COMMISSION CORRESPONDENCE

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

July 18, 1980

MEMORANDUM FOR: Commissioner Gilinsky

FROM: Edward J. Hanrahan EJH

SUBJECT: RESIDUAL FUEL OIL DEMAND AND SUPPLY

As you requested, attached is a brief study of electricity demand for oil and the supply of residual fuel oil to the U.S. economy.

Attachment:
As stated

cc: Chairman Ahearne
Commissioner Hendrie
Commissioner Bradford
Leonard Bickwit
Sam Chilk

Contact:
George Eysymontt, OPE
63-43302

Electric Utility Residual Fuel Oil Use

Utility Oil Demand

During 1979 the electric utility industry consumed oil at the rate of about 1.4 million bbls/day. Table I attached summarizes the history of oil use by the electric utility industry since the oil embargo.

There has been a shift in the energy used to produce electricity. Since 1973 an increasing share of the electricity supplied to the economy has been produced by coal and nuclear energy while the contribution made by oil and natural gas has decreased as shown in Table II.

U.S. Oil Supply

The U.S. imports both crude oil and petroleum products. U.S. petroleum imports averaged 6.3 million bbls/day in 1973. In 1979 petroleum imports averaged 8.3 million bbls/day of which 1.9 million bbls/day were petroleum products. Over 50 percent of product imports was residual fuel oil (about 1.1 million bbls/day).. Domestic refineries produced another 1.7 million bbls/day of resid, and consequently, total supply to the economy in 1979 of residual fuel oil amounted to 2.8 million bbls/day, the same amount as in 1973. Table III summarizes the supply of residual fuel oil to U.S. economy for the last 7 years. Imports of resid have been decreasing.

U.S. Residual Fuel Supply/Demand

Residual fuel oil is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes. Domestic residual fuel demand is met by domestic refinery production, imports from Puerto Rico and the Virgin Islands, and imports from areas outside U.S. territories, primarily from Venezuela, the Bahamas, and the Netherlands Antilles (see Table IV).

While residual fuel oil is the so-called "bottom of the barrel" it turns out that resid production can be minimized. On the average between 1973 and 1979 U.S. domestic resid production was between 8 and 12 percent of U.S. refinery crude throughput. Theoretically refineries could be designed to produce no resid at all. Basically, the resid can be heated (boiling point = 900°F) and additional light distillates and petroleum coke are obtained. The catch is that oil producers must modify their refineries by making an additional capital investment in their plant. Thus, in the short run, given a particular refinery, resid production can only be modified by decreasing crude throughput to that refinery.

For analytical purposes oil analysts divide the U.S. into five districts called Petroleum Administration for Defense (PAD) districts (see Chart I). A recent DOE analysis of the supply and demand balances in each of these districts provides some interesting insights into the residual

fuel oil situation in the U.S. The study was done primarily from the perspective of oil refiners who, in the short-run at least, cannot greatly alter the output of resid from their refineries. If resid is in oversupply in a district, refineries can either store the product, ship it to another district, or decrease the throughput of crude to their refineries and consequently the output of more desirable products such as gasoline or middle distillates.

Tables IV and V summarize the resid supply/demand situation in the U.S. during 1978 and the first three quarters of 1979. There are two striking things shown by these tables: virtually all imports of resid from abroad came into PAD I (the U.S. East Coast); and there is only one significant inter-district transfer of resid - from PAD III (Gulf Coast) to PAD I. PAD I in 1979 met 23 percent of its requirements for resid from domestic production -- approximately two-thirds of which comes from within the region and another third of which comes from PAD III which had an oversupply. Essentially, the other three PAD's are self-sufficient in terms of resid, i.e., the production of resid by refineries in each of these districts is all consumed within that district.

Utility Residual Fuel Oil Demand

Electric utility demand for residual fuel oil on the East Coast in 1979 was about 900,000 bbls/day. Given that a large percentage of the current generating capacity on the East Coast is base load oil-fired steam electric, an issue is how to meet present and projected electricity demand while decreasing oil consumption. Some of the existing plants can be converted at considerable time and expense to coal use. Under the provisions of the Powerplant and Industrial Field Use Act of 1978 the Secretary of Energy has the authority to prohibit petroleum and natural gas use in existing plants under certain conditions.1/ DOE is now trying to implement this part of the law.

Due to the recent sharp increase in oil prices, utilities have been given considerable incentive to convert their facilities to coal on a voluntary basis. Some orders have been issued by DOE to convert facilities to coal, but these orders have not yet been implemented. As for new facilities, the Fuel Use Act prohibits the use of natural gas or petroleum as a primary energy source in any new electric powerplant and also prohibits construction of such powerplants without the capability to use coal or any other alternate fuel as a primary energy source. The Act is riddled with exemptions for such things as lack of alternate fuel supply, site limitations, environmental requirements, or adequate capital. Peakload powerplants are also excluded. To receive an exemption utilities must petition the Department of Energy.

1/ Upon making a finding that (a) such installation has or previously had the technical capability to use coal or another alternate fuel as a primary energy source; (b) such installation has the technical capability to use coal or another alternate fuel as a primary energy source, or it could have such capability without - (i) substantial physical modification of the unit, or (ii) substantial reduction in the rated capacity of the unit; and (c) it is financially feasible to use coal or another alternate fuel as a primary energy source in such installation.

Basically, coal and nuclear base load facilities are the available options to replace existing oil-fired facilities and to meet future increases in demand. DOE released a report in June, 1980, entitled "Electric Power Supply and Demand for the Contiguous United States, 1980-189" which attempts to quantify the consequences of a nuclear licensing delay on electricity supply reliability and on the demand for oil. The data used for the study were provided by National Electric Reliability Councils (see Chart II). Based on the loads and construction schedules projected by the Councils, the DOE report concludes that if no new nuclear units were to be added in the period 1980-1985, two electric Reliability Council regions would have reserve margins below 12 percent and one region would be barely above that level. Thus, these areas would have less than satisfactory reliability (see Table VII). Each of the Regional Reliability Councils has a separate forecast of peak demand for the next 10 years and the rates of growth vary from a low of 1.9 percent per year for the Northeast Power Coordinating Council to a high of 6.2 percent per year for the Southwest Power Pool. The U.S. average increase in peak demand is projected to be 4.3 percent per year (see Table VIII). The DOE report notes that the Reliability Councils have published forecasts of peak demand growth in recent years which were too high. Should this be the case, of course, the situation may not be as unsatisfactory as suggested in the DOE report.

The report also attempts to quantify the impact of a delay in placing nuclear plants in commercial operation by calculating the additional coal, oil, and gas needed to meet projected demand on the basis of the present amounts of coal, oil, and gas generation in a particular region and the existing capacity factors of each type of generation. Table IX indicates the electric regions or power pools affected by operating license delays and specifies the nuclear plant in question and the assumption concerning its projected in-service date. Table X indicates the calculated regional increase in oil use due to nuclear licensing delays (or delays which could be attributed to other reasons, for that matter) assuming the nuclear plants scheduled for operation over the next 5 years do not operate until after 1985. Considering this to be the worst case, on the average over the 5 years, U.S. residual fuel oil consumption would have to increase by 400,000 bbls/day to make up for the lost nuclear generation. Table XI summarizes DOE's priorities for nuclear licensing based on a ranking system using an unspecified weighting factor which considers oil saving potential, energy shortages, and reserve margins.

Conclusion

Residual fuel oil is primarily imported into the East Coast of the United States. East Coast domestic refineries produce only a small fraction of the residual fuel oil needed to meet electric utility and other demand. Most of the resid is imported from Venezuela and the Caribbean. Some additional supply of residual fuel oil are provided to the East Coast market by Gulf Coast refineries. Transportation costs, as well as the demand/supply situation on the Gulf Coast, probably are a factor in explaining why more residual fuel oil does not move between U.S. refinery districts. Intracoastal shipments are subject to the Jones Act requirement that such shipments must be

made on U.S. flag vessels where available. Since U.S. flag carrier rates are approximately three times those of foreign rates, this could have a significant impact on delivered costs of resid on the East Coast from refineries on the Gulf Coast when compared with deliveries from points in the Caribbean.

East Coast utilities use approximately the same amount of residual fuel oil as is imported. Should utilities begin to shutdown or convert existing oil-fired capacity or replace such plants with nuclear and coal-fired generating stations, it seems likely that the highest cost residual fuel oil would be backed out first. In the short-run, it would appear (without looking into the delivered cost of resid from various refineries) that inter-district transfers of resid would be the first to go (about 100,000 bbls/day based on 1979 data), followed by imports (about 800,000 bbls/day from Venezuela and the Caribbean, and 200,000 bbls/day from the Virgin Islands - which is technically not within the U.S. Customs Zone). In the long-run, if residual demand on the East Coast were reduced to the level of refinery output, or less, refineries could be modified to produce more gasoline and middle distillates and less residual fuel oil.

TABLE I

Petroleum Consumed to Produce Electricity*

Year	millions bbls/day
1973	1.54
1974	1.47
1975	1.39
1976	1.52
1977	1.70
1978	1.74
1979	1.43

*Primarily residual fuel oil in steam plants, but includes lighter oils used in gas turbines and internal combustion plants.

TABLE II

Share of Total Electricity Produced by Primary Energy Source

	(Percent)	
	1973	1979
Coal	45.6	47.8
Oil	16.9	13.5
Gas	18.3	14.7
Nuclear	4.5	11.4
Hydro & Other	14.8	12.6
Total	100.0	100.0
Production (billions kw/hrs.)	1,860.7	2,247.4

TABLE III

Residual Fuel Supplied to the U.S. Economy

	% of refinery crude throughput	(millions bbls/day) Domestic Refineries	Imports	Total
1973	7.8	0.971	1.853	2.822
1974	8.8	1.070	1.587	2.639
1975	9.9	1.235	1.223	2.462
1976	10.3	1.377	1.413	2.801
1977	12.1	1.754	1.359	3.071
1978	11.3	1.667	1.355	3.023
1979	11.6	1.684	1.150	2.822

CHART I

PETROLEUM ADMINISTRATION FOR DEFENSE (PAD) DISTRICTS

TABLE IV

RESIDUAL IMPORTS BY GRADE

Year 1978 And Jan. - Sept. 1979

Country	PERCENT OF IMPORTS									
	0-0.5 Z S		0.51-1.0 Z S		1.01-2.0 Z S		2.0+ Z S		Total	
	78	79	78	79	78	79	78	79	78	79
W. Europe	7.3	6.4	6.9	7.2	---	0.4	0.2	0.4	3.9	3.6
U.S.S.R.	1.4	---	0.3	---	---	---	---	---	0.6	---
Romania	---	---	3.7	0.9	0.5	---	0.1	---	0.8	0.2
Middle East	0.7	0.9	0.1	---	0.6	0.2	0.2	1.7	0.4	0.8
Far East	5.3	9.4	0.3	---	0.3	0.2	---	---	2.1	3.2
Africa	9.5	9.3	6.0	6.6	0.4	0.4	0.1	0.4	4.5	4.5
Venezula	20.1	21.8	30.3	18.2	31.9	29.9	44.0	50.4	30.9	31.6
Other-- South America	0.5	0.3	1.8	2.6	14.2	15.4	0.2	---	3.3	3.3
N.W.I.	8.5	4.6	13.4	17.3	16.3	25.0	23.8	22.8	15.2	16.1
Trinidad	6.2	2.6	6.0	5.5	6.2	1.6	5.0	4.1	5.8	3.4
Bahamas	15.6	12.7	6.5	5.5	6.0	1.8	9.3	6.0	10.4	7.7
Canada	2.2	2.6	12.5	17.6	3.2	0.6	4.8	1.5	5.0	4.4
Virgin Islands	20.8	27.9	11.6	16.3	20.1	23.6	11.7	12.2	16.4	20.2
Other	1.8	1.5	0.6	2.3	0.3	0.9	0.6	0.5	0.7	1.0
TOTAL	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
TOTAL IMPORTS (MB/D)	463.9	380.7	253.1	191.0	250.7	202.2	375.7	353.2	1343.4	1127.2

TABLE V

RESIDUAL FUEL SUPPLY DEMAND
MB/D January - December 1978

Location - Fuel Type	Refinery Production	Imports	Receipts From Other Districts					Puerto Rico, Virgin Islands & Hawaiian FTZ	Apparent Demand
			PAD 1	PAD 2	PAD 3	PAD 4	PAD 5		
PAD 1 0-0.5% S	43.1	338.1			24.7			96.5	502.4
.51-1.0% S	62.8	188.3			59.1			30.8	341.0
1.01-2% S	50.0	195.9			2.5			50.3	298.7
2+ % S	53.8	331.0			16.2			44.4	496.4
PAD 1 TOTAL	209.7	1053.4			102.5			221.9	1587.5
PAD 2 0-.5% S	7.5	10.1							
.5-1% S	88.0	31.8			4.0			-----	21.6
1-2% S	113.1	3.7			16.9			-----	136.7
2+ % S	33.8	-----			1.8			-----	118.6
PAD 2 TOTAL	242.5	45.5			9.1			-----	42.9
					31.7				319.7
PAD 3 0-0.5% S	125.4	.6							
.5-1% S	263.2	1.2			(28.6)			-----	97.4
1-2% S	22.5	-----			(76.1)			-----	188.3
2+% S	301.5	.01			(4.3)			-----	19.2
PAD 3 TOTAL	712.6	1.8			(25.6)			.1	276.0
					(134.6)			.1	579.9
PAD 4 0-.5% S	14.0	------			-----	(6.7)		------	7.3
.5-1% S	8.2	------			-----	-----	.5	------	8.7
1-2% S	8.4	------			-----	-----	-----	------	8.4
2+% S	15.0	------			-----	-----	-----	------	15.0
PAD 4 TOTAL	45.6					(6.7)	.5		39.4
PAD 5 0-.5% S	193.5	18.6			-----	6.7	-----	------	218.8
.5-1% S	39.9	1.0			.1	-----	(.5)	------	40.5
1-2 % S	211.5	.8			-----	-----	-----	------	212.3
2+% S	18.6	.04			.3	-----	-----	.2	19.1
PAD 5 TOTAL	463.5	20.4			.4	6.7	(.5)	.2	490.7
U.S. 0-.5% S	383.5	367.5						96.5	847.5
.5-1% S	462.1	222.3						30.8	715.2
1-2% S	405.6	200.4						50.3	656.3
2+% S	422.7	331.0						44.5	793.2
U.S.TOTAL	1674.0	1121.2						222.2	3017.4

Totals may not add due to independent rounding

TABLE VI

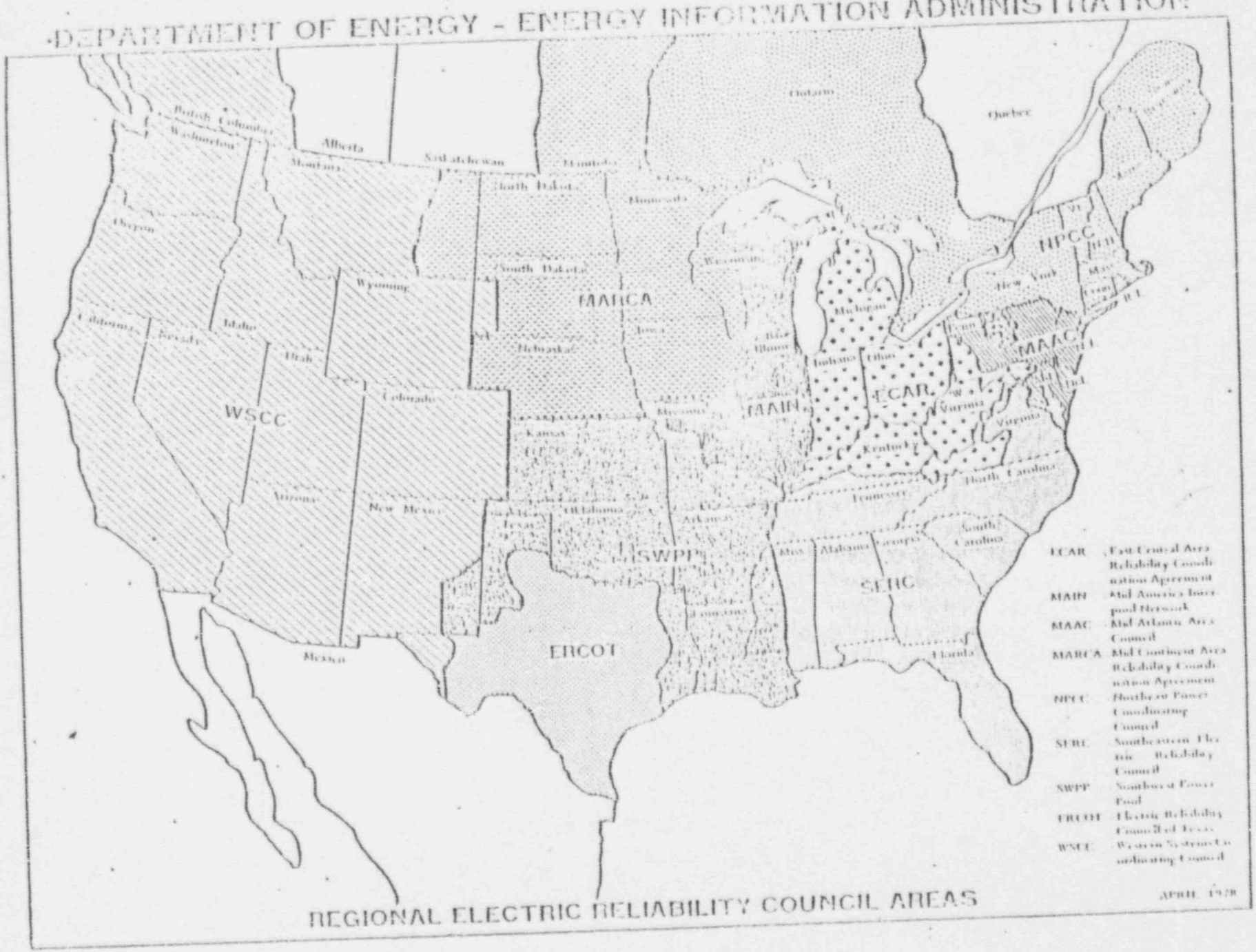
RESIDUAL FUEL SUPPLY DEMAND
MB/D January - September 1979

Destination - Fuel Type	Refinery Production	Imports	Receipts From Other Districts PAD 1	PAD 2	PAD 3	PAD 4	PAD 5	Puerto Rico, Virgin Islands & Hawaiian FTZ	Demand 1/
PAD 1 0-0.5% S	55.6	235.3			26.7			109.7	427.3
.51-1.0% S	41.0	126.4			55.1			31.9	254.4
1.01-2 % S	66.1	152.2			3.3			49.2	271.1
2 + % S	42.4	105.9			32.0			44.2	224.5
PAD 1 TOTAL	205.2	319.8			117.6			234.9	1177.5
PAD 2 0-.5% S	9.4	8.1			6.4			-----	23.9
.5-1% S	71.4	31.8			7.6			-----	110.8
1-2% S	90.8	----			---			-----	90.8
2+% S	39.4	.4			9.3			-----	39.1
PAD 2 TOTAL	211.0	40.2			23.3				272.5
PAD 3 0-.5% S	127.9	-----			(33.8)			-----	94.1
.5-1% S	202.1	.8			(62.7)			-----	140.2
1-2% S	40.0	-----			(3.8)			-----	36.2
2+% S	335.3	.8			(41.3)			.2	395.0
PAD 3 TOTAL	705.3	1.6			(141.5)			.2	565.6
PAD 4 0-.5% S	9.7	-----			----	(4.0)		-----	5.7
.5-1% S	6.0	-----			----	----	4.3	-----	10.3
1-2% S	8.4	-----			----	----	----	-----	8.4
2+% S	15.3	-----			----	----	----	-----	15.3
PAD 4. TOTAL	39.4	-----				(4.0)	4.3		39.7
PAD 5 0-.5% S	217.0	27.6			.6	4.0	-----	-----	249.2
.5-1% S	32.8	.2			----	----	(4.3)	-----	28.7
1-2% S	235.7	.9			-----	----	-----	-----	236.6
2+% S	18.0	1.7			.02	----	-----	.1	19.8
PAD 5 TOTAL	503.5	30.3			.6	4.0	(4.3)	.1	534.2
U.S. 0-.5% S	419.6	270.9						109.7	800.2
.5-1% S	353.3	159.1						31.9	544.1
1-2% S	441.0	153.1						49.2	643.3
2+% S	450.4	308.8						44.5	803.2
U.S.	1664.3	891.9						235.2	2791.4

IS MAY NOT ADD DUE TO INDEPENDENT ROUNDING

1/ Excluding stock change, which is negligable.

CHART 11


DEPARTMENT OF ENERGY - ENERGY INFORMATION ADMINISTRATION
WSCC
MARCA
MAIN
ECAR
MAAC
NPCC
SERC
SWPP
ERCOT
ECAR East Central Area Reliability Coordination Agreement
MAIN Mid America Interpool Network
MAAC Mid Atlantic Area Council
MARCA Mid Continent Area Reliability Coordination Agreement
NPCC Northeast Power Coordinating Council
SERC Southeastern Electric Reliability Council
SWPP Southwest Power Pool
ERCOT Electric Reliability Council of Texas
WSCC Western Systems Coordinating Council
APRIL 1978
REGIONAL ELECTRIC RELIABILITY COUNCIL AREAS

I.01

TABLE VII

Effect of Projected Nuclear Capacity
on Summer 1985 Reserve Margins

Council	Projected Reserve Margin, Percent With New Nuclear Units 1/	Without New Nuclear Units
ECAR	34.23	26.46
MAAC	29.91	16.09
MAIN	27.07	6.25
MARCA	24.84	19.84
NPCC	44.92	36.80
SERC	29.11	13.59
SWPP	24.07	12.22
Subtotal	30.23	18.21
WSCC	28.53	16.10
ERCOT	19.00	10.29
U.S. Total	29.06	17.22

1/ As projected through June 1985 by the Reliability Councils, April 1, 1980, but with Three Mile Island Unit 2 excluded by Staff.

TABLE VIII

Council	Ten-Year Average Annual Percent Increase of Summer Demand As Projected By The Reliability Councils in April 1980
ECAR	4.0
MAAC	2.9
MAIN	3.4
MARCA	5.5
NPCC	1.9
SERC	4.5
SWPP	6.2
WSCC	4.5
ERCOT	5.6
U.S. TOTAL	4.3

TABLE IX

REGIONAL INCREASE IN OIL USE
DUE TO NUCLEAR LICENSING DELAYS
(Includes Impact of Interregional Transfers
to Reduce Energy Shortage)

PROBABLE ADDITIONAL OIL CONSUMPTION
(BBL/DAY)

REGION	1980	1981	1982	1983	1984	1985
1. APS	0	0	0	0	0	0
2. AEP	0	0	0	0	0	0
3. NEPOOL	0	0	0	23,600	31,500	66,800
4. NYPP	0	0	0	21,300	21,300	23,900
5. PJM	0	18,000	42,500	69,100	80,400	116,200
6. CECo	1,300	17,100	37,700	60,600	88,600	99,200
7. F.C.G.	0	0	0	3,100	18,500	20,800
8. MSU	0	0	0	0	0	0
9. So. Co.	1,500	4,400	5,000	6,600	15,300	21,500
10. GSU	0	0	0	0	0	0
11. TVA	0	5,800	16,500	21,300	19,800	17,700
12. VACAR	1,400	17,100	24,000	29,600	45,600	52,700
13. CAPCo	0	0	0	0	1,000	1,200
14. CCD	0	0	0	0	0	0
15. Kentucky	0	0	0	0	0	0
16. Indiana	0	0	0	0	0	0
17. ILL-MO.	0	0	0	0	1,200	1,200
18. MECS	0	0	11,200	13,500	19,100	33,600
19. MDMS	0	0	0	0	1,100	1,900
20. MAPP	0	0	0	0	0	2,100
21. MO-KAN	0	0	0	0	0	0
22. Oklahoma	0	0	0	0	0	0
23. Texas	0	0	0	0	0	0
24. RMPP	0	0	0	0	1,600	2,400
25/ NWPP 30	0	0	0	22,600	22,600	47,700
26. Ariz-NM	0	0	0	12,200	31,000	42,000
27. So. Cal-Nev.	0	22,000	32,200	70,900	77,300	71,200
28. No. Cal-Nev.	0	25,300	57,900	77,100	70,700	75,300
Total Increase	4,200	109,700	227,000	431,500	545,600	697,400
Total NERC Oil Use (BBL/DAY) (1)	1,852,300	1,974,900	2,036,300	2,027,600	2,001,600	2,082,500
% of Total NERC Oil Use	0.2%	5.6%	11.1%	21.3%	27.3%	33.5%

(1) Data from "Summary of Projected Peak Load, Generating Capability, and Fossil Fuel Requirements", NERC, July, 1979.

Table X
Nuclear Units Affected by an Operating License Delays Through 1985

ELECTRIC REGION NO. - NAME	UNIT NAME	SUMMER CAPACITY (MW)	PROJECTED IN-SERVICE DATE MONTH-YEAR 1/
3-NEPOOL	SEABROOK #1	1,150	4-83
	SEABROOK #1	1,150	2-85
	PILGRIM #2	1,150	12-85
4-NYPP	SHOREHAM #1	820	1-83
5-PJM	3 MILE IS. #1	776	1-81
	SUSQUEHANNA #1	1,050	1-82
	SUSQUEHANNA #2	1,050	1-83
	HOPE CREEK #1	1,066	9-84
	LIMERICK #1	1,055	5-85
6-CECO	LA SALLE #1	1,048	12-80
	LA SALLE #2	1,048	12-81
	BYRON #1	1,120	10-82
	BRAIDWOOD #1	1,090	10-83
	BYRON #2	1,120	10-83
	BRAIDWOOD #2	1,090	10-84
7-FCG	ST. LUCIE #2	795	11-83
8-MSU	GRAND GULF #1	1,250	4-82
	WATERFORD #3	1,110	2-82
	GRAND GULF #2	1,250	4-85
9-SoCo.	FARLEY #2	807	9-80
	VOGTLE #1	1,150	11-84
10-GSU	RIVER BEND #1	940	4-84
11-TVA	WATTS BAR #1	1,177	9-81
	SEQUOYAH #2	1,148	6-81
	WATTS BAR #2	1,177	6-82
	BELLEFONTE #1	1,213	9-83
	BELLEFONTE #2	1,213	6-84
	YELLOW CREEK #1	1,285	11-85

Table X (cont'd)
Nuclear Units Affected by an Operating License Delays Through 1985

ELECTRIC REGION NO. - NAME	UNIT NAME	SUMMER CAPACITY (MW)	PROJECTED[1] IN-SERVICE DATE MONTH-YEAR
12-VACAR	MC GUIRE #1	1,180	12-80
	SUMMER #1	900	12-80
	MC GUIRE #2	1,180	7-82
	CATAWBA #1	1,145	12-83
	CATAWBA #2	1,145	7-85
	HARRIS #1	900	3-84
13-CAPCO	PERRY #1	1,179	5-84
14-CCD	ZIMMER #1	792	1-81
17-ILL-MO.	CALLOWAY #1	1,150	12-82
	CALLOWAY #2	948	12-82
18-MECS	MIDLAND #2	783	9-84
	FERMI #2	1,093	3-82
	MIDLAND #1	506	3-85
21-MOKAN	WOLF CREEK #1	1,150	4-83
23-TIS	COMANCHE PEAK #1	1,150	8-81
	COMANCHE PEAK #2	1,150	1-83
	SOUTH TEXAS #1	1,250	2-84
25-NWPP	WNP #2	1,100	1-83
	WNP #1	1,250	6-85
26-A Z-NM.	PALO VERDE #1	1,270	6-83
	PALO VERDE #2	1,270	5-84
27-So. Cal-Nev.	SAN ONOFRE #2	1,100	10-81
	SAN ONOFRE #3	1,100	1-83
28-No Cal. Nev.	DIABLO CANYON #1	1,084	2-81
	DIABLO CANYON #2	1,106	8-81

1/ In-service dates as projected by the Regional Electric Reliability Council April 1, 1980, updated by ERA staff where possible to reflect most recent schedules.

TABLE XI

NUCLEAR UNIT PRIORITY LIST BY YEAR

1980-85

UNIT NAME	SUMMER CAPABILITY (MW)	PROJECTED COMMERCIAL OPERATION DATE	YEAR-BY-YEAR WEIGHTED RANK (1)	POTENTIAL OIL SAVED (3) BBL/DAY
		UNITS SCHEDULED FOR 1980		
LaSalle #1	1048	12/80	1	15,800
McGuire #1	1180	12/80	2	9,700
Summer #1	900	12/80	3	7,400
Farley #2	807	9/80	4	4,400
		UNITS SCHEDULED FOR 1981		
Diablo Canyon #2	1106	8/81	1	30,300
Diablo Canyon #1	1084	2/81	2	29,700
LaSalle #2	1048	12/81	3	15,800
Sequoyah #2	1148	6/81	4	6,300
Watts Bar #1	1177	9/81	5	6,400
Comanche Peak #1	1150	8/81	6	0
San Onofre #2	1100	10/81	7	30,100
Three Mile Island #1	776	1/81 (2)	8	18,000
Zimmer #1	792	1/81	9	0
		UNITS SCHEDULED FOR 1982		
Byron #1	1120	10/82	1	16,900
McGuire #2	1180	7/82	2	9,700
Watts Bar #2	1177	6/82	3	6,400
Waterford #3	1110	2/82	4	0
Grand Gulf #1	1250	4/82	5	0
Susquehanna #1	1050	1/82	6	24,400
Fermi #2	1093	3/82	7	13,500
Calloway #1	1150	10/82	8	6,300
Calloway #2	948	12/82	9	5,200
		UNITS SCHEDULED FOR 1983		
WNP #2	1100	1/83	1	22,600
Palo Verde #1	1270	6/83	2	20,800
Byron #2	1120	10/83	3	16,900
Braidwood #1	1090	10/83	4	16,400
Catawba #1	1145	12/83	5	9,400
Bellefonte #1	1213	9/83	6	6,600
Comanche Peak #2	1150	1/83	7	0
Seabrook #1	1150	4/83	8	31,500
San Onofre #3	1100	1/83	9	30,100
Susquehanna #2	1050	1/83	10	24,400
Shoreham #1	820	1/83	11	21,300

TABLE XI
NUCLEAR UNIT PRIORITY LIST BY YEAR
1980-85

ELECTRIC REGION	UNIT NAME	SUMMER CAPABILITY (MW)	PROJECTED COMMERCIAL OPERATION DATE	YEAR-BY-YEAR WEIGHTED RANK (1)	POTENTIAL OIL SAVED BBL/DAY (3)
		UNITS SCHEDULED FOR 1983 (CONT'D)			
7	St. Lucie #2	795	11/83	12	18,500
21	Wolf Creek #1	1150	4/83	13	0
		UNITS SCHEDULED FOR 1984			
26	Palo Verde #2	1270	5/84	1	20,800
6	Braidwood #2	1090	10/84	2	16,400
12	Harris #1	900	3/84	3	7,400
11	Bellafonte #2	1213	6/84	4	6,600
13	Perry #1	1179	5/84	5	1,600
23	South Texas #1	1250	2/84	6	0
10	River Bend #1	940	4/84	7	0
5	Hope Creek #1	1066	9/84	8	24,800
18	Midland #2	783	9/84	9	9,600
9	Vogtle #1	1150	11/84	10	6,300
		UNITS SCHEDULED FOR 1985			
25	WNP #1	1250	6/85	1	25,700
12	Catawba #2	1145	7/85	2	9,400
11	Yellow Creek #1	1285	11/85	3	7,000
3	Seabrook #2	1150	2/85	4	31,500
8	Grand Gulf #2	1250	4/85	5	0
3	Pilgrim #2	1150	12/85	6	31,500
5	Limerick #1	1055	5/85	7	24,500
18	Midland #1	505	3/85	8	6,200

(1) Rank is based on a weighted factor which considers oil saving potential, energy shortage, and low reserve margins; and is only valid within a given year. For licensing purposes, it may be desirable to give preference to top ranked units in a subsequent year over the lower ranked units in the current year.

(2) Three Mile Island #1 has been shutdown for an indefinate period because of the accident at Three Mile Island #2. January 1981 was assumed by ERA staff to be the earliest possible on-line date.

(3) Potential oil saved assuming a full year of operation at 57% capacity factor, divided by 365. Total oil saved the first year depends on the number of days of operation. These figures reflect an adjustment to account for the regional dependency on oil.