82.4	113.5	37.7	233.6
TOTALS	329.2	408.3	69.7	807.0

* Calculated from 1/80 to mid point of year at 8% per year compounded annually.

** Calculated from mid point of year to the end of the year for current year's costs (or from start of current year to end of current year for all prior years' total flow) at 7.4% per year, compounded semi-annually.

TABLE III-7 CASH FLOW OF OFFSITE COAL CAPITAL COSTS

(as incurred, with AFDC)

Seward Unit 7 and Coho Unit 1
Both In Service - 1987 - 1250 MW

YEAR	COST ($ MILLIONS)	
1979	12.2	(incl. prior years)
1980	5.8	
1981	80.0	
1982	146.0	
1983	268.0	
1984	410.0	
1985	530.0	
1986	210.0	
1987	45.0	
	1707.0	

TABLE III-8 SUMMARY OF CASH FLOWS* ($ MILLIONS)

(incl. AFDC, where applicable)

	Fix TMI-2	Convert TMI-2 Coal	Convert TMI-2 Gas/Coal		Replace TMI-2 (Seward 7, Coho 1)	
1979	0	0	0		12	('79+prior yrs)
1980	0	5	5		6	
1981	70	26	19		80	
1982	15	90	56		146	
1983	10	237	141		268	
1984	5	377	233		410	
1985	0	358	207		530	
1986	0	272	172		210	
1987	0	0	6		45	
1988	0	0	25		0	
1989	0	0	92		0	
1990	0	0	451		0	
1991	0	0	233		0	
Total	100	1365	1640	(833 for gas portion)	1707	
Difference From Fix	---	1265	1540		1607	
MW Level	880	1352	1375 1352	(gas-fired) (coal-fired)	1250	
Startup	1/1/84	1/1/87	10/1/86		1/1/87	

* All cases exclude the costs for cleanup and decontamination, which are common to each and covered by insurance. The conversion options do not include the $12 million cost of the ash and sludge disposal site.

IV. THE COMPARISON

In this chapter, the alternatives are compared on the basis of electricity costs in two ways. The first comparison briefly contrasts the cost of electricity produced over the first ten years of operation for each plant arrangement, i.e., the restored nuclear unit, the converted coal plants, and offsite coal capacity. The calculated costs include recovery of investment (depreciation) with interest and earnings, taxes, fuel and inventory costs, and operation and maintenance (O&M). Since timing and capacity levels differ among the options, the second approach compares the alternatives in a more consistent manner by:

a) having the same amount of capacity installed by 1987 in each case; and

b) supplying, through generation and replacement power purchases, the identical annual quantities of electricity from 1984 through 1996.

By taking this approach, the ramifications of differences in timing, capacity levels, production, and corresponding replacement power requirements can be identified. The effects of changes in basic cost and schedule assumptions are also highlighted. The assumptions and component costs used throughout the comparison are summarized in Appendix D.

PLANT ALTERNATIVES

The average costs of electricity produced from each plant over the first ten years of operation are summarized in Table IV-1. The two values given are the arithmetic average and the "levelized cost"* more commonly used in economic comparisons of power plants. The latter puts more emphasis on costs incurred in the early years.

The "restore" results include recovery of the original \$710 million investment in TMI-2 plus the \$100 million estimated net cost of fixing the unit. The values for conversion reflect recovery of the new investment, including the \$12 million cost of the ash and sludge disposal site, <u>and \$290 million of the original TMI-2 investment</u>. This is the initial cost of the TMI-2 facilities (cooling towers, turbine-generator, switchyard, etc.) that are potentially useful to the converted plant. The offsite replacement costs do not reflect recovery of any TMI-2 investment.

*The levelized cost represents the price which would have to be charged over the time period in question so that the "present value" of total revenues equals the present value of total costs, including interest and earnings.

All the non-nuclear alternatives have electricity costs roughly double the value for restoring the unit. Among the conversion options, the initial gas-firing approach has a modest advantage (7-10%) over direct coal conversion. This advantage is due mainly to the higher level of electricity production assumed during gas-firing (85% capacity factor versus 58% typical of coal and nuclear plants). The coal conversion and offsite coal options are nearly identical in terms of electricity costs. Thus, the advantages of using existing, therefore cheaper, facilities for part of the plant is roughly compensated for by the expense associated with unique design features in the layout of the converted unit.

To put the cost differences into perspective, the amount of additional capital which could be spent in restoring TMI-2 before electricity costs exceeded the non-nuclear values is also given in Table IV-1. The capital cost of restoring TMI-2 could increase by $1450-1700 million, 14-1/2 to 17 times the estimated net cost of restoration, before electricity costs would reach the levels calculated for coal conversion and offsite coal replacement. Increases of $1150-1450 million could be justified vis a vis the gas/coal option. These equivalency values are a useful way to bound the allowable "margins for error" in capital cost estimates.

ALTERNATE EXPANSION PLANS

While the preceding comparisons are helpful, they do not show the cost consequences of schedule and capacity level differences which influence replacement power requirements. To overcome this shortcoming, the options were modified so that ultimate capacity levels and annual electricity supply for 1984 through 1996 are the same in all cases:

a) Case 1 (Restore) - in addition to the return to service of the 880 MW reactor in 1/1/84, a 472 MW coal plant was added in 1/1/87, the earliest possible date, so that capacity installed reached the 1352 MW level of the coal conversion case. (This does not mean that a 472 MW would actually be built but, instead, places all options on a consistent capacity basis.)

b) Case 2 (Coal Conversion) - no change in capacity level and timing was made; however, purchases of replacement power equal to the output of Case 1 in 1984-6 were included;

c) Case 3 (Gas/Coal Conversion) - same as Case 2, except the additional electricity generated during gas firing, in excess of the amount the coal conversion case would produce, is "sold"; and

d) Case 4 (Replace-Offsite Coal) - the two 625 MW coal plants were increased in size to 676 MW each so that total installed capacity equaled 1352 MW. As in Cases 2 and 3, replacement power was purchased in 1984-6.

The replacement power requirements and assumed cost for replacement power are summarized in Table D-7, Appendix D. The values for purchase power costs are projections based on the operating characteristics and surplus power availability of the entire Pennsylvania-New Jersey-Maryland Interconnection (PJM), a power pooling organization comprised of GPU and other Mid-Atlantic utilities. These costs are projected to increase sharply during 1984-1996 as a consequence of escalating oil prices and the reduction and eventual elimination of PJM's present excess capacity condition.

The average cost of electricity for each case is broken down by major contributing components in Table IV-2.

The capital costs of the coal units in Cases 1 and 4 were calculated using the same $/KW cost given for Seward 7 and Coho 1 in the last section, namely, $1707 million for 1250 MW or $1366/KW. (Other cost assumptions are detailed in Appendix D.)

The estimated costs differ from the individual plant values previously calculated. The 7.60¢/Kwh cost for Case 1 is higher than the 5.55¢/Kwh value cited earlier in this chapter because of the contribution of the relatively more expensive 472 MW coal unit. On the other hand, the results for Cases 2-4 are lower since replacement power costs in 1984-6 are less than the cost of production from 1987 on, bringing the average down. Even with these modifications, Case 1 retains a sizable economic advantage over the other options. This advantage would grow with time since a smaller proportion of nuclear costs (fuel, O&M) are prone to escalation.

Using Case 1 (restore) as a benchmark, Table IV-3 summarizes the potential cost penalties incurred by a typical residential customer (500 Kwh monthly usage: no electric heat or hot water) of each of our operating utilities if Case 1 were not pursued. The effects of a three year delay in restoring TMI-2 to service and a

1 1/2 year slippage in start-up of the converted coal plant are also shown, in each case yielding a penalty of a third of a dollar per month for each year of delay.

The extra costs for not selecting Case 1 are sizable, ranging from $4.25 to $5.50 a month for a Met-Ed customer. This would amount to $660 to $860 over the thirteen year period, and would continue to increase after 1996. (While averages are used here for convenience, the year by year penalties grow with time.) The impacts are greatest for a Met-Ed customer because Met-Ed owns 50% of TMI-2 (versus 25% each for Jersey Central and Penelec) and has fewer customers, i.e., lower total projected sales. Since the penalty would apply to each KWH of sales, the additional costs which all customers of Met-Ed would pay over the thirteen year period would equal nearly $1.5 billion for Case 2 and over $1.6 billion if the converted plant were delayed 1-1/2 years.

There is a large margin for error in meeting cost and schedule targets for restoring TMI-2 to service as a nuclear unit. This is evident in Table IV-4, where the required increase in investment for restoring TMI-2 before reaching the electricity costs of the other options is given. When compared to the next least costly option (Gas/Coal Conversion), a \$1250 million increase could be absorbed by Case 1 before the customer penalty reaches the \$4.25 level. Even if the unit were delayed three years, the increase which would yield \$4.25/mo. is \$1150 million. These values contain no allowance for delays or cost increases in the converted plant.

In summary, the economic comparison is overwhelmingly in favor of restoring TMI-2 as a nuclear plant. The non-nuclear options are comparable in costs, with the gas/coal conversion option having a modest advantage over the others. The large economic advantage of refurbishing TMI-2 allows considerable margin for error in meeting cost and schedule targets for restoring the unit, with the additional advantage of keeping new investment requirements to a minimum.

TABLE IV-1 ALTERNATE PLANT ELECTRICITY COSTS

	CASE 1 (RESTORE)	CASE 2 (CONVERT-COAL)	CASE 3 (CONVERT-GAS/COAL)	CASE 4 (REPLACE-OFFSITE COAL)
Average Cost in ¢/Kwh over first 10 years	5.55	11.90	11.10	12.05
Levelized Cost in ¢/Kwh over first 10 years	5.60	11.55	10.25	11.75
Change Required in Capital Investment of "Restore" Option Before Electricity Cost is Equivalent to Alternative	----	$1450-1700 Million	$1150-1450 Million	$1500-1700 Million

NOTE: 1) Costs include recovery of capital with interest and earnings, taxes, fuel and O&M costs. The composite cost of money used for present valuing is 13%.

2) The value for Case 1 includes recovery of original $710 million investment plus $100 million needed to restore. The conversion cases include recovery of $290 million of the TMI-2 investment, the value of the portions of the original plant that would be used in the converted facility.

3) Capacity factor equal to 0.58 for all cases, except during gas-firing phase of Case 3 when a value of 0.85 is assumed.

4) For the capital investment changes, the higher value is based on average cost while the lower value is the levelized result.

TABLE IV-2 COMPONENT COST SUMMARY (¢/KWH) (1984-1986)

	CASE 1*	CASE 2	CASE 3	CASE 4
84-6 Purchase Power Cost	0	1.20	0.95	1.20
87-91 Purchase Power Cost (Credit)	0	0	(1.90)	0
Capital Recovery, Taxes, and Inventory Costs	4.30	4.40	4.40	4.90
Fuel	2.15	4.00	6.15	3.80
O&M	1.15	1.55	1.00	1.35
Total Average Cost	7.60	11.15	10.60	11.25
Levelized Cost	7.15	10.30	9.45	10.50

*The contributions to the total average cost of 7.60¢/Kwh arising from the 472 MW coal plant are:

1.70 for capital, etc.;
1.35 for fuel; and
0.50 for O&M.

TABLE IV-3 AVERAGE INCREASE IN CUSTOMER'S MONTHLY ELECTRIC BILL (1984-1996)
(500 KWH's used per month)

	MET-ED	JERSEY CENTRAL	PENELEC
Case 1, 1/1/84 Return	Base	Base	Base
1A, 1/1/87 Return	$0.96	$0.31	$0.36
Case 2, 1/1/87 Startup	$5.04	$1.60	$1.89
2A, 6/1/88 Startup	$5.52	$1.75	$2.07
Case 3, 10/1/86 Startup	$4.23	$1.34	$1.58
Case 4, 1/1/87 Startup	$5.19	$1.65	$1.94
TOTAL SALES (84-96) (millions of KWH's)	147,800	232,560	197,420

TABLE IV-4 CONDITIONS FOR ELECTRICITY COST EQUIVALENCE
(Case 1 versus alternatives)

	Case 2 (Convert-Coal)	Case 3 (Convert-Gas/Coal)	Case 4 (Replace-Offsite Coal)
Change required in Capital Investment of "Restore" option before electricity cost is equivalent to alternative			
Base - Restore TMI-2 1/1/84	$1500 million	$1250 million	$1550 million
Restoration Delayed to 1/1/87	$1400 million	$1150 million	$1450 million

V. THE STRATEGY

Two sets of factors must be considered in making a major decision: what is known about the situation and what is not known. Often these factors conflict, requiring a judgement as to which is the more important. Is the payoff worth the risk? What happens if estimates are wrong? This Chapter weighs the costs and benefits of the TMI-2 options against the risks and uncertainties associated with each, and recommends a course of action which best meets the needs of our customers and the corporation.

The key known and unknown factors are:

1) The major financial commitment to the selected option should occur in early 1981, if schedules are to be met.

2) The decision on the restart of TMI-1, expected in early 1981, will help to establish whether restoring TMI-2 is a feasible option. If the undamaged TMI-1 is not allowed to restart, then assuming TMI-2 can be restored and allowed to operate is unrealistic. The TMI-1 licensing process now underway will help define the technical changes that would be required for TMI-2. It also

provides a forum for airing the views of GPU, Federal, state and local governments, and the public on this controversial issue.

3) The need to restore or replace TMI-2 is clear, given present and future demand for electricity. Ideally, GPU could keep two or more of the options on track while awaiting the outcome of the TMI-1 licensing hearings. However, GPU's current financial condition may preclude this approach. Indeed, the need to purchase replacement power, one of the main causes of our financial problems, puts a premium on reducing these purchases as early as possible.

4) While no known technical factors have been identified which would foreclose restoring TMI-2 to service, the technical feasibility of this option will not be known with confidence until after a first hand inspection has been made inside the reactor building and the pressure vessel. Initial indications of conditions within the reactor building are promising.

5) The earliest and least expensive option from the viewpoint of our customers (electricity costs) and the corporation (investment) is restoring TMI-2 to service. When compared to the alternatives, there

is a large margin for error in meeting cost and schedule targets before the benefits of this option would be eliminated.

6) All the non-nuclear alternatives have comparable economic consequences. While costs are similar, the risks and uncertainties are not. The conversion options have a number of issues not shared by the offsite coal alternative which could undermine their practicality. Also, the reliability of operation for a converted unit is a major unknown, since it would be a "first of a kind" on such a large scale.

In light of these considerations, the following strategy is recommended as the course of action which best fulfills GPU's responsibilities to its customers and stockholders:

1) Commit to restoring TMI-2 to service as the best option, even with its considerable risks and uncertainties. This commitment would be reinforced by a favorable decision on restarting TMI-1. Under these circumstances, the primary condition which would reverse this commitment is if restoration is found to be technically infeasible after first hand inspection within the containment building.

2) If TMI-1 is not allowed to restart <u>or</u> restoring TMI-2 is found to be impractical for other reasons, then redirect GPU's resources, to the extent possible, to building offsite coal plants to replace TMI-2 (and TMI-1, if necessary) as the next best course of action. Continue with the cleanup and decontamination of TMI-2. At the same time, retain the conversion option for possible future use. Attempt to reduce or eliminate the present uncertainties associated with conversion, especially the initial gas-fired approach.

The selection of the offsite coal option as the second best choice is supported by an additional strategic advantage. If difficulties in financing both plants arise, at least one plant might be completed on schedule. Financing limitations would force the delay of <u>all</u> of the capacity represented by the conversion option if that were the selected approach.

APPENDIX A

SUMMARY OF BECHTEL REPORT ON CLEANUP, DECONTAMINATION AND RESTORATION OF TMI-2

GENERAL PUBLIC UTILITIES SERVICE CORPORATION

THREE MILE ISLAND UNIT 2

CONTAINMENT RECOMMISSIONING

PRELIMINARY ASSESSMENT

OF

POTENTIAL COST

AND

SCHEDULE

BECHTEL JOB 13587-003

GENERAL PUBLIC UTILITIES SERVICE CORPORATION
THREE MILE ISLAND UNIT 2
CONTAINMENT RECOMMISSIONING
PRELIMINARY ASSESSMENT OF POTENTIAL COST AND SCHEDULE
BECHTEL JOB 13587-003

GENERAL PUBLIC UTILITIES SERVICE CORPORATION
THREE MILE ISLAND UNIT 2
CONTAINMENT RECOMMISSIONING
PRELIMINARY ASSESSMENT OF POTENTIAL COST AND SCHEDULE
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NOTE

A CAUTIONARY NOTE IS WARRANTED REGARDING THE USE OF THE COST AND SCHEDULE ASSESSMENT PRESENTED WITHOUT PROPER CONSIDERATION PAID TO THE ASSUMPTIONS AND QUALIFICATIONS STATED HEREIN. SINCE CONTAINMENT RE-ENTRY HAS NOT BEEN MADE AT THE TIME OF THIS ASSESSMENT, MANY UNCERTAINTIES EXIST. AS KNOWLEDGE OF THE STATUS OF THE CONTAINMENT IMPROVES, SO CAN THE ACCURACY OF THE COST AND SCHEDULE ASSESSMENT. FINDINGS COULD BE MUCH DIFFERENT FROM THOSE CONDITIONS ASSUMED AT THIS TIME, AND COULD RESULT IN LOWER OR HIGHER COSTS AND/OR A SHORTER OR LONGER SCHEDULE THAN SHOWN.

I. GENERAL

GENERAL PUBLIC UTILITIES SERVICE CORPORATION
THREE MILE ISLAND UNIT 2
CONTAINMENT RECOMMISSIONING
PRELIMINARY ASSESSMENT OF POTENTIAL COST AND SCHEDULE
BECHTEL JOB 13587-003

I. GENERAL

This preliminary assessment of potential cost and schedule for the recommissioning of the Three Mile Island Unit 2 containment building and systems is based on a very preliminary evaluation of the extent of damage and contamination to the materials, components and structures inside the containment. Since no entry has been made into the containment at this time, the evaluation is highly specualtive. In order to arrive at a basis for the estimate and schedule, a review has been made of the available information developed by GPUSC, B&W, the NRC and the Bechtel Containment Engineering Group. This information is summarized in Section II, Assumptions and Qualifications.

It is assumed that proper safety assessments will be performed and necessary regulatory approvals will be obtained in a timely manner needed to support the recovery plan.

The scope of this estimate includes efforts related to re-entering and cleaning up the containment, including waste disposal; removing and disposing of the fuel; refurbishing or replacing in-containment systems, structures, and components; and preparing the unit for restart. No allowances have been made for potential plant modifications which might be required prior to returning the unit to service. Potential costs are discussed in Section VII.

The schedule shown in Section IV includes three phases and support activities as follows:

- Phase I Containment Re-entry and Decontamination
- Phase II Reactor Coolant System (RCS) Cleanup
- Phase III Reconstruction and Recommissioning

Phase I involves maintaining the long-term cooling of the unit and cleaning and processing of the contaminated water in the auxiliary building, the containment sump and the reactor coolant system. It also includes preparation for re-entry, the re-entry and data acquisition tasks, and decontamination of the inside of the containment.

Phase II involves preparations for and removal of the reactor vessel head, inspection of the core, removal of the fuel and vessel internals and decontamination of the reactor coolant system.

Phase III involves requalification testing and in-service inspection of the reactor coolant and safety systems, replacement or refurbishment of components and materials, replacement of vessel internals, preoperational testing, loading fuel and startup testing.

Support activities for each phase will involve the resolution of safety issues, completion of plant modifications needed to satisfy the licensing review for recommissioning of TMI-2, and disposition of radioactive materials and spent fuel.

GENERAL PUBLIC UTILITIES SERVICE CORPORATION
THREE MILE ISLAND UNIT 2
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PRELIMINARY ASSESSMENT OF POTENTIAL COST AND SCHEDULE
BECHTEL JOB 13587-003

SUMMARY OF COST AND SCHEDULE

NOTE: The preliminary assessment of potential cost and schedule for the TMI-2 recommissioning is summarized below. This specifically relates to the assumptions and qualifications stated in Section II. As knowledge of the containment status improves, the cost and schedule assessment is subject to change.

Cost Estimate

		(Dollars in Millions)
A.	Cleanup and Radwaste Processing	33
B.	Re-entry and Hands-on Containment Decontamination	41
C.	Shielding, Rigging and Vessel Head Removal	5
D.	Core Inspection	2
E.	Fuel Removal and Disposition	23
F.	Vessel Internals Removal and RCS Decontamination	9
G.	Requalification and In-Service Inspection	5
H.	Reconstruction	26
I.	Refurbishment or Replacement of Major Equipment	15
J.	System/Component/Structure Modifications	Not Incl.
K.	Analysis, Safety Assessment, Licensing and Other Services	40
L.	Miscellaneous and Radwaste Disposal	37
	Subtotal	236
	Contingency (33%)	79
	Total Containment Recovery Costs	315

Schedule Milestones

		Months From Containment Entry
o	Containment Re-Entry	0
o	Vessel Head Removal	11
o	Fuel Removal	20
o	RCS Decontamination	26
o	ISI Complete	32
o	Fuel Load	37
o	Commercial Operation	42

NOTE: Reader is cautioned that the application of the above information should be subject to the caveat on Page 1.

II. ASSUMPTIONS AND QUALIFICATIONS

II. ASSUMPTIONS AND QUALIFICATIONS

The cost estimate and schedule is significantly influenced by the many factors which cannot be precisely defined at this time. It is expected that the information presented herein will be modified as new data is developed. Among the major factors affecting cost and schedule are the following:

1). The amount of isotopic inventory in the containment,

2). the ability to requalify major components for reuse, and

3). the extent of plant modifications required to restart TMI-2

In order to arrive at this conceptual estimate, the following specific assumptions have been made:

- o Work will proceed on two, 10-hour shifts per day, seven days per week using the "rolling four 10's" as discussed in Section VI.
- o Systems, components and structures installed to accommodate plant cooldown, cleanup and reconstruction are considered temporary and will be removed prior to return of TMI-2 to commercial operation.
- o Extraordinary political or legal actions will not be a major hinderance to TMI-2 recommissioning.
- o The reactor pressure vessel, primary loop piping, reactor coolant pump casings, steam generators and pressurizer will not require replacement.
- o Supports, bolts, studs and embeds for major components of the nuclear steam supply system will be adequate for reuse.
- o Most of the cable tray can be left in place and reused.
- o All of the containment wire, cable and conduit will be replaced.

GENERAL PUBLIC UTILITIES SERVICE CORPORATION
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PRELIMINARY ASSESSMENT OF POTENTIAL COST AND SCHEDULE
BECHTEL JOB 13587-003

- All containment instrumentation will be replaced.
- Containment piping will generally be adequate with some replacement of hanger components, snubbers, etc.
- Most of the metal reflective insulation can be reused.
- No sharing of Unit 1 systems or facilities will be permitted.
- Offsite radwaste disposal is assumed to be in the Western United States (i.e., maximum transportation cost is assumed).
- An offsite fuel processing or storage repository will be available.
- The containment can be purged in accordance with the release limits contained in the original plant technical specifications.
- Limits on tritium releases will not impact the schedule for radwaste processing.
- Worker radiation dose limits will be as presently stated in accordance with federal regulations and plant health physics procedures.
- New construction involving radwaste processing systems or for the storage of radwaste will require flood protection.
- High level waste processing systems will be installed in seismically designed structures.
- Future contract labor cleanup cost of the auxiliary building is not included.
- The cost estimates are escalated approximately ten percent per year through 1981, the anticipated center of gravity of the work.
- Contractor services (water, power, etc.) are to be provided by Metropolitan Edison and their costs are not included in the estimate.

GENERAL PUBLIC UTILITIES SERVICE CORPORATION
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Owner's costs, or those costs which are not associated with contracts and procurement of goods and services directly related to the TMI-2 recommissioning activities, are not included in this report. Examples of owner's costs (and potential credits) are:

- Replacement fuel costs are excluded.
- All Metropolitan Edison and GPU operating expenses (e.g., engineering, administration, overhead, etc.), except health physics and security, are excluded.
- Cost of federal, state or local permits and licenses are excluded.
- Cost of replacement power is excluded.
- Financing costs are excluded.
- Professional services such as legal, financial, etc. are excluded.
- Potential insurance reimbursements are not considered.
- No credit has been taken for unburned energy in the spent fuel.
- Although many items procurred for the TMI-2 recommissioning could have significant salvage value, no credit for temporary equipment salvage is assumed.

III. COST ESTIMATE

GENERAL PUBLIC UTILITIES SERVICE CORPORATION
THREE MILE ISLAND UNIT 2
CONTAINMENT RECOMMISSIONING
PRELIMINARY ASSESSMENT OF POTENTIAL COST AND SCHEDULE
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III. COST ESTIMATE

The TMI-2 containment recommissioning costs are presented as twelve separate estimates covering the three work phases. Although there is little definitive information available, qualitative or quantitative descriptions are provided for the major cost components. The scope does not represent the only basis for recommissioning the containment, but does describe a reasonable concept for the purpose of this cost estimate, given the qualifications and assumptions in Section II.

A. Cleanup and Radwaste Processing

The cost for this current long term cooling and radiation management phase includes the emergency measures associated with plant cooldown, the installation of radwaste processing systems, and remote decontamination utilizing the containment spray system.

1. Plant Cooldown Provisions and other Emergency Operations

   Auxiliary building charcoal filter trains
   Condenser air ejector filtration
   Auxiliary diesel generators
   Spent fuel pool tankage
   Auxiliary decay heat removal system
   Steam generator B closed loop cooling
   Alternate RCS pressure control system

2. Liquid Waste Processing Capability (10 GPM minimum)

   Evaporator
   Calciner
   Filtration and resin demineralizers
   Solidification and drumming systems
   Processed water storage (four 250,000 gallon tanks)

During this phase it will probably be necessary to process up to 3,000,000 gallons of contaminated water, including water that is recycled from the containment sump, and the remote steam, chemical, and water sprays recycled through the containment spray system.

Because the processing of waste will be accomplished at a faster rate than the capability for off-site shipment and disposal, interim on-site staging of packaged radwaste will be necessary. The following items are included for this:

High level waste staging facility - 5,000 square feet
Intermediate level waste staging facility - 25,000 square feet
Outside protection area for low level
radwaste interim storage - 80,000 -100,000 square feet

Estimated Cost $ 33 Million including

680,000 craft hours
140,000 supervision hours

B. Re-Entry and Hands-on Containment Decontamination

Containment re-entry and decontamination costs include the construction of service-related facilities, the removal of contaminated components which cannot be reused, radiation mapping, data acquisition, and hands-on cleanup of the entire containment:

1. Service Facilities

Personnel hatch No. 2 contamination control structure
Containment equipment hatch contamination control and service building
Containment equipment hatch personnel access control facility
Contaminated dry cleaning facility
Shielding materials
Material handling equipment
Installation of in-containment decontamination service systems and facilities

2. Containment Decontamination

Health physics training of all workers
Anti-contamination clothing and breathing apparatus
Lighting and communication systems
Shielding, robotics, and special tools
Rags, mats, and cleaning solutions

GENERAL PUBLIC UTILITIES SERVICE CORPORATION
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3. Contaminated Equipment Removal

Containment air coolers
Ductwork
Refueling machines
Fuel storage racks
Valve operators
Conduit, wire, and instrumentation
Letdown coolers

It is assumed that decontamination activities will create approximately 1,000,000 gallons of liquid waste. Equipment removal and decontamination waste materials are expected to generate about 400,000 cubic feet of dry compacted waste.

Estimated Cost — $ 41 Million including

750,000 craft hours
150,000 supervision hours

C. Shielding, Rigging and Vessel Head Removal

In order to remove the reactor vessel head it may require shielding provisions above the reactor vessel head, the steam generators, and the pressurizer. Installation of a working trolley on the polar crane and erection of a rigging platform with special tools for CRD unlatching and head detensioning are also included. Final reactor head cleaning may be accomplished utilizing a decontamination tank or a shielded area around the head storage stand at elevation 347' in the containment.

Estimated Cost — $ 5 Million including

40,000 craft hours
8,000 supervision hours

D. Core Inspection

Core inspection needed to support fuel removal and anticipated historical documentation of post-incident core status will be done primarily by operators, engineers and technicians. (Cost with Section K). Estimated costs included with this operation are for procurement and installation of TV cameras, videotape systems, borescopes, fiber optic devices and special instrumentation.

Estimated Cost — $ 2 Million including

30,000 craft hours

E. Fuel Removal and Disposition

It is assumed that the fuel and debris will be placed in shipping cans for shipment in standard spent fuel casks and transported to an off-site fuel processing/storage repository. Other options may be pursued such as storing the fuel in the on-site storage pool, in order to defer the costs of fuel shipping and disposal. For this estimate special activities associated with reactor fuel removal and disposition are:

1. Special Tooling

    Loose fuel and debris removal tools
    Underwater vacuum
    Large and small piece handling tools
    Stuck fuel assembly tools
    Loose piece shipping cans
    Large piece shipping cans
    Fuel assembly and control rod shipping cans

2. Fuel Pool Modifications

    Remove fuel transfer equipment
    Install fuel assembly and fuel debris canning station
    Install fuel staging area
    Install fuel assembly cask loading station

3. Shipment and Disposal of Fuel

    Acquire fuel assembly casks
    Acquire loose fuel disposal casks
    Obtain satisfactory repository, implement a satisfactory disposition procedure and ship fuel pieces

Estimated Cost $ 23 Million including

20,000 craft hours
8,000 supervision hours

F. Vessel Internals Removal and RCS Decontamination

Following fuel removal, the steam generators will be cleaned of debris. The reactor head will then be reinstalled and the reactor coolant system chemically flushed. Following chemical flushing, the internals will be removed and further decontaminated prior to refurbishment or disposal.

Total reactor coolant system flushing and chemical cleaning is expected to produce approximately 3,000,000 gallons of liquid radwaste.

It is planned to remove, decontaminate, and either rewind (for re-use) or dispose of the reactor coolant pump motors during this phase. Special packaging and transportation provisions for the oversize and overweight pieces, have been considered in preparing the estimate.

Steam generator tube sheets and tubes will also be inspected and repaired at this time.

Estimated Cost — $ 9 Million including

50,000 craft hours
10,000 supervision hours

G. Requalification and In-Service Inspection

Most activities associated with this phase will be carried out here by technical services peiple. Costs included are for procurement of the ISI tooling and inspection equipment, field inspection, the ILRT and SIT testing, and craft labor support for the inspection and testing technicians.

Estimated Cost — $ 5 Million including field services and miscellaneous support of

20,000 craft hours
8,000 supervision

H. Reconstruction

Major containment reconstruction will take place following removal of the fuel and includes the following major activities:

1. Refurbishment of reactor coolant system components and reinstallation of major components noted in the following section.

2. Reinstallation of the containment air coolers and associated ductwork.

3. Installation of electrical items:

   Wire and cable
   Conduit
   Lighting and communications
   Penetrations
   Motors
   Electronic instrumentation

4. Inspection, repair, or replacement of mechanical equipment such as spring hangers, snubbers, isolation valves actuators, instruments, letdown heat exchangers, and other active mechanical components.

5. Reinstallation of reflective insulation removed for in-service inspection.

6. Surface preparation and recoating of the containment.

7. Replacement of spent fuel storage racks.

8. Support activities and construction materials required in the performance of the work.

<u>Estimated Cost</u> <u>$ 26 Million</u> including

680,000 craft hours
140,000 supervision hours

I. <u>Refurbishment or Replacement of Major Equipment</u>

Subject to the findings of the requalification analysis and inspection program, it is anticipated that refurbishmentment (and in some cases, possibly replacement) of certain major components may be necessary. The long lead time for major components may warrant initiating procurement activities, even if inspection later reveals the components can be reused. Major components considered are:

Reactor coolant pump motors and impellers
Reactor internals
Reactor pressure vessel head
Control rods, drive mechanisms and associated cabling
Pressurizer safety and relief valves
In core instrumentation
Fuel handling machines

<u>Estimated Cost</u> <u>$ 15 Million</u>
(based on purchase of new equipment)

J. System/Component/Structure Modifications

No allowances have been made at this time for modifications which may be required to recommission TMI-2. A list of potential modifications is outlined in Section VII.

K. Analysis, Safety Assessment, Licensing and Other Services

For the purposes of this estimate, which predates detailed planning for Phase II (reactor coolant system cleanup) and Phase III (reconstruction and recommissioning), an allowance has been made for various technical and other related project support activities. Among the categories for which contract support may be required are the following:

Nuclear Steam Supply System (NSSS) reanalysis
Requalification analysis
Safety analysis and licensing
Waste management
In-service inspection
Quality assurance
Technician support for core inspection and fuel removal
Decontamination procedures
Offsite laboratory analysis
Support of public hearings
Reanalysis of balance-of-plant systems
Engineering to support reconstruction
Preoperational and startup testing
Planning, scheduling and cost estimating
Management of construction services
Procurement services

Estimated Cost $ 40 Million including

1,100,000 services manhours

L. Miscellaneous and Radwaste Disposal

The principal cost for these support activities are:

1. Additional health physics requirements for Unit 2

2. Additional Unit 2 plant security

3. Shipment and disposal cost of radioactive waste

4. Removal of temporary facilities

Estimated Cost $ 37 Million including

180,000 craft hours
40,000 supervision hours
400,000 security force hours
400,000 health physics hours

IV. SCHEDULE

GENERAL PUBLIC UTILITIES SERVICE CORPORATION
THREE MILE ISLAND UNIT 2
CONTAINMENT RECOMMISSIONING
PRELIMINARY ASSESSMENT OF POTENTIAL COST AND SCHEDULE
BECHTEL JOB 13587-003

IV. SCHEDULE

The schedule assumes that a somewhat conservative approach is taken with respect to containment cleanup and radwaste processing and to core inspection and fuel removal. This is intended to anticipate performance of work inside the containment in a manner which is in accordance with maintaining worker radiation dose "as low as reasonably achievable" (ALARA).

Major milestones have been established and are discussed below.

1. Containment Reentry

   Since it is predicted that at 8 months following the incident about 1.0×10^6 curies of radioactive fission products, exclusive of noble gases and airborne iodine, would be in the containment sump, the reactor coolant system, or plated out, containment reentry for the purposes of accomplishing detailed radiation surveys, data acquisition and containment decontamination would not be made until the following have been accomplished:

   - the containment has been purged
   - the water presently in the containment sump has been removed and processed
   - the reactor coolant system has been flushed
   - attempts have been made to remotely decontaminate the containment (e.g., using the containment sprays).

2. Vessel Head Removal

   Because of the high level of contamination expected throughout the containment, vessel head removal would not be made until the following have been accomplished:

   - the 305' and 347' floors have been sufficiently decontaminated to allow full time occupancy of the containment (with full-face respirators)
   - the 282' floor has been decontaminated to levels which minimize significant recontamination of the upper floors

- the polar crane has been inspected and placed in a serviceable condition or the trolley replaced

- sufficient shielding placed or the refueling cavity flooded to reduce radiation levels near the reactor vessel head to acceptable levels

3. Fuel Removal

It is assumed that significant core damage has been experienced and that much of the fuel will have to be handled with special tooling, placed in shipping containers and shipped to a processing/storage repository. It is not possible to define this task until core inspection has been performed. However, for the purpose of the scope for the cost and schedule associated with this activity, the following is assumed:

- 40% intact fuel assemblies

- 30% damaged fuel assemblies

- 25% disassembled fuel assemblies

- 5% largely destroyed fuel assemblies

4. Reactor Coolant System Decontamination Complete

It is assumed that some fuel or debris from the core has been distributed into other parts of the reactor coolant system, such as the bottom of the reactor vessel and the steam generator upper tube sheets. The reactor coolant system decontamination phase includes the following:

- Removal of the reactor vessel lower internals

- cleanup of the bottom of the vessel

- cleanup of the steam generator tube sheets and tubes

- removal of the reactor coolant pump motors and impellers

- chemical decontamination of the reactor coolant system

5. Inservice Inspection Complete

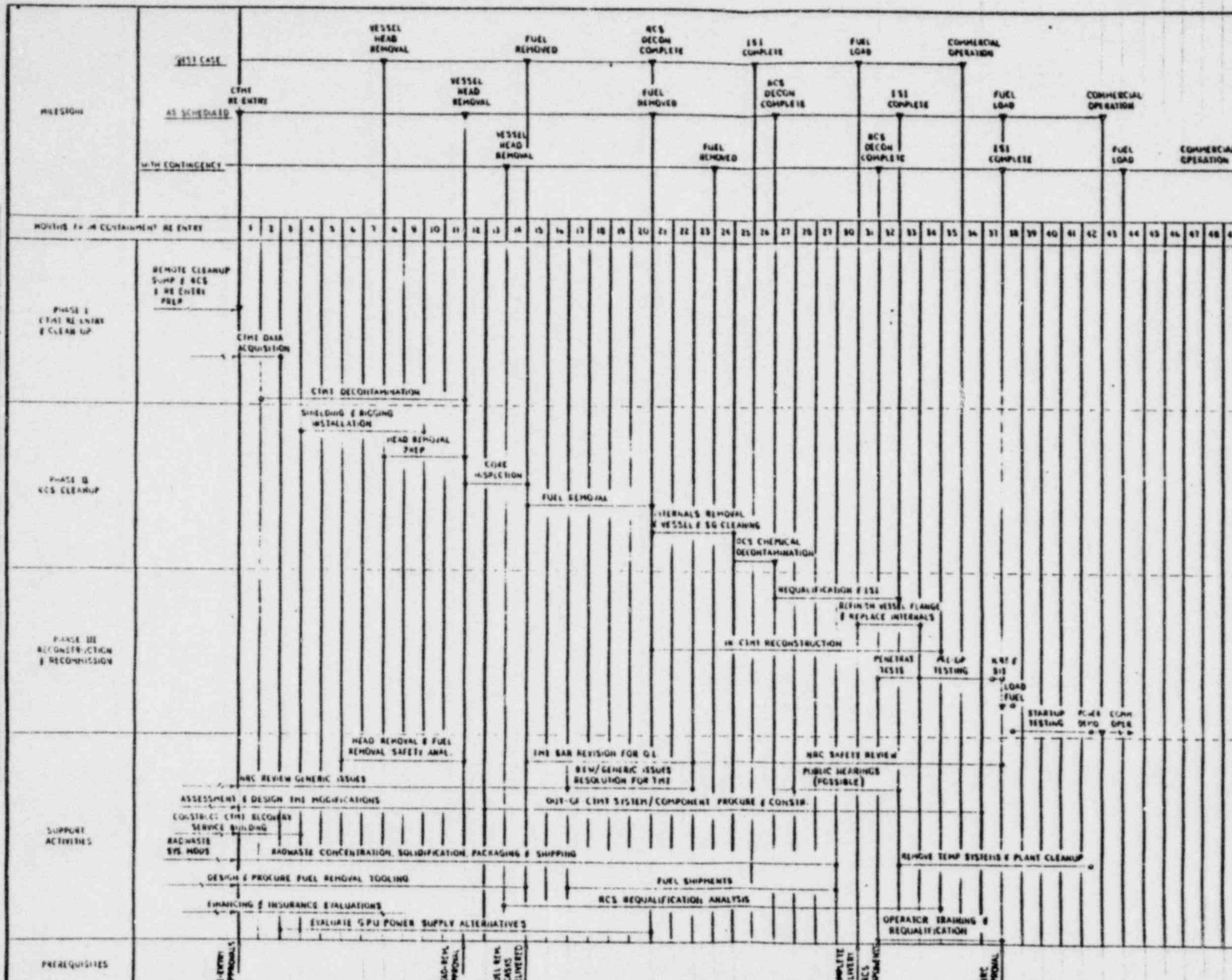
The reactor coolant system components and piping will be inspected for requalification. This inspection will be complemented by extensive supporting analysis. As noted in Section II, it is assumed that the major nuclear steam supply system components can be requalified and will not have to be replaced.

6. Fuel Load

It is assumed that fuel load will not take place until preoperational testing, containment integrated leak rate testing, inservice inspection, operator training, and the NRC safety review have been completed.

7. Commercial Operation

After startup testing has taken place and the power demonstration run has been made, commercial operation would be declared (per schedule information supplied by GPUSC).



NOTES

1. UNIT 1 CONSIDERED SEPARATELY.

2. CONTAINMENT RE ENTRY MILESTONE IS ASSUMED TO BE THE POINT WHERE DETAILED RADIATION SURVEYS, DATA ACQUISITION & DECONTAMINATION ACTIVITIES CAN BEGIN

ISSUED FOR COMMENTS

BECHTEL

GAITHERSBURG MARYLAND

GENERAL PUBLIC UTILITIES CORP.
METROPOLITAN EDISON

FIGURE 1-1
THREE MILE ISLAND UNIT 2
CTMT RECOMMISSIONING PLAN

13587-003 SK THI/CPE-7

V. CASH FLOW

GENERAL PUBLIC UTILITIES SERVICE CORPORATION
THREE MILE ISLAND UNIT 2
CONTAINMENT RECOMMISSIONING
PRELIMINARY ASSESSMENT OF POTENTIAL COST AND SCHEDULE
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V. CASH FLOW

The TMI-2 containment recommissioning cash requirements are predicated on the recovery schedule, manpower levels, anticipated engineering and procurement activity, and a uniform allocation of contingency. It is assumed that processed radwaste will be continuously shipped offsite during the cleanup and that the fuel will not be stored at the site prior to disposal. Changes in any of these conditions or other schedule perturbations would affect the anticipated cash flow.

GENERAL PUBLIC UTILIT' ERVICE CORPORATION
THREE MILE ISLAND UNIT 2
CONTAINMENT RECOMMISSIONING
CASH FLOW

(Dollars in Millions)

Cost Category	Prior to * CTMT Entry	Year After Containment Reentry							Total
		Year 1				Year 2	Year 3	Year 4	
		1st Qtr	2nd Qtr	3rd Qtr	4th Qtr				
A. Cleanup and Radwaste Processing	21	8	4						33
B. Reentry and Cleanup		6	9	9	8	9			41
C. RPV Head Removal					1	4			5
D. Core Inspection						2			2
E. Fuel Removal and Disposal						14	9		23
F. Internals Removal and RCS Cleanup						7	2		9
G. Requalification							5		5
H. Reconstruction						3	20	3	26
I. Major Equiment Purchase		1	1	1	1	3	8		15
J. System Modifications (not included)									--
K. Analysis, Safety Assessment, Licensing	11	3	4	4	4	9	3	2	40
L. Miscellaneous (Including Radwaste Disposal)	8	4	4	4	4	9	3	1	37
	40	22	22	18	18	60	50	6	236
Contingency	13	7	7	6	6	20	18	2	79
Total	53	29	29	24	24	80	68	8	315

* Subject to variance, depending on timing of containment reentry.

VI. SUPPORT INFORMATION

GENERAL PUBLIC UTILITIES SERVIEE CORPORATION
THREE MILE ISLAND UNIT 2
CONTAINMENT RECOMMISSIONING
PRELIMINARY ASSESSMENT OF POTENTIAL COST AND SCHEDULE
BECHTEL JOB 13587-003

VI. SUPPORT INFORMATION

1. Pricing Basis

Where possible, pricing is based on historical costs, current site conditions (i.e., wages ....), existing price schedules, and other published data. Certain cost allowances have also been used where scope definition is uncertain. All current (1979) pricing has been escalated at ten percent per year for approximately two years. Highlights of the significant pricing items are as follows:

Composite Manual Labor Rate: $23.00 per hour

Includes escalated composite wages, overtime, shift differential, supervision.

Engineering and Technical Service Rate: $36.00 per hour

Includes wages, per diem, travel, computer services and other engineering materials, and overhead and profit.

NSSS Component Replacement Cost:

B&W purchase order pricing (1976 basis) plus 60% escalation.

Other Component Replacement Cost:

TMI-2 historical cost (1974-75 basis) plus 80% escalation.

Radwaste Transportation: $ 7,000 per trip

Based on round trip rates for standard weight shipments to the western United States; escalated approximately 20%.

Radwaste Disposal:

Based on current disposal rates escalated 20%; high level waste rates not available, allowed $200 per cubic foot.

Liquid Waste Processing $2.00 per gallon

Includes cost of chemicals, detergents and the operational cost of the evaporators, demineralizers, etc.

Miscellaneous Tools and Supplies: Included at $3.00 per hour

Fuel Shipment and Disposal: $225 per kilogram

Based on DOE estimate (escalated) for a one time charge to receive and store spent fuel with no credit allowed for the unburned energy in the fuel.

2. Schedule Basis

The TMI-2 containment recommissioning schedule and assessment are dependent on site labor conditions. It is assumed that work will be done under the President's Agreement, rolling 4 day work weeks with 2 ten hour shifts. The two shift work operations are intended to make worker levels manageable and efficient; while achieving 7 day work weeks for critical path operations.

It is expected that health physics planning and decontamination procedures will be designed to manage exposure limits, reduce turnover, and maintain good worker morale and productivity.

The total decontamination and reconstruction effort will require approximately 3,000,000 hours of craft labor and site supervision, and 1,100,000 engineer and technical service hours. A manpower loading chart, shown in this section was used as the basis for the cash flow information presented in Section V.

3. Contingency Analysis

Contingency, as used in this assessment, is defined as an amount which should be added to the direct estimate to provide for uncertainties which exist within the estimate. The addition of the contingency to the direct estimate results in a current best estimate of that portion of the cost of recommissioning the TMI-2 containment covered in the scope of this assessment as described in Sections I, II, and III. These uncertainties are a result of the preliminary nature of the scoping details, the potential for pricing changes, and the assessment of productivity as discussed below.

Contingency has been assessed after a review of the following items:

a. Productivity

This is subject to variance depending upon conditions in the containment (radiological, environmental, access space, etc.), administrative controls (health physics, security, etc.), support required (shielding, scaffolding, materials handling into and out of the containment, etc.), worker dose limits and radiation levels, timely availability of special materials and equipment and many other items which could impact work plans.

b. Pricing

This is subject to variance depending on contract provisions such as expediting delivery of critical items, composite wage rate having a different mix than assumed (for the technical support as well as for the manual craft support), and other items which could affect the pricing basis.

c. Scope Detail

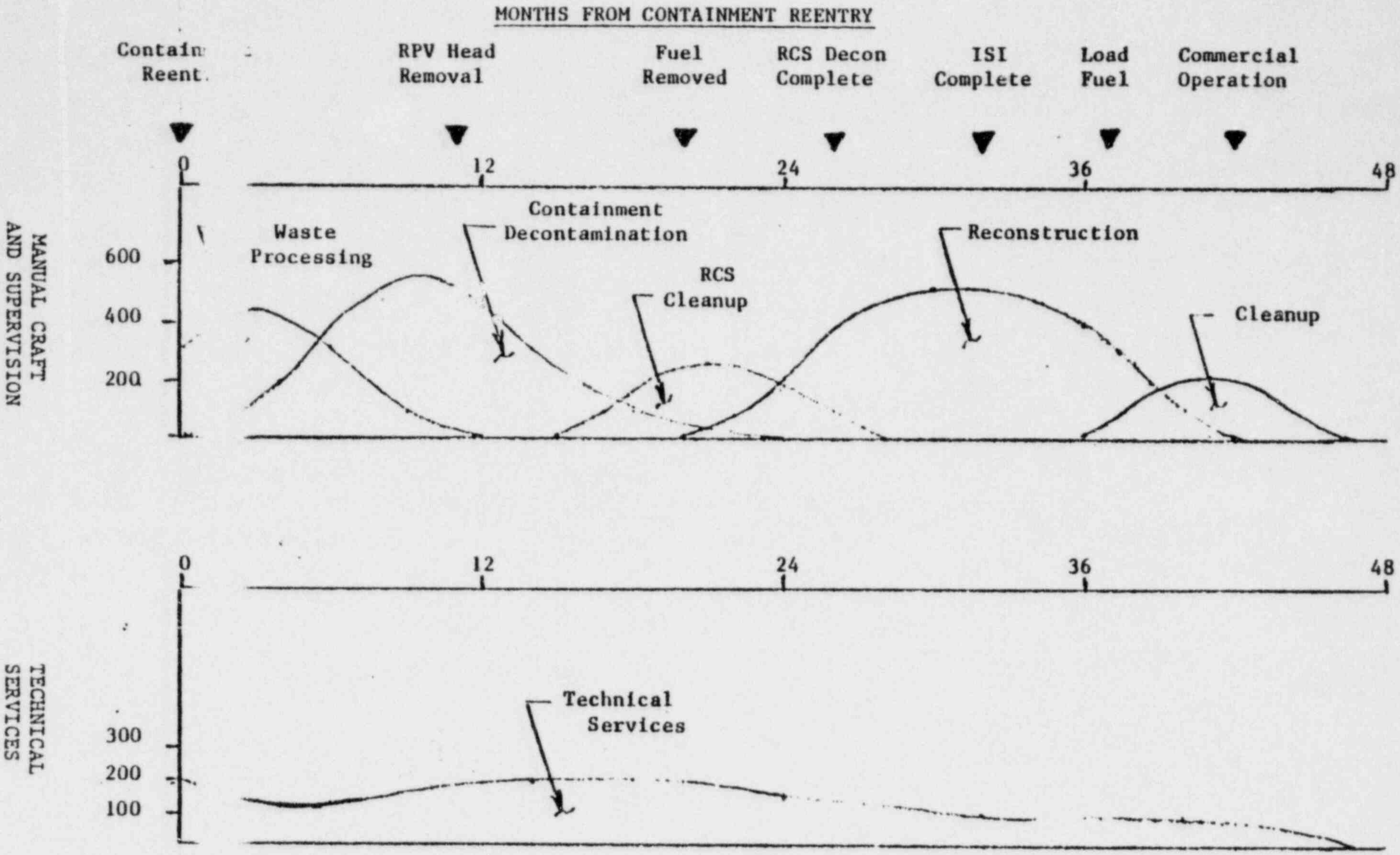
This is subject to variance as the recommissioning plan evolves. As knowledge of the status of the containment improves, alternate methods than those presented in this assessment may become necessary or may be more viable. Particular uncertainties exist at this time regarding processing, packaging and shipping of radwaste products; service systems and structures required for containment decontamination; methods required for decontamination; methods for handling, packaging and shipping of spent fuel; the amount of required reconstruction in the containment (e.g., wire and cable, equipment, recoatings, etc.); and, the types and amount of supporting technical and analytical assistance required for recommissioning.

4. Radwaste Processing/Disposal Quantities

The radwaste processing/disposal chart was used to estimate the volume and type of radwaste which is expected to be processed, shipped and disposed of at an off-site burial facility. Since the methods for on-site processing have not been completely defined and tested at this time, the quantities are subject to change.

5. Core Damage Assessment

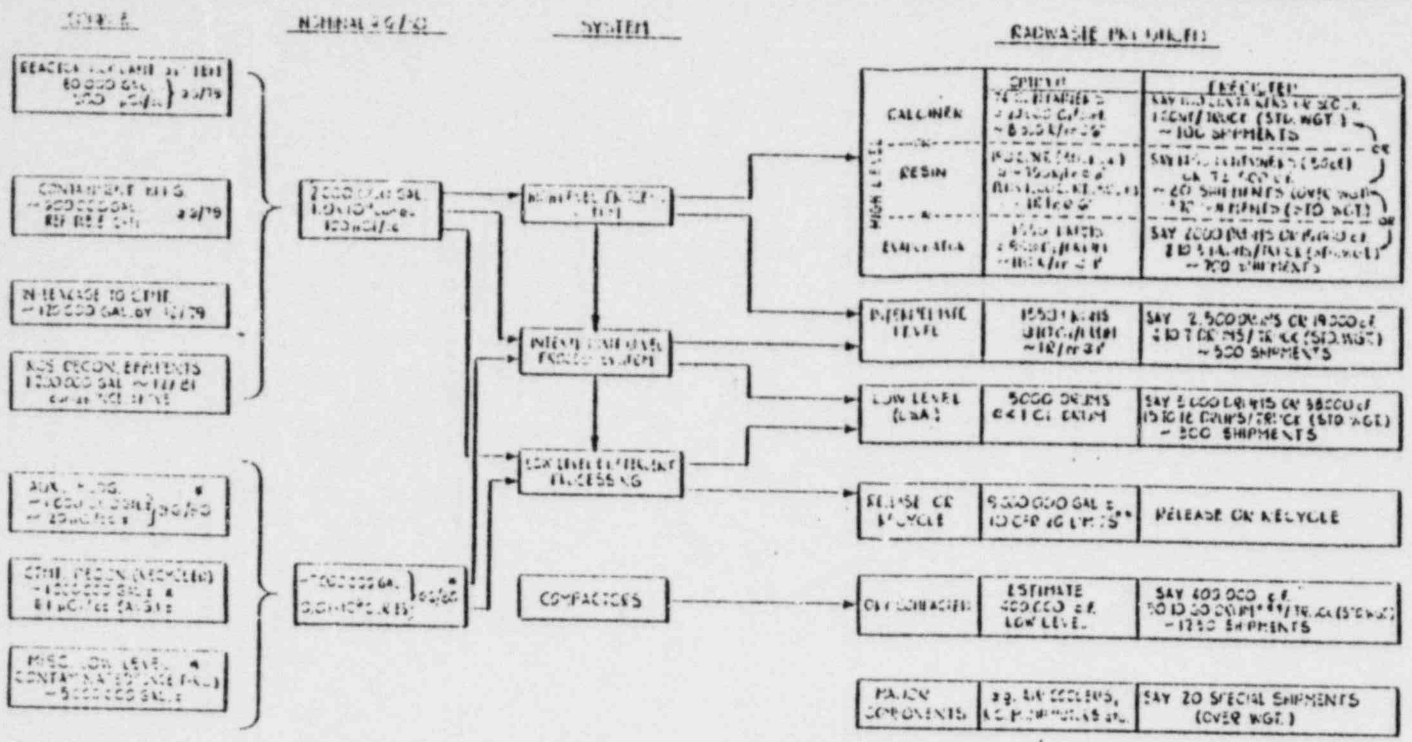
A review was made of available information from B&W, GPUSC, and the NRC in order to develop the schedule duration to be allowed for core inspection and fuel removal. For the purposes of this estimate and schedule, the core status as discussed in Section IV, Item 3 has been assumed.



TMI-2 CONTAINMENT RECOVERY

MANPOWER LOADINGS

CRAFT/SUPERVISION AND TECHNICAL SERVICES



* - VOLUME AND SPECIFIC ACTIVITY SUBJECT TO LARGE VARIANCE, HOWEVER DOES NOT SIGNIFICANTLY AFFECT RADWASTE PRODUCED.
** - TRITIUM CONCENTRATIONS WILL GOVERN RATE RELEASED.
*** - OR EQUIVALENT BOXED.

BECHTEL

GENERAL PUBLIC UTILITIES CORP.
METROPOLITAN EDISON
THREE MILE ISLAND - UNIT 2

FLOWCHART - CONTAINMENT RADWASTE PROCESSING/DISPOSAL
FIG. 4-4

SK TMI/CRE-5

VII. POTENTIAL COST AND SCHEDULE ITEMS

GENERAL PUBLIC UTILITIES SERVICE CORPORATION
THREE MILE ISLAND UNIT 2
CONTAINMENT RECOMMISSIONING
PRELIMINARY ASSESSMENT OF POTENTIAL COST AND SCHEDULE
BECHTEL JOB 13587-003

VII. POTENTIAL COST AND SCHEDULE ITEMS

Many factors are very uncertain at this time which may have significant impact on the ultimate cost and/or schedule. Among these are:

1. Radiation Conditions

   Noble gas release technical specification revisions which may or may not require special treatment beyond filtration and release.

   Possible fuel debris in the RCS which may limit access to steam generator heads and pressurizer.

   Reactor coolant drain tank and letdown heat exchanger radiation levels which require additional in-place shielding.

   Radiation levels at containment air coolers which may require special removal casks.

2. Corrosive Structural Damage

   Reactor, steam generator and pressurizer base plates and anchor bolts which may require refurbishment.

   Other embedments and structural support components which may have possible deterioriation.

   Major components (e.g., reactor vessel, steam generators) which may require extensive refurbishment for requalification.

Man-rem exposure limitations which may exhaust available manpower.

Critical crafts which may not be available to support reconstruction effort.

4. Licensing

Radwaste processing systems and other recovery support facilities which may require a construction permit and an operating license.

TMI-2 state and local issues which may impede the project's progress.

Resolution of Babcock & Wilcox generic issues which may not be supportive of the TMI-2 recommissioning schedule.

5. Legal and Political

Transportation restrictions which may involve special restrictions for TMI-2.

Fuel repository restrictions which may involve special considerations.

Processed waste disposal and discharge requirements which may involve special restrictions for TMI-2.

Injunctions and intervenor activity which may impact the TMI-2 recommissioning schedule.

6. New Plant Modifications

Many generic safety issues will be debated prior to the recommissioning of TMI-2. It is premature to attempt to quantify costs associated with modifications that may eventually be mandated by the NRC or deemed appropriate by GPU. Examples of such issues are contained in NUREG-0560, NRC Staff Report on the Generic Assessment of Feedwater Transients in Pressurized Water Reactors Designed by B&W, May 9, 1979, or modifications currently proposed for TMI Unit 1 by GPU.

APPENDIX B

SUMMARY OF GILBERT ASSOCIATES

PHASE II REPORT ON CONVERTING TMI-2

February 25, 1980

GAI Report No. 2102

TMI-2: A COAL BURNING PLANT?

SUMMARY OF A STUDY OF CONVERTING TMI-2 TO A FOSSIL-FUELED PLANT

SUBMITTED TO
GENERAL PUBLIC UTILITIES
SERVICE CORPORATION

BY
GILBERT ASSOCIATES, INC.

FOREWORD BY GPU SERVICE

Three Mile Island Unit 2 (TMI-2) is presently in the early stages of a clean-up program. This program must be completed prior to efforts being initiated to return this unit to service. There are presently no known technical factors that preclude successful decontamination and eventual reactivation as a nuclear unit. A GPU-commissioned study by Bechtel Corporation estimates that the cost of decontamination and reactivation will be approximately $400 million. About $275 million of this $400 million is associated with decontamination and clean-up of TMI-2 that would be necessary regardless of which of the courses of action described below is adopted. In the absence of extraordinary legal, political, or regulatory delays (which could also add to costs), the study indicated that decontamination and reactivation could be accomplished by some time mid-1983. However, since the condition of equipment within the reactor building remains uncertain until inspections can be made, the ability to reactivate the nuclear steam supply system cannot be considered a technical or economic certainty. For planning purposes, GPU is therefore undertaking a study of three possible courses of action regarding TMI-2:

1. Returning it to service as a nuclear unit.

2. Converting it to a fossil-fired steam supply system.

    a. with firing on Pennsylvania bituminous coal

    b. with firing on natural gas for an initial five year period followed by firing on Pennsylvania bituminous coal

3. Not reactivating this unit, and replacing it with other capacity such as new coal-fired units at other sites.

The results of an evaluation of these options will be presented in a separate "Major Commitment Review" prepared by GPU Service Corporation. This review is expected to be completed by April 1, 1980.

In order to develop detailed information on the cost and feasibility of the conversion of TMI-2 to a fossil fired unit, GPU commissioned Gilbert Associates, Inc. to perform a feasibility study of this option. The study was performed in two phases. A report describing the results of the Phase I effort was issued in October, 1979. The second report of which this is a summary, concludes the Phase II effort, providing a technical feasibility evaluation and plant cost estimates to support the in-depth evaluation of the coal conversion option for TMI-2. This report does not provide estimates of fuel costs, operating and maintenance costs, or the costs of environmental compliance. It should be emphasized that this report, in and of itself, is not sufficient to decide the attractiveness of the conversion of TMI-2 to a fossil fired unit. This judgement can only be made on a comparative basis, measuring the overall attractiveness of the conversion option against the attributes of the other two available options. It is this comparison of options that will take place in the GPU Major Commitment Review.

TMI-2: A COAL BURNING PLANT?

I INTRODUCTION

Three Mile Island Unit 2 (TMI-2), located near Harrisburg, PA is an 880-megawatt nuclear power plant. It is now out of service with a damaged nuclear reactor as a result of the accident that occurred on March 28, 1979. The unit is now in a cleanup and recovery program. However, the steam turbine area, cooling towers, and electrical switchyard were never damaged and are in operating condition. If it turns out not to be feasible to return TMI-2 to service as a nuclear plant, the unit could still be placed back in service if an alternative source of steam were available.

An electrical power plant, either nuclear or fossil, is a device to convert latent energy, in the form of fuel, into useful electric energy. Heat generated by burning fuel or splitting uranium atoms is used to heat water in either a boiler or a nuclear reactor. The heat transforms the water to steam, which is needed to energize the turbine-generator and produce electrical energy. This electricity is distributed over transmission lines to the utility's customers.

In July 1979, GPU Service Corporation commissioned Gilbert Associates, Inc. to perform a study to determine the technical feasiblity and capital cost of installing a fossil-fueled steam supply system for TMI-2 as a replacement for the nuclear reactor. This study was needed because engineering experience in fitting fossil-fuel boilers to turbines designed for nuclear service is very limited. The results of this study are to be used by GPUSC as input to a major commitment review of all options regarding the disposition of TMI-2. This report is a summary of the study, which is described in detail in Gilbert Associates Report No. 2071, "TMI-2 Coal Conversion Study, Phase II - Final Report."

II RESULTS OF THE CONVERSION STUDY

The conversion study concludes that installing two high-pressure coal-fired or two dual-fuel-fired (gas/coal) boilers with topping turbines to replace the damaged nuclear steam supply system is technically feasible, but would cost $1.4 billion and require six to seven years for design, licensing, construction, and startup. This cost is for initial operation on coal, and includes all onsite direct and indirect costs plus provisions for contingency, escalation (based on a December 1986, commercial operation date), and "allowance for funds used during construction." This cost excludes all decontamination, cleanup, and decommissioning costs associated with the nuclear facilities.

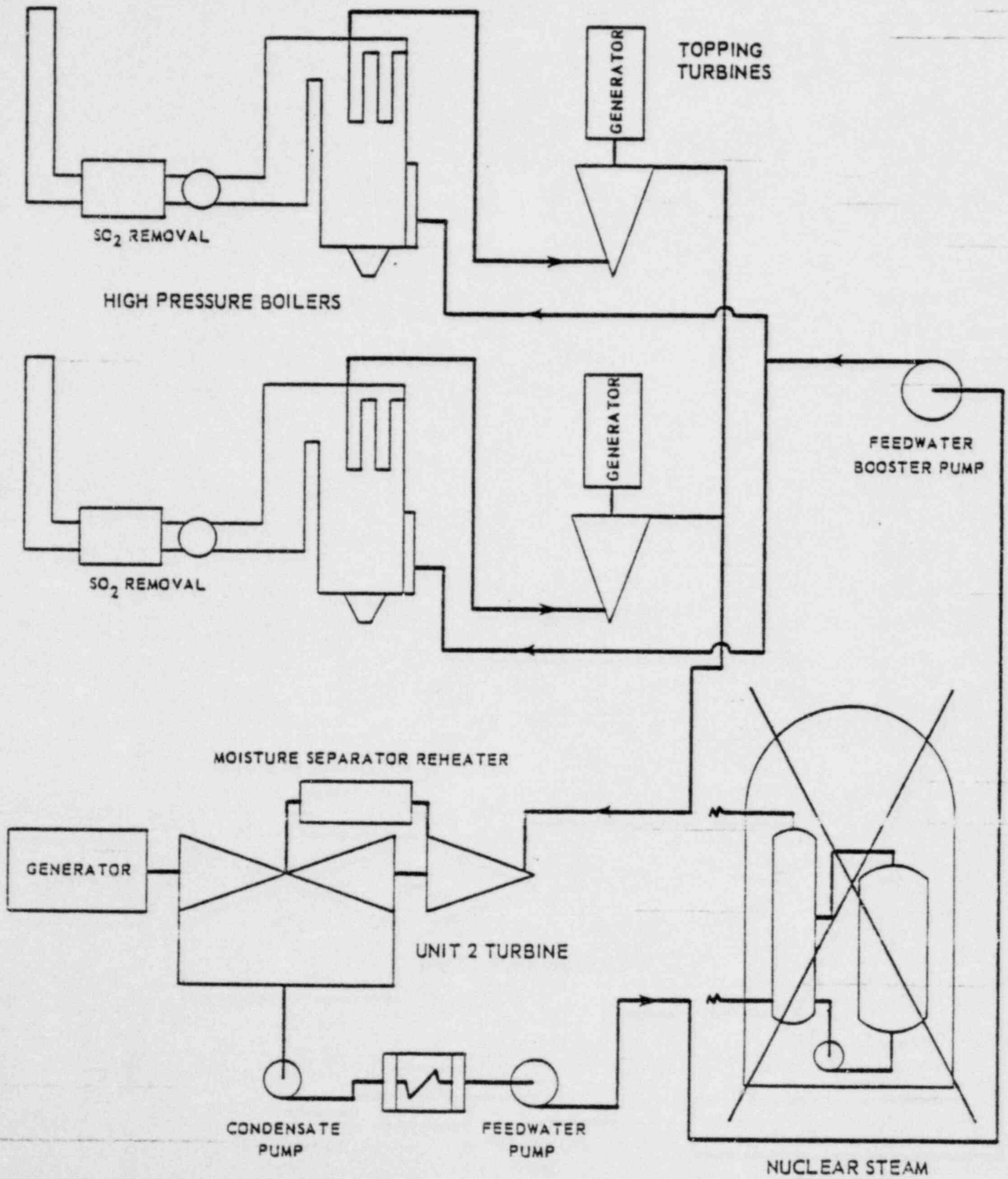
After such a conversion, TMI-2 would generate 1350 megawatts of electricity. The operating and maintenance costs would be close to those of other fossil-fueled power plants in the 1300-megawatt size range. Plant reliability and availability would also be comparable to other modern 1300-megawatt fossil-fueled power plants.

Technical Feasibility - The proposed steam supply installation consists of two high-pressure (3500 psig, $1000^{\circ}F$) boilers designed for either bituminous coal-firing or natural gas-firing. These boilers are teamed with two nominal 250-megawatt topping turbines feeding steam to the existing TMI-2 turbine. This is shown schematically in Figure 1. Space is available on the undeveloped southern half of Three Mile Island for the installation, including a coal storage pile.

Coal will be supplied from western Pennsylvania by unit train. Natural gas could be provided by pipeline if sufficient quantities can be obtained for initial (first five years) gas-fired operation.

Pollution controls, including particulate and sulfur dioxide (SO_2) removal systems, are required for coal-firing. SO_2 removal system byproducts can be trucked to a local storage site off the island.

TMI-2 COAL CONVERSION STEAM CYCLE



Schedule - Total project span including licensing, engineering, procurement, construction, and plant startup, from initial firm commitment to commercial coal-fired operation, is estimated at six to seven years. If an adequate supply of natural gas can be purchased, and a five year exemption to burn this gas under the federal Fuel Use Act obtained, then the total project span time could be reduced by about three months with all initial licenses and permits predicated on bituminous coal-firing.

Licensing feasibility requires successful resolution of several major issues: including meeting all applicable air quality standards in the Harrisburg area, getting FAA approval for a 500 to 700-foot high stack near the approaches to Harrisburg International Airport, land use for the plant itself and for ash and SO_2 removal system residue disposal, and proximity to an operating nuclear unit and to another nuclear reactor undergoing decommissioning.

Cost - The estimated capital costs (including buildings, equipment, construction, engineering, etc.) for the various alternatives are shown below. The first group shows total capital costs in current (January 1980) dollars. These figures do not include provisions for escalation or AFDC (allowance for funds used during construction) from current day to commercial operation. These would be the costs if the entire plant conversion could be accomplished in January of 1980.

	Current Cost	Net Output	Average Cost
1. Base case:			
a. Initial Coal-firing.	$810 million	1352 MW	$600/kW
2. Alternative case:			
a. Initial Gas-firing.	$495 million	1374 MW	$360/kW
b. Conversion from Gas to Coal-firing after 5 years.	$329 million	1352 MW	$243/kW
Totals	$824 million	1352 MW	$609/kW

Commercial Operation (C.O.) cost levels are shown next. These include all onsite direct and indirect costs plus a provision for escalation (inflation) and AFDC at assumed annual rates of 8 percent and 7.4 percent respectively. These costs correspond to expenditures made during a realistic construction schedule, from the start of the project to the date that the plant is declared to be in commercial operation.

	C.O.	Completion Cost	Net Output	Average Cost
1. Base case:				
a. Initial Coal-firing.	12/86	$1,365 million	1352 MW	$1,010/kW
2. Alternative case:				
a. Initial Gas-firing.	9/86	$833 million	1374 MW	$606/kW
b. Conversion from Gas to Coal-firing after 5 years.	9/91	$807 million	1352 MW	$597/kW
Totals	9/91	$1,640 million	1352 MW	$1,213/kW

The risk analysis performed for the cost estimates shows that they should be accurate to within ±12 percent for 80 percent of the instances evaluated. This does not cover uncertainties associated with the schedule, or projected escalation or AFDC rates.

III SCOPE OF THE CONVERSION STUDY

Phase I of the conversion study was an overview covering the technical feasibility of the conversion, including a conditional cost estimate for four different designs of coal-fired systems.

Phase II selected the most promising fossil-fueled steam supply system for continued and more detailed study. The 'base case' involves two boilers designed to fire either bituminous coal or natural gas, but is based on initial use of coal. The gas-firing capability would be designed into the system and used later if found advantageous.

An 'alternative case' involves the same two boilers as the 'base case,' designed to fire either bituminous coal or natural gas, but is based on the use of natural gas for the first five years of operation. All licensing would be based on coal-firing because it is unlikely that the plant could operate on natural gas for more than five years and because coal-firing is expected to have more severe environmental impacts. This increases the number and complexity of permits required. The actual construction of most coal and waste handling facilities would be deferred until after the plant begins operation on natural gas.

In both cases, the two topping turbines are used to feed steam to the existing TMI-2 turbine's main steam inlet piping. In both cases, coal-related equipment would be installed within the boiler buildings prior to initial operation.

Assumptions and Limits - The conversion study is based on maximum use of existing TMI-2 power generation and distribution facilities. The study includes development of plant design considerations with drawings and descriptions, capital cost estimates, the integrated licensing/engineering/construction schedule, and performance data for both the 'base case' (initial coal-firing) and the 'alternative case' (initial gas-firing). In addition, the results of an investigation of possible SO_2 removal system residue storage sites in the vicinity of Three Mile Island are discussed.

The conversion study assumes that all or most of the open area on Three Mile Island is available for the new installation. The study also assumes that the same soil-bearing condition exists in the new construction areas as is in the TMI-I area.

The conversion study does not include fuel cost evaluations, total cost evaluations or customer revenue requirements, evaluation of environmental impacts and associated costs in enough detail for licensing applications, or a detailed design effort. These items will be addressed in the GPUSC 'Major Commitment Review' or in future studies if it is decided to proceed with the conversion effort.

IV DESCRIPTION OF THE CONVERTED PLANT

TMI-2 as a coal-burning power plant could serve as a "baseload" unit intended to provide a steady source of electric power to the service area.

Steam Cycle - The converted plant is designed with a combination of two commercially available, high pressure, bituminous coal-fired boilers and topping turbines. It takes two boilers to supply the amount of steam required by the existing TMI-2 turbine. The steam comes from these boilers at a high pressure. Therefore, two topping turbines are also required to reduce the steam pressure for the existing low-pressure TMI-2 turbine.

Pollution Control - Coal-fired power plants require special pollution control systems to minimize environmental impacts. Effective air pollution control systems are particularly important. All coal contains sulfur ranging in amounts from less than 1 percent to more than 7 percent. The converted plant will burn medium-cleaned Pennsylvania bituminous coal with a 2.5 percent sulfur content and have a limestone sulfur dioxide (SO_2) removal or flue gas desulfurization system.

Sulfur dioxides are produced in the furnace. Should these oxides be released, they could combine with the moisture in the air and form harmful acids. The flue gas desulfurization (FGD) system removes the sulfur dioxide created during the combustion process. The SO_2 removal system is a wet limestone system with residue conditioning for offsite dry storage.

After the coal is burned, solid particles which are called fly ash remain. These particles are carried out of the boiler along with combustion gases. To meet current air quality standards, over 99 percent of the fly ash must be removed. This is accomplished by using electrostatic precipitators before the flue gas goes up the stack.

Stack height is an important pollution control factor. To meet current air quality standards, a stack height in the 500 to 700-foot range is required. Federal Aviation Administration (FAA) approval is needed since the height limit based on the TMI cooling towers is 360 feet. Increasing the stack gas temperature to 250°F could help reduce the required stack height a little, but would reduce plant efficiency.

Ash and SO_2 residue disposal is also part of the pollution control effort. A study was performed to identify and judge the suitability of potential solid waste disposal sites within a 20-mile radius of TMI. The site selection is made by screening out nonusable or problem locations on geographical area maps. Some typical 'exclusionary screens' include prime agricultural land, cities, boroughs, housing developments, area size, and rugged terrain. In the conversion study, six usable sites have been identified and their prominent features and highway access routes from TMI are described.

Use of Existing Electrical Facilities - In the converted plant, the existing 500 kV line running from TMI-2 to the existing switchyard could transport the power output from the two topping turbines as well as the existing nuclear turbine.

All auxiliary electrical supply systems required to operate the existing TMI-2 turbine rem[illegible] the converted plant. They are powered from the existing TMI-2 [illegible]ary transformer. All breakers on those motors associated with nuclear reactor operation are disconnected, locked, and tagged.

In the converted plant new control room, only manually-operated controls are duplicated. Any systems cabinets, hardware, and instrumentation not requiring manual operation for fossil plant operation remain in place in the original nuclear control room. New devices for operating existing plant equipment are located in the fossil plant's new control room.

Local controls in the existing turbine area remain in place, requiring plant operators to be located there when such controls must be manipulated.

Use of Existing Turbine Facilities - In the proposed conversion, the existing TMI-2 turbine, cooling towers, and switchyard are retained for service. Using them in combination with the two fossil-fired boilers is accomplished without any major changes to the existing equipment. The existing main steam and feedwater piping are connected to the new boilers. The existing cooling towers are used to provide cooling water to the new equipment. This eliminates the need for any change to the river water intake system. Makeup water for the SO_2 removal system will be taken from the discharge of the existing plant cooling water coolers.

Alternative Case: Initial Gas-Firing - Since natural gas currently appears to be available in sufficient quantity, it can be considered as an alternative fuel for the TMI-2 boilers for at least the first five years of operation. After five years, gas-to-coal conversion can be accomplished with a minimum service outage and with total air quality compliance.

The dual-fuel boilers will be constructed with all associated coal-firing equipment located within the plant. They will be ready for initial startup and this plan will avoid later boiler-building rework.

Coal-related systems and equipment located outside the boiler buildings can be scheduled for installation after commercial gas-fired operation has begun. This includes the coal yard, coal-handling systems, and the flue gas cleanup systems. In this alternative case, all systems and equipment are designed for dual-fueled operations.

Plant Arrangement on the Site - The topography of Three Mile Island forces a 'string-out' of buildings and equipment in a north-south direction. Several factors influence location of the boiler buildings with respect to existing facilities:

- The need to keep steam, water, and electrical lines as short as possible.

- The need to provide railroad trackage for an orderly construction and maintenance sequence proceeding from east to west.

- The need for construction laydown space.

- The need for minimal disturbance to existing facilities.

Thus, a location was selcted as close as possible to an existing southern dike, and easterly enough to be served with permanent and construction railroad trackage.

The new boilers and topping turbines are located to the south of the existing TMI-2 cooling towers. These form the "power block." The coal-handling systems are located to the south of the new boilers. The SO_2 removal (or FGD) system is located directly south and southwest of the boiler houses to shorten slurry lines to and from the gas scrubbers and associated equipment.

A 30-day coal pile with associated unloading and thawing facilities is located south of the FGD system.

A track loop, developed for a 6000-foot train of 100 cars and several engines creates an area for emergency storage of liquid SO_2 residue. Spurs off this track permit delivery of limestone for the FGD system and also provide service to the power block.

Dikes are extended for flood protection along the east and west sides of the island. The eastern dike is widened to accommodate truck traffic.

Coal conveyors enter the boiler area from the east, keeping the flue gas pollution control systems areas clear of construction interferences.

Rail access is provided to the turbine area on the west side of the converted plant.

In general, building the converted plant should require very little excavation.

APPENDIX C

ANTHRACITE COAL OPTION

TMI-2 COAL STUDY: ANTHRACITE OPTION

POSITION PAPER

GPUSC Corporate Planning
November, 1979

SUMMARY

The use of anthracite-fired boilers at Three Mile Island should not be considered as a viable option for returning any part of the TMI-2 investment to service. The adoption of such a strategy by GPU would result in excessive costs to its customers and would subject its stockholders to great potential liabilities.

The proposed anthracite option for TMI-2 would require from 2.2 to 2.9 million tons of anthracite per year, depending upon capacity factors. The existing anthracite industry cannot support this additional demand without nearly 100% expansion nor can present mining methods provide this additional volume in a cost-effective manner. New methods, previously untried in U.S. non-metal mining, will require that approximately 220 to 290 million dollars in capital be generated either directly or indirectly by GPU. The production secured by this capital investment could take from 10 to 15 years to develop and is estimated to cost $65/ton delivered. This estimate has been made for a "cost-plus" type contract where GPU takes all risks. A contract where the operator takes part or all of the risks will command a higher price commensurate with risk.

The advocation of the use of anthracite is admirable because of the potential to rejuvenate the economy of the Eastern Pennsylvania anthracite regions. However, it is not considered equitable for the customers of the GPU System to subsidize such a project when there are other options which will provide greater electric reliability at lower cost. The GPU System recognizes anthracite as a potential fuel whose use is socially desirable. GPU will continue to evaluate this fuel vs. other energy sources for future generating

stations. However, we will continue to place service to our customers above politics and will base our fuel plans upon this service cost to the customer.

INTRODUCTION

Following the accident at its Three Mile Island #2 (TMI-2) generating station, General Public Utilities (GPU) is investigating alternative actions to be used in returning all or part of TMI-2 to useful service to the customers of the GPU System. Among these alternatives are:

* a return to full service as a nuclear generating facility,
* construction of a bituminous coal-fired unit to be connected to the TMI-2 generator and electrical transmission gear (which would allow partial use of the existing facility), or
* construction of an anthracite-fired unit to be used in conjunction with existing generation and transmission equipment (which also would allow partial use of the existing facility).

These alternatives do not constitute all those being studied by GPU. However, the last one listed is of particular interest in this report. This position paper will review this last alternative, (that of building an anthracite-fired boiler at TMI-2), from the supply point of view. In this process, the study will address:

1) Potential Requirements of an Anthracite-Fired Boiler at TMI-2.
2) Anthracite Reserves and Availability of Supply.
3) Supply Development and Timing.
4) Estimated Cost of Anthracite, FOB TMI-2.

1) Potential Requirements of an Anthracite-Fired Boiler at TMI-2

The anthracite option considered in this report is "Option D" of the Gilbert/Commonwealth study performed to assess the cost and feasibility of alternative actions for returning all or part of TMI-2 to service. This option envisions the use of 13 industry-sized boilers with a cumulative heat rate of 11,900 BTU/KW-hr. and a cumulative capacity of 900 MWe. Based upon equation(1), Table I shows the amounts of anthracite required for capacity factors ranging from 60-80% (for anthracite with a quality of 13,000 BTU/lb.).

$$\text{EQ.(1) Tons/Yr.} = \frac{(8760 \text{ hrs/yr})\times(900{,}000 \text{ Kilowatts})\times(11{,}900 \text{ BTU/KW-hr})\times(\text{Capacity Factor})}{(13{,}000 \text{ BTU/lb.})\times(2{,}000 \text{ lb./Ton})}$$

TABLE 1

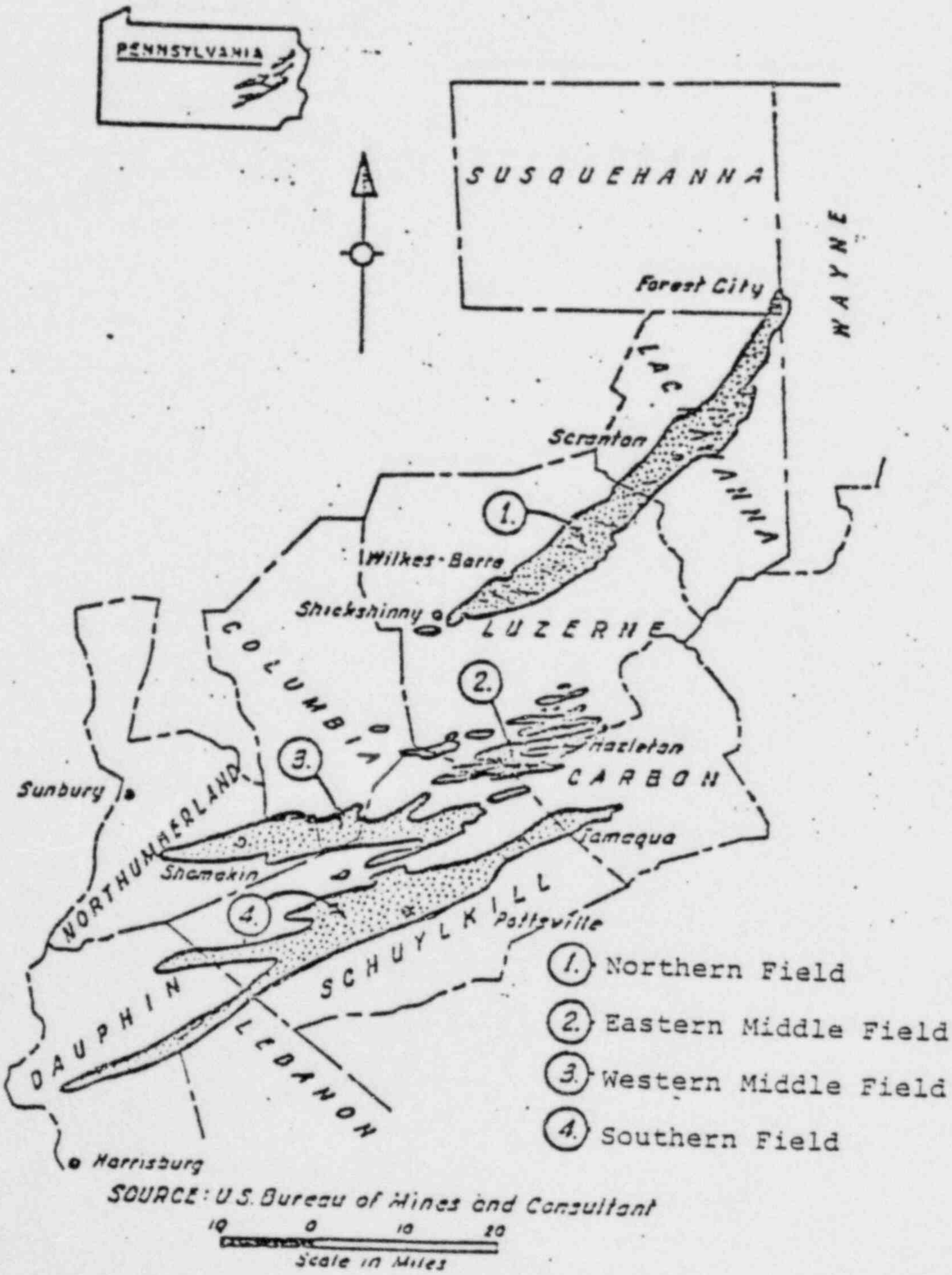
Capacity Factor	Annual Tons Required
60%	2,165,000
65%	2,345,000
70%	2,526,000
75%	2,706,000
80%	2,887,000

This annual requirement of from $2.2\text{-}2.9 \times 10^6$ tons must be met from anthracite strip mining production. This is dictated by the enormous expense of underground anthracite production and by the lack of reliability of culm bank and reclaim operations. If this additional tonnage is to be demanded of the anthracite industry, strip mining represents the most likely area for increased development.

Assuming a 35-year plant life, a 90% cleaning recovery of raw anthracite, and a 90% mining recovery of in-place reserves, Option D would require the dedication of from $93.5\text{-}124.7 \times 10^6$ tons (in-place) of anthracite which could be recovered by strip mining. For deep mining, with a mining recovery of 50%, the required reserves would swell to $168.4-224.5 \times 10^6$ tons. Culm bank recovery, with a 90% mining recovery and a 20% cleaning recovery, would require $421.0-561.4 \times 10^6$ tons of refuse as reserves and would yield large quantities of fine coal which could not be handled easily.

EXHIBIT 1

ANTHRACITE FIELDS OF NORTHEASTERN PENNSYLVANIA



from March 1975 report to U. S. Department of the Interior, Bureau of Mines; prepared by Berger Associates and A. B. Riedel Associates

EXHIBIT 2

Underground Anthracite Reserve Base
By County
January 1, 1974

MILLION SHORT TONS

COUNTY	28" to 42"	Over 42"	TOTAL
Carbon	48.86	46.94	95.80
Columbia	91.09	87.92	179.01
Dauphin	184.95	177.70	362.65
Lackawanna	186.30	178.99	365.29
Lebanon	229.24	220.24	449.48
Luzerne	304.09	292.19	596.28
Northumberland	366.69	352.30	718.99
Schuylkill	2,163.53	2,078.63	4,242.16
Wayne	1.23	1.18	2.41
Total	3,575.98	3,436.09	7,012.07

SOURCE: "The Reserve Base of Bituminous Coal and Anthracite for Underground Mining in the Eastern United States"

Bureau of Mines Information Circular 8655

ANTHRACITE FIELDS

Northern	176 square miles
Eastern Middle	33 square miles
Western Middle	94 square miles
Southern	181 square miles

2) Anthracite Reserves and Availability of Supply

Exhibits 1 and 2 show the location, content, and area of the anthracite reserves of Eastern Pennsylvania. By adjusting for anthracite produced from January 1974 through December 1977, a total reserve base of 6,998 x 10^6 tons is derived. This figure represents all in-place reserves in excess of 28 inches thick which lie within 1,000 feet of the surface. It must be realized that entire cities are underlain by these reserves and that the U.S. Bureau of Mines (USBM) reserve estimates do not address demographic and social impacts of mining. It should also be noted that the USBM estimates have nothing to do with economic mineability. They represent reserves for which the United States possesses the technology to mine.

While the distribution of anthracite reserves in more or less public knowledge, the ownership of these reserves is largely a mystery. Less than 150 million tons of anthracite reserves are identified by owner in the Keystone Coal Industry Manual. The Pennsylvania Governor's Energy Council states that most companies holding anthracite reserves consider this information to be proprietary. It may be possible to access this information. through visiting county courthouses in the anthracite regions. However, this effort may not prove justified in light of other findings of this report.

The projected requirements of the anthracite boilers in Option D represent from 70% to 93% of the anthracite produced by strip mining in 1977 (1977 strip production was 3.1 x 10^6 tons). In addition, anthracite strip production declined by 35% from 1967 to 1977. Thus, it would not appear that the needs of an anthracite unit at TMI-2 could be met by the current anthracite industry.

According to the Keystone Coal Industry Manual, there are only 17 anthracite strip operators (See Exhibit 3). Of these 17, two companies have recently been charged with price-fixing and probably should be avoided in any long-term coal supply contract. Of the remaining 15 operators, the largest produces less than 1×10^6 tons per year while 8 of the 15 produce less than 100,000 tons per year. Based upon this overview, it would appear that it would be necessary that GPU be willing to finance the establishment of an anthracite producing company which could meet the requirements of Option D. This might entail a joint venture arrangement with some company or companies which would hold enough anthracite reserves to meet the needs expressed previously. Such a joint venture would probably involve mining methods new to the Eastern Pennsylvania anthracite fields and would also involve a cost-plus-profit contract if the operator were unwilling to accept the risks in the venture.

EXHIBIT 3

	Size Range (Tons x 1000)	Comments
Beltrami	750-1,000 tpy	
Bethlehem	500-700	
C-L-S Coal	100-200	
F.J.&F. Coal	0-10	
Gale Coal	50-100	
Giza & Oley	0-10	
Glen Burn		Price-Fixing
Gowen Coal	10-50	
Jeddo-Highland		Price-Fixing
Kerris & Helfrick	100-200	
Kocher Coal	50-100	
Lehigh Valley Auth.	50-100	
Reading	500-700	
Rosini Coal	50-100	
Split Vein Coal	50-100	
Swatara Coal	100-200	
15 Strip Operators	2,410-3,570 tpy	

3) Supply Development and Timing

Proponents of the use of anthracite in large scale applications envision the use of surface mining as the most attractive method of producing large quantities of anthracite at costs less than large-scale deep mining ventures. The surface mining technique most often mentioned here is a variation of open-pit mining which is used in the copper and iron industry today. This open pit method would involve pits such as that shown in Exhibit 4.

Anthracite seams are steeply pitching (up to 90° relative to the horizontal) and lie in a series of "nested capital u's" (See Exhibit 5). An open pit, such as the one depicted in Exhibit 4, would move along the strike (or outcrop) of several such seams (indicated by arrows in Exhibit 4) and would extend to depths of 1,000 feet. Based upon the description of such a pit (made by Skelley & Loy, consultants for Pennsylvania Power & Light), the initial excavation would contain approximately 110 x 10^6 cubic yards of rock. (This amount of rock could cover one acre of ground and extend almost 13 miles into the air.) Following the initial excavation, the pit would move along the strike of the anthracite seams for the life of the reserve or of the plant, whichever came first.

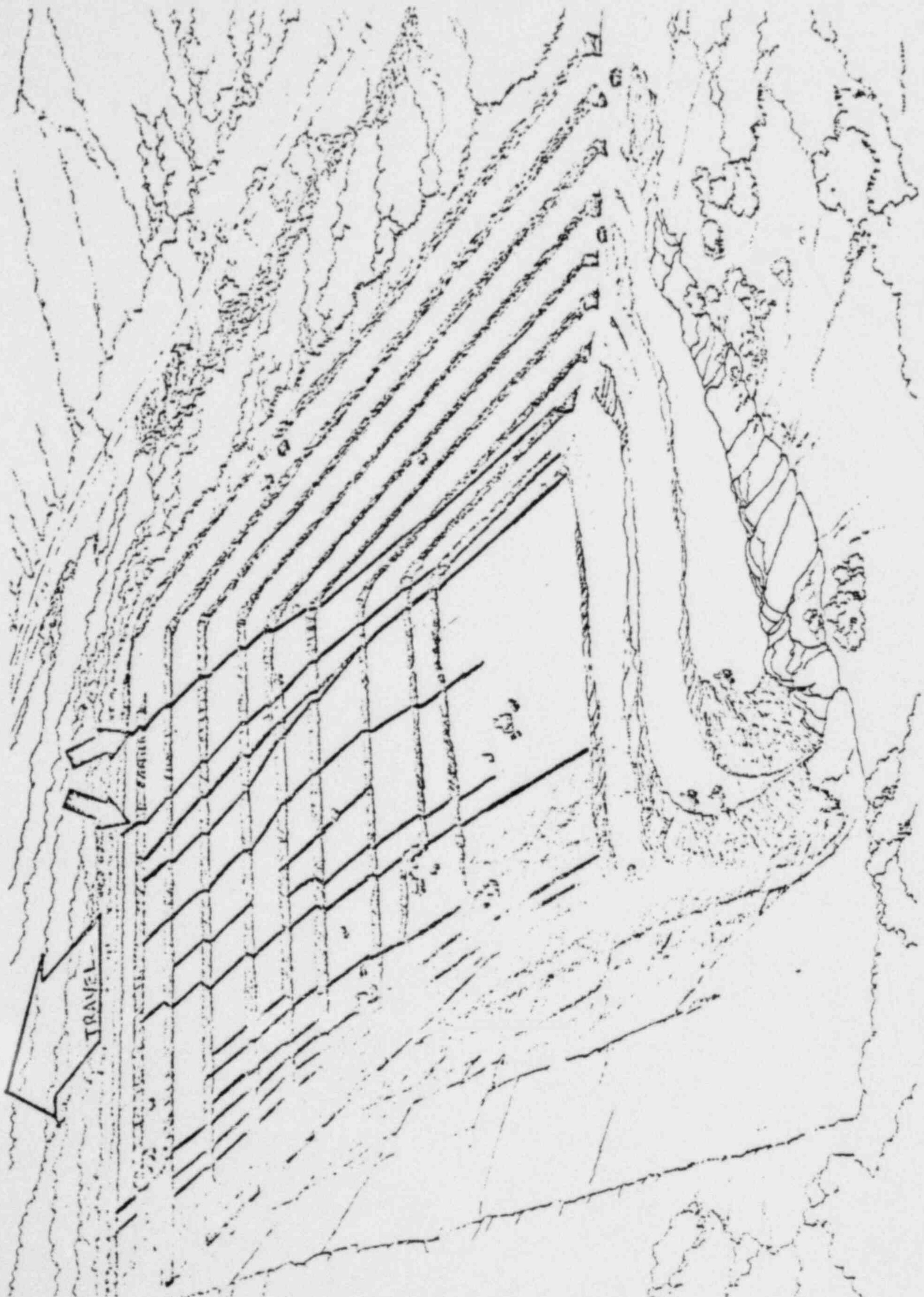
Exhibits 6, 7 and 8 show artist's conceptions of the appearance of a reserve area before, during, and after mining has taken place. If such an operation were feasible, it would have obvious advantages to the Eastern Pennsylvania economy through renovation of areas ravaged by previous mining.

From all information available to GPU, it appears that, in order to secure a dedicated source of supply for an anthracite unit at TMI-2, it will be necessary to finance the development of a mine or several mines such as the one described here. Although this method of operations on this scale of anthracite mining is untried, it remains one of the most feasible ways of securing 2.2-2.9 x 10^6 tons per year from a large scale anthracite operation. It is not anticipated that any current anthracite producer would be willing to enter anything but a cost-plus-profit contract for this untried plan. It is anticipated that the efforts required to

1) Locate sufficient anthracite reserves which would be amenable to this open-pit concept,
2) Reach equitable agreements with the owners of these reserves,
3) Prove the reserves through a drilling program,
4) Perform necessary engineering,
5) Secure necessary permits from regulatory agencies,
6) Create an anthracite mining company capable of meeting GPU needs for TMI-2, or reach an equitable agreement with an existing operator, and
7) Relocate houses, schools, hospitals, and towns lying in the path of the moving pit

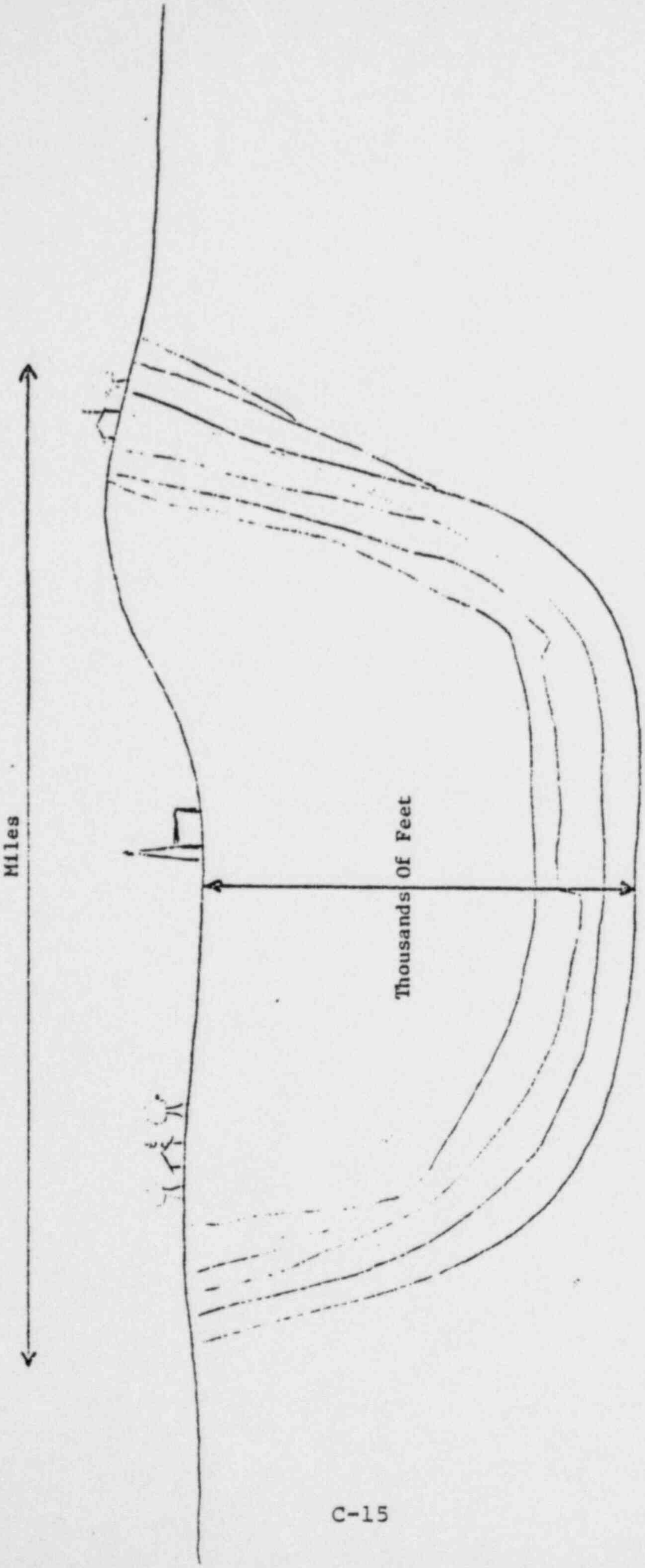
would require from 5-10 years from the time a decision was made to begin the project (depending upon the extent of negotiations and the time required to secure surface rights and to re-locate people and buildings). Following this period, the development of the initial pit would take 5-8 years to reach full capacity. Thus, a decision in January of 1980 to begin the anthracite project could take until 1990 to 1998 to be fully implemented.

EXHIBIT 4



This is an open pit mine using shovel and truck excavation and haulage used where a natural rock face provides one of the pit sidewalls.

EXHIBIT 5

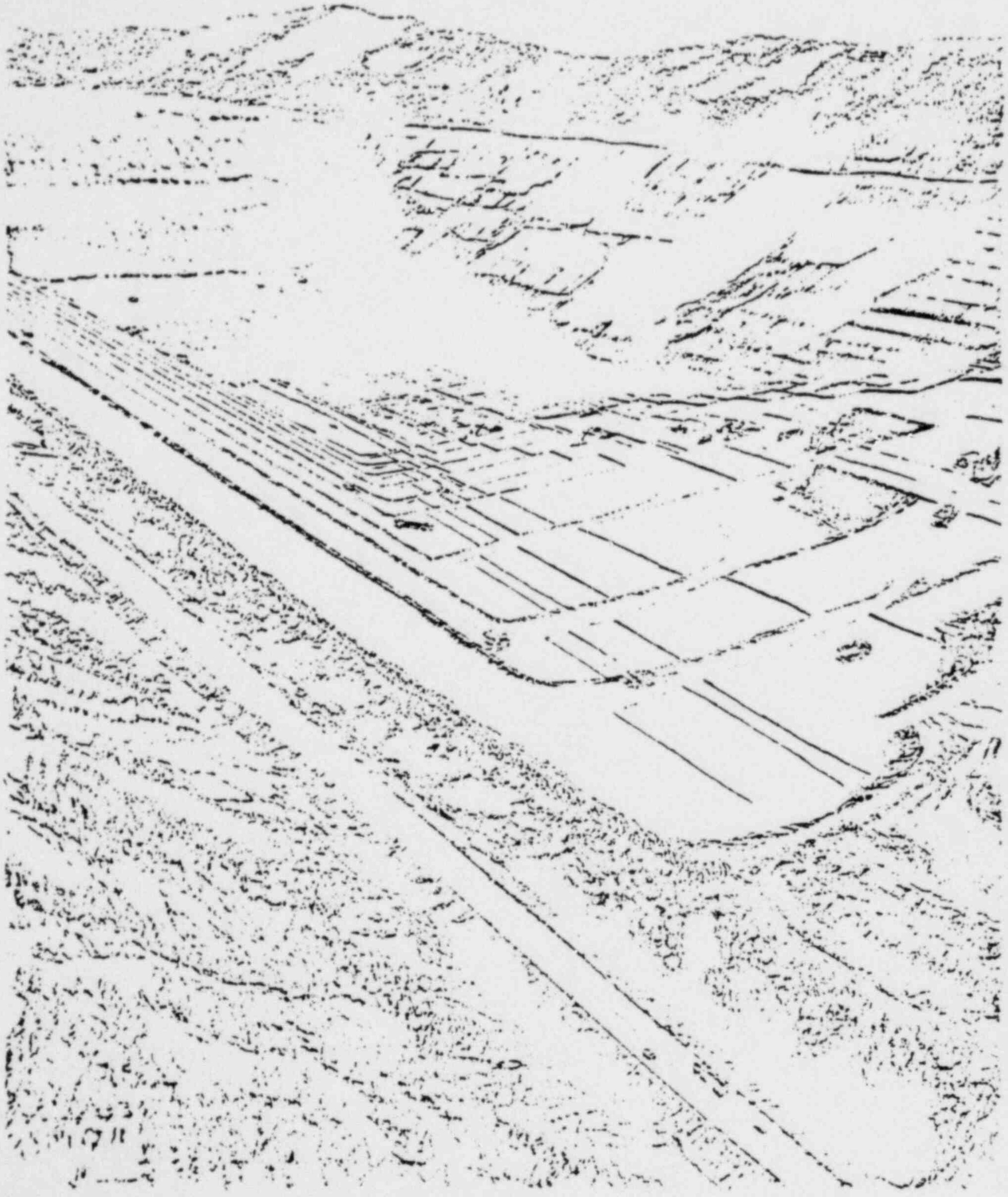


No Scale

EXHIBIT 6

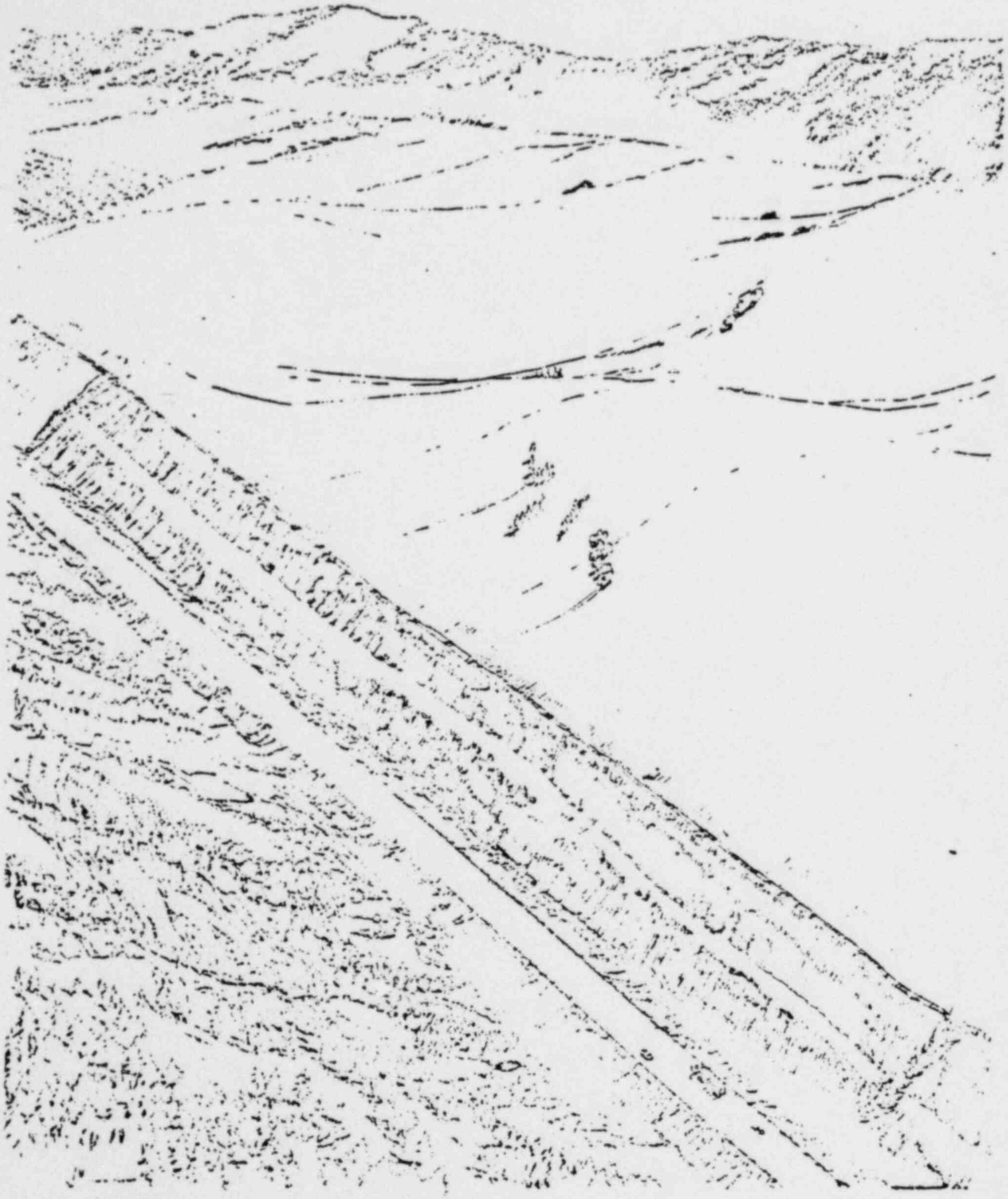
BEFORE MINING

EXHIBIT 7



DURING MINING

EXHIBIT 8



AFTER MINING

4) Estimated Cost of Anthracite, FOB TMI-2

While the cost of developing an open pit anthracite mine is not known, it is possible to make estimates based upon experiences in the bituminous coal industry. The cost of developing a bituminous coal mine with a preparation plant is approximately $50 per annual ton of production. It is anticipated that the cost of developing an open pit anthracite mine could be nearly twice that amount (depending upon methods of disposing rock from the initial excavation and the extent of relocation of towns and homes). Thus, capital costs alone for the anthracite mine could approach $20/ton. This is based upon a 20% per year charge on a total capital requirement of from $220-290 x 10^6. It is assumed that financing for this operation would come either directly or indirectly from GPU.

The productivity of the anthracite strip mining industry is approximately 10 tons per man-day. Current labor costs in the Pennsylvania mining industry are approximately $200 per man-day, including all indirect labor costs. Therefore, it is anticipated that labor costs would be $20/ton (including on-site salaried supervision).

Supply costs, including reclamation materials and power, are expected to be $10/ton (considering the quantity of drilling and blasting materials, fuel costs, and equipment parts required).

General overhead (including general & administrative costs, insurance, etc.) is expected to approximate 10% of the total cost. Royalties are also expected to approximate 5% of the total cost. Profit plus bonus to the anthracite operator would be commensurate with his risk but would probably approximate $2.00/ton with a low level of risk to the operator.

Table II presents the estimates listed above:

TABLE II

Item	$/Ton	% of Total
Labor	20.00	33
Supplies	10.00	16
Capital Charges	20.00	33
Royalty	2.94	5
Overhead	5.88	10
Profit & Bonus	2.00	3
Cost to GPU	60.82	100

In discussions with an anthracite operator in December of 1977, GPU was advised that one anthracite open-pit mine in the Tamaqua area would be expected to produce coal at a price of $54/ton. Escalated at a rate of 8% per year, this figure would become $63.00 for January 1980. The cost quoted here is for a joint venture arrangement where the anthracite operator would assume a larger portion of risk than in a cost-plus arrangement. Thus, the GPU estimates can be considered reasonable.

NOTE: The spot market price for similar size and quality anthracite was $59.00/ton FOB cleaning plants in November 1979 (from Coal Outlook, November 12, 1979). It is reasonable to assume that small quantities of anthracite from older mining operations would cost less than new production, particularly during a relatively soft market period.

Transportation charges for unit train delivery are estimated to be $4.00/ton, based upon a GPUSC Fuels Department unit train model. Estimates for truck haulage are $6/ton for a 50 mile haul (@ 10¢/ton-mile plus $1.00/ton loading charge). However, this does not include any damage to highways or the potential impact of having 30 trucks per hour traveling through Middletown, Pa., 16 hours/day. It also does not assess the cost of security checks for every truck or (in the cost-plus case) the cost of making sure that all of the anthracite is delivered to TMI-2 and not stolen enroute.

The truck scenario would require over 260 25-ton trucks (assuming 90% utilization).

Therefore, the cost of anthracite delivered to TMI-2 is estimated to range from a low of \$65/ton (for a cost-plus agreement with high risk of greater costs in an untried mining method) to potential higher costs if an operator could be found who will take some portion of the risk. This translates as 250 ¢/MMBTU delivered, (or greater) approximately twice the current price range for bituminous coal delivered to GPU.

CONCLUSIONS

1) An anthracite unit at Three Mile Island will require from 2.2×10^6 to 2.9×10^6 tons of anthracite per year, depending upon capacity factors.

2) It does not appear that the anthracite strip mining industry can support this additional demand without nearly 100% expansion.

3) Current mining methods do not appear feasible for large scale operations. New methods, financed by GPU capital, will be required to supply TMI.

4) Capital requirements for these operations will $220-290 $\times 10^6$.

5) Development of open pit anthracite mines will require 10-15 years from the time a decision is made to begin the project.

6) Delivered costs for anthracite are estimated at $65/ton or greater depending upon the amount of risk taken by GPU. For 13,000 BTU/lb. anthracite, this is 250 ¢/MMBTU or greater, twice the cost for bituminous coal.

7) For these reasons, anthracite is not a viable option for TMI at this time.

APPENDIX D

COSTS AND ASSUMPTIONS

The tables which follow delineate the costs and assumptions used throughout the report:

TABLE

D-1	Basic financial and tax assumptions
D-2	Capital cost summary (Cases 1-4)
D-3	Capital additions during the operating life of the plants to replace equipment
D-4	Fuel cost assumptions
D-5	Fuel Expenses
D-6	Operating and maintenance (O&M) costs
D-7	Purchase power costs and credits

The tables are self-explanatory.

TABLE D-1

BASIC ASSUMPTIONS

CAPITALIZATION	BONDS	PREFERRED STOCK	COMMON STOCK
Ratio	.53	.12	.35
Rate	12.25%	12.5%	14.5%

Composite Cost of Money 13% (discount rate)

GENERAL INFLATION RATE - 8%/year

DEPRECIATION METHOD - SYD

ADR Life - 16 years - nuclear

22.5 years - coal & gas

RATE BASE LIFE - Coal & Gas - 40 years

TMI-2 - through 2009

GROSS RECEIPTS TAX - 4.5% Penn.

11.9% N.J.

PUBLIC UTILITY REALTY TAX - 3%

CAPITAL STOCK TAX RATE - 1% Penn.

FRANCHISE TAX RATE - 1% N.J.

STATE NET INCOME TAX - 10.5%

FEDERAL INCOME TAX - 46%

INVESTMENT TAX CREDIT - 10%

TABLE D-2

CAPITAL COST SUMMARY
(as incurred, with AFDC)

CASE 1	a)	TMI-2 (1/1/84)	\$710 Million original investment \$100 Million net cost of restoration
	b)	472 MW Coal* (1/1/87)	\$645 Million new capital cost
CASE 2		TMI Converted to Coal (1/1/87)	\$290 Million claimed of original TMI-2 investment \$1365 Million new capital cost \$12 Million for ash/sludge disposal site
CASE 3		TMI Converted to Gas/Coal (10/1/86): convert to coal 1/1/92	\$290 Million claimed of original TMI-2 investment \$833 Million initial gas-firing \$807 Million conversion to coal \$17.6 Million** for ash/sludge disposal site
CASE 4		Offsite Coal* Replacement (1/1/87)	\$1846 Million new capital cost

* Capital costs determined by multiplying the capacity (in MW) by \$1.3656 Million/MW, the cost of Seward 7 and Coho 1.

** \$12 Million escalated at 8% per year for 5 years.

TABLE D-3

CAPITAL ADDITIONS
(as incurred, with AFDC)

TMI-2 Nuclear (880 MW)	1986	$ 7.7 Million
	1991	$24.3 Million
	1996	$37.0 Million
472 MW Coal	1989	$ 0.3 Million
	1994	$17.6 Million
TMI-2 Coal (1352 MW)	1989	$ 3.0 Million
	1994	$60.1 Million
TMI-2 Gas (1375 MW)	1989	$ 2.4 Million
	1994	$43.4 Million
Offsite Coal (1352 MW)	1989	$ 0.9 Million
	1994	$50.4 Million

These costs are for replacing equipment which wears out during the operating life of the plant.

TABLE D-4

FUEL COST ASSUMPTIONS

Nuclear		Base Cost (Year)	Assumed Escalation
	Uranium	$56.30/lb (1984)	8%/year
	Conversion	$ 5.80/KGU (1984)	4%/year
	Enrichment	$141/SWU (1984)	10%/year
	Fabrication	$178.40/KGU (1984)	6%/year
Coal			
	Cost at the mine	$33.50/Ton (1980)	9.3%/year thru 199 8%/year thereafter
	Transportation (Unit Train)		
	a) to TMI	$ 7.66/Ton (1980)	9%/year thru 1990 8.5%/year thereafter
	b) to offsite	$ 6/Ton (1980)	
Natural Gas		$ 4/MM BTU (1985)	11%/year thru 1990 9.2%/year thereafter

TABLE D-5

FUEL EXPENSE SUMMARY

YEAR	TMI-2 Nuclear Fuel ($ Million)	Offsite Coal (Cases 1 & 4) ($/Million Btu)	TMI-2 Coal (Case 2) ($/Million Btu)	TMI-2 Gas/Coal (Case 3) ($/Million Btu)
1984	32.2	------	------	------
1985	26.3	------	------	------
1986	30.2	------	------	4.44
1987	33.8	2.920	3.030	4.93
1988	38.1	3.195	3.310	5.47
1989	41.5	3.495	3.620	6.07
1990	46.4	3.805	3.950	6.75
1991	52.1	4.111	4.266	7.37
1992	58.4	4.439	4.607	4.607
1993	64.2	4.791	4.976	4.976
1994	69.9	5.178	5.374	5.374
1995	75.5	5.590	5.804	5.804
1996	81.7	6.037	6.268	6.268
Firing Rate (10^{12} Btu/yr.)		31.82 per 625 MW	70.63	101.63 (Gas) 70.63 (Coal)

NOTE: 1) Does not include inventory costs for a 30 day coal supply or the nuclear reactor core.

TABLE D-6

O&M SUMMARY
($ Millions)

YEAR	880 MW TMI-2 NUCLEAR	472 MW COAL	1352 MW TMI-2 COAL	1375 MW TMI-2 GAS	1352 MW OFFSITE COAL
1984	24.8	----	----	----	----
1985	26.6	----	----	----	----
1986	28.5	----	----	3.1	----
1987	30.4	27.5	89.6	13.4	78.6
1988	32.5	29.4	96.0	14.4	84.3
1989	35.1	31.6	102.9	15.4	90.4
1990	38.0	34.1	111.2	16.7	97.6
1991	41.0	36.8	120.1	13.5*	105.4
1992	44.3	39.7	129.7	129.7	113.9
1993	47.8	42.9	140.0	140.0	123.0
1994	51.6	46.4	151.2	151.2	132.8
1995	55.8	50.1	163.4	163.4	143.4
1996	60.2	54.1	176.4	176.4	154.9

*Shut down three months to convert to coal.

TABLE D-7

PURCHASE POWER COSTS/CREDITS
($ Millions)

YEAR	ASSUMED PRICE (mills per KWH)	CASES 2 & 4	CASE 3
1984	62.918	281.3	281.3
1985	75.733	338.6	338.6
1986	84.386	377.3	161.3
1987	92.321	0	(311.0)
1988	97.779	0	(329.4)
1989	109.243	0	(368.1)
1990	128.572	0	(433.2)
1991	145.473	0	(117.8)
1992 on	-----	0	0

POWER PURCHASES/SALES
(Millions of KWH's)

YEAR		CASES 2 & 4	CASE 3
1984		4471.1	4471.1
1985		4471.1	4471.1
1986		4471.1	1911.5
1987		0	(3369.1)
1988		0	(3369.1)
1989		0	(3369.1)
1990		0	(3369.1)
1991		0	(809.5)
1992 on		0	0
Capacity Factor		58%	85% - Gas 58% - Coal