CASE NUMBER:

99-449

Cinergy Corp.
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JOHN J. FINNIGAN, JR.
Senior Counsel

RECEIVED
FEB 03 2000
PUBLIC SERVICE COMMISSION

CINERGY®

February 2, 2000

VIA OVERNIGHT MAIL

Hon. Helen Helton
Executive Director
Public Service Commission of Kentucky
211 Sower Blvd.
Frankfort, Kentucky 40602

RE: In the Matter of: A REVIEW PURSUANT TO 807 KAR 5:058 OF THE 1999 INTEGRATED RESOURCE PLAN OF THE UNION LIGHT, HEAT AND POWER COMPANY
Case No. 99-449

Dear Ms. Helton:

Enclosed are six (6) true copies of The Union Light, Heat and Power Company's Responses to the Commission Staff's Request for Information in the above captioned case.

A copy of these responses has been forwarded to all parties of record in this case.

Very truly yours,

John J. Finnigan nlb

John J. Finnigan
Senior Counsel

JJF/nlb

Enclosures

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Responses was served on the following parties by ordinary mail, this 2nd day of February, 2000.

John J. Finnigan, Jr.

Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601

Iris Skidmore
Ronald P. Mills
Office of Legal Services
Fifth Floor, Capital Plaza Towe
Frankfort, Kentucky 40601

RECEIVED
FEB 03 2000
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

A REVIEW PURSUANT TO 807 KAR 5:058 OF THE	)	
1999 INTEGRATED RESOURCE PLAN OF THE	)	CASE NO. 99-449
UNION LIGHT, HEAT AND POWER COMPANY	)	

RESPONSE OF THE UNION LIGHT, HEAT AND POWER COMPANY COMMISSION STAFF'S REQUEST FOR INFORMATION

FIRST SET

FEBRUARY 2, 2000

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-001

REQUEST:

1. Specify each of the equations that were estimated in Section III, the Load Forecast section, of the Integrated Resource Plan ("IRP") and submit the estimation results for each (i.e., the Output).

RESPONSE:

Please see pages OA-41 through OA-136 of the Cinergy 1999 Integrated Resource Plan, Ohio Appendix, Volume II.

WITNESS RESPONSIBLE:

James A. Riddle

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-002

REQUEST:

2. Referring again to Section III of the IRP, identify the equations that contained qualitative variables. Provide a definition of each of these variables and the reason for its inclusion in that particular equation.

RESPONSE:

Please see pages OA-41 through OA-136 of the Cinergy 1999 Integrated Resource Plan, Ohio Appendix, Volume II. The output identifies and defines the qualitative variables used in each equation. Their inclusion is warranted by the data and the results of the regression estimation.

WITNESS RESPONSIBLE:

James A. Riddle

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-003

REQUEST:

3. Refer to page 1-6 of the IRP. Provide the most recent analysis, report, or study developed by Cinergy in support of its minimum reserve margin of 17 percent.

RESPONSE:

Attachment KyStaff-01-003-A is the reserve margin study that was the source for PSI Energy's stand-alone reserve margin criteria of 20%. The study documenting CG&E's stand-alone reserve margin of 17% could not be located. Attachment KyStaff-01-003-B is an excerpt from the Operating Agreement Among The Cincinnati Gas & Electric Company, PSI Energy, Inc., and Cinergy Services, Inc. that shows that the initial Cinergy System Planning Reserve Margin after the merger shall be 17%.

WITNESS RESPONSIBLE:

Diane Jenner

PSI ENERGY

RESERVE MARGIN STUDY

George F. Stevens, P.E.

System Planning Department

July 1991

TABLE OF CONTENTS

EXECUTIVE SUMMARY

The purpose of this study was to re-examine and update the reserve margin criterion used by PSI Energy in planning new generation. This study used the 1984 study by Energy Management Associates and the 1987 PSI System Planning study as general guidelines.

The reserve margin was evaluated from both the technical and the economic perspectives. From a technical standpoint, reserves must be adequate for:

1. Security of Operation - Secrure system operation during a period of severe weather, by considering a combination of weather induced load, loss of the largest generating unit and a regulating margin; and

2. Maintenance Scheduling - Scheduling unit maintenance without system reserve capacity dropping below the level required for security of operation; and

3. ECAR Member Obligation - PSI Energy's obligation as a member of ECAR

From an economic standpoint, the optimum reserve level is the level which provides the lowest overall cost when considering the societal cost of interruptions and the revenue requirement for reserve levels which minimize the societal cost.

The recommended generation expansion criteria is:

1. A minimum reserve margin of 20%; and;

2. The expected unserved energy (EUE) should not exceed the level that corresponds to the EUE when the system reserve margin is at 25%, and;

3. The initial units should be installed when reserves, utilizing existing capacity, decline to the 25% level.

Without both parts of this dual criteria, it would be possible to: 1) meet the EUE criteria but not have enough capacity for maintenance; or 2) meet the reserve margin criteria but have excessive customer outage costs (too high an EUE).

PURPOSE

The purpose of this study was to determine the appropriate criteria to be used for generation expansion planning at PSI Energy. Two prior studies, the 1984 study by Energy Management Associates, Inc. (EMA) and the 1987 study by Generation Planning, were used as general guidelines in performing this determination.

INTRODUCTION

PSI Energy currently uses a combination of expected unserved energy (EUE) and a minimum 20% reserve criterion in generation expansion studies to determine the need for new capacity additions. The EUE is calculated in the year that the reserve margin drops to 25%, and is used as a guide to establish the minimum reliability level for all future years of a study. The 25% reserve level was determined in a study by Energy Management Associates (EMA) in 1984 and was reconfirmed by PSI Generation Planning in 1987. The dynamic nature of the generation planning process requires periodic reviews of the generatioin expansion criteia.

A reserve margin for planning is the amount of installed generating capacity on a utility system above the forecasted load and is required for both technical and economic reasons.

From a technical standpoint, reserves must be adequate for:

1. Security of Operation - Secure system operation during a period of severe weather, by considering a combination of weather induced load, loss of the largest generating unit and a regulating margin; and

2. Maintenance Scheduling - Scheduling unit maintenance without system reserve capacity dropping below the level required for security of operation; and

3. ECAR Member Obligation - PSI Energy's obligation as a member of ECAR

From an economic standpoint, the optimum reserve level is the level which provides the lowest overall cost when considering the cost of customer outages (the societal cost of interrruptions) and the revenue requirements for reserve levels which minimize this outage cost.

This study evaluated the PSI Energy system to determine the generation expansion criteria. First the Security of Operation requirement was determined and then it was used to check the Maintenance Scheduling criteria. With these two parts of the technical perspective defined, the Cost of Customer Outages was then considered to further refine the expansion criteria. The final step in this study was to review PSI Energy's <u>ECAR Member Obligation</u> to verify that this committment can be fulfilled if PSI uses the recommended generation expansion criteria.

METHODOLOGY AND RESULTS

Security of Operation

The reserve margin must be adequate to insure that during periods of extreme weather conditions the system demand will be met, including the additional weather induced load, even with the loss of the largest unit on the system, and a provision for regulating margin. This criteria, called Security of Operation, considers the sum of the:

1. Weather induced load;
2. Regulating margin; and
3. Loss of the largest unit on the system.

Weather Induced Load

To determine the weather induced load caused by extreme weather conditions, 19 years of National Oceanic and Atmospheric Administration (NOAA) weather data for the Indianapolis region was analyzed for the years 1969 - 1987. The temperatures which occurred during the expected hours of the winter peak (9:00 a.m.) and the summer peak (5:00 p.m.), for the most extreme conditions for each winter and summer month, were combined into a cumulative probability distribution to determine a once-in-five-year weather extreme during the peak hour of winter and summer.

A load-temperature deviation correlation, which forecasts the impact per degree of weather induced load, was supplied by Load Forecasting for the years 1991 - 2010. This impact grows over time as appliance saturation changes in our service territory. The once-in-five-year conditions were multiplied by the load/temperature deviation correlation to compute the weather induced load.

Regulating Margin

Generally accepted operating practice requires a 1.5% regulating margin. The regulating margin was computed as 1.5% of the sum of the peak demand and the weather induced load.

Loss of the Largest Unit

The largest units on the PSI Energy system are at Gibson Station and have a winter rating of 635 MW and a summer rating of 625 MW.

Results

The computation of the reserves required for Security of Operation is shown in Appendix A. The percent reserve requirement declines over time since the largest item in the required reserves is the Gibson unit which remains a constant.

Maintenance Scheduling

Maintenance must be performed on all generating units to maintain the availability and heat rate of the units. This must be scheduled in a manner that will not affect the overall reliability of the system while specific units are off-line. Generally the method used is to schedule the larger units for maintenance in spring and fall, when system load is lower. Although load is lower, the overall system reliability must be maintained in terms of security of operation and a uniform reliability level is achieved throughout the year. Therefore, installed capacity must not only be adequate for summer and winter peak loads, but also must permit this maintenance.

The reserve margin is adequate for ability to perform maintenance if the reserves available at a specific level of percent reserve exceed the minimum reserves required for Security of Operation.

Resource Plans

Resource plans were developed for percent reserve levels from 15% to 25% in 2.5% increments. Each plan began with three TP&M combustion turbines (95 MW summer rating) and the balance of the required units were advanced combustion turbines (126 MW summer rating). The initial units were added when the percent reserve dropped to the specified level. The number of combustion turbines required ranged from 17 for 15% reserves to 24 for 30% reserves.

This method minimizes the differences between the various levels of percent reserve to the number of combustion turbines only and is the method used by EMA in the 1984 study. The resource plans and the present value of revenue requirements (PVRR) for each plan is shown in Appendix B.

Maintenance Schedule

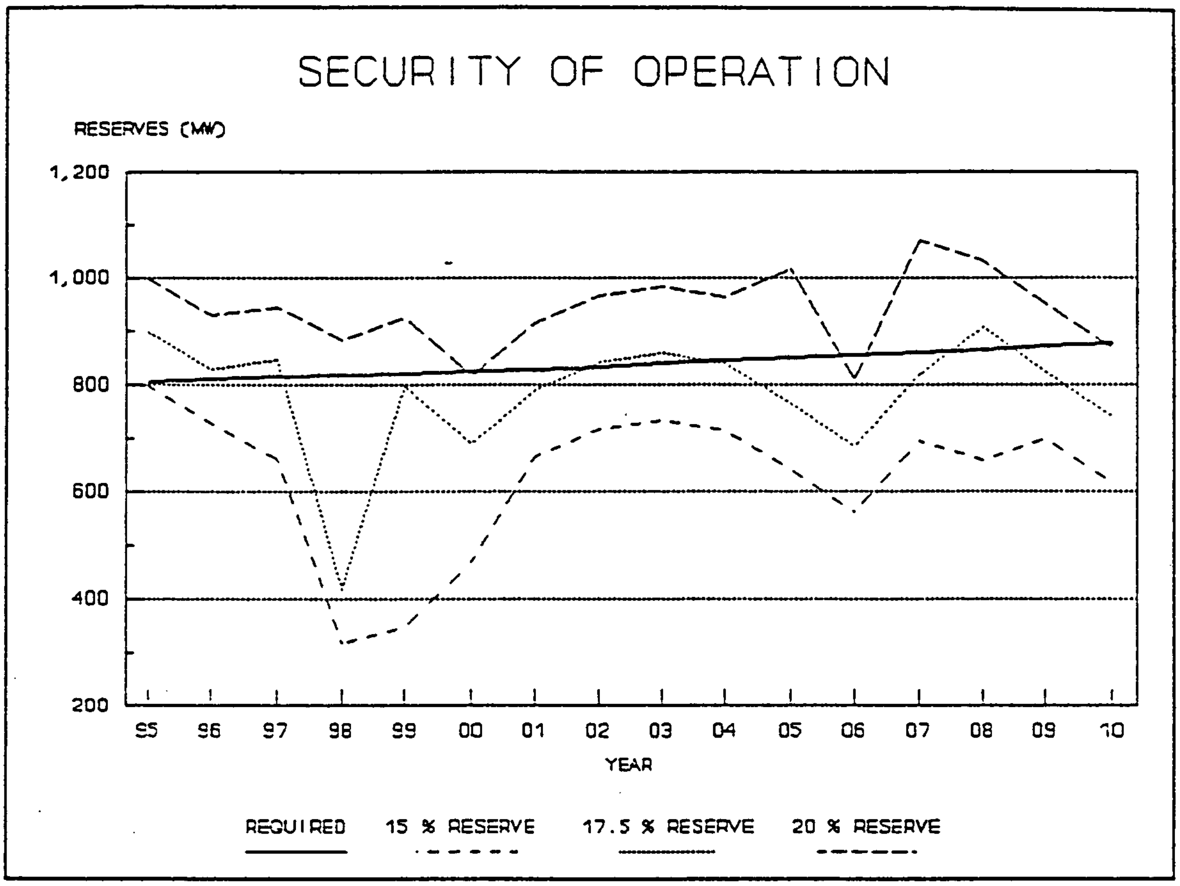
The automatic maintenance scheduling feature in PROMOD III was utilized in these runs. This feature schedules maintenance to approximately equalize reliability in each week of the year. The reserves available in each week were output on the weekly reserve summary report and compared to the reserves required for Security of Operation to assure adequate reserves for the Maintenmance Scheduling requirement.

System Model

The system model included the 1991 trend load forecast, which was adjusted for the NUCOR load and for load management. The current environmental compliance scenario, with the accompanying fuel costs and projected unit retirements, along with a forecast of off-system sales was also included in the model.

Results

The comparison of the reserves required for Security of Operation to the reserves available after scheduling maintenance for various levels of percent reserve indicates that percent reserve should not drop below 20%, as shown by the graph below.



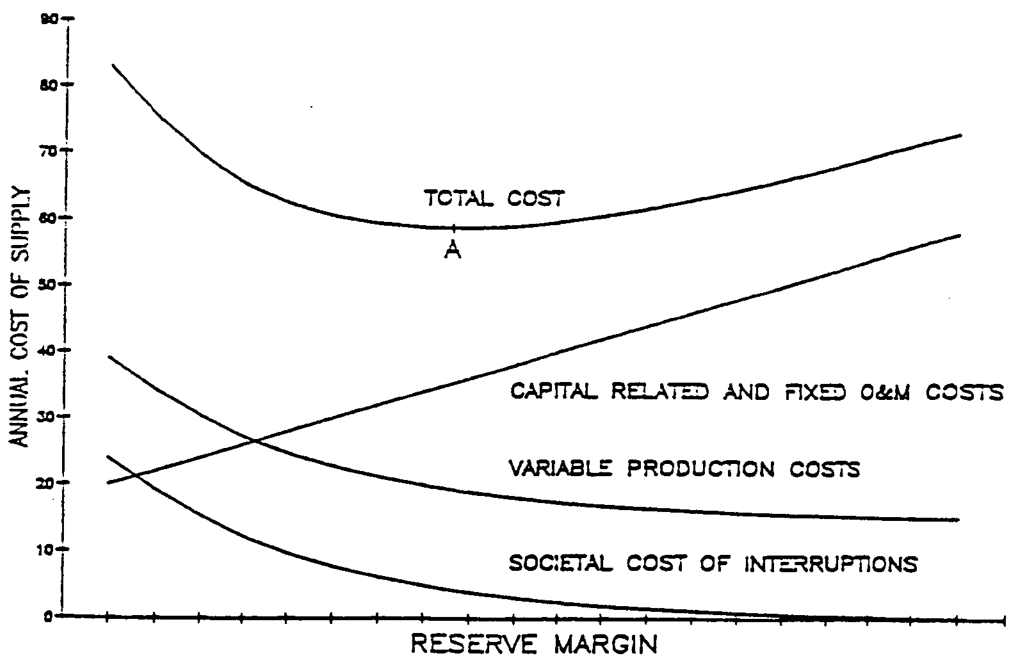
The computation of the reserves available is shown in Appendix C. Thus, when considering both Security of Operation and Maintenance Scheduling, reserves should not be allowed to drop below 20%.

Cost of Customer Outages

The cost of customer outages may be such that a reserve level greater than 20% will result in a lower total cost to the customer. This section of the study considers the trade-off between minimizing customer outage costs and the total cost to the customer.

The total cost to the customer is an aggregation of costs related to the production of energy, the annual charges for the plant investment in rate base, and the customer outage cost. The sum of these costs can be calculated for various reserve margins and plotted on a graph as shown below. From an economic standpoint, the optimum reserve level is the minimum point on the total cost curve (Point A).

TOTAL COST OF SUPPLY



New Resources

The resource plans used for the Maintenance Scheduling portion of this study were also used for customer outage cost. The present worth revenue requirements was computed for each resource plan in 1991 dollars using a 10% after tax discount rate as shown in Appendix B.

Production Cost

Each resource plan was then put into a PROMOD run for 1991-2010 to determine the present worth of revenue requirement for the production costs associated with each reserve level.

Emergency Assistance

The probability of having emergency assistance available during a period of supply shortage was not calculated since the current PROMOD III version at PSI Energy is a single area model and is limited in the number of generating units that can be modeled. EMA estimated the probability of emergency assistance being available to PSI from neighboring utilities for various reserve levels in the ECAR region. The probability of assistance was 98% for the projected level of reserves in ECAR in the 1995-2000 time period. Therefore, the Cost of Customer Outages was computed assuming 2% of the unserved energy reported in PROMOD would actually be unserved.

Societal Cost of Interruptions

The societal cost of interruptions due to supply shortages includes direct costs such as labor costs, damaged products, loss of livestock, etc., and indirect costs such as human suffering. While PSI Energy has not conducted a detailed study of the societal cost of interruptions, a very detailed study was performed by Ontario Hydro in the late 1970's and early 1980's. EMA used this data in their 1984 study and it was used in this study also.

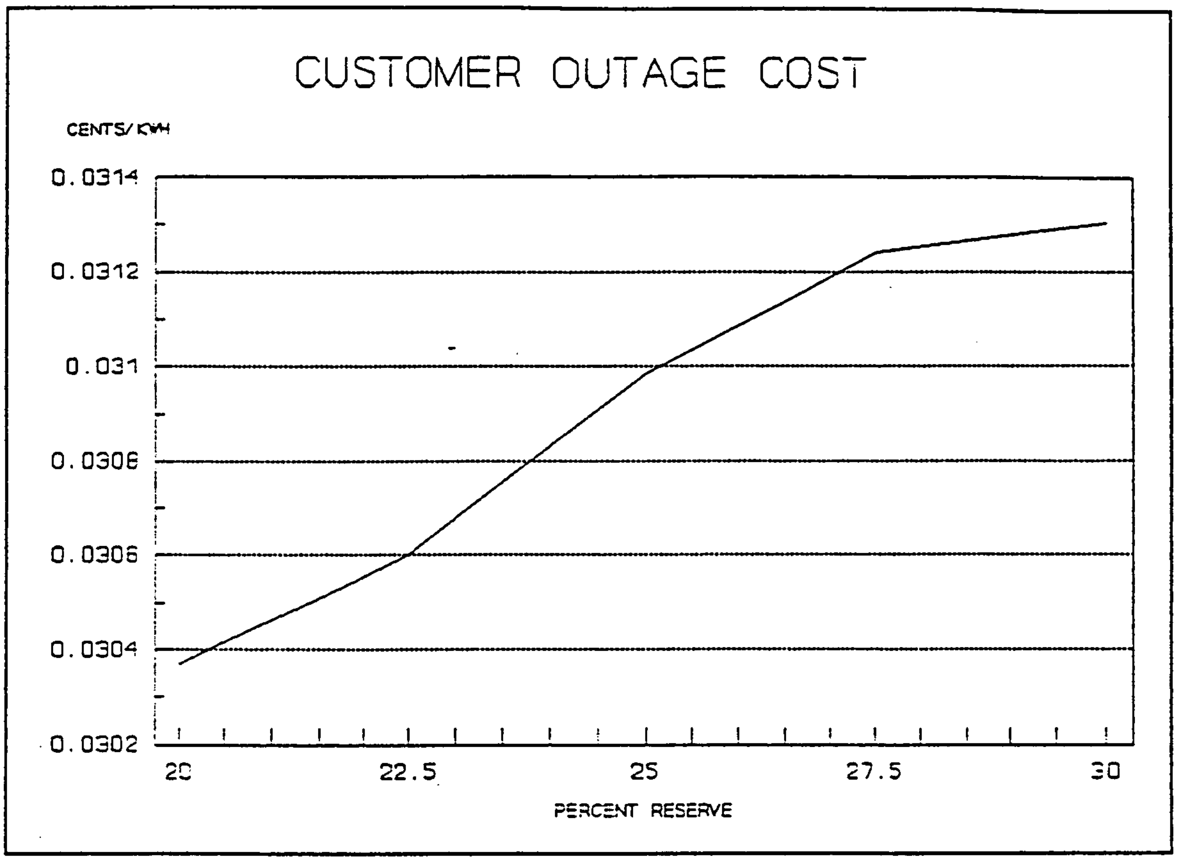
The costs developed by Ontario Hydro were escalated to 1991 dollars for use in this study, using the Data Resources Inc. (DRI) GNP implicit price deflator, which is a good indicator of the general rate of inflation. They were then weighted using the annual energy requirement of each customer class as a percent of the total system demand, to get an average interruption cost for each year of the study. This cost was multiplied by the 2 % of the unserved energy projected to be unavailable off-system to compute the annual customer outage cost.

The escalation of the outage costs and the computation of the cost of interruptions by customer class is shown in Appendix D. The calculated Cost of Customer Outages is shown in Appendix E.

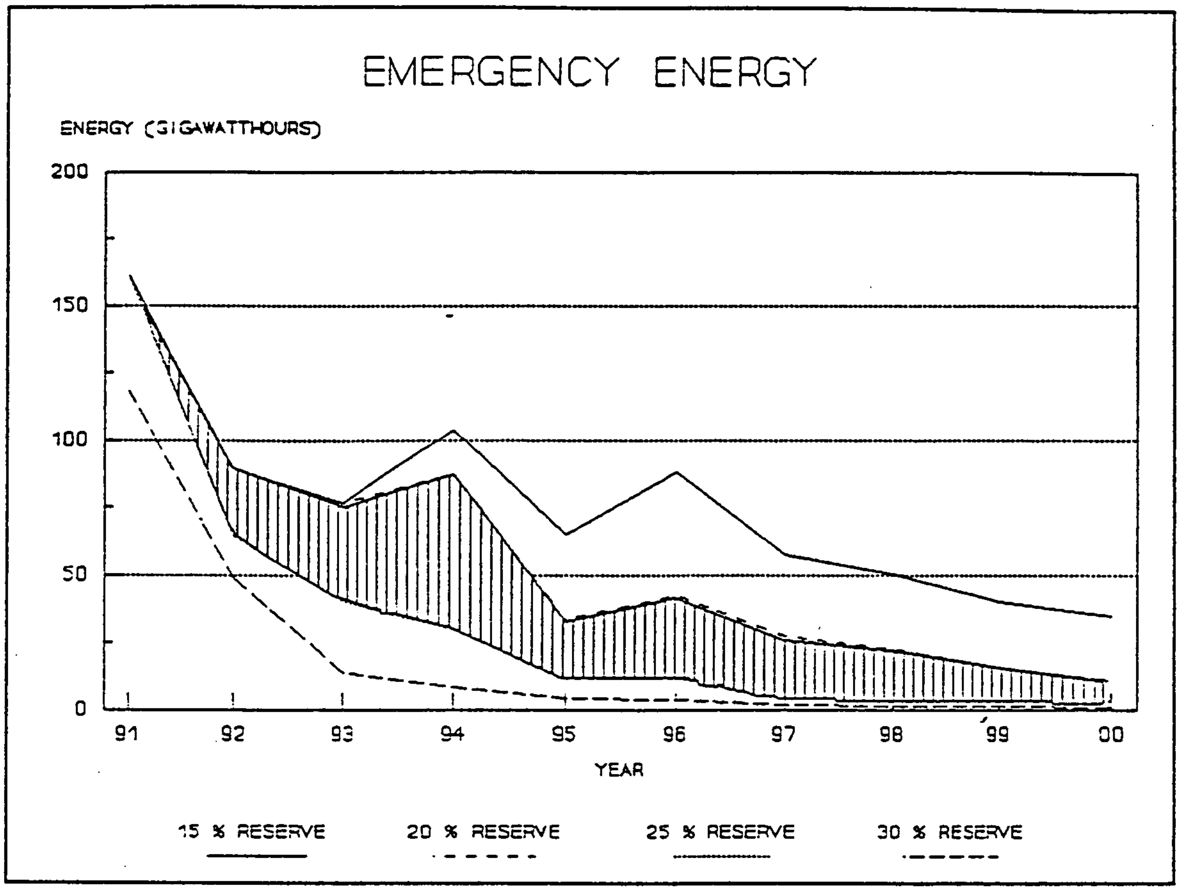
Results

The PVRR of the total customer cost was computed as the sum of the PVRR's of the customer outage costs, the production costs, and the resource plan costs. This was done for percent reserve levels from 20% to 30% to develop the total cost curve. Percent reserve levels below 20% were not considered since a minimum reserve level of 20% was required for Security of Operation and Maintenance Scheduling. The calculation of the total PVRR's is shown in Appendix F.

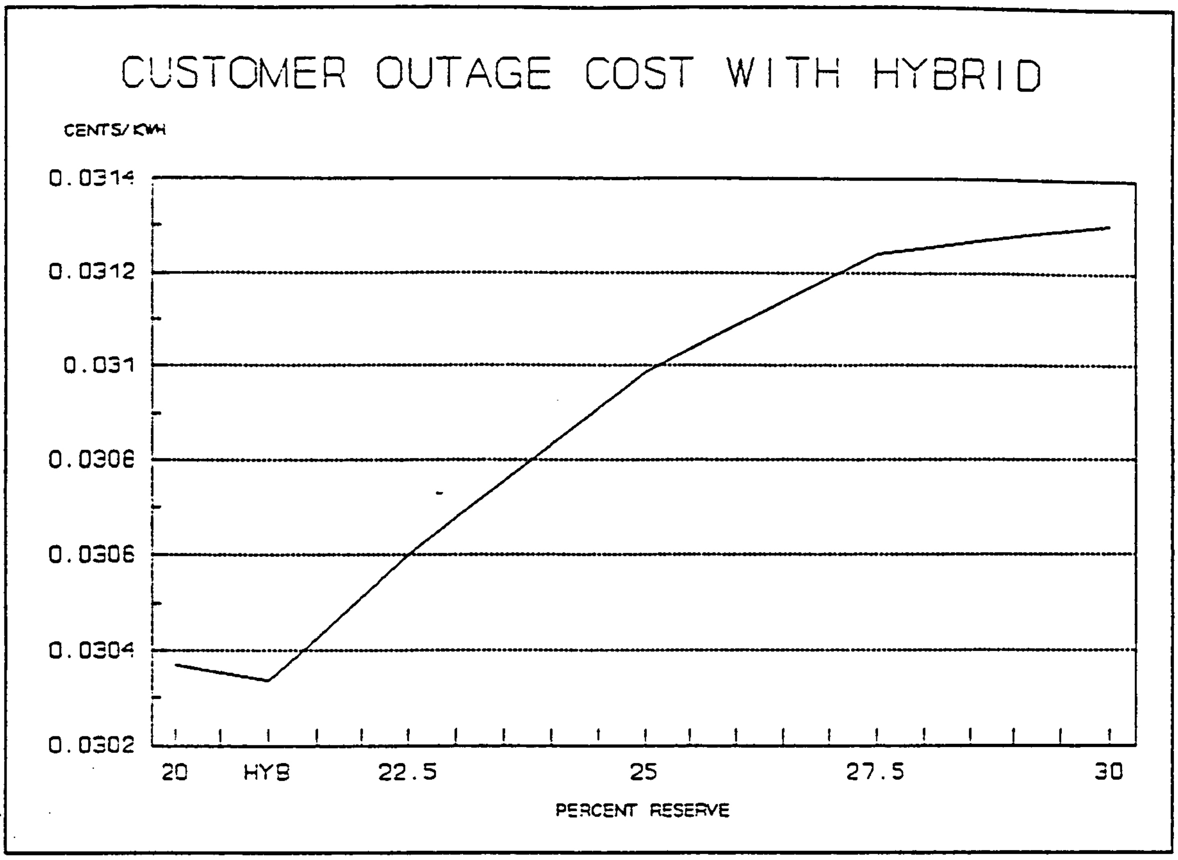
The initial results, as shown below, indicated that a 20% reserve level resulted in the lowest total levelized costs to the customer.



However, a study of the EUE graph below shows a considerable amount of customer outage cost could be eliminated if reserves were to meet the 25 % reserve level in the early years and then trend to the 20% minimum reserve level for Security of Operation.



A hybrid case was developed using the 25% level as a starting point and trending down to the 20% minimum percent reserve level required for Security of Operation and Maintenance Scheduling to check this possibility. The graph on the following page shows this result.

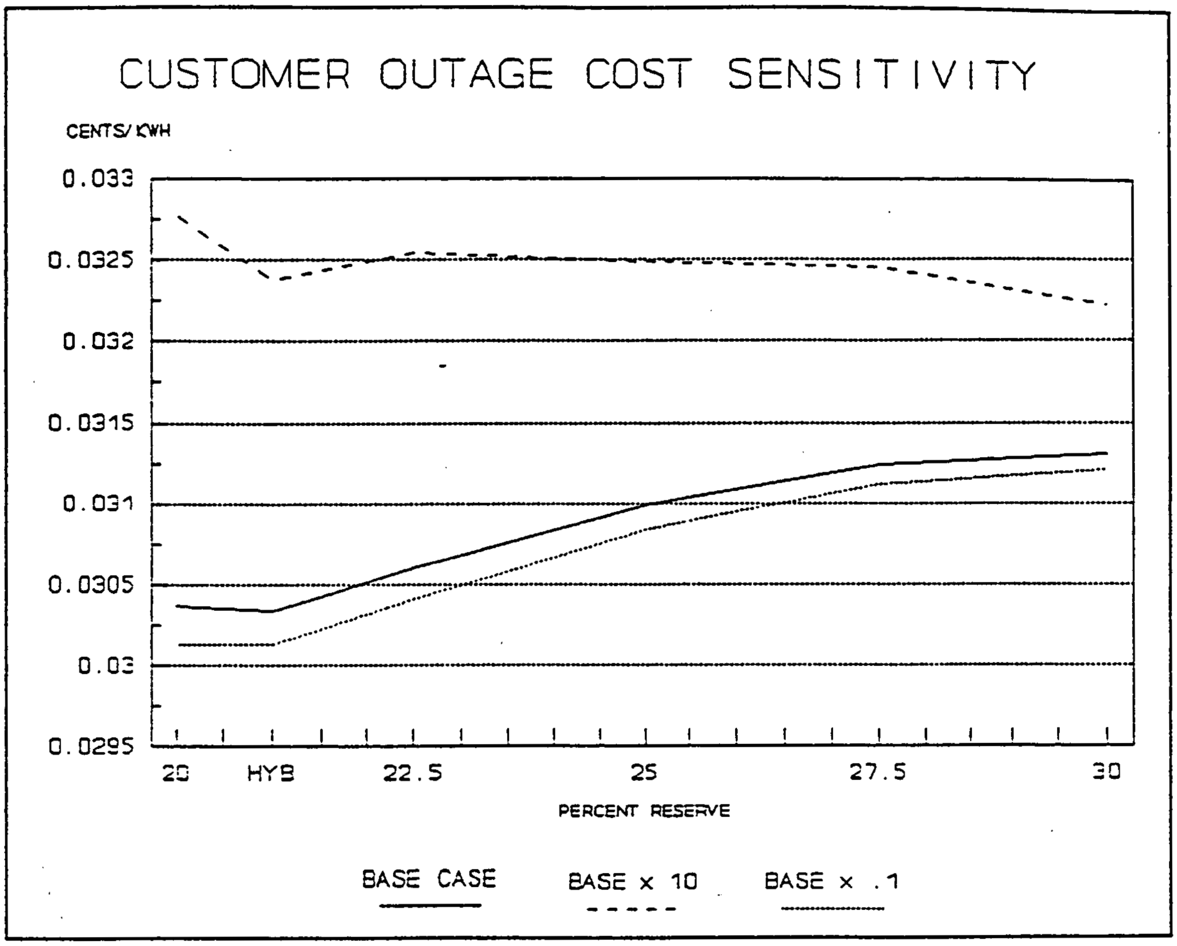


The result indicated a reduction in total customer cost in the "Hybrid" case where unit additions begin at the 25% reserve level and are trended to the 20% level. This is due to the relatively sharp decline in EUE and the customer outage cost when the first combustion turbines are added. Therefore, units should be added starting at a 25% reserve level and trending to a 20% reserve level to minimize total customer costs.

In this study the trending was performed manually to go from the 25% reserve level to the 20% level. To insure that system reliability does not drop below the 25% reserve level, expected unserved energy should be used to do the trending from 25% to 20%. With the current composition of the PSI generating system, reserve level usually drops when expansion plans are developed from a maximum EUE criteria only, since many small combustion turbines are added. If for some reason the reserves never did drop to the 20% level and remained at the 25% level, the total customer cost would barely increase above the cost for the 20% minimum reserves required for <u>Security of Operation</u>.

The societal cost of interruptions is hotly debated. NERA advocates a very different method from the "Willingness-to-Pay, Willingness-to be-Compensated" methodology employed by Ontario

Hydro. While the weighted average interruption cost of $7.73/kwh using the Ontario Hydro data was used in this study, NERA indicates it should be $20.95/kwh. Two recent EPRI studies indicate costs in the $4.00/kwh range.



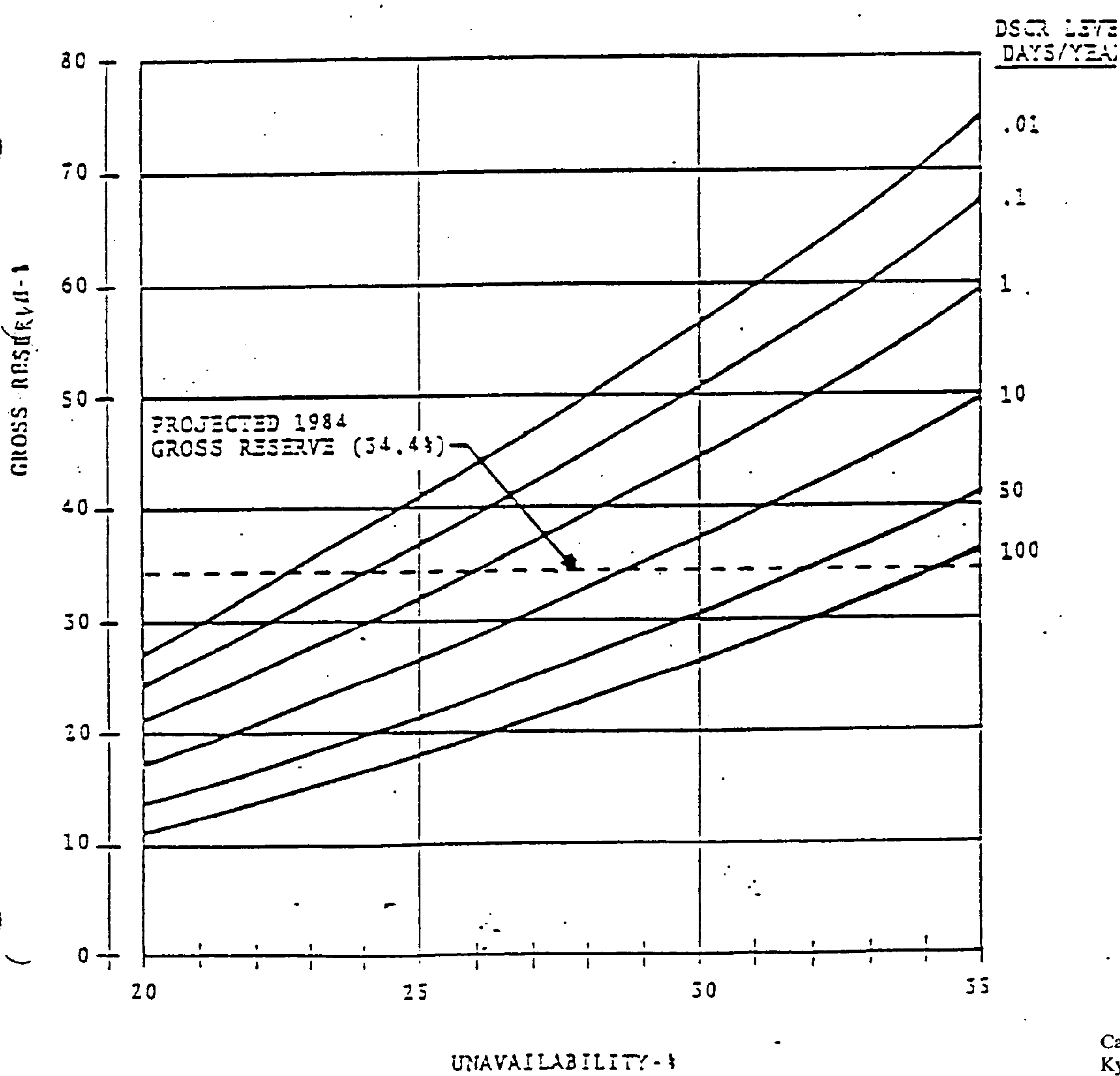
With this wide range of possible values, a sensitivity analysis was performed using customer outage costs of ten times the base case and one-tenth the base case. Even with this wide range of outage costs, the results shown in Appendix F and on the above graph, indicate that the "Hybrid" case remains beneficial.

ECAR Member Obligation

As a member of ECAR, PSI Energy expects to receive assistance during times of supply shortage; however, this also carries the obligation to maintain adequate reserves to likewise help other ecar member utilities during their times of shortage.

ECAR uses a reliability criterion of one to ten days/year Dependance on Supplemental Capacity Resources (DSCR). For the overall ECAR system, a chart is available which relates DSCR to reserve level and availability. From the chart it is clear that for the PSI Energy system, with average availability in the 75-80% range, a level of reserves in the 20-25% range insures that the DSCR for PSI would be within the criterion for ECAR as a whole and that PSI should not have a detrimental impact on ECAR.

ECAR
GROSS RESERVE REQUIREMENTS
(At time of Summer Peak Load)
vs
AVERAGE GENERATING-UNIT UNAVAILABILITY
FOR VARIOUS DSCR LEVELS
1984



CONCLUSIONS AND RECOMMENDATIONS

The results enumerated above indicate that PSI Energy should have a generation expansion planning criteria that has dual elements, a minimum reserve margin and a maximum EUE level, both of which must be maintained to meet the technical and economic requirements for reserve level.

The recommended generation expansion planning criteria is:

1. A minimum reserve margin of 20% should be maintained to assure Security of Operation and Maintenance Scheduling and;

2. The expected unserved energy (EUE) should not exceed the level that corresponds to the EUE when the system reserve margin is at 25%; and

3. The initial units should be installed when reserves, utilizing existing capacity, decline to the 25% level to further minimize total customer cost.

Without both parts of this criteria, it would be possible to 1) meet the EUE criteria but not have enough capacity to perform maintenance; and 2) meet the reserve margin criteria but have excessive customer outage costs. The EUE criteria can be met by adding small combustion turbines. If this is done with no regard to maintenance scheduling, the EUE level will minimize the customer outage cost but adequate maintenance will not be possible. The reserve margin criteria could be met by building a few large units, but EUE would be above the level that minimizes customer outage cost.

APPENDIX A

SECURITY OF OPERATION

A:SECURITY

RESERVES REQUIRED FOR SECURITY OF OPERATION

	YEAR	JANUARY PEAK (MW)	WVPA SALE (MW)	DSM (MW)	NON-FIRM LOAD (MW)	TOTAL PEAK LOAD (MW)	TEMP DEV (DEGREES)	LOAD/TEMP CORRELATION (MW/DEGREE)	WEATHER INDUCED LOAD (MW)	1.5% REG. MARGIN (MW)	LARGEST UNIT (MW)	RESERVES REQUIRED (MW)	RESERVES REQUIRED (%)
WINTER LOAD	1990-91	4229	70	0	0	4299	9.5	15.0	143	67	635	844	19.6
	1991-92	4357	70	5	0	4422	9.5	15.4	146	69	635	850	19.2
	1992-93	4479	70	15	0	4534	9.5	15.8	150	70	635	855	18.9
	1993-94	4579	70	35	0	4614	9.5	16.2	154	72	635	860	18.6
	1994-95	4676	70	55	0	4691	9.5	16.7	159	73	635	866	18.5
	1995-96	4761	70	85	0	4746	9.5	17.1	162	74	635	871	18.4
	1996-97	4856	70	115	0	4811	9.5	17.6	167	75	635	877	18.2
	1997-98	4947	70	145	60	4812	9.5	18.1	172	75	635	882	18.3
	1998-99	5031	70	170	60	4871	9.5	18.6	177	76	635	887	18.2
	1999-200	5106	70	200	60	4916	9.5	19.1	181	76	635	893	18.2
	2000-01	5207	70	230	60	4987	9.5	19.6	186	78	635	899	18.0
	2001-02	5310	70	260	60	5060	9.5	20.1	191	79	635	905	17.9
	2002-03	5415	70	260	60	5165	9.5	20.7	197	80	635	912	17.7
	2003-04	5522	70	260	60	5272	9.5	21.2	201	82	635	919	17.4
	2004-05	5631	70	260	60	5381	9.5	21.8	207	84	635	926	17.2
	2005-06	5743	70	260	60	5493	9.5	22.4	213	86	635	933	17.0
	2006-07	5856	70	260	60	5606	9.5	23.0	219	87	635	941	16.8
	2006-08	5972	70	260	60	5722	9.5	23.6	224	89	635	948	16.6
	2008-09	6090	70	260	60	5840	9.5	24.2	230	91	635	956	16.4
	2009-10	6211	70	260	60	5961	9.5	24.9	237	93	635	965	16.2

	YEAR	FORECASTED JULY PEAK (MW)	WVPA SALE (MW)	DSM (MW)	NON-FIRM LOAD (MW)	TOTAL PEAK LOAD (MW)	TEMP DEV (DEGREES)	LOAD/TEMP CORRELATION (MW/DEGREE)	WEATHER INDUCED LOAD (MW)	1.5% REG. MARGIN (MW)	LARGEST UNIT (MW)	RESERVES REQUIRED (MW)	RESERVES REQUIRED (%)
SUMMER LOAD	1991	4604	70	0	0	4674	2.0	45.0	90	71	630	791	16.9
	1992	4756	70	5	0	4821	2.0	46.2	92	74	630	796	16.5
	1993	4872	70	15	0	4927	2.0	47.5	95	75	630	800	16.2
	1994	4982	70	35	0	5017	2.0	48.7	97	77	630	804	16.0
	1995	5078	70	55	0	5093	2.0	50.1	100	78	630	808	15.9
	1996	5173	70	85	0	5158	2.0	51.4	103	79	630	812	15.7
	1997	5283	70	115	0	5238	2.0	52.8	106	80	630	816	15.6
	1998	5370	70	145	60	5235	2.0	54.2	108	80	630	819	15.6
	1999	5454	70	170	60	5294	2.0	55.7	111	81	630	822	15.5
	2000	5533	70	200	60	5343	2.0	57.2	114	82	630	826	15.5
	2001	5637	70	230	60	5417	2.0	58.7	117	83	630	830	15.3
	2002	5743	70	260	60	5493	2.0	60.3	121	84	630	835	15.2
	2003	5851	70	260	60	5601	2.0	62.0	124	86	630	840	15.0
	2004	5961	70	260	60	5711	2.0	63.6	127	88	630	845	14.8
	2005	6073	70	260	60	5823	2.0	65.3	131	89	630	850	14.6
	2006	6187	70	260	60	5937	2.0	67.1	134	91	630	855	14.4
	2007	6304	70	260	60	6054	2.0	68.9	138	93	630	861	14.2
	2008	6422	70	260	60	6172	2.0	70.8	142	95	630	866	14.0
	2009	6543	70	260	60	6293	2.0	72.7	145	97	630	872	13.9
	2010	6666	70	260	60	6416	2.0	74.7	149	98	630	878	13.7

APPENDIX B

RESOURCE PLANS FOR VARIOUS RESERVE MARGINS

A:CTCASH1

1991 $ X 1000

SUMMER LOAD	YEAR	TOTAL JULY LOAD (MW)	CAPACITY BEFORE ADDITIONS	TPM CT ADDED	ADV CT ADDED	TOTAL MW ADDED	CUM MW ADDED	CAPACITY AFTER ADDITIONS	PERCENT RESERVE	TPM PROVAL PVRR	ADV CT PROVAL PVRR	TOTAL PROVAL PVRR	CUM PROVAL PVRR
	1991	4674	5939	0	0	0	0	5939	27.1	$0	$0	$0	$0
15.0 %	1992	4821	5944	0	0	0	0	5944	23.3	$52,885	$78,484	$0	$0
RESERVE	1993	4927	5949	0	0	0	0	5949	20.7	$50,852	$77,021	$0	$0
	1994	5017	5954	0	0	0	0	5954	18.7	$49,077	$74,290	$0	$0
	1995	5093	5954	0	0	0	0	5954	16.9	$47,432	$71,803	$0	$0
	1996	5158	5974	0	0	0	0	5974	15.8	$45,720	$69,238	$0	$0
	1997	5238	5974	1	0	95	95	6069	15.9	$44,044	$66,693	$44,044	$44,044
	1998	5235	5994	0	0	0	95	6089	16.3	$42,443	$64,269	$0	$44,044
	1999	5294	5960	1	0	95	190	6150	16.2	$0	$61,967	$0	$44,044
	2000	5343	5962	0	0	0	190	6152	15.1	$0	$59,802	$0	$44,044
	2001	5417	5967	1	0	95	285	6252	15.4	$0	$57,733	$0	$44,044
	2002	5493	5879	0	2	252	537	6416	16.8	$0	$55,670	$111,340	$155,384
	2003	5601	5884	0	1	126	663	6547	16.9	$0	$53,663	$53,663	$209,047
	2004	5711	5729	0	2	252	915	6644	16.3	$0	$51,636	$103,272	$312,319
	2005	5823	5644	0	1	126	1041	6685	14.8	$0	$49,690	$49,690	$362,009
	2006	5937	5559	0	2	252	1293	6852	15.4	$0	$47,839	$95,678	$457,687
	2007	6054	5564	0	1	126	1419	6983	15.3	$0	$46,081	$46,081	$503,768
	2008	6172	5399	0	2	252	1671	7070	14.5	$0	$44,400	$88,800	$592,568
	2009	6293	5404	0	2	252	1923	7327	16.4	$0	$42,735	$85,470	$678,038
	2010	6416	5404	0	1	126	2049	7453	16.2	$0	$41,078	$41,078	$719,116

SUMMER LOAD	YEAR	TOTAL JULY LOAD (MW)	CAPACITY BEFORE ADDITIONS	TPM CT ADDED	ADV CT ADDED	TOTAL MW ADDED	CUM MW ADDED	CAPACITY AFTER ADDITIONS	PERCENT RESERVE	TPM PROVAL PVRR	ADV CT PROVAL PVRR	TOTAL PROVAL PVRR	CUM PROVAL PVRR
	1991	4674	5939	0	0	0	0	5939	27.1	$0	$0	$0	$0
17.5 %	1992	4821	5944	0	0	0	0	5944	23.3	$52,885	$78,484	$0	$0
RESERVE	1993	4927	5949	0	0	0	0	5949	20.7	$50,852	$77,021	$0	$0
	1994	5017	5954	0	0	0	0	5954	18.7	$49,077	$74,290	$0	$0
	1995	5093	5954	1	0	95	95	6049	18.8	$47,432	$71,803	$47,432	$47,432
	1996	5158	5974	0	0	0	95	6069	17.7	$45,720	$69,238	$0	$47,432
	1997	5238	5974	1	0	95	190	6164	17.7	$44,044	$66,693	$44,044	$91,476
	1998	5235	5994	0	0	0	190	6184	18.1	$42,443	$64,269	$0	$91,476
	1999	5294	5960	1	0	95	285	6245	18.0	$0	$61,967	$0	$91,476
	2000	5343	5962	0	1	126	411	6373	19.3	$0	$59,802	$59,802	$151,278
	2001	5417	5967	0	0	0	411	6378	17.7	$0	$57,733	$0	$151,278
	2002	5493	5879	0	2	252	663	6542	19.1	$0	$55,670	$111,340	$262,618
	2003	5601	5884	0	1	126	789	6673	19.1	$0	$53,663	$53,663	$316,281
	2004	5711	5729	0	2	252	1041	6770	18.5	$0	$51,636	$103,272	$419,553
	2005	5823	5644	0	1	126	1167	6811	17.0	$0	$49,690	$49,690	$469,243
	2006	5937	5559	0	2	252	1419	6978	17.5	$0	$47,839	$95,678	$564,921
	2007	6054	5564	0	1	126	1545	7109	17.4	$0	$46,081	$46,081	$611,002
	2008	6172	5399	0	3	378	1923	7322	18.6	$0	$44,400	$133,200	$744,202
	2009	6293	5404	0	1	126	2049	7453	18.4	$0	$42,735	$42,735	$786,937
	2010	6416	5404	0	1	126	2175	7579	18.1	$0	$41,078	$41,078	$828,015

SUMMER LOAD	YEAR	TOTAL JULY LOAD (MW)	CAPACITY BEFORE ADDITIONS	TPM CT ADDED	ADV CT ADDED	TOTAL MW ADDED	CUM MW ADDED	CAPACITY AFTER ADDITIONS	PERCENT RESERVE	TPM PROVAL PVRR	ADV CT PROVAL PVRR	TOTAL PROVAL PVRR	CUM PROVAL PVRR
	1991	4674	5939	0	0	0	0	5939	27.1	$0	$0	$0	$0
20.0 %	1992	4821	5944	0	0	0	0	5944	23.3	$52,885	$78,484	$0	$0
RESERVE	1993	4927	5949	0	0	0	0	5949	20.7	$50,852	$77,021	$0	$0
	1994	5017	5954	1	0	95	95	6049	20.6	$49,077	$74,290	$49,077	$49,077
	1995	5093	5954	1	0	95	190	6144	20.6	$47,432	$71,803	$47,432	$96,509
	1996	5158	5974	0	0	0	190	6164	19.5	$45,720	$69,238	$0	$96,509
	1997	5238	5974	1	0	95	285	6259	19.5	$44,044	$66,693	$44,044	$140,553
	1998	5235	5994	0	0	0	285	6279	19.9	$42,443	$64,269	$0	$140,553
	1999	5294	5960	0	1	126	411	6371	20.3	$0	$61,967	$61,967	$202,520
	2000	5343	5962	0	1	126	537	6499	21.6	$0	$59,802	$59,802	$262,322
	2001	5417	5967	0	0	0	537	6504	20.1	$0	$57,733	$0	$262,322
	2002	5493	5879	0	2	252	789	6668	21.4	$0	$55,670	$111,340	$373,662
	2003	5601	5884	0	1	126	915	6799	21.4	$0	$53,663	$53,663	$427,325
	2004	5711	5729	0	2	252	1167	6896	20.7	$0	$51,636	$103,272	$530,597
	2005	5823	5644	0	2	252	1419	7063	21.3	$0	$49,690	$99,380	$629,977
	2006	5937	5559	0	1	126	1545	7104	19.7	$0	$47,839	$47,839	$677,816
	2007	6054	5564	0	2	252	1797	7361	21.6	$0	$46,081	$92,162	$769,978
	2008	6172	5399	0	2	252	2049	7448	20.7	$0	$44,400	$88,800	$858,778
	2009	6293	5404	0	1	126	2175	7579	20.4	$0	$42,735	$42,735	$901,513
	2010	6416	5404	0	1	126	2301	7705	20.1	$0	$41,078	$41,078	$942,591

SUMMER LOAD	YEAR	TOTAL JULY LOAD (MW)	CAPACITY BEFORE ADDITIONS	TPM CT ADDED	ADV CT ADDED	TOTAL MW ADDED	CUM MW ADDED	CAPACITY AFTER ADDITIONS	PERCENT RESERVE	TPM PROVAL PVRR	ADV CT PROVAL PVRR	TOTAL PROVAL PVRR	CUM PROVAL PVRR
	1991	4674	5939	0	0	0	0	5939	27.1	$0	$0	$0	$0
22.5 %	1992	4821	5944	0	0	0	0	5944	23.3	$52,885	$78,484	$0	$0
RESERVE	1993	4927	5949	1	0	95	95	6044	22.7	$50,852	$77,021	$50,852	$50,852
	1994	5017	5954	1	0	95	190	6144	22.5	$49,077	$74,290	$49,077	$99,929
	1995	5093	5954	1	0	95	285	6239	22.5	$47,432	$71,803	$47,432	$147,361
	1996	5158	5974	0	1	126	411	6385	23.8	$45,720	$69,238	$69,238	$216,599
	1997	5238	5974	0	1	126	537	6511	24.3	$44,044	$66,693	$66,693	$283,292
	1998	5235	5994	0	0	0	537	6531	24.8	$42,443	$64,269	$0	$283,292
	1999	5294	5960	0	0	0	537	6497	22.7	$0	$61,967	$0	$283,292
	2000	5343	5962	0	1	126	663	6625	24.0	$0	$59,802	$59,802	$343,094
	2001	5417	5967	0	0	0	663	6630	22.4	$0	$57,733	$0	$343,094
	2002	5493	5879	0	2	252	915	6794	23.7	$0	$55,670	$111,340	$454,434
	2003	5601	5884	0	1	126	1041	6925	23.6	$0	$53,663	$53,663	$508,097
	2004	5711	5729	0	2	252	1293	7022	23.0	$0	$51,636	$103,272	$611,369
	2005	5823	5644	0	2	252	1545	7189	23.5	$0	$49,690	$99,380	$710,749
	2006	5937	5559	0	2	252	1797	7356	23.9	$0	$47,839	$95,678	$806,427
	2007	6054	5564	0	1	126	1923	7487	23.7	$0	$46,081	$46,081	$852,508
	2008	6172	5399	0	2	252	2175	7574	22.7	$0	$44,400	$88,800	$941,308
	2009	6293	5404	0	1	126	2301	7705	22.4	$0	$42,735	$42,735	$984,043
	2010	6416	5404	0	1	126	2427	7831	22.1	$0	$41,078	$41,078	$1,025,121

SUMMER LOAD	YEAR	TOTAL JULY LOAD (MW)	CAPACITY BEFORE ADDITIONS	TPM CT ADDED	ADV CT ADDED	TOTAL MW ADDED	CUM MW ADDED	CAPACITY AFTER ADDITIONS	PERCENT RESERVE	TPM PROVAL PVRR	ADV CT PROVAL PVRR	TOTAL PROVAL PVRR	CUM PROVAL PVRR
	1991	4674	5939	0	0	0	0	5939	27.1	$0	$0	$0	$0
25.0 %	1992	4821	5944	1	0	95	95	6039	25.3	$52,885	$78,484	$52,885	$52,885
RESERVE	1993	4927	5949	1	0	95	190	6139	24.6	$50,852	$77,021	$50,852	$103,737
	1994	5017	5954	1	1	221	411	6365	26.9	$49,077	$74,290	$123,367	$227,104
	1995	5093	5954	0	0	0	411	6365	25.0	$47,432	$71,803	$0	$227,104
	1996	5158	5974	0	1	126	537	6511	26.2	$45,720	$69,238	$69,238	$296,342
	1997	5238	5974	0	1	126	663	6637	26.7	$44,044	$66,693	$66,693	$363,035
	1998	5235	5994	0	0	0	663	6657	27.2	$42,443	$64,269	$0	$363,035
	1999	5294	5960	0	0	0	663	6623	25.1	$0	$61,967	$0	$363,035
	2000	5343	5962	0	1	126	789	6751	26.4	$0	$59,802	$59,802	$422,837
	2001	5417	5967	0	0	0	789	6756	24.7	$0	$57,733	$0	$422,837
	2002	5493	5879	0	2	252	1041	6920	26.0	$0	$55,670	$111,340	$534,177
	2003	5601	5884	0	1	126	1167	7051	25.9	$0	$53,663	$53,663	$587,840
	2004	5711	5729	0	2	252	1419	7148	25.2	$0	$51,636	$103,272	$691,112
	2005	5823	5644	0	2	252	1671	7315	25.6	$0	$49,690	$99,380	$790,492
	2006	5937	5559	0	2	252	1923	7482	26.0	$0	$47,839	$95,678	$886,170
	2007	6054	5564	0	1	126	2049	7613	25.8	$0	$46,081	$46,081	$932,251
	2008	6172	5399	0	2	252	2301	7700	24.8	$0	$44,400	$88,800	$1,021,051
	2009	6293	5404	0	1	126	2427	7831	24.4	$0	$42,735	$42,735	$1,063,786
	2010	6416	5404	0	2	252	2679	8083	26.0	$0	$41,078	$82,156	$1,145,942

---------- PVRR ($x1000) ----------

SUMMER LOAD	YEAR	TOTAL JULY LOAD (MW)	CAPACITY BEFORE ADDITIONS	TPM CT ADDED	ADV CT ADDED	TOTAL MW ADDED	CUM MW ADDED	CAPACITY AFTER ADDITIONS	PERCENT RESERVE	TPM PROVAL PVRR	ADV CT PROVAL PVRR	TOTAL PROVAL PVRR	CUM PROVAL PVRR
	1991	4674	5939	0	0	0	0	5939	27.1	$0	$0	$0	$0
27.5 %	1992	4821	5944	2	0	190	190	6134	27.2	$52,885	$78,484	$105,770	$105,770
RESERVE	1993	4927	5949	1	1	221	411	6360	29.1	$50,852	$77,021	$127,873	$233,643
	1994	5017	5954	0	1	126	537	6491	29.4	$49,077	$74,290	$74,290	$307,933
	1995	5093	5954	0	0	0	537	6491	27.4	$47,432	$71,803	$0	$307,933
	1996	5158	5974	0	1	126	663	6637	28.7	$45,720	$69,238	$69,238	$377,171
	1997	5238	5974	0	1	126	789	6763	29.1	$44,044	$66,693	$66,693	$443,864
	1998	5235	5994	0	0	0	789	6783	29.6	$42,443	$64,269	$0	$443,864
	1999	5294	5960	0	0	0	789	6749	27.5	$0	$61,967	$0	$443,864
	2000	5343	5962	0	1	126	915	6877	28.7	$0	$59,802	$59,802	$503,666
	2001	5417	5967	0	0	0	915	6882	27.0	$0	$57,733	$0	$503,666
	2002	5493	5879	0	2	252	1167	7046	28.3	$0	$55,670	$111,340	$615,006
	2003	5601	5884	0	1	126	1293	7177	28.1	$0	$53,663	$53,663	$668,669
	2004	5711	5729	0	2	252	1545	7274	27.4	$0	$51,636	$103,272	$771,941
	2005	5823	5644	0	2	252	1797	7441	27.8	$0	$49,690	$99,380	$871,321
	2006	5937	5559	0	2	252	2049	7608	28.1	$0	$47,839	$95,678	$966,999
	2007	6054	5564	0	1	126	2175	7739	27.8	$0	$46,081	$46,081	$1,013,080
	2008	6172	5399	0	3	378	2553	7952	28.8	$0	$44,400	$133,200	$1,146,280
	2009	6293	5404	0	1	126	2679	8083	28.4	$0	$42,735	$42,735	$1,189,015
	2010	6416	5404	0	1	126	2805	8209	27.9	$0	$41,078	$41,078	$1,230,093

SUMMER LOAD	YEAR	TOTAL JULY LOAD (MW)	CAPACITY BEFORE ADDITIONS	TPM CT ADDED	ADV CT ADDED	TOTAL MW ADDED	CUM MW ADDED	CAPACITY AFTER ADDITIONS	PERCENT RESERVE	TPM PROVAL PVRR	ADV CT PROVAL PVRR	TOTAL PROVAL PVRR	CUM PROVAL PVRR
	1991	4674	5939	1	0	95	95	6034	29.1	$0	$0	$0	$0
30.0 %	1992	4821	5944	2	0	190	285	6229	29.2	$52,885	$78,484	$105,770	$105,770
RESERVE	1993	4927	5949	0	2	252	537	6486	31.6	$50,852	$77,021	$154,042	$259,812
	1994	5017	5954	0	1	126	663	6617	31.9	$49,077	$74,290	$74,290	$334,102
	1995	5093	5954	0	0	0	663	6617	29.9	$47,432	$71,803	$0	$334,102
	1996	5158	5974	0	1	126	789	6763	31.1	$45,720	$69,238	$69,238	$403,340
	1997	5238	5974	0	1	126	915	6889	31.5	$44,044	$66,693	$66,693	$470,033
	1998	5235	5994	0	0	0	915	6909	32.0	$42,443	$64,269	$0	$470,033
	1999	5294	5960	0	0	0	915	6875	29.9	$0	$61,967	$0	$470,033
	2000	5343	5962	0	1	126	1041	7003	31.1	$0	$59,802	$59,802	$529,835
	2001	5417	5967	0	1	126	1167	7134	31.7	$0	$57,733	$57,733	$587,568
	2002	5493	5879	0	1	126	1293	7172	30.6	$0	$55,670	$55,670	$643,238
	2003	5601	5884	0	1	126	1419	7303	30.4	$0	$53,663	$53,663	$696,901
	2004	5711	5729	0	2	252	1671	7400	29.6	$0	$51,636	$103,272	$800,173
	2005	5823	5644	0	2	252	1923	7567	30.0	$0	$49,690	$99,380	$899,553
	2006	5937	5559	0	2	252	2175	7734	30.3	$0	$47,839	$95,678	$995,231
	2007	6054	5564	0	1	126	2301	7865	29.9	$0	$46,081	$46,081	$1,041,312
	2008	6172	5399	0	3	378	2679	8078	30.9	$0	$44,400	$133,200	$1,174,512
	2009	6293	5404	0	1	126	2805	8209	30.4	$0	$42,735	$42,735	$1,217,247
	2010	6416	5404	0	1	126	2931	8335	29.9	$0	$41,078	$41,078	$1,258,325

SUMMER LOAD	YEAR	TOTAL JULY LOAD (MW)	CAPACITY BEFORE ADDITIONS	TPM CT ADDED	ADV CT ADDED	TOTAL MW ADDED	CUM MW ADDED	CAPACITY AFTER ADDITIONS	PERCENT RESERVE	TPM PROVAL PVRR	ADV CT PROVAL PVRR	TOTAL PROVAL PVRR	CUM PROVAL PVRR
	1991	4674	5939	0	0	0	0	5939	27.1	$0	$0	$0	$0
HYBRID	1992	4821	5944	1	0	95	95	6039	25.3	$52,885	$78,484	$52,885	$52,885
RESERVE	1993	4927	5949	0	0	0	95	6044	22.7	$50,852	$77,021	$0	$52,885
	1994	5017	5954	1	0	95	190	6144	22.5	$49,077	$74,290	$49,077	$101,962
	1995	5093	5954	0	0	0	190	6144	20.6	$47,432	$71,803	$0	$101,962
	1996	5158	5974	1	0	95	285	6259	21.3	$45,720	$69,238	$45,720	$147,682
	1997	5238	5974	0	0	0	285	6259	19.5	$44,044	$66,693	$0	$147,682
	1998	5235	5994	0	0	0	285	6279	19.9	$42,443	$64,269	$0	$147,682
	1999	5294	5960	0	1	126	411	6371	20.3	$0	$61,967	$61,967	$209,649
	2000	5343	5962	0	1	126	537	6499	21.6	$0	$59,802	$59,802	$269,451
	2001	5417	5967	0	0	0	537	6504	20.1	$0	$57,733	$0	$269,451
	2002	5493	5879	0	2	252	789	6668	21.4	$0	$55,670	$111,340	$380,791
	2003	5601	5884	0	1	126	915	6799	21.4	$0	$53,663	$53,663	$434,454
	2004	5711	5729	0	2	252	1167	6896	20.7	$0	$51,636	$103,272	$537,726
	2005	5823	5644	0	2	252	1419	7063	21.3	$0	$49,690	$99,380	$637,106
	2006	5937	5559	0	1	126	1545	7104	19.7	$0	$47,839	$47,839	$684,945
	2007	6054	5564	0	2	252	1797	7361	21.6	$0	$46,081	$92,162	$777,107
	2008	6172	5399	0	2	252	2049	7448	20.7	$0	$44,400	$88,800	$865,907
	2009	6293	5404	0	1	126	2175	7579	20.4	$0	$42,735	$42,735	$908,642
	2010	6416	5404	0	1	126	2301	7705	20.1	$0	$41,078	$41,078	$949,720

APPENDIX C

MAINTENANCE SCHEDULING

CAPACITY IN EXCESS OF THAT REQUIRED FOR MAINTENANCE

	YEAR	FORECASTED JANUARY PEAK (MW)	RESERVES REQUIRED (MW)	15 % RESERVE AVAILABLE WORST WEEK (MW)	15 % RESERVE NET AVAILABLE (MW)	17.5 % RESERVE AVAILABLE WORST WEEK (MW)	17.5 % RESERVE NET AVAILABLE (MW)	20.0 % RESERVE AVAILABLE WORST WEEK (MW)	20.0 % RESERVE NET AVAILABLE (MW)
WINTER LOAD	1990-91	4229	844	0	0	0	0	0	0
	1991-92	4357	850	0	5	0	5	0	5
	1992-93	4479	855	0	15	0	15	0	15
	1993-94	4579	860	100	35	100	35	100	35
	1994-95	4676	866	200	55	200	55	200	55
	1995-96	4761	871	300	85	300	85	300	85
	1996-97	4856	877	450	115	450	115	450	115
	1997-98	4947	882	450	145	450	145	450	145
	1998-99	5031	887	450	170	450	170	450	170
	1999-2000	5106	893	450	200	450	200	450	200
	2000-01	5207	899	450	230	450	230	450	230
	2001-02	5310	905	450	260	450	260	450	260
	2002-03	5415	912	450	260	450	260	450	260
	2003-04	5522	919	450	260	450	260	450	260
	2004-05	5631	926	450	260	450	260	450	260
	2005-06	5743	933	450	260	450	260	450	260
	2006-07	5856	941	450	260	450	260	450	260
	2006-08	5972	948	450	260	450	260	450	260
	2008-09	6090	956	450	260	450	260	450	260
	2009-10	6211	965	450	260	450	260	450	260

	YEAR	FORECASTED JULY PEAK (MW)	RESERVES REQUIRED (MW)	15 % RESERVE AVAILABLE WORST WEEK (MW)	15 % RESERVE NET AVAILABLE (MW)	17.5 % RESERVE AVAILABLE WORST WEEK (MW)	17.5 % RESERVE NET AVAILABLE (MW)	20.0 % RESERVE AVAILABLE WORST WEEK (MW)	20.0 % RESERVE NET AVAILABLE (MW)
SUMMER LOAD	1991	4604	791	1135	344	1135	344	1135	344
	1992	4756	796	661	-135	661	-135	661	-135
	1993	4872	800	964	164	964	164	964	164
	1994	4982	804	645	-159	645	-159	744	-60
	1995	5078	808	798	-10	897	89	997	189
	1996	5173	812	730	-82	829	17	929	117
	1997	5283	816	660	-156	845	29	944	128
	1998	5370	819	317	-502	417	-402	883	64
	1999	5454	822	344	-478	798	-24	923	101
	2000	5533	826	467	-359	691	-135	816	-10
	2001	5637	830	665	-165	790	-40	915	85
	2002	5743	835	716	-119	841	6	966	131
	2003	5851	840	733	-107	858	18	983	143
	2004	5961	845	713	-132	838	-7	963	118
	2005	6073	850	641	-209	766	-84	1016	166
	2006	6187	855	560	-295	685	-170	810	-45
	2007	6304	861	695	-166	820	-41	1070	209
	2008	6422	866	657	-209	906	40	1031	165
	2009	6543	872	700	-172	825	-47	950	78
	2010	6666	878	617	-261	742	-136	867	-11

APPENDIX D

COST OF INTERRUPTIONS BY CUSTOMER CLASS

A:ESCALPCT

DATA RESOURCES INC. ESCALATION RATES
PGNP (1982=100)

	TREND INDEX	TREND PERCENT
1982	100.0	3.900
1983	103.9	3.657
1984	107.7	2.971
1985	110.9	2.615
1986	113.8	3.163
1987	117.4	3.322
1988	121.3	4.122
1989	126.3	4.038
1990	131.4	3.196
1991	135.6	2.876
1992	139.5	2.939
1993	143.6	2.994
1994	147.9	3.516
1995	153.1	3.723
1996	158.8	3.778
1997	164.8	3.701
1998	170.9	3.745
1999	177.3	3.948
2000	184.3	4.069
2001	191.8	8.759
2002	208.6	4.362
2003	217.7	4.364
2004	227.2	4.445
2005	237.3	4.383
2006	247.7	4.522
2007	258.9	4.519
2008	270.6	4.435
2009	282.6	4.423
2010	295.1	4.473
2011	308.3	

INTERRUPTION COST ESCALATION
($ / KWH)

CATEGORY	EMA (1-1-84)	ESCL. FACTOR	PSI (1-1-91)
Coal Mining	1.70	1.26	2.15
Mining Other	1.63	1.26	2.06
Paper Products	0.50	1.26	0.63
Food and Kindred Goods	1.80	1.26	2.28
Chemicals	5.30	1.26	6.70
Rubber Products	1.46	1.26	1.85
Stone, Clay and Glass	1.94	1.26	2.45
Primary Metals	4.18	1.26	5.29
Fabricated Metals	2.24	1.26	2.83
Transportation	5.88	1.26	7.44
Machinery	6.41	1.26	8.11
Electronics	4.93	1.26	6.23
Other Industries	4.35	1.26	5.50
Retail	15.30	1.26	19.35
Education	0.40	1.26	0.51
Goverment	0.40	1.26	0.51
Office Buildings	11.30	1.26	14.29
Domestic	0.82	1.26	1.04
Farm	90.40	1.26	114.33

A:INTRCOST

COST OF INTERRUPTIONS BY CUSTOMER CLASS

RESIDENTIAL	1990 MWH SALES	% OF LOAD	INTERRUPTION VALUE (1991 $/KWH)	CONTRIBUTION OF CLASS LOAD ($/KWH)
DOMESTIC	5,602,588	95.13	1.04	0.99
FARM	286,683	4.87	114.33	5.57
TOTAL RESIDENTIAL	5,889,271	100.00		6.55
COMMERCIAL				
RETAIL	3,896,868	51.58	19.35	9.98
EDUCATION	1,538,900	20.37	0.51	0.10
GOVERMENT	213,729	2.83	0.51	0.01
OFFICE BUILDINGS	1,905,916	25.23	14.29	3.60
TOTAL COMMERCIAL	7,555,413	100.00		13.70
INDUSTRIAL (BY SIC CODE)				
COAL MINING (12)	345,769	4.49	2.15	0.10
MINING OTHER (13,14)	78,910	1.02	2.06	0.02
PAPER PRODUCTS (26)	366,883	4.76	0.63	0.03
FOOD & KINDRED GOODS (20)	553,059	7.18	2.28	0.16
CHEMICALS (28)	886,763	11.51	6.70	0.77
RUBBER PRODUCTS (30)	467,284	6.07	1.85	0.11
STONE, CLAY & GLASS (32)	708,366	9.20	2.45	0.23
PRIMARY METALS (33)	1,187,381	15.42	5.29	0.82
FABRICATED METALS (34)	243,283	3.16	2.83	0.09
TRANSPORTATION (37)	1,031,966	13.40	7.44	1.00
MACHINERY (35)	549,878	7.14	8.11	0.58
ELECTRICAL MACHINERY (36)	314,727	4.09	6.23	0.25
OTHER INDUSTRIES	968,047	12.57	5.50	0.69
TOTAL	7,702,316	100.00		4.85

APPENDIX E

WEIGHTED AVERAGE INTERRUPTION COST

CUSTOMER OUTAGE COST VS. RESERVE LEVEL

a:INTERCST

PUBLIC SERVICE INDIANA
ENERGY FORECAST
1991 TO 2010
(GWH)

	BUDGET 1991	BUDGET 1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
DOMESTIC	5876	5991	6347	6445	6535	6618	6700	6788	6884	6972	7101	7233	7370	7507	7649	7794	7942	8093	8248	8405
COMMERCIAL	5003	5169	5532	5683	5784	5884	5989	6078	6096	6051	6164	6278	6394	6514	6638	6764	6892	7023	7157	7293
INDUSTRIAL	8095	8346	8627	8866	9062	9297	9593	9803	10027	10307	10500	10697	10898	11103	11313	11528	11746	11971	12199	12431
OTHER SALES	58	58	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
TOTAL SALES TO ULTIMATE CONSUMERS	19032	19564	20566	21054	21441	21859	22342	22729	23067	23390	23825	24268	24722	25184	25660	26146	26640	27147	27664	28189
REMC'S																				
WVPA TOTAL	1342	1370	1385	1409	1433	1456	1475	1494	1512	1531	1549	1566	1583	1600	1616	1633	1651	1669	1687	1707
OTHER REMCS	279	285	292	297	303	309	316	322	328	335	341	347	354	362	369	376	384	391	399	407
TOTAL	1621	1655	1677	1706	1736	1765	1791	1816	1840	1866	1890	1913	1937	1962	1985	2009	2035	2060	2086	2114
OTHER ELECTRIC UTILITIES																				
IMPA TOTAL	1779	1848	1987	2044	2103	2163	2226	2290	2358	2429	2499	2569	2639	2710	2780	2850	2921	2991	3061	3132
OTHER MUNICIPALS	337	353	361	366	372	378	383	389	395	401	406	413	419	426	432	439	446	452	459	467
TOTAL	2116	2201	2348	2410	2475	2541	2609	2679	2753	2830	2905	2982	3058	3136	3212	3289	3367	3443	3520	3599
TOTAL SALES FOR RESALE	3737	3856	4025	4116	4211	4306	4400	4495	4593	4696	4795	4895	4995	5098	5197	5298	5402	5503	5606	5713
TOTAL SALES	22769	23420	24591	25170	25652	26165	26742	27224	27660	28086	28620	29163	29717	30282	30857	31444	32042	32650	33270	33902

CUSTOMER OUTAGE COST	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
RESIDENTIAL																				
OUTAGE COST	6.55	6.74	6.94	7.14	7.40	7.67	7.96	8.26	8.56	8.90	9.26	9.52	9.94	10.37	10.83	11.30	11.82	12.35	12.90	13.47
PERCENT OF TOTAL ENERGY	34.47	34.21	34.30	34.05	33.92	33.72	33.42	33.29	33.26	33.22	33.20	33.17	33.16	33.13	33.11	33.09	33.07	33.05	33.03	33.01
CLASS CONTRIBUTION	2.26	2.30	2.38	2.43	2.51	2.59	2.66	2.75	2.85	2.96	3.08	3.16	3.29	3.44	3.59	3.74	3.91	4.08	4.26	4.45
COMMERCIAL																				
OUTAGE COST	13.70	14.09	14.51	14.94	15.47	16.04	16.65	17.27	17.91	18.62	19.38	19.91	20.78	21.69	22.65	23.64	24.71	25.83	26.98	28.17
PERCENT OF TOTAL ENERGY	25.91	26.04	26.50	26.59	26.57	26.52	26.42	26.36	26.06	25.54	25.54	25.54	25.54	25.54	25.55	25.55	25.55	25.55	25.56	25.56
CLASS CONTRIBUTION	3.55	3.67	3.84	3.97	4.11	4.25	4.40	4.55	4.67	4.76	4.95	5.09	5.31	5.54	5.79	6.04	6.31	6.60	6.89	7.20
INDUSTRIAL																				
OUTAGE COST	4.85	4.99	5.14	5.29	5.48	5.68	5.89	6.11	6.34	6.59	6.86	7.05	7.36	7.68	8.02	8.37	8.75	9.14	9.55	9.97
PERCENT OF TOTAL ENERGY	39.62	39.76	39.19	39.36	39.51	39.77	40.16	40.35	40.68	41.24	41.26	41.28	41.30	41.32	41.34	41.36	41.38	41.40	41.42	41.43
CLASS CONTRIBUTION	1.92	1.98	2.01	2.08	2.16	2.26	2.37	2.47	2.58	2.72	2.83	2.91	3.04	3.17	3.32	3.46	3.62	3.79	3.96	4.13
AVE. INTERRUPTION COST	7.73	7.96	8.24	8.49	8.78	9.10	9.43	9.77	10.10	10.43	10.86	11.15	11.64	12.15	12.69	13.24	13.84	14.47	15.11	15.78

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EMERGENCY ENERGY (GWH)	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	
20 % RESERVE MGN	160.9	89.1	76.4	87.4	33.7	42.4	27.5	22.9	16.0	10.9	8.6	9.3	5.4	5.5	4.0	4.9	2.4	2.5	2.7	3.3	615.8
22.5 % RESERVE MGN	160.9	89.1	58.7	61.2	23.2	20.5	10.1	7.8	8.2	6.1	5.2	5.4	3.2	3.3	2.4	2.0	1.4	1.5	1.7	2.1	474.0
25 % RESERVE MGN	160.9	64.5	40.2	30.1	12.0	11.8	5.8	4.5	4.7	3.4	3.1	3.1	1.9	2.0	1.4	1.2	0.9	0.9	1.0	0.8	354.2
27.5 % RESERVE MGN	160.9	47.0	18.6	19.5	6.9	6.8	3.3	2.4	2.6	1.9	1.7	1.8	1.1	1.1	0.9	0.7	0.5	0.3	0.4	0.5	278.9
30 % RESERVE MGN	118.5	49.0	14.0	8.4	4.1	4.0	1.8	1.4	1.5	1.0	0.6	0.9	0.6	0.7	0.5	0.4	0.3	0.2	0.2	0.3	208.4
HYBRID RESERVE MGN	160.9	64.5	53.2	61.2	30.5	32.5	23.4	23.0	17.0	10.2	8.8	9.0	5.4	5.7	4.0	4.8	2.4	2.5	2.7	3.3	525.0
PERCENT UNSERVED	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
EXPECTED UNSERVED ENERGY (MWH)																					
20 % RESERVE MGN	3218	1782	1528	1748	674	848	550	458	320	218	172	186	108	110	80	98	48	50	54	66	
22.5 % RESERVE MGN	3218	1782	1174	1224	464	410	202	156	164	122	104	108	64	66	48	40	28	30	34	42	
25 % RESERVE MGN	3218	1290	804	602	240	236	116	90	94	68	62	62	38	40	28	24	18	18	20	16	
27.5 % RESERVE MGN	3218	940	372	390	138	136	66	48	52	38	34	36	22	22	18	14	10	6	8	10	
30 % RESERVE MGN	2370	980	280	168	82	80	36	28	30	20	12	18	12	14	10	8	6	4	4	6	
HYBRID RESERVE MGN	3218	1290	1064	1224	610	650	468	460	340	204	176	180	108	114	80	96	48	50	54	66	
UNSERVED ENERGY COST ($ X 1000)																					
20 % RESERVE MGN	24873	14182	12587	14837	5919	7716	5184	4473	3231	2274	1867	2075	1257	1336	1015	1298	664	723	816	1041	$72,054
22.5 % RESERVE MGN	24873	14182	9671	10389	4075	3731	1904	1523	1656	1273	1129	1205	745	802	609	530	388	434	514	663	$58,015
25 % RESERVE MGN	24873	10266	6623	5110	2108	2147	1093	879	949	709	673	692	442	486	355	318	249	260	302	252	$44,780
27.5 % RESERVE MGN	24873	7481	3064	3310	1212	1238	622	469	525	396	369	402	256	267	228	185	138	87	121	158	$36,305
30 % RESERVE MGN	18318	7799	2306	1426	720	728	339	273	303	209	130	201	140	170	127	106	83	58	60	95	$27,473
HYBRID RESERVE MGN	24873	10266	8765	10389	5357	5915	4411	4492	3433	2128	1911	2008	1257	1385	1015	1271	664	723	816	1041	$61,185

APPENDIX F

TOTAL PVRR OF CUSTOMER COSTS

A:SUMM1

TOTAL COST TO CUSTOMER (CENTS/KWH) FOR SUMMER LOAD

	RESERVE LEVEL	20%	HYBRID	22.5%	25%	27.5%	30%
BASE CASE OUTAGE COSTS	RESOURCE PLAN PVRR	$942,591	$949,720	$1,025,121	$1,145,942	$1,230,093	$1,258,325
	PRODUCTION COST PVRR	$7,172,219	$7,166,547	$7,166,112	$7,162,169	$7,154,785	$7,152,164
	CUSTOMER COST PVRR	$72,054	$61,185	$58,015	$44,780	$36,305	$27,473
	TOTAL COST PVRR ($X1000)	$8,186,864	$8,177,452	$8,249,248	$8,352,891	$8,421,183	$8,437,962
	LEVELIZED COST (CENTS/KWH)	0.0303709	0.0303360	0.0306023	0.0309868	0.0312402	0.0313024
OUTAGE COSTS 10 TIMES BASE CASE	RESOURCE PLAN PVRR	$942,591	$949,720	$1,025,121	$1,145,942	$1,230,093	$1,258,325
	PRODUCTION COST PVRR	$7,172,219	$7,166,547	$7,166,112	$7,162,169	$7,154,785	$7,152,164
	CUSTOMER COST PVRR	$720,540	$611,850	$580,150	$447,800	$363,050	$274,730
	TOTAL COST PVRR ($X1000)	$8,835,350	$8,728,117	$8,771,383	$8,755,911	$8,747,928	$8,685,219
	LEVELIZED COST (CENTS/KWH)	0.0327766	0.0323788	0.0325393	0.0324819	0.0324523	0.0322197
OUTAGE COSTS ONE TENTH BASE CASE	RESOURCE PLAN PVRR	$942,591	$949,720	$1,025,121	$1,145,942	$1,230,093	$1,258,325
	PRODUCTION COST PVRR	$7,172,219	$7,166,547	$7,166,112	$7,162,169	$7,154,785	$7,152,164
	CUSTOMER COST PVRR	$7,205	$6,119	$5,802	$4,478	$3,631	$2,747
	TOTAL COST PVRR ($X1000)	$8,122,015	$8,122,386	$8,197,035	$8,312,589	$8,388,509	$8,413,236
	LEVELIZED COST (CENTS/KWH)	0.0301303	0.0301317	0.0304086	0.0308373	0.0311190	0.0312107
	TOTAL CT'S ADDED	19	19	20	22	23	24
	TOTAL EUE	615.8	524.8	473.9	354.1	278.9	208.5

if such Generating Resources were not centrally dispatched under System Dispatch. Beginning on or about January 1, 1995, and thereafter, economic dispatch shall reflect the market value of sulfur dioxide ("SO_2") emission allowances as a cost component ("environmentally affected dispatch").

1.23 System or CINergy System shall mean the CINergy registered holding company electric utility system.

1.24 System Dispatch shall mean the centralized, economic commitment and dispatch of the System's Generating Resources. Beginning on or about January 1, 1995, and thereafter, economic dispatch shall reflect the market value of sulfur dioxide ("SO_2") emission allowances as a cost component ("environmentally affected dispatch").

1.25 System Energy Transfer shall mean the transfer of electric energy from one Operating Company's Generating Resources to the other Operating Company to serve the other Operating Company's load.

1.26 System Planning Reserve Margin shall mean the minimum reserve margin (reflected as the amount of the seasonal demonstrated capability of System Generating Resources that exceeds forecasted System load, expressed as a percent of the forecasted System load) that is deemed by the Operating

Case No. 99-449
KyPsc-01-003-B
Page 1 of 2 pages

Committee to be appropriate for the planning of the economic and reliable operation of the System. Initially such System Planning Reserve Margin shall be 17%. The future System Planning Reserve Margin shall be consistent with the CINergy IRP(s) filed from time to time with the state commissions having jurisdiction over the retail rates of the Operating Companies; provided, that any change to the System Planning Reserve Margin recommended by the Operating Committee will require, subject to Section 8.05 of this Agreement, the filing of an amendment to this Agreement with the FERC and its approval and acceptance by the FERC pursuant to Section 205 of the Federal Power Act.

ARTICLE II

TERM OF AGREEMENT

2.01 This Agreement shall take effect on March 2, 1994, or such later date as may be fixed by any requisite regulatory approval or acceptance for filing and shall continue in full force and effect until terminated by mutual agreement of the Parties.

2.02 This Agreement will be reviewed periodically by the Operating Committee to determine whether revisions are necessary or appropriate.

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-004

REQUEST:

4. Refer to page 1-10 of the IRP. Provide the national economic forecast obtained from Data Resources, Inc. ("DRI") used in developing the forecasts contained in the IRP.

RESPONSE:

This data is both voluminous and confidential in its nature. It is proprietary as well to Cinergy and the vendor, Standard & Poors DRI. It is available for inspection at the offices of Cinergy in Cincinnati, Ohio after a confidentiality agreement is entered into.

WITNESS RESPONSIBLE:

James A. Riddle

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-005

REQUEST:

5. Refer to pages 2-6 through 2-7 of the report. Provide the "Standard and Poor's DRI Utility Cost and Price Review for First Quarter, 1998" and "The U.S.Economy – 25 – Year Focus – Winter Issue 1999" used in developing the forecasts contained in the IRP.

RESPONSE:

This data is both voluminous and confidential in its nature. It is proprietary as well to Cinergy and the vendor, Standard & Poors DRI. It is available for inspection at the offices of Cinergy in Cincinnati, Ohio after a confidentiality agreement is entered into.

WITNESS RESPONSIBLE:

James A. Riddle

REQUEST:

6. Refer to pages 3-25 through 3-26 of the report. Explain in more detail how the increases in appliance efficiencies are reflected in the model of energy use and indicate for how long these efficiency increases have been modeled as part of the ULH&P/Cinergy forecasting process.

RESPONSE:

Appliance efficiency impacts are captured through the use of a variable called APPLSTK@EFF@CGE in the KWH USE PER CUSTOMER – RESIDENTIAL equation found on page OA-91 and OA-92 of the Cinergy 1999 Integrated Resource Plan, Ohio Appendix, Volume II. See also pages 3-74 and 3-75 of the Cinergy 1999 Integrated Resource Plan, Volume I for further explanation of appliance saturations and efficiencies. This variable has been used in the ULH&P/Cinergy forecasting process since 1988.

WITNESS RESPONSIBLE:

James A. Riddle

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-007

REQUEST:

7. Refer to pages 3-28 through 3-29 of the report, specifically, the portion that discusses weather-sensitive industrial usage. Provide a more detailed discussion of this subject that focuses particularly on its frequency and its magnitude.

RESPONSE:

Please see pages OA-95 through OA-1114 of the Cinergy 1999 Integrated Resource Plan, Ohio Appendix, Volume II. These contain the regression output of the industrial equations by two digit SIC code. By looking for those equations which contain either or both of the variables CDDB and HDDB, one can determine if there is significant weather sensitivity in the usage of that industrial group. Likewise, by looking at the coefficient on that weather variable, one can determine the relative magnitude of that sensitivity.

WITNESS RESPONSIBLE:

James A. Riddle

REQUEST:

8. Refer to page 3-34 of the report. Provide a more detail description and discussion of the process conducted to identify the breakpoints where the relationship between load and temperature change. Also, provide a summary of the analysis and the results obtained therefrom.

RESPONSE:

The process used to identify the breakpoints associated with the relationship between load and temperature involved numerous regression analyses using a spline transformation of temperature. The steps in the process included creating spline variables for a piece-wise linear representation of temperature data, estimating the regression equation between load and the transformed weather variables, creating a new spline with slightly different breakpoints, and re-estimating the regression equation to see if the fit of the model improved. Those steps were repeated until the breakpoints that provided the best fit to the data could be identified.

The attachment provides the regression results from the spline model that provides the best fit to the daily peak load data from the hot summer of 1988. The variable definitions are as follows:

Constant	=	constant term
SAT	=	qualitative variable for a Saturday
SUN	=	qualitative variable for a Sunday
HOL	=	qualitative variable for a holiday
LOG(MWHSEND)	=	natural logarithm of monthly sendout
TEMPMAX0to80 TEMPMAX80to 90 TEMPMAX90	=	|spline on maximum temperature |for the current day with breakpoints |at 80 and 90 degrees
TEMPMAXL10to80 TEMPMAXL180to 90 TEMPMAXL190	=	|spline on maximum temperature |for the prior day with breakpoints |at 80 and 90 degrees
TEMPMAXL20to80 TEMPMAXL280to 90 TEMPMAXL290	=	|spline on maximum temperature |for two days prior with breakpoints |at 80 and 90 degrees
Humidity	=	humidity
CDDSUML3	=	cumulative cooling degree days for the season lagged 3 days
JUL3	=	qualitative variable for July 3rd
JUL4WEEK	=	qualitative variable for the week of July 4th

The coefficients on the current day temperature spline variables in the model reveal how the slope on temperature changes as the maximum temperature increases.

WITNESS RESPONSIBLE:

James A. Riddle

ORDINARY LEAST SQUARES

FREQUENCY: M
INTERVAL: 1971:1 TO 1980:6 (114 OBS.)
DEPENDENT VARIABLE: LOG(MAXLOAD)

	COEFFICIENT	STD.ERROR	T-STAT	INDEPENDENT VARIABLE
0)	0.66659	0.77625	0.85873	CONSTANT
1)	1.0785	0.38564	2.7967	SAT
2)	-1.6839	0.36406	-4.6252	SUN
3)	-0.23382	0.022401	-10.438	HOL
4)	0.43076	0.056065	7.6833	LOG(MWHSEND)
5)	0.0085553	0.00162	5.2811	TEMPMAX0@80
6)	0.02285	0.0013257	17.236	TEMPMAX80@90
7)	0.011683	0.0015484	7.5454	TEMPMAX90
8)	-0.00017723	0.0019015	-0.093204	TEMPMAXL10@80
9)	0.0053424	0.0013822	3.865	TEMPMAXL180@90
10)	0.0025273	0.0016702	1.5131	TEMPMAXL190
11)	0.0024673	0.0013455	1.8337	TEMPMAXL20@80
12)	0.003219	0.0012967	2.4824	TEMPMAXL280@90
13)	-0.00033772	0.0014861	-0.22726	TEMPMAXL290
14)	0.0024375	0.0002628	9.2754	HUMIDITY
15)	0.000043852	0.0000097312	4.5063	CDDSUML3
16)	-0.15611	0.031647	-4.9328	JUL3
17)	-0.039393	0.017297	-2.2775	JUL4WEEK
18)	0.022911	0.0061681	3.7144	SAT*TEMPMAX80@90
19)	-0.03378	0.014591	-2.3152	SAT*TEMPMAXL10@80
20)	0.012713	0.0048247	2.635	SAT*TEMPMAXL180@90
21)	0.014423	0.013023	1.1075	SAT*TEMPMAXL20@80
22)	-0.019804	0.0057574	-3.4398	SAT*TEMPMAXL280@90
23)	0.0063997	0.0039687	1.6125	SAT*TEMPMAXL290
24)	0.0052539	0.0013497	3.8926	SAT*HUMIDITY
25)	0.028019	0.0072287	3.876	SUN*TEMPMAX0@80
26)	-0.0090906	0.0039684	-2.2907	SUN*TEMPMAXL10@80

R-BAR SQUARED:0.97813
DURBIN-WATSON:1.64
STANDARD ERROR:0.029058   NORMALIZED:0.0036486

REQUEST:

9. Refer to pages 3-36 through 3-37 of the report, specifically, the manner in which sendout is weather normalized. If any analysis has been conducted to determine the greater degree of accuracy obtained by weather normalizing each sales sector separately, as opposed to in the aggregate, provide the results of such analysis. Also, given the differences in industrial loads for different SIC codes, explain whether any consideration has been given to disaggregating the industrial sector by SIC codes for weather normalization purposes.

RESPONSE:

No analysis has been conducted to determine the greater degree of accuracy obtained by weather normalizing each sales sector separately, as opposed to in the aggregate. Disaggregating the industrial sector by SIC codes for weather normalization purposes was rejected because the SIC equations utilize quarterly data. For weather normalization monthly frequency is required.

WITNESS RESPONSIBLE:

James A. Riddle

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-010

REQUEST:

10. Refer to page 3-36, paragraph 3 of the report. Explain, from this discussion, whether for forecasting purposes, one of ULH&P/Cinergy's assumptions is that demand is not a function of price in the short-term. Also, for purposes of this request, provide ULH&P/Cinergy's definitions of short-term and long-term.

RESPONSE:

No. Cinergy does assume that demand is a function of price in the short term. Rather the distributed lag structure allows the model to determine price impacts over several time periods as customers change their usage patterns to price signals. A commercial customer may respond initially to a price change by adjusting thermostats or hours of operation. Subsequent response might include acquiring more efficient equipment. The lag structure allows both of these impacts to be captured. For these purposes, short term would be a month or so, long term would be anything greater.

WITNESS RESPONSIBLE:

James A. Riddle

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-011

REQUEST:

11. Refer to page 3-55 of the report that indicates that historical and projected numbers of residential customers are being provided disaggregated by electric heating and non-electric heating. The table referenced includes only one column reflecting the numbers of customers. Provide the numbers disaggregated into the two different categories referred to in the text.

RESPONSE:

Please see the attached form for the information requested.

WITNESS RESPONSIBLE:

James A. Riddle

NUMBER OF YEAR-END CUSTOMERS

Year	Electric Space Heating	Non-Electric Space Heating	Total Service Area
1990	147,777	457,042	604,819
1991	150,154	462,721	612,875
1992	153,142	468,543	621,685
1993	153,828	467,283	621,111
1994	157,134	473,925	631,059
1995	158,740	482,144	640,884
1996	158,677	486,552	649,668
1997	158,535	498,893	657,428
1998	159,438	506,360	665,798
1999	161,813	512,787	674,600
2000	160,146	523,180	683,326
2001	162,837	529,417	692,254
2002	165,598	535,727	701,325
2003	169,255	540,615	709,870
2004	171,016	547,363	718,379
2005	171,275	555,368	726,643
2006	168,897	564,770	733,667
2007	173,537	567,067	740,604
2008	179,298	568,482	747,780
2009	175,972	579,136	755,108
2010	178,342	584,112	762,454
2011	179,893	589,193	769,086
2012	179,591	596,014	775,605
2013	179,298	602,625	781,923
2014	187,564	600,612	788,176
2015	188,036	606,247	794,283
2016	187,326	611,922	799,248
2017	184,048	620,041	804,089
2018	185,858	623,096	808,954
2019	186,984	626,871	813,855

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-012

REQUEST:

12. Refer to page 3-67 of the report. Provide the value-added for individual SIC codes obtained from the Federal Reserve Board and the industrial productions indices obtained from DRI.

RESPONSE:

The value added weights are as follows:

SIC21 = 1.6	SIC25 = 1.4	SIC31 = 0.3	SIC39 = 1.3
SIC22 = 1.8	SIC27 = 6.8	SIC32 = 2.1	
SIC23 = 2.2	SIC29 = 1.4	SIC34 = 5.0	
SIC24 = 2.0	SIC30 = 3.5	SIC38 = 5.4	

The industrial production indices are both voluminous and confidential in their nature. It is proprietary as well to Cinergy and the vendor, Standard & Poors DRI. It is available for inspection at the offices of Cinergy in Cincinnati, Ohio after a confidentiality agreement is entered into.

WITNESS RESPONSIBLE:

James A. Riddle

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-013

REQUEST:

13. Refer to pages 3-82 through 3-83 of the report, specifically the references to the increases in load factor over the forecast horizon. Identify the reasons for this anticipated increase, including but not limited to greater impacts from Demand Side Management ("DSM"), greater utilization of interruptible loads, and improved appliance efficiencies.

RESPONSE:

Load factors increase due to a change in the amount of weather sensitive load relative to the total load. Any factors, such as improved appliance efficiencies, which reduce thelevel of weather sensitive load relative to total load would tend to improve the load factor. Also, load factor is impacted by the fact that industrial sales are projected to grow faster than the more weather sensitive residential and commercial sales. Industrial sales tend to have a higher load factor.

WITNESS RESPONSIBLE:

James A. Riddle

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-014

REQUEST:

14. Refer to pages 3-83 and 3-84 of the report. Provide a detailed discussion of the Census Bureau's X-11 procedure and how it is employed to perform the seasonal adjustments that are incorporated into the electric load forecasting models.

RESPONSE:

Refer to the following for an explanation of the Census Bureau's X-11 procedure:

U.S. Bureau of the Census (1967), *The X-11 Variant of the Census Method II Seasonal Adjustment Program,* U.S. Department of Commerce, Technical Paper No. 15 (1967 Revision), Washington, DC: Government Printing Office.

U.S. Bureau of the Census (1969), *The X-11 Information for the User,* U.S. Department of Commerce, Washington, DC: Government Printing Office.

Using software capable of performing the X-11 procedure, data is tested for seasonality.

If seasonality is determined to exist in the data, the seasonally adjusted data is captured by the software and is used in the forecasting models.

WITNESS RESPONSIBLE:

James A. Riddle

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-015

REQUEST:

15. Refer to page 3-94 of the IRP report that discusses the interruptible load in the different of Cinergy's service territory. Identify the 37 megawatts ("MW") of load available for interruption in the Kentucky service territory and reconcile the combined 86 MW available for interruption in Kentucky and Ohio with the amounts of 33 MW and less shown for the Cincinnati Gas and Electric ("CG&E") system in Figure 1-4 on page 1-42 of the report.

RESPONSE:

The 37 MW available for interruption in Kentucky is attributable to 4 different customers, 3 of which are available for interruption under the Energy Options program. The approximately 86 MW of load available for interruption in Kentucky and Ohio can be reconciled with the amounts shown in Figure 1-4 on page 1-42 by combining numbers in the column titled "ENERGY OPTIONS" with the column titled "INDUSTRIAL INTER LOAD".

WITNESS RESPONSIBLE:

James A. Riddle

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-016

REQUEST:

16. Refer to page 3-119, Figure 3-15 of the report. Explain the reasons for the Sales for Resale, Column 5, declining to zero beginning in 1998.

RESPONSE:

This reflects the fact that the city of Williamstown, KY is no longer a full requirements wholesale customer of ULH&P.

WITNESS RESPONSIBLE:

James A. Riddle

REQUEST:

17. On pages 1-6 and 1-7 of the report reference is made to the emphasis of the first 5 years of the forecast period. Figures 3-22 and 3-24 show projected load growth for the Ohio and Kentucky service territories separately. Explain the reasons for the higher projected load growth in Kentucky versus Ohio during the first 5 years of the forecast period.

RESPONSE:

It is projected that population and employment in the Kentucky service area will continue to grow at a faster rate relative to the Ohio service area as it has done so over the past several years. Consequently, load growth will be higher for Kentucky than Ohio over the next five years.

Based on estimates from the Census Bureau, population in the Kentucky service area has grown over the last five years at an annual rate of 1.4% compared to 0.5% for Ohio. Likewise, Kentucky service area employment has grown at an annual rate of 3.9% versus 2.3% for the Ohio service area.

WITNESS RESPONSIBLE:

James A. Riddle

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-018

REQUEST:

18. Refer to page 4-2 of the report. Describe the extent to which DSM programs already in place have been affected by the revision to the Total Resource Cost ("TRC") test. Also, describe the impact this revision has had on potential programs screened since the revision became effective.

RESPONSE:

The programs in place and the programs considered by the Kentucky Collaborative in developing the December 1, 1999 filing have not been affected by the revisions to the Total Resource Cost test ordered by the Public Utilities Commission of Ohio.

WITNESS RESPONSIBLE:

Victor A. Needham

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-019

REQUEST:

19. Refer to page 4-9 concerning the DSM application ULH&P planned to be file in October 1999. The application was ultimately filed in December 1999. Provide a general description of the application, including but not limited to, any programs that are being discontinued, any new programs being proposed, and the most recent benefit to cost ratios for the programs that are proposed to be continued beyond the pilot period originally authorized by the Commission.

RESPONSE:

Please see the attached Commission order granting approval for an extension of time to file the DSM program report. Also enclosed are our cover letter, Airborne receipts, application and program report filed in Case No. 95-312 instead of Case No. 99-414.

WITNESS RESPONSIBLE:

Victor A. Needham

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

October 25, 1999

James B. Gainer
Legal Division
The Union Light Heat & Power Co
139 E. Fourth Street
Cincinnati, OH. 45202

Honorable John J. Finnigan
& James B. Gainer
Attorneys at Law
2500 Atrium II
P. O. Box 960
Cincinnati, OH. 45201 0960

RECEIVED
OCT 27 1999
LE... ..EPT.

RE: Case No. 99-414

We enclose one attested copy of the Commission's Order in the above case.

Sincerely,

Stephanie J. Bell
Stephanie Bell
Secretary of the Commission

SB/hv
Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

DEMAND SIDE MANAGEMENT PROGRAMS AND COST RECOVERY FILING FOR DEMAND SIDE MANAGEMENT PROGRAMS BY THE UNION LIGHT, HEAT AND POWER COMPANY	)))))	CASE NO. 99-414

ORDER

On October 1, 1999, The Union Light, Heat and Power Company ("ULH&P") filed in Case No. 95-312[1] a motion for an extension of time, from October 1, 1999 to December 1, 1999, to file its annual Demand Side Management ("DSM") program report. Second, ULH&P requested authority to continue billing its current Gas Rider DSMR Demand Side Management Rate and its current Electric Rider DSMR Demand Side Management Rate beyond their scheduled expiration date of December 31, 1999, until the Commission has issued an Order approving new rates for the forthcoming period, based on the DSM program report. Third, ULH&P requested that the Commission open a docket to review and receive comments on ULH&P's DSM programs.

ULH&P premises its request for additional time to file its DSM program report on two factors. The first is that it has just recently received the results of outside,

[1] Case No. 95-312, The Annual Cost Recovery Filing for Demand Side Management by The Union Light, Heat and Power Company.

independent evaluations of two of its programs and needs to review and analyze those results before submitting its report to the Commission. The second factor is that ULH&P is awaiting notification as to whether it may be awarded a state grant to help fund its DSM programs in the future. Should it receive the grant, this will impact the future budgets and cost-effectiveness determinations of ULH&P's programs. Without knowing whether the grant will be awarded, ULH&P is not able to prepare a meaningful budget for certain of the individual programs.

ULH&P's current DSM cost recovery rates are scheduled to expire December 31, 1999. With the request for an extension until December 1, 1999 to file its annual DSM program report, ULH&P recognizes that the Commission would not have adequate time to review the report and issue an Order on future programs and cost recovery rates prior to the December 31, 1999 expiration date.

The request to open a docket to receive comments from the interested parties on ULH&P's DSM programs is consistent with the Principles of Agreement for Demand Side Management ("Agreement") entered into by ULH&P and the members of its DSM collaborative. The signatories to the Agreement committed to recommend to the Commission by January 1, 2000 to open a docket for review and comment on the DSM programs if ULH&P had not filed a general rate case on or before July 1, 1999.

Having considered the motion and being otherwise sufficiently, the Commission HEREBY ORDERS that:

1. This case is established to investigate and review ULH&P's DSM programs and to receive public comments on those programs.

2. ULH&P is granted an extension of time until December 1, 1999 to file its annual DSM program report.

3. ULH&P shall continue to bill its currently effective DSM cost recovery rates until such time as the Commission issues an Order prescribing new rates.

4. Case No. 95-312 is hereby closed. The record in Case No. 95-312 shall be incorporated by reference into the record in this proceeding.

5. Any comments on ULH&P's DSM programs shall be filed no later than January 5, 2000.

Done at Frankfort, Kentucky, this 25th day of October, 1999.

By the Commission

ATTEST:

Executive Director

USE THE INTERNATIONAL AIR WAYBILL FOR SHIPMENTS TO PUERTO RICO

1 FROM (Company) CINERGY
Street Address: ATRIUM 2 25TH FL, 221 E 4TH ST
City: CINCINNATI | State: OH | ZIP CODE (Required): 45202
Sent by (Name/Dept) | Phone Number: 513-287-2644

2 TO (Company) Public Service Commission of Kentucky
Street Address: 730 Schenkel Lane — AIRBORNE CANNOT DELIVER TO P.O.BOX
City: Frankfort | State: KY | ZIP CODE (Required): 40602 — MUST BE U.S. CITY, STATE, & ZIP CODE
Attention: (Name/Dept) HON. HELEN HELTON | Phone Number (Important)
Description: DOCUMENTS

3 THANK YOU FOR SHIPPING WITH AIRBORNE EXPRESS
Sender's Signature: Norma Bales | Date 11/30/99
Airborne Signature | Route No. | Date | Time

Preprint Format No. 69397651 | Origin CVG | Airbill Number 8102680456

4 Method of Payment (Assumed sender unless otherwise noted)
[X] Bill Sender ▶ 153905549 (Airborne Sender account no.)
[ ] Bill Receiver ▶ (Airborne Receiver account no.)
[ ] Bill 3rd Party ▶ (Airborne Customer account no.)
[ ] Paid in Advance — Check No. | Amount $
Billing Reference *will appear on invoice*: 023

5 Service Type — One box must be checked with an "X". Assumed Express Service unless otherwise noted.
[X] Express (Letter - 150 lbs)
[X] Next Afternoon (Letter - 5 lbs) — Next Afternoon Shipments over 5 lbs will be charged at the Express rate. Next Afternoon delivery to Bold Red destinations only.
[X] Second Day (Letter - 150 lbs)

6 # of Pkgs: 2 of 2 | **7** Weight (LBS): 1 (SUBJECT TO CORRECTION) | **8** One box must be checked: [ ] Letter Express [ ] Express Pack [ ] Other Packaging

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Declared Value [ ] or Full Insurance [ ] | Shipment Valuation $ .00
Received At: [ ] Drop Box # | [ ] Airborne Terminal

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Sent by (Name/Dept): John Finnigan | Phone Number: 513-287-2644

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Street Address: ...henkel Lane — AIRBORNE CANNOT DELIVER TO P.O.BOX
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Attention: (Name/Dept) HON. HELEN HELTON | Phone Number (Important)
Description: DOCUMENTS

3 THANK YOU FOR SHIPPING WITH AIRBORNE EXPRESS
Sender's Signature: Norma Bales | Date 11/30/99
Airborne Signature | Route No. | Date | Time

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6 NO. OF PKGS: 1 of 2 | **7** WEIGHT (LBS.): 1 (SUBJECT TO CORRECTION) | **8** CHECK IF: [ ] LETTER EXPRESS [X] EXPRESS PACK

Special Instructions: [ ] Saturday Delivery (Extra Charge, Express Only, Not available to all locations) [ ] Hold at Airborne [ ] Lab Pack [ ]

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Rm 25 AT II
P.O. Box 960
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Tel 513.287.3601
Fax 513.287.3810
jfinnigan@cinergy.com

JOHN J. FINNIGAN, JR.
Senior Counsel

November 30, 1999

CINERGY.

Hon. Helen Helton
Executive Director
Public Service Commission of Kentucky
730 Schenkel Lane
P.O. Box 615
Frankfort, Kentucky 40602

RE: In the Matter of : The Annual Cost Recovery Filing for Demand Side Management by The Union Light, Heat and Power Company
Case No. 95-312

Dear Ms. Helton:

Enclosed are an original and fifteen (15) true copies of Joint Application for The Adjustment of the 2000 DSM Cost Recovery Mechanism and for Filing the Amended Tariff Sheets for Gas Rider DSM (Original Sheet No.), Electric Rider DSM (Original Sheet No.) for docketing in the above captioned case.

Please date stamp the extra copies of the enclosed application upon filing and return in the enclosed, self-addressed envelope for our files.

Very truly yours,

John J. Finnigan nlb

John J. Finnigan
Senior Counsel

JJF/nlb

Enclosures

BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:	)	
The Annual Cost Recovery Filing	)	Case No. 95-312
for Demand Side Management by	)	
The Union Light, Heat and Power Company	)	

JOINT APPLICATION FOR THE ADJUSTMENT OF THE 2000 DSM COST RECOVERY MECHANISM AND FOR FILING THE AMENDED TARIFF SHEETS FOR GAS RIDER DSM (ORIGINAL SHEET NO.), ELECTRIC RIDER DSM (ORIGINAL SHEET NO.)

Now, come the Joint Applicants, with the consensus of the Collaborative, pursuant to this Commission's December 1, 1995 Order in Case No. 95-312 approving the Joint Application seeking to establish demand-side management (DSM) for The Union Light, Heat and Power Company's (Union Light or ULH&P) customers, and hereby make the following filing to adjust the cost recovery mechanism for calendar year 2000. (Order at 4.) The Order and the Joint Application are attached to this filing as Appendices A and B, respectively. The Joint Applicants are The Union Light, Heat and Power Company of 107 Brent Spence Square, Covington, Kentucky 41011, the Office of the Kentucky Attorney General (AG), and the Northern Kentucky Community Action Commission (CAC). The Collaborative Members are Darla Griffin (CAC), Ann Louise Cheuvront (AG), Nina Creech (People Working Cooperatively), Carl Melcher (Northern Kentucky Legal Aid), Karen Reagor (Kentucky NEED Project), Martha Daugherty (League of Women Voters), George Sundrup (Cinergy), Jennifer Griola (Brighton Center), Geoffrey Young (Division of Energy), and Shawn Cox (Northern Kentucky Home Builders Association). The Joint Applicants request that this Application be processed in an expeditious manner to permit implementation of the new riders during the first billing cycle of January 2000.

I. INTRODUCTION

A. Background

On December 1, 1995, the Kentucky Public Service Commission (KyPSC or Commission) approved a Joint Application filed in Case No. 95-312 by Union Light, the Office of the Kentucky Attorney General, the Northern Kentucky Community Action Commission, Citizens Organized to End Poverty in the Commonwealth, and two individuals: Susan York and Hazel Buchanan. This application requested approval of a DSM plan and recovery mechanism that were developed through a DSM Collaborative composed of representatives of Union Light and its customers. The Commission approved the DSM plan for the period ending December 31, 1999, and required the submission of annual update filings as well as a final report at the end of the DSM plan in 1999.

This filing presents the Applicants' third annual report. The following information related to the calculation of the Rider is required in this report and is provided herein:

1) Projected program and administrative costs, lost revenues and shareholder incentive for calendar year 2000;
2) Actual program and administrative costs, and shareholder incentives for each program from July 1, 1998 to June 30, 1999;
3) Reconciliation of actual versus projected costs and revenues for the period[1];
4) The decoupler calculation for the residential class; and
5) A proposed adjustment for each class[2].

[1] This reconciliation also reflects an adjustment to correct for the failure to reconcile the decoupler adjustment component of the 1998 Rider in the 1999 filing. (See the Commission's Order in Case No. 95-312, dated December 1, 1995, at page 4, paragraph 3. Reconciliation of the decoupler adjustment was inadvertently omitted from the calculation of the 1999 Rider, filed in the fall of 1998. An adjustment has also been made to remove revenues resulting from the DSM Riders from the net revenues used in calculating the decoupler adjustment.

[2] Application in Case No. 95-312, dated July 15, 1995 (approved by Commission Order dated December 1, 1995), at pages 10-11.

The following activities are to be updated in conjunction with each annual filing and are addressed herein:

1) "ULH&P shall recalculate on an annual basis the electric and gas usage-per-customer growth factors contained in the residential decoupling mechanism using customer usage data from the most recent eleven-year period; and

2) ULH&P shall perform a study which compares the electricity and gas patterns of DSM program participants with those of non-participants, and shall present the findings to the Commission in annual update reports and a final report at the end of the DSM plan in December 1999."[3]

B. Definitions

For the purposes of this Application, the following terms will have the meanings established in the Principles of Agreement Demand Side Management (Exhibit 1 to Joint Application dated July 15, 1995):

1) **"DSM Revenue Requirements"** shall mean the revenue requirements associated with all Program Costs, Administrative Costs, Lost Revenues (less fuel savings) including the effects of decoupling, and the Shareholder Incentive.

[3] KyPSC Order in Case No. 95-312, dated December 1, 1995 at page 6.

2) **"Collaborative"** shall mean the Union Light DSM Collaborative which was established by the Signatories and other parties separately from this process.

3) **"Program Costs"** shall mean the costs incurred for planning, developing, implementing, monitoring and evaluating the DSM programs described in Section XI of the Principles of Agreement Demand Side Management (Exhibit 1 to Joint Application) (pp. 11-19) and the DSM programs that have been approved by the Collaborative.

4) **"Administrative Costs"** shall mean the costs incurred by or on behalf of the collaborative process and that are approved by the Collaborative, including, but not limited to, costs for consultants, employees and administrative expenses.

5) **"Lost Revenues"** shall have the meaning in Section IV of the Principles of Agreement Demand Side Management.

6) **"Shareholder Incentive"** shall have the meaning in Section IV of the Principles of Agreement Demand Side Management.

7) **"DSM Cost Recovery Mechanism"** shall have the meaning in Section IV of the Principles of Agreement Demand Side Management.

II. ANNUAL UPDATE USAGE STUDY

On May 28, 1997, Union Light submitted a supplemental filing containing a progress report on a study being performed to compare the electricity and gas usage of DSM program participants with those of non-participants. The work plan for the conduct of that study was also included in the supplemental filing. The Company approved the work plan, which was prepared by Barakat and Chamberlin Inc. (BCI), in June 1997. The work plan consisted of two major components: a program process evaluation, focusing on the program's operation, administration, and delivery; and an energy savings assessment, comparing the electric and gas consumption of program participants with that of non-participants, measuring the program's effect on the energy consumption of participating customers. The program was judged by the third-party evaluation contractor to have been very effective in reducing energy consumption. This finding and the estimated resultant savings for electric and gas customers who received measures are reflected in the following statement.

> *The program has been very successful in reducing both gas and electric consumption. Compared to other low-income programs, the energy savings induced by this program's efforts are impressive. Overall savings for electric customers receiving weatherization or water heating measures were estimated at 1,893 kWh annually, and overall savings for gas customers receiving weatherization or water heating measures were estimated at 165 CCF annually.*

The average participant in the program was estimated to save 1,332 kWh and 115 CCF as a result of participation in the program. The complete report is attached to this Application as Exhibit 1.

III. RECALCULATION OF THE ELECTRIC AND GAS USAGE-PER-CUSTOMER GROWTH FACTORS

The recalculation of the factors through June 1999 is provided as Exhibit 2 to this filing, as required by the third ordering provision of the Commission's December 1, 1995 Order in Case No. 95-312. As discussed in that Order, this information is available for use in the design of a decoupling mechanism "in the event the Collaborative requests a continuation of residential revenue decoupling." The Collaborative is not requesting continuation of residential revenue decoupling in this filing.

IV. CALCULATION OF THE 2000 DSM COST RECOVERY MECHANISM

A. Summary of DSM Activity

Union Light proposes to continue to offer the following four demand-side management (DSM) programs in Union Light's service territory in 2000 under the jurisdiction of this Commission:

Program 1: Residential Conservation and Energy Education

Program 2: Residential Home Energy House Call

Program 3: Residential Comprehensive Energy Education Program

Program 4: Residential New Construction/Renovation Program

All of the programs listed above have been approved by this Commission in previous filings and are currently available to Union Light's customers. More detailed descriptions of the programs are provided in Exhibit 3.

In addition to the continuing programs listed above, the Collaborative requests that funds be approved for use for the review and development of additional programs. These funds will be referred to hereafter as Program 5: Program Development Funds. As described in preceding filings, the Collaborative has focused on innovative low-cost approaches for influencing the market, such as educational programs and collaborations with groups such as homebuilders' associations.

B. 2000 DSM Riders

In accordance with the Commission's order in Case No. 95-312, the Joint

Applicants submit the proposed DSM Riders (Exhibits 4 and 5). These riders are intended to recover the 1999 program costs and to reconcile the actual DSM revenue requirement, as previously defined, to the revenue recovered under the DSM Riders beginning with July 1, 1998 through June 30, 1999. Exhibit 6 consists of two spreadsheets. Exhibit 6a tabulates the reconciliation of the DSM Revenue Requirement associated with Union Light's programs between July 1, 1998 and June 30, 1999, and the revenues collected through the DSM Riders over the same period. An adjustment to the residential rider to account for reconciliation of decoupler adjustments for the previous periods is also reflected in Exhibits 6a and 6b, as described in footnote 1. Exhibit 6b tabulates the derivation of the decoupler adjustment, including the previous period adjustments, reflected in Exhibits 6a and 7 of this filing. The true-up adjustment is based upon the difference between the actual DSM revenue requirement and the revenues collected during the period July 1, 1998 through June 30, 1999.

The actual DSM revenue requirement for the period July 1, 1998 through June 30, 1999, consists of program costs, lost revenues (reflected as the decoupler adjustment for residential programs), and shared savings. Shared savings are applicable only to the non-residential programs. The actual program costs incurred are reflected in column (2) labeled "Program Exp 7-98 thru 6-99." The lost revenues or the decoupler adjustment are reflected in column (3) labeled "Lost Revenues 7-98 thru 6-99." The data for every transaction for which a rebate is paid is collected in the appropriate program's database. The calculation of lost revenues for C&I programs is performed using these databases. The impacts are multiplied by the marginal rate of the appropriate tariff to determine the dollar amount of the lost revenues. The data collected and used in the calculation of lost revenues are program specific. For the commercial lighting program, the impacts are calculated by taking the difference between the demand related to the original lighting fixtures and the demand related to the new energy efficient fixture. The demand is then multiplied by the number of hours of usage for the particular type of building in which the new lighting was installed. The estimates of average hours of usage for various building types were developed as part of an impact evaluation performed on the lighting program offered by The Cincinnati Gas & Electric Company (CG&E) in Ohio. The motors database uses a model sponsored by the U.S. Department of Energy (Motor Master Plus) and updated each year to accurately reflect the impacts resulting from replacement of inefficient motors. The manufacturer and model numbers and estimated hours of usage of the original inefficient motor and the new motor are entered into the model and the resulting impacts are calculated. The impacts resulting from the installation of adjustable speed drives are similarly calculated using a model offered by MagneTek (Energy Savings Predictor). The motor size, voltage, annual operating hours, application, and percentages of time at different operating levels are entered into the program. Energy and demand impacts are then compared to the existing flow control methods (by-pass valves, etc.).

The residential decoupler adjustment for the period July 1, 1998 through June 30, 1999 is attached as Exhibit 8, was calculated in accordance with the provisions of the KyPSC's December 1, 1995 Order in Case No. 95-312.

Exhibit 7, page 1 contains the calculation of the 2000 DSM Riders. The calculation includes the reconciliation adjustments calculated in Exhibit 6a and b and the DSM revenue requirement for 2000. The DSM revenue requirement for 2000 includes the costs associated with the four Residential DSM programs and program development funds planned for 2000.

The 2000 DSM Riders, Exhibits 4 and 5, replace the 1999 DSM Riders, which were implemented in the first billing cycle in January, 1999. These riders, to be effective with the first billing cycle in January 2000, are applicable to service provided under two sets of electric service tariffs as follows:

Residential Electric Service provided under:

Rate RS, Residential Service, Sheet No. 30

Rate REC, Residential Energy Conservation Rate, Sheet No. 32

Non-Residential Electric Service provided under:

Rate DS, Service at Secondary Distribution Voltage, Sheet No. 40

Rate DT, Time-of-Day Rate for Service at Distribution Voltage, Sheet No. 41

Rate EH, Optional Rate for Electric Space Heating, Sheet No. 42

Rate SP, Seasonal Sports, Sheet No. 43

Rate GS-FL, Optional Unmetered General Service Rate for Small Fixed Loads, Sheet No. 44.

Rate RTP, Experimental Real Time Pricing Program, Sheet No. 99

Rate DP, Service at Primary Distribution Voltage, Sheet No. 45

Rate TT, Time-of-Day Rate for Service at Transmission Voltage, Sheet No. 51

These riders would also be applicable to service provided under the following two residential gas service tariffs:

Residential gas service provided under:

Rate RS, Residential Service, Sheet No. 30

Calculation of the Residential Charge

The proposed residential charge per kWh for 2000 was calculated by dividing the sum of: 1) the reconciliation amount calculated in Exhibits 6a and 6b; 2) the decoupler adjustment calculated in Exhibit 6a and 6b; and 3) the DSM Revenue Requirement associated with the DSM programs during calendar year 2000, by the projected sales for the same period. DSM Program Costs for 2000 include the total implementation costs plus program rebates. There are no Shareholder Incentives associated with the non-resource programs planned for implementation in 2000. The calculations in support of the residential recovery mechanism are provided in Exhibit 7.

The residential decoupler adjustment for the period July 1, 1998 through June 30, 1999, attached as Exhibit 8, was calculated in accordance with the provisions of the KyPSC's December 1, 1995 Order in Case No. 95-312.

Calculation of the Non-Residential Charge

The proposed non-residential charge per kWh for 2000 was calculated by dividing the sum of: 1) the reconciliation amount calculated in Exhibit 6a and 2) the DSM Revenue Requirement associated with the DSM programs during calendar year 2000 from Exhibit 7, by the projected sales for the same period.

Allocation of the DSM Revenue Requirement

As required by 1994 House Bill 501, the DSM Cost Recovery Mechanism attributes the costs, lost revenues, and shared savings to the respective class that benefits from the programs. The amounts associated with the reconciliation of the Rider are similarly allocated as demonstrated in Exhibit 7. As required, qualifying industrial customers are permitted to "opt out" of participation in, and payment for, the 1999 DSM programs. In fact, most of Union Light's nine transmission level (Rate TT) customers met the "opt-out" requirements prior to the implementation of the DSM Riders in May 1996, and are not subject to the DSM Cost Recovery Mechanism.

WHEREFORE, the Joint Applicants ask for a timely review of this Application and for an Order approving the 2000 Riders DSM contained in Exhibits 4 and 5 hereto.

Respectfully Submitted,

THE UNION LIGHT, HEAT AND POWER COMPANY

By:______________________________

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing filing was served on the following on November 30, 1999 via ordinary United States mail, postage prepaid:

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EXHIBIT 1

Final Report

Evaluation of the Low-Income Conservation and Energy Education Program

Prepared for:
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October 27, 1999

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Table of Contents

Tables & Figures

This report contains the results of quantec's evaluation of the Low-Income Conservation and Energy Education Program (Program) at Union Light Heating & Power (ULH&P). This evaluation assessed the Program's performance in terms of operational efficiency and delivery, as well as Program energy savings.

The Program was designed to provide services, including energy education and a mix of energy conservation measures to just over 600 income-eligible households by the end of 1999. It sought to leverage and combine its funding with the State and Gas weatherization programs, thus providing more comprehensive coverage to low-income customers.

Together, these programs provide assistance to low-income customers by:

1. Installing energy efficiency measures
2. Providing energy education
3. Providing health and safety inspections and repairs

Customers were eligible to participate if they received ULH&P natural gas or electric service in their name, if their household income did not exceed 150% of the federal poverty guidelines, and if they had not participated in the Program at their current address since 1992. Customers who received Program services at their current address in or prior to 1991 were eligible, but not specifically targeted for participation. Participants may live in single-family or multi-family dwellings of not more than eight units.

As originally designed, ULH&P was to develop a program brochure and mailing list for the targeted customer group. This brochure was to describe Program benefits and encourage customers to participate. It was also to remind LIHEAP participants of their obligation to take advantage of any energy conservation services made available to them. The brochure directed customers to respond to the Northern Kentucky Community Action Committee (NKCAC), who was to act as intake coordinators. The actual installation work was to be performed primarily by NKCAC. A second contractor, People Working

Cooperatively (PWC), was to provide assistance on an as-needed basis.

Major Findings

Process evaluation findings were based on interviews conducted with Cinergy staff, contractors, non-utility parties, and other utilities. To assess the level of Program-induced savings, we analyzed customers' pre and post billing data using a statistical regression model. This approach allows for estimation of *net* savings by controlling for all other factors that may have caused observed changes in consumption.

The major findings are as follows:

Regulatory Process

- → The Program was designed through a collaborative process, an approach not unique to this Program. Most low-income programs are designed through similar processes.
- → The collaborative process offered some advantages in the creation of ideas and in ensuring that non-represented parties' interests were considered and accounted for. Though collaborative processes tend to be slow and inefficient, the process for this Program was exceptionally slow. For example, nearly ten months passed from the time the commission approved the Program to the finalization of its design and delivery.
- → An unusual feature of this Program was the main intake and installation contractor being a signatory party to the settlement agreement. This led to an awkward relationship between the subcontractor and utility, and, in our opinion, contributed to delays in the Program's implementation.

Program Design

- → The Program was designed to assist low-income customers manage their energy bills, reduce energy consumption, and reduce costs associated with bill collections. Although achieving energy savings was considered one of the primary objectives, the Program went considerably beyond a simple resource acquisition effort. The overall welfare of the participants was taken into account in all facets of the Program.

- The Program was designed to piggyback with two other weatherization programs, thus giving the effort considerable strength. The combined funds of the three programs provided a significant opportunity for achieving energy savings as well as providing health and safety assistance to low-income customers.

Program Delivery

- The Program proved to be very slow in recruiting customers and installing measures. As of June 30, 1998, it achieved only 33% of its targeted participation rate (slightly over 200 homes completed). According to the original plan, the Program should have had over 300 participants (see Figure ES-1).

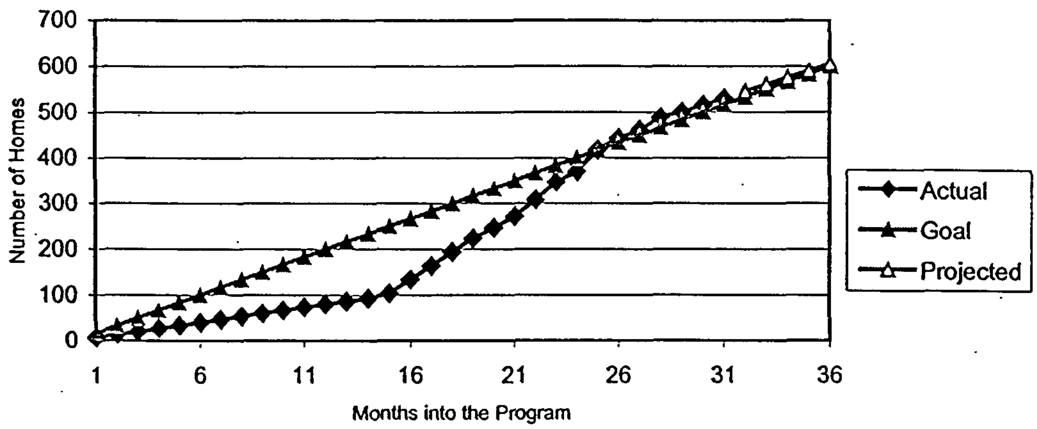
- Early delays were mainly caused by NKCAC's inability to handle the work. The number, size, and quality of NKCAC's crews were insufficient to meet the intake and weatherization demands of the Program.

- A high staff turnover rate at Cinergy until summer of 1997 contributed to delays in meeting targeted Program participation rates. The problems associated with NKCAC's inability to deliver were not quickly corrected by Cinergy staff due to this high turnover and the fact that NKCAC was a signatory party to the joint application and principles of agreement.

- Changes implemented in the first quarter 1998 have improved delivery markedly. Through July 1999, completions averaged 21 per month, and the Program was back on track to meet its original goals. The overall objective of 600 homes appears to be well within reach.

- To facilitate increased participation and reduce the amount of required pre-screening analysis, all low-income customers who met the dwelling type requirements were eligible to participate. This effectively eliminated minimum gas and electric bills as criteria for eligibility, allowing Cinergy and its subcontractors to focus on dwelling attributes (e.g., observed weatherization opportunities in both large and small homes) as an indicator of savings opportunities without prematurely eliminating interested customers.

Figure ES-1
Participation Rates



Program-Induced Savings

The Program has been very successful in reducing both gas and electric consumption. Compared to other utility low-income programs, the energy savings induced by this Program's efforts are impressive. Overall savings for customers with electric heating and water heating who received weatherization or water heating measures were estimated at 1,893 kWh annually, and overall savings for gas customers receiving weatherization or water heating measures were estimated at 165 CCF annually. The average Program participant is estimated to reduce electric and gas consumption by 1,331 kWh and 115 CCF, respectively.

Overall

→ Many aspects of the Program have been very effective. For example, PWC's educational process, assignment of work crews, and implementation of the weatherization measures have been successful and efficient. PWC's ability to pick up and take over work started by NKCAC has been critical to expected achievement of the Program's participation goals.

→ Most of the positive changes began to take place when Cinergy appointed a new project manager. Two of the most significant issues previously mentioned have been corrected: PWC and NKCAC have switched roles, with NKCAC responsible for four completions each month and for providing services on an as-needed basis, and Cinergy has taken a more active role in managing the Program. Cinergy's new project manager meets regularly with the contractors to review performance, initiates more frequent communications between collaborative members, and monitors more closely the delivery of the Program.

→ Due to the slow rate at which participants were enrolled in the Program, a significant opportunity potentially could have been lost. One of the Program's most powerful components was its expected piggybacking with State programs. Combining funding sources was to provide the Program with significant strength in offering energy savings, as well as in health and safety services. However, funding for the State programs was significantly cut in 1999. Efforts to leverage state funding were intensified in early 1999; the state program weatherization managers now attend the collaborative meetings, and efforts to match ratepayer funding are underway.

→ Communication between the Collaborative, Cinergy, NKCAC, and PWC was insufficient for much of the collaborative process. Communication has improved over time, however, and the Management Panel (a subset of the Collaborative) has been used extensively by Cinergy to resolve issues. As subcontractor performance is a potentially important topic at Management Panel meetings, no subcontractors should be on the Panel. Additionally, Program delivery can potentially be improved by obtaining insights from the entire collaborative through panel member rotations.

→ The saving analyses confirmed Cinergy's expectation that low-income customers can realize substantial savings from the Program. Average energy savings per participant exceed 17% of pre-Program gas usage, and 16% of pre-Program electric usage.

Program Summary

The Low-Income Conservation and Energy Education Program (Program) is offered by Cinergy through its subsidiary, Union Light Heat & Power (ULH&P or the Company). The Program was designed to target just over 600 households by the end of 1999, offering them energy education and a mix of energy conservation measures.

The Program was designed to leverage its investment with two other weatherization programs, thus providing more comprehensive coverage to low-income customers. The two other programs are:

1. **The State Weatherization Program**, executed by the Northern Kentucky Community Action Commission (NKCAC)
2. **The Gas Weatherization Program**, executed by People Working Cooperatively (PWC) on behalf the Company

Client Eligibility

Customers were eligible to participate if they received ULH&P natural gas or electric service in their name, if their household income did not exceed 150% of the federal poverty guidelines, and if they had not participated in the Program at their current address since 1992. Customers who received Program services at their current address in or prior to 1991 were eligible, but not specifically targeted for participation. Participants may live in single-family or multi-family dwellings of not more than eight units.

The Program only pays for measures that reduce the fuel served by ULH&P. Customers that only purchase gas service from ULH&P could only receive measures to help reduce gas consumption. Likewise, customers purchasing only electric service from ULH&P could only receive measures that reduced electric consumption. State Weatherization programs were not under these constraints and could provide additional services if desired.

The combination of the three programs provides assistance to low-income customers by:

1. Installing energy efficiency measures
2. Providing energy education
3. Proving health and safety inspections and repairs

Program crews first perform a health and safety inspection at various intervals during the measure installation process. Air sealing work is accomplished using blower door diagnostics. Crews continue improving air sealing until the leakage reduction target is achieved. Crews also check appliances and provide informal energy education to occupants. Post-installation inspections are conducted on all participating homes, and measure installation and customer satisfaction is checked.

PWC crews consist of a field coordinator/inspector who conducts the blower door test, an HVAC technician, and three installers. From the interview with NKCAC, the composition of their crews remained unclear. However, five installers were available to conduct the work.

Intake and Program Promotion

Originally, ULH&P developed a Program brochure and mailing list for the targeted customer group. This brochure was intended to describe Program benefits and encourage customers to participate. The brochure also reminded LIHEAP participants of their obligation to take advantage of any energy conservation services made available to them. The brochure directed potential participants to respond to NKCAC for further information.

NKCAC was to provide intake services that resulted from this mailing and to determine customers' eligibility. At that point, NKCAC was to divide the weatherization projects between PWC and themselves.

II. Process Evaluation Data Collection

As process evaluations require data from several primary important sources, data collection for this process evaluation consisted of interviews with Program staff, trade allies, and non-utility parties. An interview was also conducted with the low-income Program manager at American Electric Power (AEP). AEP offers a program similar to ULH&P's and serves as a good process comparison. Table 1 below displays the data collection process.

The following issues were covered in the interviews:

- → Program regulatory background
- → Program design
- → Program marketing and delivery
- → Overall Program assessment

Each of these issues is discussed separately in the following pages.

Table 1
Data Collection

In-Person Interviews		
Name	**Position**	**Agency**
Kathy Schroder	Program Manager	Cinergy
Victor Needham III	DSM Programs Manager	Cinergy
David Mussleman	Senior Counsel	Cinergy
Jock Pitts	Program Director	PWC
Nina Creech	Program Manager	PWC
Carl Melcher	Attorney	NKY Legal Fund
Tom Musk	Program Manager	NKCAC
Phone Interviews		
Name	**Position**	**Agency**
Don Music	Manager	American Electric Power
Ann Louise Cheuvront	Assistant Attorney General	Office of the Attorney General

Program Regulatory Background

In 1994, the Company filed tariffs for implementation of DSM programs in the Northern Kentucky service territory. The initial list of programs did not include a low-income program. The Public Service Commission (PSC) wanted a low-income program designed and included in the package. Further, the PSC and other stakeholders decided that DSM programs needed to be designed with the assistance of local parties in a collaborative setting.

Thus, a collaborative was formed among the following members:

1. Northern Kentucky CAC
2. Northern Kentucky Legal Aid Fund
3. The Attorney General Office
4. Committee for the Elimination of Poverty in the Commonwealth (CoEPIC)
5. PSC Staff
6. Industrial Customers
7. The Company

Upon their request, the industrial customers were later exempt from any rate impacts and from participation in any of the programs, and they withdrew from the collaborative.

On December 1, 1995, the DSM programs were approved by the PSC. NKCAC was a signatory to the agreement *as well as* the contractor for the Program intake and measure installation, a fairly unusual situation compared to similar programs across the country.

Program Design

The Program was based on a similar Program designed by and implemented through the Louisville Gas & Electric (LG&E) Collaborative. Most members of the Program collaborative were also involved in the LG&E collaborative.

Although energy savings were considered a primary objective, this Program went considerably beyond resource acquisition. The Program was designed to be a social service, offering low-income customers assistance in controlling their energy expenses and improving the health and safety conditions of their households. An additional benefit to the utility included potential savings associated with lowered collection costs.

After the commission approved the Program, it took nearly ten months to finalize its design and delivery. This included setting the maximum dollar limit on per home expenditures, deciding the best way to approach potential Program participants, finalizing forms, training vendors, and deciding on an evaluation contractor.

Program Marketing and Delivery

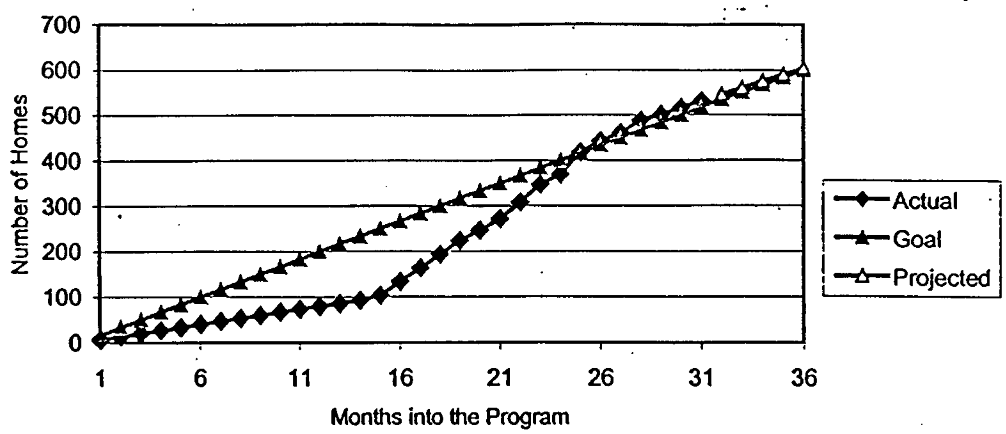
Originally, Program delivery was set up so that NKCAC conducted the intake, screened customers, performed some of the weatherization work, and referred some of the weatherization work to PWC.

The first Program marketing activity took place on October 16, 1996, with the release of 483 direct mail pieces targeting customers that were both LIHEAP recipients and high energy users. This was followed by another direct mailing of 385 letters targeting the same customers on October 18, 1996.

Figure 1 displays actual and projected Program participation rates. Initial projections were rarely met during early Program kick-off periods. Figure 1 displays the Program's actual participation rates for the first 30 months of operation as well as projected participation rates through the end of 1999. The overall combined "level" of the actual and the projected participation rates through mid-1999 is basically as expected. However, there are still some points to consider:

1. Since the first quarter 1998, there has been a dramatic improvement in the average monthly production. The Program is now on track with its original projections, and Cinergy's Program manager expects to meet the participation goal of just over 600 households by the end of 1999.
2. Although slow, early penetration rates are expected for any Program of this sort; this Program's early participation rates fell significantly below the targets.

Figure 1
Participation Rates

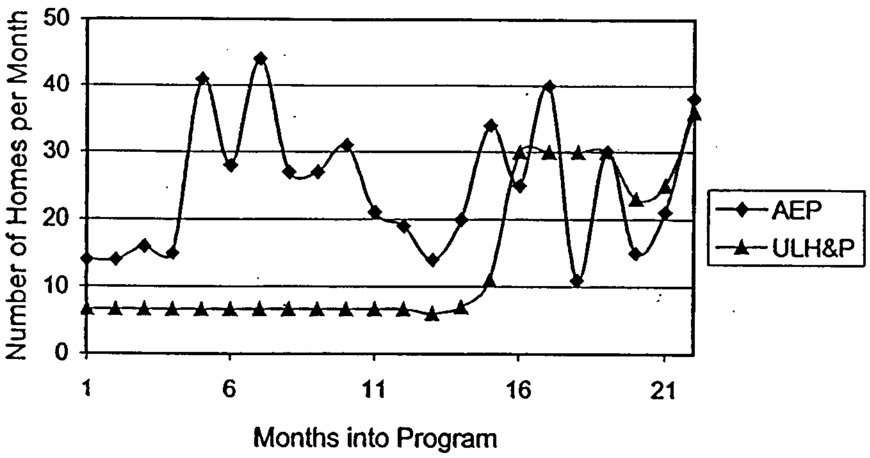


We originally intended to benchmark this Program against two similar programs. Unfortunately, we were only able to get information on one. Mr. Don Music of AEP/Ashland was extremely helpful and provided all of the necessary information, but we were unable to get similar data from the LG&E Program.

Figure 2 displays the number of homes that participated in the AEP Program each month relative to the ULH&P Program. Data for AEP were available for nearly two years after Program inception, which allows comparisons to be made for the periods before and after changes in ULH&P Program delivery and management.

While a direct comparison between the programs is misleading due to differences in their respective service territories, the graph does demonstrate the inability of the ULH&P program to attract customers quickly in its initial stages. More importantly, Figure 2 demonstrates that the subsequent changes in the ULH&P increased monthly participation to levels comparable to AEP's.

Figure 2
Benchmarking: Number of Homes per Month



IV. Energy Savings Analysis

To estimate the Program's savings, quantec applied a billing analysis approach that combines customer billing data, Program participant information, and weather data. The specific technique is known as ordinary least squares (OLS) regression.

This approach isolates and quantifies the factors affecting each household's electric (or gas) energy consumption each month. In this framework, Program participants' energy consumption depends on household and demographic characteristics, weather, and the installation of the Program's measures. In equation form, the general OLS formulation is as follows:

$$E = \alpha + \delta^*C + \beta_1{}^*M_1 + \beta_2 M_2 + \ldots + \beta_n{}^*M_n + \varepsilon, \qquad (1)$$

where:

E	=	average daily energy (or gas) usage each month
α	=	the intercept term
C	=	the set of household characteristics, demographics, weather and other non-Program factors affecting consumption usage
δ	=	the vector of coefficients associated with characteristics set C
M_1-M_n	=	binary variables set equal to 1 in the post-period if the households received the corresponding measure or group of measures (1, 2, ..., n) provided to participants through the Program
ε	=	the regression model error term

Coefficients $\beta_1, \beta_2, \ldots, \beta_n$ represent the *net* savings from each measure or group of measures.

Data Development

The data development effort matched billing, weather, and Program tracking information for each customer. As there were relatively few customers and associated billing periods, our objective in this matching process was to minimize the consequences of "missing data" and to keep as many customers as possible for model estimation.

quantec initially received billing data from Cinergy for 201 Program participants. The billing database contained energy consumption data from May 1997 through June 1999. These data were then merged with measure installation dates from the Program tracking database. As shown in Table 2, 147 of the 201 participants received measures. The remaining customers decided to forego further Program involvement after initial contact with PWC, only received Program educational materials, or lived in dwellings that were in such bad shape that it didn't make sense to invest in efficiency improvements.

Table 2
Sample Disposition

	Number	Share	Adjusted Share
Participants in bill/usage data set	201		
Gas & electric service	136	67.7%	68.7%
Electric only	56	27.9%	28.3%
Gas only	6	3.0%	3.0%
Can't tell - all data missing	3	1.5%	
Number with billing data and install dates	147		
Gas & electric service	101	68.7%	
Electric only	42	28.6%	
Gas only	4	2.7%	

The 147 participants with billing data and install dates are representative of the Program population. As demonstrated in Table 2, their respective shares of gas and electric service, electric service only, and gas service only are nearly identical.

Additional screening of the remaining participants was necessary before the electric and gas OLS models could be finalized. First, in the process of merging data from the billing and Program tracking databases, some customers were eliminated because the account codes did not match. Second, the OLS models require both pre-participation and post-participation data (at least three months of each), and some customers did not have enough months of pre or post data.[1] Third, preliminary OLS model specifications showed that electric customers would have measurable impacts only if they received weatherization measures for heating or cooling, or electric water heater measures.

Similarly, gas customers only had measurable impacts if they received weatherization or gas water heater measures. For example, an electric/gas combination customer might have gas heat and water heat and not have air conditioning. In this instance the customer would be included in the gas model but would be excluded from the electric model.

The results of this screening process are shown in Table 3. A total of 66 participants were included in the electric model, and a total of 71 participants are included in the gas model.

Table 3
Screening Results

Model/Screening Criteria	Number of Participants
Electric Model	
Gas & electric + electric	143
Have measure data	119
Have measure data and at least 3 months pre/post	91
Have measure data, at least 3 months, and heating, cooling, or water heat measures	66
Gas Model	
Gas & electric + gas	105
Have measure data	89
Have measure data and at least 3 months pre/post	73
Have measure data, at least 3 months, and heating or water heat measures	71

1 Additionally, each customer who received heating (cooling) measures was required to have at least one month of winter (summer) usage in both the pre and post periods.

The final step in the data development process merged Cincinnati airport weather data into the analysis data set. The weather-matching process created both cooling and heating degree-day variables (CDD, HDD) that were unique for all customers. This is because each account has different beginning and ending meter-read dates for each revenue month.

Model Specifications

The next step in the analysis process was to estimate a series of preliminary OLS models and develop final specifications for electric and gas savings.

The final set of variables in the electric equation is shown below. With the exception of the dependent variable, (+) implies that we expect a positive correlation with electric usage, and (-) implies a negative correlation with electric usage.

> QELEDAY: This is the dependent variable — average daily electric consumption each month
>
> INCOME: The household's annual income (+)
>
> SFAM: A binary variable set equal to 1 if the home is a detached single-family home, and zero otherwise (+)
>
> HHSIZE: Family size (+)
>
> ELECWH: A binary variable set equal to 1 if the customer has electric water heat, and zero otherwise (+)
>
> ELECHDD: An interactive variable equal to customer-specific heating degree-days if the customer has electric heat, and zero otherwise (+)
>
> ELECCDD: An interactive variable equal to customer-specific cooling degree-days if the customer has electric heat, and zero otherwise (+)
>
> HEATMEAS: A binary variable set equal to 1 in the post period if the customer has electric heat and received weatherization measures, and zero otherwise (-)

COOLMEAS: A binary variable set equal to 1 in the post period if the customer has electric heat and received weatherization measures, and zero otherwise (-)

WATMEAS: A binary variable set equal to 1 in the post period if the customer has electric water heat and received water heater retrofit measures, and zero otherwise (-)

The final gas model is nearly identical, with QGASDAY replacing QELECDAY as the dependent variable and the elimination of the cooling end-use and cooling measure variables.

Energy Savings

Electric and gas model results are presented in Tables 4 and 5, respectively. All of the demographic and end-use/weather variables have the right signs and are statistically significant. All of the Program measure variables also have the correct negative sign. The weatherization measures are statistically significant, and the water heating measures are nearly so (one-tail test).

Table 4
Electric OLS Model Results

Parameter	Coefficient Estimate	T-Ratio	PROB > |T|
INTERCEPT	-0.8063	-0.453	0.6504
INCOME	0.0004	3.553	0.0004
HHSIZE	4.6087	13.634	0.0001
SFAM	6.3561	5.796	0.0001
ELECWH	15.2610	13.016	0.0001
ELECHDD	0.0249	15.016	0.0001
ELECCDD	0.0644	14.026	0.0001
HEATMEAS	-6.3415	-5.065	0.0001
COOLMEAS	-2.9595	-2.738	0.0063
WATMEAS	-1.8033	-1.120	0.2630
R-Square	0.4282		
Number of Observations	1,391		
Number of Participants	66		

Table 5
Gas OLS Model Results

Parameter	Coefficient Estimate	T-Ratio	PROB > |T|
INTERCEPT	-0.324	-1.504	0.1327
INCOME	0.000	4.036	0.0001
HHSIZE	0.083	2.651	0.0081
SFAM	0.202	1.624	0.1045
GASWH	0.298	1.839	0.0661
GASHDD	0.005	44.580	0.0001
HEATMEAS	-0.382	-3.745	0.0002
WATMEAS	-0.132	-1.168	0.2430
R-SQUARE	0.5862		
Number of Observations	1,469		
Number of Participants	71		

The savings coefficients on HEATMEAS, COOLMEAS, and WATMEAS in Tables 4 and 5 show the daily savings associated with each of these end-use/measure combinations. To obtain annual savings for each combination, each coefficient is multiplied by 365. Average savings per customer in the model are then given by multiplying the annual savings for each end-use/measure combination by the share of customers who received that combination. These results of these calculations are contained in Table 6.

Table 6
Annual Energy Savings for Customers in OLS Models

Category	Gas (CCF)	Electric (kWh)	Proportion with Measures: Gas	Proportion with Measures: Electric
Heating measures	139.5	2,314.7	100.0%	43.9%
Cooling measures		1,080.2		68.2%
Water heating measures	48.1	658.2	53.5%	21.2%
Overall model savings	*165.2*	*1,893.2*		

The estimates in Table 6 must be discounted to derive savings for the average electric or gas participant, and for the average participant regardless of fuel type. These estimates are contained in Table 7.

Table 7
Annual Energy Savings by Participant Category

Category	Gas (CCF)	Electric (kWh)
Overall - end-use model	165.2	1,893.2
Overall savings - adjusted by % of fuel with measures	160.7	1,373.1
Overall savings - per Program participant	115.3	1,331.5

The first row of Table 7 simply repeats the last row of Table 6 and shows the average annual savings for each modeled participant, assuming all received the measures modeled. The second row shows savings estimates adjusted by the share of customers by fuel type who received the measures in the models. For gas customers, this factor is 97.3% (71 of 73 customers), and for electric customers this factor is 72.5% (66 of 91 customers). The last row shows average energy saved per participant. These estimates are given by multiplying the results (adjusted by % of fuel with measures) by the share of participants with that fuel (71.7% gas, 97% electric).

Tables 8 and 9 use the regression model results to show the savings estimates for various end-use/measure combinations.

Table 8
Electric Savings Estimates for Alternative End Use Combinations

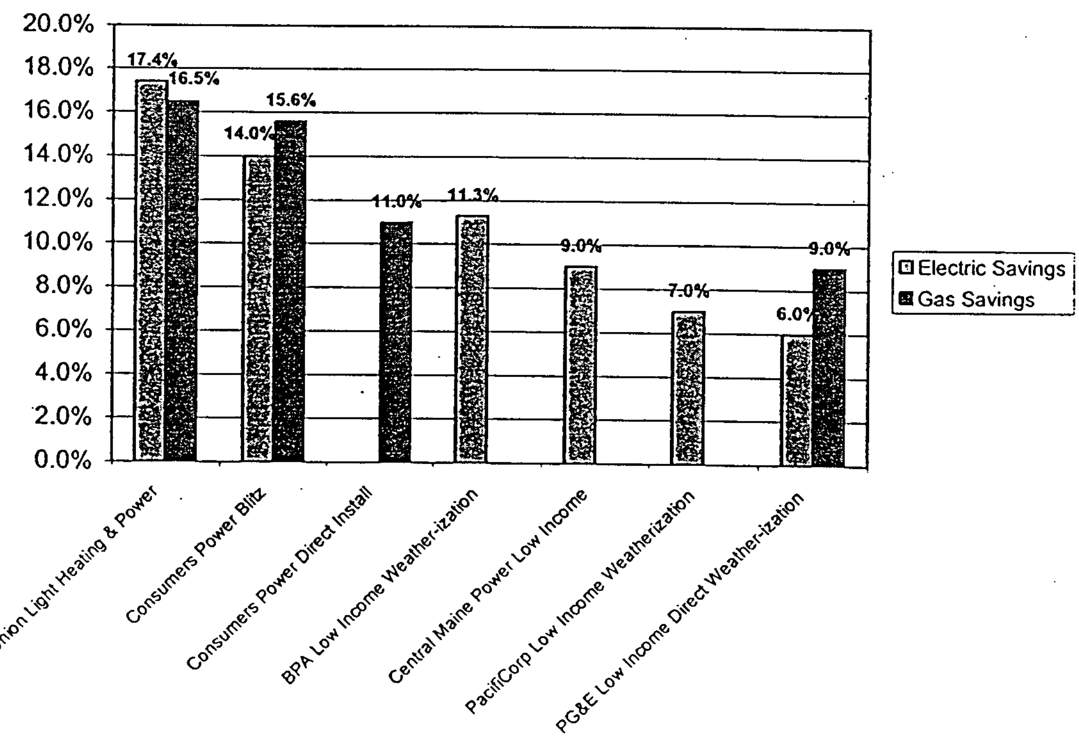
Electric Savings by End Use/Measure Combinations	Cooling Measures	Heating Measures	Water Heating Measures	Annual Electric Savings
Type 1	Yes	Yes	Yes	4,053
Type 2	Yes	Yes	No	3,395
Type 3	Yes	No	Yes	1,738
Type 4	Yes	No	No	1,080
Type 5	No	Yes	Yes	2,973
Type 6	No	Yes	No	2,315
Type 7	No	No	Yes	658
Type 8	No	No	No	0

Table 9
Gas Savings Estimates for Alternative End Use Combinations

Gas Savings by End Use/Measure Combinations	Heating Measures	Water Heating Measures	Annual Gas Savings
Type 1	Yes	Yes	187.6
Type 2	Yes	No	139.5
Type 3	No	Yes	48.1

Figure 3 compares the savings estimates from ULH&P with other utility low-income programs. To enable comparisons across different climate zones, we have only included savings analyses where percentage savings are reported. As the table indicates, the Program has saved more than the other programs.

Figure 3
Energy Savings Comparison with other Utility Low-Income Programs[2]



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[2] See the References section for the savings' information sources.

While we can only offer hypotheses as to why ULH&P's low-income Program is generating relatively high savings estimates, the process evaluation and subsequent Program improvements indicate that this performance is likely a combination of the following:

- → After a difficult start, Cinergy put together a superior management team that provides very effective leadership and Program support.
- → PWC's individual staff members have more than five years of experience across most positions in the organization, and there is little staff turnover.
- → PWC's leveraging of other funds.
- → Use of cellulose insulation.
- → Measure "flexibility" and focus on health (e.g., fix broken walls, doors, and windows).
- → Old building stock.
- → Random inspections by a third party.

V. Overall Program Assessment

Regulatory/Collaborative Process

1. Most low-income programs we are familiar with have been designed through a collaborative process. While this process is typically slow and inefficient, it has become the model nationwide. Yet, in this case, the process appears to have been exceptionally slow. For example, it took nearly ten months to finalize the Program's design and delivery.

2. Having the main intake and delivery contractor be a signatory party to the settlement agreement is rare. This may have led to the significant delays in correcting delivery problems that occurred in the Program's first year of implementation.

Program Design

The design of this Program is similar to that of many other low-income programs. Further, taking advantage of other funding supplied by state programs provides a great asset. To date, the opportunity to leverage those funds has been foregone. The potential to leverage state funding for the Program after 1999 appears promising.

Initial Program Delivery

1. Involving community action agencies early in the design is typical for programs of this type. Yet, in this case, NKCAC was not prepared to handle the additional work load. This caused some significant delays in the delivery of the Program.

2. Corrective actions were significantly delayed. This was mainly due to:
   a. Lack of cooperation form the NKCAC
   b. Significant staff turnover at Cinergy
   c. The political realities of NKCAC being a participating party to the settlement agreement.

3. High staff turnover at Cinergy, compounded by assigning the DSM programs' manager to another position in the company,

did not allow the continuity required for the successful implementation of the Program.

4. Having NKCAC be both the intake coordinator and prime contractor was the main reason why the Program did not achieve the desired penetration rates.

Subsequent Program Management and Delivery Changes

The Program was well conceived, especially piggybacking it with other state programs. Subsequent changes in Program Management at Cinergy and the reversal of the roles of NKCAC and PWC have made dramatic improvements in the Program, exemplified by large increases in participation and superior energy savings relative to other utility low-income programs.

Cinergy has already taken a very active role in the Program. Although this role has come a bit late, it made a significant difference in the Program's execution. The current Program manager implemented many changes that have revived the Program. In the first quarter 1998, contracts and budgets were modified and the contractor roles were reversed. PWC became the prime intake and delivery contractor, and NKCAC was held responsible for only four completions per month. This was consistent with their production since the Program's inception. PWC began aggressive intake, including co-locating intake stations with NKCAC and other community LIHEAP facilitators, such as Brighton Center.

Energy Savings

The saving analyses confirmed Cinergy's expectation that low-income customers can realize substantial savings from the Program. Average energy savings per participant exceed 17% of pre-Program gas usage, and 16% of pre-Program electric usage.

Recommendations

While significant changes in Program delivery have already taken place, further adjustments are necessary. Currently, PWC has taken a more active role in Program intake and measure installation. PWC conducts all marketing activities, including direct mailings and telephone solicitation, and should continue to do so. More aggressive solicitation approaches should also be considered, such as leaving literature in neighborhoods where weatherization jobs are being conducted. We also recommend that PWC become the primary intake contractor and that cases only be referred to NKCAC when faced with overflow or where health and safety related repairs are required.

Communication between the Collaborative, Cinergy, NKCAC, and PWC was insufficient for much of the collaborative process. Communication has improved over time, however, and the Management Panel (a subset of the Collaborative) has been used extensively by Cinergy to resolve issues. As performance of the providers is a potentially important topic at Management Panel meetings, no providers should be on the Panel. Additionally, Program delivery can potentially be improved by obtaining insights from the entire collaborative through a rotation on the Management Panel.

References

Consumers Power – Carlson, L. et al, "Survivors: Effective Low-Income Programs," 1997 Energy Evaluation Conference Proceedings, pp. 417-424.

BPA – Haeri, M. H., et al, "Evaluation of the Bonneville Power Administration Low Income Weatherization Program, ERC International, July 1988.

Central Maine Power – Khawaja, M. S., et al, "Impact Evaluation of the Low-Income Segment of the Weather Shield and Attic Attack Program," H. Gil Peach & Associates, June 1990.

PacifiCorp – Khawaja, M.S., et al, "PacifiCorp Low Income Program Impact Evaluation," Barakat & Chamberlin, Inc., September 1995.

PG&E – "Impact Evaluation of the Low Income Direct Weatherization Program," Cambridge Systematics, Inc., August 1988.

ORDINARY LEAST SQUARES

EXHIBIT 2
RECALCULATION OF GROWTH FACTOR

FREQUENCY: A
INTERVAL: 88 TO 98 (11 OBS.)
DEPENDENT VARIABLE: LOG(ELECACTUAL)

```
COEFFICIENT STD.ERROR T-STAT   INDEPENDENT VARIABLE

0) 9.1429    0.059701  153.15      CONSTANT
1) 0.0081566 0.0029484   2.7664    TIME
```

R-BAR SQUARED:0.39951
DURBIN-WATSON:2.95
STANDARD ERROR:0.030923 NORMALIZED:0.0033229

?SN PLOT

```
DATE    ACTUAL  FITTED  PLOT :*=ACTUAL:+=FITTED

1988  9.2855 9.2652       ----*
1989  9.2626 9.2734      *++
1990  9.2588 9.2816     *+++++
1991  9.3315 9.2897          ----------*
1992  9.2366 9.2979 *++++++++++++++
1993  9.3179 9.306               ---*
1994  9.3134 9.3142                *
1995  9.3434 9.3223                  ----*
1996  9.3589 9.3305                    -------*
1997  9.3129 9.3387               *+++++++
1998  9.3446 9.3468                      *
```

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(EXP(0.0081566)-1)=0.008190 elec

ORDINARY LEAST SQUARES

FREQUENCY: A
INTERVAL: 88 TO 98 (11 OBS.)
DEPENDENT VARIABLE: LOG(GASACTUAL)

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COEFFICIENT STD.ERROR T-STAT   INDEPENDENT VARIABLE

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(EXP(-0.021348)-1)=-0.021122 gas

EXHIBIT 3

DSM PROGRAMS

The Kentucky Collaborative has taken an active role in developing and considering DSM programs to be implemented in Union Light's service territory. Some of the functions performed by these groups are: 1) review of cost-benefit analyses, as appropriate; 2) approval of programs and modifications to programs; 3) selection of program contractors; and 4) collection of data to support program development.

Union Light will offer the following programs in 2000, the costs of which shall be recoverable through the DSM Cost Recovery Mechanism established in section II of the Agreement.

Program 1:	Residential Conservation and Energy Education
Program 2:	Residential Home Energy House Call
Program 3:	Residential Comprehensive Energy Education Program
Program 4:	Residential New Construction/Renovation Program
Program 5:	Program Development Costs

Except as provided in the Agreement, these programs will be terminated on January 1, 2002. If the Collaborative recommends that programs continue, a new application may be filed with the Commission.

Program 1: Residential Conservation and Energy Education

The Collaborative proposes to continue the Residential Conservation and Energy Education program funded at a level of no more than $1,000,000, to be expended between the date of Commission approval and January 1, 2002. This program is directed at weatherizing housing stock and educating customers on energy use. Approximately 300 customers are expected to participate in 2000.

This program has served more than 550 low-income customers in ULH&P's service territory since 1997. The program was judged by a third-party evaluation contractor to have been very effective in reducing energy consumption. This finding and the estimated resultant savings for electric and gas customers who received measures are reflected in the following statement.

> *The program has been very successful in reducing both gas and electric consumption. Compared to other low-income programs, the energy savings induced by this program's efforts are impressive. Overall savings for electric customers receiving weatherization or water heating measures were estimated at 1,893 kWh annually, and overall savings for gas customers receiving weatherization or water heating measures were estimated at 165 CCF annually.*

The average participant in the program was estimated to save 1,332 kWh and 115 CCF as a result of participation in the program. The complete report is attached to this Application as Exhibit 1.

While People Working Cooperatively, one of the contractors that deliver the program, has worked to leverage community funding to enhance the efficiency of the program, there has been little leveraging of state funding as contemplated at the start of the program. ULH&P is currently working with the state of Kentucky's weatherization program to facilitate better leveraging with state funding. Additionally, ULH&P and the Collaborative will review the results of the Commission's examination of on-going programs being offered by other Kentucky utilities as well as the resultant design efforts by those utilities to identify features that may further improve the effectiveness of this program.

<u>Program 2: Residential Home Energy House Call</u>

The Home Energy House Call consists of three major components:

1) Home Energy Survey
2) Comprehensive Energy Audit & Review
3) Measures Installation Opportunity

When a Home Energy House Call is requested by a customer, a qualified home energy specialist visits the site to gather information about the home. A questionnaire about the energy usage is also completed.

The energy specialist gives the customer a detailed report that explains how their home uses energy each month. The specialist will also check the home for air leaks, inspect the furnace filter, and look at the insulation levels in different areas. If needed, the specialist will recommend cost saving do-it-yourself measures to make the home more energy efficient.

In addition to helping the customer with energy efficiency, the Home Energy House Call assists the customer with 'Earth Perks' also. This part of the program looks at the natural resources and pollution prevention needs of the customer's home and community and offers a list of action items. This list of action items is prioritized by the home's environmental profile. In 2000, Union Light expects approximately 500 customers to participate in this program.

Since the beginning of the program, nearly 1,700 customers have participated. Home Energy House Call was designed as primarily an education program. As such, quantification of savings and assessments of cost-effectiveness are difficult. However, a recent evaluation comparing the consumption of participants and non-participants of the program revealed estimated average electric savings ranging from 995 kWh for gas heated customers to more than 1200 kWh for electrically heated customers. The economies of scale resulting from leveraging of the program with the program offered to CG&E's customers in Ohio and the fact that participants pay for the measures they decide to implement keep the program cost low. Utility cost test results using these assumptions yield cost-effectivess ratios of just over 1.0.

Program 3: Residential Comprehensive Energy Education Program

This energy education program was developed by the Collaborative for implementation in late 1997. The contract for implementation of this program was awarded to Kentucky NEED during the third quarter of 1997. The program has provided unbiased educational information on all energy sources, with an emphasis on the efficient use of energy. Energy kits, with materials emphasizing cooperative learning, are provided to teachers. The Leadership Training Workshops are structured to educate teachers and students to return to their schools and communities and families and conduct similar training and implement behavioral changes that reduce energy consumption in the community and home. Educational materials and Leadership Training Workshops are designed to address students of all aptitudes, and have been provided for students and teachers in grades 5 through 12.

Since October 1997, 21 teacher/student workshops have been held, directly training 88 teachers and 1,739 students in the service territory. These teacher/student teams have impacted 2,000 students and their families. Students who attend workshops are encouraged to mentor other students in their schools – further spreading the message of energy conservation. Teams of high schools students serve as facilitators at workshops. Through this approach, all grade levels are either directly or indirectly presented the energy efficiency and conservation message. Several of the student teams have made presentations to community groups, sharing their knowledge of energy, promoting energy conservation an demonstrating that the actions of each person impact energy efficiency. In addition to impacts on other students and community groups, it is intended that these students will share this information with their families and reduce consumption in their homes. Approximately 30 percent of the schools in the six counties served by ULH&P have participated.

Three new components of the program will be introduced in the 1999-2000 NEED materials: *Building Buddies* for grades K-3, *Monitoring & Mentoring* for grades 4-6 and *Learning & Conserving* for grades 7-12. (Copies of these curricula elements are available upon request.) These components explore energy use and encourage conservation in the home and at school. Each component teaches students how to measure energy consumption and identifies actions that can be taken to conserve and therefore reduce energy consumption. The KyNEED Project provider will explore a model school-based energy education program with the director of a program implemented by the Wake County Public Schools, Wake County North Carolina. The *Energy Savers* program and the integration of energy education in the curriculum reportedly saved Wake County Public Schools over $1,000,000 in 1999. This information will be shared with the appropriate school officials in Northern Kentucky.

The KyNEED Project will partner with the Kentucky Division of Energy promoting their SWAT, Jr. (Student Weatherization and Audit Training) Program in area high schools. Through this program, students are trained, in September, to perform informal energy audits of their schools. Along with the audit, these students are then encouraged to mentor students in area schools using the NEED materials and are often facilitators at area workshops.

The members of the Residential Work Team have requested that some of this funding be used to subsidize training for Work Team members. Allocation of these funds for this purpose will require consensus of the entire Collaborative. Any member of the Collaborative using these funds will be required to file a written report and to share the knowledge gained through the training with the Collaborative.

Program 4: Residential New Construction/Renovation Program

The Construction Subcommittee of the Residential Work Team developed this program during 1997 as a low cost approach to build awareness of and encourage investment in energy efficiency in the new home and the renovation markets in Northern Kentucky. The program will be offered as a partnership between the Collaborative, Union Light, and the Northern Kentucky Homebuilders Association, which joined the Residential Work Team and the Construction Subcommittee in 1997. It consists of two major elements:

1) Energy-Efficient Home Contest
   The most efficient entries in each category (e.g., new single-family, new multi-family, renovation - single-family, and renovation – multi-family) will be awarded a $3,000 prize, up to a maximum of five prizes at 15,000. They will also be featured at Homebuilders Association home shows and in appropriate magazines and/or periodicals.

2) Informational Activities

Informational activities will include meetings and educational seminars with area builders and trade allies such as lenders, real estate agents, appraisers, designers, architects, engineers, equipment providers, and code officials.

The SAVEE program provides a low cost vehicle to enhance promotion of energy efficiency in new home construction and in the renovation of existing homes. The program encourages market push through its work directly with the builder community and encourages market pull from consumers through its presence at home shows and through advertising and other promotion.

The program is promoted primarily through the Homebuilders Association of Northern Kentucky. Builders entered two homes in the contest in 1998, which was the first year of the program. A process evaluation was performed in 1998 to identify opportunities to increase builder awareness of the program and to better focus the marketing and promotion of the program. The SAVEE subcommittee reviewed the results of the analysis and implemented specific program enhancements and modifications.

The deadline for contest submissions for 1999 is November 1, 1999. Aggressive targeted cooperative advertising promoting the winning builders of the 1998 SAVEE contest is expected to increase awareness of and participation in the program in 1999.

RIDER DSMR

DEMAND SIDE MANAGEMENT RATE

The Demand Side Management Rate (DSMR) shall be determined in accordance with the provisions of Rider DSM, Demand Side Management Cost Recovery Rider, Sheet No. 75 of this Tariff.

The DSMR to be applied to residential customer bills beginning with the January 2000 revenue month is 0.0146 cents per kilowatt-hour. (D)

The DSMR to be applied to non-residential service customer bills beginning with the January 2000 revenue month for distribution service is 0.0583 cents per kilowatt-hour, and 0.00000 cents per kilowatt-hour for transmission service. (I)

The Union Light, Heat and Power Company
107 Brent Spence Square
Covington, Kentucky 41011

Ky.P.S.C. Gas No. 5
Sheet No. 62.4
Cancels and Supersedes
Sheet No. 62.3

RIDER DSMR

DEMAND SIDE MANAGEMENT RATE

The Demand Side Management Rate (DSMR) shall be determined in accordance with the provisions of Rider DSM, Demand Side Management Cost Recovery Rider, Sheet No. 61 of this Tariff.

The DSMR to be applied to residential customer bills beginning with the January 2000 revenue month is 4.11430 cents per hundred cubic feet. (I)

The DSMR to be applied to non-residential service customer bills beginning with the January 2000 revenue month is 0.00 cents per hundred cubic feet.

Issued by authority of an Order by the Kentucky Public Service Commission, dated in Case No. 95-312.

Issued: Effective: January 3, 2000

Issued by J. L. Turner, President

Exhibit 6a
Kentucky DSM Rider
Comparison of Revenue Requirement to Rider Recovery

Residential	(1) Projected Costs 1999 Rider (2)	(2) Program Exp thru 6-99 (3)	(3) Decoupler Adjustment Gas	(4) Decoupler Adjustment Elec	(5) Total Program Expend. Gas	(6) Total Program Expend. Electric	(7) Rider Collection (4) Gas	(8) Rider Collection (4) Electric	(9) Over/(Under) Recovery (5) Gas	(10) Over/(Under) Recovery (5) Electric
Peak Conservation Plan (1)	$0	$11,393	$0	$0	$0	$11,393	NA	NA	NA	NA
Home Energy House Call	$84,000	$69,609	$0	$0	$45,246	$24,363	NA	NA	NA	NA
Income Qualified Programs	$500,000	$900,231	$0	$0	$585,150	$315,081	NA	NA	NA	NA
Comp. Residential Education	$75,000	$42,592	$0	$0	$27,685	$14,907	NA	NA	NA	NA
Collaborative & Support	$32,000	$37,029	$0	$0	$24,069	$12,960	NA	NA	NA	NA
Renovation/New Construction	$40,000	$17,594	$0	$0	$11,436	$6,158	NA	NA	NA	NA
RS Total	$731,000	$1,078,448	$1,911,429	($420,194)	$693,586	$384,863	$100,436	$1,478,405	($2,605,015)	$35,331

Commercial	(1) Projected Costs 1999 Rider (2)	(2) Program Exp thru 6-99 (3)	(3) Lost Revenues through 6-99	(4) Shared Savings through 6-99	(5) Total Expenditures Distribution	(6) Total Expenditures Transmission	(7) Rider Collection (4) Distribution	(8) Rider Collection (4) Transmission	(9) Over/(Under) Recovery (5) Distribution	(10) Over/(Under) Recovery (5) Transmission
Lighting Rebate	$400,000	$527,532	$313,371	$29,469	$870,372	$0	NA	NA	NA	NA
Thermal Energy Storage	$0	$0	$0	$0	$0	$0	NA	NA	NA	NA
High Efficiency Motors	$2,200	$2,265	$3,322	$358	$5,946	$0	NA	NA	NA	NA
Adjustable Speed Drives	$3,000	$23,512	$51,102	$61,396	$136,010	$0	NA	NA	NA	NA
Small C&I Audits	$0	$42,427	$0	$0	$42,427	$0	NA	NA	NA	NA
Customized Efficiency Audits	$0	$16,314	$0	$0	$16,314	$0	NA	NA	NA	NA
C&I Total	$405,200	$612,050	$367,795	$91,223	$1,071,068	$0	(1,109,845)	$0	(1,099,177)	$0
Total	$1,136,200	$1,690,498	$2,279,224	($328,971)	$1,764,654	$384,863	($1,009,409)	$1,478,405	($3,704,192)	$35,331

(1) Recovers costs associated with shutdown of program.
(2) Amounts included in Rider filed on October 1, 1998.
(3) & (4) - residential - Reconciliation of adjustment for July 1, 1997 through June 30, 1998 with actual recovery (Column (7) Fall 1998 filing section of Exhibit 6b - Column (7) (gas) or Column (8) (electric)) + decoupler adjustment from Exhibit 7 of this filing. This effectively adjusts the allowed recovery used to compare revenues to account for allowed recovery of previous period adjustments and the current
(3) & (4) - C&I - calculated lost revenues and shared savings.
(5) & (6) Estimated expenditures from July 1, 1998 through June 30, 1999.
(7) & (8) Revenues collected through Rider between July 1, 1998 through June 30, 1999.

Calculations:
Total expenditures residential gas = column (1) x .65
Total expenditures residential electric = column (1) x .35
Over/(under) recovery gas = col (3) + col (7) + (col (5) - col (7)) in residential section. Used in Exhibit 8 - Total recovery without carrying charges applied to true-up amount (col (5)-col (7)).
Over/(under) recovery electric = col (4) + col (8) + (col (6) - col (8)) in residential section. Used in Exhibit 8 - Total recovery without carrying charges applied to true-up amount (col (6)-col (8)).
Total expenditures commercial = col (2) + col (3) + col (4)
Over/(under) recovery distribution = col (7) - col (5) in commercial section.
Over/(under) recovery transmission = col (8) - col (6) in commercial section.

Exhibit 6b
Review and Reconciliation of Residential Revenue and Cost Statements

Fall 1997 filing covering true-up for period May 1996 through June 1997 and recovery of 1998 program cost

	(1) Decoupler Adjustment Exhibit 5	(2) DSM Rider Collection Exhibit 4	(3) Net Decoupler Adjustment (1)+(2)	(4) Program True-Up Amount Exhibit (4)	(5) Recovery of 1998 DSM Program Costs Exhibit (6)	(6) Total for Rider Collection Sum (3 to 5)
Electric	$ 2,096,209	$ 814,158	$ 2,758,380	$ (300,375)	$ 330,013	$ 2,788,018
Gas	$ (632,334)	$ 200,221	$ (409,547)	$ (90,775)	$ 399,750	$ (100,572)

(1) From Exhibit 5 of Joint Application of the 1998 DSM Cost Recovery Mechanism filed in November 1997.
(2) From Exhibit 4, Columns (7) and (8) of the 1998 DSM Cost Recovery Mechanism filed in November 1997.
(3) Column (1) + Column (2) - adjusts for the fact that the decoupler adjustment in Column 1 included revenues collected through the DSM Rider. This adjustment effectively reduces the actual revenues net of fuel that were compared to expected revenues net of fuel.
(4) From Column (7)-Column (9) (gas) and Column (8) - Column (10) (electric), Exhibit 4 of Joint Application of the 1998 DSM Cost Recovery Mechanism filed in November 1997, multiplied by allowed carrying charge of 1.0551.
(5) DSM 1998 Program Cost Summary from Exhibit 6 of Joint Application of the 1998 DSM Cost Recovery Mechanism filed in November 1997.
(6) Amount that should have been recovered through 1998 Rider including true-up of residential decoupler.

Fall 1998 filing covering true-up for period July 1997 through June 1998 and recovery of 1999 program cost

	(1) Decoupler Adjustment Exhibit 5	(2) DSM Rider Collection Exhibit 4	(3) Total for Recovery Set Last Period Minus Actual Recovery Period (Col 6 above)	(4) Net Decoupler Adjustment (1)+(2)+(3)	(5) Program True-Up Amount Exhibit (6)	(6) Recovery of DSM Program Costs Exhibit (6)	(7) Total for Rider Collection Sum (4 to 6)
Electric	$ 1,403,777	$ 1,054,771	$ 1,733,248	$ 4,191,795	$ (927,043)	$ 255,850	$ 3,520,602
Gas	$ 2,075,251	$ 32,823	$ (133,395)	$ 1,974,679	$ 234,611	$ 475,150	$ 2,684,440

(1) From Exhibit 5 of Joint Application of the 1999 DSM Cost Recovery Mechanism filed in October 1998.
(2) From Exhibit 4, Columns (7) and (8) of the residential section of the 1999 DSM Cost Recovery Mechanism filed in October 1998.
(3) Column (6) from Fall 1997 filing - Column (3) reflects the reconciliation of amounts set for recovery and the actual amounts recovered. This amount is used in Column (4) to adjust allowed residential revenues for the amount allowed to be recovered in the previous reconciliation.
(4) Column (1) + Column (2) + Column (3). a.) Column (1) + Column (2) adjusts for the fact that the decoupler adjustment in Column 1 included revenues collected through the DSM Rider. This adjustment effectively reduces the actual revenues net of fuel that were compared to allowed revenues net of fuel. b.) Addition of Column (3) reflects the allowance in allowed revenues net of fuel to account for previous year's reconciliation.
(5) From Column (9) (gas) and (10) (electric), Exhibit 4 of Joint Application of the 1999 DSM Cost Recovery Mechanism filed in October 1998, multiplied by allowed carrying charge of 1.055.
(6) DSM 1999 Program Cost Summary from the residential section of Exhibit 6 of Joint Application of the 1999 DSM Cost Recovery Mechanism filed in October 1998.
(7) Amount that should have been recovered through 1999 Rider including true-up of residential decoupler.

Fall 1999 filing covering true-up for period July 1998 through June 1999 and recovery of 2000 program cost

	(1) Decoupler Adjustment Exhibit 7	(2) DSM Rider Collection Exhibit 6	(3) Total for Recovery Set Last Period Minus Actual Recovery Period (Col 7 above)	(4) Net Decoupler Adjustment (1)+(2)+(3)	(5) True-Up Amount Exhibit (6)	(6) Recovery of DSM Program Costs Exhibit (6)	(7) Total for Rider Collection Sum (4 to 6)
Electric	$ (2,462,391)	$ 1,478,405	$ 2,042,197	$ 1,058,211	$ (1,148,548)	$ 274,750	$ 184,413
Gas	$ (672,575)	$ 100,436	$ 2,584,004	$ 2,011,865	$ 622,985	$ 510,250	$ 3,145,100

(1) From Exhibit 7 of Joint Application of this filing.
(2) Columns (7) (gas) and (8) (electric) of the residential section of Exhibit 6 of this filing.
(3) Column (6) from Fall 1998 filing section above - Column (3) reflects the reconciliation of amounts set for recovery and the actual amounts recovered. This amount is used in Column (4) to adjust allowed residential revenues for the amount allowed to be recovered in the previous reconciliation.
(4) Column (1) + Column (2) + Column (3)- Column (1) + Column (2) adjusts for the fact that the decoupler adjustment in Column 1 included revenues collected throught the DSM Rider. This adjustment effectively reduces the actual revenues net of fuel that were compared to allowed revenues net of fuel. Addition of Column (3) reflects the allowance in allowed revenues net of fuel to account for previous year's reconciliation.
(5) From Column (5) - Column (7) (gas) and Column (6) - Column (8) (electric), Exhibit 6a of Joint Application of this filing, multiplied by allowed carrying charge of
(6) DSM 2000 Program Cost Summary from the residential section of Exhibit 6 of this filing.
(7) Amount that to be recovered through 2000 Rider including true-up of residential decoupler.

EXHIBIT 7

THE UNION LIGHT, HEAT AND POWER COMPANY
DEMAND SIDE MANAGEMENT COST RECOVERY RIDER (DCRR)
SUMMARY OF CALCULATIONS

JANUARY, 2000 THROUGH DECEMBER, 2000

RATE SCHEDULE	DECOUPLER ADJUSTMENT (1)	TRUE-UP AMOUNT (2)	DSM COST RECOVERY TOTAL (3)	ESTIMATED BILLING DETERMINANTS (4)		DSM COST RECOVERY RIDER (DCRR)	
ELECTRIC RIDER DSM							
RESIDENTIAL RATE RS	$1,058,211	($1,148,548)	$274,750	1,259,892	MWh	$0.000146	$/kWh
DISTRIBUTION LEVEL RATES DS, DP, DT, GS-FL, & SP	NA	$1,099,177	$0	1,884,473	MWh	$0.000583	$/kWh
TRANSMISSION LEVEL RATE TT	NA	$0	$0	427,981	MWh	$0.000000	$/kWh
TOTAL ELECTRIC DCRR RECOVER	$1,058,211	($49,371)	$274,750	3,572,346	MWh		
GAS RIDER DSM							
RESIDENTIAL RATE RS	$2,011,865	$593,150	$510,250	7,571,797	MCF	$0.411430	$/MCF
NON-RESIDENTIAL RATES GS & F	NA	$0	$0	0	MCF	$0.000000	$/MCF
TOTAL GAS DCRR RECOVERY	$2,011,865	$593,150	$510,250	7,571,797	MCF		

(1) Net decoupler adjustment: Column 4 of Exhibit 6b. Electric - Column (4) + Column (8) and Gas - Column (3) + Column (7) from Residential section of Exhibit
(2) Residential: Column 5 of Exhibit 6b. Electric - Column (6) - Column (8) and Gas - Column (5) - Column (7) from Exhibit 6a multiplied by 1.0503 (average three-month commercial paper rate) to include interest on over or under-recovery.) Distribution Level: Column (9) of Exhibit 6a multiplied by 1.0503.
(3) From Page 2 OF 4.
(4) From Page 3 OF 4.

EXHIBIT 7

THE UNION LIGHT, HEAT AND POWER COMPANY
DEMAND SIDE MANAGEMENT COST RECOVERY RIDER (DCRR)
SUMMARY OF CALCULATIONS FOR 2000 PROGRAMS

JANUARY, 2000 THROUGH DECEMBER, 2000

RATE SCHEDULE	1999 PROGRAM DSM COST RECOVERY TOTAL AMOUNT	DSM PROGRAM COSTS	DSM SHARED SAVINGS	DSM LOST REVENUES
ELECTRIC RIDER DSM				
RESIDENTIAL RATE RS	$274,750	$274,750	NA	NA
DISTRIBUTION LEVEL RATES DS, DP, DT, GS-FL, & SP	$0	$0	$0	$0
TRANSMISSION LEVEL RATE TT	$0	$0	$0	$0
TOTAL ELECTRIC DCRR RECOVERY	$274,750	$274,750	$0	$0
GAS RIDER DSM				
RESIDENTIAL RATE RS	$510,250	$510,250	$0	$0
NON-RESIDENTIAL RATES GS & FT	$0	$0	$0	$0
TOTAL GAS DCRR RECOVERY	$510,250	$510,250	$0	$0

THE UNION LIGHT, HEAT AND POWER COMPANY
DEMAND SIDE MANAGEMENT COST RECOVERY RIDER (DCRR)
SUMMARY OF BILLING DETERMINANTS
JANUARY, 2000 THROUGH DECEMBER, 2000

			ELECTRIC (MWH)		GAS (MCF)
YEAR	MONTH	RATE RS	RATE DS, DP, DT GS-FL, EH, & SP	RATE TT	RATE RS
1999	JANUARY	133,115	160,906	28,753	1,515,405
	FEBRUARY	125,915	163,842	29,613	1,512,734
	MARCH	111,431	155,294	29,739	1,188,143
	APRIL	88,268	161,283	30,836	663,597
	MAY	77,649	143,317	27,840	349,387
	JUNE	93,073	152,142	38,048	193,527
	JULY	122,509	159,708	38,276	138,435
	AUGUST	122,662	165,131	51,974	123,769
	SEPTEMBER	109,512	168,680	44,144	136,202
	OCTOBER	80,277	142,630	41,564	200,503
	NOVEMBER	84,418	149,049	37,365	509,202
	DECEMBER	111,063	162,491	29,829	1,040,893
	TOTAL(1)	1,259,892	1,884,473	427,981	7,571,797

(1) TOTALS ARE USED ON PAGE 1 OF 4.

EXHIBIT 7

THE UNION LIGHT, HEAT AND POWER COMPANY
DEMAND SIDE MANAGEMENT COST RECOVERY RIDER (DCRR)
PROGRAM COST - 2000 PROGRAMS

JANUARY, 2000 THROUGH DECEMBER, 2000

RESIDENTIAL PROGRAMS	BUDGET	ALLOCATIONS ELECTRIC	GAS	BUDGETS ELECTRIC	GAS
HOME ENERGY HOUSE CALL	$85,000	35.00%	65.00%	$29,750	$55,250
RES. CONSERVATION AND ENERGY EDUCATION	$500,000	35.00%	65.00%	$175,000	$325,000
COMP. RESIDENTIAL EDUCATION	$75,000	35.00%	65.00%	$26,250	$48,750
PROGRAM ADMINISTRATION (COLLABORATIVE)	$35,000	35.00%	65.00%	$12,250	$22,750
RENOVATION/NEW CONSTRUCTION	$40,000	35.00%	65.00%	$14,000	$26,000
PROGRAM DEVELOPMENT	$50,000	35.00%	65.00%	$17,500	$32,500
TOTAL RESIDENTIAL	$785,000			$274,750	$510,250

Exhibit 8
ULH&P
Residential Decoupler Calculation
Electric

	January 1994 thru December 1994		July 1998 thru June 1999
Net Revenue	$52,754,518		$62,097,997
Average Number of Customers	98,765		107,400
Net Revenue per Customer	$534		$578
Customer Factor		= 107,400 / 98,765	1.0874
Growth Factor (Fg)		g= 0.00819, n= 54	1.0374
Adjusted Level Net Revenue		= 62,089,973 X 1.0874 X 1.0374	$59,511,748
Net Revenue Difference Actual vs. Adjusted			$2,586,249

Exhibit 8
ULH&P
Residential Decoupler Calculation
Gas

	January 1994 thru December 1994		July 1998 thru June 1999
Net Revenue	$20,016,031		$21,439,950
Average Number of Customers	64,202		73,209
Net Revenue per Customer	$312		$292.86
Customer Factor		= 73,209 / 64,202	1.1403
Growth Factor (Fg)		g= -0.021122, n= 54	0.9084
Adjusted Level Net Revenue		= $21,438,573 X 1.1403 X 0.9192	$20,733,545
Net Revenue Difference Actual vs. Adjusted			$706,405

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-020

REQUEST:

20. Refer to pages 5-7 through 5-12 of the report. Provide CG&E's current fuel procurement manual that sets out its present fuel procurement strategies.

RESPONSE:

See attached.

WITNESS RESPONSIBLE:

John R. Kreinest

CONFIDENTIAL &
PROPRIETARY

Cinergy Services, Inc.

FUEL DEPARTMENT

POLICIES & PROCEDURES
MANUAL

OCTOBER 1995

Cinergy Services, Inc.

FUEL DEPARTMENT

POLICIES AND PROCEDURES

OUTLINE

I. INTRODUCTION TO THE FUEL DEPARTMENT

This section will introduce the reader to the Fuel Department and outline the structure and format of the Policies and Procedures Manual. This section will also provide the mechanics necessary to access and coordinate the information presented in this manual. The following additional areas will be discussed:

* Confidentiality of documents
* Regulatory requirements
* Equal Employment Opportunity (EEO)
* Environmental stewardship
* Legal support and involvement
* Audits
* Gifts, gratuities and conflicts of interest
* Consultants

II. OBJECTIVES AND POLICIES

A. Objectives

1. Cinergy
2. Fuel Department

B. Policies

1. Fuel and Transportation Management Policy

III. FUEL PLANNING AND NEW TECHNOLOGIES

A. Fuel Planning

1. Long Term Fuel Cost Projections (10 years)

   a. Projected Generation and Burn
   b. Inventory Management
   c. Fuel Supply Agreements (Short and Long Term)
   d. Transportation

2. Short Term Fuel Cost Projections (< 2 years)

   a. Projected Generation and Burn
   b. Inventory Management
   c. Fuel Supply Agreements
   d. Transportation

3. Compliance Planning

   a. Regulatory Requirements
   b. Quality of Fuel
   c. Quantity of Fuel
   d. Test Burn Requirements
   e. Implementation of Testing Programs
   f. SO_2 Credit Trading

4. Strategic Planning

   a. New Plant Sites
   b. Coal Contract/Spot Mix
   c. Coal Blending
   d. Coal and Transportation Contract Strategy
   e. Federal, State and Local Regulatory and Legislative Mandates
   f. System Planning, System Dispatch and Fuel Supply Management
   g. Coal Industry Analysis
   h. Competitor Analysis

5. Budgets (Fuel Planning & New Technologies)

   a. Fuel Budget
   b. Operation and Maintenance Budget
   c. Capital Budget

B. New Technologies

1. Regulatory Requirement
2. Interdepartmental and Intradepartmental Coordination and Communication
3. Availability and Feasibility of Advanced Technologies
4. Testing Program
5. Implementation and System Integration

IV. FUEL (AND SO_2 SORBENTS) SUPPLY PROCUREMENT, CONTRACTS, AND CONTRACT ADMINISTRATION

A. Fuel (and SO_2 Sorbents) Supply Procurement

1. Coal

a. Quantity
b. Effective Date and Term
c. Qualification of Suppliers
d. Quality Specifications
e. Request for Proposals
f. Evaluation
g. Negotiations
h. Recommendations
i. Purchase Orders

2. Alternate Fuels

a. Gas
b. Oil
c. Other

3. SO_2 Sorbents

B. Fuel (and SO_2 Sorbent) Supply Contracts

1. Coal Supply Contracts

a. Term of Agreement
b. Source and Reserves

c. Quantity
d. Scheduling and Shipment
e. Quality Specifications
f. Performance Under Contract
g. Base Price & Adjustments
h. Quality Adjustments
i. Changes in Legal Requirements
j. Title and Right to Resell
k. Weighing, Sampling, and Analysis
l. Billing and Payment
m. Force Majeure
n. Audits and Records
o. Waivers and Remedies
p. Assignments
q. EEO Compliance
r. Governing Law
s. Option Tonnage
t. Liquidated Damages

2. Alternate Fuel Supply Contracts

3. SO_2 Sorbent Supply Contracts

C. Fuel (and SO_2 Sorbents) Supply Contract Administration (Terms and Conditions)

1. Coal Supply Contracts

a. Source and Reserves
b. Term of Agreement
c. Quantity
d. Scheduling and Shipment
e. Quality Specifications
f. Base Price & Adjustments
g. Quality Adjustments
h. Changes in Legal Requirements
i. Weighing, Sampling, and Analysis
j. Billing and Payment
k. Force Majeure
l. Audits and Records
m. Invoice Approval
n. Expected Mining Practices
o. Freeze Conditioning

2. Alternate Fuel Supply Contracts

3. SO_2 Sorbent Supply Contracts

D. Inventories

1. Coal
2. Alternate Fuels
3. SO_2 Sorbents

E. Budgets

1. Operation and Maintenance Budget
2. Capital Budget

V. TRANSPORTATION PROCUREMENT, CONTRACTS, CONTRACT ADMINISTRATION, OPERATIONS AND RAIL CAR MAINTENANCE

A. Transportation Procurement

1. Rail

a. Origin and Destination
b. Effective Date and Term
c. Volume Capability
d. Equipment Requirements
e. Request for Proposals
f. Evaluation
g. Negotiations
h. Recommendation

2. Barge

a. Origin and Destination
b. Effective Date and Term
c. Volume Capability
d. Equipment Requirements
e. Request for Proposals
f. Evaluation
g. Negotiations
h. Recommendation

3. Truck

4. Gas Pipeline

B. Transportation Contracts

1. Rail Contracts

a. Origin
b. Destination
c. Effective Date and Term
d. Shipping and Volume Capability
e. Tariffs
f. Base Rate(s) & Rate Adjustments
g. Performance Standards
h. Detention
i. Loading & Unloading Constraints
j. Equipment Obligations & Requirements
k. Designated Routes
l. Weighing
m. Billing and Payments
n. Regulatory Requirements
o. Force Majeure
p. Audits and Records
q. Interchange Guidelines
r. Private Rail Car Equipment
s. Liabilities
t. Claims and Responsibility
u. Termination Provision
v. Assignments
w. Insurance

2. Barge Contracts

a. Term
b. Quantity
c. Origin
d. Destination
e. Effective Date and Term
f. Shipping and Volume
g. Base Rates & Adjustments
h. Demurrage
i. Liability
j. Claims and Responsibility
k. Equipment
l. Fleeting Arrangements
m. Force Majeure
n. Insurance
o. Audits and Records

p. Performance Standards
q. Loading and Unloading Constraints
r. Weighing
s. Billings and Payments
t. Equipment Obligation and Requirements
u. Regulatory Requirements

3. Truck Contracts

a. Term
b. Quantity
c. Price
d. Delivery
e. Equipment
f. Standard Purchase Order Terms for The Company

4. Gas Pipeline Contracts

C. Transportation Contract Administration

1. Rail

a. Origin
b. Destination
c. Effective Date and Term
d. Shipping and Volume Capability
e. Tariffs
f. Base Rate(s) & Rate Adjustments
g. Performance Standards
h. Detention
i. Loading & Unloading Constraints
j. Equipment Obligations & Requirements
k. Designated Routes
l. Weighing
m. Billing and Payments
n. Regulatory Requirements
o. Force Majeure
p. Audits and Records
q. Insurance
r. Invoice Approval Procedures

2. Barge Contracts

a. Origin
b. Destination

c. Effective Date and Term
d. Shipping and Volume
e. Base Rate and Rate Adjustments
f. Demurrage
g. Liability
h. Equipment
i. Force Majeure
j. Audits and Records
k. Performance Standards
l. Equipment Obligations and Requirements
m. Billing and Payments
n. Regulatory Requirements
o. Insurance
p. Invoice Approval Procedures
q. Loading and Unloading
r. Weighing

3. Truck Contracts

a. Origin
b. Destination
c. Effective Date and Term
d. Quantity
e. Price
f. Invoice Approval
g. Force Majeure
h. Audits and Records
i. Performance Standards
j. Loading and Unloading
k. Weighing

4. Gas Pipeline Contracts

D. Transportation Operations

1. Equipment Requirements

a. Long Term Requirements
b. Short Term Requirements
c. Joint Ownership
d. Payment Procedures

e. Equipment Specifications
f. Equipment Budgeting

2. Administrative Procedures

a. Rules and Regulations
b. Operating Meetings
c. Scheduling and Coordinating Deliveries
d. Train, Barge and Truck Locations
e. Track Inspections
f. Derailments
g. Claims and Responsibility
h. Ancillary Charges

E. Transportation Rail Car Maintenance

1. Strategies and Research

a. Contract Strategy
b. New Component Research

2. Field Activity

a. Scheduling
b. Inspections

3. Administrative Procedures

a. Rules and Regulations
b. Contract Administration
c. Invoice Approval
d. Audits and Records
e. Repair Guidelines
f. Continuing Education and Training

F. Budgets

1. Operation and Maintenance Budget
2. Capital Budget

CONFIDENTIAL &
PROPRIETARY

Cinergy Services, Inc.

FUELS DEPARTMENT

POLICIES AND PROCEDURES MANUAL

TABLE OF CONTENTS

3. SO_2 Sorbent Supply Contracts (Terms and Conditions)

D. Fuel (and SO_2 Sorbent) Supply Inventories

1. Coal Supply Inventory
2. Alternate Fuel Supply Inventory
3. SO_2 Sorbent Supply Inventory

E. Fuel Supply Budget

V. TRANSPORTATION PROCUREMENT, CONTRACTS, CONTRACT ADMINISTRATION, OPERATIONS AND RAILCAR MAINTENANCE

A. Transportation Procurement

1. Rail
2. Barge
3. Truck
4. Gas Pipeline

B. Transportation Contracts

1. Rail Transportation Contracts
2. Barge Transportation Contracts
3. Truck Transportation Contracts
4. Gas Pipeline Transportation Contracts

C. Transportation Contract Administration (Terms and Conditions)

1. Rail Transportation Contracts
2. Barge Transportation Contracts
3. Truck Transportation Contracts
4. Gas Transportation Pipeline Transportation

D. Transportation Operations

1. Equipment Requirements
2. Administrative Procedures

E. Transportation Railcar Maintenance

1. Strategies and Research
2. Field Activity
3. Administrative Procedures

F. Transportation Budget

Cinergy Services, Inc.

FUEL DEPARTMENT

POLICIES AND PROCEDURES

I. INTRODUCTION TO THE FUEL DEPARTMENT

The Fuel Department ("The Department") of Cinergy ("The Company") provides a broad range of fuel procurement and transportation services for each of the Company's fossil fuel generating stations. These services include, among others, those treated in the following sections of this Manual. The scope encompasses a variety of planning, projection and budgeting functions, solicitations and evaluation of proposals for fuel and transportation contracts, selection of suppliers and shippers, contract negotiation, administration and enforcement, and ongoing transportation maintenance and operations support.

The Department is also responsible for communicating and coordinating its activities with other departments as well as with outside sources.

The Department is responsible for the prudent expenditure of a large part of Cinergy's annual operating budget. In recognition of this responsibility, the policies and procedures outlined in this Manual incorporate the common goal of achieving maximum value for each dollar spent on fuel procurement and transportation matters.

A. Relationship To Company Policies and Procedures

The breadth of the Department's services, the volume of fuel required by Cinergy and the inherent uniqueness of fuel and transportation contracts has led to adoption by the Department of its own set of Policies and Procedures. Notwithstanding this, in all material respects the Department subscribes to the procurement objectives and policies of the Company. Differences are attributable to the need to establish specific practices across a broad spectrum of fuel services offered by the Department.

The Department evaluates its fuel services Policies and Procedures on a continuing basis. The objective of this self evaluation is the continuing assurance of effective Policies and Procedures geared for maximum results. No Policies and Procedures Manual can consider all of the circumstances and conditions which exist or may arise in the industry. Therefore, the guidelines outlined in this manual are subject to review and modification to reflect changing circumstances or needs of the Company, the effect of state and/or federal legislation, the orders or rules of any state commission, or any other event which may impact Cinergy's procurement and use of fuel.

B. Purpose and Use of this Manual

As reflected in the Outline, this Manual is organized by functions, beginning with fuels planning, budgeting and research, and continuing with fuel and transportation procurement across a range of contracting services from requests for proposals through contract enforcement. The reader can use the Outline both as a general overview of areas discussed and a map for finding specific topics. Topics discussed can be reviewed quickly for reference, or studied in detail as part of specific training.

Functions are treated in terms of General Observations, Objectives and Responsibilities, supplemented by detailed procedures which describe specific tasks or steps to achieve the general objectives.

Distrubution of this Manual and/or the policies and procedures contained herein, will be to all members of the Fuel Department and other appropriate personnel within Cinergy.

C. Adherence to Company Policies

From time to time The Company issues (and updates) policies governing the conduct of employees in their business relationships with others. The Department is responsible for assuring that its personnel comply in full with these policies. In addition to this basic responsibility The Department recognizes that its operations require extensive communication with outside sources, particularly suppliers, shippers and other vendors. It is important that such communications be conducted in accordance with accepted Company guidelines. The Department, therefore, undertakes the following additional responsibilities: (1) To assure that its standards of conduct are made known to suppliers, shippers, vendors and others who have dealings with The Department, and (2) To provide for assurance in its contracts that parties contracting with the Department acknowledge, accept and will abide by such standards. Specifically:

1. Confidentiality of Documents - The Department will protect The Company from disclosure of proprietary information (as may be contained in such documents as contracts, proposals, audit reports, studies, task force reports, supporting work papers, etc.) which, if disclosed could have harmful effect on The Company or The Department.

2. Regulatory Requirements - The Department will provide appropriate protection in its contracts against violation of applicable regulatory requirements by any party contracting with The Department.

3. Equal Employment Opportunity - Other Laws - The Department will provide appropriate assurance in its contracts that any such party will comply with applicable state and Federal equal opportunity, affirmative action and equivalent law or regulation.

4. Environmental Stewardship - The Department's environmental stewardship policy will be consistent with The Company's Environmental Charter. The Department will provide assurance in its contracts that any such party will comply with applicable State, Local and Federal environmental law and regulation.

5. Legal Support - The Department recognizes that sound legal advice, timely obtained, can result in essential contract protection, effective resolution of disputes and commercial disagreements, and prevention of exposure to undue legal or business risk. The Department, therefore, undertakes to consult with counsel in areas involving non-standard business or legal concepts and non-standard contract provisions.

6. Audits - The Department will cooperate with, and participate as necessary in, audits of its contracts and records, whether internal, external or regulatory in nature. Where suppliers' costs or procedures affect the

price or provisions of the agreement, The Department will include applicable audit rights in the contract. Additionally, The Department will assure that The Company's audit rights under applicable contracts are exercised and enforced.

7. Gifts, Gratuities and Conflicts of Interest - The Department is responsible for assuring compliance with Company policies against acceptance of gifts and gratuities and the establishment of relationships by any employee of The Department which may impair that employee's duty of primary loyalty to The Company. In achieving such assurance, the procedures outlined in the introductory paragraphs of this Section C will be observed.

8. Consultants - Where The Department secures the assistance of consultants, such services shall be contracted for in writing in standard Company format or as otherwise approved by counsel, such contracts to include, among other terms, a statement of work, a price or other form of cost estimate prescribing any applicable budgetary constraints, and The Company's standard confidentiality and other provisions.

In any area not specifically mentioned above but involving or having the potential to involve Company policy(ies) The Department is expected to assure appropriate review and approval in accordance with the general guidelines and intentions expressed in this Section C.

Cinergy Services, Inc.

FUEL DEPARTMENT

POLICIES AND PROCEDURES

II. OBJECTIVES AND POLICIES

This section covers objectives and policies of Cinergy and The Department. The concepts expressed are intended as broad guidelines rather than specific procedures. They are best used as definitions of goals and standards, whereas the procedures elsewhere defined chart specific courses for attaining the goals.

GENERAL

1. OBJECTIVES - The Company and The Department believe that clear statements of objectives are essential to the establishment of teamwork and rapport essential to a high performance organization. All of us need purposes and goals. Therefore, objectives are articulated both for Cinergy and for The Department.

   A. Cinergy - In the broadest sense Cinergy's operating objectives are expressed in the key elements of Cinergy's Vision which consists of three interrelated elements: Purpose, Core Values, and Mission.

      1. ***Purpose:*** Cinergy will continually challenge who we are and what we do to become the world's leading energy services innovator and to create superior value for all stakeholders.
      2. ***Core Values:*** Innovation, Integrity, Performance, Respect, Safety and Service.
      3. ***Mission:*** We will be the Supplier of Choice, Investment of Choice, and Employer of Choice.

   B. The Department - The Department subscribes fully to these principles. At its operating level this means the establishment of policies and procedures which make sense in the environment of today and tomorrow.

Policies or procedures are not necessarily adopted because they applied in the past. The Department will question - in a constructive way - yesterday's values and objectives, and will not adopt them, or will adopt them with changes, dependent upon their current and future relevance.

This Manual was prepared during a period of high activity and change in the utility and fuel industries. On the one hand Clean Air Act Amendments, State Implementation Plan requirements, and industry deregulation will have a profound effect on Cinergy and its companion utilities for years to come. On the other, fuel prices continue to be depressed, the number of viable suppliers is shrinking, and the threat of competition from alternative fuels and independent power producers will play large roles in determining the structure of both industries in the future.

Since tomorrow is full of uncertainty, The Department intends to structure its policies and procedures with a maximum degree of flexibility and responsiveness to change. In some respects, depending on circumstances at the time, it may be prudent to modify time honored rules of procurement and contracting (such as assuring long term supply or contracting with the low bidder). In others those rules may still apply. The important point is that The Department intends to govern by policies and procedures which afford maximum control over the circumstances of procurement and contracting, as the circumstances change.

With these caveats The Department has prepared the following statement of its objectives:

> The objective of The Department's fuel procurement and contracting policy is to serve the best interests of The Company's customers, employees, shareholders, suppliers and others interested in The Company's success by assuring the adequate and dependable supply of fuel at the best overall value to The Company, consistent with market and operating conditions. Fuel and transportation procurement and contracting will be conducted consistent with this objective but with enough

control and flexibility to permit timely accommodation to changes in conditions, however arising.

Vital to the accomplishment of this objective is the maintenance of fair and impartial relationships with interested persons. In the conduct of its business, The Department will comply with applicable rules, regulations, laws and other directives of The Company and government entities. Inherent in the conduct of its business is the adherence to The Company's Statement of Vision, as the Statement applies to the Department's particular functions.

2. POLICIES - The Department hereby adopts several major policies centered around the basic objective of obtaining an adequate supply of suitable quality fuel at the optimum evaluated cost consistent with market and operating conditions. The major policy areas expressed in this Manual apply both to the fuel and transportation functions, it being recognized that the concepts are fundamental ones and that fuel and transportation strategies must be carefully coordinated. Achievement of objectives in one area without conforming it to the other can be, and likely will be, counterproductive. The precepts are: Competitive Pricing, Multiple Sourcing, Flexibility of Spot and Contract Mix, and Flexibility in Procurement and Contracting. Each is discussed below. It is also recognized that implementation of these policies may be limited to some extent under provisions of existing contracts and that the policies are formulated subject to that limitation.

A. Competition/Market Pricing - Experience teaches that long term, single source contracts with cost escalators can lead to inflated prices and discourage competitive incentives. The Department also recognizes that the best suppliers and shippers maintain their competitive edge by improving efficiency of operation and productivity wherever possible, thereby improving their operating results, and that these continuing efforts permit the transportation and supply of fuel at lower, more competitive prices. The Department desires to buy its fuel at competitive prices from reliable and efficient suppliers and shippers. To accomplish this, the preferred method is to seek competitive proposals for major procurements. In this way frequent market and supplier assessments can be made without jeopardizing assurance of supply and reliable transportation from major segments of the supplier and shipper base.

B. Maintenance of Competitive Prices - Maintenance of price at competitive levels throughout the term of multiple year contracts is equally important. The nature of longer term contracts, and their susceptibility to change over time, makes it essential that means other than constant negotiation or use of escalators be available to conform price to competitive conditions and to avoid locked-in price distortions. In each case The Department will consider alternative strategies to assure the contractual maintenance of fair and reasonable pricing throughout the term of its contracts.

C. Multiple Sources - A major advantage of multiple sources is the spreading of risk afforded by splitting tonnage requirements among several suppliers or, where possible, the splitting of transportation modes. Long term single source contracts are inherently subject to changed conditions over time, and imbalance or inequity in price or other terms is almost certain to occur. These risks can be softened by staggering contract terms, mixing spot and contract purchases, providing for competitive transportation options, and contracting for smaller portions of requirements with several sources.

The Department recognizes that differences among contracts in commencement and expiration dates can help to "dollar average" against inequities. Frequent use of requests for proposals and new contracts keep market conditions current and can help to neutralize older contract prices. Suppliers and shippers can be frequently evaluated, and decisions to change source, specifications, transportation methods, contract terms etc. can be made more easily in new contracts. Strikes, union problems, environmental changes and other force majeure issues can be spread over a larger base and are much less likely to cause disruption or delay of supply. At the same time, a stable supply base from qualified and responsible suppliers and shippers can be maintained. The essential point is that contract or performance problems on one contract will not jeopardize overall supply and transportation.

The Department also recognizes that use of multiple sources enhances competition. The best suppliers and shippers will be constantly alert to The Department's requirements as a way of increasing sales and profit opportunities.

In recognition of these fundamental factors, The Department will endeavor, wherever possible, to identify and maintain a multiple supplier and shipper base with staggered contract terms, thereby assuring continuing competition for large portions of its fuel requirements.

D. <u>Contract/Spot Mix</u> - A judicious balancing of short term, medium and long term contracts is a good way to achieve critical procurement goals such as : (1) assurance of adequate supply from reliable suppliers, (2) competitive, market based pricing, (3) frequent market intelligence through requests for proposals, (4) continuing evaluation of suppliers, (5) flexibility in responding to changing regulatory, market or economic conditions, and (6) efficient delivery of shipments. The Department adopts the following general policy with respect to contract/spot mix:

1. <u>Short Term Contracts</u> - (<u>Less than 2 years</u>). In these shorter term contracts fixed/incremental pricing without escalators can be used, eliminating the need for audits, cost reviews, monitoring and other contract administration functions. Prices can be predicted with reasonable certainty and budgets drawn up accordingly. Shipping alternatives would be similarly tailored to accommodate specific terms and sources selected.

2. <u>Long Term Contracts</u> - (More than 2 years). These longer term contracts may be subject to escalation and its inherent flaws in tracking costs or market price. Reopeners or adjustment provisions will be important protections for both parties in the event of market price/contract price distortion. In order to assure minimum supply it is important to have a majority of tonnage requirements covered under long term contracts with responsible suppliers.

3. Flexibility - The above is only a general guideline and is subject to change as conditions vary. The contract/spot mix will be reviewed on a regular basis and is subject to revision at any time, depending on The Department's best judgment. Contract terms and time periods will be structured to afford maximum leeway for changes. For example, a provision in a long term contract for annual reduction of quantities by 10% or 20% can make large tonnages available for spot purchase in any year when conditions favor increasing spot tonnage and vice-versa. Contracts may also include provisions permitting the right to substitute transportation modes upon reasonable notice.

E. Quality - The purchases made by the Department will meet the requirements of the boilers, gas turbines, and auxiliary equipment for which it was purchased.

1. Specifications - Coal specification may include moisture, ash calorific value, sulfur, volatility, grindability, hydrogen, chlorine, ultimate analysis, mineral ash analysis, fusion temperature, etc. Specifications for all purchases made by the Department will include parameters required to assure compatability with equipment operation and environmental compliance.

2. Evaluation - Suppliers will be evaluated in terms of delivered cost, busbar evaluation, uncommitted proven reserves, reputation for reliability, managerial integrity, financial stability and proximity to transportation. By-product handling and disposal, along with various environmental limits at the station sites, are also taken into consideration.

F. Terms- Responding to Policy - The terms and conditions of The Department's contracts will be drafted to respond to these basic policies and objectives. The following areas are recognized as essential:

1. Price - For spot and shorter term contracts price would be established from evaluations of proposals and fixed annual increases not subject to the vagaries of cost or indexed escalators. The price would be inclusive of costs for the period except

for any premium/penalty adjustments and any negotiated exceptions, such as government impositions. For longer term contracts a price redetermination clause will be considered for the purpose of keeping the base price competitive. In transportation contracts, similar rationale will apply, and volume discount/incremental pricing terms should be obtained wherever possible.

2. Term - Multiple contracts with staggered, expiration dates are contemplated wherever possible. Term contracts would be supplemented by spot orders at current market prices. Transportation contract expiration dates will consider fuel supply contract expirations.

3. Equity and Hardship - Depending on the provisions of the individual agreements, protection against unfairness or inequity (whether in price or other terms) may be considered for longer term fuel or transportation contracts. Such an Equity and Hardship or similar provision would give either party the right to negotiate for equitable adjustments. Failure to agree quickly to an equitable adjustment by negotiation would rise to a Disputes clause, perhaps affording termination rights if settlement is not achieved.

4. Source and Supply Assurance - The source provisions of The Department's fuel contracts should include language equivalent to a warranty of supply assurance, including dedication of reserves and non-diversion of supply. Brokering or substituting sourcing would not be allowed without express permission, and then only if prices are not increased. Substitution of transportation modes would be allowed at The Department's option.

5. Contract Rights and Remedies - The following additional rights should be covered:

   a. Specific remedies in the event of non-compliance with specifications, including suspension of deliveries, rejection of shipments, or termination of the contract for default.

b. The right to demand compliance with each and every specification, not just a weighted average.

c. The right to add or subtract tonnage by written notice within minimum/maximum ranges. (This gives additional access to the spot market).

d. The right to withhold payment on disputed portions of invoices until the dispute is resolved.

6. Disputes - Disputes would be resolved first by negotiation in good faith. Failure to agree would permit either party to terminate the contract or suggest a more formalized disputes procedure, such as binding arbitration.

G. Determination of Fuel Needs - The Department receives The Company's forecast of electric energy on an annual basis. Load forecast scenarios for mild and severe weather bands are also received for sensitivity analyses. This projection generally is for the next 10 years. The Company's budget for fuel is also based on a 10 year period. The Company also develops a generation expansion plan defining the start-up and retirement of base-load and peaking units.

The Fuel Department uses the above information as the framework for establishing the fuel purchase needs for the planning period.

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FUEL DEPARTMENT

POLICIES AND PROCEDURES

III. FUEL PLANNING AND NEW TECHNOLOGIES

A. FUEL PLANNING

1. LONG TERM FUEL COST PROJECTIONS

OBJECTIVE

The objective of this section is to develop a long term projection of Cinergy fuel costs for use in implementing the Department's long term fuel buying program.

GENERAL

The basis for developing long term fuel cost projections focuses on the following areas:

1. Accurate projections of generation and burn.
2. Sound inventory management.
3. Favorable coal supply agreements.
4. Mix of contract and spot purchases.
5. Flexible transportation agreements.

RESPONSIBILITY

The task of developing and coordinating long term fuel cost projections is the responsibility of the Manager Fuel Planning and the Accountant/Economist.

PROCEDURES

A. Preparation and Refinement of Initial Burn Projections - At this stage interdepartmental coordination is essential to minimize projection discrepancies.

(1) **The Coordination Process** - As a first step, the Fuel and Power Supply Departments collaborate in

the preparation and refinement of ten year burn projections by station. The Department inputs preliminary price and quality projections into the computer model used by Resource Planning. Using additional data gathered from Power Operations, Electric System Operations, Engineering and others, Resource Planning projects burn by generating station. The Department then reviews and refines the fuel projections and prepares them for use consistent with these Procedures.

(2) **Coal Inventory Management** - At the same time a number of Departments, including the Fuel Department, work together closely to project coal inventory levels over the same period. the Department is responsible for collecting, organizing and assembling the data into a format that is compatible with the required data needs of Resource Planning, Electric Systems Operations, and other departments that need inventory forecasts.

B. Projection of Fuel Costs - Burn projections from the previous step are used in conjunction with the following information and data to develop fuel cost projections over the forecast period. The following specific procedures are used:

(1) **Coal and Transportation Base Costs** - The Department determines current base price and transportation rates under existing contracts.

(2) **Adjustment of Base Costs - Coal and Transportation** The Department reviews existing agreements to calculate adjustment rates. Additional non-contract specific information such as legislative and regulatory impact, union agreements, current and expected market conditions are also considered, and the combination of current and future factors are used to project adjustment rates over the applicable period.

(3) **Impact of Fuel and Transportation Agreements** - In developing its projections the Department assesses numerous other variables suggested by existing contract clauses, such as term, quality (including

adjustments), quantity, coal sources, reopeners or buy out clauses, delivery options, economic hardship, force majeure and equivalent clauses, all of which are analyzed to assess their effect on projections.

(4) **Data Exchange** - The data relating to commonly owned units is exchanged with the appropriate companies.

(5) **Data Review** - General data parameters for the input and output are reviewed with the areas supplying input.

C. <u>Finalization of Long Term Fuel Cost Projections</u> - The data developed from the foregoing steps is assimilated and analyzed. The Fuel Planning function plays the lead role in coordinating the process both within and outside the Department.

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FUEL DEPARTMENT

POLICIES AND PROCEDURES

III. FUEL PLANNING AND NEW TECHNOLOGIES

A. FUEL PLANNING

2. SHORT TERM FUEL COST PROJECTIONS

OBJECTIVE

The objective of this section is to develop a short term projection (24 months) of Cinergy fuel costs for use in implementing the Department's short term fuel buying program.

GENERAL

The basis for the development of short term fuel cost projection focuses on the following areas:

1. Accurate Projections of generation and burn.
2. Inventory management.
3. Contract vs. spot coal purchases.
4. Flexibility in transportation agreements.

RESPONSIBILITY

The task of developing and coordinating short term fuel cost projections is the responsibility of the Manager Fuel Planning with the Accountant/Economist and others.

PROCEDURES

Same as 3(A)(1) except for change in period from ten to 2 years.

III. FUEL PLANNING AND NEW TECHNOLOGIES

A. FUEL PLANNING

3. COMPLIANCE FUEL PLANNING

OBJECTIVE

The objective of this section is to research, develop, coordinate and implement the use of compliance fuels.

GENERAL

Compliance fuel planning focuses on the following strategic areas of concern:

1. Regulatory requirements (Federal, State and local).
2. Quantity of fuel required and available.
3. Quality of fuel required and available.
4. Test Burn Program.
5. SO_2 Credit Trading.

Interaction with other departments and communication with external sources for information and assistance will be required in the search for and use of compliance fuels.

RESPONSIBILITY

The task of developing, coordinating, monitoring and assisting in the use of compliance fuels at Cinergy is the responsibility of the Manager Fuel Planning.

PROCEDURES

A. Monitoring Regulatory and Legislative Requirements - The Fuel Planning function in conjunction with Environmental monitors regulatory and legislative mandates and changes as they relate to Cinergy's production of emissions. Using data and information obtained from internal and external sources, Fuel Planning develops a long range system wide fuel compliance strategy that is incorporated in the Integrated Resource Plan.

B. Responding to Regulatory and Legislative Requirements - Fuel Planning is responsible for initiating studies, interacting with other departments and establishing the optimum response to regulatory and legislative compliance requirements. In evaluating potential compliance solutions, the following areas, among others, are considered:

1. Technological improvements.
2. Capital improvements to generating plants.
3. Impact of increasing power purchases and sales.
4. Alternative generating sources and fuel.
5. Trading (purchasing/selling) emission credits.

A test burn program can be initiated if alternative fuel sources are involved in a potential compliance plan. Fuel Planning coordinates the compliance plan test burn program with the Department, Power Operations and the individual generating plants.

C. Test Burn Program

(1) Test Burn Strategy - A major objective is identification of potential alternative fuels which are compatible with Cinergy's equipment and can therefore be used where regulatory or environmental constraints or changes dictate such use. Interaction with both internal and external areas such as boiler manufacturers, combustion engineering and operating personnel assists in identifying the best fuels to use to achieve maximum operating efficiency and regulatory compliance.

(2) **Coordination of Test Burn Program** - The test burn program is coordinated and administered by the Fuel Department with close involvement by Power Operations, Environmental, the individual

generating plants, boiler manufacturers, fuel suppliers and shippers. Test burns are coordinated and monitored by each station individually with documentation of results developed by third party consultants or by the stations themselves.

(3) **Test Burn Results** - When the test burn is completed, results are analyzed and the compatibility of the fuel is determined by the Department, Power Operations and the applicable station. At this point, the Department determines the long term strategic implications on Cinergy's fuel and transportation agreements.

D. <u>SO_2 Emission Credits</u> - The Accountant/Economist function in conjunction with other departments determines the potential requirement or excess of SO_2 emission credits in the Cinergy system. The Manager Fuel Planning utilizes these projections to devise an overall strategy that will optimize The Company's use of these emissions credits.

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FUEL DEPARTMENT

POLICIES AND PROCEDURES

III. FUEL PLANNING AND NEW TECHNOLOGIES

A. FUEL PLANNING

4. STRATEGIC PLANNING

OBJECTIVE

The objective of this section is to define and develop a fuel planning strategy encompassing major elements of Cinergy's fuel and generation programs, from site identification through the planning stages, the procurement, transportation of, and contracting for fuels and the internal management of fuel and systems.

GENERAL

The strategy focuses on the following areas:

1. New Plant Sites.
2. Coal Contract/Spot Mix.
3. Blending.
4. Coal and Transportation Contract Strategy.
5. System Planning and Dispatch Fuel Supply Management.
6. Federal, State and Local Regulatory Issues.
7. Coal Industry Analysis.
8. Analysis of Competitor's Fuel Procurement Activity.

RESPONSIBILITY

The Fuel Department is responsible for establishing and implementing coal and contract strategies, optimum contract mix, and insuring contractual compliance with regulatory constraints applicable to fuel procurement. It is responsible for coordination in related areas as appropriate.

PROCEDURES

A. Coal Contract/Spot Mix - The Fuel Department is instrumental in striking a delicate balance between assurance of adequate fuel supply and achievement of maximum flexibility in terms and access to spot prices where market conditions are favorable. To achieve the balance the following procedures are followed:

(1) **Review of Current Contracts** - The Department reviews existing contracts and provides an assessment, based on contract terms and other factors of tonnage which will become available for contract purchase in the short term. Burn projections for the relevant period are considered in detail in preparing the assessment.

(2) **Review of External Conditions** - Concurrently, the Department reviews relevant market projections and public information related to current and projected prices in source areas and, using available data and information, evaluates the advantages and disadvantages of short term, spot, or longer term contracting.

(3) **Establishment of Spot/Contract Mix** - Using the results of (1) and (2) and, if desired, input from consultants, the Department selects the proportion of spot and contract fuel purchases over the applicable period.

C. Coal Blending - Assessment of sources, specifications, contract provisions, cost and transportation implications, other contract implications, operations issues, capital requirements, future compliance needs, and other related factors are considered by the Department in determining the feasibility and benefit of coal blending.

D. Coal and Transportation Contract Strategy

(1) Parallel Provisions in Fuel and Transportation Contracts - The Fuel Department monitors and coordinates the operational and economic terms and conditions provided for in both coal supply and

transportation contracts. Awareness to market and industry trends and forecasts are vital to maintaining the optimum flexibility in coordinating parallel provisions in coal supply and transportation contracts.

(2) Supplier Flexibility - Due to new demands and requirements imposed on coal and transportation suppliers caused by suppliers both external and internal operational and economic conditions, it is important for the Department to consider the adaptability of suppliers in dealing with changing conditions.

(3) Maximum Number of Alternatives - In defining and developing a fuel planning strategy, the Department reviews as many alternatives as practicable which would impact directly in the terms and conditions developed in a Coal Supply and/or Transportation contract. The following contract related areas are representative of alternatives considered for evaluation:

a. Multiple Vendors and Shippers - What would the operational and economic incentives provide to Cinergy if multiple coal suppliers and multiple railroads (or other modes of delivery) were utilized?

b. Staggering of Contract Terms - In certain economically competitive situations it may be advantageous for Cinergy to allow certain Fuel Supply and Transportation Contracts to expire in exchange for alternative supply and transportation alternatives.

c. Contract Reopeners - Market and Industry review of trends and forecasts are used in evaluating the economic opportunities available through Fuel Supply and Transportation Contract reopeners. Appropriate timing of reopeners and suitable topics subject to negotiation are critical to this evaluation.

d. Fixed and Incremental Pricing - The economic incentive available to Cinergy to maintain a market competitive price for Fuel and Transportation during a rapid period of price escalation may best be achieved through firm or fixed pricing in Fuel Supply and Transportation Contracts. Conversely, in order to maintain the optimum pricing structure in a period of declining market prices it may be appropriate to discourage the use of fixed pricing and encourage the use of alternative pricing methods.

E. System Planning, System Dispatch and Fuel Supply Management - The communication and interaction with other departments and personnel within Cinergy is vital to the appropriate weighing of the information and alternatives outlined above. Input from Electric System Operations and the impact of purchased and net interchange power is vital to the Fuel Planning Process.

F. Federal, State and Local Regulatory Requirements - Although this area is covered preliminarily under "planning for compliance", it is also necessary to consider the effects of mandatory legislative requirements on the specific terms and conditions contained in Fuel Supply and Transportation Contracts.

G. Coal Industry Analysis - Regular monitoring and analysis of coal supplier activities and capabilities is necessary to assess the viability of supply strategies.

H. Analysis of Competitor's Fuel Procurement Activity - The expected impact of major procurement changes of large coal consumers competing for common supplies should be monitored and considered in the strategic planning process.

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FUEL DEPARTMENT

POLICIES AND PROCEDURES

III. FUEL PLANNING AND NEW TECHNOLOGIES

A. FUEL PLANNING

5. BUDGET

(a) Fuel and Transportation

OBJECTIVE

The objective of this section is to identify fuel and transportation sources and project for at least 24 months purchase prices and transportation rates for use in Cinergy's corporate budget and rate case planning processes.

GENERAL

Fuel sources and related transportation alternatives are identified for planning purposes. Prices are furnished to Budgets and Forecast for use in developing the corporate budget.

RESPONSIBILITY

The Manager Fuel Planning is responsible for projecting fuel prices and transportation rates for a minimum period of 24 months and for providing the projections to other departments in timely fashion.

PROCEDURES

On a periodic basis, fuel and transportation costs and quantities are forecasted using the guidelines and assumptions provided by Budgets and Forecast. Inconsistencies are identified and justified through analysis and interaction with other departments.

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FUEL DEPARTMENT

POLICIES AND PROCEDURES

III. FUEL PLANNING AND NEW TECHNOLOGIES

A. FUEL PLANNING

5. BUDGET

(b) O&M and Capital Budgeting

OBJECTIVE

The objective of this section is to project for at least 24 months the Operation & Maintenance (O&M) cost and the Capital Cost associated with Fuel Planning for use in Cinergy's corporate budget and rate case planning processes.

GENERAL

The Department projects O&M and capital needs associated with The Fuel Planning process and furnishes them to Budgets and Forecast for use in the corporate budget.

RESPONSIBILITY

The Accountant/Economist is responsible for compiling the forecasted O&M and Capital Costs associated with the Fuel Planning area for a minimum period of 24 months and for providing the forecasts to other departments in timely fashion.

III. FUEL PLANNING AND NEW TECHNOLOGIES

B. NEW TECHNOLOGIES

OBJECTIVES

The objective of this practice is to research, develop, coordinate and implement the use of new technologies in the purchase and transportation of fuel for Cinergy.

GENERAL

The use of new technologies in Cinergy's fuel and transportation program focuses on the following areas:

A. Regulatory requirements (Federal, State and local).
B. Interdepartmental coordination and communication.
C. Availability and feasibility of advanced technologies.
D. Implementation and System Integration.

RESPONSIBILITY

Within the Fuel Department the task of researching, developing, coordinating and implementing new fuel and transportation technologies is the responsibility of the Manager Fuel Planning and Manager Fuel Procurement.

PROCEDURES

The designated Department representative will participate in the investigation and evaluation of new technologies conducted by the appropriate Project Team.

Cinergy Services, Inc.

FUEL DEPARTMENT

POLICIES AND PROCEDURES

IV. FUEL (AND SO_2 SORBENT) SUPPLY PROCUREMENT, CONTRACTS, AND CONTRACT ADMINISTRATION

A. FUEL (AND SO_2 SORBENT) SUPPLY PROCUREMENT

1. COAL

OBJECTIVE

The objective of this section is to obtain the optimum value for the total dollars spent on the procurement of coal. This optimum value is achieved through requests for proposals from qualified coal producers combined with the flexibility to react to purchasing situations which may further contribute to optimizing the overall value of coal procurement.

GENERAL

Communication from Electric System Operations and individual generating plants establishes specific fuel requirements such as the quality of coal, quantity of coal and any other important handling and burning characteristics. These specific plant requirements are integrated with current and expected supply and demand and price projections to determine the optimum value of long term and short term coal purchases. A process of requesting competitive proposals is implemented among qualified coal producers to insure that the optimum value is achieved. Appropriate communication with the generating plants is necessary before the final execution of a contract (long term) or spot (short term) coal supply agreement.

RESPONSIBILITY

It is the responsibility of the Fuel Procurement Manager and Fuel Contract Manager to coordinate the purchase of coal.

PROCEDURES

A. Quantity and Term - The Department receives input from Electric System Operations and individual generating stations regarding additional quantities of coal required. The 10 year and 2 year budgets are used as guidelines for long and medium term requirements. Some of the items considered in determining the quantity of coal needed include amounts of coal already under contract, flexibility of existing agreements, inventory levels, planned outages, power sales, BTU value, projected burn and other related factors that could affect the utilization or deliverability of coal.

Short term requirements are discussed at regular planning meetings within the Department and frequent communications with Electric Systems Operations. The Department also has frequent discussions with Generating Stations to determine their individual requirements.

B. Qualification of Suppliers - Normally, potential suppliers must demonstrate their ability to supply the quantity and quality requested. To determine the reliability and capability of the supplier, the Department draws upon its prior experience with the supplier, databases of suppliers' historical production (e.g. RDI Database), consultant's reports, new mine permit applications, financial data (e.g. Dunn & Bradstreet Reports, Annual Reports, etc.), periodic discussion with state mining officials, site visits and/or other information deemed necessary by the Department.

C. Quality Specifications - Specifications were originally based on design requirements for each unit and have been expanded based on operational experience at each station. These desired specifications are provided to the Department by Power Operations and are periodically reviewed with each station. The Department uses these desired specifications along with the product qualities generally available in the market place to prepare specs for requests for proposals.

D. Request for Proposals (RFPs) - Periodically the Department will issue requests for proposals to meet short or long term coal requirements. These requests contain pertinent information which may include primary delivery point(s), quality specifications, quantity, period of delivery, response deadline and other terms and conditions as needed.

The RFPs are issued to a sufficient number of qualified suppliers to insure a representative market price can be obtained. Qualified suppliers can be either an "approved vendor" or a "test vendor." An "approved vendor" is one who has delivered coal to The Company within the last 24 months, has materially met the terms and conditions of the applicable purchase agreement, has not misrepresented the source/origin of the coal offered during the previous solicitation for proposals, and whose coal has not caused adverse effects in handling, boiler operation, unit derate, or a material increase in operating cost to generate power. A "test vendor" is any other vendor who submits a proposal. Volume limitations may be placed on proposals submitted by test vendors.

The Department accepts all sealed competitive proposals received up to the proposal receipt deadline. All sealed proposal packages are recorded upon receipt and stored unopened in a locked file.

E. Evaluation - All proposals are opened concurrently in the presence of a Manager and/or the General Manager of the Department with a representative of the Internal Audit Department present. The proposals are recorded and checked for completeness and accuracy. Any proposals deemed deficient are excluded from the evaluation process. Transportation rates, dumping charges, etc. are verified at a later time.

Proposals are evaluated on busbar costs, quality specifications, transportation logistics, capability and dependability of supplier, and other data deemed necessary by the Department. Tonnage limitations may be imposed on new and test vendors. With the help of computer programs the evaluated proposals are matched with station requirements. This is an iterative process that continues until the proposal/requirement match is optimized. The selected proposals are then forwarded to Department Managers recommendation or, if necessary, further negotiation.

For long term contract solicitations, the lowest twenty evaluated cost proposals are ranked on a present value basis. From this list, a review of best offers is made to determine a short-list of potential suppliers for further negotiations. A test burn may be required of any or all of the short-listed potential suppliers. In addition, the potential suppliers may be reviewed in more detail. The areas checked may include: corporate responsibility, finances, reserves, coal quality, engineering reports, etc.

F. Negotiations - Negotiations (if necessary) are conducted with suppliers by individuals designated by the General Manager Fuel. Where practicable, at least two persons from the Department will be present at the negotiations. Personnel from Stations, Power Operations, Internal Audit, Legal and other departments are included in the negotiation process as appropriate. The negotiations will include discussions regarding various clauses that The Company typically includes in its coal supply agreements. If any of the above proceedings fall short of The Company's requirements for a good supplier, negotiations will cease. Negotiations will then continue with the supplier that submitted the next acceptable proposal on the list.

G. Recommendations - The negotiators make a recommendation to the Department's management who will determine if it should be presented to the appropriate approval authority. Consideration is given to: 1) delivered costs, evaluated costs and present value calculations, 2) reserve and production evaluations, 3) test burn results, and 4) contract negotiation results. The Company's Authorized Approvals Manual documents the approval authority as delegated by the Board of Directors.

H. Purchase Orders/Agreements - Purchase Orders or standardized coal supply agreements may be used to convey delivery instructions for selected contracts.

I. Review - The Department managers will review the vendor's performance as reported by the Field Manager/Representatives and other Department personnel and note any concerns regarding quantity, quality, etc. for future reference.

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FUEL DEPARTMENT

POLICIES AND PROCEDURES

IV. FUEL (AND SO_2 SORBENT) SUPPLY PROCUREMENT, CONTRACTS, AND CONTRACT ADMINISTRATION

A. FUEL (AND SO_2 SORBENT) SUPPLY PROCUREMENT

2. ALTERNATE FUEL

OBJECTIVE

The objective of this section is to secure adequate quantities of competitively priced alternate fuels whenever system requirements allow for such procurement.

GENERAL

The procurement of alternate fuels is coordinated with the specific fuel supply requirements of each generating plant. Consideration is given to each generating plants' operational constraints related to such areas as quality, handling, economics and impact on the environment. Alternate fuels such as fuel oil, wood chips, petroleum coke, natural gas, and tire derived fuel may be considered, studied, and even tested for potential use and procurement.

RESPONSIBILITY

It is the responsibility of the Fuel Department managers to investigate, coordinate tests, and purchase the alternate fuel supply for generation.

PROCEDURES

Procedures for purchasing alternate fuels are similar to those for purchasing coal. Contracts are used where feasible, however purchase orders are commonly used to define terms and conditions of these procurements. If unrelated to a test program, the Department may issue purchase RFPs with the applicable specifications.

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FUEL DEPARTMENT

POLICIES AND PROCEDURES

IV. FUEL (AND SO_2 SORBENT) SUPPLY PROCUREMENT, CONTRACTS, AND CONTRACT ADMINISTRATION

A. FUEL (AND SO_2 SORBENT) SUPPLY PROCUREMENT

3. SO_2 SORBENTS

OBJECTIVE

The objective of this section is to obtain sufficient quantities of competitively priced SO_2 sorbent, lime or dolomite as SO_2 sorbents in flue-gas desulfurization (FGD).

GENERAL

Communication from the applicable generating plants establishes the specific SO_2 sorbent requirements such as quality, quantity and handling characteristics. As in the coal procurement process, these specific generating plant requirements are integrated with current and expected supply and demand and projected prices to determine the optimum value of long term and short term SO_2 sorbent purchases. A process to solicit competitive proposals is implemented among qualified SO_2 sorbent suppliers to insure that the optimum value is achieved. Communication with the applicable generating plants is maintained before the final execution of a contract (long term) or spot (short term) SO_2 sorbent agreement.

RESPONSIBILITY

It is the responsibility of the Fuel Chemist and Senior Contract Analyst to coordinate the purchase of SO_2 sorbents.

PROCEDURES

SO_2 sorbent, fixative agents, Dolmitic Lime and Quicklime quantities are projected by station personnel. The Department works closely with the station to determine the appropriate specifications for these products. Analytical analysis may include the determination of calcium and magnesium content, Bond Work Index and reactivity tests.

Procedures for purchasing these products are similar to those for purchasing coal. Contracts are used where feasible, however Purchase Orders are commonly used to define terms and conditions of these procurements.

Cinergy Services, Inc.

FUEL DEPARTMENT

POLICIES AND PROCEDURES

IV. FUEL (AND SO_2 SORBENT) SUPPLY PROCUREMENT, CONTRACTS, AND CONTRACT ADMINISTRATION

B. FUEL (AND SO_2 SORBENT) SUPPLY CONTRACTS

1. COAL SUPPLY CONTRACTS

OBJECTIVE

The objective of this section is to develop, negotiate and execute coal supply contracts that provide for control and operating flexibility with optimum economic benefits.

GENERAL

Coal supply contracts are agreements that establish specific performance standards and define the rights and obligations of the parties to the agreement. The following terms and conditions should be considered in the development and negotiation of a solid coal supply contract:

1. Term of Agreement
2. Source and Reserves
3. Quantity
4. Scheduling and Shipment
5. Quality Specifications
6. Performance Under Contract
7. Base Price & Adjustments
8. Quality Adjustments
9. Changes in Legal Requirements
10. Title and Right to Resale
11. Weighing, Sampling, and Analysis
12. Billing and Payment
13. Force Majeure
14. Audits and Records
15. Waivers and Remedies
16. Assignments
17. EEO Compliance
18. Governing Law

19. Option Tonnage
20. Liquidated Damages

RESPONSIBILITY

It is the responsibility of the Fuel Department management to develop, negotiate and execute coal supply contracts.

PROCEDURES

The extent to which the above terms and conditions are included in the agreement depends in part upon the length of the time period the agreement covers. Negotiations for a long term agreement should consider including each of the above terms and conditions, whereas medium and/or short term agreements follow a generalized format that may be limited to the following:

a) Effective date and term.
b) Quantity.
c) Quality requirements.
d) Weighing, sampling and analysis.
e) Quality Adjustments.
f) Scheduling and shipment.
g) Billing and Payment.
h) Force Majeure.
i) Other terms and conditions specifically required for this agreement.

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FUEL DEPARTMENT

POLICIES AND PROCEDURES

IV. FUEL (AND SO_2 SORBENT) SUPPLY PROCUREMENT, CONTRACTS, AND CONTRACT ADMINISTRATION

B. FUEL (AND SO_2 SORBENT) SUPPLY CONTRACTS

2. ALTERNATE FUEL SUPPLY CONTRACTS

OBJECTIVE

The objective of this section is to develop, negotiate and execute supply contracts for alternate fuels that provide for control and operating flexibility with optimum economic benefits.

GENERAL

Supply contracts for alternate fuels are developed, negotiated and executed as necessary to accommodate operational and environmental needs and requirements. The terms and conditions reflected in such alternate fuel supply contracts are designed to reflect the applicable terms and conditions reflected in Section IV.B.1.

RESPONSIBILITY

It is the responsibility of the Fuel Department management to develop, negotiate and execute alternate fuel supply contracts.

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FUEL DEPARTMENT

POLICIES AND PROCEDURES

IV. FUEL (AND SO_2 SORBENT) SUPPLY PROCUREMENT, CONTRACTS, AND CONTRACT ADMINISTRATION

B. FUEL (AND SO_2 SORBENT) SUPPLY CONTRACTS

3. SO_2 SORBENT SUPPLY CONTRACTS

OBJECTIVE

The objective of this section is to develop, negotiate and execute supply contracts for SO_2 sorbent, lime or dolomite as SO_2 sorbents in flue gas desulfurization (FGD) that provide for control and operating flexibility with optimum economic benefits.

GENERAL

The terms and conditions to consider in the development and negotiation of a solid supply contract for either SO_2 sorbent, lime or dolomite should follow the general terms and conditions described in Section IV. B.1. for coal supply contracts.

RESPONSIBILITY

It is the responsibility of the Fuel Department management to develop, negotiate and execute supply contracts for SO_2 sorbent, lime or dolomite as SO_2 sorbents in FGD.

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IV. FUEL (AND SO_2 SORBENT) SUPPLY PROCUREMENT, CONTRACTS, AND CONTRACT ADMINISTRATION

C. FUEL (AND SO_2 SORBENT) SUPPLY CONTRACT ADMINISTRATION

1. COAL SUPPLY CONTRACTS (TERMS AND CONDITIONS)

OBJECTIVE

The objective of this section is to make sure that the parties are in compliance with the terms and conditions contained in the executed coal supply contracts.

GENERAL

In order to administer provisions outlined in coal supply contracts and to enforce compliance among the appropriate parties, it is necessary to perform regular, periodic reviews of the terms and conditions contained in each executed Coal Supply contract. The specific performance standards provided for below are representative of the terms and conditions that should be reviewed and administered on a regular basis:

1. Source and Reserves
2. Term of Agreement
3. Quantity
4. Scheduling and Shipment
5. Quality Specifications
6. Base Price & Adjustments
7. Quality Adjustments
8. Changes in Legal Requirements
9. Weighing, Sampling, and Analysis
10. Billing and Payment
11. Force Majeure
12. Audits and Records
13. Invoice Approval
14. Expected Mining Practices

15. Freeze Conditioning

RESPONSIBILITY

It is the responsibility of the Fuel Contract Manager and Fuel Procurement Manager to enforce compliance with contract terms and conditions contained in Coal Supply Contracts.

PROCEDURES

1. Source and Reserves

Source and reserves are verified by the Department's Field Managers/Representatives.

2. Quantity

The quantity of coal to be delivered is specified in the agreement. Depending on the terms of the agreement, the Department may be allowed to vary the quantities to be delivered (e.g., tonnage options). Notification is made according to the agreement if specified, otherwise the Department will notify the supplier verbally and/or in writing, depending on the circumstances involved.

Quantities received at the station are entered into a computerized information system that creates a daily fuel report This report is used by the Department to verify tons received versus contracted quantities and by accounting to verify invoiced quantities.

3. Weighing, Sampling and Analysis

Coal shipments are sampled and analyzed according to respective agreements. The stations enter this information into the computerized system. This data is monitored by the Department and compared to quality specifications per the contract. A monthly report by supplier, listing quantity, quality and monthly weighted averages can be produced and used by the Department to compare to contract requirements. This report is also used to determine the premiums/penalties to be applied to the monthly invoice.

Coal shipments delivered by barge and railroad are normally weighed by both the stations and suppliers. The stations may enter both of weights into the computerized system. These weights are reviewed by the Department personnel for variances. Depending on the respective agreements, the Generating Station will enter either the supplier's or station's weights into the system. Accounting uses the system's reports to compare the tons received to tons invoiced.

Shipments delivered by trucks are also entered into system, but the station weights are excluded at stations where the Company does not have truck scales. When stations weights are not available, the Department's Field Managers/Representatives periodically obtain comparison weights and provide these to the Department for comparison.

4. Base Price and Escalations

The Base Price of coal is determined according to the respective agreements. Short term agreements are normally priced on a fixed basis. Long term agreements are escalated normally by a fixed rate and/or some type of economic indicator. Department personnel, with the assistance of Internal Audit (as required), will verify that the escalations are according to the agreements. Areas for verification may include: compliance with the coal supply agreement, accuracy of computations, matching of indices to government publications, review of supporting documentation provided by the coal supplier, and/or visits to the coal supplier's offices to review additional information. Department personnel will notify accounting of any price change.

5. Scheduling and Shipment

The Department's Field Managers/Representatives coordinate the scheduling and shipment of coal to the Company's Generating Stations with coal suppliers, carriers and station personnel.

6. Audits and Records

The Department, with the assistance of Internal Audit, performs audits of the supplier's records as permitted by the respective agreements.

7. Billing and Payment

Suppliers submit invoices to accounting per the schedules outlined in the respective agreements. Accounting verifies the invoice amounts to the report from the computerized system. Inconsistencies are reported to the Department for resolution.

8. Force Majeure

When a force majeure event occurs the party experiencing the force majeure will notify the affected party(s) according to their respective agreement. Coal supply and/or utilization related force majeure procedures are administered by the Manager Fuel Contracts or Manager Fuel Procurement.

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C. FUEL (AND SO_2 SORBENT) SUPPLY CONTRACT ADMINISTRATION

2. ALTERNATE FUEL SUPPLY CONTRACTS (TERMS & CONDITIONS)

OBJECTIVE

The objective of this section is to make sure that the parties are in compliance with the terms and conditions contained in each executed Alternate Fuel Supply Contract.

GENERAL

In order to administer the provisions outlined in the Alternate Fuel Supply contracts and to enforce compliance among the appropriate parties, it is necessary to perform regular, periodic reviews of the terms and conditions contained in each executed Alternate Fuel Supply Contract.

RESPONSIBILITY

It is the responsibility of the Manager Fuel Contracts or Manager Fuel Procurement to enforce compliance with the contract terms and conditions contained in Fuel Supply Contracts for Alternate Fuels.

PROCEDURES

The procedures for administering these contracts are similar to procedures used for coal contracts in Section IV.C.

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C. FUEL (AND SO_2 SORBENT) SUPPLY CONTRACT ADMINISTRATION

3. SO_2 SORBENT SUPPLY CONTRACTS (TERMS & CONDITIONS)

OBJECTIVE

The objective of this section is to make sure that the parties are in compliance with the terms and conditions contained in each executed SO_2 Sorbent Supply Contract.

GENERAL

In order to administer the provisions outlined in the SO_2 Sorbent Supply Contract and to enforce compliance among the appropriate parties, it is necessary to perform regular, periodic reviews of the terms and conditions contained in each executed SO_2 Sorbent Supply Contract.

RESPONSIBILITY

It is the responsibility of the Manager Fuel Contracts or Manager Fuel Procurement to enforce compliance with the contract terms and conditions contained in SO_2 Sorbent Supply Contracts.

PROCEDURES

The procedures for administering these contracts are similar to procedures used for coal contracts in Section IV.C.

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D. INVENTORIES

1. COAL
2. ALTERNATE FUEL
3. SO_2 SORBENT

OBJECTIVE

The objective of this section is to maintain coal, alternate fuels, and SO_2 sorbents (lime and limestone) inventories at the levels established collectively by the applicable generating plants, the Fuel Department, the Electric System Operations, and other departments within The Company.

GENERAL

Inventory levels for each generating plant are established annually by the Fuel Department after communication and interaction with the Generating Stations and other appropriate departments. As the current established inventory levels vary from the desired levels, corrective action is taken to stabilize the affected inventories through amending existing purchase orders and/or modifying the procurement program. Periodic physical inventory measurements are made for verification/reconciliation with The Company records.

RESPONSIBILITY

It is the responsibility of the Department Managers to maintain the coal, alternate fuels and SO_2 sorbents inventories at the established budgeted levels.

PROCEDURES

The Manager Fuel Planning develops optimum coal inventory strategies consistent with the Generating Station's load and coal contractual requirements. The computer system reports are monitored to ensure that coal inventories are being maintained at planned levels. The generating plants monitor the inventory of alternate fuels and SO_2 sorbents, and inform the Department when additional supply is needed.

A physical inventory of the coal stockpiles will be made periodically. The frequency is typically one time per year. The Fuel Department will coordinate the schedule for the physical inventory measurements with applicable departments and Generating Stations.

The Engineering Department will procure and direct the aerial survey and density determination for the coal stockpiles. The Generating Stations will prepare the coal stockpile for the aerial survey, document the bunker inventory at the time of the aerial survey, suspend reclaim and storage activity during the aerial survey, and provide assistance with the on-site density testing. The Engineering Department will report the measured physical inventory to Internal Audit.

Internal Audit reviews the procedures and calculations and compares the results with the Company records. The Fuel Department, in conjunction with Internal Audit, the Engineering Department, and the Generating Stations, review the results and either schedule an additional survey to confirm the results or recommend acceptance of the results.

Adjustments (if necessary) are made to the Company records by the Accounting Department in accordance with Company guidelines accepted by the appropriate regulatory bodies.

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IV. FUEL (AND SO_2 SORBENT) SUPPLY PROCUREMENT, CONTRACTS, AND CONTRACT ADMINISTRATION

E. BUDGETS

1. O&M AND CAPITAL BUDGET

OBJECTIVE

The objective of this section is to forecast for at least 24 months the Operation and Maintenance (O&M) cost and the capital cost (non-fuel costs) associated with the procurement of fuel and SO_2 sorbents for use in Cinergy's corporate budget.

GENERAL

The Fuel Department forecasts the O&M and capital costs (non-fuel costs) requirements associated with the fuel and SO_2 sorbents procurement process and furnishes this data to the Budgets and Forecast Department for use in the corporate budget.

RESPONSIBILITY

The Accountant/Economist is responsible for compiling the forecasted O&M and capital costs associated with the procurement of fuel and SO_2 sorbents and for providing the forecasts to other departments on a timely basis.

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V. TRANSPORTATION PROCUREMENT, CONTRACTS, CONTRACT ADMINISTRATION, OPERATIONS AND RAILCAR MAINTENANCE

A. TRANSPORTATION PROCUREMENT

1. RAIL

OBJECTIVE

The objective of this section is to obtain an efficient, dependable and economic rail transportation of fuel or SO_2 sorbents to Cinergy's fossil generating plants.

GENERAL

Where feasible fuel or SO_2 sorbents can be transported by rail to the appropriate fossil generating plants under either a short term contract, long term (greater than two year) contract or tariff. In order to insure continued competition and flexibility among qualified rail carriers, requests for proposals are utilized whenever possible. The potential acquisition of leased and/or purchased railcar equipment is reviewed with particular attention to the resulting economic value achieved through efficient railcar utilization.

RESPONSIBILITY

It is the responsibility of the Manager Fuel Contracts to obtain the rail transportation of fuel or SO_2 sorbents to Cinergy's fossil generating plants.

PROCEDURES

1. Origin & Destination

The origin and destination of rail transportation agreements are selected to provide the Department flexibility needed to transport fuel or SO_2 sorbents from multiple suppliers at the optimum price.

2. <u>Effective Date and Term</u>

Effective date and term are negotiated to provide anticipated transportation needs. The term of the agreements will normally be one to two years or in some cases the term is matched to a particular coal or SO_2 sorbent supply agreement.

3. <u>Volume Capability and Equipment Requirements</u>

Volume levels and equipment requirements for the transportation agreements are determined in conjunction with the Fuel Planning section and generating stations.

4. <u>Request for Proposals</u>

Periodically, the Department will issue requests for proposals to meet rail transportation requirements as determined by the above. The RFPs are issued to railroads having the capability to service the desired origin and/or destination.

5. <u>Evaluation</u>

Alternative transportation proposals are evaluated in conjunction with projected fuel or SO_2 sorbent supplies to determine the optimum delivered price.

6. <u>Negotiations</u>

Negotiations are conducted with suppliers by individuals designated by the General Manager Fuel. Where practicable, at least two persons from the Department will be present at the negotiations. Personnel from Stations, Power Operations, Internal Audit, Legal and other departments are included in the negotiation process as appropriate.

7. Recommendation

The negotiators make a recommendation to the Department's management who will determine if it should be presented to the appropriate approval authority. The Company's Authorized Approvals Manual documents the approval authority as delegated by the Board of Directors.

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A. TRANSPORTATION PROCUREMENT

2. BARGE

OBJECTIVE

The objective of this section is to obtain, on an as required basis, efficient, dependable and economic barge transportation of fuel or SO_2 sorbents to Cinergy's generating plants.

GENERAL

Whenever appropriate, any combination of rail, barge and truck modes of transportation may be used to facilitate the delivery of fuel or SO_2 sorbents. Requests for proposals are utilized whenever possible to insure continued competition and flexibility among qualified transporters. The rationale for incorporating barges in the transportation of fuel or SO_2 sorbents on the inland waterways include the following:

1. An economic advantage exists over other modes of transportation of fuel or SO_2 sorbents.

2. Barge transportation maintains the competitive nature of both rail and trucking rates.

3. Barge transportation maintains the flexibility of access to multiple modes of transportation available to Cinergy.

RESPONSIBILITY

It is the responsibility of the Manager Fuel Procurement or Manager Fuel Contracts to obtain, when appropriate, barge transportation of fuel or SO_2 sorbents.

PROCEDURES

Procedures for procuring transportation by barge are similar to those for rail.

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A. TRANSPORTATION PROCUREMENT

3. TRUCK

OBJECTIVE

The objective of this section is to obtain, on an as required basis, efficient, dependable and economic truck transportation of fuel or SO_2 sorbents to Cinergy's fossil generating plants.

GENERAL

Whenever appropriate, direct trucking from the supply source to the power plant may be used, or any combination of rail, barge and truck modes of transportation may be incorporated to facilitate the delivery. Requests for proposals are utilized whenever possible to insure continued competition and flexibility among qualified motor carriers of fuel or SO_2 sorbents. The rationale for utilizing trucks in the transportation of fuel or SO_2 sorbents are the same as those listed under V. A.2. Barges.

RESPONSIBILITY

It is the responsibility of the Manager Fuel Contracts or Manager Fuel Procurement to obtain, when appropriate, motor transportation of fuel and SO_2 sorbents.

PROCEDURES

Procedures for procuring transportation by truck are similar to those for rail. A list is maintained of trucking companies with the capability to service the stations requirements. The Manager Fuel Contracts updates this list periodically based upon performance and price competitiveness.

As agreements are entered into for fuel or SO_2 sorbents to be delivered by truck, open purchase orders or individual trucking contracts may be issued to one or more trucking companies who can supply the service and provide the optimum delivered price.

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A. TRANSPORTATION PROCUREMENT

4. GAS PIPELINE

OBJECTIVE

The objective of this section is to obtain an efficient, dependable and economic pipeline transportation of gas to Cinergy's gas burning generating plants.

GENERAL

A competitive selection process is implemented whenever possible among qualified pipeline transporters of gas to insure continued competition and flexibility. Specific attention is directed to applicable laws and regulations governing the transportation of gas to Cinergy's plants capable of utilizing gas.

RESPONSIBILITY

It is the responsibility of the Fuel Department Managers to obtain the pipeline access necessary for the transportation of gas to Cinergy's gas burning generating plants.

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B. TRANSPORTATION CONTRACTS

1. RAIL CONTRACTS

OBJECTIVE

The objective of this section is to develop, negotiate and execute rail transportation contracts that provide for control and operating flexibility with optimum economic benefits.

GENERAL

Since 1980, with the legislative passage of the "Staggers Act", it may be in the best interest of The Company to establish rail transportation contracts with qualified railroads instead of relying on rail tariffs published by the Interstate Commerce Commission (ICC). The following terms and conditions should be considered in the development and negotiation of a solid rail transportation contract:

1. Origin.
2. Destination.
3. Effective date and term of contract.
4. Shipping and volume capability.
5. Tariffs
6. Base Rate(s) & Rate Adjustments.
7. Performance standards.
8. Detention.
9. Loading and Unloading Constraints.
10. Equipment Obligations and Requirements.
11. Designated routes.
12. Weighing.
13. Billing and Payments
14. Regulatory Requirements.
15. Force Majeure.
16. Audits and Records.

17. Insurance.
18. Interchange Guidelines.
19. Private Railcar Equipment.
20. Liabilities.
21. Claims and Responsibility.
22. Termination Provision.
23. Assignments.
24. Other Terms and conditions specifically required by this Agreement.

RESPONSIBILITY

It is the responsibility of the Manager Fuel Contracts to develop, negotiate and execute rail transportation contracts.

PROCEDURES

The above terms and conditions may be included in rail transportation agreements as deemed necessary by the Department.

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B. TRANSPORTATION CONTRACTS

2. BARGE CONTRACTS

OBJECTIVE

The objective of this section is to develop, negotiate and execute barge transportation contracts that provide for control and operating flexibility with optimum economic benefits.

GENERAL

The following terms and conditions should be considered in the development and negotiation of a competitive barge transportation contract:

1. Term of contract.
2. Origin.
3. Destination.
4. Effective Date and Term.
5. Shipping and Volume capability.
6. Base Rates and Adjustments.
7. Demurrage.
8. Liability.
9. Claims and Responsibility.
10. Equipment.
11. Fleeting Arrangements.
12. Force Majeure.
13. Insurance.
14. Audits and Records.
15. Performance Standards.
16. Loading and Unloading constraints.
17. Weighing.
18. Billing and Payments.
19. Equipment Obligation & Requirements.

20. Regulatory requirements.

RESPONSIBILITY

It is the responsibility of the Manager Fuel Procurement or Manager Fuel Contracts to develop, negotiate and execute barge transportation contracts.

PROCEDURES

Barge transportation agreements are similar to rail except they exclude those items which are rail specific.

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B. TRANSPORTATION CONTRACTS

3. TRUCK CONTRACTS

OBJECTIVE

The objective of this section is to develop, negotiate and execute truck transportation agreements that provide for control and operating flexibility with optimum economic benefits.

GENERAL

The following terms and conditions should be considered in the development and negotiation of a competitive truck transportation agreement:

1. Term of Contract.
2. Quantity.
3. Price.
4. Delivery.
5. Equipment.
6. Performance standards.
7. Other standard purchase order terms.

RESPONSIBILITY

It is the responsibility of the Manager Fuel Contracts or Manager Fuel Procurement to develop, negotiate and execute truck transportation agreements.

PROCEDURES

Truck agreements are entered into using individual contracts with trucking companies or open purchase orders.

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POLICIES AND PROCEDURES

V. TRANSPORTATION PROCUREMENT, CONTRACTS, CONTRACT ADMINISTRATION OPERATIONS AND RAILCAR MAINTENANCE

B. TRANSPORTATION CONTRACTS

4. GAS PIPELINE CONTRACTS

OBJECTIVE

The objective of this section is to develop, negotiate and execute gas pipeline transportation contracts that provide for the reliable and economic transportation of gas to Cinergy's gas burning generating plants.

GENERAL

Specific attention is focused on the applicable laws and regulations governing the inter-state and intra-state transportation of gas to Cinergy's gas burning generating plants.

RESPONSIBILITY

It is the responsibility of the Department's managers to develop, negotiate and execute gas pipeline transportation contracts.

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C. TRANSPORTATION CONTRACT ADMINISTRATION

1. RAIL CONTRACTS (TERMS & CONDITIONS)

OBJECTIVE

The objective of this section is to make sure that the parties are in compliance with the terms and conditions contained in the executed Rail Transportation Contracts.

GENERAL

In order to administer the provisions outlined in the Rail Transportation Contracts and to enforce compliance among the appropriate parties, it is necessary to perform regular, periodic reviews of the terms and conditions contained in each executed Rail Transportation Contract. The specific performance requirements provided for below are representative of the terms and conditions that should be reviewed and administered on a regular basis:

1. Origin.
2. Destination.
3. Effective date and term of contract.
4. Shipping and volume capability.
5. Tariffs
6. Base Rate(s) & Rate Adjustments.

7. Performance standards.
8. Detention.
9. Loading and Unloading Constraints.
10. Equipment Obligations and Requirements.
11. Designated routes.
12. Weighing.
13. Billing and Payments
14. Regulatory Requirements.
15. Force Majeure.
16. Audits and Records.
17. Insurance.
18. Invoice Approval

RESPONSIBILITY

It is the responsibility of the Manager Fuel Contracts to enforce compliance with the contract terms and conditions contained in Rail Transportation Contracts.

PROCEDURES

The Department's Field Managers/Representatives are responsible for verifying that origin, destination, volume requirements and other terms and conditions follow the respective agreements.

Performance standards, loading/unloading constraints and other operational considerations are covered in the agreement or under the published rail tariff which is referenced by the respective agreement. Compliance with these standards is verified by the Department's Field Managers/Representatives.

1. Base Rate and Adjustments

   The Base Rate is determined according to the respective agreements. Agreements are normally escalated by a fixed rate and/or some type of economic indicator. The Department will verify that escalations are according to the agreements and will notify Accounting of the price change. The Senior Contract Analyst monitors transportation agreements and notifies the Department of potential volume related cost savings.

2. Equipment Obligations and Requirements

Equipment obligations and requirements are determined in Section C. The Field Managers/Representatives assure the needed equipment is available to transport the fuel as required.

3. Weighing

Weights are based upon the requirements of the agreement with each supplier. Accounting uses the weights entered into the reporting system to verify the tons invoiced by the transportation supplier. These weights are the same as those used to verify the tons invoiced by the coal suppliers.

4. Invoice Approval

Suppliers submit invoices to Accounting per the schedules outlined in the respective agreements. Accounting verifies the invoice amounts to the applicable computer report. Inconsistencies are reported to the Senior Contract Analyst for resolution.

5. Force Majeure

When a force majeure event occurs the party experiencing the force majeure will notify the affected party(s) according to their respective agreements. Transportation related force majeure procedures are administered by the Manager Fuel Contracts.

6. Audits and Records

The Senior Contract Analyst, with the assistance of Internal Audit, audits the supplier's records as permitted by the respective agreements.

7. Insurance

When insurance is provided for in the agreement, a copy of the Certificate of Insurance is maintained by the Senior Contract Analyst.

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C. TRANSPORTATION CONTRACT ADMINISTRATION

2. BARGE CONTRACTS (TERMS & CONDITIONS)

OBJECTIVE

The objective of this section is to make sure that the parties are in compliance with the terms and conditions contained in the executed Barge Transportation Contracts.

GENERAL

In order to administer the provisions outlined in the Barge Transportation Contracts and to enforce compliance among the appropriate parties, it is necessary to perform regular, periodic reviews of the terms and conditions contained in each executed Barge Transportation contract.

RESPONSIBILITY

It is the responsibility of the Manager Fuel Procurement and Manager Fuel Contracts to enforce compliance with the contract terms and conditions contained in Barge Transportation Contracts.

PROCEDURES

Procedures for administration of barge transportation agreements are similar to those for rail except for rail specific issues.

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C. TRANSPORTATION CONTRACT ADMINISTRATION

3. TRUCK CONTRACTS (TERMS & CONDITIONS)

OBJECTIVE

The objective of this section is to make sure that the parties are in compliance with the terms and conditions contained in the executed Truck Transportation Contracts.

GENERAL

In order to administer the provisions outlined in the Truck Transportation Contracts and to enforce compliance among the appropriate parties, it is necessary to perform regular, periodic reviews of the terms and conditions contained in each executed Truck Transportation Contract.

RESPONSIBILITY

It is the responsibility of the Senior Contract Analyst to enforce compliance with the contract terms and conditions contained in Truck Transportation Contracts.

PROCEDURES

Procedures for administration of truck transportation agreements are similar to those for rail except for rail specific issues.

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C. TRANSPORTATION CONTRACT ADMINISTRATION

4. GAS PIPELINE CONTRACTS (TERMS & CONDITIONS)

OBJECTIVE

The objective of this section is to make sure that the parties are in compliance with the terms and conditions contained in the executed Gas Pipeline Transportation Contracts.

GENERAL

In order to administer the provisions outlined in Gas Pipeline Transportation Contracts and to enforce compliance among the appropriate parties, it is necessary to perform regular, periodic reviews of the terms and conditions contained in each executed Gas Pipeline Transportation Contract.

RESPONSIBILITY

It is the responsibility of the Department managers to enforce compliance with the contract terms and conditions contained in Gas Pipeline Transportation Contracts.

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D. TRANSPORTATION OPERATIONS

1. EQUIPMENT REQUIREMENTS

OBJECTIVE

The objective of this section is to secure unit trains, on either a short term or long term basis, such that the equipment obtained satisfies recognized contractual and operational requirements.

GENERAL

Specific attention is focused on the following areas in securing unit trains for movement of coal to Cinergy's fossil generating plants:

1. Long term requirements.
2. Short term requirements.
3. Joint ownership.
4. Payment procedures.
5. Equipment specifications.
6. Equipment budgeting.

RESPONSIBILITY

It is the responsibility of the Senior Contract Analyst to obtain, monitor and insure that the recognized contractual and operational requirements of the unit train equipment is satisfied.

PROCEDURES

The Department utilizes a least cost method based upon delivered cost per MBTU to determine the equipment requirements. Company owned equipment is utilized to its fullest extent to provide the greatest return on the Company's investment. The Field Managers/Representatives schedule the company equipment and identify additional equipment needs.

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D. TRANSPORTATION OPERATIONS

2. ADMINISTRATIVE PROCEDURES

OBJECTIVE

The objective of this section is to administer the support procedures necessary to maintain the efficient, economic transportation operation of unit trains, barges and trucks to Cinergy's fossil generating plants.

GENERAL

In order to maintain the efficient, economic transportation operation of unit trains, barges and trucks, it is necessary to coordinate the following administrative support procedures:

1. Applicable AAR, FRA and ICC rules and regulations.
2. Regularly scheduled operational meetings.
3. Efficient scheduling and coordination of deliveries.
4. Track Inspection.
5. Prompt attention to derailments and claims.
6. Approval procedures for accounts payable and accounts receivable.

RESPONSIBILITY

It is the responsibility of the Des Field Managers/Representatives to administer the procedures necessary to maintain the efficient, economic transportation of fuel and SO_2 sorbent to Cinergy's fossil generating plants.

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V. TRANSPORTATION PROCUREMENT, CONTRACTS, CONTRACT ADMINISTRATION OPERATIONS AND RAILCAR MAINTENANCE

E. TRANSPORTATION RAILCAR MAINTENANCE

1. STRATEGIES AND RESEARCH

OBJECTIVE

The objective of this section is to develop the strategies and coordinate the research necessary to maintain an economically competitive railcar maintenance program.

GENERAL

Regular communication combined with the efficient consolidation of industry knowledge obtained from railcar manufacturers, carrying railroads, railcar repair facilities, the ICC and AAR is vital in the development of a cost competitive railcar maintenance program. Short term and long term strategies focusing on the procedures necessary to test new railcar components, as well as the procedures necessary to evaluate the efficient utilization of railcar repair shops located at designated power plants should be researched.

RESPONSIBILITY

It is the responsibility of the Manager Fuel Contracts to develop the strategies and coordinate the research necessary to maintain an economically competitive railcar maintenance program.

PROCEDURES

Outside contractors are used for railcar maintenance and repair work. Such contractor(s) must possess a thorough knowledge and understanding of A.A.R. and specifications, proper repair facilities and mobile equipment and the necessary A.A.R. licenses. Thus, arrangements must be made with a qualified and reputable rail equipment maintenance company to handle the routine inspection and repair of the equipment, as well as any extraordinary repair work. Inherent to the successful accomplishment of this policy is a good working knowledge of A.A.R. rules and regulations by the Field Manager/Representative. Additionally, related A.A.R. reference material must be maintained by the Department.

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FUEL DEPARTMENT

POLICIES AND PROCEDURES

V. TRANSPORTATION PROCUREMENT, CONTRACTS, CONTRACT ADMINISTRATION OPERATIONS AND RAILCAR MAINTENANCE

E. TRANSPORTATION RAILCAR MAINTENANCE

2. FIELD ACTIVITY

OBJECTIVE

The objective of this section is to schedule, on a regular basis, visits to shops and sites that are directly involved with the economical maintenance of railcar equipment.

GENERAL

It is valuable for personnel involved in private railcar maintenance to maintain an active schedule of field inspection visits to shops and sites practicing an active economical program of railcar maintenance. Visits and communication with personnel actively associated with the following areas are strongly encouraged:

1. Railcar lessors and manufacturers.
2. AAR billing personnel.
3. Private and Railroad railcar repair facilities.
4. PSI (and other utility) Fossil Generating plants.
5. Railroads.

RESPONSIBILITY

It is the responsibility of the Field Managers/Representatives to schedule visits on a regular basis.

PROCEDURES

1. Inspection Program

The railcars are inspected on scheduled intervals and contractor work requirements are authorized by the Department as a result of these inspections.

Also, some work activities may be assigned as a result of railroad inspections or Cinergy employee or contractor observations of the equipment in use, throughout the month.

2. Maintenance Program

The heart of the Maintenance Program is the "Power Maintenance Information System" (P.M.I.S.) which provides a list of job orders based on a selected sort sequence and can be used to find and review job information.

Scheduled maintenance and inspections are pre-determined for the life of the equipment and can be located on the P.M.I.S. 1210 Index Report.

A complete history of work performed on the equipment is maintained in the P.M.I.S. "History" (HIST) program, sorted by plant, equipment number and date.

Cinergy Services, Inc.

FUEL DEPARTMENT

POLICIES AND PROCEDURES

V. TRANSPORTATION PROCUREMENT, CONTRACTS, CONTRACT ADMINISTRATION OPERATIONS AND RAILCAR MAINTENANCE

E. TRANSPORTATION RAILCAR MAINTENANCE

3. ADMINISTRATIVE PROCEDURES

OBJECTIVE

The objective of this section is to provide the administrative support necessary to maintain a reliable and economic private railcar maintenance program.

GENERAL

The administrative support necessary to effectively and economically maintain a reliable private railcar maintenance program rely on familiarity with the following administrative procedures:

1. AAR and FRA rules and regulations.
2. Audits.
3. Invoice approvals.
4. Contract administration.
5. Railcar repair guidelines.
6. Maintenance and repair billing guidelines.

RESPONSIBILITY

It is the responsibility of the Manager Fuel Planning to administer the procedures necessary to maintain a reliable and economic private railcar maintenance program.

PROCEDURES

In addition to authorizing work requirements, the Department conducts a monitoring and oversight program of repair activities. The majority of jobs of significant dollar amounts are inspected, documented and approved for payment by the Field Manager/Representative. Periodically, material and labor charges by the contractor are subjected to financial audit and report by internal auditors.

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-021

REQUEST:

21. Refer to page 5-13 of the report. With the increased availability of propane describe any efforts or plans currently being considered to use propane at more units as either a back-up fuel or possibly as a primary fuel.

RESPONSE:

To my knowledge, there are no plans being considered to use propane at more units as either a back-up fuel or primary fuel. Propane is more expensive than natural gas (roughly 1.5x more over the last 4 years) and propane requires very expensive storage facilities. Propane made sense at Woodsdale since it was a back-up fuel and since the facility is located adjacent to the TEPPCO storage caverns at Todhunter, Ohio.

WITNESS RESPONSIBLE:

John R. Kreinest

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-022

REQUEST:

22. Refer to pages 5-24 and 5-25 of the report. Provide additional information regarding the diversity exchange agreements with East Kentucky Power Cooperative, Inc. regarding any changes, updates, or other modifications that have occurred since the time the IRP was prepared.

RESPONSE:

There have been no changes, updates, or other modifications regarding the diversity exchange agreements with East Kentucky Power Cooperative, Inc. since the time the IRP was prepared.

WITNESS RESPONSIBLE:

Diane Jenner

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-023

REQUEST:

23. Refer to page 5-30 of the report. Provide, in summary form, a schedule which reflects the differences in the price estimates for Combustion Turbines and Combined Cycle Units based on the EPRI data and the information obtained from vendors.

RESPONSE:

This information is contained in KYStaff-01-023-A, and is confidential. ULH&P will provide this information if a confidentiality agreement is executed.

WITNESS RESPONSIBLE:

Diane Jenner

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-024

REQUEST:

24. Refer to page 5-45 of the report. Provide chapters 5 and 6 of the 1995 CinergyIRP filing which contained the "extensive screening" of repowering options.

RESPONSE:

See Attachments KYStaff-01-024-A and B.

WITNESS RESPONSIBLE:

Diane Jenner

5. SUPPLY-SIDE RESOURCES

A. INTRODUCTION

The phrase "supply-side resources" encompasses a wide variety of options. These can include existing generating units on a utility's system, repowering or refurbishing options for these units, existing or potential purchases from other utilities, IPPs and cogenerators, and new utility-built generating units (conventional, advanced technologies, and renewables). The evaluation of these options considers technical feasibility, fuel availability and price, length of the contract or life of the resource, construction or implementation lead time, capital cost, O&M cost, reliability, and environmental effects. This chapter will discuss in detail the specific options considered, the screening processes utilized, and the results of the screening processes.

B. EXISTING UNITS

1. Description

Figure 5-1 contains information concerning CINergy's existing generating units. This Figure shows the station name and location, system (CG&E or PSI), unit number, type of unit, installation date, tentative retirement year, net dependable summer and winter capability (CINergy share), and current environmental control measures. For those units which are jointly owned with other utilities, Figure 5-2 shows the total capability of the unit and the share owned by each company. Actual capability changes during the past five years (1990-1994) are shown in Figure 5-3. Figure 5-4 gives a summary of actual loads and required generating capability for 1990-1994. The approximate fuel storage capacity at each generating station is shown in Figure 5-5.

PSI has a total installed net summer generation capability of 6,031 Megawatts (MW) (including the ownership interests of Indiana Municipal Power Agency (IMPA) and Wabash Valley Power Association, Inc. (WVPA) in Gibson Generating Station Unit No. 5). This capacity consists of 5,691 MW of coal- or oil-fired steam capacity, 45 MW of hydroelectric capacity and 295 MW of peaking capacity. The steam capacity is comprised of 21 coal-fired units and one oil-fired unit located at six stations. The hydroelectric generation is a run-of-river facility comprised of three units. The peaking capacity consists of seven oil-fired diesels located at two stations, eight oil-fired combustion turbine (CT) units located at two stations, and one natural gas-fired CT with oil back-up, which is the newest unit, Cayuga 4.

CG&E has a total installed net summer generation capability of 5,121 MW, which includes 4,184 MW of coal-fired steam capacity and 937 MW of combustion turbine (CT) peaking capacity. The coal-fired capacity is comprised of 18 units located at seven stations. Twelve of the CTs are oil-fired and eight are natural gas-fired. This includes the six newest, located at the Woodsdale Generating Station, which are natural gas-fired with propane as a back-up fuel. Seven coal-fired steam units supplying capacity and energy to CG&E are commonly owned with Columbus Southern Power Company (CSP) and The Dayton Power and Light Company (DP&L). Four additional coal-fired steam units supplying capacity and energy to CG&E are commonly owned with DP&L.

The largest units on the CINergy system are the five Gibson units at about 620-630 MW each, Zimmer Unit 1 at about 605 MW (CINergy share), and the two Cayuga units at about 500 MW each. The smallest coal-fired units on the system are 45 MW units at Edwardsport and Noblesville. The large range in sizes of the coal-fired units on CINergy's system is due mainly to the vintage of the units.

The peaking units on the CINergy system range in size from 2-3 MW oil-fired internal combustion units at

Wabash River and Cayuga to the 99 MW Cayuga Unit 4 gas-fired CT. The newest units on the system are the Woodsdale 1-6 gas-fired CTs (77 MW each) and the Cayuga 4 CT.

The Wabash River Coal Gasification Repowering Project (WRCGRP), which is an integrated coal gasification combined cycle repowering facility, is currently estimated to be added to the system during the Third Quarter of 1995. This project is a joint venture between PSI and Destec, Inc. that was approved by DOE as a Clean Coal IV project in the national Clean Coal Technology program. A substantial portion of the funding is provided by the Federal Government. PSI will supply Destec with high sulfur local coal for gasification. The synthetic gas (syngas) produced by Destec will then be utilized as fuel for a combustion turbine (CT) unit. A heat recovery steam generator (HRSG) placed in the exhaust stream of the CT will generate steam from the waste heat. This steam and additional high pressure steam from the gasification process will be used to operate the existing steam turbine of Wabash River Unit 1.

2. Availability

The availabilities of the units used for resource planning purposes were derived from the historical

Generating Availability Data System (GADS) data on these units. The data for the jointly-owned units operated by DP&L and CSP were provided by those companies. This IRP assumes that CINergy's generating units will generally continue to operate at their present availability and efficiency (heat rate) levels.

3. Maintenance Requirements

A comprehensive maintenance program is important in providing reliable low cost service. The following tabulation outlines the general guidelines governing the preparation of a maintenance schedule for existing units operated by CINergy (both fully and jointly owned). It is anticipated that future units will be governed by similar guidelines.

Scheduling Guidelines for Units Operated by CINergy

1. An average of one turbine inspection per station per year, not less than six months apart in a station.
2. A maximum of four turbine inspections (two in the spring, two in the fall) per year for all plants.
3. Major maintenance on baseload units 400 MW and larger is to be performed at about six to eight year intervals (Beckjord 6, Cayuga 1-2, East

Bend 2, Gibson 1-5, Miami Fort 7-8, and Zimmer 1).

4. Major maintenance on intermediate-duty units between 140-400 MW is to be performed at about six to eight-year intervals (not to exceed ten years) (Beckjord 4-5, Gallagher 1-4, Wabash River 1 and 6, and Miami Fort 6).
5. Major maintenance on semi-peaking units up to about 150 MW is to be performed at about eight to ten-year intervals (not to exceed ten years) (Beckjord 1-3 and Wabash River 2-5).
6. Due to the more limited run-time of steam peaking units, judgment and predictive maintenance will be used to determine the need for major maintenance (Edwardsport 6-8, Miami Fort 5, and Noblesville 1-2).
7. Major maintenance on CT peaking units is to be performed at about 25,000 equivalent operation hours (Cayuga 4, Connersville 1-2, Dicks Creek 1 and 3-5, Miami Fort 1-6, Miami-Wabash 1-6, Beckjord 1-4, and Woodsdale 1-6).

The general maintenance requirements for all of the existing generating units were entered into the PROSCREEN II® model (described in Chapter 8) which was used to develop the IRP.

4. Fuel Supply

Coal

Electricity generated from coal accounts for over 90% of CINergy's total electric generation. The cost of coal is the most significant element in CINergy's cost of electric production. The goal of CINergy's Fuels Department is to provide a reliable supply of fuel in quantities sufficient to meet generating requirements, of the quality required to meet environmental regulations, at the least cost. The "cost" of the coal is the evaluated cost which includes the purchase price of the coal FOB the shipping point, transportation to the stations, sulfur content, and the effects of the coal quality on boiler operation and station operation.

CINergy utilizes a committee approach to set broad fuel procurement policies such as: contract/spot ratios, inventory levels, and aid in contract negotiations. CINergy will generally seek the expertise of an independent consultant to review such policies. The policies are then combined with economic and market forecasts and probabilistic dispatch models to provide a five year strategy for fuel purchasing. The strategy provides a guide to meet the goal of having a reliable supply of low cost fuel.

To provide fuel supply reliability, CINergy purchases coal from a widely dispersed supply area, uses a mix of term contract and spot market purchases, and purchases from a variety of proven suppliers. CINergy also maintains stockpiles of coal at each Station to guard against short-term supply disruptions.

Coal supplied to CINergy currently comes primarily from the states of Illinois, Indiana, Kentucky, Ohio, Pennsylvania, and West Virginia. These states are rich in coal reserves with decades of remaining economically recoverable reserves. In addition, limited testing of coal from the Powder River Basin (PRB) has been conducted on Gibson Unit 3 and operational problems appear to be manageable if PRB is proven to be economically feasible.

Approximately 80% of the coal supplied to CINergy is under term contracts. Contract commitments offer CINergy greater reliability than spot market purchases. The financial stability, managerial integrity, and overall reliability of the suppliers is evaluated prior to entering into a contractual commitment. Dedicated, proven reserves assure coal of the specified quantity and quality. Specified pricing, delivery schedules, and length of contract provide suppliers with the financial stability for capital investment and labor requirements and guard CINergy against price fluctuations in the market. The percentage of coal under contract is a strategic decision that is made with the assistance of a committee of upper level management from several different departments having a vested interest in fuel-related decisions.

PSI has seven long-term coal supply agreements. Currently, all of PSI's coal-fired generating stations, except Noblesville and Edwardsport, receive coal under long-term coal supply agreements. Individual coal supply agreements may provide for delivery of coal to several PSI generating stations. Because the Noblesville and Edwardsport Generating Stations are older stations used essentially for peaking purposes, coal is not customarily delivered under long-term coal supply agreements. The coal requirements for Noblesville and Edwardsport Generating Stations are supplied by either diverting contract tonnages from other stations or from short-term purchases. Wabash River and Cayuga Generating Stations customarily receive approximately 30% and

80%, respectively, of their annual coal requirements under long-term coal supply agreements. Gibson Generating Station customarily receives approximately 85% of its annual coal supply requirements under long-term agreements. Gallagher Generating Station customarily receives approximately 50% of its annual coal supply requirement under long-term coal supply agreements.

All of CG&E's coal-fired power plants receive contract coal. CG&E has roughly two-thirds of its burn requirement under contract. The Public Utilities Commission of Ohio (PUCO), which annually requires both a financial audit and a management performance audit of CG&E's fuel procurement policies and practices, has approved the contract-to-spot targets currently employed by CG&E.

CINergy fills out the remainder of its fuel needs with spot coal purchases. Spot coal purchases are used to 1) take advantage of low priced incremental tonnage, 2) test new coal supplies, and 3) supplement coal during peak periods or during contract delivery disruptions.

CINergy also maintains coal stockpiles at the Stations in order to assure fuel supply reliability.

The actual amount of coal kept on hand is another strategic decision made via a committee approach. In general, disruptions that could affect the coal supply are evaluated along with their potential duration, and the probability that they will occur. Sufficient coal is then kept on hand to meet those potential supply disruptions.

Natural Gas

CINergy's use of natural gas for electric generating purposes is limited to peaking and emergency applications. This natural gas is currently purchased on the spot market and is transported (delivered) using interruptible transportation tariffs. The high hourly demand combined with the low capacity factor associated with this type of application make contracting for firm gas and transportation prohibitively expensive. This being the case, backup fuels are utilized at the newer gas-fired peaking facilities. At Woodsdale, propane is the back-up fuel and at Cayuga Unit 4, oil is the back-up fuel.

The availability of natural gas for peaking and emergency service is not expected to be a problem in the long-term. However, the transportation, or deliverability, of the gas from the producer areas, in the South and Southwest, to the Midwest and Northeast markets may become more problematic as the capacities of the transmission pipelines are reached, either during winter peak demand, or summer maintenance and storage recharge periods. Short-term availability and/or transportation problems during the periods described above are also expected to be encountered from time to time.

Propane

The long-term availability of propane is very favorable. The phase-out of lead in gasoline along with the sustained demand for gasoline will mean that refinery output of propane will continue to grow. Currently, CINergy's use of propane for electric generation is limited to use as a back-up and emergency start-up fuel for one of CINergy's natural gas-fired peaking plants (Woodsdale).

Oil

CINergy uses fuel oil for starting coal-fired boilers and for flame stabilization during low load periods. Some combustion turbine peaking facilities are also oil-fired or use oil as a back-up fuel. In addition, one steam unit is oil-fired. Oil supplies are expected to be sufficient to meet needs for the foreseeable future.

Synthetic/Alternate Fuels

CINergy will continue to explore fuels that can compete with coal for the lowest cost production of electricity. Technologies being considered are Refuse Derived Fuel (RDF), tire chips, and advanced coal slurry. An example of CINergy's activity in utilizing new fuel technologies is the Wabash River Coal Gasification Repowering Project (WRCGRP) described earlier. Historically, both CG&E and PSI have supported EPRI and various other research organizations in developing new economically competitive, environmentally conscious sources of energy.

CINergy's Fuels Department monitors potential changes in the fuel industry including mining methodologies, and the availability of different fuels. To the extent that any of these potential changes has an influence on the IRP, they have been incorporated.

The focus of CINergy's fuel-related R&D efforts is to develop leading-edge technologies and provide information, assessments, and decision-making tools to support fossil power plants in reducing their costs for coal utilization and managing environmental risk.

5. Fuel Prices

The coal and oil prices for both existing and new units utilized in this IRP were developed using a combination of consultants and in-house expertise and judgment. The basis of the gas and propane prices was the August 1993 DRI Energy Review Executive Summary. CINergy's projected fuel prices are considered by CINergy to be proprietary competitive information which are filed under seal in the General Appendix.

6. Retrofit or Condition Assessment

Both PSI and CG&E have had refurbishment or engineering condition assessment programs for a number of years. Through these types of programs, CINergy intends to maintain its generating units, where economically feasible, at their current levels of efficiency and reliability. In fact, many of the steps necessary to preserve the existing performance have already been taken.

The tentative retirement dates shown in Figure 5-1 could change based on other factors such as environmental regulations and unit operating performance. In any event, more detailed economic and engineering analysis will be performed as these tentative dates approach.

The Wabash River Coal Gasification Repowering Project previously described represents an extension in the previous tentative retirement date (2007) of the Wabash River Unit 1 steam turbine. Other units could be candidates for similar future repowering projects. The screening of some of these potential options is discussed later in this chapter.

7. Efficiency Improvements

Some lighting and efficiency improvements at generating stations were included in the DSM options (see descriptions in Chapter 4 and in the Short-Term Implementation Plan). Due to modeling constraints, it is impossible to include all potential efficiency or operating improvements as individual options. Instead, CINergy routinely evaluates individual potential modifications or refurbishments to the existing generating units via a cost-benefit analysis. If the proposed enhancements prove to be cost justified, they are budgeted and generally undertaken during a future scheduled unit maintenance outage. The outcome and validity of this IRP have not been affected by this approach.

CINergy also pursues opportunistic off-peak power sales at night and on weekends which enhances the efficient utilization of the generating and transmission facilities. Additionally, CINergy may also pursue valley filling and strategic load growth demand-side activities that may contribute to more efficient utilization of existing generating and transmission facilities.

8. Environmental Regulations

The technology available to meet environmental regulations has added constraints to the power plant fuel cycle and also expends energy to operate. The net result is a reduction in the "energy and capacity for load" capability and a lower overall efficiency. The loss in capability must be replaced by newly acquired resources, by off-system purchased power, or by the increased operation of less efficient units. On either a system or regional basis, lost capacity ultimately translates into a cost (to replace the reduction in capacity) for new resource additions.

Likewise, one potential effect of meeting environmental regulations can be to degrade the reliability (i.e., the "availability") of each generating unit by increasing the complexity of the overall system. This could translate into a "cost to replace the unavailable capacity" in terms of newly installed resource additions.

The technology to meet environmental regulations for fossil-fueled generation generally includes flue gas scrubbers, flue gas conditioning, precipitators for particulate removal, water injection or special burners for NO_x control, and cooling towers.

East Bend Unit 2, Gibson Unit 5 and Zimmer Unit 1 were originally constructed incorporating flue gas scrubbing systems. East Bend Unit 2 has been in commercial operation since early 1981. Gibson Unit 5 has been in commercial operation since late 1982. The W.H. Zimmer Station Unit 1 has been in commercial operation since early 1991. Gibson Unit 4, which originally entered commercial service in 1979, was retrofitted with a flue gas scrubbing system during 1994.

The above mentioned flue gas scrubbers reduce the net output capacity. At East Bend and Gibson the reduction in output is about 1.0-1.5% and at Zimmer the reduction is about 2%.

The environmental standards limiting the stack discharge of particulates have necessitated retrofitting precipitators on several existing generating units. The upgraded precipitators require more "energy to function" amounting to about 1% of generating unit output at 70% capacity factor, and 3/4% of unit capacity at full load. Data on the effect of these precipitators on the efficiency of the fuel cycle is not available.

In the future, new sources may have to meet more stringent standards for the reduction of particulates, which might require an alternate technology (e.g., baghouse filters) that could result in higher investment and operating costs for particulate removal.

The first six Woodsdale combustion turbine units and the Cayuga 4 combustion turbine required water injection to control NO_x emissions. Additional capital expenditures were required for water treatment, injection systems, and controls. The addition of these systems will also reduce unit efficiency and reliability. The specific magnitude of these reductions is currently not known; only future operating experience can provide accurate data. Any future combustion turbine units planned at Cayuga, Woodsdale, or other sites will at least require similar water injection systems or special low NO_x combustors.

CINergy has either natural draft or forced draft cooling towers installed for condenser waste heat rejection on eleven generating units in which it has ownership interests. The Gibson station has a large dedicated cooling lake.

The capital cost required for the construction of thermal pollution control equipment in modern steam-cycle power plants has increased over the conventional methods for generating plants sited on major inland waterways (e.g., once-through cooling). The cooling systems cause an overall reduction in the efficiency of the energy cycle of about 2% in the summer season and 1% in the winter season. For a system which has its greatest generation capacity requirement in the summer, the 2% reduction in available output at peak load must be replaced by additional installed capacity, and the efficiency reduction must be replaced by the purchase of additional fuel.

Equipment modifications and fuel changes associated with compliance with the Clean Air Act Amendments of 1990 (described in more detail in Chapter 6) has increased, and will continue to increase, the cost of electricity. The various options available to achieve compliance along with the specific assumptions utilized (including SO_2 Emission Allowance prices) are also discussed in Chapter 6.

CINergy supports R&D efforts concerning products that cover air toxics measurement and control, NO_x, SO_2 and particulate control, heat rate improvement analysis, waste and effluent management, pollutant prevention, and by-product use.

C. EXISTING NON-UTILITY GENERATION

At the time that the analysis for this IRP was performed, there were no signed contracts to purchase the output of non-utility generators, on either the PSI or the CG&E system. Therefore, no non-utility generators were modeled in the analysis. Since that time four small contracts (ranging from 2 to 4 MW each) have been signed, and that capacity will be modeled in subsequent IRPs. The capacity of these generators is small enough that it would not change the results of this analysis.

Some of PSI's and CG&E's customers have electric production facilities for self-generation or peak shaving. Self-generation facilities are normally of the baseload type and are generally sized to meet the steam or other thermal demands for industrial processes or heating. Peak shaving equipment is typically oil- or gas-fired and is generally used only to reduce the customer's peak billing demand. The relationship of these facilities to the load forecast was discussed in Chapter 3.

One new cogeneration source of which PSI was aware at the time of the modeling was approximately 27 MW at Purdue University which was scheduled to be in service November, 1994 but which was subsequently delayed to May, 1995. This unit was anticipated to provide the majority of Purdue's electricity at the West Lafayette campus. In addition to the project's economics, Purdue based its decision to construct this unit on its plans to conduct future engineering research. Since this reduction was not in the historical loads, a 27 MW offset to the load was modeled in the IRP analysis.

In the PSI service territory, there are currently about eight customers which have an installed generator nameplate capacity of 1 MW or more. The total for these customers is approximately 57 MW (including the new unit at Purdue). In the CG&E service territory, there are currently about nine customers which have an installed generator nameplate capacity of 1 MW or more. The total for these customers is approximately 104 MW. Depending on whether it is operated at peak, this capacity can reduce the load otherwise required to be served by CINergy which, like DSM programs, can also reduce the need for new capacity. Since transmission and distribution (T&D) planning are dependent on the location of the loads, the effects of this capacity on T&D planning is location-specific. To the extent that fewer new T&D resources are required to serve these customers or the local areas in which they reside, CINergy's planning reflects that.

D. **EXISTING POOLING AND BULK POWER AGREEMENTS**

At present, CINergy does not participate in any formal type of power pooling other than the common economic dispatch of the CG&E and PSI generating units. CG&E has participated with The Dayton Power and Light Company (DP&L) and Columbus Southern Power Company (CSP) in the joint construction and ownership of 11 generating units during the past 29 years. PSI co-owns Gibson Unit 5 with Wabash Valley Power Association, Inc. (WVPA) and Indiana Municipal Power Agency (IMPA), and provides Reserve Capacity and Back-up Energy for this unit. These co-ownership arrangements are expected to continue and will provide significant cost savings into the future.

CINergy is interconnected directly with East Kentucky Power Cooperative, Inc., Louisville Gas & Electric Company, Indiana Michigan Power Company, Ohio Power Company, The Dayton Power and Light Company, Columbus Southern Power Company, Ohio Valley Electric Corporation, Central Illinois Public Service, Hoosier Energy, Indianapolis Power and Light, Kentucky Utilities, Northern Indiana Public Service, and Southern Indiana Gas and Electric, and indirectly with the Tennessee Valley Authority. With these utilities, CINergy has interconnection agreements which enable the parties to perform the following functions:

1. Furnish mutual emergency and standby assistance up to the point where it imposes an economic burden or jeopardizes the ability of the supplying system to supply its own load requirements. The emergency condition normally has a time limitation of forty-eight hours.
2. Permit the interchange, sale and purchase of energy to effect operating economies.
3. Permit the exchange of power and energy for planned maintenance outages of generation and transmission facilities for some of the parties.
4. Permit the transfer of electric energy through the transmission system of one party for the benefit of a third party.
5. Provide for the purchase and sale of short-term and limited-term power and energy requirements to meet short range capacity deficiencies.

As a matter of routine operation, CINergy contacts its neighboring interconnected utilities and utilities beyond them on a daily basis in the interest of promoting opportunistic purchases and sales. CINergy also routinely meets with these utilities on an approximately semi-annual basis to discuss the daily interconnection operations, opportunities for short-term energy transactions which may be beneficial to both companies, and the long term purchase/sale of capacity as an alternative to the construction/operation of additional generation facilities. Transaction opportunities are also discussed with companies beyond the directly-interconnected companies listed above.

CG&E signed an agreement with East Kentucky Power Cooperative (EKPC), a winter peaking utility, for 150 MW of seasonal capacity exchange, also referred to as diversity power, in May 1987. Under the terms of the eight (8) year agreement which began April 1, 1988, and ends March 31, 1996, CG&E supplies EKPC with 150 MW of power in the months of December, January, and February and EKPC supplies CG&E with 150 MW of power in the months of June, July, and August. This agreement is working well for both parties and has been extended for one year to March 31, 1997. A separate three year agreement for 50 MW of diversity power covering April 1, 1997, through March 31, 2000, has also been signed. These EKPC agreements are modeled for the summer and winter periods defined above at 150 MW through the end of March, 1997, at 50 MW through the end of March, 2000, and then at zero thereafter.

CINergy has contracts with WVPA and IMPA to provide firm partial requirements service through January 1, 2007. The contracts will continue thereafter unless five years written notice by either party has been given. CINergy serves the WVPA load in the PSI control area above WVPA's ownership in Gibson Unit 5. In addition, CINergy has a 35 year contract to provide 70 MW of firm capacity and energy to WVPA for their use outside of the PSI control area. CINergy serves the IMPA load in the PSI control area above IMPA's ownership in Gibson Unit 5 and their member-owned generation in the PSI control area. These obligations have been modeled as firm load throughout the study period in the IRP.

CINergy has numerous multi-year contracts to sell Limited-Term and Short-Term power which range from 3 MW to 80 MW each. Since these power sales are non-firm, and CINergy is not contractually obligated to install generation to serve them, the capacity associated with them has not been included in the expansion plan modeling. Additional information can be found in the Short-Term Implementation Plan in Volume II.

The billing on the previously described classes of power and energy and contracts is set forth in appropriate rate schedules filed with FERC. CINergy also has filed agreements with other utilities who are not directly interconnected and with various power brokers and marketers.

E. NON-UTILITY GENERATION AS FUTURE RESOURCE OPTIONS

It is CINergy's practice to cooperate fully with potential cogenerators and independent power producers. A major concern, however, exists in situations where either ratepayers would be subsidizing generation projects through higher than avoided cost buyback rates, or the safety or reliability of the electric system would be jeopardized. Both PSI and CG&E typically receive several requests a year for independent/small power production and cogeneration buyback rates. Currently, on the CG&E system, prospective cogenerators proposing the sale of 100kW or less are sent both a copy of the filed tariff for small power producers of 100kW and under, and a copy of the standard interconnection agreement. The larger prospective cogenerators are provided with an explanation of the CG&E methodology for determining avoided cost for capacity and energy and, if requested, interconnection requirements. The CG&E avoided costs are determined on a case-by-case basis depending on MW size, contract length, and the projected reliability of the cogeneration unit. Currently, on the PSI system, prospective cogenerators (regardless of size) are given the interconnection requirements and the calculation of PSI's avoided cost rates.

A customer's decision to self-generate or cogenerate is, of course, based on economics. Customers know their costs, profit goals, and competitive positions. The cost of electricity is just one of the many costs associated with the successful operation of their business. If customers believe they can lower their overall costs by self-generating they will investigate this possibility on their own. There is no way that a utility can know all of the projected costs and/or savings associated with a customer's self-generation. However, during a customer's investigation into self-generation, the customer will usually contact the utility for an estimate of electricity buyback rates. With CINergy's comparatively low electricity rates and avoided cost buyback rates, the payback for most self-generation/cogeneration projects on the system exceeds the three year or less payback criterion used by most commercial and industrial customers. CINergy's avoided costs are generally determined by: system energy costs based largely on coal burned in efficient existing generating units and marginal capacity costs based on gas turbine units and DSM options. These factors make cogeneration and small power production generally uneconomical for most customers.

For these reasons, neither PSI nor CG&E attempts to forecast specific megawatt levels of this activity in their service areas. The electric load forecasts covered in Chapter 3 do consider the impacts on electricity consumption caused by the relative price differences between alternate fuels (such as oil and natural gas) and electricity. As the relative price gap favors alternate fuels, electricity is displaced lowering the forecasted use of electricity and increasing the use of the alternate fuels. Some of the decrease in forecasted electricity consumption may be due to self-generation/cogeneration projects, but the exact composition cannot be determined.

Other supply-side options such as simple-cycle combustion turbines, combined-cycle combustion turbines, and coal-fired units (discussed later in this chapter) could represent potential non-utility generating units, purchases, or utility-constructed units. At the time that CINergy initiates the acquisition of new capacity, a decision will be made as to the best source.

F. SUPPLY-SIDE RESOURCE SCREENING

A list of over seventy supply-side resources was developed as potential alternatives for the IRP process. Due to the size and run time limitations of the PROVIEW™ model (described in detail in Chapter 8), it was necessary to determine, through a screening process, which of these resources were the most viable and cost effective.

1. Model Description

The supply-side resource options considered for planning purposes were initially screened via a set of relative dollar per kilowatt-year vs. capacity factor screening curves. The model utilized was a spreadsheet based screening curve model that was developed in-house.

This screening curve analysis model calculates the fixed costs associated with owning and maintaining a technology type over its lifetime and computes the present worth back to a start year. This is used to compute a levelized fixed $/kW-year value which represents the cost of operating the technology at a zero capacity factor or not at all, i.e., the Y-intercept on the graph. Then the variable costs, such as fuel and emission costs, associated with operating the technology at 100% capacity factor, or at full load, over its lifetime are calculated and the present worth is computed back to the start year. This levelized operating $/kW-year is added to the levelized fixed $/kW-year value to arrive at a total owning and operating value at 100% utilization in $/kW-year. Then a straight line is drawn connecting the two points. This line represents the technology's "screening curve". This process is repeated for each supply technology to be screened resulting in a family of lines (curves). The lower envelope along the curves represents the least costly supply options for various capacity factors or unit utilizations.

Lines that never become part of the lower envelope, or those that become part of the lower envelope only at very high capacity factors (95%+), probably will not be part of the least cost solution, and therefore can generally be eliminated from further analysis. However, SO_2 emission compliance and global climate change are both complicating factors in this simplified supply-side screening analysis. Even though the SO_2 emission costs of the various technologies are taken into account in the screening curves, the technologies cannot be viewed in isolation to quantify the impacts on both total system emissions and emission related system operating costs.

2. Screening Process

Information Source

Many of the specific technology parameters used in the spreadsheet model were based on information taken from Section 8 of the Technical Assessment Guide (TAG™), Electricity Supply-1993, Volume 1:Rev. 7, dated June, 1993, published by the Electric Power Research Institute (EPRI) of Palo Alto, California. The TAG™ provides up-to-date information for use in preliminary resource planning. The report includes summaries of conventional and advanced power generation technologies, including discussions of their status and trends in future development, estimated cost and power performance data, economic factors, and environmental emissions data. Plant Engineering first reviews the TAG™ generation technologies and performs a preliminary screening to eliminate those technologies that are not technically feasible. Plant Engineering also supplies CINergy-specific technology parameters when available (e.g., existing site CT information for Cayuga and Woodsdale). In addition, specific repowering options were supplied by Sargent & Lundy as part of the SO_2

compliance screening (see Chapter 6). Figure 5-6 is a complete listing of the technologies that survived the technical feasibility screening. These survivors were then screened using the spreadsheet model discussed previously.

The following is a description of how the final options from each technology category were determined.

Baseload Resources

Figure 5-7 compares the eight survivors taken from the four subsets of the Generic Baseload Coal Resources.

Five of the eight are in the lower envelope at capacity factors consistent with baseload units so they must be given further consideration. These five are the 500 MW Pulverized Coal, the 500 MW Pulverized Coal burning Powder River Basin Coal, the 320 MW Pressurized Fluidized Bubbling Bed (PFBC), the 1350 MW Evolutionary Advanced Light Water Reactor (ALWR), and the EPRI State-of-the-Art Power Plant (SOAPP).

Upon further investigation, the $/kW values for the ALWR units were considered much too low since the EPRI TAG™ numbers don't include such costs as liability for accidents, waste disposal and storage, decommissioning, and regulatory and licensing problems. With these types of costs included, the supply curve for the ALWR would no longer fall in the lower envelope, so these units were eliminated from further analysis.

The PFBC and the EPRI SOAPP were screened from the list due to the lack of proven commercial operating experience but will continue to be monitored in the future.

Intermediate Resources

The optimum natural gas-fired combined cycle unit size (225 MW) was chosen using the screening curve shown in Figure 5-8.

Peaking Resources

Figure 5-9 compares the four survivors taken from the four subsets of the Generic Peaking Resources (all natural gas-fired). Three of the four are shown to be in the lower envelope at capacity factors consistent with peaking capacity. The existing site CT and the generic new site CT were chosen as supply side alternatives for the PROSCREEN II® integration. The generic inlet cooling was not chosen due to a lack of proven commercial use, but will continue to be evaluated in future analyses.

<u>**Repowering Resources**</u>

See Section H which follows.

<u>**Fuel Cells**</u>

Figure 5-10 is the screening curve for the different fuel cells considered. The 2 MW Molten Carbonate Fuel Cell was the only option in the lower envelope.

<u>**Renewable Resources**</u>

The information obtained from a continuing review of available alternative energy technologies was considered in the preparation of the 1995 IRP. The market for renewable resources in Central Indiana and Southwestern Ohio is very limited. With wind speeds averaging 5-6 MPH and relatively low solar power density, generation of significant amounts of electricity using wind or solar energy is not cost-effective relative to conventional fuels. This is not to say that these technologies may not have specialized applications supplying limited amounts of power in very remote locations. However, their use on a large utility scale is not practical in this region and no major breakthroughs on a utility scale are anticipated in the near future. Consequently, under current environmental assumptions, they continue to be not as cost competitive or as reliable in the Midwest as central station coal units or combustion turbine-based technologies. However, since solar technologies become more viable options in a global climate change scenario, they were still included as part of the screening process. Figure 5-11 is the solar technology screening curve.

Biogas, or landfill gas, generally has both high levels of contaminants and a low-heat content resulting in an overall quality far below that required for pipeline quality natural gas. It is possible to process the gas to pipeline quality standards but doing so increases the cost. This low grade gas may be collected, transported short distances and used in various manufacturing processes, but this activity is generally best suited to private enterprise ventures, not utility-scale projects. Currently, landfill gas is collected by three private ventures on three major landfills within CINergy's service territory.

At the present time, the use of tire-derived fuel is not a significant utility scale energy source. Over time, as operational and environmental issues are resolved, tires or tire residue may become a competitive, but limited, fuel source.

Municipal solid waste (MSW) burning to produce energy is rarely economical from the energy production standpoint. The technology to burn this waste cleanly and reliably is very expensive. Generally, when communities resort to MSW burning it is to dispose of the waste more economically than alternative methods, not to generate low-cost energy. In most instances, the energy sales help to offset some of the costs associated with burning the waste. Siting a MSW burning facility is also a challenge. Concerns abound about truck traffic, odors, vectors, and air toxins. CINergy is not only willing but obligated to purchase power and energy from a MSW facility within our service territory. However, CINergy will defend electric customers against subsidizing the disposal costs of municipal solid wastes.

Five various types of wood fired units were evaluated using the screening curve. The results showed that whole tree energy boilers make up part of the lower envelope of the curve (see Figure 5-12).

The focus of CINergy's R&D efforts with regard to Renewables is to provide planning and evaluation methods to assure a strategic advantage in the deployment of emerging renewables, and the use of storage to manage energy supply.

Hydro Resources

Hydro resources tend to be site-specific; therefore, CINergy evaluates both pumped storage capacity and run-of-river energy resources on a project-specific basis. The 1994 Ohio Forms Only IRP filing contained an evaluation of the proposed Summit Pumped Hydro project.

Battery Resources

At present, batteries perform best in systems that require relatively short bursts of energy on an infrequent basis. Demonstration plants such as the 10 MW CHINO Battery Plant at Southern California Edison have been difficult to maintain and have proven to be more suitable for power system stabilization than as a capacity resource. Other demonstration projects, such as EPRI's Transportable Battery System, should further quantify the benefits and appropriate applications of battery storage systems. However, at this point in time, large utility scale battery storage systems are not commercially viable.

3. Final Supply-Side Alternatives

The technologies that survived the above screening process within each of the previous technological categories were then screened against each other in order to develop the final supply-side alternatives to be carried into the optimization model.

The resultant curve, Figure 5-13, shows that the Existing Site/Generic New Site CT, the New Combined-Cycle, and the New Coal (500 MW FGD PulvCoal) burning Midwest or Eastern coal make up the lower envelope of the final curve. This Figure also shows the Photovoltaic Fixed Flat Plate (PVFP) to be in the lower envelope in the upper capacity factor region. However, due to the fact that it is dark nearly half the time and cloudy part of the remaining daylight time, the PVFP has a maximum expected capacity factor of approximately 20% for this region of the country. Therefore, it was eliminated from the Base Case assumptions. The Whole Tree Energy Boiler and the Molten Carbonate Fuel Cell were also screened out on a $/kW-year basis. However, all three of these technologies were re-considered in the Global Climate Change environmental scenario (see Chapter 8).

As a result of the screening process, the following supply technologies were selected to be utilized as candidate supply-side resources in the PROVIEW™ dynamic optimization computer runs: 1) 113 MW existing site CT and 150 MW generic new site CT units for peaking capacity, 2) 225 MW generic combined-cycle units for intermediate capacity, and 3) 500 MW generic flue-gas-desulfurization clean coal units for baseload energy (nominal ratings). The summer ratings for these units are 100 MW, 131 MW, 198 MW, and 500 MW, respectively. More detailed information on the final supply side technologies screened can be found in Figure 5-14. Since the SO_2 emissions of each of these potential resources will be modeled in the optimization process, their effects on compliance with the Clean Air Act Amendments of 1990 was factored into the analysis.

4. Unit Size

As described previously, various unit sizes were screened for the combustion turbine, the combined cycle plant and the coal unit. Generally, the simple cycle combustion turbine unit sizes selected for planning purposes are the largest proven designs available from equipment vendors. This size offers lower $/kW installed costs while avoiding large spikes in the reserve margin. The unit sizes selected for planning purposes for both the generic combined-cycle units and the generic new clean coal units are also sizes that offer reasonable $/kW installed costs while minimizing the risk of very large reserve margin spikes.

5. **Cost, Availability, and Performance Uncertainty**
Supply-side alternative costs used for planning purposes for conventional technology types such as simple cycle combustion turbine units, combined cycle units, and flue-gas-desulfurized coal units are relatively well known and are estimated in the EPRI TAG™. CINergy experience also confirms their reasonability. The TAG™ costs include step-up transformers and a simplified substation to connect with the transmission system. Since any additional transmission costs would be site specific and since specific sites requiring additional transmission are unknown at this time, no other transmission costs have been included in the screening process. A listing of the projected Generating Facility Costs from the screening curves can be found in Figure 5-15 (Ohio Form IRP-1). The availability and performance of conventional supply-side options is also relatively well known and estimated in the EPRI TAG™.

6. Lead Time for Construction

The estimated construction lead time and the lead time used for modeling purposes for the proposed simple cycle combustion turbine units is about two years. For the combined cycle units, the estimated lead time is about three years and for the new coal units, about six years. However, site selection, licensing, permitting, bidding, and obtaining regulatory approvals may require an additional four to five years. Due to these uncertainties, judgment is also used.

7. RD&D Efforts and Technology Advances

New energy and technology alternatives are needed to ensure a long-term sustainable electric future. CINergy's research, development, and delivery (RD&D) activies enable CINergy to track new options including modular and potentially dispersed generation systems, combusion turbines, advanced fossil technologies as well as enhancements to existing fossil power facilities. Emphasis is placed on providing information, assessment tools, validated technology, demonstration/deployment support, and RD&D investment opportunities for planning and implementing projects utilizing new fossil power generation technology to assure a strategic advantage in electricity supply and delivery.

Within the 20-year horizon of this forecast, it is expected that significant advances will be made in combustion turbine technology. Advances in stationary industrial combustion turbine technology should result from ongoing research and development efforts to improve both commercial and military aircraft engine efficiency and power density. CINergy's Wabash River Coal Gasification Repowering Project is an example of the emerging IGCC technology. (More information concerning the Wabash River project can be found in Section B above).

Another item with great promise in the coal combustion area is the fluidized bed combustion boiler. This technology may allow utilities to comply with recently enacted acid rain legislation without resorting to flue gas scrubbers. Nationally, both atmospheric and pressurized fluidized bed pilot plants are either currently under construction or recently completed to test both the economic and operational feasibility of utility scale fluidized bed boilers.

G. PURCHASE OPTION SCREENING

1. Introduction

CINergy considers purchased power a viable supply-side resource alternative. One long-term purchase and one short-term purchase were included in the supply mix for the optimization process. This section of the report describes the screening process used to select the most appropriate purchases to include in the optimization process.

In order to use the most representative purchase cost data possible in the IRP, in November, 1993, PSI sent out a request for proposals for short and long-term purchases to over 20 companies. The request letter asked for firm peaking proposals for the short-term and firm intermediate or baseload proposals for the long-term. Twelve companies replied with offers. The proposals received were grouped by type and screened using a set of relative dollar per kW-year vs. capacity factor screening curves.

The screening curves used for the short-term proposals were constructed by computing the total cost of each proposal at ten capacity factor levels between 1% and 10%. The total cost included four months (summer peak period) of demand and energy charges and any associated wheeling and emission allowance costs. The method used to screen the long-term proposals was identical to the supply-side screening process described earlier in Section F.

Results and assumptions for the short-term and long-term purchase screening are described below.

2. Short-Term Purchases

The short-term proposals received were separated into firm and limited term groups. The proposals were checked for consistent assumptions and any missing data. For example, appropriate transmission and emission allowance costs were added to proposals submitted without these costs in order to put all proposals on a level playing field.

Another key assumption was the availability and cost of the proposals in 1997. The original request for proposals had been for the 1995-96 time period based on preliminary analyses. However, subsequent data updates indicated that peaking power would also be required in 1997. Therefore, it was assumed that proposals received for 1995-96 would still be representative of those available in 1997. However, years beyond 1997 were judged to be too distant to assume that the proposals received would be available at the costs provided. A conservative escalation rate for 1997 of

10% was applied to all of the proposals received which did not contain cost escalation rates.

Figures 5-16 and 5-17 show the short-term screening curves for Firm and Limited Term purchases, respectively. Bid 2 was identified as the least expensive firm proposal and was passed along to the short list. Similarly, Bid 7 and Bid 9 from the Limited Term screening curve were selected as the least cost proposals and passed on to the short list.

Figure 5-18 shows the short list of least expensive proposals on the same curve. Although Bid 7 appears to be the clear winner from the short list, two concerns arose which led to the selection of Bid 9 and Bid 2 as the proposals to pass to the integration and optimization process. The first concern involved deliverability and flexibility. CINergy felt that Bids 7 and 9 were close enough in price to let these issues break the tie. The Bid 9 purchase had a lower probability of being interrupted for transmission line overloads or constraints than the Bid 7 purchase. Furthermore, the Bid 9 seller only required 10 minute notification for delivery whereas the Bid 7 seller was less flexible and required 24 hour notification. Therefore, Bid 9 was used for peaking purchases in

1995-96, and in combination with Bid 2 for 1997 as described below.

The second concern was to ensure that any purchase modeled as a supply option conformed to CINergy's planning practices. The expected size of purchase needed in 1997 caused some concern in using the Bid 9 Limited Term proposal as the sole purchase source to help meet reserve requirements in 1997. Therefore, CINergy took a more conservative approach for the IRP and assumed that a large portion (2/3) of any purchase would be provided by a Firm source. Therefore, both the Bid 2 Firm and the Bid 9 Limited Term proposals were selected to include in the optimization process for 1997.

To reduce the number of supply options in the integration process, only one representative generic purchase was modeled which was a 2/3 and 1/3 weighted average of the Bid 2 and Bid 9 energy and capacity costs, respectively. The costs of the weighted average combination of Bid 2 and Bid 9 modeled in the integration process are shown in Table 5-1.

Table 5-1

1997 Short-Term Purchase

Capacity Cost ($/kW-Year)	40.4
Energy Cost ($/MWH)	52.4

3. Long-Term Purchases

Because of the great variety in the long-term proposals received, the key elements of timing and contract length were settled first.

Early IRP analysis showed a preference for peaking supply-side options through the year 1999. Therefore, long-term baseload purchase proposals covering years 1995-1999 were removed from consideration. The year 2000 was assumed to be the first year a long-term purchase might be needed.

The remaining proposals ranged from ten to twenty years in duration. CINergy assumed that a purchase longer than ten years might lock-in CINergy for an excessive period, reducing flexibility. Furthermore, CINergy assumed a purchase of ten years added more variety to the supply mix than a twenty year purchase. Therefore, all long-term purchases were evaluated using a ten year contract period.

The long-term purchase screening curve is shown in Figure 5-19.

Bids B and D were the least expensive proposals. However, because these bids were both Limited Term, they were eliminated for reliability concerns. Bid A was the least expensive firm proposal and was included in the optimization process. The capacity and energy costs and escalation rates used in the modeling are shown in Table 5-2.

Table 5-2

Long-Term Purchase

Capacity Cost ($/kW-Year in 1995)	90.0
Capacity Cost Escalation	5.2%
Energy Cost ($/MWH in 1995)	21.0
Energy Cost Escalation	1.6%

H. REPOWERING OPTION SCREENING

Using the same screening model as described earlier in Section F, screening curves were developed for the repowering options. When these curves were compared to each other, it was apparent that certain technologies did not fit CINergy's present needs. These can be re-considered in future IRP analyses.

Initially, the screening curves were compared by station. For example, at Wabash River Station the combined cycle gas turbine (CCGT) options on units 2-4 were compared to pressurized fluidized bed combustion (PFBC) options on units 5 and 6. After analyzing these curves, CINergy decided to screen similar technologies against each other, i.e., the atmospheric fluidized bed combustion (AFBC) and PFBC unit repowerings were compared as were the CCGT repowering options. The remaining options included repowering all units at Noblesville, Edwardsport, and Gallagher and Units 2-5 at Wabash River Station as CCGTs and repowering Wabash River Units 5-6 and both Cayuga units as PFBC and AFBC plants. Since the curves associated with these alternatives were all in the lower envelope, the PROVIEW™ module of PROSCREEN II® (see description in Chapter 8, Section B) was used to perform a more rigorous screening. By using the PROVIEW™ optimization module, both economic and timing issues could be studied.

The large number of repowering options remaining made a single PROVIEW™ run impractical. Therefore, several PROVIEW™ runs were made with each alternative installed in a pre-specified year to determine the optimal repowering dates. The years chosen to evaluate were 1997, 2000, 2004, and each unit's tentatively scheduled retirement year. These years were selected for the following reasons: (1) 1997 was the earliest date one could physically complete a repowering project, (2) 2000 was the first year of Phase II and repowering in that year would compete with a long-term purchase alternative scheduled to become available in that year, and (3) 2004 was the first year by which a coal unit could physically be constructed.

In the case of Noblesville units 1 & 2, it was more economical to repower in the year 2004 instead of the units' tentatively scheduled retirement year of 2006. However, in all other cases, the optimal repowering year for each unit was the unit's tentatively scheduled retirement year.

Since the tentative retirement dates for all repowering options except Noblesville and Edwardsport were well outside of the decision window (1994-2004), these options were eliminated from consideration in this analysis. The Edwardsport and Noblesville repowering options were then made available as alternatives in the resource integration process. The repowering options eliminated can be re-evaluated in future IRP analyses to determine their viability.

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FORM FE2-1: SUMMARY OF EXISTING ELECTRIC GENERATING FACILITIES

STATION NAME & LOCATION	SYSTEM*	FOOT NOTES	UNIT	TYPE OF UNIT*	INSTALLATION DATE MONTH & YEAR	TENTATIVE RETIREMENT YEAR	MAXIMUM GENERATING CAPABILITY (net kW) SUMMER	WINTER	ENVIRONMENTAL PROTECTION MEASURES*
W.C.Beckjord	CG&E		1	CF-S	6-1952	Unknown	94,000	94,000	E.P.
New Richmond,			2	CF-S	10-1953	Unknown	94,000	94,000	E.P.
Ohio			3	CF-S	11-1954	Unknown	128,000	128,000	E.P.
			4	CF-S	7-1958	Unknown	150,000	150,000	E.P.
			5	CF-S	12-1962	Unknown	238,000	238,000	E.P.
		A	6	CF-S	7-1969	Unknown	155,250	157,500	E.P.
			1-GT	OF-GT	4-1972	Unknown	46,600	61,200	None
			2-GT	OF-GT	4-1972	Unknown	46,600	61,200	None
			3-GT	OF-GT	6-1972	Unknown	46,600	61,200	None
			4-GT	OF-GT	6-1972	Unknown	46,600	61,200	None
						Station Total:	1,045,650	1,106,300	
Cayuga	PSI		1	CF-S	10-1970	2025	500,000	505,000	E.P. & Cool Twr
Cayuga, Indiana			2	CF-S	6-1972	2027	495,000	500,000	E.P. & Cool Twr
			3 A	OF-IC	6-1972	2007	3,000	3,000	None
			3 B	OF-IC	6-1972	2007	3,000	3,000	None
			3 C	OF-IC	6-1972	2007	2,000	3,000	None
			3 D	OF-IC	6-1972	2007	2,000	2,000	None
			4	GF/OF-GT	6-1993	2028	99,000	120,000	W.I.
						Station Total:	1,104,000	1,136,000	
Conesville Conesville, OH	CG&E	B	4	CF-S	6-1973	Unknown	312,000	312,000	E.P. & Cool Twr
Connersville	PSI		1	OF-GT	5-1972	2005	42,000	49,000	None
Connersville, Indiana			2	OF-GT	5-1972	2005	43,000	49,000	None
						Station Total:	85,000	98,000	
Dicks Creek	CG&E		1	GF-GT	9-1965	Unknown	92,000	110,000	S.C.
Middletown,			3	GF-GT	6-1969	Unknown	14,200	19,500	S.C.
Ohio			4	OF-GT	10-1969	Unknown	15,000	21,400	None
			5	OF-GT	10-1969	Unknown	15,000	21,400	None
						Station Total:	136,200	172,300	
East Bend Boone County Kentucky	CG&E	C	2	CF-S	3-1981	Unknown	414,000	414,000	E.P. & Cool Twr SO2 Scrubber
Edwardsport	PSI	D	6	OF-S	7-1944	2004	45,000	45,000	E.P.
Edwardsport,		D	7	CF-S	1-1949	2004	45,000	45,000	E.P.
Indiana		D	8	CF-S	12-1951	2004	75,000	75,000	E.P.
		D				Station Total:	160,000	160,000	
Gallagher	PSI		1	CF-S	6-1959	2014	140,000	140,000	E.P.
New Albany, Indiana			2	CF-S	12-1958	2013	140,000	140,000	E.P.
			3	CF-S	4-1960	2015	140,000	140,000	E.P.
			4	CF-S	3-1961	2016	140,000	140,000	E.P.
						Station Total:	560,000	560,000	
Gibson	PSI		1	CF-S	5-1976	2031	630,000	635,000	E.P.
Owensville, Indiana			2	CF-S	4-1975	2030	630,000	635,000	E.P.
			3	CF-S	3-1978	2033	630,000	635,000	E.P.
		E	4	CF-S	3-1979	2034	623,000	628,000	E.P. & SO2 Scrubber
		F	5	CF-S	10-1982	2037	308,000	313,000	E.P. &
						Station Total:	2,821,000	2,846,000	SO2 Scrubber

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FORM FE2-1: SUMMARY OF EXISTING ELECTRIC GENERATING FACILITIES

STATION NAME & LOCATION	SYSTEM*	FOOT NOTES	UNIT	TYPE OF UNIT*	INSTALLATION DATE MONTH & YEAR	TENTATIVE RETIREMENT YEAR	MAXIMUM GENERATING CAPABILITY (net kW) SUMMER	WINTER	ENVIRONMENTAL PROTECTION MEASURES*
Killen Wrightsville, OH	CG&E	G	2	CF-S	6-1982	Unknown	198,000	198,000	E.P. & Cool Twr
Markland Florence, Indiana	PSI		1	HY	4-1967	Unknown	15,000	15,000	None
			2	HY	1-1967	Unknown	15,000	15,000	None
			3	HY	2-1967	Unknown	15,000	15,000	None
						Station Total:	45,000	45,000	
Miami Fort North Bend, Ohio	CG&E		5	CF-S	12-1949	Unknown	80,000	80,000	E.P.
			6	CF-S	11-1960	Unknown	163,000	163,000	E.P.
			1-GT	OF-GT	3-1971	Unknown	48,000	64,500	None
			2-GT	OF-GT	6-1971	Unknown	48,000	64,500	None
			3-GT	OF-GT	7-1971	Unknown	14,200	19,500	None
			4-GT	OF-GT	8-1971	Unknown	14,200	19,500	None
			5-GT	OF-GT	9-1971	Unknown	14,200	19,500	None
			6-GT	OF-GT	10-1971	Unknown	14,200	19,500	None
		H	7	CF-S	5-1975	Unknown	320,000	320,000	E.P. & Cool Twr
		H	8	CF-S	2-1978	Unknown	320,000	320,000	E.P. & Cool Twr
						Station Total:	1,035,800	1,090,000	
Miami-Wabash Wabash, Indiana	PSI		1	OF-GT	6-1968	2002	16,000	17,000	None
			2	OF-GT	6-1968	2002	16,000	17,000	None
			3	OF-GT	6-1968	2002	15,000	17,000	None
			4	OF-GT	6-1968	2002	15,000	17,000	None
			5	OF-GT	8-1969	2002	15,000	18,000	None
			6	OF-GT	7-1969	2002	16,000	18,000	None
						Station Total:	93,000	104,000	
Noblesville Noblesville, Indiana	PSI		1	CF-S	9-1950	2006	45,000	45,000	E.P. & Cool Twr
			2	CF-S	12-1950	2006	45,000	45,000	E.P. & Cool Twr
						Station Total:	90,000	90,000	
J.M.Stuart Aberdeen, Ohio	CG&E	I	1	CF-S	5-1971	Unknown	228,150	228,150	E.P.
		I	2	CF-S	10-1970	Unknown	228,150	228,150	E.P.
		I	3	CF-S	5-1972	Unknown	228,150	228,150	E.P.
		I	4	CF-S	6-1974	Unknown	228,150	228,150	E.P. & Cool Twr
						Station Total:	912,600	912,600	
Wabash River West Terre Haute, Indiana	PSI	J	1	CF-S	12-1953	2021	85,000	85,000	E.P.
			2	CF-S	8-1953	2008	85,000	85,000	E.P.
			3	CF-S	9-1954	2009	85,000	85,000	E.P.
			4	CF-S	1-1955	2010	85,000	85,000	E.P.
			5	CF-S	5-1956	2011	95,000	95,000	E.P.
			6	CF-S	8-1968	2023	318,000	318,000	E.P.
			7A	OF-IC	5-1967	2002	3,000	3,000	None
			7B	OF-IC	5-1967	2002	3,000	3,000	None
			7C	OF-IC	5-1967	2002	2,000	2,000	None
						Station Total:	761,000	761,000	
Woodsdale Trenton, Ohio	CG&E		1	GF/PF-GT	5-1993	Unknown	77,000	94,000	W.I.
			2	GF/PF-GT	7-1992	Unknown	77,000	94,000	W.I.
			3	GF/PF-GT	5-1992	Unknown	77,000	94,000	W.I.
			4	GF/PF-GT	7-1992	Unknown	77,000	94,000	W.I.
			5	GF/PF-GT	5-1992	Unknown	77,000	94,000	W.I.
			6	GF/PF-GT	5-1992	Unknown	77,000	94,000	W.I.
						Station Total:	462,000	564,000	

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FORM FE2-1: SUMMARY OF EXISTING ELECTRIC GENERATING FACILITIES

STATION NAME & LOCATION	SYSTEM*	FOOT NOTES	UNIT	TYPE OF UNIT*	INSTALLATION DATE MONTH & YEAR	TENTATIVE RETIREMENT YEAR	MAXIMUM GENERATING CAPABILITY (net kW) SUMMER	WINTER	ENVIRONMENTAL PROTECTION MEASURES*
W.H.Zimmer Moscow, OH	CG&E	K	1	CF-S	3-1991	Unknown	604,500	604,500	E.P. & Cool Twr SO2 Scrubber
						SYSTEM TOTAL:	10,839,750	11,173,700	

*LEGEND:

CF = Coal Fired
OF = Oil Fired
GF = Natural Gas Fired
PF = Propane Fired

S = Steam
GT = Simple-Cycle Combustion Turbine
HY = Hydro
IC = Internal Combustion

E.P. = Electrostatic Precipitor
S.C. = Smokeless Combustor
Cool Twr = Cooling Tower(s)
W.I. = Water Injection, NOx

CG&E = The Cincinnati Gas & Electric Company PSI = PSI Energy

FOOT NOTES:

(A) Unit 6 is commonly owned by The Cincinnati Gas & Electric Company (37.5% – Operator); The Dayton Power and Light Company (50%) and Columbus Southern Power Company (12.5%).
(B) Unit 4 is commonly owned by The Cincinnati Gas & Electric Company (40%); The Dayton Power and Light Company (16.5%) and Columbus Southern Power Company (43.5% – Operator).
(C) Unit 2 is commonly owned by The Cincinnati Gas & Electric Company (69% – Operator) and The Dayton Power and Light Company (31%).
(D) Total Plant is limited to 160,000kW due to boiler capability.
(E) A SO_2 scrubber was recently completed (11/94) on Unit 4. The summer and winter ratings shown here have been reduced by an estimated 7MW derate associated with the scrubber addition. The actual derate will depend on the results of testing yet to be completed.
(F) Unit 5 is commonly owned by PSI Energy (50.05% – Operator); Wabash Valley Power Association (25%) and Indiana Municipal Power Agency (24.95%). For modeling purposes the WVPA and IMPA loads are included in the PSI load and the full unit share is included.
(G) Unit 2 is commonly owned by The Cincinnati Gas & Electric Company (33%) and The Dayton Power and Light Company (67% – Operator).
(H) Units 7 and 8 are commonly owned by The Cincinnati Gas & Electric Company (64% – Operator) and by The Dayton Power and Light Company (36%).
(I) This station is commonly owned by The Cincinnati Gas & Electric Company (39%); The Dayton Power and Light Company (35% – Operator) and Columbus Southern Power Company (26%).
(J) Unit 1 will be repowered in 1995 as an integrated coal gasification combined cycle generating facility in a Joint Venture between PSI Energy and Destec.
(K) Unit 1 is commonly owned by The Cincinnati Gas & Electric Company (46.5% – Operator); The Dayton Power and Light Company (28.1%) and Columbus Southern Power Company (25.4%).

FIGURE 5-2

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SUPPLEMENT TO FORM FE2-1

MAXIMUM NET DEMONSTRATED CAPABILITY OF JOINTLY OWNED GENERATING UNITS

Station Name and Location	Unit Number	Installation Date	Total MW		CG&E Share		CSP Share		DP&L Share		PSI Share		WVPA Share		IMPA Share	
			Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Walter C. Beckjord New Richmond, OH	6	7-1969	414	420	155	158	52	52	207	210	-	-	-	-	-	-
Conesville Conesville, OH	4	6-1973	780	780	312	312	339	339	129	129	-	-	-	-	-	-
East Bend Boone County, KY	2	3-1981	600	600	414	414	-	-	186	186	-	-	-	-	-	-
Gibson Owensville, IN	5	10-1982	620	625	-	-	-	-	-	-	308	313	156	156	156	156
Killen Wrightsville, OH	2	6-1982	600	600	198	198	-	-	402	402	-	-	-	-	-	-
Miami Fort North Bend, OH	7	5-1975	500	500	320	320	-	-	180	180	-	-	-	-	-	-
	8	2-1978	500	500	320	320	-	-	180	180	-	-	-	-	-	-
J. M. Stuart Aberdeen, OH	1	5-1971	585	585	228	228	152	152	205	205	-	-	-	-	-	-
	2	10-1970	585	585	228	228	152	152	205	205	-	-	-	-	-	-
	3	5-1972	585	585	228	228	152	152	205	205	-	-	-	-	-	-
	4	6-1974	585	585	228	228	152	152	205	205	-	-	-	-	-	-
W. H. Zimmer Moscow, OH	1	3-1991	1300	1300	605	605	330	330	365	365	-	-	-	-	-	-

NOTE: Totals may not add due to rounding to whole numbers.

FIGURE 5-3

CINergy

FORM FE2-2 PART 3: ACTUAL GENERATING CAPABILITY CHANGES [In MegaWatts]

				CAPABILITY CHANGES [1]		SEASONAL TOTAL	
YEAR	UNIT DESIGNATION	NOTES	COMMENT	SUMMER	WINTER	SUMMER	WINTER
1990	Conesville – Unit 4	[2]	(uprated)	24.0			
						24.0	0.0
1991	Zimmer – Unit 1	[3]		604.5	604.5		
						604.5	604.5
1992	Woodsdale G.T. – Unit 2			77.0	94.0		
	Woodadale G.T. – Unit 3			77.0	94.0		
	Woodsdale G.T. – Unit 4			77.0	94.0		
	Woodsdale G.T. – Unit 5			77.0	94.0		
	Woodsdale G.T. – Unit 6			77.0	94.0		
						385.0	470.0
1993	Woodsdale G.T. – Unit 1			77.0	94.0		
	Cayuga G.T. – Unit 4			99.0	120.0		
						176.0	214.0
1994	Gibson – Unit 4	[4]	(derate)		–7.0		
						0.0	–7.0

[1] CINergy portions indicated, of CG&E jointly owned units with DP&L and CSP.

[2] The 780MW Unit 4 at Conesville Station is commonly owned by The Cincinnati Gas & Electric Co. (40%), the Dayton Power & Light Co. (16.5%), and Columbus Southern Power Co. (43.5%).

[3] The 1300MW Zimmer Station is commonly owned by the Cincinnati Gas & Electric Co.(46.5%), the Dayton Power & Light Co.(28.1%), and Columbus Southern Power Co.(25.4%).

[4] An estimated 7MW derate, associated with the scrubber addition, was used for modeling, the actual derate will depend on the results of testing yet to be finalized.

FORM FE2-2 PART 1: SUMMARY OF ACTUAL LOADS AND REQUIRED GENERATING CAPABILITY [In MegaWatts] [1]

Calendar Year>	1990		1991		1992		1993		1994	
Forecast Year>	Year -5		Year -4		Year -3		Year -2		Year -1	
	summer	winter	summer	winter	summer	winter	summer	winter	summer	winter
1. TOTAL ELECTRIC POWER PEAK GENERATING CAPABILITY REQUIRED										
(a) Net Utility Service Area Peak Load [2]	8621	7528	9068	7957	8829	8072	9603	8895	9537	8321
(b) Purchased Power Used to Meet Peak Load [Firm]	400	0	150	0	150	0	150	0	150	0
(c) Power Sales Coincident with Service Peak Load	138	302	133	285	63	201	70	220	70	220
(d) Power Pooling (Net Power Available from Pool(-) or Committed to Pool(+))	0	0	0	0	0	0	0	0	0	0
NET CAPABILITY REQUIRED (a)-(b)+(c)+(d) [3] [Not including Reserve Requirements]	8359	7830	9051	8242	8742	8273	9523	9115	9457	8541
2. REPORTING UTILITY'S ACTUAL HISTORIC GENERATING CAPABILITY [4]										
(a) Previous Year Capability [5]	10180	10204	10204	10204	10809	10809	11279	11279	11493	11493
(b) Retirements and other Decreases in capacity	0	0	0	0	0	0	0	0	0	7
(c) Uprating and Increases in Capability	24	0	605	605	385	470	176	214	0	0
(d) Seasonal Deratings	232	21	232	21	317	21	355	21	355	2[illegible]
NET CAPABILITY [3] [4]	9972	10183	10577	10788	10962	11258	11138	11472	11138	11465
3. DIFFERENTIAL BETWEEN EXISTING AND REQUIRED CAPABILITY FOR EACH YEAR (2-1) [3][4]	1613	2353	1526	2546	2220	2985	1615	2357	1681	2924

[1] WINTER designated Year -5 is that WINTER SEASON which followed the SUMMER of Year -5, etc.

[2] Historical native peak load served, net of any DSM and/or interruptible loads (sum of PSI and CG&E actual individual peak loads).

[3] Totals may not be exact due to rounding to whole numbers.

[4] Assuming increases and decreases in Capability, including all appropriate unit derates, for Equipment in-service at the time of the seasonal peak.

[5] "Previous Year Capability" (Year -5) equals "Net Capability" from Year -6 plus "Seasonal Deratings" from Year -6, etc.

Figure 5-5

APPROXIMATE FUEL STORAGE CAPACITY

Generating Station	Coal Capacity (Tons)	Oil Capacity (Gallons)	Propane Capacity (Gallons)
W.C. Beckjord	550,000	2,100,000	–
Cayuga	700,000	250,000 #2 High Sulfur +250,000 #2 Low Sulfur	–
Conesville	750,000	420,000	–
Connersville	–	500,000	–
Dicks Creek	–	500,000	–
East Bend	300,000	540,000	–
Edwardsport	75,000-80,000	250,000	–
Gallagher	750,000	104,000	–
Gibson	2,800,000-3,000,000 w/three piles	500,000	–
Killen	190,000	2,650,000	–
Miami Fort	700,000	4,000,000	–
Miami-Wabash	–	750,000	–
Noblesville	70,000-75,000	45,000	–
J.M. Stuart	900,000	50,000	–
Wabash River	500,000	187,000	–
Woodsdale	–	–	540,000
W.H. Zimmer	1,000,000	3,000,000	–

Figure 5-6

SUPPLY-SIDE SCREENING FOR 1995 IRP -TECHNOLOGICAL SCREEN SURVIVORS

Generic Baseload Resources

Pulverized Coal Units:
500MW Subcritical Limestone FGD
300MW Subcritical Limestone FGD
500MW Subcritical Limestone FGD - PRB
300MW Subcritical Lime Spray Dryer FGD
300MW Subcritical Wellman Lord FGD
400 MW EPRI SOAPP Unit

Fluidized Bed Units:
200MW AFBC - Bubbling Bed
200MW AFBC - Circualating Bed
200MW AFBC - Circulating Bed - PRB
80MW PFBC - Bubbling Bed
320MW PFBC - Bubbling Bed

Coal Gasification Combined Cycle Units:
500MW Entrained Flow - Medium Integration
500MW Entrained Flow - High Integration
500MW Entrained Flow - No Integration
500MW Moving Bed - Medium Integration
500MW Moving Bed - No Integration
500MW Humid Air Turbine

Nuclear Units:
1350MW Evolutionary Advanced Light Water Reactor
600MW Passive Safety Advanced Light Water Reactor
1488MW Advanced Modular Reactor

Generic Intermediate Resources

Combined Cycle Units:
120MW Combined Cycle
150MW Combined Cycle
225MW Combined Cycle

Generic Peaking Resources

Combustion Turbine:
50MW Simple Cycle - Heavy Duty
80MW Simple Cycle - Heavy Duty
100MW Simple Cycle - Heavy Duty
150MW Simple Cycle - Heavy Duty
25MW Simple Cycle - Aeroderivative
35MW Simple Cycle - Aeroderivative
45MW Simple Cycle - Aeroderivative
50MW Simple Cycle - STIG
Existing Site Peaking Resources
113MW Existing Site Generic CT
Inlet Cooling
12MW Generic Inlet Cooling

Figure 5-6 (Cont'd)

Repowering Alternatives (By Unit)

Wabash River 2-4:
89MW AFBC
223MW CCGT
256MW IGCC

Wabash River 5:
113MW AFBC
230MW CCGT
253MW IGCC

Wabash River 6:
320MW AFBC

Cayuga 1-2:
460MW AFBC
591MW PFBC

Gallagher 1-4:
136MW PFBC
407MW CCGT
249MW IGCC

Edwardsport 6-7:
140MW CCGT
114MW IGCC

Edwardsport 8:
221MW CCGT
143MW IGCC

Noblesville 1-2:
137MW CCGT
118MW IGCC

Miami Fort 5:
80MW AFBC
150MW CCGT

Beckjord 4:
150MW AFBC

Repowering Alternatives (By Technology)

Fluidized Bed Repowering:
Cayuga 1-2 591MW PFBC
Wabash River 5 113MW AFBC
Wabash River 6 320MW AFBC
Gallagher 1-4 136NW PFBC
Beckjord 4 150MW AFBC
Wabash River 2-4 89MW AFBC
Miami Fort 5 80MW AFBC

CCGT Repowering:
Gallagher 1-4 407MW CCGT
Wabash River 5 230MW CCGT
Wabash River 2-4 223MW CCGT
Edwardsport 6-7 140MW CCGT
Noblesville 1-2 137MW CCGT
Edwardsport 8 221MW CCGT
Miami Fort 5 150MW CCGT

Generic Fuel Cells

10MW Phosphoric Acid
25MW Phosphoric Acid
100MW Phosphoric Acid
2MW Molten Carbonate
400MW Molten Carbonate Fuel Cell

Generic Renewable Resources

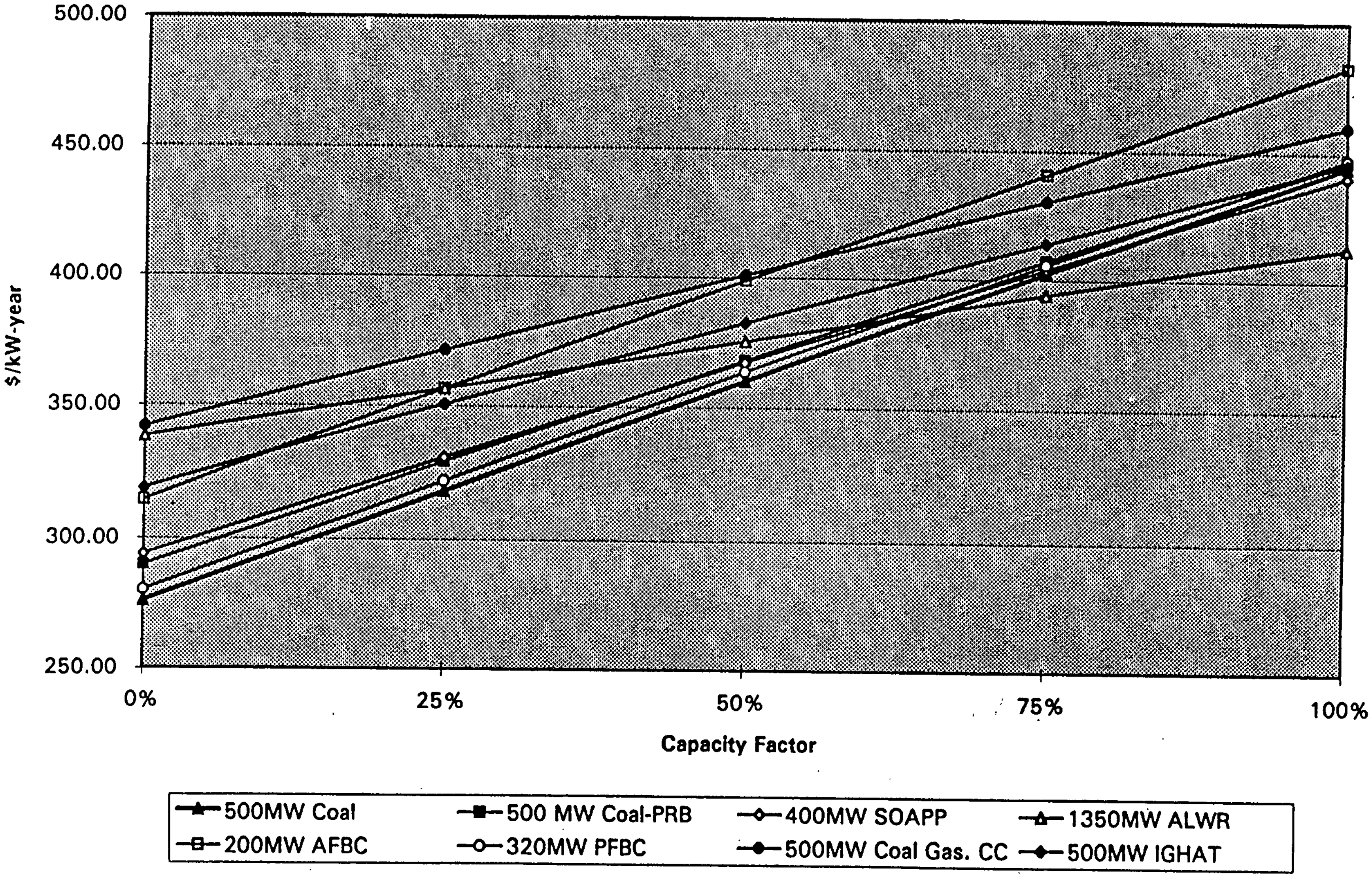
Municipal Solid Waste Units:
40MW Mass Burn
40MW RDF Fired Stoker
30MW Tire Fired Mass Burn

Wood Fired Units:
50MW Wood Fired Stoker
50MW Wood fired CFB
100MW Whole Tree Energy
100MW Wood Fired Gasification-CC-Conventiona
100MW Wood Fired Gasification - CC - Advance

Solar Units:
50MW Photovoltaic Fixed Flat Plate
50MW Photovoltaic Fresnel Lens High Conc.
200MW Thermal Trough/Gas Hybrid

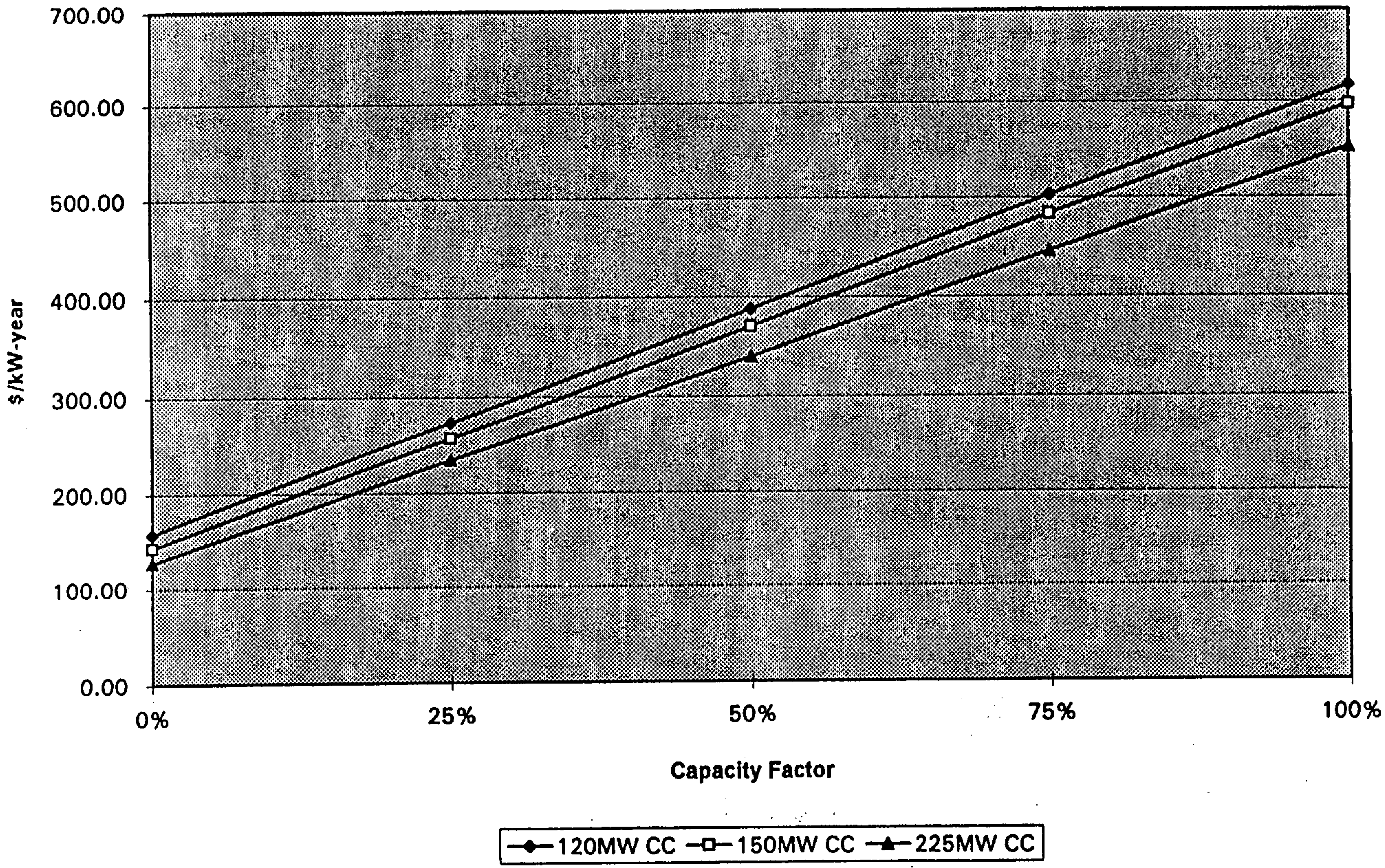
Note: Capacity shown represents per unit TOTAL capacity after repowering (including original unit)

BASELOAD RESOURCES CATEGORY
Screening Curve



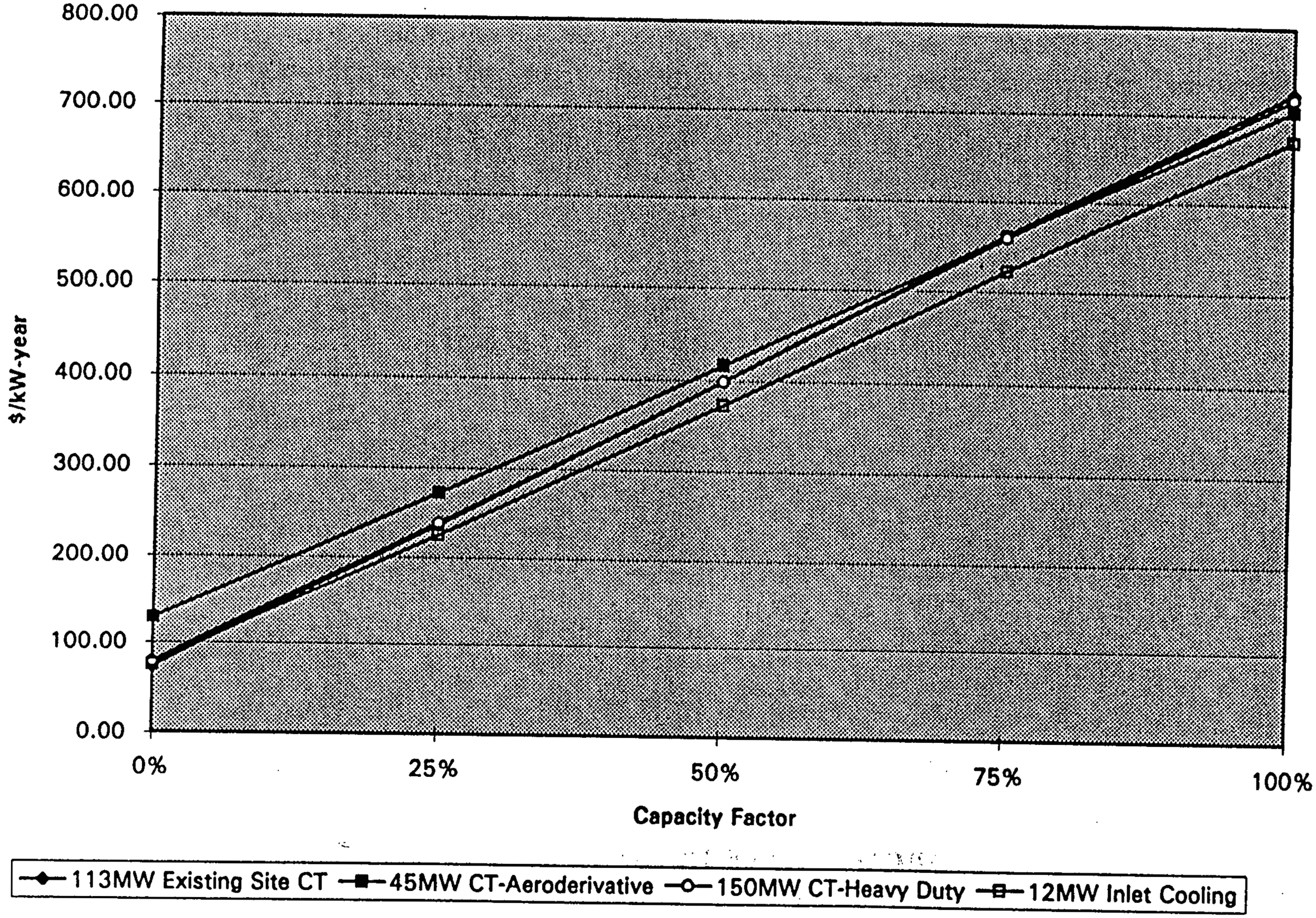
FI 5-8

INTERMEDIATE RESOURCES CATEGORY
Screening Curve



FI 5-9

PEAKING RESOURCES CATEGORY
Screening Curve



FUEL CELLS CATEGORY
Screening Curve

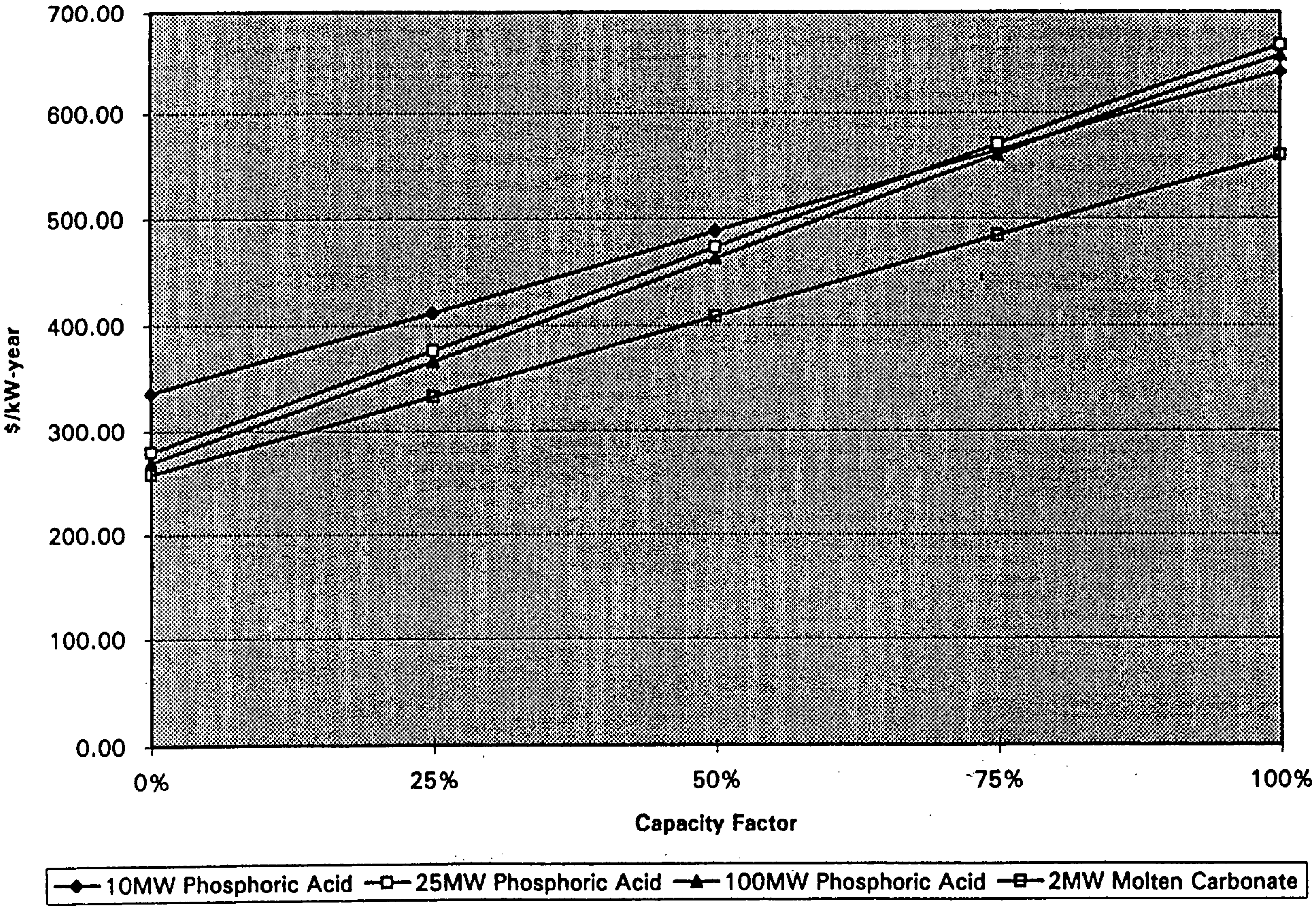
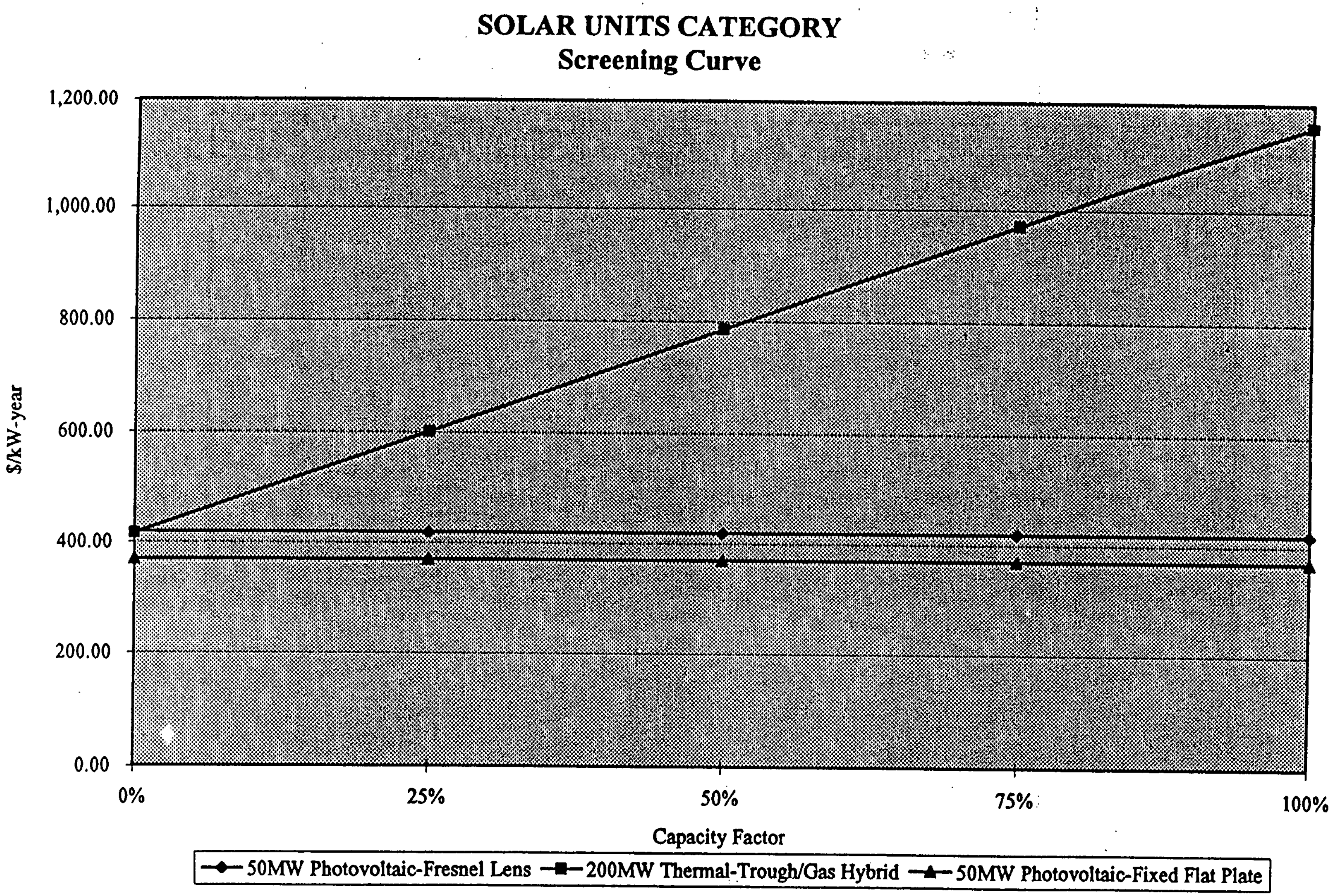


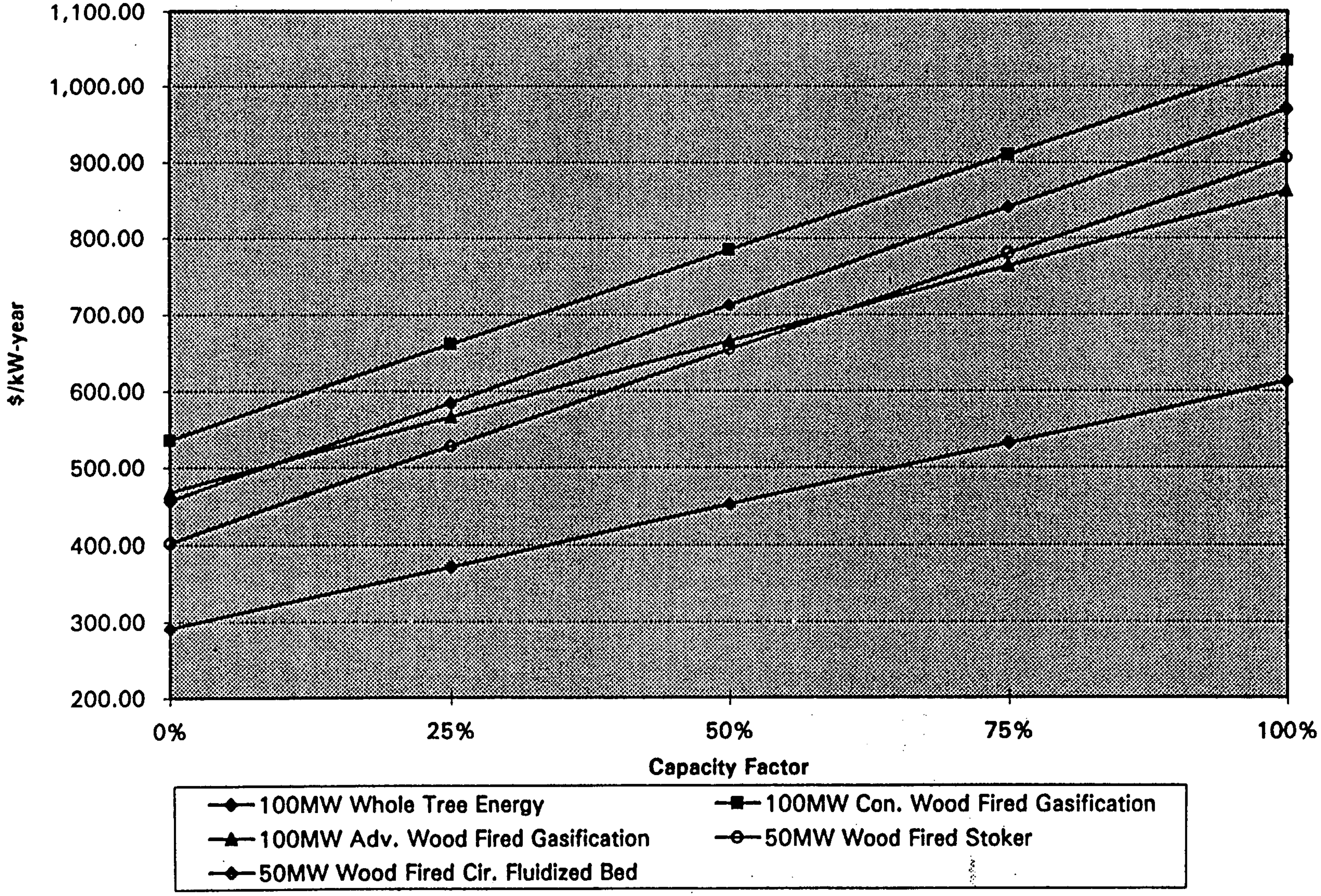
FIG 5-11



SOLAR UNITS CATEGORY
Screening Curve
1,200.00
1,000.00
800.00
600.00
400.00
200.00
0.00
$/kW-year
0%
25%
50%
75%
100%
Capacity Factor
50MW Photovoltaic-Fresnel Lens
200MW Thermal-Trough/Gas Hybrid
50MW Photovoltaic-Fixed Flat Plate

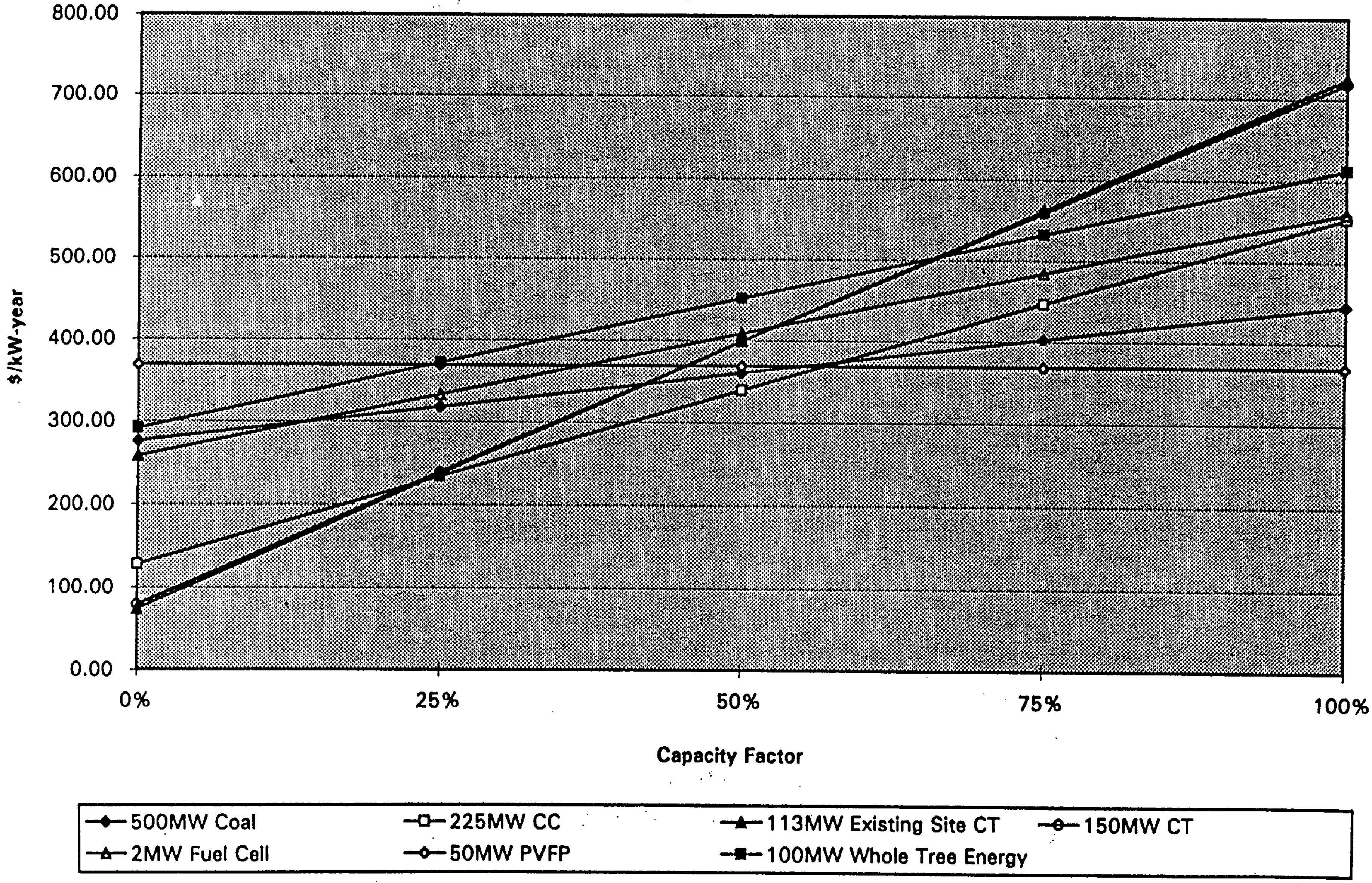
FIGURE 5-12

WOOD FIRED UNITS CATEGORY
Screening Curve



FIGUR 13

FINAL SUPPLY-SIDE ALTERNATIVES
Screening Curve



FINAL SUPPLY-SIDE ALTERNATIVES

SCREEN CURVE DATA

Discount Rate: 8.7%							
1994 Dollars	Plant A	Plant B	Plant C	Plant D	Plant E	Plant F	Plant G
GRAPH LEGEND:	500MW PC	225MW CC	113MW Existing Site CT	150MW CT	2MW Fuel Cell	50MW PVFP	100MW Whole Tree Energy
Size (MWe)	500.0	225.0	113.0	150.0	2.0	50.0	100.0
Capital Cost ($/kWe)	1549.00	664.00	437.00	476.00	1611.00	3063.00	1766.00
Annual Fixed Charge Rate	14.02%	13.48%	13.48%	13.48%	14.02%	11.75%	11.75%
Book Life (yrs)	30	30	30	30	30	30	30
Heat Rate (Btu/kWh)	9548	7300	11291	11100	6450	0	10654
Var. O&M ($/MWh)	3.1	0.4	0.1	0.1	0.2	0	7.3
Fixed O&M ($/kW-yr)	39.5	27.1	10.40	10.4	22.7	6.4	59.8
Fuel Cost ($/MMBtu)	1.15	3.27	3.27	3.27	3.23	0.00	1.50
Fuel Escalation Rate	2.73%	6.55%	6.55%	6.55%	4.79%	0.00%	5.00%
O&M Escalation Rate	4.06%	3.47%	3.47%	3.47%	3.47%	3.47%	3.47%
SO_2 Emission Rate (lbs./MMbtu)	0.16	0.00	0.00	0.00	0.00	0.00	0.02

NOTE: The values shown are relative values used for planning purposes. Absolute values may vary considerably depending on many factors, including but not limited to: unit MW size, seasonal deratings, specific site requirements, equipment vendor(s), ultimate number of units planned on a specific site, and future and/or unforseen regulatory requirements. An estimate of AFUDC is included in the capital costs.

CINergy

FORM IRP–1

GENERAL SUPPLY – SIDE PLANNING INFORMATION

Marginal Costing Period Durations (1):

	Summer Season Months (June through September)			Winter Season Months (All Other Months)		
	On Peak	Mid Peak	Off Peak	On Peak	Mid Peak	Off Peak
Annual Hours:	784	262	1882	1562	1041	3229

Seasonal Demand Related Capacity Cost Allocation Factors:

Summer 98.5 %
Winter 1.5 %

NOTE: Estimate supplied for reporting purposes only. CINergy does not use this in the evaluation of potential resources.

Generating Reserve Criteria:

Planned Average Generating Reserve Margin for the IRP Period: 17.0 % (2)

Projected Generating and Transmission Facility Costs:

Parameters	Trans. Data(3)	Generating Facility Data				
Facility Designation		ECT	NCT	NCC	NCoal	
Capital Cost ($/kW)(4)	135	437	476	664	1549	
Fixed O&M Cost ($/kW–yr)(4)	2.54	10.4	10.4	27.1	39.5	
Cost Escalation Rates (%/yr):						
Capital Cost	5.0	3.78	3.78	3.78	4.19	
Fixed O&M Cost	2.0	3.50	3.50	3.50	4.10	
LARR Rate (%/yr)	13.0	13.48	13.48	13.48	14.02	
Facility Book Life (years)		30	30	30	30	
Capacity Factors (5):						
Summer	N/A	Varies by Year, see note (5)				
Winter	N/A	Varies by Year, see note (5)				

Note: Capital and fixed O&M costs are in 1994 dollars, and capital costs include an estimate of AFUDC.

NOTES: (1) Period breakdowns are approximate and are provided as a filing requirement only, they are NOT necessarily recommended or used by CINergy.

(2) This value is the average of the minimum reserve margin constraints used in PROVIEW™ for the period 1995 through 2015.

(3) Used in the DSManager DSM screening at CG&E.

(4) The values shown are relative values used for planning purposes. Absolute values may vary considerably depending on many factors, including but not limited to: unit MW size, seasonal deratings, specific site requirements, equipment vendor(s), ultimate number of units planned on a specific site and future and/or unforseen regulatory requirements. MW ratings are estimated nominal values.

(5) This is a meaningless figure for transmission. For generating facilities, capacity factor varies by year depending on, among other things, new unit additions, relative fuel costs and the actual performance of the other generating units on the system.

F 5-16

SHORT-TERM FIRM PURCHASE PROPOSALS

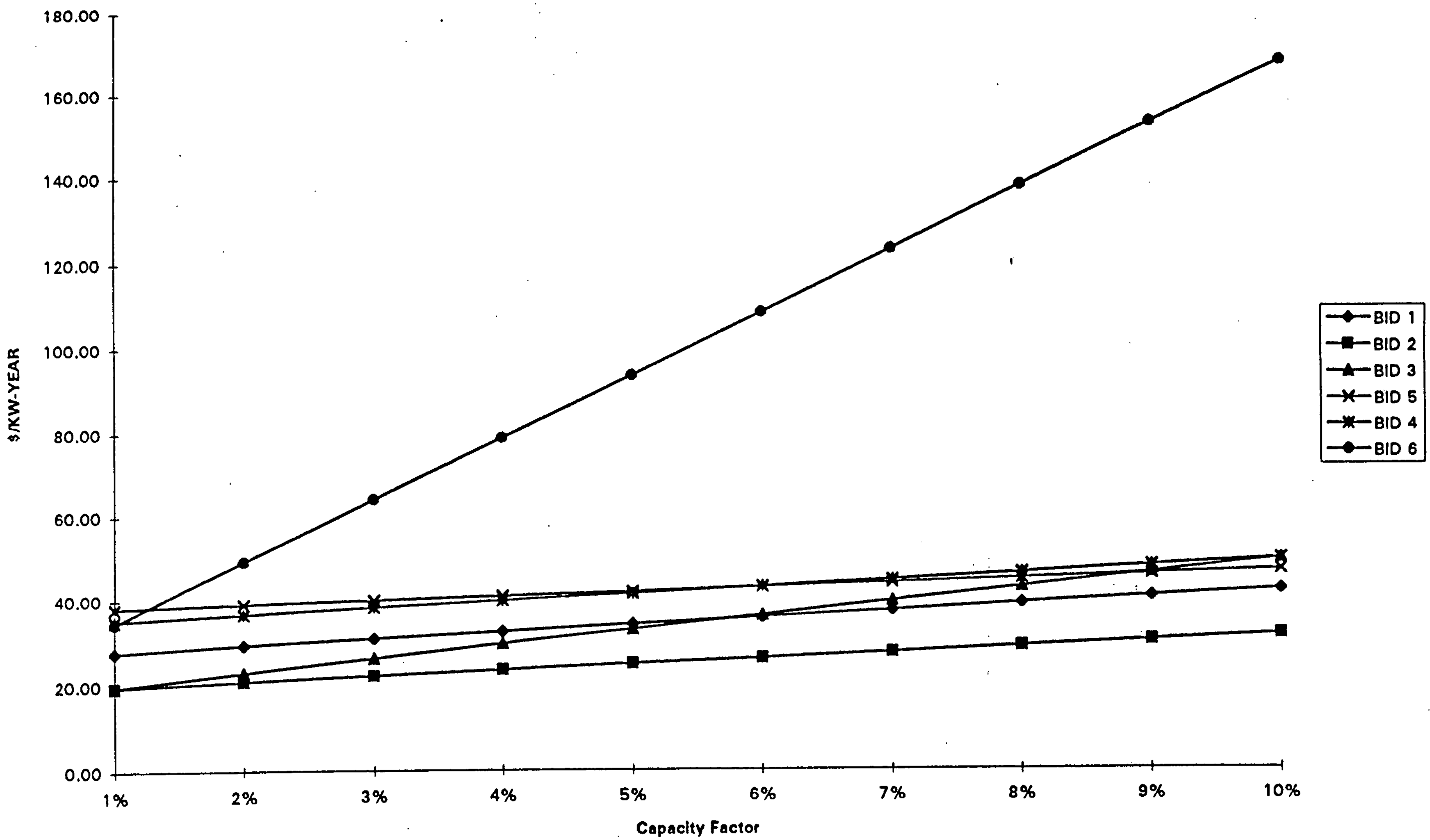
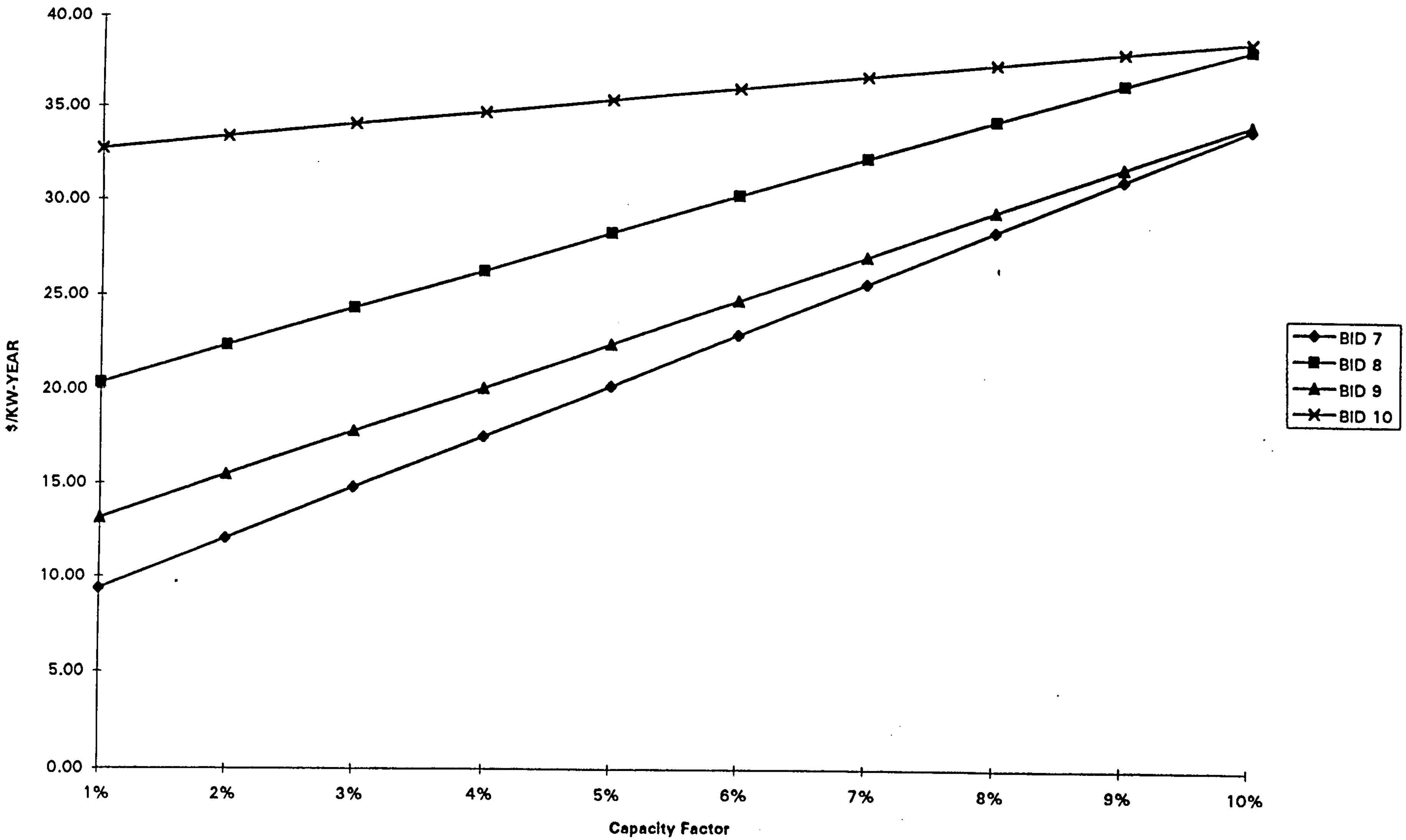


Figure 5-17

SHORT-TERM LIMITED-TERM PURCHASE PROPOSALS



F_ 5-18

SHORT LIST
BEST SHORT-TERM PURCHASE PROPOSALS

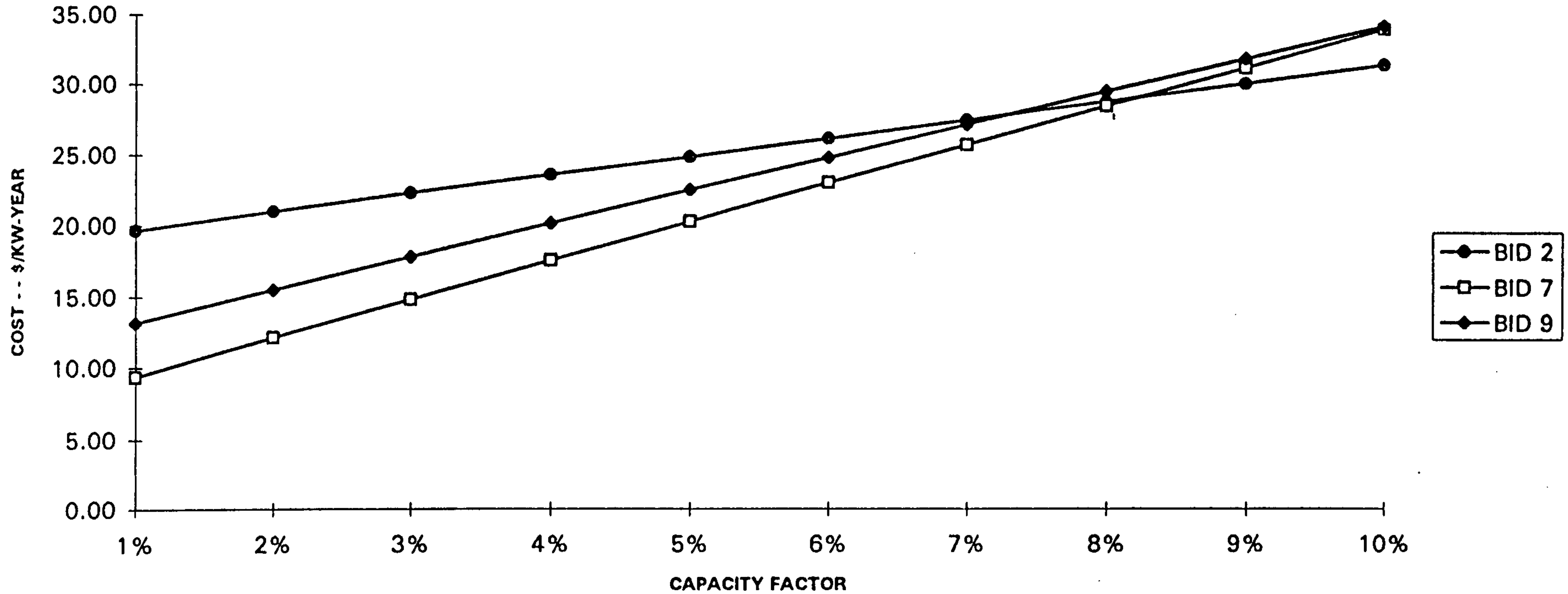
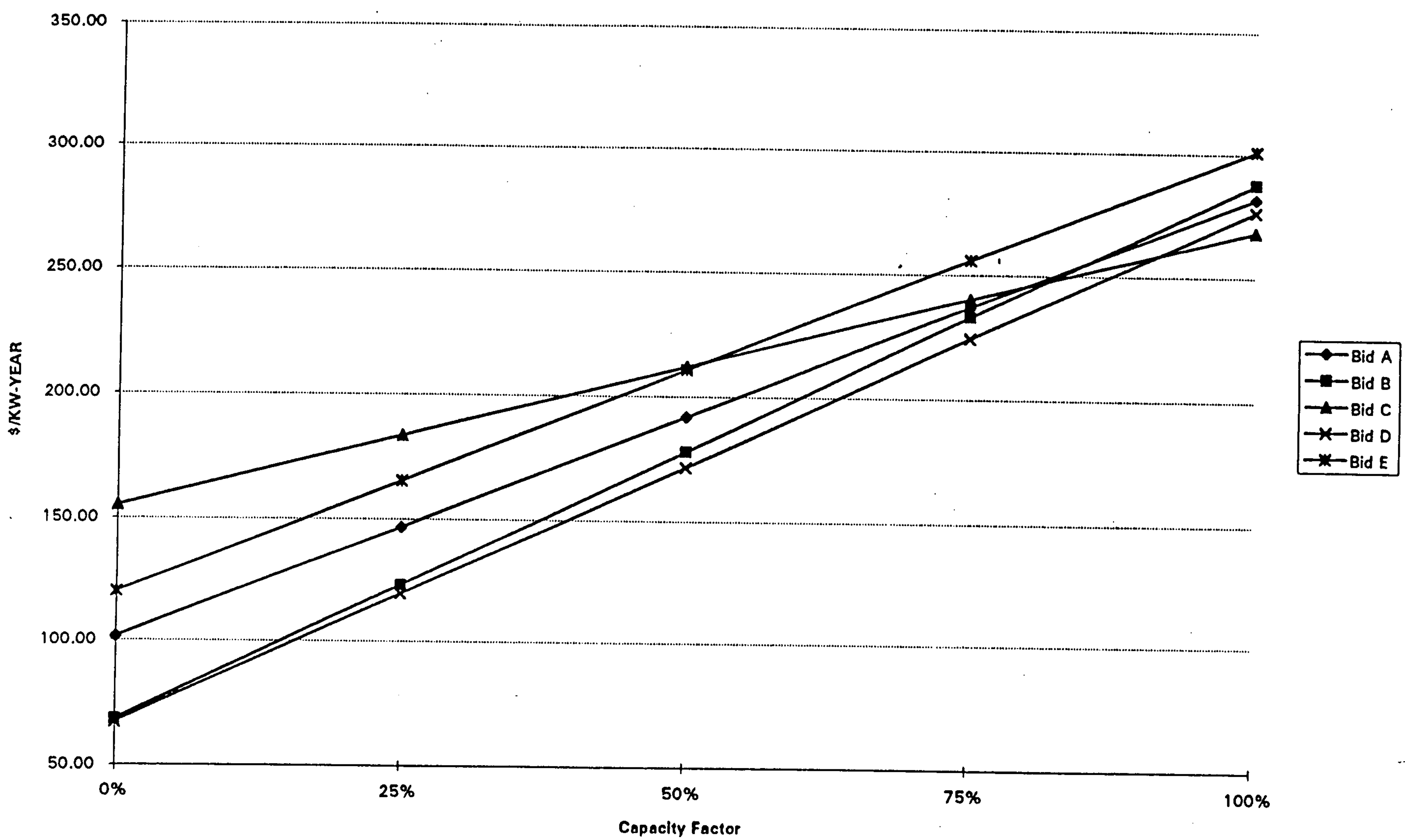


FIGURE 5-19

LONG-TERM PURCHASE PROPOSALS



6. CLEAN AIR COMPLIANCE

A. INTRODUCTION

The Clean Air Act of 1970 and subsequent Clean Air Act Amendments of 1977 set forth a structure of air pollution control known as the "command and control" method in which ambient standards are set, allowable emissions are calculated for each plant, and limits are incorporated on a plant-by-plant basis.

Title IV (i.e., the acid rain provisions) of the Clean Air Act Amendments of 1990 (CAAA) left the existing mechanism in place, strengthened it, and added another layer of provisions in order to achieve even greater sulfur dioxide (SO_2) and nitrous oxide (NO_x) emission reductions. The ultimate goal of the CAAA is to reduce annual SO_2 emissions from U.S. sources by 10 million tons from 1980 levels. Additionally, NO_x emissions will be reduced by 2 million tons annually compared to the levels which would otherwise have occurred. The CAAA calls for the reductions to occur in two phases. Phase I began January 1, 1995, and continues through December 31, 1999. Phase II will begin January 1, 2000, and continue indefinitely.

During Phase I the CAAA targets existing generating units which are 100 megawatts (MW) or greater, and had an SO_2 emission rate of 2.5 lbs. of SO_2/MMBtu (i.e., emitted 2.5 lbs. of SO_2 per million Btu of fuel consumed) or greater during 1985. These units are commonly referred to as "Phase I affected units". Any source which includes one or more affected units is referred to as an "affected source". All existing units which are not Phase I affected units are defined by the CAAA as Phase II affected units. A utility may voluntarily opt a Phase II affected unit into Phase I, whereby the opt-in unit would become a Phase I affected unit and receive allowances based upon the lower of 2.5 lbs. of SO_2/MMBtu and the unit's actual 1985 emission rate.

A unique feature of the CAAA is that rather than requiring a "command-and-control" method of SO_2 emission reduction, a market-based "allowance" system is employed. During Phase I the affected units are given allowances by the U.S. Environmental Protection Agency (USEPA) based upon an emission rate of 2.5 lbs. of SO_2/MMBtu and fuel consumption equal to the average annual amount of fuel consumed by that unit during the 1985-1987 baseline period. In Phase II, allowances will be allocated to affected units in the same manner as Phase I, except that the emission rate will be lowered to 1.2 lbs. of

SO_2/MMBtu. An affected unit must hold one allowance for each ton of SO_2 emitted by that unit in a given year. It can achieve this by: (1) reducing the SO_2 emissions of the unit to the level allocated by the USEPA; (2) transferring allowances from early- or over-complying units; or (3) purchasing allowances from another utility or industrial opt-in source. This ability to purchase allowances from or sell allowances to other sources has created a market for SO_2 allowances.

For the most part, any new units added after 1987 will not be allocated allowances for Phase II. Instead these units must obtain allowances from the market or from other pre-1987 units.

Another important aspect of the allowance system is the ability to save, or "bank", allowances for future use. Allowances allocated to an affected unit may be used in the year in which they are allocated, or later. For example, a vintage 1995 allowance may be used in any year 1995 or later. Thus, a utility could over-comply on its Phase I affected units or purchase allowances in order to build up a "bank" of allowances. This "bank" could then be used to delay necessary SO_2 reductions on a unit (or group of units) at a later date by transferring the banked allowances to that unit.

Title IV contains provisions to discourage the reduction of SO_2 emissions on Phase I affected units simply by shifting generation away from these units onto Phase II units during the Phase I period. In each year of Phase I, the total fuel input to Phase I units (in BTU) must be greater than or equal to the average heat input to the Phase I units during the baseline period 1985-1987. Otherwise, there are provisions for surrendering allowances back to the USEPA. This situation is referred to as underutilization (or reduced utilization).

Although Congress defined the number of Phase I allowances originally allotted to each affected unit (CAAA Section 404 Table A), the USEPA was given the authority to make adjustments to this allotment by allocating additional allowances (commonly referred to as "bonus" allowances). Although the bonus allowance allocation process is complex, there are basically three types of bonus allowances- Midwestern bonus allowances; qualifying Phase I technology bonus allowances; and qualifying energy conservation and renewable energy bonus allowances. During Phase I, bonus allowances are allocated to most affected utility sources in three Midwestern states- Illinois, Indiana, and Ohio- since it was anticipated that these three states would be the states most economically affected by the CAAA. During

Phase II, there are utilities in ten states, including Indiana, Ohio, and Kentucky, which will receive Midwest bonus allowances. The qualifying Phase I technology and conservation bonus allowances are available to affected units in all states.

Figure 6-1 shows the number of allowances allotted by the USEPA for affected units on the CINergy system.

The purpose of the compliance planning process is to develop an integrated resource/compliance plan which meets the future resource needs of CINergy while at the same time meeting the requirements of the CAAA in a reliable and economic manner.

B. **PHASE I COMPLIANCE PLANS**

CG&E filed a petition with the Public Utilities Commission of Ohio (PUCO) on June 30, 1992, (Case No. 92-1172-EL-ECP) seeking approval of its Phase I Environmental Compliance Plan (ECP). On September 3, 1992, the ECP case was consolidated with the 1991 and 1992 Electric Long-Term Forecast Report proceedings. Intervenor status was granted to the following parties in the case: the Office of Consumers' Counsel (OCC), Industrial Energy Consumers (IEC), the Sierra Club (Sierra Club) and three individual members, the City of Cincinnati (the City), Armco Steel Company and Air

Products and Chemicals (Armco/Air Products), the Citywide Coalition for Utility Reform (CCUR), and the United Mine Workers of America (UMWA). A stipulation was submitted by all parties in the ECP case except the City and CCUR. The stipulation was approved and the ECP was found reasonable by the PUCO in an Opinion and Order dated February 24, 1994.

The CG&E Phase I ECP includes the following:

1. Modify W. C. Beckjord Units 5 and 6 and Miami Fort Units 5, 6, and 7 to allow the burning of lower sulfur coals in the range of 1.2 to 2.0 lbs. of SO_2/MMBtu;
2. Designate East Bend Unit 2 as a substitute ("opt-in") unit, and increase its scrubber SO_2 removal;
3. Build up an operating reserve of SO_2 allowances of approximately 13 percent of the Phase I annual allotment;
4. Use allowance purchases and sales to optimize CG&E's electric production operations with respect to compliance with the requirements in Phase I;
5. Use emissions affected economic dispatch of its generating units to minimize costs in a manner consistent with underutilization regulations;
6. Designate W. H. Zimmer Unit 1 as a compensating unit if reduced utilization becomes a concern;

7. Implement DSM programs consistent with cost-effectiveness criteria established by the PUCO, and study additional DSM programs for possible implementation to create bonus allowances, reduce unit emissions, and offset possible unit underutilization;
8. Install, operate and maintain low NO_x burners at W. C. Beckjord Unit 5 and other units as necessary to comply with the NO_x requirements of the CAAA; and
9. Install, operate and maintain continuous emission rate monitors (CERMs) at all Phase I affected, substitute, and compensating units.

CG&E was also required to follow the development of the allowance market and develop in-house market expertise.

In accordance with the Indiana Environmental Compliance Plan Pre-Approval Act, PSI filed a petition with the Indiana Utility Regulatory Commission on January 2, 1992, (Cause No. 39346) requesting approval of its Phase I Environmental Compliance Plan, including its estimated cost and schedule. Public hearings were conducted in this cause during August, 1992, and November through December, 1992. An order was issued on October 27, 1993, approving PSI's Environmental Compliance Plan.

The approved PSI Phase I ECP includes the following:

1. The use of environmental dispatch (sometimes referred to as "emissions affected dispatch") in the dispatch of its generating units;
2. A continued commitment to DSM/conservation programs;
3. Tailored coal switching at most of its generating units; this includes the blending/switching of lower-sulfur coals at most of its units, tailoring the sulfur content to the operating parameters and the economics of each individual unit. This includes:
   a) the addition of flue gas conditioning equipment on Gibson Unit 3, Gallagher Units 1-4, Cayuga Units 1-2, and the burning of lower sulfur coals at these units, and the inclusion of the already installed flue gas conditioning equipment on Wabash River Unit 3;
   b) the addition of new precipitators on Gibson Units 1-2 and Wabash River Unit 6, combined with the burning of lower sulfur coals at these units, and the upgrade of the precipitators on Gallagher Units 1-4 and Wabash River Units 2-5;
4. Installation of the Gibson Unit 4 flue gas desulfurization system (scrubber). This scrubber is needed for economic compliance with the Gibson

County State Implementation Plan (SIP) as well as for CAAA compliance reasons;

5. Installation of CERMs on all of its Phase I and Phase II affected units;
6. Installation of low NO_x burners and over-fire air capability on all applicable Phase I affected units;
7. Build up an operating reserve of 30,000 SO_2 emission allowances;
8. The use of an emission allowance banking strategy as part of an overall economic strategy to delay the installation of higher cost options in Phase II.

Both PSI and CG&E plan to comply with Phase I requirements using their commission pre-approved Phase I plans, with a few minor changes. Subsequent to the approval of the Phase I plans, it was determined that certain projects could be delayed or eliminated while still meeting Phase I requirements (for example, flue gas conditioning at Miami Fort and Gallagher stations).

Prior to the merger of PSI and CG&E, each company had studied the issue of how best to manage the SO_2 emission allowances, and each had assigned the responsibility to a single department (the Fuels Department at CG&E and the Financial Department at PSI), with representatives of other departments becoming involved as needed. Both companies participated in the USEPA allowance auctions in 1993 and 1994, and have analyzed other potential offers from brokers wishing to purchase or sell allowances. Since the formation of CINergy, an interdepartmental working group has been created to perform these functions.

The SO_2 emission allowance market impacts the Phase I and Phase II strategies in two ways. First, the projected allowance market price is the basis against which the cost of compliance options are compared to determine whether the options are economic (i.e., it is a "market-based" compliance planning process). Second, CINergy plans to use an emission allowance banking strategy to delay implementation of higher cost options in Phase II. The economics of the banking strategy are dependent upon the market price of allowances.

C. PHASE II COMPLIANCE PLANNING PROCESS

1. Process Description

The Phase II compliance planning process involved three phases: 1) an initial technical feasibility screening of possible compliance options; 2) an economic screening of the feasible options that survived the technical feasibility screening; and 3) integration of the most economic options from the economic screening into the optimization process along with the supply- and demand-side resource options to develop an integrated resource/CAAA compliance plan. The reason for the analysis being performed in three steps is that it would be virtually impossible to evaluate all possible technologies in one step. There are no computer models on the market today which have the capability to perform the necessary analyses for such a large number of options. This section of the report describes the first two phases of the process. The third phase is described in Chapter 8.

2. Technical Feasibility Screening

In general, the purpose of a technical feasibility screening is to prepare a list of available technologies, analyze each from a technical perspective, and screen out those technologies which are not feasible for use at a particular unit or station. To the extent possible, work previously performed for the Phase I planning process was used in the technical feasibility screening.

During Phase I planning, CG&E had performed a technical screening of technologies for its units using a Kepner-Tregoe® decision analysis.

Technologies contained in this analysis included coal switching/blending options, natural gas firing/co-firing, switching to low sulfur oil, and post-combustion processes such as wet FGD, sorbent injection, and dry spray FGD. The results from this Phase I screening were reviewed to determine if the technical parameters (i.e., development status and performance experience) of the compliance options had changed since the initial analysis. Through this review process, candidate options were chosen for the CG&E units to be included in the economic screening. Figure 6-2 shows the technologies chosen for further analysis on the CG&E system.

Sargent & Lundy Engineers was employed to perform a similar analysis for the units on the PSI system (Clean Air Act Amendments - Phase II Compliance Study, SL-4926, December 1994). This analysis involved the following steps: 1) create a list of candidate control technologies; 2) develop a technical profile of each technology; and 3) perform a technology screening. The list of candidate technologies was developed from Sargent & Lundy's data base, a review of relevant literature, and input from PSI engineering staff. Figure 6-3 lists the candidate control technologies.

A technical profile of each of the technologies shown in Figure 6-3 was then developed which contained the following for each technology:

- Description
- Performance capabilities
  - SO_2 removal
  - NO_x removal
  - Air toxins removal
  - Reagent use
- Space requirements
- Development status
  - Current status
  - Predicted status in the mid-1990s
  - Predicted status in year 2000
- Performance history
- Unit impacts
- Outage time required to install
- Secondary environmental risks
- Load-following and turndown capabilities
- Fuel flexibility
- Waste disposal requirements
- By-product potential
- Relative cost
  - Capital
  - Operation and maintenance
- Commercial Availability

The technical profile was used as a source of information in the technology screening.

Technology screening was performed to determine the applicability of the candidate technologies to the units in the PSI generating system. The most promising technologies for controlling SO_2 and NO_x emissions were identified through the screening process. The screening was performed for two scenarios. The first was based upon predicted technology development status in the mid 1990s, while the second was based upon the predicted technology development status in the year 2000. For purposes of the screening evaluation, PSI's units were combined into the following groups:

Cayuga Units 1-2
Edwardsport Units 7-8
Gallagher Units 1-4
Gibson Units 1-3
Gibson Units 4-5
Noblesville Units 1-2
Wabash River Units 2-5
Wabash River Unit 6

Wabash River Unit 1 was not included in the study since this unit is in the process of being repowered with an integrated gasification combined cycle (IGCC) process, a Clean Coal technology project scheduled for a Third Quarter 1995 in-service date. Edwardsport Unit 6, an oil-fired unit, was not included due to its very low capacity factor.

To perform the technology screening, ratings were first assigned to the control technologies. Each technology was rated in the following categories, which are the screening criteria:

- SO_2 performance
- NO_x performance
- Power block space required
- Peripheral space required
- Development status in the mid-1990s
- Development status in 2000
- Number of suppliers actively marketing the technology
- Unit impacts
- Outage time required
- Secondary environmental risks
- Air toxins removal
- Greenhouse gas impacts
- Operating flexibility
- Fuel flexibility

The technologies were rated based upon the data presented in the technical profiles described earlier. For each of the screening criteria, the technologies received a 0 to 10 rating with 10 being the most favorable rating and 0 the least favorable.

In general, the ratings received by each technology were the same for all units within the PSI system because the ratings reflect the inherent characteristics of the technology. In some cases, however, the ratings are unit-specific. For example, AFBC repowering has not been demonstrated for supercritical units. For this reason, a unit-specific rating for the development status of this technology was used for Gibson station (which has supercritical units).

CO_2 removal processes were included in the SO_2 technology screening based on the possibility that some of these processes might also remove SO_2. However, none of the processes examined was determined to provide SO_2 removal. CO_2 removal is not required by the CAAA.

The next step in the screening process was the assignment of unit-specific weighting factors. The unit-specific weighting factors indicate the importance of each of the screening criteria at each generating unit. Overall ratings were calculated for each technology at each unit using the weighted average of the technology ratings and the unit-specific weighting factors.

The final step in the technical feasibility screening was an "order of magnitude" economic screening. Some of the technologies studied in the technical screening were very similar in nature (for example, there are numerous types of wet scrubbers). For those technologies, an order of magnitude estimate was developed and the overall rating and costs were compared for each to determine which technology should be used in the detailed economic screening.

Figure 6-4 shows the technologies chosen for further analysis on the PSI system.

It should also be noted that, for the CG&E units which are jointly owned by Columbus Southern Power and Dayton Power & Light, the impacts on the co-owners must be considered and a decision made jointly as to how to meet CAAA requirements. The results of this study reflect only the preliminary economic analysis performed by CINergy, from a CINergy perspective.

3. **Economic Screening**

a. **Methodology and Data Assumptions**

The second phase of the CAAA compliance planning process was a detailed economic screening of options to determine which should be evaluated along with the supply- and demand-side options in the integration phase.

CINergy employed The NorthBridge Group (NorthBridge), an economic and strategic consulting group, to assist in the economic screening process. NorthBridge had worked closely with PSI in its Phase I compliance planning process, and had developed compliance planning models of the PSI system. These models were developed in Lotus® 1-2-3, and contain cost and performance characteristics for each compliance option to be considered, for each unit or group of units. The models have been brought in-house, and will continue to be developed for future studies.

CINergy worked with NorthBridge to update these models to incorporate the CG&E system and update other data from the Phase I planning study.

Although Phase II does not begin until the year 2000, in order to ensure that possible economic options are considered, the study encompassed the years 1995 through 2005.

For those options being analyzed in the economic screening, Sargent & Lundy prepared capital cost estimates, operation and maintenance cost estimates, and operational impact assessments (heat rate, capacity, availability, etc.) for the PSI units. Similar data were reviewed and updated for the CG&E units from the study performed for CG&E's Phase I compliance plan.

The economic screening was performed using a marginal cost methodology whereby options which are dominated by others are eliminated, and those remaining are ranked into "supply curves" based on the cost per incremental ton of SO_2 removed. The procedure used was designed to capture the key interactions and tradeoffs inherent in compliance decisions:

- Compliance options were ranked not for individual units but for entire stations in order to reflect station-wide facilities and constraints. This was accomplished by comparing the costs and tons of SO_2 removed for the feasible combinations of unit-specific options at each station.

- Plans were developed by examining a series of annual supply curves reflecting annual tons removed and annualized costs (including a levelized carrying charge for capital), rather than through use of a single lifecycle supply curve. This allowed planners to take into account changes in the relative economics of various compliance options over time.
- Impacts of compliance options on performance variables such as heat rate, capacity rating and availability were explicitly valued in order to make the screening assessments as complete as possible. Where an option could be implemented in more than one way -- for example, either replace a pulverizer or accept a performance penalty -- both approaches were considered.

Much of the analysis was carried out with the assistance of two specialized computer models: the first model computes the tons removed and costs for each compliance option at individual units, and the second model determines feasible station-wide combinations and develops the rankings. These models do not directly value the effects of changes in dispatch. Instead, dispatch effects are incorporated into the analysis through a process of iteration: a preliminary option ranking is developed assuming an initial set of capacity factors, a dispatch model (see Chapter 8 for a more detailed description of the PROMOD III® production cost and reliability evaluation program used for the dispatch modelling) is then used to estimate the capacity factors if the options suggested by the preliminary ranking were in place. These two steps are iterated until the results are judged stable.

After the marginal cost supply curve was created, the marginal cost of each on-system compliance option was compared to the projected market price of SO_2 emission allowances. Ignoring other possible factors, options with a marginal cost less than the market price of allowances are deemed to be economic. The marginal cost supply curves for the years 1995, 2000, and 2005 are included in the General Appendix. CINergy considers these to be competitive information and has filed them under seal.

An important aspect of this market-based compliance planning process is the projected price of SO_2 emission allowances. CINergy uses an emission allowance price forecast prepared by ICF Resources, Inc. (ICF) in its planning (this forecast is produced in a proprietary report entitled "The Potential Market Value of SO_2 Allowances", 1994 Edition). The 1994 edition of the forecast was used in this IRP. The projected allowance prices are considered to be proprietary to ICF and are filed under seal in the General Appendix.

For the base scenario, the major assumptions (such as load forecast and fuel forecast) were coordinated with those used in the supply- and demand-side resource option screening. The discussion of data assumptions in Chapter 5 applies to the CAAA compliance screening as well.

b. **Sensitivity Analyses**

Finally, sensitivity analysis was also an important part of the overall process. Scenarios reflecting alternative assumptions for major variables were tested in order to assess how robust the base scenario supply curves really were, which assumptions were most critical, and which compliance options were sufficiently promising in scenarios other than the base case to merit further examination. For the CINergy sensitivity analyses, changes in capacity factors, relative fuel prices, coal contract constraints, equipment modification costs, replacement power costs and market allowance prices were considered.

In the capacity factor sensitivity, the base scenario capacity factors were adjusted by 10% above and below those used in the base. In the relative fuel price sensitivity, the fuel prices were adjusted 15% above and 10% below those used in the base. Also, since PSI and CG&E had prepared the fuel forecasts independently prior to the reorganization, slightly different prices were assumed for some fuels. Therefore, sensitivities were run in which coal price forecasts for CG&E units were used at PSI stations, and coal price forecasts for PSI units were used at CG&E stations. This was done to determine whether the economic compliance options from the base case (Central Appalachian 1.6 lbs. of SO_2/MMBtu coal at most CG&E units and PRB coal at most PSI units) were sufficiently robust to withstand differentials in delivered coal prices between the PSI and CG&E units. The coal contract constraint sensitivity assumed no existing long-term coal contracts. For those compliance options with which CINergy has little experience (e.g., switching to Powder River Basin Coal), high and low capital cost estimates were prepared for the retrofit. For other options, the capital cost used for the high and low capital sensitivity analyses were 120% and 80%, respectively, of the base scenario capital costs.

c. **Results**

Base Scenario

Most of the potential opportunities for economically reducing SO_2 emissions on the CINergy system between 1995 and 2005 include the blending of, or switching to, Powder River Basin (PRB) coal at Gibson and Cayuga stations after the year 2000. PRB coal is a very low sulfur (typically <0.8 lbs. of SO_2/MMBtu) coal which is abundant in the Powder River Basin of Wyoming and Montana. Due to other characteristics of the coal (e.g., low heat content, unique ash qualities, and dusting characteristics) a significant amount of testing is necessary to determine how successfully units designed to burn higher sulfur, higher heat content midwestern coals can burn the PRB coal. Smaller opportunities exist at Gallagher and Wabash River stations after 2000, and at Gibson in the earlier years. Beckjord, Miami Fort, Conesville and Stuart do not appear to have any opportunities to economically reduce SO_2 emissions below Phase I levels. All of the economic options studied involve the blending or switching of PRB or low-sulfur Illinois Basin coals. Further, the economic blending options included a method of blending a variable amount of PRB coal with the base coal in the boiler by partitioning the coal bunker. PRB coal would be loaded into part of the bunker and the base coal loaded into the other. The blend of PRB/base coal can be adjusted by adjusting the speed of the coal feeders. The term used for this type of in-boiler blending was "platooning." The economic CAAA compliance options from the base scenario are shown in Figure 6-5.

Sensitivity Scenarios

Capacity Factor Sensitivity

In the low capacity factor sensitivity, the PRB coal options from the base scenario supply curves would be delayed until after 2000 at Cayuga and Gibson stations and eliminated through 2005 at Gallagher station. Gibson Units 1-2 would also go only to a 60/40 blend of PRB and base coals, not to 100% PRB coal as in the base scenario. Economic options at other units would be unchanged from the base scenario.

In the high capacity factor sensitivity, Gibson Unit 3 and Cayuga Units 1-2 would burn slightly higher proportions of PRB coal, somewhat earlier. Miami Fort Unit 8 would install a dry scrubber. Economic options at other units would be unchanged from the base scenario.

Relative Fuel Price Sensitivity

Raising the price of the base coals at each station by 15% would cause most units to adopt some compliance option different from that shown in the base scenario. The PRB options at Cayuga and Gibson would be accelerated. Wabash River Units 2-5 would switch to Illinois Basin 1.2 lb. coal by 2005. Gallagher would switch to Central Appalachian (CA) 1.6 lb. coal in 1995. Conesville Unit 4 would switch to CA 1.2 lb. coal by 2005. Miami Fort Unit 5 would switch to CA 1.6 lb. coal and Miami Fort Unit 8 would install a dry scrubber. Miami Fort Units 6-7, Stuart Units 1-4 and Beckjord Units 5-6 would switch to Central Appalachian 1.2 lb. coal in 1995, but would switch back to their base 1.6 lb. coal by 2000 or 2005. Only Beckjord Units 1-4 would burn their base coals throughout the study period.

Lowering the price of the base coals by 10% would result in all PSI units burning the base coals through at least 2000. By 2005, Gibson Units 1-3 would switch to blends of PRB and base coals in PRB proportions ranging from 40% to 60%. Economic options at other units would remain unchanged from the base scenario.

Raising the price of PRB coal by 15% relative to other coals would make all PRB coal options uneconomic through 2005. Gallagher Units 1-4 and Gibson Units 1-3 would burn their base coals indefinitely. At Cayuga Units 1-2, a switch to Illinois Basin 1.2 lb. coal by 2005 would become economic. Economic options at other units would remain as in the base scenario.

Lowering the price of PRB coal by 10% would retain or accelerate the PRB options found in the base scenario at Cayuga, Gallagher and Gibson stations. Wabash River Unit 6 would adopt a 60% PRB coal blend by 2005 instead of switching to Illinois Basin 1.2 lb. coal. Economic options at other units would remain as in the base scenario.

Lowering the price of CA 1.2 lb. coal by 10% would cause Gallagher Units 1-4 to adopt the coal by 2000 and Conesville Unit 4 to switch by 2005. Stuart Units 1-4 would switch in 1995 but return to the base coal by 2000. Economic options at other units would remain as in the base scenario.

Raising the price of Illinois Basin 1.2 lb. coal by 15% would cause Wabash River Unit 6 to continue burning its base 2.5 lb. coal through 2005. Economic options at other units would remain as in the base scenario.

Lowering the price of Illinois Basin 1.2 lb. coal by 10% would result in all unscrubbed units at Cayuga, Gallagher and Gibson switching to 1.2 lb. coal or blends of 1.2 lb. coals by 2005. Wabash River Unit 6 would also burn 1.2 lb. coal (as in the base scenario), but Units 2-5 would continue to burn the 2.5 lb. base coal. Economic options at other units would remain as in the base scenario.

Using a CG&E unit coal price forecast for CA 1.6 lb. coal at PSI units would result in 1.6 lb. coal becoming the economic option at all unscrubbed units at Cayuga, Gallagher and Gibson by 2005. Using a PSI unit coal price forecast for PRB coal would cause Miami Fort Unit 8 to adopt that coal by 2005. Using a coal price forecast for either PSI units or other CG&E units for CA 1.2 lb. coal would make that coal economic at Stuart station in 1995, though not in

2000 or 2005. Economic options at other units would remain as in the base scenario.

Coal Contract Constraint Sensitivity

Sensitivity analysis of base scenario coal contract constraint assumptions was performed for Cayuga, Conesville, Gibson and Wabash River stations. This was done by assuming that the contracts were eliminated in 1995. There was no analysis performed to determine any costs associated with eliminating these contracts, nor was there any detailed discussion as to the feasibility of eliminating the contracts. Rather, this sensitivity analysis was merely an analysis performed to determine if the contracts were a binding constraint on the selection of economic options.

At Cayuga station, the sensitivity scenario showed the same economic compliance options as in the base scenario, except earlier. A 60% PRB blend would appear economic for both Units 1-2 as of 1995 and would grow more economic each year.

Gibson station is in a different situation than Cayuga, primarily due to geography. Since Gibson station is located near the mine mouth, and there are no other large generating plants near the mine, it was assumed that there would be a cost associated with transporting the coal (from the eliminated contract) to the Ohio River market. Once this cost was taken into account, the economic options were the same as in the base scenario.

At Wabash River, the sensitivity scenario results were the same as the base scenario.

At Conesville the absence of a contract constraint results in a switch to CA 1.2 lb. coal being economic in 1995 but not in 2000. These results stem from the fact that the projected contract price for the base coal is relatively high in 1995 and somewhat lower in 2000.

Capital Modification Cost Sensitivity

In the low capital sensitivity scenario, changes from the base scenario in degree but not direction of economic options appeared at a number of stations. The PRB coal option at Gibson Units 1-3 would be slightly accelerated. Cayuga Units 1-2 would switch to 100% PRB coal by 2005. Gallagher Units 1-4 would switch to 100% PRB coal by 2000, and could implement a 70% PRB coal blend as of 1995. Wabash River Units 2-5 would join Unit 6 in the switch to Illinois Basin 1.2 lb. coal by 2005. Miami Fort Unit 8 would install a dry scrubber by 2005. Economic options at other stations would remain as in the base scenario.

In the high capital cost sensitivity scenario, changes from the base scenario in direction as well as degree occurred. Cayuga Units 1-2 would switch to Illinois Basin 1.2 lb. coal by 2005 (or might continue to burn the 2.5 lb. base coal if the 1.2 lb. coal price projections were considered inconsistent with such a significant demand increase). By 2005 Gibson Units 1-3 would switch to blends of PRB and base coal in PRB proportions of 50%, 50%, and 60%, respectively. All other units would burn their base coals through 2005.

Replacement Power Cost Sensitivity

Replacement power costs were used to analyze the expected impacts of some compliance options on the generating units, such as changes to unit availability or capacity. For the base scenario, an own-load (native system) method was used to project replacement power costs. Avoided production costs were used for the energy component, and incremental peaking capacity cost for the capacity component. For the sensitivity analysis, a market approach was used, in which a range of projected market prices were forecast. The high and low range of this forecast was used for the high and low replacement energy cost sensitivities, respectively. For the replacement capacity costs, zero was used for the low sensitivity, and the base scenario cost was used for the high sensitivity.

In the high replacement power cost sensitivity, Gibson Units 1-3 would adopt the same options as in the base scenario through 2004, but in 2005 Units 1-2 would remain at a 60/40 blend of PRB and base coals rather than progressing to the 100% PRB coal option. Economic options at all other units would be unchanged from the base scenario.

In the low replacement power cost sensitivity, Gibson Units 1-2 again would stay at the 60/40 blend of PRB and base coals in 2005. This result matches that in the high sensitivity because in both cases the result is driven entirely by the replacement energy costs, which in 2005 are higher in both the high and low sensitivity scenarios than in the base scenario; replacement capacity costs have little impact in this particular situation because no capacity derates are involved. The PRB blend option at Gibson Unit 3 would be accelerated to 1995. The only other change from the base scenario supply curves for this sensitivity is that the dry scrubber option at Miami

Fort Unit 8 would become economic by 2005; this result occurs because under the zero replacement capacity cost assumption in the low scenario, the derate associated with the scrubber would be seen as less costly than in the base scenario. Economic options at all other units would be unchanged from the base scenario.

SO_2 Emission Allowance Market Price Sensitivity

CINergy used the high and low SO_2 emission allowance price projections from the 1994 ICF Resources emission allowance price forecast for the high and low price sensitivity scenarios.

In the low allowance price sensitivity, the most economic compliance strategy, in general, would be to buy and use inexpensive allowances. Only two stations had economic on-system compliance opportunities, but not until after 2000: the 60% PRB coal blend option at Cayuga Units 1-2 and a PRB blend option at Gibson Units 1-3 in PRB proportions of 40%, 40%, and 60%, respectively. All other units would burn their base coals through 2005.

The economic options in the high SO_2 allowance price sensitivity almost exactly duplicated those from the base scenario, with three additions. By 2005 it would be economic to install a dry scrubber at Miami Fort Unit 8, to switch Miami Fort Unit 5 to CA 1.6 lb. coal and to switch Conesville Unit 4 to CA 1.2 lb. coal. The first PRB coal blending options at Cayuga and Gibson stations would also be advanced to 1995.

d. **Conclusions**

Although the sensitivity analysis did not identify any specific compliance plan which was robust in all scenarios, in most of the sensitivity cases there were some blends of low-sulfur coal which were economic. In most cases, Gibson and Cayuga stations have economic options containing blends of PRB coal from 50% to a full 100% switch. Gallagher and Wabash River stations have economic options containing lower blend percentages of PRB coal or switches to midwestern low-sulfur coal.

Based upon these screening results, the economic options shown in the base scenario are essentially the same as those considered as options in the IRP. Minor changes in the percent blends and timing for the most economic options were developed by later refinement of the screening analysis. However, these alterations do not significantly affect the results.

The options considered for inclusion into the IRP were:

- 50% PRB coal at Gibson Unit 3
- 100% PRB coal at Gibson Units 1-3
- 60% PRB coal at Cayuga Units 1-2
- 30% PRB coal at Gallagher Units 1-4
- 100% midwestern low-sulfur coal at Wabash River Unit 6

It should be noted that the PRB coal blend percentages shown in the screening analysis results are preliminary, and may change significantly pending potential future test burns of the PRB coal and as updated information becomes available. The costs associated with each PRB coal option are based upon extrapolation of results from somewhat limited testing that was conducted on Gibson Unit 3 as well as other unit-specific factors. Before a commitment is made to switch to PRB (or blend of PRB) coal at any unit, further testing would need to be conducted.

FIGURE 6-1

SO2 ALLOWANCES ALLOCATED TO CINERGY UNITS

Operating Company	Plant Name	Boiler No.	Percent Ownership	ALLOWANCES ALLOCATED 1995	1996	1997	1998	1999	2000-2009	2010 & after
CG & E	Conesville	4	40.0	21,342	21,342	21,342	21,342	21,342	8,326	8,380
CG & E	Miami Fort	5-1	100.0	417	417	417	417	417	142	143
CG & E	Miami Fort	5-2	100.0	417	417	417	'417	417	142	143
CG & E	Miami Fort	6	100.0	12,475	12,475	12,475	12,475	12,475	4,866	4,900
CG & E	Miami Fort	7	64.0	27,048	27,048	27,048	27,048	27,048	10,552	10,620
CG & E	Miami Fort	8	64.0	0	0	0	0	0	11,529	11,605
CG & E	W. C. Beckjord	1	100.0	0	0	0	0	0	1,830	470
CG & E	W. C. Beckjord	2	100.0	0	0	0	0	0	1,853	709
CG & E	W. C. Beckjord	3	100.0	0	0	0	0	0	2,521	1,073
CG & E	W. C. Beckjord	4	100.0	0	0	0	0	0	3,245	2,133
CG & E	W. C. Beckjord	5	100.0	9,811	9,811	9,811	9,811	9,811	3,825	3,851
CG & E	W. C. Beckjord	6	37.5	9,236	9,236	9,236	9,236	9,236	3,603	3,626
CG & E	W. H. Zimmer	1	46.5	0	0	0	0	0	7,448	7,497
CG & E	East Bend	2	69.0	12,277	12,277	12,277	12,277	12,277	12,783	12,868
CG & E	Woodsdale	1	100.0	0	0	0	0	0	292	294
CG & E	Woodsdale	2	100.0	0	0	0	0	0	292	294
CG & E	Woodsdale	3	100.0	0	0	0	0	0	292	294
CG & E	Woodsdale	4	100.0	0	0	0	0	0	292	294
CG & E	Woodsdale	5	100.0	0	0	0	0	0	292	294
CG & E	Woodsdale	6	100.0	0	0	0	0	0	292 *	294 *
CG & E	Killen	2	33.0	0	0	0	0	0	4,757	4,789
CG & E	Stuart	1	39.0	16,474	16,474	16,474	16,474	16,474	7,785	7,837
CG & E	Stuart	2	39.0	15,622	15,622	15,622	15,622	15,622	7,384	7,433
CG & E	Stuart	3	39.0	15,220	15,220	15,220	15,220	15,220	7,194	7,242
CG & E	Stuart	4	39.0	16,619	16,619	16,619	16,619	16,619	7,853	7,905
Total - CG & E owned units				156,958	156,958	156,958	156,958	156,958	109,390	104,988

Note: number of allowances shown are CINergy's portion for jointly owned units

* Not yet allocated

FIGURE 6-1 (CONT'D)

SO2 ALLOWANCES ALLOCATED TO CINERGY UNITS

Operating Company	Plant Name	Boiler No.	Percent Ownership	ALLOWANCES ALLOCATED 1995	1996	1997	1998	1999	2000-2009	2010 & after
PSI Energy	Cayuga	1	100.0	46,499	46,458	36,581	36,581	36,581	13,867	13,981
PSI Energy	Cayuga	2	100.0	40,255	41,015	37,415	37,415	37,415	14,179	14,474
PSI Energy	Gibson	1	100.0	44,288	44,288	44,288	44,288	44,288	16,785	16,899
PSI Energy	Gibson	2	100.0	44,956	44,956	44,956	44,956	44,956	17,039	17,153
PSI Energy	Gibson	3	100.0	45,033	45,033	45,033	45,033	45,033	17,069	17,183
PSI Energy	Gibson	4	100.0	62,538	54,757	57,254	57,408	57,289	16,755	16,868
PSI Energy	Gibson	5	50.1	0	0	0	0	0	8,762	8,822
PSI Energy	R. Gallagher	1	100.0	13,212	13,187	7,115	7,115	7,115	2,803	2,821
PSI Energy	R. Gallagher	2	100.0	12,166	12,149	7,980	7,980	7,980	3,027	3,047
PSI Energy	R. Gallagher	3	100.0	12,515	12,494	7,159	7,159	7,159	2,713	2,732
PSI Energy	R. Gallagher	4	100.0	12,089	12,074	8,386	8,386	8,386	2,825	2,846
PSI Energy	Wabash River	1	100.0	5,438	5,434	5,320	5,217	5,217	1,659	1,673
PSI Energy	Wabash River	2	100.0	5,593	5,583	3,135	3,135	3,135	1,341	1,350
PSI Energy	Wabash River	3	100.0	4,111	4,111	4,111	4,111	4,111	1,557	1,569
PSI Energy	Wabash River	4	100.0	0	0	0	0	0	1,475	1,485
PSI Energy	Wabash River	5	100.0	4,755	4,752	4,023	4,023	4,023	1,524	1,536
PSI Energy	Wabash River	6	100.0	16,962	16,948	13,462	13,462	13,462	5,102	5,136
PSI Energy	Noblesville	1	100.0	0	0	0	0	0	64	63
PSI Energy	Noblesville	2	100.0	0	0	0	0	0	52	51
PSI Energy	Noblesville	3	100.0	0	0	0	0	0	39	39
PSI Energy	Edwardsport	6-1	100.0	0	0	0	0	0	0	0
PSI Energy	Edwardsport	7-1	100.0	0	0	0	0	0	335	337
PSI Energy	Edwardsport	7-2	100.0	0	0	0	0	0	341	343
PSI Energy	Edwardsport	8-1	100.0	0	0	0	0	0	361	364
Total PSI owned units				370,410	363,239	326,218	326,269	326,150	129,674	130,772

Note: number of allowances shown are CINergy's portion for jointly owned units

* Not yet allocated

FIGURE 6-2

COMPLIANCE OPTIONS CONSIDERED FOR CG&E UNITS IN DETAILED PHASE II ANALYSIS

	BeckJ 1-4	BeckJ 5	BeckJ 6	M Fort 5	M Fort 6-7	M Fort 8	Cones 4	Stuart 1-4	Killen 2
PRB Coal (.7#/MMBTU)	X	X	X	X	X	X		X	X
Compliance Coal (<1.2)	X	(1)	(1)	X	(2)	(3)	X	(1)	(3)
Low Sulfur Coal (1.2-2.5)	(4)			X	(2)		X	(1)	
Med. Sulfur Coal (>2.5)				(1)	(1)		X	(6)	
Nat Gas Firing	X	X	X	X	X	X		X	X
Nat Gas Co-Firing	X	X	X	X	X	X	X	X	X
Wet FGD	X	X	X	X	X	X	X	X	X
Sorbent Injection	X	X	(5)	X	(6 only)	(5)	(5)	(5)	(5)
Dry FGD	X	X	X	X	X	X		X	
CCGT Repowering				X					
IGCC Repowering									
AFBC Repowering	(4 only)			X					
PFBC Repowering									

(1) No capital required; unit can burn this fuel now

(2) Modifications are now being made to burn this coal

(3) Base coal for this unit (NSPS requirements)

(4) Can now burn down to 1.8# coal. Will go to 1.6# in phase I. Phase II study will look at cost to go below 1.6#

(5) Not considered on units greater than 300 MW

(6) SIP limit of 3.16#. Only fuels below 3.16# considered

FIGURE 6-3

SO_2, NO_x, and CO_2 Control Technologies

Post Combustion SO_2 Control

West Limestone
FGD/Inhibited Oxidation
Wet Limestone FGD/Forced Oxidation
Wet Lime FGD
Mag Lime FGD
Wet Limestone/Lime FGD with Additives
Lime Dual Alkali FGD
Limestone Dual Alkali
Dowa Process
Wellman Lord FGD
Magnesium Oxide FGD
Chiyoda FGD
Saarberg-Holter FGD
Citrate FGD
Lurgi CFB
Sodium Wet Scrubbing
Flyash - Alkali Scrubbing
Cat-Ox Process
Phosphate Process
Sulf-X Process
Pircon-Peck Process
Walther Ammonia Process
SOXAL Process
NSP Bubbler FGD
ISPRA Process
HYPAS Process
ADVACATE Process
CANSOLV Process
Dow Regenerable FGD Process
Ammonia FGD with Forced Oxidation
Spray Dryer FGD
Furnace Sorbent Injection
Economizer Sorbent Injection
Tampella LIFAC
Duct Sorbent Injection
Duct Spray Dryer
Gas Suspension Spray Dryer
Kellogg Weir FGD
Synergetic Reactor FGD

Post Combustion SO_2 Control (Cont'd)

Wet Scrubbing with NO_x Control
Sodium Acetate Dual Alkali
Ammonia Dual Alkali
Consol Process
Ishikawajima-Harima FGD
Soda-Mag FGD
Potassium Tartrate FGD
Ecotech FGD
Enelco FGD
Resin Adsorption
Ammonia Regenerative Process
$CaCl_2$ Process
Aqueous Carbonate Process

Simultaneous SO_2/NO_x Control

Slagging Combustors
NOXSO System
Copper Oxide Process
Activated Coke/Char Process
Sanitech Nelson Process
Electron Beam Process
ENEL Pulse Energization
Concord UV Process
Iron Chelate Scrubbing
PURI-FIRE
Catalytic SO_2/NO_x Process
Parsons Flue Gas Cleanup
Lehigh University Low Temp SCR
Solid State Electrochemical
High Temperature Spray Dryer
ZnO Spray Dryer
Wet Limestone/Yellow Phosphorus
Pence Process

Figure 6-3 (Cont'd)

Repowering

Atmospheric Fluidized Bed
Pressurized Fluidized Bed
Coal Gasification Combined Cycle
Combined Cycle Gas Turbine
Fuel Cells

Fuel Cleaning/Switching

Coal Switching
Coal Blending
Conventional Physical Coal Cleaning
Heavy-Media Physical Coal Cleaning
Agglomeration Coal Cleaning
Froth Flotation Coal Cleaning
Chemical Coal Cleaning
Biological Coal Cleaning
Natural Gas Firing
Natural Gas Cofiring
Petroleum Coke Firing
Tire Derived Fuel Firing
Biomass Firing
Refuse Firing

NO_x Control

Selective Catalytic Reduction
Low NO_x Burners
Natural Gas Reburning
Coal Reburning
Thermal $DeNO_x$
Urea Injection
Overfire Air
SCR/SNCR

CO_2 Control

Primary/Secondary Amine Chemical Solvent
Tertiary Amine Chemical Solvent
Hot Potassium Carbonate Processes
Physical Solvent Processes
Membrane Processes
Extractive Processes
Solid Bed Processes
Biological Processes

FIGURE 6-4

COMPLIANCE OPTIONS CONSIDERED FOR PSI UNITS IN DETAILED PHASE II ANALYSIS

	Cay 1-2	Edw 6	Edw 7-8	Gal 1-4	Gib 1-3	Gib 4-5	Nob 1-2	Wab 2-5	Wab 6
PRB Coal (.7#/MMBTU)	X			X	X			X	X
Compliance Coal (<1.2)	X			X	X			X	X
Low Sulfur Coal (1.2-2.5)	X		(1)	X	X		(1)	X	X
Med. Sulfur Coal (>2.5)	X		X	X	X		X	X	X
Nat Gas Firing	X	X	X	X	X		X	X	X
Nat Gas Co-Firing	X	X	X	X	X		X	X	X
Wet FGD	X			X	X			X	X
Increase FGD Perf w/DBA						X			
CCGT Repowering		X	X	X			X	X	
IGCC Repowering	X	X	X	X			X	X	X
AFBC Repowering	X			X				X	X
PFBC Repowering	X								
Low No_x Retrofit			X			(5 only)	X	(4 only)	

(1) Will look at coals with sulfur content down to the precipitator break point

FIGURE 6-5

Economic CAAA Compliance Options - Base Scenario										
	Option in Indicated Year(s)									
Unit(s)	1995-96	1997	1998	1999	2000	2001	2002	2003	2004	2005
Gibson 3	no change	50% PRB						100% PRB		
Cayuga 2	no change				50% PRB		60% PRB			
Gibson 1-2	no change							100% PRB		
Cayuga 1	no change								60% PRB	
Wabash River 6	no change								100% IL 1.2#	
Gallagher 1-4	no change									30% PRB
All other units	no change									

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-025

REQUEST:

25. Refer to pages 546 and 547 of the report. Provide the specific analysis, studies, etc. that have been relied upon to form the basis for the expectation that Fuel Cells will be commercially available in 25 MW increments during the 2009-2019 time period.

RESPONSE:

This information is contained in KYStaff-01-025-A and B, and is confidential. ULH&P will produce this information if a confidentiality agreement is reached.

WITNESS RESPONSIBLE:

Diane Jenner

REQUEST:

26. Refer to page 5-59 of the report. Provide definitions and/or descriptions of the different types of proposals identified therein.

RESPONSE:

Summer 5X16 Power Purchase Proposal – Cinergy would be required to purchase a fixed block of energy, 5 days per week, 16 hours per day for specified summer months. The purchases would occur Monday through Friday, excluding NERC Holidays. Cinergy would pay the bidder a fixed energy price for each MWh.

Summer Daily Call/Unit Power Purchase Proposal – Cinergy would be able to pre-schedule energy on a daily basis from a designated unit or other energy source during specified summer months. The power would typically be available Monday through Friday, with a minimum run time of 4 to 16 hours. A fixed capacity payment would be paid to the bidder - energy charges would vary according to run time and the method used to calculate the energy charge. A daily call option normally has a fixed energy charge, while energy from a unit power purchase is usually calculated using a gas price index plus a variable operations and maintenance component (O&M). Unit power purchases may be based on unit availability, or backed up by the promise to pay liquidated damages (LD) in case of failure to deliver.

Calendar Daily Call/Unit Power Purchase Proposal – Cinergy would be able to pre-schedule energy on a daily basis from a designated unit or other energy source during each month of the year. The power would typically be available Monday through Friday, with a minimum run time of 4 to 16 hours. A fixed capacity payment would be paid to the bidder - energy charges would vary according to run time and the method used to calculate the energy charge. A daily call option normally has a fixed energy charge, while energy from a unit power purchase is usually calculated using a gas price index plus a variable operations and maintenance component (O&M). Unit power purchases may be based on unit availability, or backed up by the promise to pay liquidated damages (LD) in case of failure to deliver.

Renewable Proposal – Two types of renewable energy proposals were presented to Cinergy, run-of river hydro and energy generated from landfill gas. The run-of-river hydro proposals called for long-term contracts (> 20 years), while the landfill gas proposals were for approximately 5 years. For both types of proposals, energy price was specified for the length of the contract, and there was no capacity payment. Energy would be purchased on a take-and-pay basis (only energy generated would be paid for).

Interruptible DSM Proposal – The only DSM proposal received called for the bidder to form a load cooperative that would reduce demand during the peak load hours of the year (up to 50 hours). Those customers enrolled in the load cooperative would be notified of a load reduction request whenever Cinergy specified. In exchange for this service, the bidder would receive a fixed capacity payment from Cinergy, some of which would be passed along to those customers enrolled in the load cooperative.

WITNESS RESPONSIBLE:

Diane Jenner

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-027

REQUEST:

27. Refer to page 5-60 of the report. Provide the current status of contract negotiations with power suppliers. Also, indicate whether there are any plans for issuing a new Request for Proposals in early 2000 for power supplies in the 2000-2003 period.

RESPONSE:

Cinergy is still negotiating with the bidder that submitted run-of-river hydro proposals. A Power Purchase Agreement has been drafted by Cinergy and forwarded to the bidder. Cinergy is still waiting for the bidder to provide comments on the draft PPA. No contract negotiations are taking place with any other power suppliers who submitted bids during the RFP process.

Currently, Cinergy has no plans to issue another RFP for power supplies in the 2000-2003 time period.

WITNESS RESPONSIBLE:

Diane Jenner

REQUEST:

28. Refer to page 6-31 of the report, which references Figure GA-6-3 in the General Appendix. Provide the compliance screening curve data and final CAAA compliance option results for the 1999 IRP.

RESPONSE:

This information is contained in KYStaff-01-028-A and B and is confidential. ULH&P will produce this information if a confidentiality agreement is reached.

WITNESS RESPONSIBLE:

Diane Jenner

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-029

REQUEST:

29. Refer to pages 6-31 to 6-37 or the report which references Figure GA-6-4 in the General Appendix. Provide the NOx compliance plan referenced therein.

RESPONSE:

This information is contained in KYStaff-01-029-A, and is confidential. ULH&P will produce this information if a confidentiality agreement is reached.

WITNESS RESPONSIBLE:

Diane Jenner

KY PSC
Staff Data Request Set No. 1
Case No. 99-449
Date Received: Jan. 10, 2000
Response Due Date: Feb. 8, 2000

KyStaff-01-030

REQUEST:

30. Reference pages 8-12, and 8-33 through 8-38 concerning the Least Cost Plan and the basis for its selection. After all sensitivity analysis and environmental considerations are taken into consideration, provide the Present Value Total Cost ("PVTC") of the other plans against which it was measured in arriving at its PVTC of $29,869,692,000.

RESPONSE:

As stated on page 8-9 of the IRP, the integration analysis was performed over the ten year modeling period 1999-2008 with infinite end effects. Then, after the plan was selected, the first ten years were fixed and PROVIEW™ was re-run for the 2009-2019 period. Therefore, Cinergy only has the PVTC of the selected plan for the 1999-2019 time period but does not have the PVTC of the other plans for the 1999-2019 time period. However, the PVTC of the significantly different plans for the 1999-2008 time period is shown on pages 8-12 and 8-16 of the IRP.

WITNESS RESPONSIBLE:

Diane Jenner