UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
James P. Gleason, Chairman
Frederick J. Shon
Dr. Oscar H. Paris

In the Matter of CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. (Indian Point, Unit No. 2) POWER AUTHORITY OF THE STATE OF NEW YORK (Indian Point, Unit No. 3)	Docket Nos. 50-247 SP 50-286 SP April 12, 1983

LICENSEES' TESTIMONY
OF EUGENE T. MEEHAN ON COMMISSION QUESTION 6

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1. INTRODUCTION

My name is Eugene T. Meehan. I am a Vice President of Energy Management Associates, Inc. (EMA). A statement of my professional qualifications is attached as Appendix A.

This testimony addresses Commission Question 6 in this proceeding which asks:

> What would be the energy, environmental, economic or other consequences of a shutdown of Indian Point Unit 2 and/or Unit 3?

Specifically, this testimony examines the economic production cost penalty in terms of increased dollars required to supply electricity, and the energy penalty in terms of increased oil used to generate electricity, that would result from the shutdown of the Indian Point nuclear generating units 2 and 3 (Indian Point). Increased production costs and oil usage resulting from the shutdown of Indian Point would impose consequent damages upon the economic and energy situation. Other witnesses testifying on behalf of the licensees will address the consequent effects of increased production costs and oil usage of an Indian Point shutdown.

The analysis of the production cost penalty was conducted for the 1984 to 1999 period. The demand for electricity in New York State and the resources for supplying electricity in the State are forecast annually in the Report of Member Electric Systems of the New York Power Pool (NYPP) pursuant to Section 5-112 of the Energy Law of New York State (5-112 Report). The 1983 5-112 Report was filed on April 1, 1983. This study was conducted while that report was being prepared, and the data being developed for inclusion in that report served as the basis for the demand and resource assumptions used in EMA's analysis for the reference scenario analyzed herein. In addition to determining the production cost penalty associated with the Indian Point shutdown for a reference scenario, the sensitivity of the penalty to load growth, fuel prices, nuclear plant capacity factor and coal conversions was analyzed.

If the energy Indian Point would normally supply is unavailable, there would be three major direct effects on production costs:

1. Increased fuel costs within NYPP resulting from the replacement of Indian Point energy by oil, gas, and coal generation;

2. Increased purchased power costs resulting from the replacement of some Indian Point energy with additional purchases from Canada; and
3. Increased purchased power costs for volumes of Canadian imports common to the with and without Indian Point scenarios resulting from increases in the value of NYPP energy displaced by those imports.

The annual direct production cost penalties for the State of New York, the Consolidated Edison Company of New York, Inc. (Con Ed) and the Con Ed Service Area are reported herein. The additional quantities of oil that would be used to replace Indian Point generation are also reported.

2. PROMOD III® OVERVIEW

The effects of the Indian Point shutdown were determined by simulating the operation of the New York Power Pool generating system with and without Indian Point. The PROMOD III System is a comprehensive tool for performing major production cost analyses. The PROMOD III System is capable of simulating the operation of an integrated power pool in which transmission limitations affect the commitment and dispatch of generating units.

A. General Description.

The PROMOD III program contains five basic modules:

- Input Module - This module reads all input data and performs preliminary diagnostic scans.
- Preprocessing Module - This module creates initial working files, performs detailed diagnostic checks, and provides an organized display of the basic data.
- Probabilistic Simulation Module - This module simulates the operation of the generation system to meet the load and energy forecast in the most economic manner, subject to operating constraints and transmission limits.

  The principal quantities computed by this module are:

  - Expected generation for each generating unit
  - Expected fuel costs
  - Expected fuel consumption
- Energy Storage Module - This module simulates the operation of energy storage projects, such as pumped storage hydro plants. It determines the optimal economic utilization of these projects, the cost of generation for energy storage, and the operating cost savings attributable to each energy storage project. Data inputs to the model include the energy storage efficiency, the size of the storage reservoir, and the pumping and generating capacity of the project.
- Billing Reconstruction Module - This module determines for internal (intra-pool) economy energy transactions the associated billing costs, savings to buyers and profits to sellers. For external economy energy transactions (between NYPP and neighboring

pools or utilities), this module determines total pool billing dollars and savings and allocates billing dollars and savings to individual companies. In accordance with the principle of cost minimization through central dispatch, all dispatch decisions are made on the basis of minimizing total cost. Billing reconstruction is performed after the fact, and does not interfere with total cost minimization.

The PROMOD III System stands out from less sophisticated production costing programs in its treatment of forced outages of generating units and its recognition of transmission transfer limits. It is these forced outages that are the major disruption of fuel budget forecasts, operating cost forecasts, and projected utilization of high cost peaking equipment. Since these outages are random and are unpredictable, PROMOD III employs an advanced probabilistic technique to properly consider their resultant impact on fuel requirements, operating costs, and reliability. Generating units can be represented by a multi-state failure model to give explicit consideration to partial loss of unit capability and forced outages of varying severities. Possible failure states of each unit are considered in combination with possible failure states of all other units in order to obtain the best forecast of expected fuel consumption, operating costs, and plant capacity factors.

B. Utility Industry Acceptance.

PROMOD III has been used extensively in both the public and private sectors of the utility industry.

Over fifty utilities across the country, as well as four utilities in Canada and Australia. are using PROMOD III for reliability analyses, generation planning, fuel budgeting, marginal costs analyses, and load management studies. In addition to the New York Power Pool and six NYPP utilities, many major power companies use PROMOD III. These include American Electric Power, Commonwealth Edison, Duke Power, Detroit Edison, Florida Power and Light, Southern California Edison, Virginia Electric and Power Company, and the PJM Power Pool. PROMOD III has been used in studies and testimony done by the Staff of the New York State Department of Public Service and is leased from EMA by the United States Department of Energy. PROMOD III results

have been accepted as evidence by numerous state regulatory commissions.

Table 2.1 contains a list of companies using PROMOD III for planning and budgeting purposes.

Since 1977, PROMOD III has been increasingly employed by EMA and its clients in developing supporting evidence for regulatory hearings. Table 2.2 provides a partial list of such hearings. Table 2.3 illustrates the variety of applications in which utilities have used PROMOD III. No attempt has been made to record each analysis performed by utilities using PROMOD III. Hence, Tables 2.2 and 2.3 present a noncomprehensive view of all PROMOD III applications.

C. <u>NYPP Experience</u>

EMA has worked very closely with the member companies of the New York Power Pool to ensure that PROMOD III correctly models the pool operations and billing reconstruction procedures of NYPP. The PROMOD III model is currently licensed from EMA and used by:

- Central Hudson Gas and Electric Corporation
- Consolidated Edison Company of New York, Inc.
- New York Power Pool
- New York State Electric and Gas Corporation
- Niagara Mohawk Power Corporation
- Orange and Rockland Utilities, Inc.
- Rochester Gas and Electric Corporation

Additionally, EMA has performed a wide variety of consulting studies employing PROMOD III for New York State clients. All New York utilities, as well as the New York State Department of Public Service, have been involved in these studies. Hence, the PROMOD III model has been subjected to thorough review by New York State utilities and regulatory authorities. The EMA staff has become very familiar with the NYPP generating system.

EMA's work with NYPP led to the development of billing reconstruction algorithms specifically designed to model the interaction between NYPP and Ontario Hydro (OH) and Hydro Quebec (HQ). These algorithms model the pool's use of external economy energy in the most

TABLE 2.1

PROMOD III USERS

- ALLEGHENY POWER SYSTEM, INC.
- AMERICAN ELECTRIC POWER COMPANY, INC.
- ATLANTIC CITY ELECTRIC COMPANY
- BALTIMORE GAS & ELECTRIC COMPANY
- CAROLINA POWER & LIGHT COMPANY
- CENTRAL & SOUTH WEST CORP.
- CENTRAL HUDSON GAS & ELECTRIC CORP.
- CLEVELAND ELECTRIC ILLUMINATING CO.
- COLORADO SPGS. DEPT. OF PUB. UTILITIES
- COMMONWEALTH EDISON COMPANY
- CONSOLIDATED EDISON CO. OF N.Y., INC.
- THE DAYTON POWER AND LIGHT COMPANY
- DELMARVA POWER & LIGHT COMPANY
- DEPARTMENT OF ENERGY
- DETROIT EDISON COMPANY
- DUKE POWER COMPANY
- DUQUESNE LIGHT COMPANY
- EL PASO ELECTRIC COMPANY
- FLORIDA POWER CORPORATION
- FLORIDA POWER & LIGHT COMPANY
- GENERAL PUBLIC UTILITIES
- GULF STATES UTILITIES
- HOUSTON LIGHTING AND POWER COMPANY
- ILLINOIS POWER COMPANY
- IOWA ELECTRIC LIGHT & POWER COMPANY
- JACKSONVILLE ELECTRIC AUTHORITY
- LOS ANGELES DEPT. OF WATER & POWER
- LOWER COLORADO RIVER AUTHORITY
- MIDDLE SOUTH SERVICES, INC.
- MONTANA POWER COMPANY
- MUNICIPAL ELECTRIC AUTHORITY OF GA.
- NEW BRUNSWICK ELECTRIC POWER COMM.
- NEW YORK POWER POOL
- NEW YORK STATE ELECTRIC & GAS CORP.
- NIAGARA MOHAWK POWER CORPORATION
- NORTHERN INDIANA PUBLIC SERVICE CO.
- NORTHERN STATES POWER COMPANY
- NOVA SCOTIA POWER CORPORATION
- OMAHA PUBLIC POWER DISTRICT
- ORANGE AND ROCKLAND UTILITIES, INC.
- PENNSYLVANIA-JERSEY-MARYLAND PWR. POOL
- PENNSYLVANIA POWER & LIGHT COMPANY
- PORTLAND GENERAL ELECTRIC COMPANY
- POTOMAC ELECTRIC POWER COMPANY
- PUBLIC SERVICE COMPANY OF COLORADO
- PUBLIC SERVICE COMPANY OF INDIANA
- PUBLIC SERVICE COMPANY OF NEW MEXICO
- PUBLIC SERVICE ELECTRIC & GAS COMPANY
- PUERTO RICO ELECTRIC POWER AUTHORITY
- ROCHESTER GAS & ELECTRIC CORPORATION
- SALT RIVER PROJECT
- SAN DIEGO GAS & ELECTRIC COMPANY
- SASKATCHEWAN POWER CORPORATION
- SAVANNAH ELECTRIC AND POWER COMPANY
- SIERRA PACIFIC POWER COMPANY
- SOUTH CAROLINA ELECTRIC & GAS COMPANY
- SOUTHERN CALIFORNIA EDISON COMPANY
- SOUTHERN ENGINEERING CO. OF GEORGIA
- STATE ENERGY COMM. OF W. AUSTRALIA
- TAMPA ELECTRIC COMPANY
- TEXAS UTILITIES SERVICES INC.
- THE TOLEDO EDISON COMPANY
- UTAH POWER & LIGHT COMPANY
- VIRGINIA ELECTRIC AND POWER COMPANY
- WISCONSIN POWER & LIGHT COMPANY

TABLE 2.2

PROMOD III USE IN REGULATORY PROCEEDINGS

YEAR	CLIENT	CASE DESCRIPTION
1983	Florida Power Corporation	Forward Looking Fuel Clause Adjustment Hearing. Docket No. 830001-EU.
1983	Florida Power Corporation	Annual Planning Workshop for Florida Electric Utilities and the Public Service Commission. Docket No. 830004-EU.
1982	West Penn Power Company	Analysis of the Economics of the Purchase by West Penn Power Company of a Share of the Bath County Pumped Storage Project. Docket No. -A-00103260, et al, Before the Pennsylvania Public Utilities Commission.
1982	Rochester Gas and Electric Corp.	Determination of Marginal Energy Costs For Use in Rate Proceedings. Case No. 28313.
1982	Pennsylvania Power and Light Co.	Development of Fuel Cost Savings Associated With Addition of New Nuclear Plant. Docket No. -R-822169.
1982	Public Service Electric and Gas	Development of Levelized Fuel Adjustment For Use in Rate Proceeding. Docket No. 812-76.
1982	Savannah Electric Power Company	Fuel Cost Recovery Clause. GA PSC Docket No. 3381-U.
1982	Savannah Electric Power Company	Determination of Economic Benefits of Oil to Coal Conversion. GA PSC Docket No. 3361-U.
1982	Tampa Electric Company	Rate Hearings. Case No. 820007-EU, Case No. 830004-EU.
1982	Atlantic City Electric Company	Levelized Energy Adjustment Clause. Docket No. 8210-892.

TABLE 2.2
PROMOD III USE IN REGULATORY PROCEEDINGS
(Continued)

YEAR	CLIENT	CASE DESCRIPTION
1982	Atlantic City Electric Company	Marginal Energy Adjustment Clause. Docket No. 8210-904.
1981	Atlantic City Electric Company	Levelized and Marginal Energy Adjustment Clause. Docket No. 7911-951.
1981	Niagara Mohawk Power Corporation Rochester Gas & Electric Corporation New York State Electric & Gas Corp. Central Hudson Gas & Electric Corp. Long Island Lighting Company	Analysis of Economic and Financial Implications of the Nine Mile Point 2 Nuclear Generating Unit. Case No. 28059.
1981	Niagara Mohawk Power Corporation	Marginal Energy Cost Analysis. Case No. 27741 - Phase II.
1981	Arkansas Power & Light Company	Power Supply Planning Analysis. Docket No. 81-144-U.
1981	Consolidated Edison Company	Analysis of Replacement Cost of Indian Point 2 Power. Case No. 27869
1981	Mississippi Power & Light Company	Power Supply Planning Analysis. Docket No. U-3967.
1981	Public Service Company of Oklahoma	Power Supply Planning Analysis. Case No. 27068.
1980	Florida Power & Light Company Florida Power Corporation Tampa Electric Company	Continuing use of PROMOD III to Determine Prospective Fuel Cost Recovery Charges.
1980	Los Angeles Department of Water and Power	City of Los Angeles Department of Water and Power PURPA proceedings.
1979	Virginia Electric and Power Company	Continuing Use in Fuel Factor Hearing Before the Virginia State Corporation Commission.
1979	U.S. Department of Energy	ICC Rail Rate Hearing. Docket #37063. L&N Railroad.
1978	San Diego Gas & Electric Company	Marginal Cost Study Before the Public Service Commission of the State of California.

TABLE 2.2
PROMOD III USE IN REGULATORY PROCEEDINGS
(Continued)

YEAR	CLIENT	CASE DESCRIPTION
1978	Niagara Mohawk Power Corporation	NYPP Long Range Generation and Transmission Plan Pursuant to Article VIII Section 149-B of the Public Service Law. Case No. 27319.
1978	Commonwealth Edison Company	Illinois Commerce Commission. Construction Program Investigation. Docket No. 78-0646.
1978	Detroit Edison Company	Generic Hearings to Determine the Effectiveness of Interrupting Specified Electric Services With Respect to Load Management by Major Michigan Electric Utilities. Case No. U-5845.
1977-78	El Paso Electric Company	FERC Rate Cases. Docket Nos. ER-78-520 and ER-77-488.
1977	Public Service Company of Colorado	Generic Rate Structure Hearing. PUC Case No. 5693.
1977	Jacksonville Electric Authority	Hearings Before Florida Environmental Regulatory Commission on the Existing/New Source Rule (3/27/77).

TABLE 2.3

PROMOD III USE IN UTILITY ANALYSIS

CONSULTANT	CLIENT	PROJECT
EMA (1981)	Niagara Mohawk Power Corp. New York State Electric and Gas Corp. Rochester Gas and Electric Corp. Long Island Lighting Company Central Hudson Gas & Electric Company	Evaluation of New York State Department of Public Service Alternatives to Nine Mile Point 2
EMA (1981)	Consolidated Edison	Evaluation of Replacement Power Cost due to Sustained Unit Outage
Controller General of the United States (1981)	Commonwealth Edison	Economic Impact of Closing Zion Nuclear Facility
EMA (1981)	Public Service Company of Oklahoma	Generation Expansion Planning Study
EMA (1980)	Middle South Utilities	Generation Expansion Planning Study
EMA (1979)	Electric Power Research Institute	Compressed Air Energy Storage Study
EMA (1979)	Electric Power Research Institute	Spinning Reserve Cost Analysis
EMA (1979)	Gulf Mineral Resources Company	Market Survey For Solvent Refined Coal
EMA (1979)	California Power Pool	Increased Integration Study
EMA (1979)	Los Angeles Department of Water and Power	Marginal Energy Cost Study
EMA (1979)	Central Hudson Gas & Electric Company	Marginal Energy Cost Study
EMA (1978)	Stone and Webster	Southwest Solar Study
EMA (1978)	Detroit Edison Company	Load Management Study

TABLE 2.3

PROMOD III USE IN UTILITY ANALYSIS
(continued)

CONSULTANT	CLIENT	PROJECT
EMA (1977)	Edison Electric Institute	Load Management Study
Florida Power Corp. (1979)	Department of Energy	Ocean Thermal Energy Conversion Study
Gordian Associates (1979)	Carolina Power and Light Company	Marginal Cost Study
National Economic Research Associates (1976-1979)	Los Angeles Dept. of Water & Power Public Service Company of Colorado Public Service Co. of New Mexico Rochester Gas and Electric Company San Diego Gas and Electric Company Virginia Electric and Power Company	Marginal Cost Studies
Southern Engineering (1979)	Big Rivers Electric Cooperative	Generation Expansion Study
Stone and Webster (1978)	El Paso Electric Company	Marginal Cost Study

economic fashion, determine the payments to OH and HQ in accordance with the contracts with those parties, and determine the allocation of external energy and resultant savings to individual companies based upon the agreement among the NYPP companies.

Additionally, EMA's work with NYPP resulted in the development of billing reconstruction logic that captures the effect of the agreements governing Con Ed and the Power Authority of the State of New York (Power Authority) interchange energy. Since the Power Authority does not directly participate in NYPP internal economy interchange, it is necessary to model this accounting arrangement when conducting an analysis examining individual company production cost impacts.

3. DATA ASSUMPTIONS

There are four principal categories of data required to conduct the analysis of the production cost penalty of the Indian Point shutdown. These categories are:

1. Demand and capacity expansion forecasts;
2. Fuel price forecasts;
3. Forecasts of Canadian imports; and,
4. Unit and system operating characteristic data.

A description of the key items in each area follows.

A. Demand and Capacity Expansion Forecasts.

The demand forecast reflects the NYPP utilities' most recent available forecasts as of February, 1983. Many of these were developed for use in the 1983 5-112 Report. This forecast reflects a compound energy consumption growth rate of 1.4% and a compound electric peak load growth rate of 1.2%. The demand forecasts were developed by the individual NYPP companies and input into the PROMOD III System on an individual company basis.

Table 3.1 illustrates the annual NYPP peak and energy consumption forecasts for the 1984 to 1999 period.

Two sensitivity analyses were conducted with respect to load growth. The first assumed low load growth. Low load growth was defined as a 0.7% compound energy consumption growth rate, as opposed to the 1.4% which was forecast. The second assumed a change in the compound pool energy consumption growth rate from 1.4% to 2.2%. For 1998 and 1999, the pool reserve margin falls below the required NYPP minimum in scenarios without Indian Point. This occurs from 1996 onward in the high load growth scenario. For these scenarios, in addition to the added production costs computed herein, the shutdown of Indian Point would result in the need for more capacity. Ms. Streiter's testimony addresses added capacity costs. Table 3.2 compares the NYPP energy consumption requirement for the reference case, the low load growth scenario, and the high load growth scenario for selected years.

The capacity expansion forecast was developed based upon the most recent available updates by NYPP member companies to expansion plans. The major capacity additions beyond units already in service are illustrated in Table 3.3.

TABLE 3.1

NYPP FORECAST ANNUAL PEAK LOADS AND ENERGY REQUIREMENTS

YEAR	FORECAST ANNUAL PEAK MW	FORECAST ENERGY REQUIREMENT GWH
1984	21,620	120,068
1985	21,750	121,891
1986	21,990	123,609
1987	22,180	125,311
1988	22,610	126,909
1989	22,870	128,636
1990	23,150	130,370
1991	23,430	132,287
1992	23,750	134,295
1993	24,060	136,178
1994	24,410	138,195
1995	24,720	140,260
1996	25,050	142,427
1997	25,350	144,472
1998	25,660	146,617
1999	25,980	148,818

Table 3.2

COMPARISON OF FORECAST NYPP ANNUAL ENERGY REQUIREMENT WITH ANNUAL ENERGY REQUIREMENT FOR SENSITIVITY ANALYSIS SCENARIOS

	LOW LOAD GROWTH	NYPP FORECAST	HIGH LOAD GROWTH
	GWH		
1991	125,219	132,287	139,915
1999	132,729	148,818	167,242

TABLE 3.3

CAPACITY EXPANSION SCHEDULE

Unit	Max Capacity (MW)	In-Service Date	Fuel
Shoreham	809	1/1984	Nuclear
Somerset	625	11/1984	Coal
Nine Mile Point 2	1085	11/1986	Nuclear
Prattsville	1000	9/1989	Pumped Storage

Note: For all sensitivity analysis scenarios except the alternate fuel cost scenarios the capacity expansion schedule included the 700 MW Fossil unit in service as of May 1990 and the Jamesport (400 MW) unit in service as of January 1994.

During the course of this analysis, two planned coal units were moved beyond the planning horizon; the 700 MW Fossil unit and the Jamesport unit. The reference scenario and the alternate fuel cost sensitivity scenarios were redone to reflect this major change to the NYPP capacity expansion plan. There was not sufficient time to redo the other sensitivity analysis scenarios. Hence, the sensitivity analysis scenarios for low and high load growth, 57 percent and 69 percent nuclear capacity factor, and no coal conversion, all contain 1100 MW of baseload capacity that has been recently deleted from the plan. For these sensitivity scenarios the effect of the shutdown on production costs is understated. Judging from the results obtained for the reference scenario, penalties associated with the shutdown would increase roughly 10%.

The coal conversion schedule is based upon the most recent information available from NYPP member utilities. Table 3.4 details the coal conversion schedule.

The coal conversion process has been plagued with lengthy delays related to regulatory approval. There is a reasonable possibility that the utilities will not be able to achieve their coal conversion plans (see testimony of Sally Streiter). A sensitivity analysis has been conducted which assumes no coal conversion.

B. Fuel Price Forecasts.

The fuel prices (excluding nuclear fuel) used in the analysis were developed for NYPP by ICF, Inc. That forecast was requested from ICF for use in NYPP long-range planning studies. The forecast fuel prices and the details underlying the forecast were presented to NYPP in November, 1982, in an ICF report entitled "Forecast of Fuel Markets and Prices in New York State". Nuclear fuel prices were taken from the most recent NYPP Economic Parameters Study.

Table 3.5 illustrates the fuel prices used for the reference case.

Sensitivity analyses were also performed with respect to gas and oil prices. Sensitivities were performed using the ICF low and ICF high estimates for oil and gas prices for all years. Tables 3.6 and 3.7 illustrate the fuel prices used for the low and high price sensitivity

TABLE 3.4

COAL CONVERSION SCHEDULE

Unit	Max Capacity (MW)	Conversion Date
Ravenswood 3	928	6/1983
Lovett 5	202	10/1984
Lovett 4	197	12/1984
Arthur Kill 3	501	11/1985
Arthur Kill 2	350	7/1986
Danskammer 3	126	9/1986
Port Jefferson 3	190	1/1988
Danskammer 4	227	9/1988
Lovett 3	63	1/1989
Port Jefferson 4	190	1/1989

TABLE 3.5

NYPP/ICF FUEL PRICE FORECAST
(NOMINAL MIDYEAR ¢/MBTU)

Sulfur Content	Upstate or Downstate	1983 Fuel Price	1983 Escalation Rate	1985 Fuel Price	1985 Escalation Rate	1990 Fuel Price	1990 Escalation Rate	1995 Fuel Price	1995 Escalation Rate
Oil -- Residual									
.3%	D	555.0	11.50	689.7	11.05	1164.9	8.08	1718.2	9.13
.7%	U	546.0	12.01	684.8	11.31	1170.1	8.32	1744.7	9.13
.7%	D	526.0	12.10	660.3	11.42	1134.0	8.33	1691.7	9.17
1.0%	U	528.0	12.31	666.4	11.55	1151.2	8.46	1727.9	9.15
1.0%	D	508.0	12.42	641.9	11.68	1115.1	8.51	1677.3	9.16
1.5%	D	483.5	13.11	618.6	12.02	1091.0	8.70	1655.6	9.18
2.0%	U	479.0	13.59	617.4	12.24	1099.6	8.90	1684.5	9.18
2.0%	D	459.0	13.76	594.1	12.39	1065.3	8.93	1633.9	9.18
2.8%	U	448.0	14.37	585.6	12.75	1067.0	9.22	1658.0	9.18
2.8%	D	427.0	14.72	562.3	12.93	1032.6	9.22	1605.0	9.22
Oil -- Distillate									
-	U	683.0	10.10	828.1	8.92	1269.7	8.93	1947.2	8.94
-	D	693.0	10.16	840.4	8.93	1288.6	8.93	1976.1	8.94
Gas -- Natural									
-	U	404.7	20.91	571.7	12.93	1038.5	10.48	1707.2	10.24
-	D	430.2	19.22	593.7	12.41	1055.5	10.30	1722.0	10.12
Coal									
1.0%	U	262.1	7.87	305.0	8.57	460.0	7.88	672.0	7.68
1.0%	D	279.4	7.86	325.0	8.47	488.0	7.82	711.0	7.63
1.4%	U	257.2	7.63	298.0	8.50	448.0	7.76	651.0	7.92
1.4%	D	276.8	7.69	321.0	8.42	481.0	7.67	696.0	7.88
2.0%	U	242.3	7.69	281.0	7.80	409.0	7.71	593.0	7.69
2.0%	D	261.8	7.75	304.0	7.77	442.0	7.65	639.0	7.63
2.0%	U	206.8	7.72	240.0	7.53	345.0	7.96	506.0	9.26
2.0%	D	236.0	7.75	274.0	7.48	393.0	7.87	574.0	8.97
Uranium									
-	-	69.6	7.00	79.6	7.00	111.7	7.00	157.2	7.00

TABLE 3.6

FUEL PRICE FORECAST
(LOW PRICE SENSITIVITY ANALYSIS)
(NOMINAL MIDYEAR ¢/MBTU)

Sulfur Content	Upstate or Downstate	1983 Fuel Price	1983 Escalation Rate	1985 Fuel Price	1985 Escalation Rate	1990 Fuel Price	1990 Escalation Rate	1995 Fuel Price	1995 Escalation Rate
Oil -- Residual									
.3%	D	555.0	1.61	573.3	9.90	919.2	7.94	1347.1	9.13
.7%	U	546.0	1.99	568.4	10.17	922.7	8.21	1368.8	9.14
.7%	D	526.0	1.88	546.4	10.29	891.7	8.21	1323.0	9.17
1.0%	U	528.0	2.15	550.0	10.48	905.5	8.38	1354.3	9.12
1.0%	D	508.0	2.05	529.2	10.57	874.6	8.39	1308.5	9.16
1.5%	D	483.5	2.42	507.2	10.94	852.2	8.63	1289.3	9.19
2.0%	U	479.0	2.68	505.9	11.21	860.8	8.86	1315.8	9.18
2.0%	D	459.0	2.69	483.9	11.35	828.2	8.93	1270.0	9.22
2.8%	U	448.0	3.08	476.5	11.73	829.9	9.25	1291.7	9.18
2.8%	D	427.0	3.23	454.5	11.94	799.0	9.29	1245.9	9.22
Oil -- Distillate									
-	U	683.0	1.16	699.5	7.92	1024.0	8.87	1566.4	8.88
-	D	693.0	1.15	709.3	7.91	1037.8	8.88	1588.1	8.91
Gas -- Natural									
-	U	381.0	11.07	470.0	13.75	895.0	10.51	1475.0	9.50
-	D	408.0	9.03	485.0	13.34	907.0	10.35	1484.0	9.43

TABLE 3.7

FUEL PRICE FORECAST
(HIGH PRICE SENSITIVITY ANALYSIS)

(NOMINAL MIDYEAR ¢/MBTU)

Sulfur Content	Upstate or Downstate	1983 Fuel Price	1983 Escalation Rate	1985 Fuel Price	1985 Escalation Rate	1990 Fuel Price	1990 Escalation Rate	1995 Fuel Price	1995 Escalation Rate
Oil -- Residual									
.3%	D	590.0	11.23	730.1	12.12	1293.8	9.21	2009.8	10.21
.7%	U	581.0	11.71	725.2	12.39	1300.7	9.41	2038.7	10.22
.7%	D	561.0	11.78	700.7	12.50	1262.9	9.45	1983.3	10.23
1.0%	U	562.0	12.08	705.6	12.65	1280.0	9.57	2021.9	10.22
1.0%	D	541.0	12.20	681.1	12.77	1242.2	9.59	1964.0	10.26
1.5%	D	516.0	12.80	656.6	13.12	1216.5	9.81	1942.3	10.27
2.0%	U	512.0	13.19	656.6	13.32	1226.8	10.00	1976.1	10.24
2.0%	D	491.0	13.45	632.1	13.47	1189.0	10.04	1918.2	10.29
2.8%	U	480.0	14.02	623.5	13.84	1192.4	10.28	1944.7	10.29
2.8%	D	459.0	14.24	599.0	14.02	1154.6	10.32	1886.9	10.31
Oil -- Distillate									
-	U	723.0	9.88	873.5	9.87	1398.6	9.91	2243.6	9.96
-	D	734.0	9.87	885.7	9.92	1420.9	9.92	2279.7	9.95
Gas -- Natural									
-	U	381.0	28.08	625.0	12.75	1139.0	10.26	1856.0	10.51
-	D	408.0	26.51	653.0	12.18	1160.0	10.04	1872.0	10.46

analysis scenarios, respectively. An additional sensitivity analysis was conducted which used ICF low oil and gas prices estimates through 1989, ICF mid-range (reference scenarios) oil prices from 1995 onward, and interpolated oil and gas prices for the intervening years. This scenario is referred to as the delayed oil price increase scenario. Table 3.8 illustrates the oil and gas prices used in this scenario.

C. Forecasts of Energy Imports.

Hydro Quebec and Ontario Hydro are the largest external power suppliers to NYPP. From 1984 through 1996, it is forecast that 12,000 GWH will be imported from Hydro Quebec. The HQ imports will fall into three categories -- firm, prescheduled economy, and economy. An annual schedule of the imports for each category is presented in Table 3.9.

Imports from Hydro Quebec consist of hydro power that remains constant in quantity in both the scenarios with and without Indian Point. The price for economy energy from Hydro Quebec is based upon the value of NYPP generation displaced by the HQ economy energy. The price of prescheduled economy energy and firm energy from HQ is determined primarily by the NYPP average cost of fossil generation. Hence, payments to HQ for firm, economy and prescheduled energy increase in the scenario without Indian Point as a result of the increase in cost of NYPP average fossil generation, and the increase in the value of the energy displaced by HQ imports.

Ontario Hydro coal-fired economy energy for 1984 through 1986 is modeled with a potential annual energy of 6800 GWH; from 1987 onward 10,000 GWH is available. For 1984 through 1986 an additional 3,504 GWH of firm energy is imported by Niagara Mohawk Power Corporation from Ontario Hydro. Using lower estimates of economy power from OH would increase the production cost penalties and additional oil usage associated with an Indian Point shutdown.

The Ontario Hydro purchase is scheduled economically (subject to transmission system constraints) using a dispatch cost in the range of the more expensive NYPP upstate coal generation. This dispatch cost is substantially less expensive than the cost of NYPP oil generation.

TABLE 3.8

FUEL PRICE FORECAST
(DELAYED OIL PRICE INCREASE SENSITIVITY ANALYSIS)
(Nominal Midyear ¢/MBTU)

Sulfur Content	Upstate or Downstate	1983 Fuel Price	1983 Escalation Rate	1985 Fuel Price	1985 Escalation Rate	1989 Fuel Price	1989 Escalation Rate	1995 Fuel Price	1995 Escalation Rate
Oil -- Residual									
.3%	D	555.0	1.61	573.3	9.90	919.2	10.99	1718.2	9.13
.7%	U	546.0	1.99	568.4	10.17	922.7	11.20	1744.7	9.13
.7%	D	526.0	1.88	546.4	10.29	891.7	11.26	1691.7	9.17
1.0%	U	528.0	2.15	550.0	10.48	905.5	11.37	1727.9	9.15
1.0%	D	508.0	2.05	529.2	10.57	874.6	11.46	1677.3	9.16
1.5%	D	483.5	2.42	507.2	10.94	852.2	11.70	1655.6	9.18
2.0%	U	479.0	2.68	505.9	11.21	860.8	11.84	1684.5	9.18
2.0%	D	459.0	2.69	483.9	11.35	828.2	11.99	1633.9	9.18
2.8%	U	448.0	3.08	476.5	11.73	829.9	12.23	1658.0	9.18
2.8%	D	427.0	3.23	454.5	11.94	799.0	12.33	1605.0	9.22
Oil -- Distillate									
-	U	683.0	1.16	699.5	7.92	1024.0	11.31	1947.2	8.94
-	D	693.0	1.15	709.3	7.91	1037.8	11.33	1976.1	8.94
Gas -- Natural									
-	U	381.0	11.07	470.0	13.75	895.0	11.36	1707.2	10.24
-	D	408.0	9.03	485.0	13.34	907.0	11.28	1722.0	10.12

TABLE 3.9

ANNUAL HYDRO QUEBEC IMPORTS

YEAR	FIRM	PRESCHEDULED	ECONOMY
	(GWH)		
1984	3000	7000	2000
1985	3000	7000	2000
1986	3000	7000	2000
1987	3000	9000	0
1988	3000	9000	0
1989	3000	9000	0
1990	3000	9000	0
1991	3000	9000	0
1992	3000	9000	0
1993	3000	9000	0
1994	3000	9000	0
1995	3000	9000	0
1996	3000	9000	0
1997	3000	0	3000
1998	3000	0	3000
1999	3000	0	3000

Since the OH purchase is scheduled economically, its usage expands in the scenario without Indian Point.

The cost of Ontario Hydro imports is based on the value of energy displaced by those imports on a split-the-savings basis. The payment for OH economy energy would increase if Indian Point were shut down. There are two reasons why the Ontario Hydro payments will increase as a result of the shutdown. First, payments will increase as a result of additional OH imports; second, payments will increase for the OH imports common to both scenarios due to the increased value of the energy displaced by the purchase as a consequence of the shutdown.

The cost of replacing Indian Point power, and the amount of additional oil that will be used to replace Indian Point power, are potentially understated in the EMA analysis. This understatement results from the conservative assumption that there are no economy sales that will be made to neighboring (New England and Pennsylvania-New Jersey-Maryland) power pools heavily dependent upon oil. In 1982 NYPP economy sales to neighboring power pools exceeded 4000 GWH. If such sales were considered, both the cost to New York State of the shutdown, and the amount of additional oil usage resulting from the shutdown, would increase.

D. Unit and System Operating Characteristic Data.

In order to simulate the operation of NYPP, both unit and system operating data are required. The principal unit data consist of:

1. Unit capacities;
2. Heat rates;
3. Availabilities; and,
4. Maintenance requirements.

These data have been supplied by the individual utilities to the NYPP planning staff. The data are reviewed and updated annually (more frequently if necessary) by the utilities and the NYPP staff. The utilities derive these data from the operating experience of existing units and from projections of operating characteristics of new units. These data are routinely used in a variety of generation planning analyses conducted by NYPP.

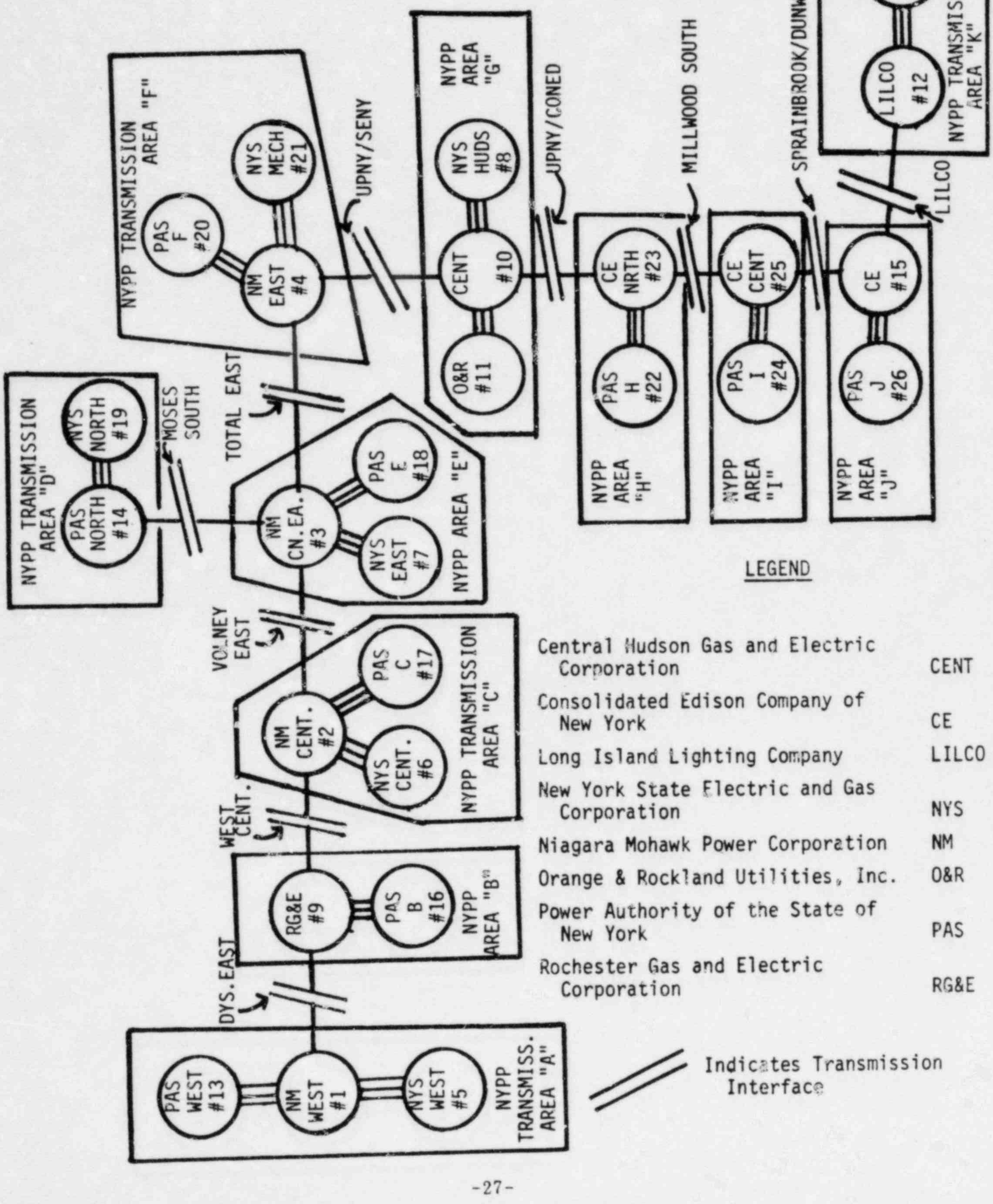
The maintenance schedule used in the analysis was developed by the NYPP staff. Minor modifications to the maintenance schedule were made to ensure that the schedule was in general conformance with the cooling tower settlement agreement concerning the operation of units on the Hudson River.

The availability of all nuclear units (including Indian Point) was set so that those units had a maximum possible mature capacity factor of 63 percent. Sensitivity analyses were conducted in which the nuclear unit availabilities were adjusted to restrict the maximum possible capacity factor for those units to 57 and 69 percent.

Figure 3.1 illustrates the NYPP transmission areas and critical upstate to downstate interfaces which were modeled. Eleven transmission areas and ten critical interfaces are modeled. Within each transmission area there are several load areas. These load areas represent each company's load within the transmission area. Limits for the Total East and the UPNY/SENY interfaces are illustrated in Table 3.10. These limits assume construction of a major transmission reinforcement between Central and Southeast New York, now planned for Fall of 1986. Without this reinforcement, all production cost penalties will increase.

FIGURE 3.1

NYPP LOAD AREAS



LEGEND

Central Hudson Gas and Electric Corporation	CENT
Consolidated Edison Company of New York	CE
Long Island Lighting Company	LILCO
New York State Electric and Gas Corporation	NYS
Niagara Mohawk Power Corporation	NM
Orange & Rockland Utilities, Inc.	O&R
Power Authority of the State of New York	PAS
Rochester Gas and Electric Corporation	RG&E

Indicates Transmission Interface

TABLE 3.10

INTERFACE POWER TRANSFER LIMITS

(MW)

	TOTAL EAST		UPNY/SENY	
Year	West-to-East	East-to-West	North-to-South	South-to-North
1984	3850	3850	2000	2000
1985	3850	3850	2000	2000
1986	3850	3850	2000	2000
1987	6350	6350	5000	5000
1988	6350	6350	5000	5000
1989	6350	6350	5000	5000
1990	6350	6350	5000	5000
1991	6350	6350	5000	5000
1992	6350	6350	5000	5000
1993	6350	6350	5000	5000
1994	6350	6350	5000	5000
1995	6350	6350	5000	5000
1996	6350	6350	5000	5000
1997	6350	6350	5000	5000
1998	6350	6350	5000	5000
1999	6350	6350	5000	5000

4. PRESENTATION OF RESULTS

The Statewide, Con Ed Service Area, and Con Ed penalties for the reference case and the various sensitivity analysis scenarios are presented in Tables 4.1, 4.2 and 4.3, respectively. Sensitivity analyses were conducted primarily for the years 1991 and 1999.

The production cost penalties in the tables referenced above include:

1. Increased fuel costs within NYPP;
2. Increased purchased power costs for additional volumes of Ontario Hydro energy imported as a result of the Indian Point shutdown; and,
3. Increased purchased power costs for volumes of Canadian energy common to the scenarios with and without Indian Point resulting from an increase in the value of the energy displaced by Canadian imports in the scenario without Indian Point.

Changes in operation and maintenance costs, or any revenue and fuel tax effects, are not included in the analysis conducted by EMA. Production cost penalties for the Con Ed Service Area and Con Ed are also affected by changes in the cost of internal economy transactions.

The shutdown of Indian Point also has adverse effects on other utilities in the state. Table 4.4 illustrates the year-by-year effect on Orange and Rockland Utililities, Inc. (O&R). While O&R receives some small benefit from the shutdown in several years, the overall effect is increased production costs for O&R. This effect predominates because O&R is primarily a purchaser of economy energy, and the removal of Indian Point increases the cost of the economy energy available to O&R.

The Indian Point shutdown will increase the usage of oil to generate electricity in New York State. Table 4.5 illustrates cumulative increased oil usage by year for the reference case. Table 4.6 illustrates for the sensitivity analysis scenarios the increased oil usage for the years 1991 and 1999.

The composition of the energy used to replace Indian Point is of substantial interest. Table 4.7 presents for oil, coal, gas and Ontario Hydro imports, the increase in generation in each category as a percentage of the total generation increase. Table 4.8 illustrates for 1991 and 1999 the percentage composition of additional energy production resulting from the Indian Point shutdown for the reference case and the various sensitivity analysis cases.

TABLE 4.1

NEW YORK STATE
PRODUCTION COST PENALTY RESULTING
FROM INDIAN POINT SHUTDOWN

	Scenarios								
	Reference Case	Low Load Growth	High Load Growth	Low Fuel Prices	Delayed Oil Price Increase	High Fuel Prices	No Coal Conversion	57% Capacity Factor	69% Capacity Factor
	(Millions of Dollars)								
1984	463	--	--	412	412	498	--	--	--
1985	533	--	--	423	423	572	--	--	--
1986	549	--	--	437	437	592	620	--	--
1987	503	--	--	415	415	541	--	--	--
1988	576	--	--	469	469	625	700	--	--
1989	650	--	--	528	528	712	--	--	--
1990	819	--	--	642	657	927	--	--	--
1991	965	750	971	731	788	1101	1011	832	926
1992	1073	--	--	810	920	1239	--	--	--
1993	1188	--	--	890	1070	1381	--	--	--
1994	1306	--	--	976	1238	1547	--	--	--
1995	1438	--	--	1073	1438	1724	--	--	--
1996	1604	--	--*	1195	1604	1944	--	--	--
1997	1859	--	--*	1395	1859	2271	--	--	--
1998	2090*	--	--*	1568*	2090*	2582*	--*	--*	--*
1999	2339*	1917	2705*	1758*	2339*	2916*	2247*	2048*	2388*

Note: Load growth, coal conversion and nuclear capacity factor sensitivity scenarios assume 700 MW Fossil and Jamesport in-service. Production cost penalties for these scenarios are understated.

* Indicates that removing Indian Point from service will result in an added capacity need if minimum pool reliability target is to be met.

TABLE 4.2

CON ED SERVICE AREA
PRODUCTION COST PENALTY RESULTING
FROM INDIAN POINT SHUTDOWN

	Scenarios								
	Reference Case	Low Load Growth	High Load Growth	Low Fuel Prices	Delayed Oil Price Increase	High Fuel Prices	No Coal Conversion	57% Capacity Factor	69% Capacity Factor
	(Millions of Dollars)								
1984	455	--	--	409	409	488	--	--	--
1985	529	--	--	423	423	564	--	--	--
1986	510	--	--	414	414	545	636	--	--
1987	489	--	--	405	405	524	--	--	--
1988	564	--	--	463	463	612	729	--	--
1989	641	--	--	519	519	701	--	--	--
1990	731	--	--	586	599	820	--	--	--
1991	836	685	853	653	679	940	880	718	820
1992	931	--	--	724	814	1060	--	--	--
1993	1043	--	--	806	952	1202	--	--	--
1994	1170	--	--	900	1115	1365	--	--	--
1995	1304	--	--	1000	1304	1543	--	--	--
1996	1469	--	--	1123	1469	1758	--	--	--
1997	1570	--	--	1214	1570	1885	--	--	--
1998	1781	--	--	1372	1781	2165	--	--	--
1999	2009	1526	2403	1547	2009	2472	1920	1738	2006

Note: Load growth, coal conversion and nuclear capacity factor sensitivity scenarios assume 700 MW Fossil and Jamesport in-service.

TABLE 4.3

CON ED
PRODUCTION COST PENALTY RESULTING
FROM INDIAN POINT SHUTDOWN

	Scenarios								
	Reference Case	Low Load Growth	High Load Growth	Low Fuel Prices	Delayed Oil Price Increase	High Fuel Prices	No Coal Conversion	57% Capacity Factor	69% Capacity Factor
	(Millions of Dollars)								
1984	200	--	--	182	182	213	--	--	--
1985	227	--	--	187	187	240	--	--	--
1986	211	--	--	179	179	222	262	--	--
1987	227	--	--	193	193	241	--	--	--
1988	271	--	--	226	226	293	204	--	--
1989	312	--	--	256	256	340	--	--	--
1990	347	--	--	286	292	393	--	--	--
1991	404	328	426	319	340	453	378	347	403
1992	446	--	--	350	392	506	--	--	--
1993	502	--	--	391	460	576	--	--	--
1994	572	--	--	443	546	666	--	--	--
1995	639	--	--	492	639	755	--	--	--
1996	728	--	--	558	728	870	--	--	--
1997	692	--	--	548	692	817	--	--	--
1998	798	--	--	629	798	956	--	--	--
1999	918	653	1200	722	918	1114	870	806	920

Note: Load growth, coal conversion and nuclear capacity factor sensitivity scenarios assume 700 MW Fossil and Jamesport in-service.

TABLE 4.4

ORANGE AND ROCKLAND
PRODUCTION COST PENALTY RESULTING
FROM INDIAN POINT SHUTDOWN

REFERENCE CASE

YEAR	PENALTY ($ MILLIONS)
1984	5
1985	0
1986	4
1987	-2
1988	-3
1989	-3
1990	4
1991	4
1992	6
1993	7
1994	10
1995	9
1996	11
1997	21
1998	27
1999	31

TABLE 4.5

CUMULATIVE INCREASED OIL USAGE RESULTING
FROM INDIAN POINT SHUTDOWN
REFERENCE CASE

	Thousands of Bbls.
1984	13,904
1985	27,997
1986	39,852
1987	45,745
1988	51,975
1989	58,260
1990	67,475
1991	78,640
1992	90,487
1993	103,280
1994	116,677
1995	130,475
1996	144,728
1997	160,066
1998	175,696
1999	191,607

TABLE 4.6

INCREASED OIL USAGE RESULTING FROM INDIAN POINT SHUTDOWN

	Scenarios								
	Reference Case	Low Load Growth	High Load Growth	Lower Fuel Prices	Delayed Oil Price Increase	Higher Fuel Prices	No Coal Conversion	57% Capacity Factor	69% Nuclear Capacity
	(Thousands of Bbls)								
1991	11165	4875	11210	11165	11165	11165	13380	8912	8306
1999	15911	12660	18197	15911	15911	15911	15778	13979	16288

Note: Load growth, coal conversion and nuclear capacity factor sensitivity scenarios assume 700 MW Fossil and Jamesport in-service.

TABLE 4.7

PERCENTAGE OF INCREMENTAL GENERATION OCCASIONED BY INDIAN POINT SHUTDOWN BY RESOURCE CATEGORY REFERENCE CASE

	Oil	Coal	Gas	Ontario Hydro
	(Percent)			
1984	92	4	3	1
1985	92	6	2	0
1986	78	17	2	3
1987	37	35	4	24
1988	39	34	5	22
1989	40	37	4	19
1990	61	27	7	5
1991	75	16	7	2
1992	80	13	6	1
1993	86	10	3	1
1994	90	8	1	1
1995	92	6	1	1
1996	94	5	1	0
1997	98	1	1	0
1998	98	1	1	0
1999	99	0	1	0

TABLE 4.8

PERCENTAGE OF INCREMENTAL GENERATION
OCCASIONED BY INDIAN POINT SHUTDOWN BY
RESOURCE CATEGORY

Year and Resource Category	Scenarios: Reference Case	Low Load Growth	High Load Growth	Lower Fuel Prices	Delayed Oil Price Increase	Higher Fuel Prices	No Coal Conversion	57% Capacity Factor	69% Nuclear Capacity
<u>1991</u>									
Oil	75	30	75	75	75	75	90	66	49
Coal	16	48	15	16	16	16	3	24	36
Gas	7	2	7	7	7	7	6	6	4
Ontario Hydro	2	20	3	2	2	2	1	4	11
<u>1999</u>									
Oil	99	85	100	99	99	99	99	98	96
Coal	0	14	0	0	0	0	0	1	3
Gas	1	0	0	1	1	1	1	1	1
Ontario Hydro	0	1	0	0	0	0	0	0	0

Note: Load growth, coal conversion and nuclear capacity factor sensitivity scenarios assume 700 MW Fossil and Jamesport in-service.

Qualitative analysis was applied to the potential adjustment to the penalty in cases that would combine the most optimistic and pessimistic assumptions from the various sensitivity analysis scenarios. There are two important findings of that analysis.

First, it is necessary to recognize that it is highly unlikely that all the events that tend to either increase or decrease the penalty from that derived for the reference case would occur simultaneously. For example, if low load growth and low oil prices materialized, the possibility that the utilities would not achieve their coal conversion plans would increase. The economic attractiveness of those plans would decrease as load growth and fuel prices fell below forecast values. Hence, a combined analysis of low load growth, low fuel prices, and full realization of coal conversion plans is not realistic. Similarly, given high load growth and high fuel prices, the utilities would most probably be compelled to achieve their plans. Hence, examining high load growth and high fuel prices in conjunction with reduced coal conversion is not realistic. In sum, there are self-governing bounds upon combining optimistic and pessimistic assumptions, which tend to reduce the uncertainty of the range of the forecast penalty.

Second, the effects of reasonable combinations of optimistic assumptions and reasonable combinations of pessimistic assumptions would be decidedly non-symmetrical. Pessimistic assumptions (e.g., high oil prices and high load growth), when combined, could be expected to exaggerate each other in terms of the economic impacts associated with a shutdown. Higher load growth would increase the amount of oil used to replace Indian Point generation, rendering the effect of [illegible] oil prices more severe. Optimistic assumptions (e.g., low oil prices and low [illegible] growth), when combined, would tend to neutralize each other in terms of the economic impacts associated with a shutdown. Low load growth would reduce the amount of oil used to replace Indian point generation, rendering the effect of low oil prices less beneficial. The combined increase in penalty resulting from high load growth and high oil prices would be greater than the sum of the individual effects. The combined decrease in penalty resulting from low load growth and low oil prices would be less than the sum of the individual effects. This non-symmetry is important to recognize when evaluating projections based upon data that by nature are uncertain. The amount by which the adverse economic impact of closing Indian Point could increase, if pessimistic assumptions prove true, far

exceeds the decrease in the adverse economic impact that would occur if more optimistic assumptions prove true.

Further qualitative analysis was conducted with respect to the impact that cogeneration and conservation induced by the price increase resulting from the shutdown of Indian Point may have upon the production cost penalty. With respect to cogeneration, current policies reimburse cogenerators for 100 percent of the avoided cost associated with the supply of cogenerated electricity. Hence, the utility production costs determined for each of the scenarios that have been analyzed would not change if added cogeneration resulted from an Indian Point shutdown. Utility production costs, including payments to cogenerators, do not vary with the amount of cogeneration. Even if the policy with respect to payments to cogenerators were to change so that utilities only paid, say, 90 percent of the avoided cost, the impact on the production cost penalty would not be large. Given that assumption, which in itself would represent a major change in policy, and the assumption that cogeneration could serve as a replacement for twenty percent of the energy generated by Indian Point, the effect on the production cost penalty would be less than two percent.

Conservation is more complicated. If the rate increase that would result from an Indian Point shutdown results in additional conservation the direct production cost penalty of the shutdown would decrease. Focusing on the reduced direct production cost penalty would, however, be very misleading. The economic impact of the shutdown is not necessarily reduced by conservation, it is merely transferred from an increase in utility production costs to increases in costs that are borne in the first instance by ratepayers. These costs come either in the form of reduced usage and satisfaction from electricity consumption or as funds expended on devices to enable customers to reduce electricity purchases. Substituting self generation for utility purchases is an example of one way in which customers could conserve in response to the shutdown of Indian Point. If, for example, all of the energy generated by Indian Point in 1984 was replaced by self generation the effect of the shutdown directly on utility production costs could be completely eliminated. The economic impact of the shutdown, however, would not be reduced it would simply have been shifted. In this particular example it is likely that in addition to being shifted the total economic impact will increase dramatically as the cost of new self generation in 1984 is significantly greater than the NYPP cost of replacing Indian Point power.

5. CONCLUSION

A shutdown of the Indian Point nuclear generating station will impose severe fuel replacement and purchased power cost penalties upon New York State, Con Ed, and the Con Ed service area. The annual penalty for New York State starts at \$463 million in 1984 and increases to over \$2.3 billion in 1999, with a total penalty of \$18.0 billion over the 1984-1999 period. The Con Ed annual penalty begins at \$200 million in 1984 and rises to \$918 million in 1999, with a total penalty of \$7.5 billion. The annual penalty for the Con Ed service area is initially \$455 million in 1984 escalating to over \$2.0 billion in 1999, with a total penalty of \$16.0 billion over the sixteen year period. The design life of the plants extends beyond the 1999 period analyzed herein. Hence, there will be additional production cost penalties associated with the shutdown of Indian Point which are not reported herein.

A shutdown of Indian Point would also result in substantial increased use of oil within New York State, totalling close to 192 million barrels over the sixteen-year period between 1984 and 1999.

In addition to sending American dollars overseas to foreign oil suppliers, \$1.9 billion more dollars would be exported to Canada in the form of increased payments for purchased Canadian energy over this sixteen-year period.

Lower than forecast oil prices and lower load growth would reduce the penalties associated with the Indian Point shutdown. However, even scenarios with low load growth or low oil prices do not result in insignificant penalties. Higher than forecast load growth and higher than forecast oil prices would substantially increase the cost penalty associated with the Indian Point shutdown. The inability of the utilities to fully achieve their transmission capacity expansion and coal conversion plans, a distinct possibility, would serve to increase the already high costs associated with an Indian Point shutdown. The assumption that there will not be any NYPP external economy sales to neighboring power pools is conservative, and results in the potential understatement of the penalty of an Indian Point shutdown.

In sum, there would be a substantial economic penalty imposed upon the State of New York, the Con Edison service area and Con Edison by the shutdown of Indian Point. The shutdown would result in higher electric rates, probably higher oil prices, and increase the state's exposure to foreign supply embargoes. The shutdown would be an obstacle to the goal of reducing dependence on oil of New York State and the nation.

APPENDIX A

QUALIFICATIONS OF EUGENE T. MEEHAN

Mr. Meehan joined Energy Management Associates, Inc. (EMA) in September, 1980. At EMA he has directed studies on topics including the examination of utility expansion plans, marginal costs, the determination of avoided cost for use in ratemaking proceedings, the strategic analysis of pursuing an interruptible rate program, and fuel budgeting. He has worked extensively with New York utilities.

Prior to joining EMA, Mr. Meehan was employed by National Economic Research Associates, Inc. (NERA). He joined NERA in April, 1973. His work at NERA primarily concerned the development and application of methods for quantifying the marginal costs of providing electric service, engagements that required detailed knowledge of utility planning and operating procedures. He participated in NERA's research as part of the Electric Power Research Institute's study on rate design and was active in marginal cost studies for 25 electric utilities throughout the United States and Canada. He had primary responsibility for all research in 15 of those 25 studies.

Mr. Meehan co-authored and maintained the engineering economic model used by NERA to determine fixed charge rates and incremental revenue requirements. That model was used in marginal cost studies and in evaluation of the relative economics of coal and nuclear capacity alternatives.

He has testified before the Public Utilities Commission of Ohio in Case Nos. 76-823-EL-A/R and 78-92-EL-A/R, the Minnesota Public Service Commission in Docket No. EO15/GA-80-76, the New York Public Service Commission in Case 27353 -- Phase II, Case 28059 and Case 28223, and the Arkansas Public Service Commission in Docket No. U-2972 and Docket No. U-3108.

Mr. Meehan received a Bachelor's degree in Economics from Boston College in 1972, graduating cum laude. He has completed 38 credits of course work at the Graduate School of Business Administration of New York University (NYU). Among the courses that he has completed at NYU are the intensive courses in microeconomic and macroeconomic theory required as core courses for the doctoral program.