Report on the Electric Utility Baseline Strategy for 2005-2030 Electric Infrastructure

Prepared for

Rochester Public Utilities
Rochester, Minnesota

Project 34945

June 2005

June 15, 2005

Mr. Wally Schlink
Rochester Public Utilities
4000 E. River Rd. NE
Rochester, MN 55906-2813

RE: Baseline Electric Infrastructure Study
Rochester Public Utilities
Project 34945

Dear Mr. Schlink:

Burns & McDonnell was authorized to assist the Rochester Public Utilities (RPU) in its assessment of future requirements for its electrical infrastructure. The RPU desired a baseline assessment of its financial requirements over a study period to 2030. The assessment included the review of traditional resources associated with meeting RPU's projected demand and energy needs to develop a traditional resource expansion plan. The impacts which demand side and renewable options might have on the traditional plan were also included. The costs for several futures were modeled in a detailed financial model developed by RPU. The model allowed a detailed assessment of a variety of measures such as rates, average bills and debt requirements to be developed. These parameters were used to identify the more attractive future for RPU to pursue. This report provides the results of the assessment.

The assessment for RPU identified issues which need to be confronted within the time frame between now and 2015 and from 2016 to 2030. These periods were selected to coincide with the various options associated with the Silver Lake Plant capacity under the contract with the Minnesota Municipal Power Agency.

Conclusions and Recommendations

The results of this study indicate that the Silver Lake Plant Unit 4 should be kept in operation throughout the study period. The determination of the status of Units 1-3 depends on the cost of replacement capacity at the end of the MMPA contract.

With the above assumption on Silver Lake Unit 4, the RPU is not in need of significant resource expansion to meet its projected demand and energy requirements until approximately 2016. Prior to that date, RPU should rely on the market for seasonal purchases to make up any deficits. Post 2016, a mixture of market, gas and coal-fired resources provide the lowest cost evaluated plan.

The above conclusion on use of market capacity is tempered by the fact that RPU will have to correct the existing transmission limitations into the RPU service territory or add internal generation in order to regain previous levels of power supply reliability for its customers. The current limitations reduce the firm import of its supply from the Southern Minnesota Municipal Power Agency when the load in the area around RPU exceeds certain levels. These levels are being exceeded during an increasing number of hours per year. Therefore, reliance on the market for firm imports during the summer months is not considered prudent until the transmission limitation is removed.

Challenges which RPU will confront over the next ten years include environmental controls and upgrades to the Silver Lake Plant Unit 4 and potentially Units 1-3 to continue operation in compliance with expected environmental regulations. The investments in these units will help prolong the time when RPU will need replacement coal capacity.

RPU should pursue the aggressive demand side management reductions identified. The achievement of the estimated reductions will postpone the need for additional base load capacity.

Synopsis of Process

Burns & McDonnell developed the traditional resource plan by first reviewing the load projections prepared by RPU. The forecast allowed an assessment of the capacity and energy deficiencies associated with various futures. The primary variance in the futures was due to the assumptions used for the capacity at the Silver Lake Power Plant.

Resource expansion plans were developed which provided an assessment of the benefits of gas and coal-fired resource options. Participation in projects being developed in the region were considered along with resources that RPU could develop on its own. These options were reviewed on a net present value basis to determine the lower cost options.

Risk analysis was performed on the lower cost options. Assumptions were varied to determine their impact on the evaluation. Risk profiles of the probable net present values were determined. The report provides a complete description of the process and the results identified.

A variety of demand side options were considered to reduce the demand and energy needs of RPU. Benefit cost analysis was performed on the options to determine the attractiveness of the options from the utility rate payers, participant and society perspectives. This review was aided by input from a Citizen's Advisory group.

The estimated reductions in demand and energy requirements were removed from the forecast. The revised forecast was then used to assess the RPU renewable energy needs to meet the state renewable portfolio standard.

The various futures with and without the DSM and renewable impacts were modeled in the detailed financial forecast model. The results indicated that an aggressive DSM approach would provide benefits to RPU in delaying base load capacity.

Summary

The results of the infrastructure plan have identified the lower cost approaches to meeting the RPU demand and energy requirements to the year 2030 include a combination of market purchases, gas and coal-fired resource additions, ongoing modifications to the Silver Lake Plant and a variety of DSM programs. Renewable energy should be pursued from wind resources and the Olmstead Waste to Energy Facility biomass facility.

We look forward to discussing any aspect of this report with you at your convenience.

Sincerely,
BURNS & MCDONNELL

Jeff Greig
General Manager
Business & Technology Services

Kiah Harris
Project Manager

KH/pma

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Summary

The management of Rochester Public Utilities (RPU) is interested in developing a long range baseline infrastructure plan for the utility. The growth of the customer load will require acquisition of additional generation resources, potential modifications of existing resources and upgrades to the utility's local and the region's transmission systems. These projects will be competing for capital from the RPU. In order to minimize the investment in these areas, a long range plan is needed which provides a coordinated approach to resource expansion.

The approach taken by RPU was to develop a multi-phased approach to understanding these needs. The various phases include:

- Environmental modifications necessary at the Silver Lake Plant (SLP),
- Transmission upgrade studies for regional improvements,
- Review of traditional resource expansion alternatives,
- Review of demand side management and renewable alternatives.

This report provides information on the traditional generation resource planning undertaken to provide a baseline for comparing the demand side management (DSM) and renewable options and understanding how RPU intends to use the transmission system.

Being a municipal utility, RPU is responsible to the citizens of Rochester, who are the customers it serves. In order to understand the issues of importance to its customers, RPU has periodic customer satisfaction surveys performed. According to customer satisfaction research conducted by Morgan Marketing in 2001, keeping the price for electricity as low as possible and aggressively pursuing energy conservation and renewable generation strategies were ranked in order as the highest needs among 18 performance attributes.

The development of this plan recognizes those needs. Phase I herein reviewed the needs and traditional approaches to meeting the resource needs of RPU's customers in a low cost manner in accordance with reliability standards in the industry. It established a baseline from which to measure potential impacts of renewable energy sources and customer modifications to consumption. The Phase II effort reviewed conservation, demand side management and renewable options to be integrated into the RPU system which could reduce or eliminate the need for the addition of the traditional resources.

The development of the long range baseline infrastructure plan (Plan) will incorporate aspects of an integrated resource plan and a financial plan for the utility. Issues which the Plan will cover include, but are not limited to:

- Basic generation and transmission resource expansion, including additional internal generation and participation in regional generation;
- Consideration of the renewable portfolio requirements of Minnesota;
- Demand side management, customer involvement in managing loads;
- Estimated costs for the utility and financial model development.

The analysis required to support the decisions on the traditional resource options is the subject of Parts II, III and IV in this report. The assessment of renewable and demand side management issues is the subject of Part V. Part VI is a discussion of the detailed financial forecast for a variety of futures. RPU retained Burns & McDonnell to assist RPU in the development of the Plan. The first effort was to analyze the power supply needs to the 2030 time frame in order to identify any longer term issues which could impact shorter term decisions.

The review of these issues was divided into two major time periods. The periods were from 2005 to 2015 and from 2016 to 2030. These time frames were developed to coincide with the termination of the Minnesota Municipal Power Agency (MMPA) sales contract, at which time the RPU will regain the complete output of the SLP for its own use.

Current Conditions

Generation Resources

RPU projected the demand and energy growth for the study horizon to be 2.7 percent. This compares to an historic growth of 3.5 percent for the past 15 years. It is expected that the RPU load factor will remain relatively constant over the study horizon.

The capacity and energy resources for RPU include:

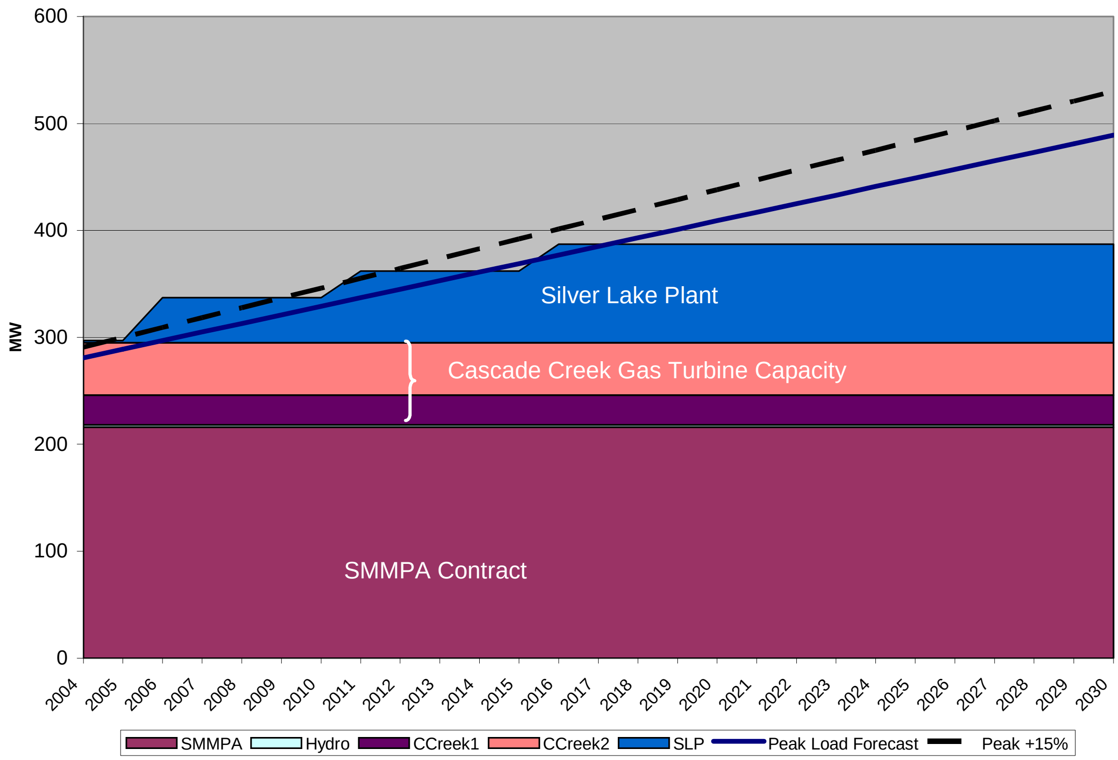
- Contract with Southern Minnesota Municipal Power Agency (SMMPA),
- Combustion Turbines at Cascade Creek,
- Steam units at the Silver Lake Power Plant,
- Zumbro Hydro Facility.

The available capacity and load forecast are shown in Figure S-1. The figure also includes the 15 percent reserve margin required by Mid-Continent Area Power Pool (MAPP) on RPU load above the Contract Rate of Demands (CROD).

The SLP has two contracts for energy sales. The MMPA contract provides for electrical sales to the MMPA when the units are available. The contract has various options for RPU to reduce the amount of capacity offered to MMPA. These options to adjust capacity allocated to MMPA under the contract are available in 2005 and 2010. The above balance of loads and resources reflect the current thinking of RPU on the amount of capacity which will be available to RPU from the contract.

Steam sales to the Franklin Heating Station were scheduled to begin in 2004. The steam sales are not anticipated to limit the electrical output of the SLP steam generators until after the 2010 time frame. These reductions in electric capacity have been accounted for in the balance of loads and resources.

Figure S-1
RPU Balance of Loads and Resources
2004-2030



RPU recently completed a study on the environmental aspects of the SLP with regard to existing and potential environmental regulations. It is expected that the RPU will need to make investments in additional emission controls or implement other emission reduction strategies within the next 5 years. Various options are currently under consideration by RPU. Estimated impacts to the SLP have been considered in this study using the results of the environmental report "Analysis of Existing and Potential Regulatory Requirements and Emission Control Options for the Silver lake Plant". In addition to issues at the SLP, RPU considers the long term availability of the Cascade Creek Unit 1 to be in question due to parts availability.

Transmission

RPU is undertaking studies with regional utilities to assess options for reducing the constraints into the southeast Minnesota region and Rochester. Several transmission projects are being considered which will affect the 161kV and 345kV systems in the region.

The development of a project to increase the transfer capacity into the RPU service territory is important to allow RPU to rely on the firm delivery of its CROD amount. Current transmission limitations do not allow the full CROD capacity to be delivered on a firm basis. It is also desirable through the development of a project to have increased transfer capacity for importation of market power or participation in regional projects, such as for a coal or wind resource, on a firm basis.

Use of local generation is becoming more of an issue as area loads increase and the capability of the transmission system becomes more limited. Due to must run issues during portions of the year and contract requirements of MMPA, the SLP is required to remain operational for the foreseeable future. The current limitations on the transmission system being below the level required to support the RPU load from outside resources point out the importance of generation internal to the RPU service area.

Resource Options

The capacity requirements for RPU were reviewed with various futures for the SLP. The futures for the SLP included retirement of the entire plant, maintaining only Unit 4 and maintaining all existing units. The analysis assumed retirement of the existing Cascade Creek Unit 1 in 2015. The capacity needs are summarized in Table S-1.

Table S-1
Range of Capacity Requirements for Various SLP Retirement Scenarios
(MW of Capacity Deficiency)

	2016	2020	2025	2030
All Units in Service	8	56	123	201
Retire CC Unit 1	36	84	151	229
Retire CC1, SLP 1-3	83	131	198	276
Retire CC1, SLP 1-4	128	176	243	321

Expansion alternatives were developed to review various scenarios to eliminate the deficits. These scenarios included various combinations of participation in a regional coal-fired power plant and RPU constructed resources such as combined cycle and simple cycle generation. The scenarios considered for RPU are included in Table S-2.

Table S-2
Resource Portfolios

	Existing Capacity - MW			Capacity Added – MW (year installed)				
Case	CROD	Other	SLP	Coal	Combined Cycle	Twin Pac		
None216-100Coal	216	51	0	100(15)		50(15)	50(20)	50(25)
None216-50Coal	216	51	0	50(15)		100(15)	50(20)	50(25)
None216-100CC	216	51	0		100(15)	50(15)	50(20)	50(25)
None216-LMS100	216	51	0		100(15)	50(15)	50(20)	50(25)
None216-SC	216	51	0			150(15)	50(20)	50(25)
45216-50Coal_CoalFirst	216	51	45	50(15)		50(15)	50(20)	50(25)
45216-50Coal_SLPfirst	216	51	45	50(15)		50(15)	50(20)	50(25)
45216-100CC	216	51	45		100(15)		50(20)	50(25)
45216-LMS100	216	51	45		100(15)		50(20)	50(25)
45216-SC	216	51	45			100(15)	50(20)	50(25)
45216-LMS100-50Coal	216	51	45	50(20	100(15)			50(25)
All216-50Coal_CoalFirst	216	51	92	50(15)			50(20)	50(25)
All216-50Coal_SLPfirst	216	51	92	50(15)			50(20)	50(25)
All216-100CC	216	51	92		100(20)	50(20)		
All216-LMS100	216	51	92		100(20)	50(20)		
All216-SC	216	51	92			50(15)	50(20)	50(25)

The case titles are developed such that the None, 45 or All refers to the amount of SLP capacity available, 216 refers to the CROD amount and the last numbers refer to the MW of resource added. SC refers to simple cycle, CC refers to combine cycle, and LMS 100 refers to a new simple cycle unit being developed. References to CoalFirst and SLPFirst are associated with the order of dispatch.

The simple cycle units considered in this study are based on the current Cascade Creek Unit 2 type facility, the Pratt and Whitney Twin Pac. The combined cycle unit is based on a purchase of a 125MW portion of an area combined cycle project. The coal resources are assumed to be from a regional project whereby RPU would purchase the indicated amount as an owner.

Production cost analysis was performed to determine the amount of energy that each resource would provide over the period 2016 to 2030. Table S-3 provides a summary of the gas and coal energy assumed in the analysis.

Table S-3
Summary of Energy Sources from Gas or Coal Portfolios

Energy in GWh	**2016**		**2020**		**2025**		**2030**	
	Gas	Coal	Gas	Coal	Gas	Coal	Gas	Coal
None216-100Coal	3	1,839	21	2,023	72	2,257	171	2,490
None216-50Coal	36	1,806	79	1,965	187	2,142	423	2,238
None216-Gas	121	1,721	248	1,796	479	1,850	773	1,888
45216-Coal	4	1,838	25	2,019	79	2,250	187	2,474
45216-Gas	34	1,808	93	1,951	243	2,086	536	2,125
All216-Coal	4	1,838	25	2,019	79	2,250	187	2,474
All216-Gas	34	1,808	93	1,951	243	2,086	536	2,125

Note: Above numbers do not include a negligible amount of hydro energy

The above table reflects the energy estimated to be taken from the various generation resources within the respective expansion portfolios. The energy in the gas columns includes energy generated by RPU and purchased from the market. The coal energy includes that purchased from SMMPA and generated by RPU. As seen, where the coal energy is limited to the existing resources, significant increases in the gas energy is necessary. It should be noted that all of the cases include additional gas-fired resources.

Results

The results of the production cost modeling for the traditional portfolios are summarized in Table S-4. The net present values for the cases were developed for the 15 year study horizon in 2015 dollars. The values shown reflect the incremental costs of each option and, therefore, do not include those RPU costs which would be common among all of the cases.

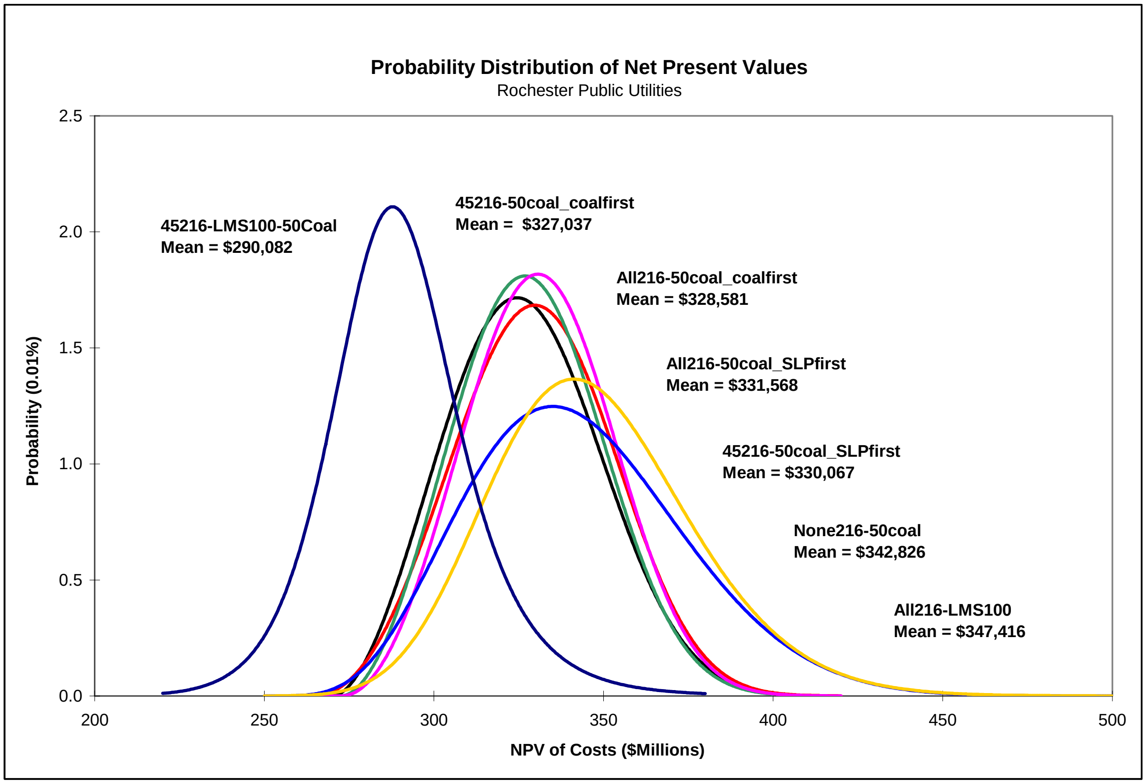
Table S-4
Summary of Net Present Values for Portfolio Options
(2015 $000)

Case	NPV	% Above Base
45216-LMS100-50Coal	$288,674	-
45216-LMS100	$320,892	11.2%
45216-50Coal_CoalFirst	$325,782	12.9%
All216-50Coal_CoalFirst	$327,201	13.3%
45216-50Coal_SLPfirst	$328,750	13.9%
All216-50Coal_SLPfirst	$330,169	14.4%
None216-50Coal	$342,102	18.5%
All216-LMS100	$347,789	20.5%
45216-SC	$347,544	20.4%
All216-SC	$351,098	21.6%
None216-100Coal	$353,725	22.5%
None216-LMS100	$362,430	25.5%
None216-SC	$387,146	34.1%
All216-100CC	$389,434	34.9%
45216-100CC	$396,788	37.5%
None216-100CC	$435,755	51.0%

The above portfolios all have a mixture of coal and natural gas resources used to minimize RPU's overall average energy costs. The results indicate that the availability of low cost energy from the SLP Unit 4 or an additional coal plant purchase is a lower cost scenario than relying only on natural gas for the energy needs above the CROD level.

Risk analysis of the lower evaluated cases was performed. The analysis varied certain assumptions, such as fuel forecast, capital costs, interest rates and other factors. The results are summarized in Figure S-2. The curves show the distribution of probable net present values with the changes in assumptions for the various cases. A higher probability of a net present value indicates reduced risk in that scenario.

Figure S-2
Probable Net Present Values
Lower Evaluated Cases



The risk analysis shown above indicates that combining the benefits of the LMS100 case with the 50MW coal case provides a lower risk case than the all gas cases. The major advantage is the delay of acquisition of the coal unit until its energy can be more fully utilized. This allows RPU to capture the early benefits of the LMS100 portfolio and the later benefits of the 50MW coal portfolios. Therefore, the sequencing of the unit additions should be considered with the gas unit in 2016 and the coal purchase in 2020.

Demand Side Management and Renewable Options

RPU is active in promoting demand side programs to its customers to help conserve electric energy, and reduce demand in its service territory. Numerous programs are offered to assist customers in reducing their electrical requirements. The development of the financial plan for RPU requires the assessment of the impacts that customers are making, and could make, in the reduction of future electrical requirements; therefore, delaying the need for additional capacity.

Current DSM Efforts

Utilities in Minnesota are required to invest a portion of the revenues into DSM programs. For RPU, this amounts to approximately $1,300,000 per year. RPU has created a department to manage the budget associated with DSM programs. The department is staffed with individuals who work with customers to promote the various DSM programs in place, provide energy audit services, and look for new programs to implement.

RPU is working with the cities of Owatonna and Austin, Minnesota on DSM offerings. These utilities have formed the Triad, which allows the cities to share personnel, study costs, and other assets in order to reduce the overheads and program costs associated with the DSM programs.

The programs offered by RPU include:

- Conserve and $ave – a program to promote the use of Energy Star appliances and other high-efficiency equipment in place of lower efficiency options. The program is open to residential, commercial, and industrial customers. Rebates are provided for a variety of appliances, equipment, and lighting options.
- Partners Load Management – a program to allow RPU to control central air conditioner compressors and electric water heaters during times of high demand and reduce the load on the system.
- Energy Audits – these are provided to customers upon request.

The cumulative estimated reductions due to these programs as of January 1, 2004 are:

- Energy savings of 7,860 MWh.
- Demand savings of 5,960 kW.

Using an average of $600/kW of installed capacity and $55 per MWh as an avoided energy cost, the programs have provided approximately $3,500,000 of reduced investment cost and $432,000 of annual energy savings.

Study Approach

A variety of tasks were undertaken to develop the expected impacts that current and potential DSM programs could provide in reducing the RPU need for additional power supply resources. These tasks included an end use survey of RPU's customers, a benefit cost analysis of RPU programs, and an estimation of the electric energy and demand reduction potential for RPU's customer base.

In addition to these tasks, public involvement was solicited to discuss options and considerations from the ratepayer's perspective. RPU developed a task force made up of a representative from the various rate classes and other involved citizens served by RPU.

The results of these efforts are more fully described in Part V. Table S-5 provides a summary of the estimated energy impacts due to expanded DSM programs that were considered likely for RPU. Discussions with the RPU DSM staff and management resulted in revisions to the forecast used to develop the traditional resource plan.

Table S-5
Estimated Additional DSM and Efficiency Impacts
To RPU Energy Forecast

Program	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential											
Central AC	0	236	475	709	709	709	709	709	709	709	709
Blower Motors	0	692	1,391	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076
CFLs	0	63	127	190	190	190	190	190	190	190	190
Refrigerators	0	42	84	125	125	125	125	125	125	125	125
Gas switched appliances	0	83	168	250	250	250	250	250	250	250	250
Commercial											
Central Air more than 7 years old	0	123	248	370	370	370	370	370	370	370	370
No Compact FL	0	185	373	556	556	556	556	556	556	556	556
Non electronic ballast flourescent	0	517	1,040	1,552	1,552	1,552	1,552	1,552	1,552	1,552	1,552
VSD on 3 HP AC unit fans	0	658	1,322	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973
Computers	0	122	245	365	365	365	365	365	365	365	365
Printers	0	43	86	128	128	128	128	128	128	128	128
Copiers	0	55	111	165	165	165	165	165	165	165	165
Gas switched appliances	0	250	503	750	750	750	750	750	750	750	750
Total	0	3,069	6,170	9,208	9,208	9,208	9,208	9,208	9,208	9,208	9,208
Cumulative Total	0	3,069	9,239	18,447	27,656	36,864	46,073	55,281	64,489	73,698	82,906

The estimated demand and energy impacts, including the Mayo cogeneration project, are shown in Table S-6. The Original Energy Forecast was the energy projection used for developing the resource plan described above. The Existing DSM Impacts include the existing RPU DSM program estimated savings. The Future DSM impacts are one half of the saving shown in Table S-5. The Revised Energy Forecast is determined by subtracting the Future and Existing DSM Impacts from the Original Energy Forecast. The Aggressive Energy Forecast includes the remainder of the savings estimated in Table S-5.

Table S-6
Estimated DSM and Efficiency Improvement Impacts
Demand (MW) and Energy (MWh)

Year	Annual Peak	Demand Adjustments	Adjusted annual Peak	Original Energy Forecast	Future DSM Impacts	Existing DSM Impacts	Revised Energy Forecast	Aggressive Energy Forecast
2005	277	16.6	260	1,377,767	0	8,590	1,369,177	1,369,177
2006	284	21.8	262	1,414,967	1,535	56,310	1,357,122	1,355,588
2007	292	23.1	269	1,453,171	4,620	64,550	1,384,001	1,379,382
2008	300	25.1	275	1,495,732	9,224	72,650	1,413,858	1,404,635
2009	308	25.3	283	1,532,702	13,828	80,650	1,438,224	1,424,396
2010	316	26.9	289	1,574,085	18,432	88,500	1,467,153	1,448,721
2011	325	29.2	296	1,616,585	23,036	96,210	1,497,339	1,474,302
2012	334	31.8	302	1,663,932	27,641	103,790	1,532,501	1,504,861
2013	343	34.9	308	1,705,059	32,245	111,150	1,561,664	1,529,420
2014	352	38.4	314	1,751,096	36,849	118,450	1,595,797	1,558,948
2015	362	42.8	319	1,798,375	41,453	125,770	1,631,152	1,589,699

Renewable Energy Options

The state of Minnesota has implemented requirements for renewable energy under Minnesota Statute 2003 Chapter 216B. Retail electric utilities must offer customers an opportunity to purchase, at cost, renewable energy beginning July 1, 2002. RPU is offering customers the opportunity to purchase this energy under its Wind Power program in association with SMMPA.

Utilities are required to generate or procure renewable energy sufficient to ensure that by 2005, 1 percent of total retail sales are from renewable energy. This “Renewable Energy Objective” (REO) ramps up by 1 percent each year until 2015 when a total of 10 percent of retail sales must be from renewable energy. The REO also requires that, of the renewable generation required, in 2005 at least 0.5 percent be from biomass energy technology, increasing to 1.0 percent by 2010. For RPU, the retail sales energy above the CROD from SMMPA would be subject to RPU compliance with the REO.

The integration of this energy into RPU’s resource mix will require adjustments to the dispatch determined in the traditional resource portfolios identified above.

There are several renewable energy options in commercial use. The most often considered include solar, wind, and biomass. In addition, the REO allows the use of electricity generated using municipal solid waste and existing hydro-electric generation to count towards the renewable requirement. The application of these options requires an assessment of their energy production capabilities, resultant power costs and the benefit to the RPU requirements. A more detailed discussion of renewable options can be found in Part V.

The Olmstead Waste to Energy Facility (OWEF) qualifies as biomass renewable energy under the Statute. Since utilities are to provide 1 percent of their energy from biomass, it could satisfy the RPU biomass renewable requirements through the study period. When combined with the Zumbro River hydro facility total renewable requirements could be satisfied until approximately 2027. Table S-7 provides an assumed purchase scenario. Due to the requirement in the REO of obtaining energy from biomass, the output of the OWEF will be required beginning in 2005.

Table S-7
RPU Estimated Annual Renewable Energy Requirements (MWh)

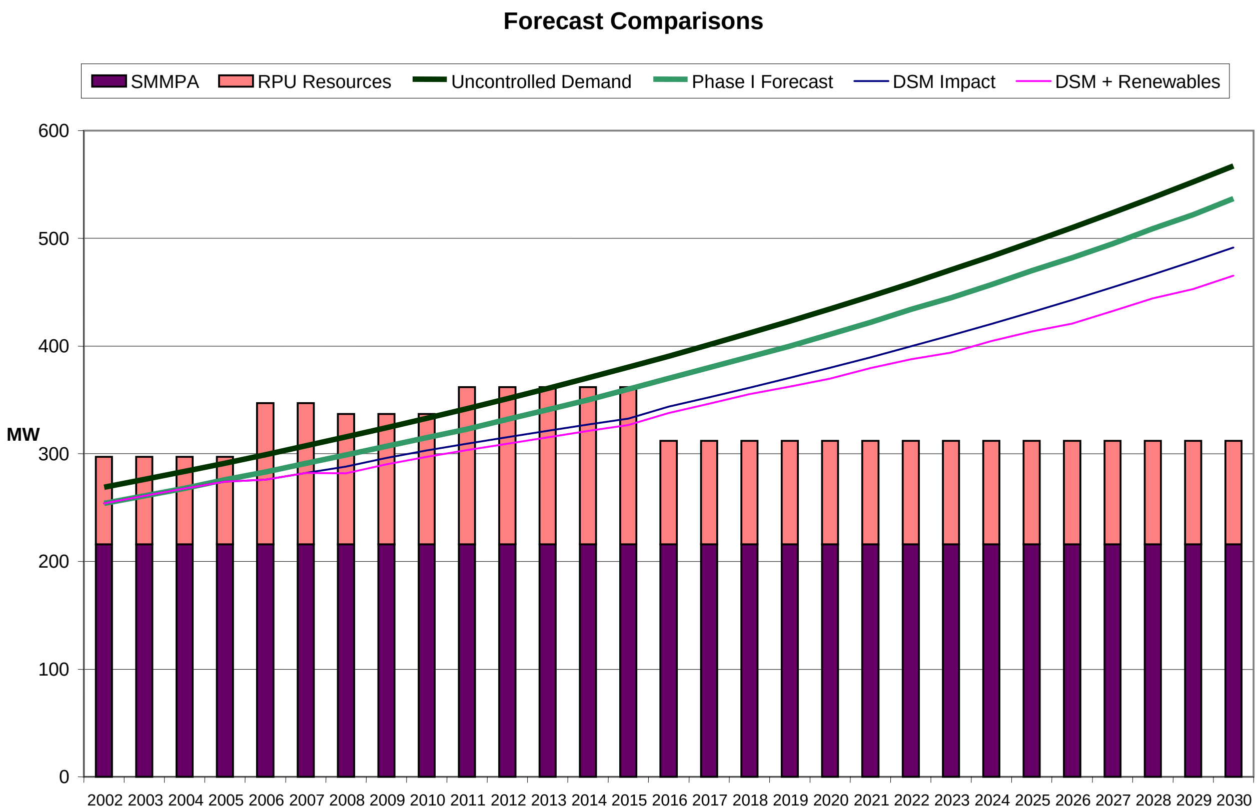
Year	Renewable Requirement (10%)	From Biomass	Available from OWEF 1.9MW @ 75%CF	Available from OWEF 5MW @ 75%CF	From Zumbro River	Total Hydro & Biomass
2016	7,059	71	12,483		9,000	21,483
2017	8,230	82	12,483		9,000	21,483
2018	9,628	96	12,483		9,000	21,483
2019	11,243	112	12,483		9,000	21,483
2020	13,411	134	12,483		9,000	21,483
2021	15,942	159	12,483		9,000	21,483
2022	19,008	190	12,483		9,000	21,483
2023	22,485	225		32,850	9,000	41,850
2024	26,446	264		32,850	9,000	41,850
2025	30,570	306		32,850	9,000	41,850
2026	34,949	349		32,850	9,000	41,850
2027	39,614	396		32,850	9,000	41,850
2028	44,543	445		32,850	9,000	41,850
2029	49,634	496		32,850	9,000	41,850
2030	54,980	550		32,850	9,000	41,850

Note: All energy values in MWh

DSM and Renewable Impacts on RPU Supply Needs

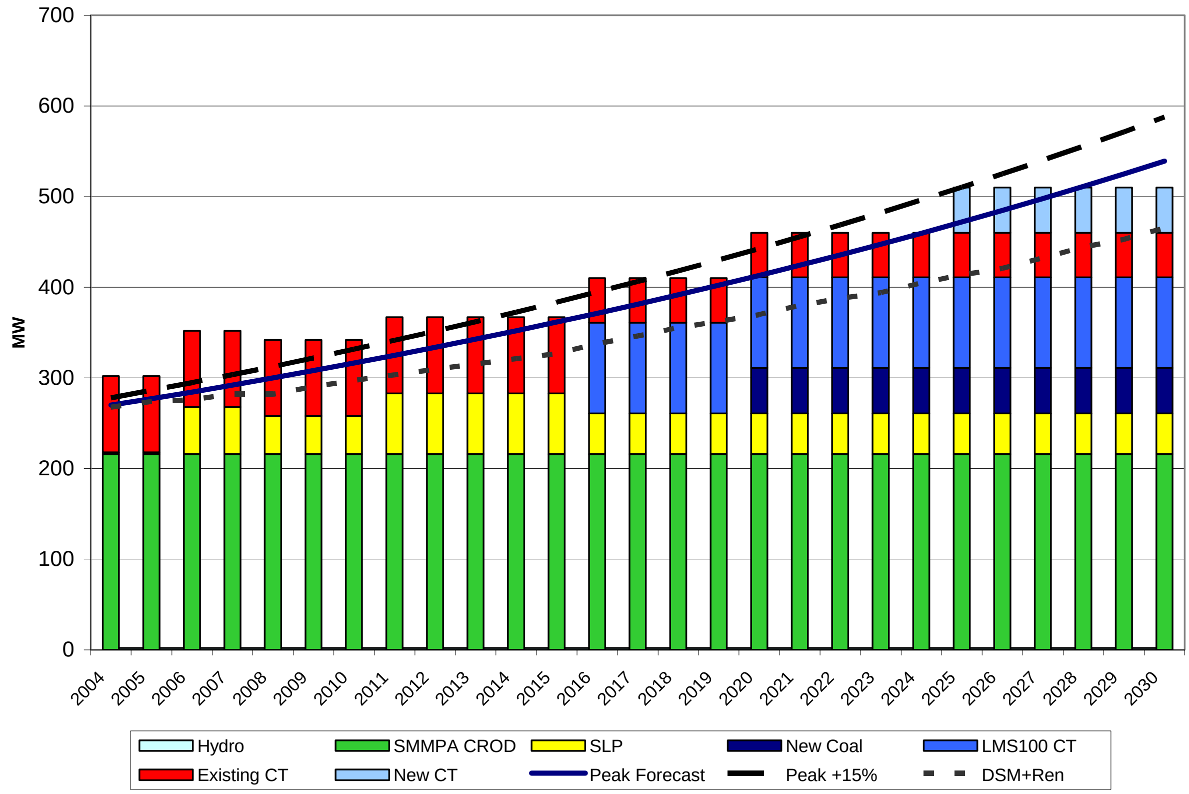
The balance of loads and resources using the DSM and renewable impacts was modified to include the above forecasts. The resulting impacts are shown in Figure S-3.

Figure S-3
Comparison of Base and Revised Forecasts
With DSM and Renewable Impacts



The impacts to the forecast indicate that the projected impacts of DSM and renewables do not delay the year when RPU becomes capacity deficit, however, they substantially reduce the amount of capacity needed. In addition, they delay the need for additional capacity in the future. Figure S-4 is the balance of loads and resources of the recommended traditional resource plan. As shown, the impact of the DSM and renewables on the forecast allows a delay in the installation of the LMS-100 combustion turbine by about 2 - 3 years. The impacts also allow a delay in the need for the coal unit by a similar period.

Figure S-4
Impact of DSM and Renewables
On Lowest Evaluated Traditional Resource Plan
Balance of Loads and Resources



Financial Analysis

The results of the resource planning, demand side management and renewable assessments were reviewed on an incremental cost approach to determine lower evaluated options. In order to bring these options together to determine the recommended RPU future, a financial forecast model was developed by RPU to incorporate the total costs of RPU. This model allowed a complete evaluation of future costs, the impact to average rates and other financial factors of interest to RPU.

The financial model was used to analyze the following futures:

- The recommended traditional resource expansion plan from Part IV with the forecast unaffected by demand side management,
- The recommended plan adjusted by using the normal demand side management forecast with SLP operating on coal and adjustments to the new resources,

- The recommended plan adjusted by using the normal demand side management forecast with SLP operating on natural gas and the coal unit replaced with gas-fired capacity,
- The recommended plan adjusted by using the aggressive demand side management results with SLP operating on coal and adjustments to the new resources,
- The recommended plan adjusted by using the aggressive demand side management results with SLP operating on natural gas and the coal unit replaced with gas-fired capacity.

A complete discussion of assumptions and methodology can be found in Part VI.

A variety of assumptions were made to the financial model. The main driver for the model is the energy and demand forecast. The load forecast was used to derive estimates for a variety of other assumptions, such as:

- Energy dispatch from RPU sources, including market sources, above the SMMPA supplied energy,
- Generation fuel expense,
- Purchased power expense for energy, capacity, and transmission,
- Administrative and general costs,
- Distribution and substation additions,
- Retail revenue forecasts.

Forecasts for investment in other projects, such as for transmission upgrades, capital investments in plant, and other improvements were provided by the respective operating divisions of RPU. The Silver Lake Plant was assumed to have the recommended environmental modifications from the Utility Engineering report “Rochester Public Utilities Emissions Control Feasibility Study, Silver Lake Plant,” Dec 2004 in the futures with coal. The budgets for the demand side management and marketing programs were included based on the level of DSM considered in the forecast.

The list of input assumptions is included in Appendix V.

The financial model uses the energy forecast and estimated energy price from the resources available to determine the amount of energy derived from each source. If the load level is at or below the 216MW level of the SMMPA contract, then the energy is assumed to come from SMMPA. If the load is above the 216MW level, then the lowest cost resource is dispatched to provide the energy with the exception that small load increments were dispatched first from peaking units until the point where the increment was high enough to feasibly dispatch baseload generation.

The economic impacts of resource additions were determined based on the estimated capital, fixed and variable operating and maintenance costs. The targeted financial goals for debt service coverage ratios, average cash balances and other targets based on capital investments were included. In-service years and the amount of capacity added were adjusted in the futures with demand side management included to reflect the benefits to delays in and amounts of capital investment.

Estimates of purchases from the market were made using a forecast market demand and energy price. For certain years, market capacity was purchased on a seasonal basis to provide the necessary capacity shortfall rather than install a new resource. Also, when market energy was estimated to be lower cost than an RPU resource’s energy cost, the market was used to provide the energy.

The operation of the SLP to meet wholesale energy and steam production contract obligations was modeled. The operations included estimated energy and steam production based on current discussions with counter parties to the contracts.

The operation and capital budgets of each RPU division were incorporated to provide a complete financial picture of the utility. The revenue requirements were then used to determine the amount of adjustment to rates necessary to meet those requirements. Average impact to retail rates and customer average bills were also estimated. The model covers a thirty year time period from 2005 to 2034.

Externalities

The values of externalities were included in this analysis. The 2003 values of externalities used by the Minnesota Public Utilities Commission (Rural) for utilities to evaluate externalities were adjusted for the gross domestic price inflator (4.4%) for 2004. A midpoint range for the adjusted values was selected for use in the analysis.

The emissions from the resources considered in the financial model were placed on a dollar per MWh basis for use with the expected dispatch MWh determined from the financial model. Externalities on contract and market purchases were also included to reflect one half of the purchases from new coal units and one half from combined cycle gas units.

Renewable energy from the Zumbro River facility was included in the financial model as the primary renewable resource, wind energy under the SMMPA program included at its historical average, and with OWEF assumed to be the biomass resource.

Results

Resource Plan

The reduction in the demand and energy forecast with the DSM impacts provides an opportunity to delay the gas resource considered for 2016 and the in service year and amount of capacity for the coal resource considered in 2020. In the financial model, the combustion turbine considered for installation in 2016 was delayed two years and the coal unit was reduced to 25MW and its in service date delayed to 2025.

Rates

Figures S-5 and S-6 provide the results based on average retail rate impacts and average customer bills. As seen, there are significant advantages in the demand side management impacts on both rates and average bills. When considering the cost impacts due to the futures with and without coal, it is seen that the coal case provides economic benefits.

The rate impacts determined from the analyses indicate that RPU, in any of the futures, is expected to need rate increases of from 1 to 3 percent in almost each year of the assessment. The differences in the expected and aggressive demand side management scenarios were not significant. The more detailed results of the financial model analyses are included in Part VI and Appendix V.

Figure S-5
Retail $/MWH-Major Customer Classes

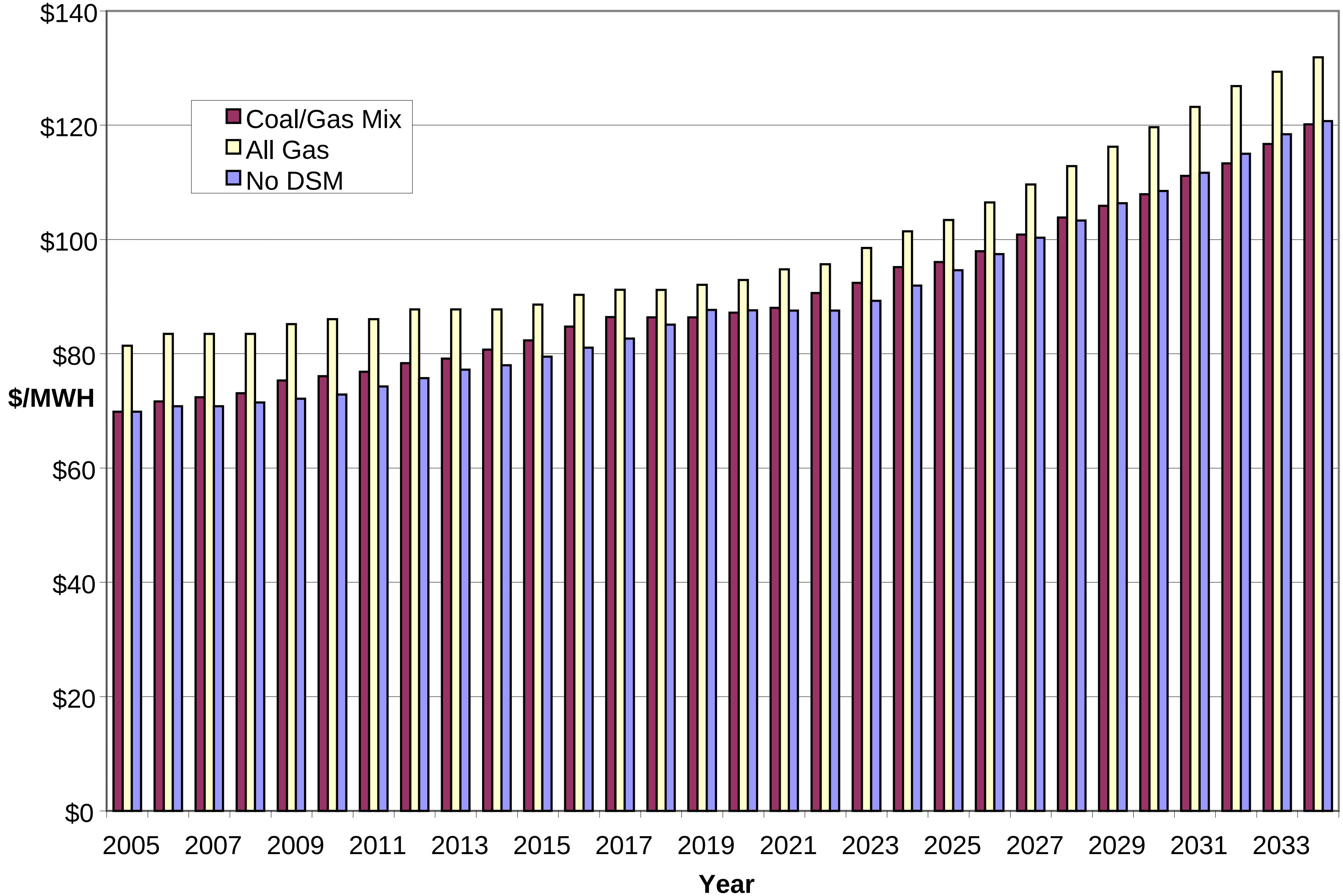
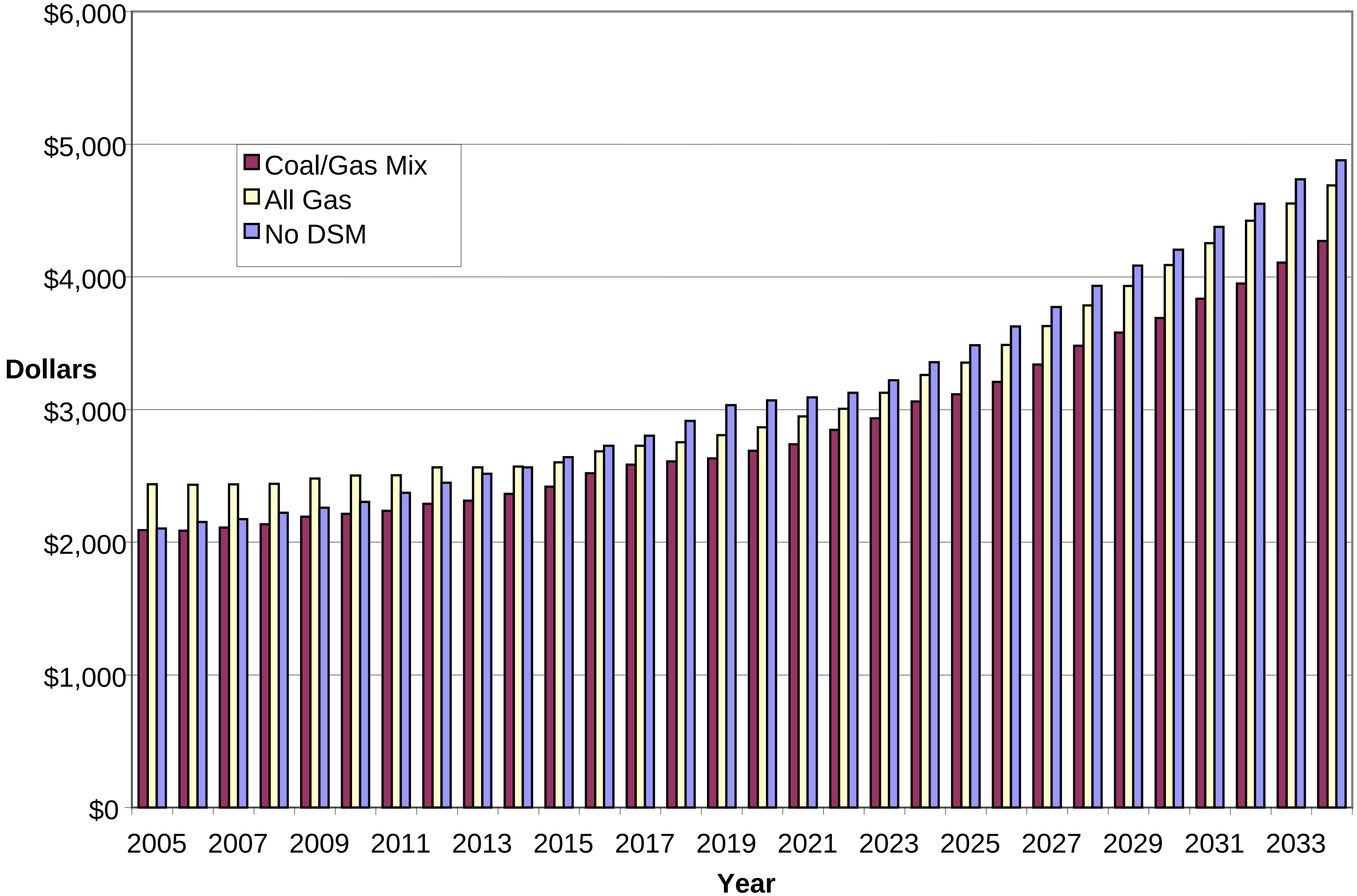


Figure S-6
Average Annual Bill-Major Customer Classes



Emissions

The emissions from each of the futures were considered from both absolute tons per externality and the cost aspect using the Minnesota value for externalities. Table S-8 provides the summary of tons emitted by externality based on the energy dispatch used for the RPU retail resource future over the thirty years of the analysis. As shown, there is a substantial advantage to the demand side reductions. The costs of the externalities and the total costs of the specific future are included in Table S-9.

Table S-8
Total Tons of Emissions by Scenario

Scenario	SO2	Nox	PM10	Pb	CO	CO2
Original Forecast	7,808	4,587	770	1.25	9,811	10,472,370
Normal DSM Coal & Gas	5,228	3,105	485	0.79	7,048	6,263,420
Normal DSM All Gas	379	5,086	296	0.10	8,341	3,784,419
Aggressive DSM Coal & Gas	4,931	2,886	448	0.73	6,504	5,720,385
Aggressive DSM All Gas	343	4,714	272	0.09	7,644	3,474,437

Table S-9
Retail Portion of RPU Costs of Various Plans with Externalities
(2004$ 000's)

Scenario	Retail Revenue	Externalities	Total
Original Forecast	$ 5,649,613	$22,308	$ 5,671,921
Normal DSM Coal & Gas	$ 5,134,851	$13,390	$ 5,148,241
Normal DSM All Gas	$ 5,672,269	$ 8,325	$ 5,680,594
Aggressive DSM Coal & Gas	$ 5,104,864	$12,236	$ 5,117,100
Aggressive DSM All Gas	$ 5,569,761	$ 7,646	$ 5,577,408

Summary

Overall, RPU is in relatively good condition to meet its load requirements for several years without any additions to its resource mix. Challenges to RPU in the area of transmission reliability and understanding what future market operation impacts will bring are typical of the environment in which utilities operate today and will be a primary focus of RPU. The transmission issues confronting RPU may require additional internal generation to maintain reliability within the RPU service territory prior to when units would be needed to serve load growth. Plant related issues will include the investment necessary to bring the SLP into compliance with environmental regulations currently taking affect. Based on the analysis performed for RPU in this effort, Burns & McDonnell offers the following conclusions and recommendations.

Conclusions

Based on the analysis performed for this study, Burns & McDonnell has developed the following conclusions:

1. The uncertainty surrounding the conversion of the electricity wholesale market in the RPU region from its traditional operation to its new operation under MISO and the existing transmission limitations for importing power into the RPU area makes it necessary for RPU to continue to have capacity available within its service area for reliability and economic purposes.
2. The use of traditional resources to meet the RPU capacity obligations is lower cost than the use of wind or solar equivalent capacity. Energy costs from certain renewable options can be attractive when compared to the energy costs from coal, gas, or market resources.
3. The impacts of demand side management allow RPU to delay and reduce the amount of capacity required when compared to the forecast without significant demand side management effects included.
4. The future evaluated with coal and gas energy and aggressive demand side management was the only future that provided both lower average rates and lower average total bills when compared to the other futures. This ranking is not changed with the inclusion of externalities.
5. The emissions from the aggressive demand side management future with coal and gas are approximately one-half of the emissions from the traditional resource future.
6. Considering the load forecast, RPU has several years before it is in a capacity deficit condition due to load needs. Estimates of DSM and renewable impacts to the forecast provide the opportunity for RPU to delay the installation of resources by two to three years, depending on the successful acceptance of the DSM programs by the RPU customers.
7. The development of the MISO Day 2 market will make day ahead pricing more predictable and potentially provide RPU with the opportunity to engage customers in demand adjustments based on the cost of energy. The current Partners program could see a decrease in the number of MW under control due to more efficient air conditioners being installed on the system and potential fuel switching of water heaters. These two developments are an indication that RPU should consider realigning its approach to demand reductions on the customer side of the meter. Because of this need, RPU should prepare a pilot program for implementation of demand response type programs across the residential, commercial and industrial classes in order to gain experience and begin shifting away from the direct control programs to market based programs.
8. RPU's renewable obligations under the Minnesota Statute Chapter 216B can be met for several years through purchase of energy from the OWEF and the Zumbro River hydro facility. If the OWEF facility is expanded, as is being considered, RPU renewable energy requirements could be satisfied until approximately 2027 with these two resources.

9. Discussions with the OWEF should proceed to determine if additional output is available. If it is not, then wind energy should be pursued as the next renewable option to satisfy energy obligations under the REO. Based on the cost and output of photovoltaic units, solar photovoltaic is the most expensive renewable option for the RPU to pursue.
10. Based on information from RPU, the SMMPA is in discussions on acquisition of additional resources which could affect the cost of capacity and energy under the CROD. At the current time, there is insufficient information to be able to determine how DSM programs could reduce the impact of these potential costs. If SMMPA moves ahead with resource acquisitions based on RPU impacts to the SMMPA resource mix, RPU should discuss with SMMPA the ability of DSM options to reduce the resource need impacts to SMMPA.

Recommendations

Based on the analysis performed for RPU in this effort, Burns & McDonnell is of the opinion that RPU should:

Over the next few months:

1. Minimize its involvement in reviewing participation in regional coal projects. RPU is not in need of additional coal capacity with the current 216MW CROD level and load forecast until approximately 2020. Therefore, participation in any coal plant currently being developed does not appear to be advantageous.
2. Pursue firming up the transmission system to allow firm delivery of the CROD amount of 216MW.
3. Improved transmission import capability should be reviewed with area utilities to allow increased access to market capacity. Although the resource plans presented in this study anticipate future resource additions, there is also continued reliance on market purchases to meet future load growth.
4. Consider taking options on approximately 100 acres of land within the RPU service territory near a high pressure gas line and transmission facilities under RPU control for installation of future combustion turbine capacity.
5. Develop a parallel path project to accelerate installation of combustion turbine capacity required in the long term plan to maintain system reliability should the selected transmission upgrade project be delayed.
6. Develop the upgrade plan and timing for SLP Units 1-4 for the addition of emission controls and other life extension modifications.
7. RPU should monitor the operations of the MISO Day 2 market to determine how to participate in the market over the next few months.

Between 2005 and 2015:

1. RPU should continue to design and market DSM programs to achieve the levels of forecast reductions for demand and energy. Periodic comparison of actual results to those forecasts should be made to determine if adjustments in the forecast results are necessary.
2. RPU should take advantage of renewable energy from the Zumbro River resource to the full extent of its output. The renewable energy from the OWEF should be considered to provide the RPU biomass energy requirements. Purchases above the requirements should be compared to the cost of other energy available.
3. Complete the transmission upgrade or the installation of additional combustion turbines to maintain system reliability.
4. If the transmission upgrade is completed, compare the market conditions at the time to the installation of additional generation resources within the service territory.
5. Review the then current generation technology, fuel options and RPU needs against the long range plan developed herein to determine if new technologies or reduced RPU needs have usurped the analysis and recommendations associated with current options.
6. Complete the modifications to the SLP Unit 4. Initiate the emission controls to be applied to Units 1-3 in light of their expected operation.
7. Around 2014, assuming that new generation is required in accordance with the long range plan and that generation has not been installed in connection with the transmission issue, begin the process for installation of approximately 50 to 100MW of natural gas-fired generation for an in service date of 2018. The generation should be low capital cost with as low an operating cost as is consistent with expected operating capacity factors.

Between 2015 and 2030:

1. Install generation as necessary and prudent using the long range plan prepared above as a guide and comparing the assumptions used herein to the existing market conditions and resultant DSM impacts to the RPU needs. The generation additions should follow the in service schedule identified in portfolio 45216-LMS100-50Coal as modified by DSM results.
2. Around 2015, depending on the status of the RPU system needs, the regional market for base load projects being developed, and other technology considerations for resource options, RPU should consider taking an option on approximately 1500 acres to support the development of a coal-fired generation plant within the RPU service territory. The site should have access to rail, electric transmission and water infrastructure to support several hundred megawatts of generation.

3. If development of a local coal unit appears likely, purchase the necessary land and begin the development process around 2017 for an in service date of 2025.

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Part I

Introduction

The management of Rochester Public Utilities (RPU) is interested in developing a long range baseline infrastructure plan for the utility. The growth of the customer load will require acquisition of additional generation resources and upgrades in the utility's local and the region's transmission systems. These projects will be competing for capital from the RPU. In order to minimize the investment in these areas, a long range plan is needed which provides a coordinated approach to resource expansion.

The RPU is confronted with numerous decisions associated with its power supply resources. Several of these decisions will need to be made in the next several months. The outcome of these decisions could have a significant impact on the financial requirements of the RPU over the next several years. In order to develop information about the various futures available to RPU and what the financing requirements might be for the futures, RPU decided to study how various long term decisions could impact the near term financing requirements.

The approach taken by RPU was to develop a multi-phased approach to understanding these needs. The various phases include:

- Environmental modifications necessary at the Silver Lake Plant
- Transmission upgrade studies for regional improvements
- Review of traditional resource expansion alternatives
- Review of demand side management and renewable alternatives

This report provides information on the traditional generation resource planning undertaken to provide a baseline for comparing the DSM and renewable options and understanding how RPU intends to use the transmission system.

Being a municipal utility, RPU is responsible to the citizens of Rochester, who are the customers it serves. In order to understand the issues of importance to its customers, RPU has periodic customer satisfaction surveys performed. According to customer satisfaction research conducted by Morgan Marketing in 2001, keeping the price for electricity as low as possible and aggressively pursuing energy conservation and renewable generation strategies were ranked in order as the highest needs among 18 performance attributes. The research included telephone, mail-in and personal interviewing of residential, commercial and industrial customers.

The development of this plan recognizes those needs. Phase I herein reviewed the needs and traditional approaches to meeting the resource needs of RPU's customers in a low cost manner in accordance with reliability standards in the industry. It established a baseline from which to measure potential impacts of renewable energy sources and customer modifications to consumption. The Phase II effort reviewed conservation, demand side management and renewable options to be integrated into the RPU system which could reduce or eliminate the need for the addition of the traditional resources.

Utility Issues

The utility industry in general and RPU specifically are operating amidst changing local, regional and national issues which affect utility operations. On the local level, many of the issues require decisions by local officials who regulate RPU and will determine the local course of the utility. Regional and national issues are typically beyond the influence of these officials. These issues are closely watched by RPU and others and RPU is a participant in the national debates. However, the decision on what policies to implement on a state, regional or national level is beyond the RPU control.

The issues which RPU is confronting on the local, regional and national levels include:

Generation

Local

- Silver Lake Plant Emissions
- Status of local generation in future system needs
- Must Run issues required of local generation and emission impacts
- System operation changes based on Midwest Independent Transmission System Operator (MISO) development
- Reserves available

Regional and National

- Status of regional generation
- Cost and availability of natural gas as a utility fuel
- Availability and value of regional joint generation projects
- Implementation of MISO Market Operations
- Technology advancements
- New emission/operation regulations

The use of local generation is becoming more of an issue as load increases and the capability of the transmission system becomes more limited. Due to regional reliability issues during portions of the year and contract requirements of RPU, the Silver Lake Plant (SLP) may be required to remain operational. The useful life of the facility and improvements necessary to keep the plant compliant with operating permits is a concern. A study on the emission improvements recommended for the plant is being prepared.

Transmission and Distribution

Local

- Transmission for firm delivery of Southern Minnesota Municipal Power Agency (SMMPA) contract rate of delivery
  - Maximum import of the transmission system
  - Ability to build new transmission facilities outside of Rochester
- Distribution reliability
  - New substation and lines will be continually needed as the load grows
  - Capital requirements
  - Rights of way
- Reserves available

Regional and National

- Status of regional transmission improvements
- Implementation of MISO operations
- Technology advancements
- New Regulations

The transmission import capacity into RPU is constrained during certain hours of the year. Capacity has degraded to the point that the firm delivery of the SMMPA Contract Rate of Delivery (CROD) is being affected.

Load Growth

- Annexation, expansion of RPU service territory impacts capital needs
- Growth rates affect RPU investments
  - Local economy
  - Mayo Clinic
- Risks of economic development expansion (ie Genomics)
  - Overbuild
  - Underbuild
- Matching the investment to meet changes in load

The RPU load growth is closely linked to the growth of the Mayo Clinic and other major employers in the area. Average system growth is projected by the RPU forecasting group to be approximately 2.7% per year between 2004 and 2030.

Financial and Administrative

Local

- Impact of requirements on the rates
- Impact of Homeland Security regulations and capital needed to meet the needs
- Training and attraction of qualified staff
- RPU productivity due to the time it takes to report and comply with the new regulations
- Knowledge and communication of the capital dollars needed to:
  - Internal stakeholders
  - External stakeholders

Regional and National
- Cost of Borrowing
- Availability of staff versus the need

Long Range Plan

The development of the long range baseline infrastructure plan (Plan) will incorporate aspects of an integrated resource plan and a financial plan for the utility. Issues which the Plan will cover include, but are not limited to:

- Basic generation and transmission resource expansion including addition of internal resources and participation in regional projects.
- Consideration of the renewable portfolio requirements of Minnesota
- Demand side management, customer involvement in managing loads
- Estimated costs for the utility and financial model development

The RPU is not required to file the Plan with a regulatory agency at the state or federal level. However, the Plan is organized and includes the basic requirements of these types of studies performed by state regulated entities.

The analysis required to support these decisions is the subject of this report. RPU retained Burns & McDonnell to assist the RPU in the development of the Plan. The first effort was to analyze the power supply needs to the 2030 time frame in order to identify any longer term issues which could impact shorter term decisions. The major power supply resource issues which confront RPU include:

- The benefit of the Silver Lake power plant as a long term resource
- The investment in the Silver Lake power plant for emission controls
- The upgrade of the transmission capability into Rochester to allow firm use of the purchased capacity and energy
- The development of renewable resources to meet Minnesota requirements
- The participation in regional coal plants

The review of these issues was divided into two major time periods. The periods were from 2005 to 2015 and from 2016 to 2030. These time frames were developed to coincide with the termination of the Minnesota Municipal Power Agency (MMPA) contract, at which time the RPU will regain the complete output of the SLP for its own use.

The first period reviewed was from 2016 to 2030. This period allowed a review of the load growth of RPU compared to the available resources. Various generation expansion plans were evaluated which included futures with differing amounts of the SLP available.

The second period reviewed was from 2005 to 2015. This period was reviewed after the later period to determine what shorter term actions needed to be taken in order to efficiently invest capital to support RPU’s longer term power supply plan.

Methodology

The initial effort in the review was for RPU to determine what the major decisions and future options available to meet its power supply requirements might be. The use of a decision tree process resulted in identification of the decisions, assumptions and sequencing of the issues. The development of the analysis required review of the following issues:

- RPU's projected demand and energy requirements
- Status of RPU resources
- Sources of energy
- Transmission capabilities
- Renewable resource requirements in Minnesota
- Regional coal-fired generation projects

The review of the power supply alternatives for RPU was performed using a load forecast prepared by RPU over the study horizon. The forecast was applied to the hourly load profile of RPU which resulted in an hourly forecast for the entire study period.

A review of the load growth of RPU and the energy needs of the utility indicated that the energy available from the SMMPA would approach its maximum utilization in the 2010 to 2015 time frame. Resource planning is needed to determine the future requirements of the utility considering various scenarios for the MMPA contract, the contract for steam sales to the Mayo clinic, improvement of the transmission system and the future of the SLP.

Burns & McDonnell reviewed the projected demand and energy needs of RPU. These needs were compared to the existing sources, which allowed the resource needs of RPU to be identified. The development of these items allowed expansion plans to be created. These plans were reviewed using an hourly costing model which allowed each expansion alternative to be evaluated for fixed and variable costs. Assumptions for the analysis were developed by Burns & McDonnell with input by RPU.

In order to assist in developing the various futures for power supply which RPU could pursue, decision tree analysis was used to organize the options. Meetings were held with RPU to construct the decision tree used to organize the analysis. Risk assessment was performed on the various futures to identify the variability of the outcome with changes in the assumptions. A summary decision tree from the more extensive one developed with RPU is shown in Figure I-1 at the end of this section. This decision tree is for the period 2016 to 2030.

Burns & McDonnell used an hourly and monthly spreadsheet production cost model to review the costs of the various futures considered. The use of this model allowed application of ranges of probable values for certain assumptions to determine the risk of various futures. Estimates and projections prepared by Burns & McDonnell relating to interest rates and other financial analysis parameters, construction costs and schedules, operation and maintenance costs, equipment characteristics and performance, and operating results are based on our experience, qualifications and judgment as a professional consultant. Since Burns & McDonnell has no control over the numerous factors affecting the basis for the estimates and projections, Burns & McDonnell does not guarantee that the actual future costs will not vary from those used by Burns & McDonnell in the preparation of this study.

Study Development

The power supply study is the initial effort for the overall development of the RPU Plan. RPU desired the review of supply side expansion plans first to allow study of effective, economical demand side management, other customer related options and renewable energy resources to reduce or eliminate the need for development of additional traditional supply side resources.

Report Organization

Part II provides the review of the existing RPU resources and of the supply side resources considered to meet RPU's future demand and energy needs. Part III discusses the portfolio analysis of the various approaches and provides conclusions and recommendations on the attractive alternatives and other issues associated with the supply side needs. Part IV provides the projected resource requirements of RPU over the study period which allows the estimated timing and needs for additional funds. The demand side and renewable analyses are included in Part V of this study. Part VI includes detailed financial forecasts for a variety of futures.

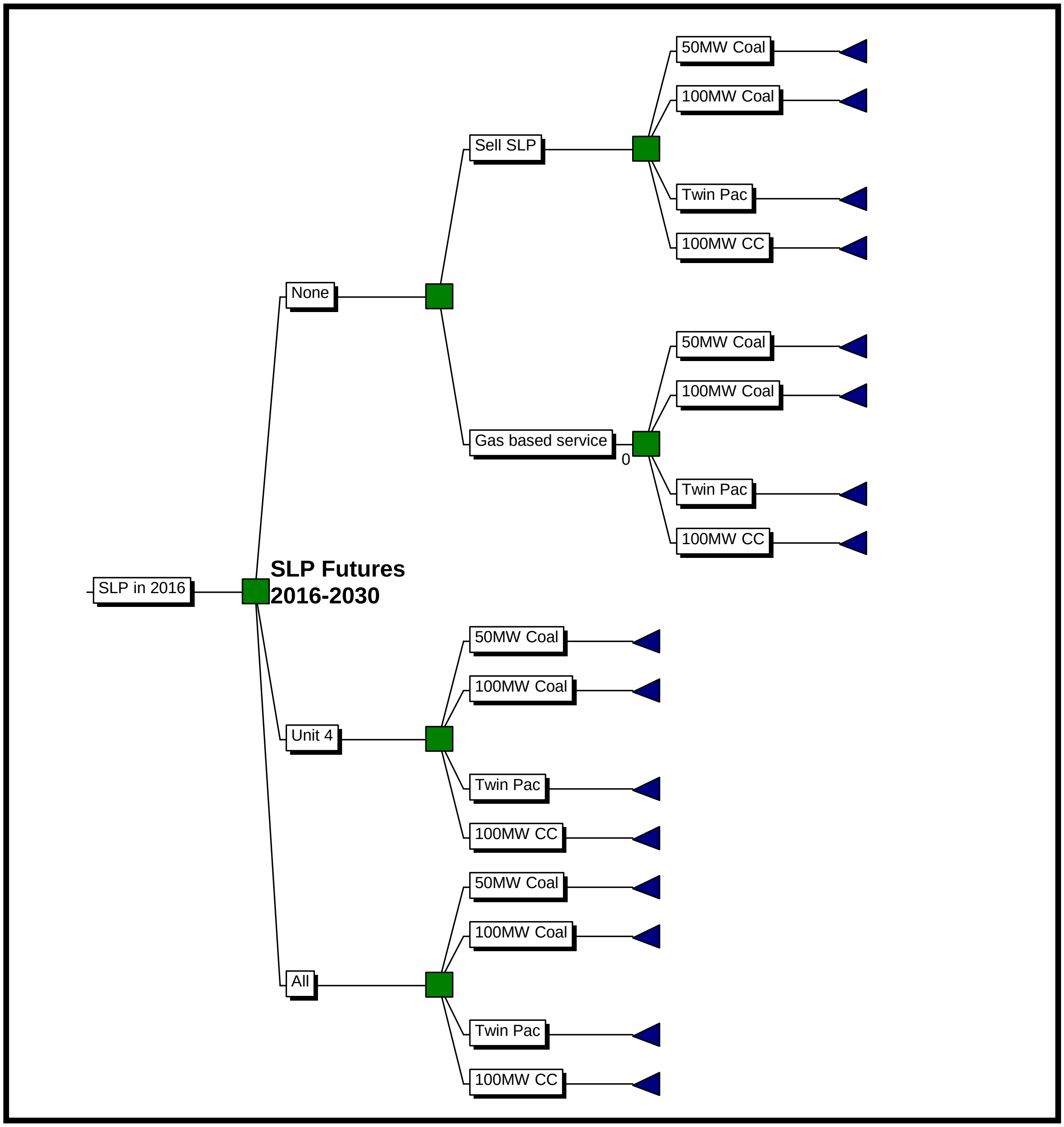

Figure I-1
Summary Decision Tree
Traditional Power Supply Options

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Part II

Power Supply Resources

Rochester Public Utilities (RPU) is responsible to meet the electrical energy needs of the citizens of Rochester, Minnesota and certain areas surrounding Rochester. The loads include general residential and commercial loads as is typical of large metro areas. Larger customers served by RPU include the various hospitals within Rochester, such as the Mayo Clinic, and a large IBM facility. RPU owns and operates generation resources to meet its demand and energy needs. RPU is also a member of the Southern Minnesota Municipal Power Agency (SMMPA) which provides RPU with a major portion of its energy requirements.

This part of the report discusses:

- RPU's projection of its demand and energy needs
- The existing RPU supply side resources
- Options for meeting demand and energy needs

Load Forecast

RPU continually reviews its demand and energy requirements. The development of the forecast considers the historical load growth, effects of economic development, weather, the impacts of ongoing demand side management programs and various other factors. RPU develops the forecast and applies it to a typical yearly hourly load profile. This provides an hourly load forecast for the study horizon to 2030. The forecast provided by RPU is summarized on an annual basis on Table II-1. The monthly and hourly load forecasts are included in Appendix I.

The RPU load growth is closely linked to the growth of the Mayo Clinic and other major employers in the area. Average system growth is projected by the RPU forecasting group to be approximately 2.7% per year between 2004 and 2030. This compares to an average compound growth of 3.5% over the past 15 years.

There are considerations of large employment opportunities in the RPU area, such as the Genomics facility. Also, Rochester is discussing annexation of various areas around the current city limits. These issues could have substantial impacts to the system resource requirements.

Table II-1
RPU Forecast of Demand and Energy
2003-2030

Year	Annual Peak Demand (MW)	Total Annual Energy Requirements (MWh)
2003	261	1,306,276
2004	268	1,344,534
2005	276	1,377,767
2006	283	1,414,967
2007	291	1,453,171
2008	299	1,495,732
2009	307	1,532,702
2010	315	1,574,085
2011	323	1,616,585
2012	332	1,663,932
2013	341	1,705,059
2014	350	1,751,096
2015	360	1,798,375
2016	370	1,851,046
2017	379	1,896,798
2018	390	1,948,012
2019	400	2,000,608
2020	411	2,059,202
2021	422	2,110,100
2022	434	2,167,072
2023	445	2,225,583
2024	457	2,290,766
2025	470	2,347,559
2026	482	2,410,943
2027	495	2,476,038
2028	509	2,548,370
2029	522	2,611,549
2030	537	2,682,061

Resource Review

RPU has a number of resources to meet its demand and energy requirements. These include a diverse mix of coal, gas and hydro-electric generating units. The RPU also has a significant amount of energy provided under its contract with the SMMPA. The units owned and operated by RPU are located at the following sites:

- Silver Lake Power Plant
- Cascade Creek Substation
- Zumbro Hydro Plant

To efficiently manage its resources, RPU has entered into contracts for electric sales to the Minnesota Municipal Power Agency and for steam sales to the Franklin Heating Station (Mayo Clinic). These contracts are furnished from the Silver Lake resources. Based on a forecast of expected resource allocations for these sales, the resources that RPU will have available to meet its obligations are summarized in Table II-2 and shown graphically in Figure II-1.

Figure II-1
RPU Forecasted Load and Resources

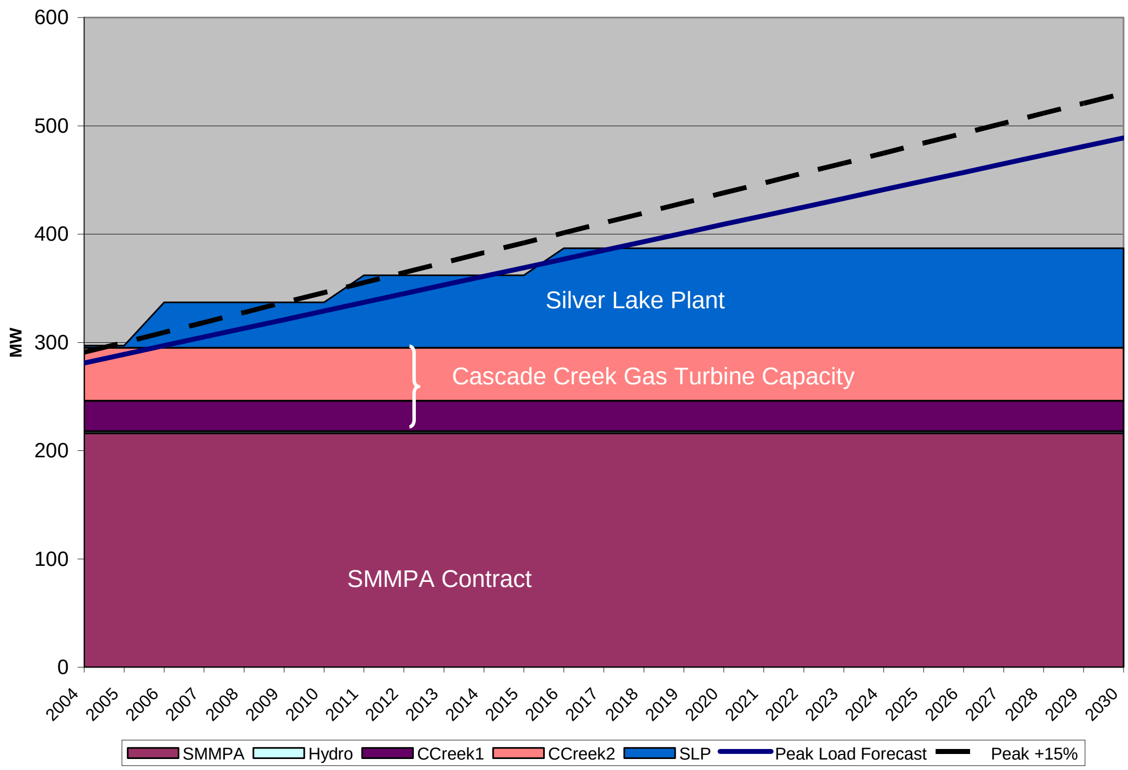


Table II-2

RPU GENERATION CAPABILITY FORECAST 2004 - 2030

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak Load Forecast	270	277	284	292	300	308	316	325	334	343	352	362	371	381	392	402	413	424	436	447	460	472	485	498	511	525	539
Peak Load w15% Reserves	278	286	295	304	313	322	332	341	351	362	372	383	395	406	418	430	443	455	469	482	496	510	525	540	555	571	588
Generation Capability SMMPA w15% Reserves	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216
SLP Capacity Available w/ Mayo project	2	2	52	52	42	42	42	67	67	67	67	67	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92
Hydro	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Gas Turbine 1	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
Gas Turbine 2	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Available RPU Capability	81	81	131	131	121	121	121	146	146	146	146	146	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171
Total Generation Capability	297	297	347	347	337	337	337	362	362	362	362	362	387	387	387	387	387	387	387	387	387	387	387	387	387	387	387
Excess Capability	19	11	52	43	24	15	5	21	11	0	-10	-21	-8	-19	-31	-43	-56	-68	-82	-95	-109	-123	-138	-153	-168	-184	-201

As shown in the above table and graph, RPU becomes resource deficit in 2013. The following paragraphs provide a description of the above resources and issues associated with continued production from the generating units over the study period. Detailed assumptions about the units and their operating parameters can be found in Appendix II.

Silver Lake Plant

The Silver Lake Power Plant was conceived by the RPU during World War II. The first unit rated 7500kW was in full service in December, 1949. The annual growth of Rochester electrical load in the late 1940s was approximately 15 percent. This growth prompted planning for a second unit that was brought on line in 1953. This unit was sized to 11,500kW.

Continual planning due to load growth and attraction of customers such as IBM indicated that a third unit at the plant was needed. The unit was sized at 22,000kW. Construction began in mid-1961 and the unit went into commercial operation in November, 1962. This unit was cooled with a cooling tower and also with cooling water from Silver Lake. The resulting warm water allowed portions of Silver Lake to be ice free in the winter, leading to the attraction of the Canadian Geese to winter on the lake.

Average energy consumption per customer essentially doubled between the mid-1950s and late 1960s. In addition, the population of Rochester continued to expand. The fourth unit added at SLP was part of a larger overall power supply expansion plan. This unit was rated at 58,000kW. This unit was constructed with an electrostatic precipitator to remove particles from the unit's emissions. The construction of the unit was completed in 1969.

Fuel for the plant was provided by natural gas and coal. The utility conformed to Pollution Control Agency guidelines and installed precipitators on each of the three remaining units in the 1970s. The plant has been operating steadily since its units went commercial. Reduced utilization of the plant occurred in 1988 due to RPU's participation in SMMPA. The Sherburne County Unit 3 went commercial in 1988 and all of the requirements of the RPU could be met with SMMPA resources. When SMMPA provided all of the energy requirements of the RPU, the excess capacity and energy of the SLP was contracted to the Minnesota Municipal Power Agency. Current usage of the plant to meet steam and electricity contract sales maintains its viability and usefulness. The RPU capped its purchases from the SMMPA in 2000 and is providing the capacity and energy above a base amount of 216MW.

Plant Basics

The SLP consists of four boilers which produce steam to operate steam turbine-electric generator combinations that are dedicated to each boiler. Figure II-2 shows the SLP with Unit 1 on the left. The units in the plant can be fired on coal or natural gas.

Figure II-2
View of the Silver Lake Power Plant

The SLP is required to operate within the guidelines of the Mid-Continent Area Power Pool (MAPP). The MAPP requirements include regular testing of the units in the power plant to make sure they can deliver the power that the RPU records for their capacity. These tests have shown that the plant has the capabilities shown in Table II-3:

Table II-3
Unit Data

Unit	Installed Date	Tested kW (2002)
1	1949	9,360
2	1953	14,520
3	1961	24,000
4	1969	61,945
	Total	**109,825**

Environmental

The SLP is operated to minimize environmental impacts to the Rochester area and in compliance with federal and state environmental regulations. The units are equipped with particulate controls. RPU purchases low bituminous sulfur coal for the plant to minimize the release of sulfur dioxide and comply with emission limits contained in the operating permit.

There are a variety of recently enacted and newly proposed regulations which will affect electric generating plants. The regulations will affect all generating units at the SLP. These regulations may require additional emission control equipment be added at the plant or changes to the fuel used for energy production.

RPU recently completed a study on the environmental aspects of the SLP with regard to existing and potential environmental regulations. It is expected that the RPU will need to make investments in additional emission controls or implement other emission reduction strategies within the next 5 years. Various options are currently under consideration by RPU. Estimated impacts to the SLP have been considered in this study using the results of the environmental report "Analysis of Existing and Potential Regulatory Requirements and Emission Control Options for the Silver lake Plant".

Due to the permit restrictions contained in the current air permit SLP, Unit 4 is limited to a 60-70% annual capacity factor. This will be significantly reduced if the recently proposed Interstate Air Quality Rule is promulgated and no modifications are made to the SLP.

Sales

The SLP has two contracts for energy sales. The MMPA contract provides for electrical sales to the MMPA when the units are available. The contract has various options for RPU to reduce the amount of capacity offered to MMPA. These options to adjust capacity allocated to MMPA under the contract are available in 2005 and 2010. The above balance of loads and resources reflect the current thinking of RPU on the amount of capacity which will be available to RPU from the contract.

The steam sales to the Franklin Heating Station are going to begin 2004. The steam sales are not anticipated to limit the electrical output of the steam generators until after the 2010 time frame. These reductions in electric capacity have been accounted for in the balance of loads and resources.

Retirement

Units 1-3 at the SLP will be attaining almost 65 years of service in 2015. Unit 4 will be reaching 45 years of operation. The investment in maintaining the units in operable condition has been estimated and included in the analysis. One of the major investments to be considered is the environmental controls required to keep the units in compliance with expected future environmental regulations. A recent study prepared for RPU by R.W. Beck and Associates has provided several options and their associated costs for the units with regard to compliance with anticipated future environmental regulations.

Although the components of the units can be repaired or rebuilt to keep the units in serviceable condition using after market providers and salvage operations from similar retired units, the efficiency of the units is below current technology being developed for coal fired power plants. Due to the age, size and efficiency of units 1-3, these units, if maintained, will most likely be used only for regulatory reserve service with minimal operating time.

Cascade Creek

The RPU has two units in the Cascade Creek substation. Cascade Creek Unit 1 was installed in 1975. The unit is a Westinghouse 251 machine and has a capacity rating of 28MW. Modifications to the unit in 2002 allow the unit to be operated on fuel oil or natural gas. The unit is reaching a point where replacement parts are becoming difficult to obtain. Aftermarket manufacturers can support the unit for some time. However, RPU plans on retiring the unit after 2015. The retirement of this unit will increase the deficit after 2015 by 28MW.

Cascade Creek 2 is a Pratt and Whitney FT8 Twin Pac, which became commercial in 2002. The unit is rated at 49MW. The unit consists of a single electric generator with dual engines based on aircraft engine technology. The dual engine approach allows the unit to be operated at half load with high efficiency. This flexibility minimizes operating costs when RPU needs resources to follow load more closely. This unit is assumed to be operational throughout the study period.

Zumbro River

The Zumbro River hydro-electric plant is a run of river unit located on the Zumbro River. The plant is located 10 miles to the north of the city. The unit was installed in 1919 and has a maximum capacity of 2MW. The unit has a typical annual capacity factor of 50 percent. Although the unit is over 80 years old, significant investment has been made in the facility and it is assumed to remain available throughout the study period.

Southern Minnesota Municipal Power Agency (SMMPA)

RPU began taking power supply from the SMMPA in 1982. The SMMPA provided all requirements service to RPU until 2000 when RPU accepted an offer to limit its purchases from the SMMPA. The contract rate of delivery (CROD) was set at 216MW. RPU is required to take all energy from the SMMPA when the demand is at or below the CROD level. The SMMPA will provide the CROD throughout the study period.

Transmission Issues

Electrical System Reliability

To operate reliably and in compliance with NERC and MAPP standards, RPU and other electric utilities developed their systems to operate with no noticeable degradation of service in the event of a loss of a system facility. In many cases, this is true even when an outage of a major system element coincides with the outage of another element for maintenance.

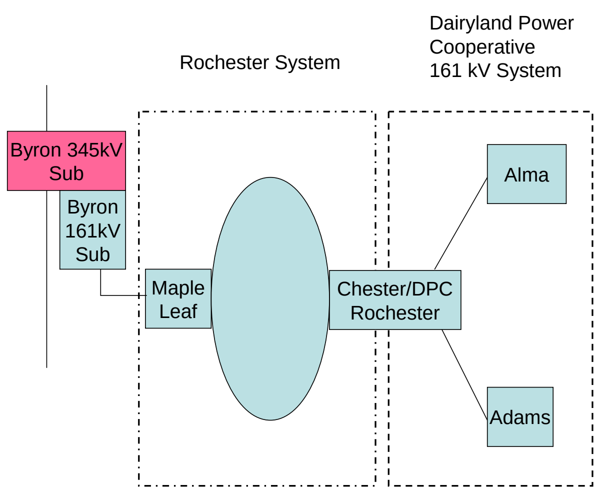
Changes in the electric industry over the past several years have caused the reliability of the system for delivery of firm energy to degrade. Increased use of the system for market transactions has increased loading of the system to the point that when outages occur, the remaining system is left with a reduced capability to transfer power over interconnections. Recent uncertainty in the ownership, operation and regulation of the transmission system has left the responsibility to correct system deficiencies in question.

RPU imports a significant amount of energy under its contract with the SMMPA. The transmission system which interconnects RPU to the regional transmission network is configured as indicated in Figure II-3. The strongest source to the interconnected network is through the Byron substation and is the primary path for the SMMPA energy.

With all of the lines in service, the system was designed to allow firm importation of the SMMPA energy whenever RPU called for it.

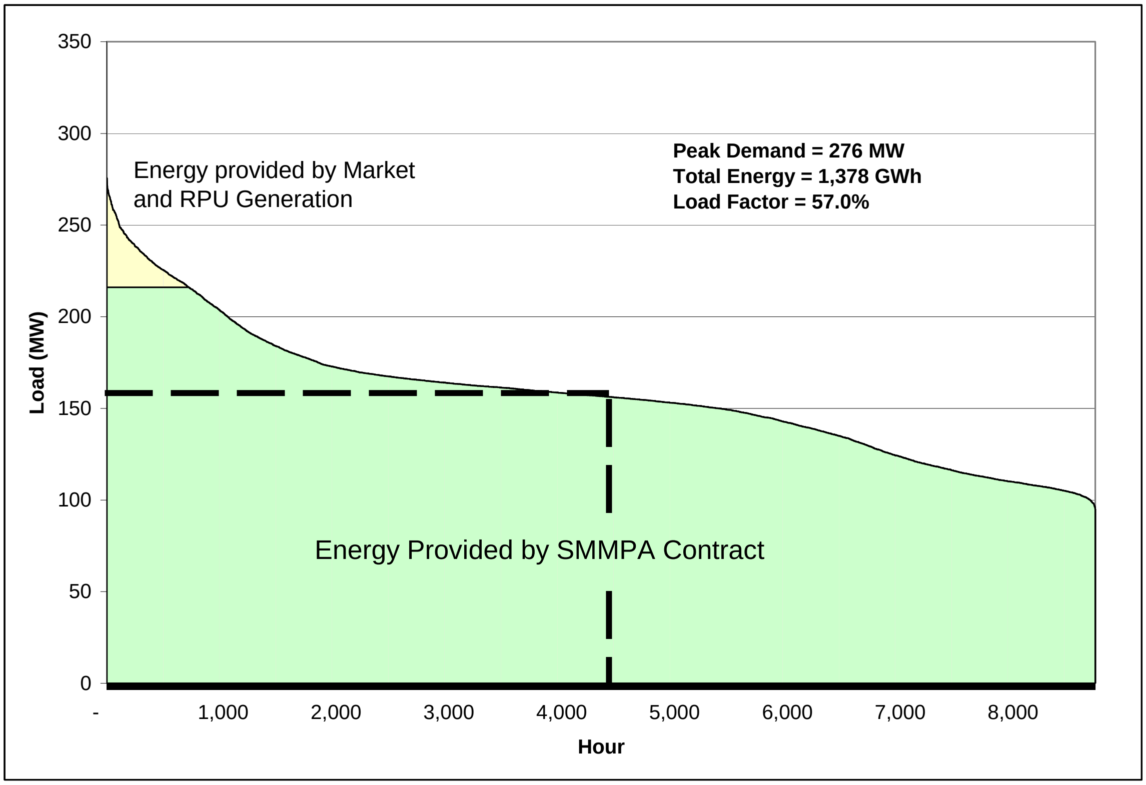
Recent changes in the usage of the system by others have led to curtailments of energy imports with the regional interconnections intact. An example of the transmission limitations that exist occurred on August 12, 2003 from 20:00 hours to 22:00 hours. RPU was required to generate because SMMPA was not able to secure transmission to deliver the energy required by RPU to meet loads. This condition is interesting because RPU's load was below the CROD level of 216 MW, for which RPU pays firm delivery. This condition is expected to escalate both in magnitude and frequency. Under current plans, no relief of the transmission situation in Southeast Minnesota is expected before 2010.

Figure II-3
Area Interconnections with RPU



With the Byron/Maple Leaf 161 kV line out of service, voltage and other considerations on the Dairyland Power Cooperative system limit the ability to import energy from the interconnected system to about 160 MW. Figure II-4 shows a load duration curve projection for 2005 for the RPU load. This curve shows the magnitude of the load in each of the 8760 hours of the year in order from highest to lowest. As shown, the RPU load alone is projected to be above the 160 MW level of import approximately 50 percent of the time. The use of generation internal to the area, such as the SLP is required to mitigate the risk of blackout during this condition.

Figure II-4
RPU 2005 Load Duration Curve



Another situation also requires the use of RPU generation to assist the area interconnected network. The rating on the Byron/Maple Leaf 161 kV line is a limiting factor in setting the transfer limit on the Byron 345 kV lines. The rating of these lines is a contributor to the calculation of the capability to import and export power from Minnesota to Wisconsin and points south and east. RPU, as a part of the interconnected system and with generation accredited in MAPP, is obligated to operate generation to assist these transfers during certain system outages. Running RPU generation is a partial mitigation for certain outages. While the RPU does not specifically benefit from this operation, it is an obligation that may be incurred from time to time.

The above discussion provides a description of the area interconnection limitations to which the community of Rochester is exposed. RPU faces several impacts due to these limitations. The SLP and Cascade Creek generating units assist in reducing the impacts and thus the costs to RPU and the community of Rochester. The increased reliability for Rochester is increased in numerous ways by the generation located within the service area of RPU.

The electrical wholesale market is moving towards a new market operation being promoted by the Federal Energy Regulatory Commission (FERC). The new operation is based on the concept of locational marginal pricing (LMP). The concept behind LMP is that the energy from generation required to alleviate a transmission constraint will be higher cost than the energy that could be imported if there were no constraint. Since Rochester is in a constrained load pocket, it could be subjected to substantial costs if the SLP or Cascade Creek generation was not available. The generation located in the RPU service area will reduce the exposure to market pricing and high LMP costs.

System Improvements

RPU is undertaking studies with regional utilities to assess options for reducing the constraints into the southeast Minnesota region and Rochester. Several transmission projects are being considered which will affect the 161kV and 345kV systems in the region.

The development of a project to increase the transfer capacity into the RPU service territory is important to allow RPU to rely on the firm delivery of its CROD amount. In addition, it is also desirable through the development of a project to have increased transfer capacity for importation of market power or participation in regional projects, such as for a coal or wind resource, on a firm basis.

Use of local generation is becoming more of an issue as regional loads increase and the capability of the transmission system becomes more limited. Due to must run issues during portions of the year and contract requirements of MMPA, the SLP is required to remain operational for the foreseeable future. The current limitations on the transmission system being below the level required to support the RPU load from outside resources point out the importance of generation internal to the RPU service area.

Potential Resource Options

The capacity needs of RPU are projected to increase substantially over the study period. The range of capacity needs is reflected in Table II-4 for various retirement scenarios of Cascade Creek Unit 1 and Silver Lake Plant Units 1-4.

Table II-4
Range of Capacity Requirements for Various Retirements Scenarios
(MW of Capacity Deficiency)

	2016	2020	2025	2030
All Units in Service	8	56	123	201
Retire CC Unit 1	36	84	151	229
Retire CC1, SLP 1-3	83	131	198	276
Retire CC1, SLP 1-4	128	176	243	321

In addition to an assessment of demand shortfalls, a review of energy needs is also necessary to determine if only peaking type resources are needed, or if low cost energy, reflective of intermediate or base load resources, is potentially beneficial. Figures II-5 A through C provide the estimated load duration curves for RPU for the years 2005, 2010 and 2015, respectively.

Figure II-5A
Approximate RPU Load Duration Curve
2005

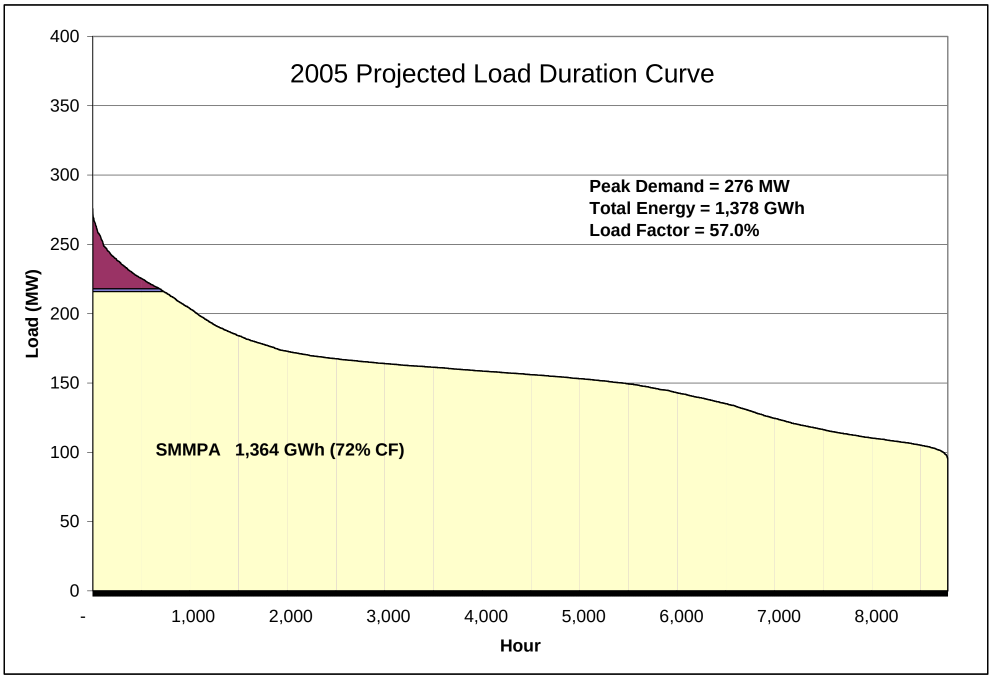


Figure II-5B
Approximate RPU Load Duration Curve
2010

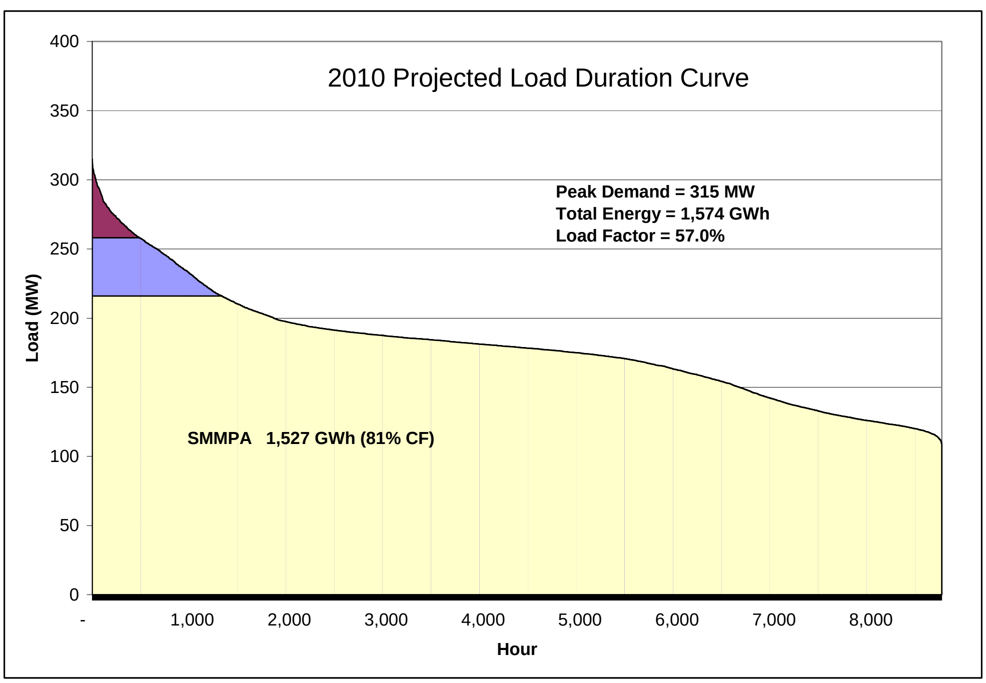
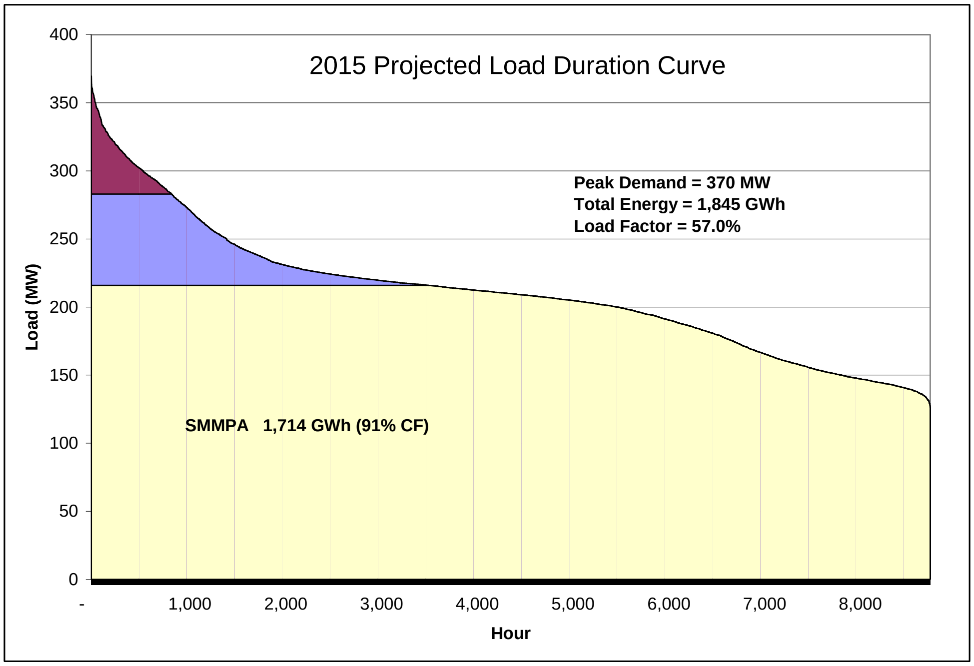


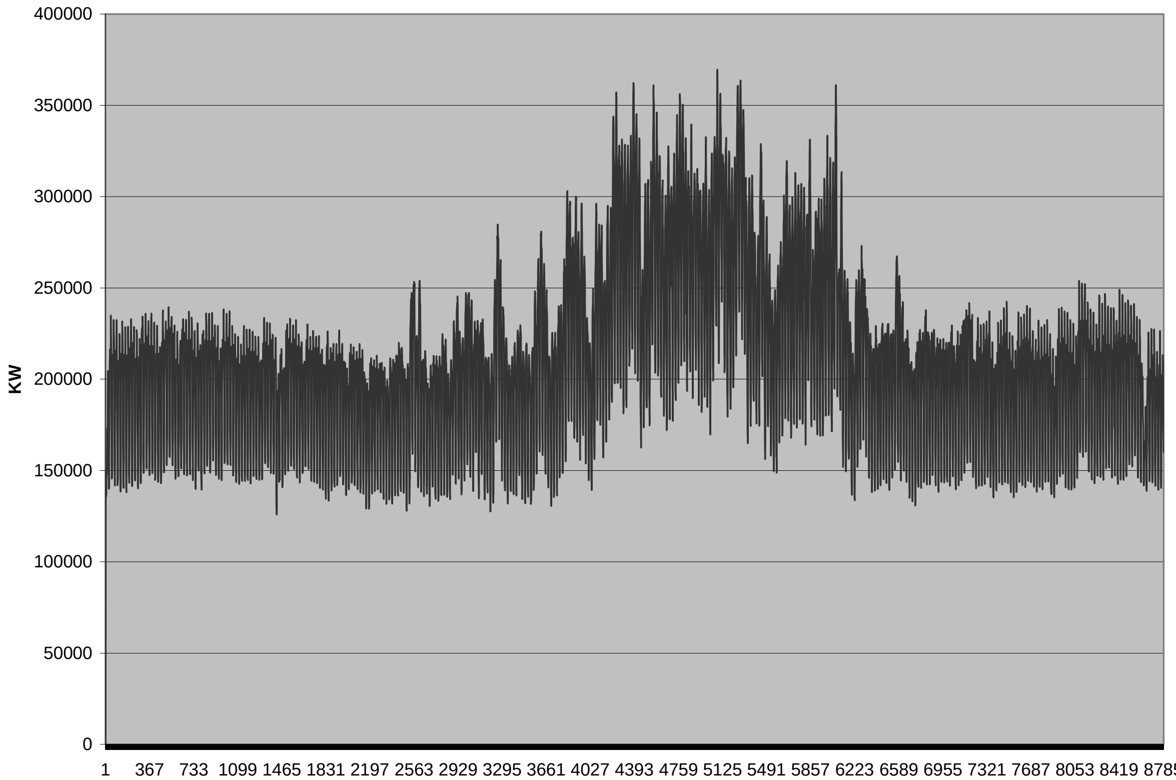
Figure II-5C
Approximate RPU Load Duration Curve
2015



A review of the load duration curves indicates that the SMMPA CROD level would approach its maximum utilization in the 2010 to 2015 time frame. The energy (represented by the colored areas above the SMMPA energy) would be provided by RPU. Therefore, in addition to capacity needs, RPU will also need to consider the availability of low cost energy resources for the period beyond 2016.

The projected hourly loads for RPU during the year 2016 are shown in Figure II-6. Review of the hourly loads indicates that the majority of the RPU needs occur in the summer months, between May and September. There are several hours when the load will be below the CROD level. This indicates that resources may need to be cycled if load following is required.

Figure II-6
RPU Projected Hourly Load – 2016



The operational issues associated with meeting the projected RPU load requirements can also be reviewed by looking more closely at the load swings. Graphs for the hourly loading during winter and summer weeks are shown in Figures II-7A and B respectively for every five years from 2016 to 2030. The growth in the daily swings from winter to summer provide an indication of the seasonal types of energy needs which RPU will be required to provide. The load on the figures is the load above the CROD amount. Therefore, the zero point on the vertical axis represents a load of 216MW, provided by the SMMPA contract.

Figure II-7A
RPU Projected Hourly Loads Week of January 1-7

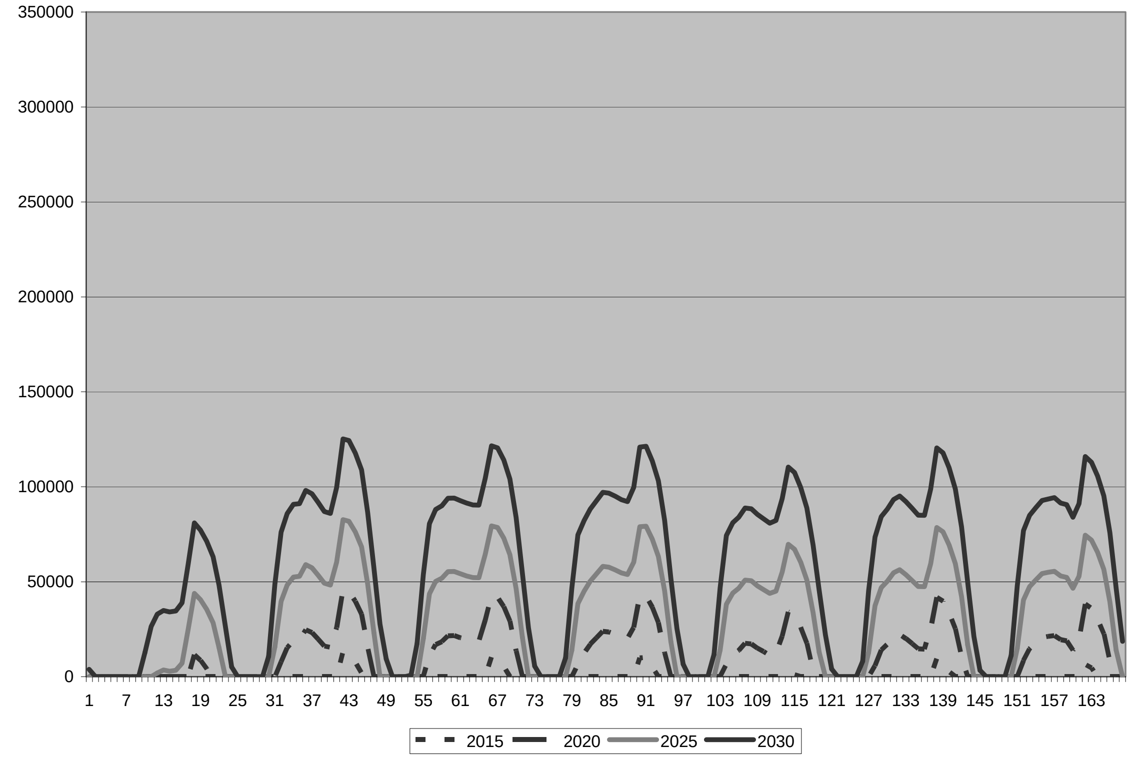
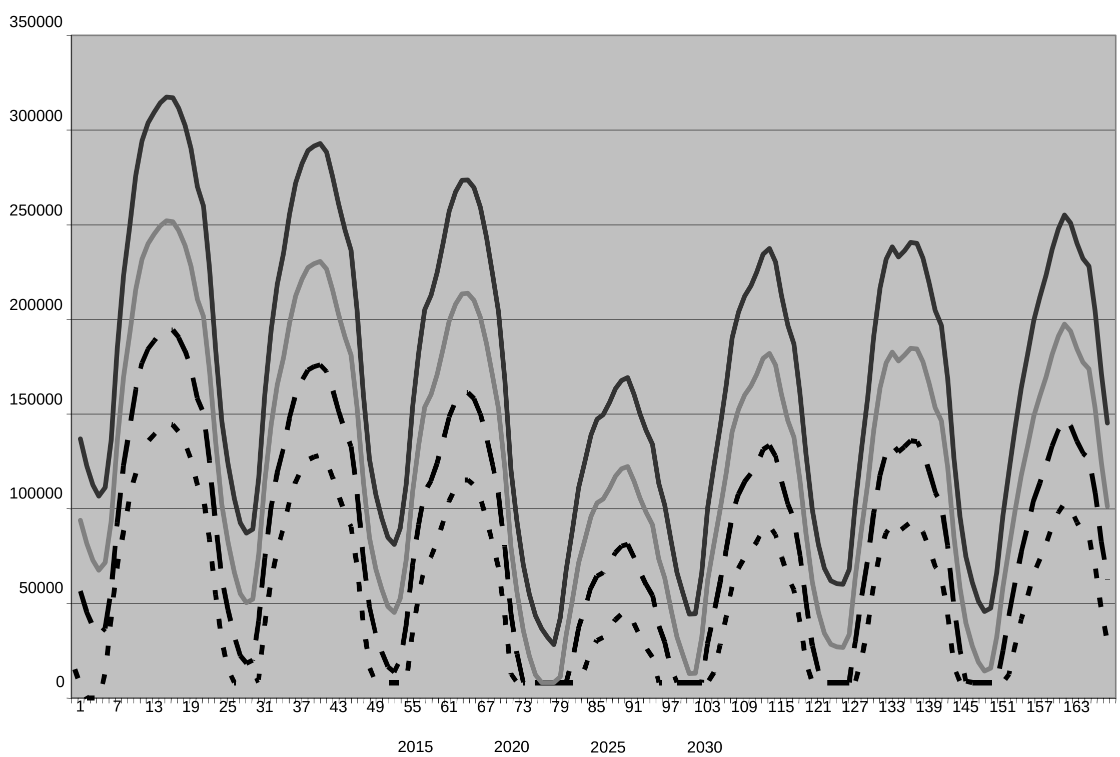


Figure II-7B
RPU Projected Hourly Loads Week of July 1-7



Fuel Considerations

The availability to develop resources within a utility's service area requires a review of area capabilities for the delivery of low cost fuel for the units. Current utility options for fuel include coal, natural gas, fuel oil, water, and renewable options such as solar, wind and biomass.

Coal

RPU currently burns coal at the SLP facility. The coal is delivered by barge/truck and rail, with approximately 50 percent delivered by each method. It is not expected that the consumption of coal will increase beyond the limitations of the permits for SLP Unit 4. If RPU pursued the development of an additional coal resource within its service area, rail facilities to deliver the coal from the Powder River Basin in the west or from eastern mines, besides those currently available from Illinois and Indiana, would need to be expanded. Currently, the RPU service area has a rail line being reactivated which would allow delivery of Powder River Basin coal. Acquisition of several hundred acres of property adjacent to the rail line would be required or a rail loop would have to be constructed if the property was located remote from the rail line.

The use of coal by the utility industry is expected to increase. Its availability within the United States has certain security advantages. Its price has been historically low and stable when compared to natural gas and fuel oil. Its main disadvantage lies in the emission during its combustion. New requirements are increasing the controls necessary on new coal plants to reduce the emissions to levels that are approximately one tenth of units constructed under prior Clean Air laws.

Natural Gas

The use of natural gas in new utility plant is typically limited to simple or combined cycle applications. Modern gas units require gas pressures typical of interstate lines. Additional gas based resources for RPU would require the acquisition of additional property, since the existing Cascade Creek site is fully utilized and the SLP site has inadequate gas capacity. Modern units could be placed on a site of less than one hundred acres.

The historical availability of natural gas has been such that it was abundant in the summer months when residential and commercial heating demands were low and subject to interruption during the winter when the heating demands increased. When utilities developed the peaking gas resources, they were typically required in the summer with minimal expectations for operation in the winter. Utilities relied on this pattern and purchased the gas on a non-firm basis to reduce delivery costs. For the minimal hours of operation in the winter, back up operation on fuel oil could be relied on if the gas delivery was curtailed.

Recent demands for peaking and combined cycle energy fired from natural gas in both the summer and winter have increased to the point where the electric utilities are affecting the storage and availability of natural gas. In addition, due to environmental restrictions, more natural gas is used by many utilities to achieve compliance with their operating permits, which occurs primarily in the summer months. The use of non-firm purchasing approaches to the gas is becoming more of a problem in the winter months as utilities are required to provide increasing amounts of energy from these units to meet winter demands.

Dependence on natural gas by the utility industry has become more of a concern as the United States becomes an importer of the fuel from Canada and through liquefied natural gas ports from other countries. The cost of gas is expected to remain volatile and increase with the increasing demand for it by other countries as their economies improve. It is expected that over the study horizon, natural gas costs will not only increase due to commodity pressure, but from the need to firm up the delivery as well.

Other Options

The use of fuel oil is only considered on an emergency basis or when its cost is below the cost of natural gas. Emissions from use of fuel oil in electric plants typically restrict its use to few hours of the year. It is not considered as a basis for any resource expansion plan for RPU.

RPU and the surrounding regions do not have significant access to hydro-electric based development. The current hydro resources are fully committed. One area of potential access to hydro-electric power is the further development by Manitoba Hydro of projects that have been considered for several years. Access to this energy would require significant improvement in the region's transmission facilities.

Renewable resources are an increasing source of energy for utilities. Wind is the primary source and Minnesota has several hundred megawatts of wind in operation and more is being developed. In addition, wind resources are being developed in the neighboring states of Iowa, South Dakota and North Dakota are developing wind resources. Solar is becoming an increasing option for higher cost utilities on the east and west coasts as the cost of solar systems decrease and the cost of the utilities' energy increases.

A consideration for the use of solar and wind is the inability to dispatch the resource. Variability and availability of the energy can create operational issues with area generating units and can lead to a degradation of frequency and voltage control if the amount of solar and wind energy becomes a high component of the utility's energy needs. The inability to dispatch the resources has to be considered with regards to the CROD requirements.

Biomass is another option for renewable energy. Biomass plants are typically rated below about 50MW and operate in a steam cycle similar to the SLP plants. The candidates for biomass are typically;

- wood chips and other tree product residues,
- agricultural wastes such as fruit pits and nut hulls, and
- grasses.

The limiting factor on the development of a biomass plant is the availability of fuel. These plants are developed in areas where there is a continuous, ready availability of the fuel. Due to the poor storage capabilities of most of the candidate biomass fuel options, a continuing supply of quality fuel is necessary to make the process viable. The regional surrounding RPU is not known to have an adequate supply of typical candidate biomass fuels.

However, there is one area where RPU may have access to a limited amount of biomass fuel. Minnesota has also included municipal solid waste as a biomass fuel under Minnesota 2003 Statute 216. Therefore municipal waste and refuse derived fuel (RDF) burned in a power plant will be counted as biomass energy. The availability of RDF is typically sufficient in municipal areas the size of Rochester to support several megawatts of RDF fired generation.

Olmsted County has developed a municipal solid waste to energy facility. The Olmsted Waste to Energy Facility (OWEF) currently produces approximately 1.9MW of biomass fueled energy. This resource could be a source of biomass energy for RPU.

Summary

The RPU is confronted with several long term decisions associated with its generation and transmission resources. Based on the review of the resource issues as identified in this part, the following observations can be developed.

1. The projected load growth indicates that the CROD obtained from the SMMPA will essentially be fully utilized in the 2010 to 2015 time frame.

2. The SLP facility will be subjected to environmental regulations being implemented and future regulations under consideration. The cost of these regulations, the ongoing maintenance costs, sales obligations and the efficiency of the existing units require an assessment of an RPU future with varying amounts of the SLP available.

3. The RPU transmission system supplying RPU is currently inadequate to deliver the firm requirements of the CROD amount and to be relied upon to provide firm access to outside resources. Therefore, any reliance on resources outside the RPU area for firm energy will require the upgrading of the system in the vicinity of RPU. Depending on the location of any resource in which RPU may want to participate or purchase capacity from, upgrades of the regional system may also be required.

4. RPU capacity needs include resources to provide low cost capacity and energy over the study period. The ability to acquire the capacity and energy from outside the RPU service territory or the need to locate resources within the service area will be dependent on the transmission system upgrades pursued in the region by regional utilities.

5. The existing RPU generation locations do not have adequate space or access to fuel and transmission to support significant additional facilities. RPU will need to acquire additional property to support most types of generation options constructed within its service area.

6. RPU has options for development of wind and solar units and purchasing biomass energy from the Olmsted Waste to Energy Facility for renewable resources.

7. The market changes in the electric industry surrounding RPU will impact the resource decisions. Due to the uncertainty associated with the implementation of the MISO market, the level of participation by regional utilities, and the rules which participants will be required to follow, it is difficult for any firm conclusion to be made on the availability of market capacity and energy as a reliable resource which could be used by RPU to meet its needs.

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Part III

Resource Options Analysis

Part II provided a review of the expected capacity and energy needs of RPU over the study period. From the review, RPU is expected to have needs for both capacity and low cost energy resources beginning in 2013 and increasing each year thereafter. Additionally, a discussion of the existing resources indicates that the Cascade Creek Unit 1 is anticipated to be retired in 2015. Also, the future of the SLP is uncertain due to the age of the facilities and the ongoing operation, maintenance and environmental upgrades needed to keep the plant operational. This part of the report discusses portfolio options considered for RPU using traditional resource options.

Regional Market Conditions

Coal Unit Development

RPU's projected need for low cost energy limits the traditional options for supplying this energy to energy produced by coal. The amount of capacity required by RPU is expected to be in the 50 to 100MW level. In order to attain reduced capital and operating costs, it is typical for utilities to join and construct a unit to be shared among several parties. Therefore, the ability for RPU to obtain coal energy is realistically dependent on participating in a joint facility.

The MAPP region maintains a 15% reserve margin and penalizes those utilities who fall below this level. As such, the capacity margins in the MAPP region are projected to be maintained to have sufficient generation available to meet unit outages and weather extremes. The generation used to meet the reserve margin in the MAPP region, as in other regions, has primarily been natural gas fired simple and combined cycle combustion turbine units. There are coal plants being considered in the MAPP region. Plants are being developed by the following entities:

- OPPD – 600MW Nebraska City 2. Participation in the unit is through contract sales. The unit is fully subscribed.
- South Dakota – A large coal plant in eastern South Dakota is being considered by regional utilities. Participation will be through ownership shares.
- Mid-American Energy – Council Bluffs Unit 4. Participation is through ownership shares. The unit is fully subscribed and under construction.

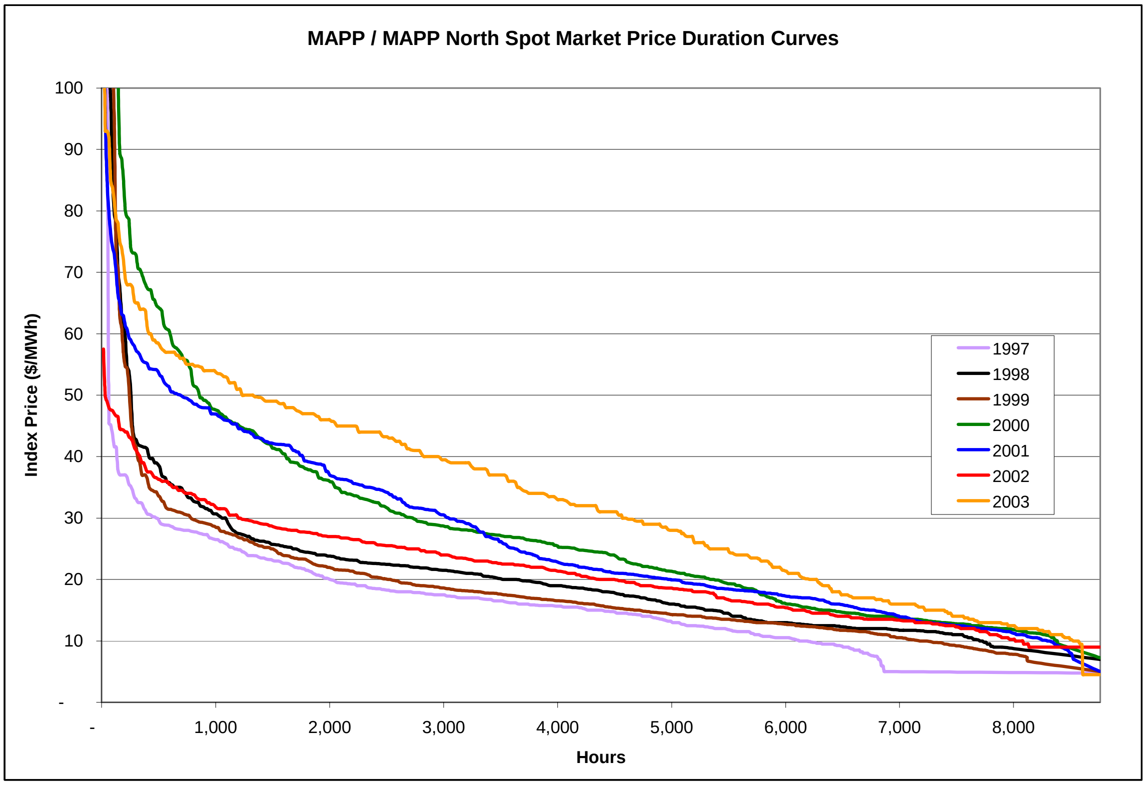
These plants are all located on the west side of MAPP. Significant transmission constraint and operational issues would need to be resolved before reliable firm service could be provided to RPU from these facilities. There are other utilities discussing units in MAPP which may offer reduced transmission delivery issues to RPU. In addition, RPU could join with other interested parties and develop a unit which could be sited more beneficially to RPU and have an in service date more in line with the needs of RPU.

Market Pricing

The power supply market in the MAPP regional is undergoing significant change. The Midwest Independent System Operator (MISO) is gaining operational control of a significant amount of transmission as utilities comply with orders of the Federal Energy Regulatory Commission (FERC) for regulated utilities to transfer operational control of their transmission systems to an independent operator. Additionally, MISO is furthering the FERC agenda of implementing a standard market design for the wholesale market. The operational rules of this market are currently being developed and the MISO is working towards implementation of the market by January 1, 2005. It is expected that this schedule will slip due to the numerous issues still to be resolved.

The MAPP regional has traditionally had a surplus of low cost energy. The pricing of this energy is increasing to reflect the marginal price of the combined cycle units that have recently been commissioned in the region and the need for additional base load facilities. Figure III-1 provides an indication of the increase in MAPP prices for the north region. The graphs reflect the increase in pricing due to the increased reliance on natural gas for electricity production.

Figure III-1
MAPP Spot Energy Pricing 1997-2003



The development of portfolio options for RPU considered the availability of a coal plant for RPU participation.

Resource Requirements

Portfolios were developed to reflect the decision tree issues associated with the following availability of the SLP beyond 2015:

- SLP fully retired
- Units 1-3 retired, Unit 4 remains operational
- All SLP units available

In addition, the retirement of the Cascade Creek Unit 1 was assumed to occur in 2015. The retirement of this unit increases the capacity required by 28MW in the study period.

Figures III-2 through 4 shows the balance of loads and resource for each of the above SLP futures.

Figure III-2
RPU Balance of Loads and Resources –No SLP

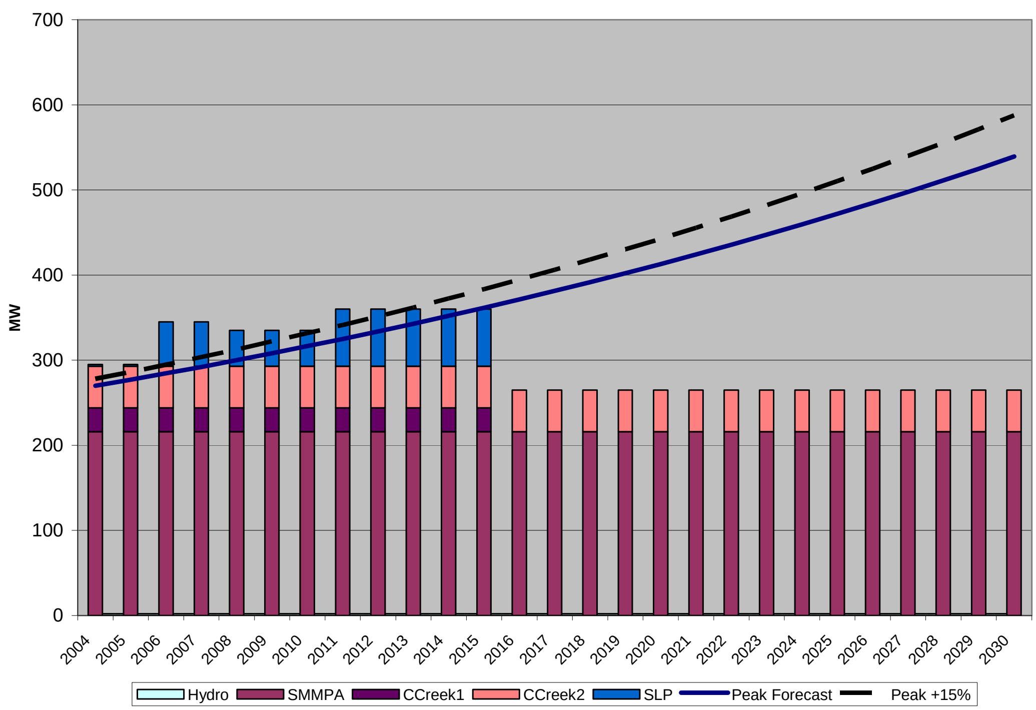


Figure III-3
RPU Balance of Loads and Resources -45MW of SLP

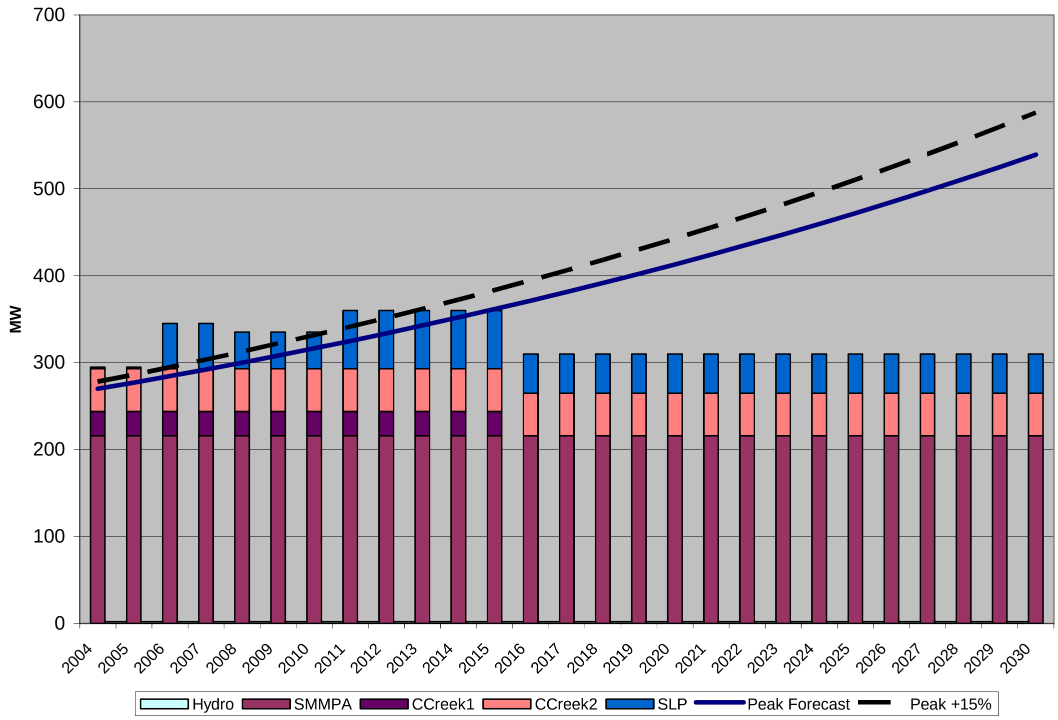
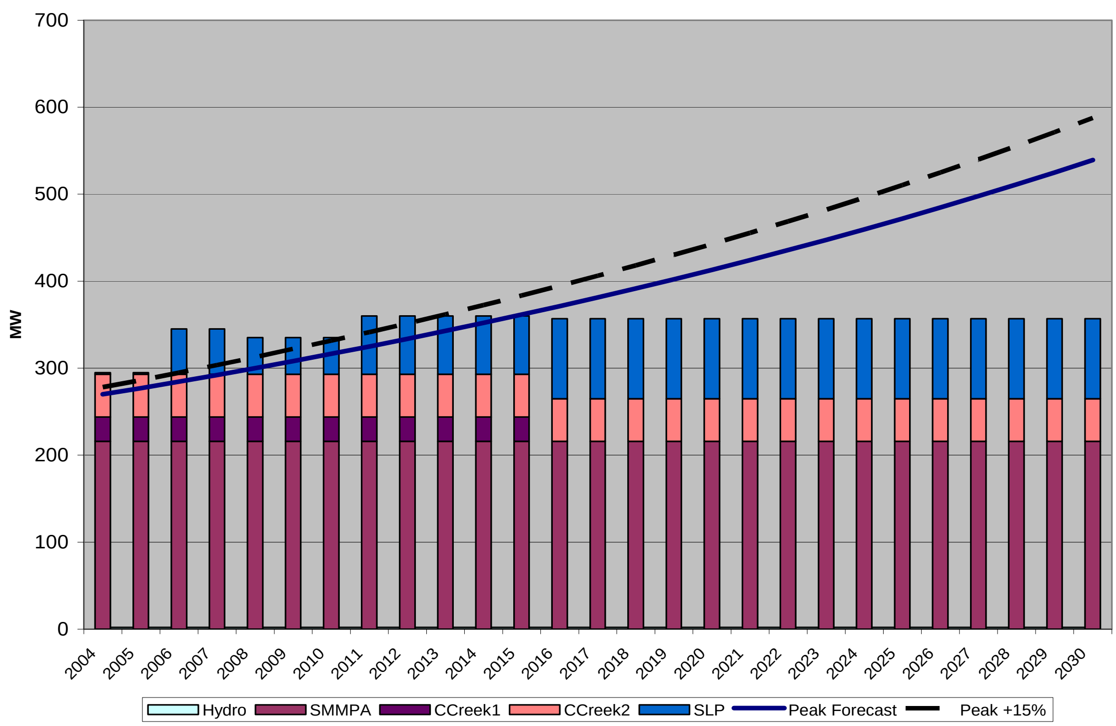


Figure III-4
RPU Balance of Loads and Resources –All SLP



The resource requirements were developed to maintain the reserve requirements of RPU. The current level of reserves is required by MAPP to be 15 percent of the amount of load requirements above the CROD amount.

Traditional Options

The traditional options included new resources fueled by coal and natural gas. These options are discussed in more detail in the following paragraphs.

Gas-Fired Options

Gas fired generation today is performed by combustion turbines operating in simple cycle or combined cycle mode. Simple cycle combustion turbines operate similar to jet aircraft engine technology. These units vent their exhaust direct to a stack and typically have efficiencies above 10,000 Btu per kWh. Combined cycle units include the simple cycle machine with its exhaust vented into a heat recovery steam generator (HRSG) and then through a stack. The steam produced by the HRSG drives a steam turbine/electric generator combination as in a typical steam driven plant. Combined cycle plants have efficiencies in the upper 6000 Btu per kWh range.

RPU currently operates two simple cycle combustion turbines. The new unit added at Cascade Creek is the latest to be added to the system. These units are typically operated when the load increases on the system during a few hours of the day. Simple cycle units typically have the lowest capital cost of larger generating options. Project costs in the range of $400 to $600 per kW are typical, with the smaller units having the higher cost per kW. Due to their efficiency, these units are typically operated at capacity factors below 15 to 20 percent.

Combined cycle plants have higher capital costs than simple cycle machines, due to the steam cycle cost. Project costs for these machines range from $500 per kW to $750 per kW, again with the smaller plants having the higher cost per kW. These plants have been the predominate plant installed by merchant independent power producers over the past few years and are expected to account for the majority of the installed capacity for the foreseeable future. Since these plants operate at higher efficiencies, they operate at capacity factors above those of simple cycle machines and are typically between 25-50%.

Gas-fired combustion turbines have nitrous and carbon oxides as their main emissions. Simple cycle units use water in emission control and in inlet air fogging systems. Combined cycle units also use water in cooling cycles for the steam condensing and boiler makeup.

The existing gas fired generation on RPU's system is used primarily for peaking and reserve service. The gas supply for these units is operated on a non-firm basis. Operating with a non-firm fuel supply allows the energy to be produced for essentially the cost of the gas commodity and a small delivery charge. RPU could develop gas-fired units within its service territory without the need for partners due to the lower effect of economies of scale.

Coal-Fired Options

Traditional coal-fired steam power plants are being considered for electricity production again as the cost of natural gas and the concern over its availability increases. Coal-fired plants, such as RPU's Silver Lake Plant, burn coal to produce steam which drives a steam turbine/electrical generator to generate electricity. Coal plants are being designed to reduce the emissions from the coal burning process to very low levels. Facilities added to clean the exhaust path include scrubbers to remove the sulfur dioxide, baghouses to remove the particulates and selective catalytic reduction equipment to remove nitrous oxide. Processes are being developed to also reduce the mercury in the exhaust.

To achieve economies of scale, coal plants are typically above 250 MW in capacity. At this size, there are two combustion types, fluidized bed and pulverized coal. There are major differences in the boiler and plant design for the two units. The main difference is in the method to control sulfur emissions. The fluidized bed units blend limestone in the combustion chamber to achieve reductions in the sulfur emissions. Pulverized coal units use scrubbers to inject lime into the exhaust stream and remove the sulfur. The SLP coal units are pulverized coal units. The current upper commercial limit on the fluidized bed units is 250 MW.

Coal plants typically operate with capacity factors of 60-80%. In order to achieve these economies of scale, a joint owned unit would be required or RPU would have to enter into contract sales to support the costs of the facility until the entire plant could be used for RPU requirements.

It is assumed that any new plant would burn coal from the Powder River Basin. However, new facilities are considering bituminous coal from the east as it is easier to remove the mercury from the exhaust stream. A coal plant developed by RPU could be served by the Dakota Minnesota and Eastern railroad, which is extending its system into the Powder River Basin. Another area option might be the Union Pacific line. Expansion of the rail system would be needed if an additional unit is located in RPU’s service territory. No specific siting assessment has been performed for this option.

Traditional Resource Portfolios

Considering the capacity needs for the SLP availability scenarios, the resource portfolios shown in Table III-1 were developed.

Table III-1
Resource Portfolios

	Existing Capacity - MW			Capacity Added - MW(year installed)				
Case	CROD	Other	SLP	Coal	Combined Cycle	Twin Pac		
None216-100Coal	216	51	0	100(15)		50(15)	50(20)	50(25)
None216-50Coal	216	51	0	50(15)		100(15)	50(20)	50(25)
None216-100CC	216	51	0		100(15)	50(15)	50(20)	50(25)
None216-LMS100	216	51	0		100(15)	50(15)	50(20)	50(25)
None216-SC	216	51	0			150(15)	50(20)	50(25)
45216-50Coal_CoalFirst	216	51	45	50(15)		50(15)	50(20)	50(25)
45216-50Coal_SLPfirst	216	51	45	50(15)		50(15)	50(20)	50(25)
45216-100CC	216	51	45		100(15)		50(20)	50(25)
45216-LMS100	216	51	45		100(15)		50(20)	50(25)
45216-SC	216	51	45			100(15)	50(20)	50(25)
All216-50Coal_CoalFirst	216	51	92	50(15)			50(20)	50(25)
All216-50Coal_SLPfirst	216	51	92	50(15)			50(20)	50(25)
All216-100CC	216	51	92		100(20)	50(20)		
All216-LMS100	216	51	92		100(20)	50(20)		
All216-SC	216	51	92			50(15)	50(20)	50(25)

The case titles are developed such that the None, 45 or all refers to the amount of SLP capacity available, 216 refers to the CROD amount and the last numbers refer to the MW of resource added. SC refers to simple cycle, CC refers to combine cycle, and LMS 100 refers to a new simple cycle unit being developed. References to CoalFirst and SLPFirst are associated with the order of dispatch.

The simple cycle units considered are based on the current Cascade Creek Unit 2 type facility, the Pratt and Whitney Twin Pac. The combined cycle unit is based on a purchase of a 125MW portion of an area combined cycle project. The coal resources are assumed to be from a regional project whereby RPU would purchase the indicated amount as an owner.

Transmission delivery charges for the coal plant were included to provide an assumption on the MISO transmission service fees. No transmission was assessed the combined cycle unit or the simple cycle units as they were expected to be constructed within RPU's service territory.

Hourly and monthly production cost models were developed that dispatched the resources on an economic dispatch basis, considering limitations on energy from Unit 4. Assumptions for the new and existing units are included in Appendix II.

The energy to supply the RPU projected load growth is summarized in Table III-2 for the coal and gas resource options. The load curves produced in Part II provide an indication that the energy is more heavily utilized in the summer season than the winter period.

Table III-2
Summary of Energy Sources from Gas or Coal Portfolios

Energy in GWh	2016		2020		2025		2030	
	Gas	Coal	Gas	Coal	Gas	Coal	Gas	Coal
None216-100Coal	3	1,839	21	2,023	72	2,257	171	2,490
None216-50Coal	36	1,806	79	1,965	187	2,142	423	2,238
None216-Gas	121	1,721	248	1,796	479	1,850	773	1,888
45216-Coal	4	1,838	25	2,019	79	2,250	187	2,474
45216-Gas	34	1,808	93	1,951	243	2,086	536	2,125
All216-Coal	4	1,838	25	2,019	79	2,250	187	2,474
All216-Gas	34	1,808	93	1,951	243	2,086	536	2,125

Note: Above numbers do not include a negligible amount of hydro energy

The above table reflects the energy estimated to be taken from the various generation resources within the respective expansion portfolios. The energy in the gas columns includes energy generated by RPU and purchased from the market. The coal energy includes that purchased from SMMPA and generated by RPU. As seen, where the coal energy is limited to the existing resources, significant increases in the gas energy is necessary. It should be noted that all of the cases include additional gas-fired resources.

The cases that are based solely on natural gas-fired resource additions would require a gas supply adequate to provide approximately 3056 MCF of gas per hour at approximately 600psi when all of the units are operational in 2030. The RPU gas consumption in 2030 with one of the all gas portfolios would be approximately 5360 million cubic feet. Even though a portion of the gas requirements are expected to be met by market purchases, it is considered that the energy provided by the market would also be gas based. Therefore, even if the gas is not directly used by RPU, it will be required by the regional generation providing the market energy.

Production Cost Results

The results of the production cost modeling for the traditional portfolios are summarized in Table III-3. The net present values for the cases were developed for the 15 year study horizon in 2015 dollars. The values shown reflect the incremental costs of each option and, therefore, do not include all of RPU’s costs which would be common among all of the cases.

Table III-3
Summary of Net Present Values for Portfolio Options
(2015 $000)

		% Below Base
45216-LMS100	$320,892	-
45216-50Coal_CoalFirst	$325,782	1.52%
All216-50Coal_CoalFirst	$327,201	1.97%
45216-50Coal_SLPfirst	$328,750	2.45%
All216-50Coal_SLPfirst	$330,169	2.89%
None216-50Coal	$342,102	6.61%
All216-LMS100	$347,789	8.38%
45216-SC	$347,544	8.31%
All216-SC	$351,098	9.41%
None216-100Coal	$353,725	10.23%
None216-LMS100	$362,430	12.94%
None216-SC	$387,146	20.65%
All216-100CC	$389,434	21.36%
45216-100CC	$396,788	23.65%
None216-100CC	$435,755	35.80%

The above portfolios all have a mixture of coal and natural gas resources used to minimize RPU's overall average energy costs. The results indicate that the availability of low cost energy from the SLP unit 4 or an additional coal plant purchase is a lower cost scenario than relying only on natural gas for the energy needs above the CROD level. Details for each of the above cases can be found in Appendix III.

Summary

Based on the evaluations of several traditional resource options, Burns & McDonnell offers the following conclusions about resource expansion plans.

1. The addition of capacity is required to meet the MAPP reserve requirements and to satisfy RPU's obligation to serve its load requirements over the period 2016 to 2030.
2. The review of traditional additions of natural gas and coal-fired options indicates that the addition of coal capacity decreases the exposure to the supply and price risk of natural gas.
3. The scenarios with SLP remaining operational provide lower evaluated costs than the total retirement of SLP.
4. The lower cost scenarios include the addition of a 50MW value of coal capacity or a low capital cost combined cycle type resource along with continued investment in Twin Pac type combustion turbines to meet peaking needs.

5. RPU will need to participate in a coal project to acquire the 50MW portion with any economies of scale. The exposure to transmission congestion and delivery problems would be reduced if the plant was developed in or near the RPU service area.
6. The gas based resources can be developed solely by RPU. Consideration of the capabilities of the gas infrastructure for the Rochester area will have to be reviewed closer to the time that the facilities are needed to determine if pipeline capabilities need to be expanded to support the expected gas demand.

Based on the above conclusions, the lower cost options from the traditional resource portfolios were reviewed in greater detail in Part IV.

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Part IV

Economic Analysis of Preferred Options

The development of the power supply options in Part III identified several low cost evaluated options for RPU to consider in the long range planning. The lower cost plans included a mix of coal and gas-fired resources to minimize the average energy costs. With the long term plan identified, decisions on the near term issues can be made with more certainty on their long term affects on RPU's rates. This part of the report provides a closer assessment of the long range options and provides recommendations on the near and longer term power supply paths which RPU should pursue.

Options for Review

The lower cost evaluated options for RPU in Part III are shown in Table IV-1. The options included reflect the various scenarios considered for the SLP plant.

Table IV-1
Lowest Evaluated Cost Traditional Resource Portfolios

		% Below Base
45216-LMS100	$320,892	-
45216-50Coal_CoalFirst	$325,782	1.52%
All216-50Coal_CoalFirst	$327,201	1.97%
45216-50Coal_SLPfirst	$328,750	2.45%
All216-50Coal_SLPfirst	$330,169	2.89%
None216-50Coal	$342,102	6.61%

The options include the following characteristics:

- Coal energy is provided through SLP for the lower cost cases, with the possible addition of a 50MW amount.
- Gas resources include simple cycle combustion turbines similar to the Twin Pac unit and an efficient unit with low capital and operating costs, represented by the LMS100 unit currently becoming commercial from GE.

The options were evaluated with certain assumptions subjected to modification over a range. The analysis used the @risk software from Palisades. The factors subjected to variation are summarized in Table IV-2.

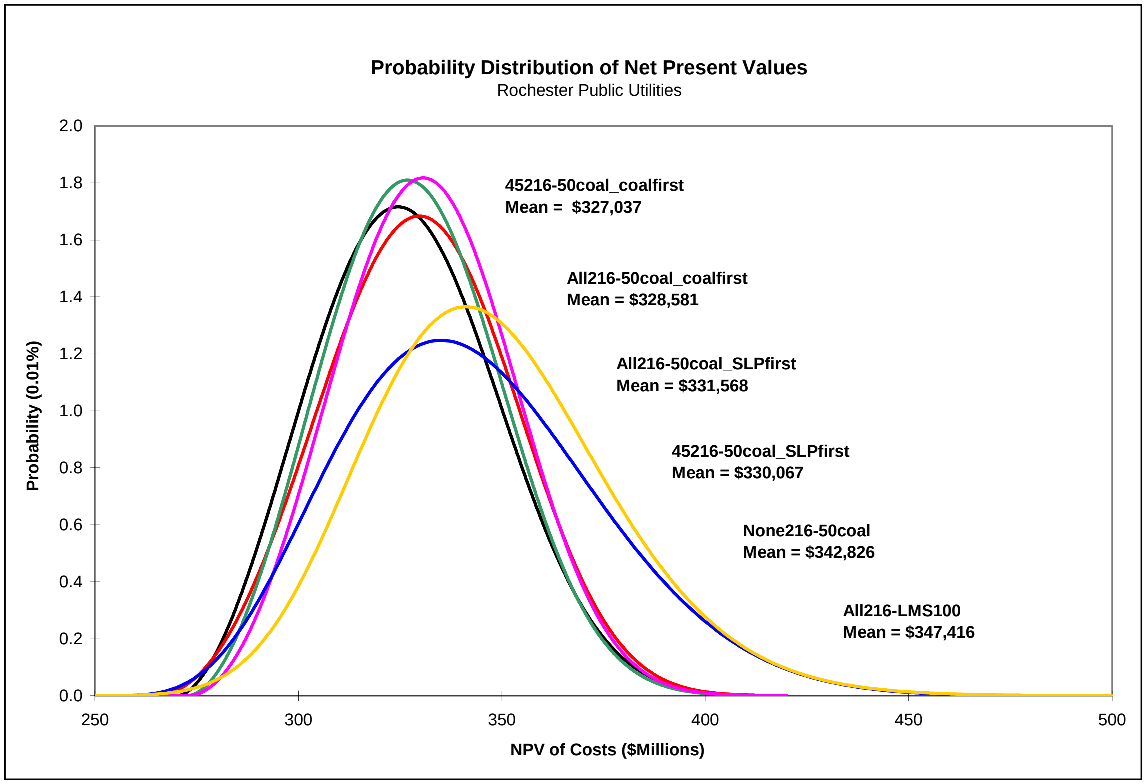
Table IV-2
Assumption Variations Used to Evaluate Lower Cost Resource Portfolios

	Min.	Likely	Max.
Load Escalation	2.0%	2.7%	3.4%
Fuel Prices			
Gas Commodity 2006 Price ($/MMBtu)	$3.62	$4.82	$7.23
Gas Commodity Real Escalation	0.0%	1.0%	2.0%
Gas Transportation 2006 Price ($/MMBtu)	$0.32	$0.42	$0.53
Gas Transportation Escalation			
Coal Commodity 2006 Price ($/MMBtu)	$0.35	$0.41	$0.52
Coal Commodity Real Escalation	0.0%	0.5%	1.0%
Coal Transportation 2006 Price ($/MMBtu)	$0.55	$0.65	$0.75
Fuel Oil 2006 Price	$4.62	$5.44	$6.25
Financial Rates			
Inflation Rate	1.5%	2.5%	3.5%
Interest Rate	5.5%	6.5%	8.0%
Discount Rate		8.0%	
Resource Data			
Market Data:			
On-Peak Market Energy Availability	10.0%	40.0%	50.0%
On-Peak Market Price Adjustment	-10.0%	0.0%	10.0%
New Unit Data:			
Capital Cost Variance	-15.0%	0.0%	15.0%
Coal Unit Data:			
Transmission cost ($/kW-mo)	$3.17	$3.73	$4.29
SO2 Allowance Cost ($/ton)	$954	$1,122	$1,290
NOx Credit Costs ($/ton)	$1,267	$1,491	$1,715
CO2 Tax ($/ton)	$0	$0	$0
Particulate Costs ($/ton)	$0	$0	$0

Emission costs for the coal units were varied using a @risk function. The detailed assumptions for the above factors can be found in Appendix II.

The results of the risk analysis are summarized in Figure IV-1.

Figure IV-1
Probability Distributions for the Lower Evaluated Resource Portfolios



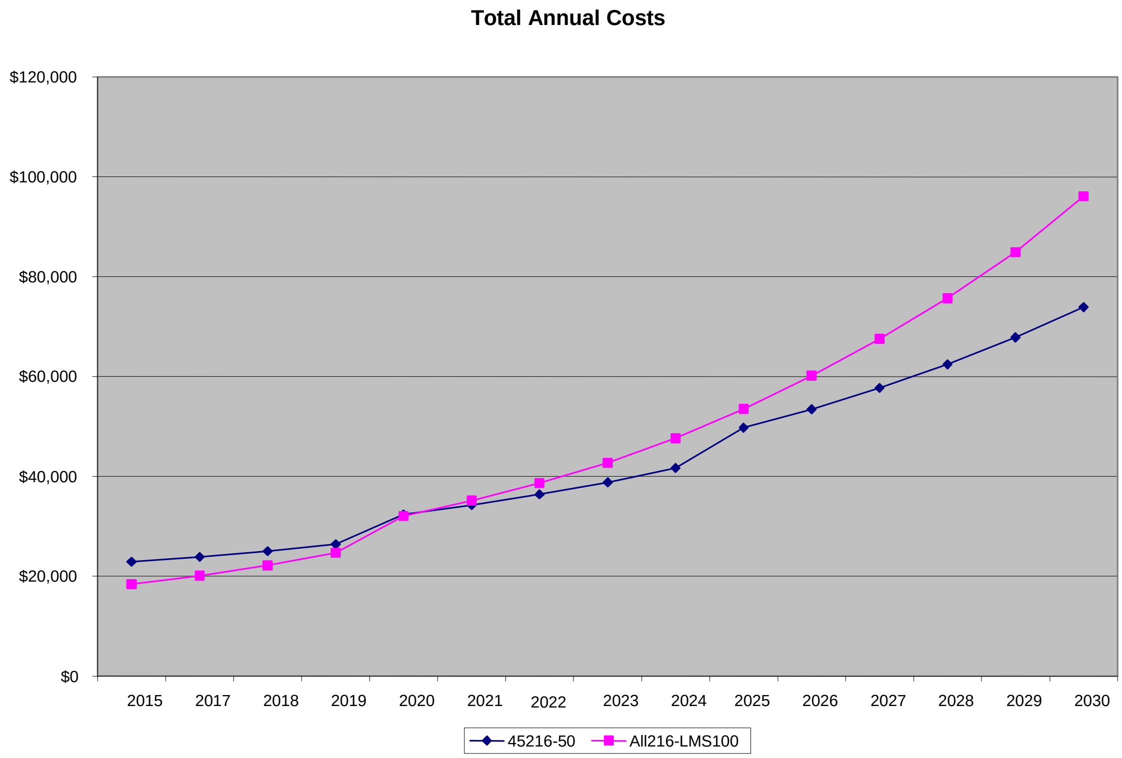
The results of the risk analysis indicate that the portfolios with approximately 100MW of coal energy provided through SLP Unit 4 and an additional 50MW result in the lower cost options. The scenario with the LMS100 case is shifted up due to the low probability that the capital cost will remain at the level of the initial units GE is bidding to obtain market acceptance. The portfolio with no SLP and 50MW of new coal capacity shows a broader distribution primarily due to the variance in capital and interest costs.

The four portfolios with the more narrow distribution indicate the following:

1. The SLP Unit 4 should be maintained in service.
2. An approximately 50MW amount of additional coal capacity provides value to RPU in offsetting the exposure to gas based energy.
3. Using the SLP Units 1-3 as regulatory reserves operated on natural gas or retiring them and replacing the capacity with a Twin Pac unit makes little difference since the energy expected to be generated by them is negligible.

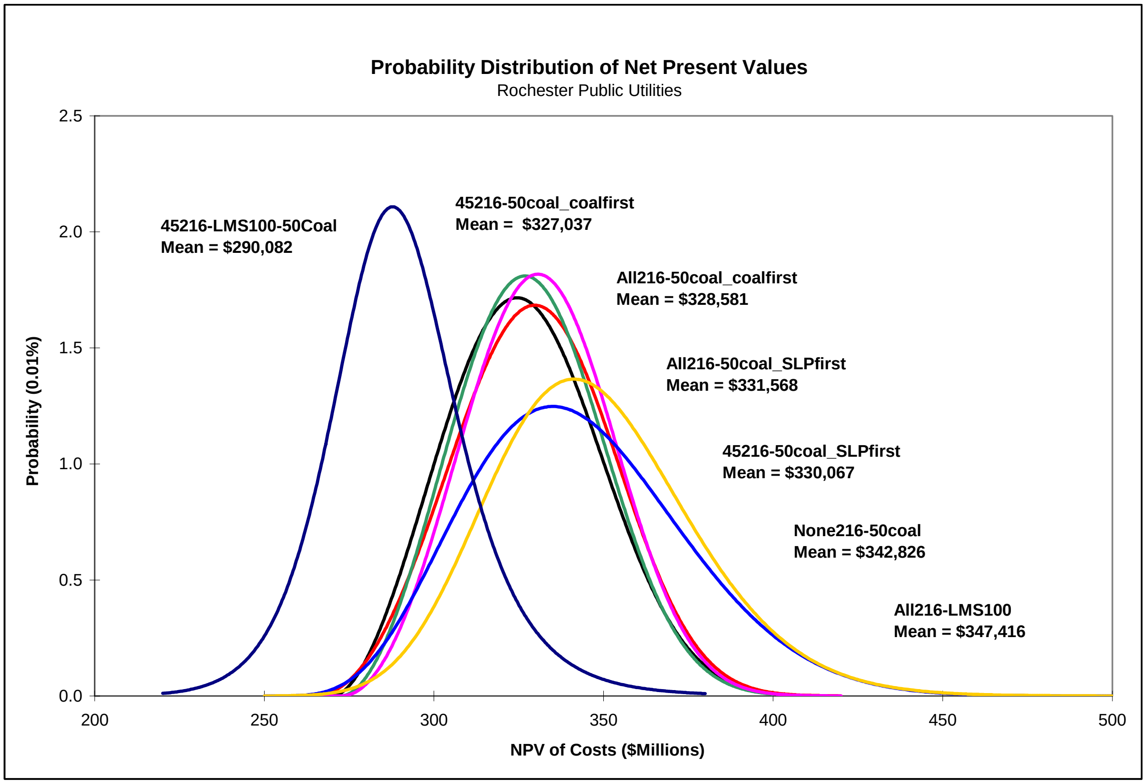
The above analysis has been performed on a net present value basis. A review of the total, demand related and energy related annual costs provide an insight to determine if the timing of the coal units might make a difference in the evaluation. Due to RPU's low load in the winter until about 2020, additional coal capacity would be difficult to fully utilize. To review this issue, the annual costs of the portfolios with the LMS100 and the 50MW coal purchase were compared. The annual total costs for the cases are shown in Figure IV-2. The total costs for the two cases cross about 2020, indicating that the energy from the coal unit does not begin to overcome its high capital cost until this point.

Figure IV-2
Total Annual Costs for the 50MW Coal Case and the LMS100 Case
($000)



A case was developed which reflected this type of sequencing for the gas and coal units. The net present value for the revised case was $288,674,000 or approximately 10 percent below the lowest evaluated case above. Application of the risk analysis to this case was performed and is included in Figure IV-3.

Figure IV-3
Probable Net Present Values
With Coal in 2020 Case



The risk analysis shown above indicates that combining the benefits of the LMS100 case with the 50MW coal case provides a lower risk case than the all gas cases. The major advantage is the delay of acquisition of the coal unit until its energy can be more fully utilized. This allows RPU to capture the early benefits of the LMS100 portfolio and the later benefits of the 50MW coal portfolios. Therefore, the sequencing of the unit additions should be considered with the gas unit in 2016 and the coal purchase in 2020.

Near Term Issues

The above analysis provides an insight to the course which RPU should pursue over the next ten years. The balance of loads and resources using the above 45216-LMS100-50Coal case is shown in Figure IV-4. As shown, the resource additions will still require that RPU acquire seasonal capacity to maintain its MAPP reserve requirements. The costs for these acquisitions have been included in the analysis. Figure IV-5 is an approximate energy dispatch curve to provide an indication of the sources of energy for the RPU in 2030.

Figure IV-4
RPU Balance of Loads and Resources
45216-LMS100-50Coal

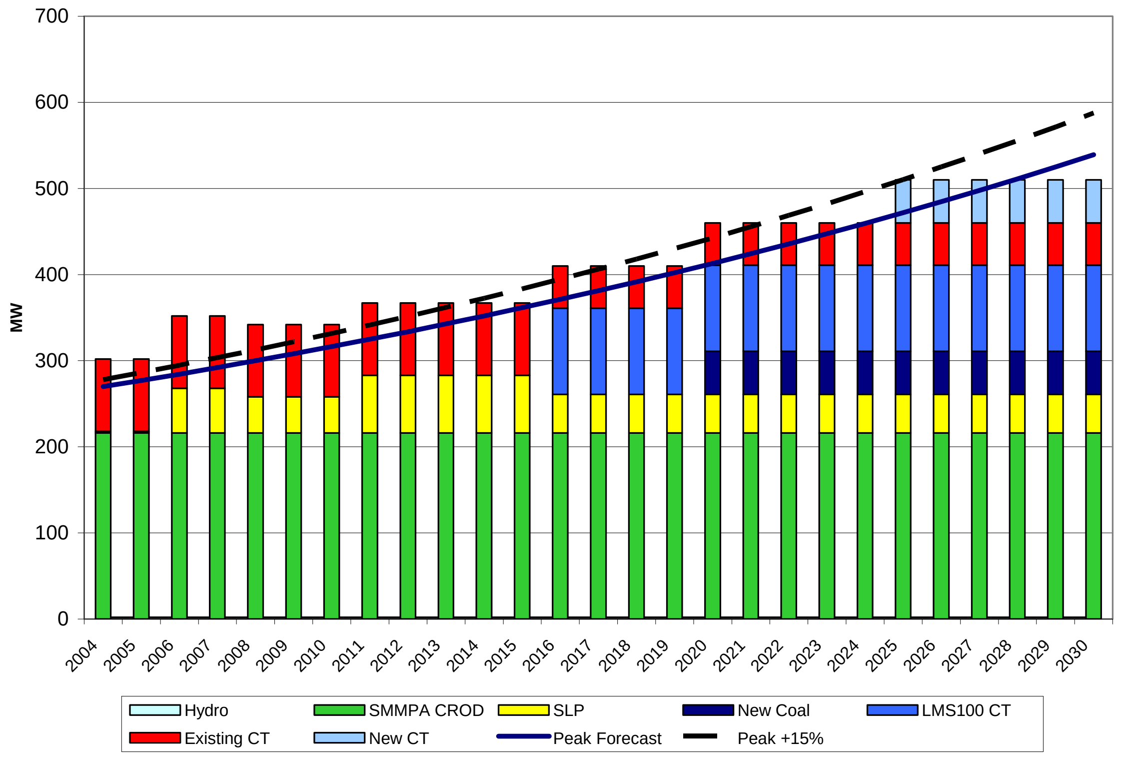
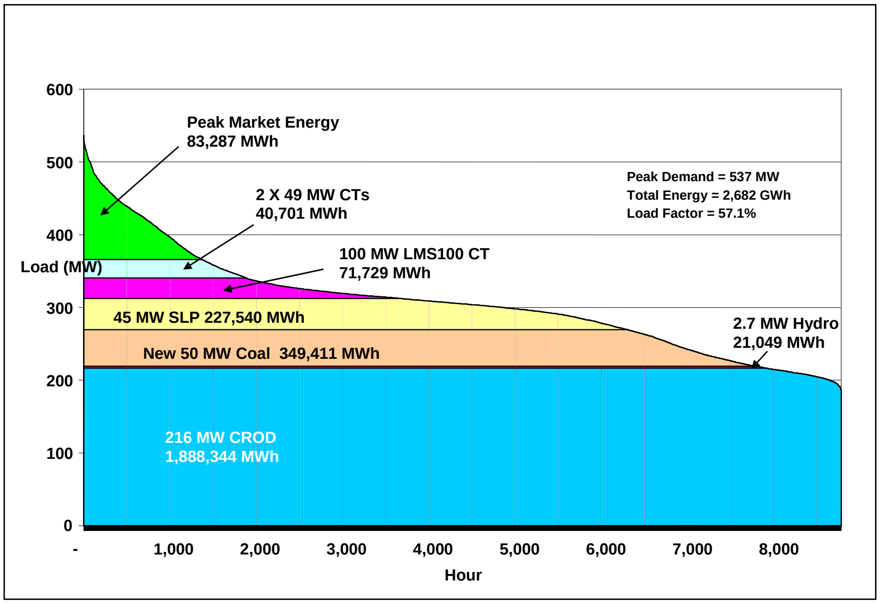


Figure IV-5
Approximate 2030 Energy Sources for RPU



Silver Lake Power Plant

The longer term portfolio options indicate that it is advantageous to continue the operation of the SLP, especially Unit 4 on coal. RPU should identify and implement strategies that will result in reduced air emissions and allow for continued operation on coal at an increased capacity factor. A boiler assessment should also be performed to determine if it would be beneficial to replace components which have had tubes plugged over the years to continue operation and delay maintenance investment.

Units 1-3 should be maintained in sufficient status to allow MAPP accreditation. Since these units are capable of being fired on natural gas available at the site, fuel switching may be an option to emission controls through the addition of flue gas based emission control devices. The cost of maintaining these units should be compared to replacing them with another resource closer to the 2016 time frame.

Maintaining the SLP plant also allows continued servicing of the Franklin Heating Station contract with excess steam and avoids any need to assess options for disposition of the contract with the Mayo Clinic.

Coal Unit Participation

There are several opportunities for RPU to participate in coal plants being developed in the regional. The units which are inviting participants are scheduled for in service dates of approximately 2010. Analysis of the coal portfolios indicates that RPU does not need coal capacity until after 2016 and more probably closer to 2020 based on the current forecast of load. Therefore, there is no urgency for RPU to identify a resource in which to participate.

RPU should maintain contact with regional utilities who may be considering a resource closer to the time when RPU could absorb the energy. It is expected that additional units will be required by others at a similar time that RPU is in need of coal energy.

Transmission Investment

RPU should aggressively pursue the upgrading of the transmission system. Certainly the firm delivery of the CROD energy should be regained since RPU is paying the SMMPA for firm all-requirements capacity and energy up to 216MW. This should be the number one priority of RPU in discussions with SMMPA.

RPU is participating in studies with other utilities on transmission projects which would improve the import capabilities into the service area. It is expected that the approach to improving the transmission system reliability into the RPU service area will be determined within the next 12 to 18 months. Currently, the state of the transmission system does not permit reliance on the market for firm purchases. Therefore, RPU will only be using the transmission system for non-firm energy deliveries above the CROD amount until increased firm transfer capability is available into RPU’s area. Sufficient generation capacity will need to exist within RPU’s service area to firm up the transmission system.

In discussions with RPU, it is uncertain what will happen to the CROD amount past 2030, which is the current termination date of the SMMPA contracts with its members. If the CROD energy is not available, then RPU will be in need of essentially 250MW of coal capacity. This amount of capacity requirement would support the construction of a unit within the RPU service area by RPU as the sole owner. With this amount of capacity inside the RPU service area, the import capability required of the transmission system would be reduced.

Due to the length of time it takes to construct transmission lines and complete the upgrade, it is recommended that RPU develop a parallel project to install similar Twin Pac units to maintain the required probable outage hour levels as would be maintained with the transmission upgrade. Should the upgrade be delayed, the generating units could be installed within RPU's service area and used for transmission reliability service until the upgrade was completed.

Summary

Overall, RPU is in relatively good condition to meet its load requirements for several years without any additions to its resource mix. Challenges to RPU in the area of transmission reliability and understanding what future market operation impacts will bring are typical of the environment in which utilities operate today and will be a primary focus of RPU. Plant related issues will include the investment necessary to bring the SLP into compliance with environmental regulations currently taking affect.

Based on the analysis performed for RPU in this effort, Burns & McDonnell is of the opinion that RPU should:

Over the next few months:

1. RPU is not in need of additional coal capacity with the current CROD level and load forecast until approximately 2020. Therefore, participation in any coal plant currently being developed does not appear to be advantageous.

2. Pursue firming up the transmission system to allow firm delivery of the CROD amount of 216MW.

3. Consider taking options on approximately 100 acres of land within the RPU service territory near a high pressure gas line and transmission facilities under RPU control for installation of future combustion turbine capacity.

4. Develop a parallel path project to accelerate installation of combustion turbine capacity required in the long term plan to maintain system reliability should the selected transmission upgrade project be delayed.

5. Develop the upgrade plan and timing for SLP Units 1-4 for the addition of emission controls and other life extension modifications.

Between 2005 and 2015:

1. Complete the transmission upgrade or the installation of additional combustion turbines.

2. If the transmission upgrade is completed, compare the market conditions at the time to the installation of additional generation resources within the service territory.

3. Review the then current generation technology, fuel options and RPU needs against the long range plan developed herein to determine if new technologies or reduced RPU needs have usurped the analysis and recommendations associated with current options.

4. Complete the modifications to the SLP Unit 4. Initiate the emission controls to be applied to Units 1-3 in light of their expected operation.

5. Around 2010, depending on the status of the RPU system needs, the regional market, and other technology considerations for resource options, RPU should consider taking an option on approximately 1500 acres to support the development of a coal-fired generation plant within the RPU service territory. The site should have access to rail, electric transmission and water infrastructure to support several hundred megawatts of generation.

6. Around 2012, assuming that new generation is required in accordance with the long range plan and that generation has not been installed in connection with the transmission issue, begin the process for installation of approximately 50 to 100MW of natural gas-fired generation for an in service date of 2016. The generation should be low capital cost with as low an operating cost as is consistent with expected operating capacity factors.

Between 2015 and 2030:

1. Install generation as necessary and prudent using the long range plan prepared above as a guide and comparing the assumptions used herein to the existing market conditions. The generation additions should follow the in service schedule identified in portfolio 45216-LMS100-50Coal.

2. If development of a local coal unit appears likely, purchase the necessary land and begin the development process around 2015 for an in service date of 2020.

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Part V

Demand Side Management and Renewable Options

Rochester Public Utilities (RPU) is active in promoting demand side programs to its customers to help conserve electric energy, and reduce demand in its service territory. Numerous programs are offered to assist customers in reducing their electrical requirements. The development of the financial plan for RPU requires the assessment of the impacts that customers are making, and could make, in the reduction of future electrical requirements, and delay the need for additional capacity.

Current DSM Efforts

Utilities in Minnesota are required to invest a portion of the revenues into DSM programs. For RPU, this amounts to approximately $1,300,000 per year. RPU has created a department to manage the budget associated with DSM programs. The department is staffed with individuals who work with customers to promote the various DSM programs in place, provide energy audit services, and look for new programs to implement.

RPU is working with the cities of Owatonna and Austin, Minnesota on DSM offerings. These utilities have formed the Triad, which allows the cities to share personnel, study costs, and other assets in order to reduce the overheads and program costs associated with the DSM programs.

The programs offered by RPU include:

- Conserve and $ave – a program to promote the use of Energy Star appliances and other high-efficiency equipment in place of lower efficiency options. The program is open to residential, commercial, and industrial customers. Rebates are provided for a variety of appliances, equipment, and lighting options.
- Partners Load Management – a program to allow RPU to control central air conditioner compressors and electric water heaters during times of high demand and reduce the load on the system.
- Energy Audits – these are provided to customers upon request.

The cumulative estimated reductions due to these programs as of January 1, 2004 are:

- Energy savings of 7,860 MWh.
- Demand savings of 5,960 kW.

Using an average of $600/kW of installed capacity and $55 per MWh as an avoided energy cost, the programs have provided approximately $3,500,000 of reduced investment cost and $432,000 of annual energy savings.

Study Approach

A variety of tasks were undertaken to develop the expected impacts that current and potential DSM programs could provide in reducing the RPU need for additional power supply resources. These tasks included an end use survey of RPU's customers, a benefit cost analysis of RPU programs, and an estimation of the electric energy and demand reduction potential for RPU's customer base.

In addition to these tasks, public involvement was solicited to discuss options and considerations from the ratepayer's perspective. RPU developed a task force made up of a representative from the various rate classes and other involved citizens served by RPU.

End Use Survey

RPU retained Morgan Marketing Partners of Madison, Wisconsin to perform an end use survey of their residential and commercial customers. Large industrial customers were not surveyed due to the unique nature of their loads. These customers are actively involved in reducing the consumption of their processes. Also, RPU devotes a staff person to work with these individuals to help them reduce their consumption.

The survey questionnaire was developed and mailed to 1,497 residential, and 2,193 commercial and industrial customers. These responses provided a statistically significant result and were considered to be acceptable for use in analyzing the appliance inventory in the RPU service territory. The questionnaires and a summary of the results of the survey are included in Appendix IV.

Benefit Cost Analysis

In addition to the end use survey, RPU needed to perform a benefit cost analysis of the various DSM offerings applicable to RPU. RPU retained the Center for Energy and the Environment (CEE) to perform this analysis. The CEE is a not-for-profit corporation in Minnesota that is funded by utilities to assist with DSM program analysis. The CEE is very experienced in performing analyses of DSM programs in accordance with the requirements of the Minnesota state regulatory bodies for utilities. The CEE works with the Triad and has the information on the various programs offered, avoided costs, and other information necessary to perform the benefit cost analysis.

The analysis of avoided costs for RPU is different from the other members of the Triad in that the other Triad members are full service customers of SMMPA, while RPU takes a portion of its requirements from SMMPA and a portion from other resources. The RPU avoided costs vary between seasons based on whether the demand is being provided solely by SMMPA or from both SMMPA and RPU resources.

The analysis looked at the benefit and costs using the four typical tests for DSM programs. These included:

- Revenue requirements – this test looks at the benefit cost from the RPU perspective;

- Rate impact – this test looks at the benefit cost from the non-participant perspective;
- Participant – this test looks at the benefit cost from the participant's perspective;
- Societal – this test looks at the benefit cost from society's perspective.

A variety of conservation programs were selected for the residential and commercial sectors. The initial assessment of the programs identified that the avoided costs for RPU needed to be revised when compared to the other Triad members. RPU has a different cost structure due to the limitation of the demand and energy received from the SMMPA. This means that the avoided demand charge is different through the year. Also, the method of meeting demand in the summer is through combustion turbine capacity, which is lower cost than that of the SMMPA demand. This information was updated in the CEE model for RPU.

The program costs for each of the programs were provided by RPU to CEE for use in the assessment. These costs included staff, rebates and incentives, advertising, and other costs associated with maintaining the various programs. The model used by CEE processed the information with regard to the specific test being developed. The appliances and programs selected for review were based on the experience of CEE in performing these tests for a variety of utilities in Minnesota. The results are shown on Table V-1.

Table V-1
Summary of Benefit Cost Analysis Results

Cost Benefit Analysis for Rochester Public Utilities				
2004 Results	**B/C Ratio**			
Program Name	**Revenue Requirements**	**Rate Impact Measure**	**Participant**	**Societal**
RESIDENTIAL				
Electric VSD/ECM Motors	**5.53**	**1.09**	**2.21**	**1.83**
Clothes Washer (Elec WH)	**4.14**	**1.28**	**0.89**	**0.96**
13 SEER Central A/C	**4.10**	**2.01**	**1.13**	**1.95**
14 SEER Central A/C	**3.53**	**1.86**	**1.07**	**1.73**
Ground Source Heat Pumps (3 ton unit example)	**2.31**	**1.27**	**0.98**	**1.08**
Room A/C	**1.70**	**1.14**	**1.89**	**1.52**
Dish Washer (Elec WH)	**1.47**	**0.80**	**1.60**	**0.98**
Refrigerator	0.93	0.53	2.50	0.83
Dish Washer (Gas WH)	0.64	0.47	0.98	0.43
CFL's	0.60	0.30	19.48	0.59
Clothes Washer (Gas WH)	0.42	0.35	0.24	0.10
Load Management	0.00	0.00	38,950.33	0.00
COMMERCIAL				
VSD (200 hp)	**40.34**	**1.61**	**5.21**	**6.38**
Premium Efficiency AC 3-Phase Motor (200 hp)	**4.02**	**1.10**	**7.00**	**3.55**
ECPM (1.5 hp)	**2.99**	**0.94**	**8.90**	**2.33**
VSD (3 hp)	**2.92**	**1.06**	**1.12**	**0.96**
Air-Conditioners EER=11.0 (7.5 tons)	0.83	0.54	2.55	0.69
Lighting Retrofit - Exit Sign (20W Incan. to LED)	0.66	0.45	4.29	0.57
Lighting Retrofit (F40T12 4 lamp to F32T8 LP 4 lamp)	0.57	0.40	6.95	0.53
Premium Efficiency AC 3-Phase Motor (1.5 hp)	0.20	0.18	3.36	0.19
GSHP (5 ton unit example)	0.13	0.12	2.20	0.12
ECPM (0.1 hp)	0.11	0.10	2.06	0.11

The results indicate that most of the residential and all of the commercial programs evaluated are beneficial from the Participant perspective. However, only about half of the programs are beneficial from the other three perspectives. All of the appliances are currently included in the Triad Conserve and $ave program. The load management program does not look beneficial at this point due to the excess capacity and the cool summer weather that has depressed demand during the summer months. With this combination, RPU does not need to cycle air conditioners or water heaters to reduce demand. The Participants see this as a significant benefit since they are still provided a credit from RPU for having the switch installed.

CEE has recommended that the overhead costs and incentives for the Triad should be reviewed to improve the number of programs with a benefit cost ratio greater than one.

The Triad has developed a report on the modifications to the demand side management programs currently in effect and additional programs to be undertaken in their report “Next Level”. This report identifies numerous adjustments to the programs in the areas of incentives, education, and expected participation levels. A copy of the report is included in Appendix IV.

Task Force

As part of the assessment of DSM programs and opportunities, RPU created a Task Force made up of representatives from residential, commercial, and industrial RPU rate classes. In addition, representatives from local environmental groups were included. There were 12 members in total. The group met three times to discuss the issues associated with DSM programs. The first meeting was held to educate the group on the current supply and demand side issues and opportunities facing RPU. The second meeting provided information about the end use survey and the benefit cost study being prepared for RPU. The third meeting was to provide the estimated impacts of various DSM activities and to collect feedback and recommendations from the group on how RPU should proceed.

In general, the Task Force had the following recommendations:

1. Programs involving rebates should be simple and provide immediate benefit to the customer.
2. Conservation programs and other efficiency enhancing programs require continual education of the customers.
3. Revising rate structures to support demand side and renewable energy efforts should be pursued.
4. Implementing time-of-use rates should be pursued.

The summary of recommendations from the group is included in Appendix IV.

Review of Conservation Potential

The potential for electrical energy and demand reductions on the RPU system were estimated using the end use survey data and typical savings information from a variety of sources used to estimate the reductions by appliance or facility change. The end use survey information provided an estimate of the number of appliances on the system that were available for enhanced efficiencies. The appliance usage was estimated to determine the amount of energy savings which could result from a conversion. The expected usage patterns through the day were approximated in order to estimate total demand reduction. Assumptions for energy reductions were obtained from Energy Star calculators that are available from the Department of Energy, the assumptions in the Benefit Cost study and other sources.

Residential Potential

The residential customers of RPU are typical of households across the US. The use of central air conditioning is widespread. The availability of natural gas has led to a high utilization of gas-fired heating systems and water heaters. Therefore, the maximum electrical demand is in the summer season. (See Figure II-6 in Part II for the RPU annual load shape.)

The number of central AC units older than 5 years provided an estimate of the number of units that had a SEER of below 8. Units installed within five years have had a SEER of at least 10. From the survey, an estimated 20,000 central AC units have a SEER of 8 or less. The benefit cost analysis identified that conversion of this appliance to a SEER of 13 and14 was beneficial from all perspectives. In addition to the AC units, conversion of the blower motor in the air handler was also beneficial from all perspectives. These two categories represent the largest efficiency enhancement benefits available from the residential sector.

Another category of appliances with a high potential for savings are the washer and dryers. Energy Star washers reduce the water necessary to clean clothes and also remove more water than traditional washers to reduce the drying time necessary. New efficient dryers have moisture sensors that determine when the clothes are dry. From the benefit cost study, it is seen that the current level of benefits from the Participant's perspective do not make replacement of units with an Energy Star rated unit attractive. This is primarily due to the high cost of the replacement appliances.

Other kitchen appliances provide minimal benefit from all perspectives. Compact fluorescent lights (CFL) provide significant benefits from the Participant's perspective. From the end use survey, it appears that over half of the homes in RPU's service territory have some amount of CFLs installed. The residential CFL replacements provide primarily energy reductions with minimal impact on the RPU peak.

Table V- 2 provides a summary of the maximum potential reductions for the residential sector estimated from a variety of efficiency improvements for appliance conversions or for change out of central AC units to a SEER 13. The number and efficiency of existing appliances was determined from the end use survey.

An area of interest to some utilities is the conversion of electric appliances to natural gas, where gas is available. A list of appliances that could potentially be converted and the expected electrical reductions is also included in Table V- 2.

Table V-2
Estimated Maximum Potential Reductions
Residential RPU Customers

Residential			Estimated Savings		
			Energy		Demand
Energy Star Conversions	Quantity	Unit	Each (kWh)	Total (MWh)	(MW)
Central Air more than 5 years old	20,484	Customers	346	7,091	4.7
Room Air more than 5 years old	2,618	each	58	151	0.1
Refrigerator more than 5 years old	13,176	each	95	1,252	0.2
Freezer more than 5 years old	1,231	each	80	98	0.0
No Compact FL	15,214	Customers	124	1,887	0.0
Washing Machine	38,705	Customers	361	13,973	2.4
Dishwasher-heated drying (elec DHW)	1,175	Customers	103	121	0.0
Dishwasher-heated drying (gas DHW)	8,617	Customers	45	388	0.0
				24,960	7.4

			Total Use		
Other Options			Each (kWh)	Total (MWh)	Demand (MW)
Electric heat-Main	788	Customers	43,174	34,021	n/a
Dryer	30,342	Customers	995	30,190	5.2
Spa/Hot tub	585	Customers	1,680	983	n/a
Water Heater	4,375	Customers	4,811	21,048	1.5
Range/Oven	30,704	Customers	256	7,860	n/a
				94,103	

Commercial Potential

The commercial sector of RPU reviewed in the survey is made up primarily of small commercial office buildings, shopping malls, restaurants, and other typical buildings. Estimates of reductions for the commercial sector required comparing end used information from the survey with industry data, forecast sales by class, correlation with SMMPA data in its Integrated Resource Plan and other factors.

References and calculation tools used in the commercial assessment include:

- ***End-use Survey of RPU Commercial Customers:*** A survey sent to 2,145 of RPU's commercial customers. Used to determine quantities of customers and appliances.

- ***eQUEST:*** *A* computer simulation program that is a full implementation of the widely recognized DOE 2.2 calculation engine. It can perform hourly calculations for an entire year and incorporates local weather data.

- ***U.S. Department of Energy – 2004 Buildings Energy Data Book:*** This reference includes over 100 pages of data tables dealing directly with buildings and their energy use.

- ***Energy Star Homepage:*** Web site with a variety of reference material and calculation tools for various technologies. Estimates that involved use of these calculation tools includes room air conditioners, freezers, washing machines, dishwashers, computers, printers, and copiers.

- ***SMMPA Integrated Resource Plan 2003-2018:*** In particular Table VII-8, *"SMMPA Sales Profile"*, which has an end-use breakdown of electricity use for commercial customers. The metric used is the Energy Use Indices (EUI) which has the units of kWh/yr/sq ft.

There are a number of assumptions included in the DSM measure energy reduction estimates for commercial customers that involve usage estimates per square foot of commercial building space. A review of the 2,145 survey population of customers used in the survey indicated the following:

- 61.5% consisted of small commercial properties totaling 5,000 sq. ft. or less,
- 28.8% were 5,001 – 25,000 sq. ft.,
- 9.1% were 25,001 – 250,000 sq. ft. and
- 0.6% were 250,000 or more sq. ft.

Due to the effort in the existing DSM programs on the large customers, the focus of the analysis in this study was on the commercial space of less than 25,000 square feet. A review of information included in the SMMPA IRP provided that RPU commercial customers account for 50 percent of the SMMPA commercial customers' energy use. Based on other information about the square feet of commercial office space in the member cities' service areas, it was determined that RPU's commercial customers account for 50 percent of the SMMPA commercial customers' floor space (i.e., 50 percent of 67,210,000 sq. ft. or 33,605,000 sq. ft.).

The above area of commercial space was used to derive an estimated energy usage. One reference for determining the energy usage was data from the US Department of Energy – 2004 Building Energy Data book. To determine the potential reduction for estimating DSM impacts, it was assumed that the DSM measures will have 100 percent penetration. In other words all customers that are candidates for a given DSM measure will implement the measure.

The approach used to determine the potential energy savings for RPU's commercial customers included three basic steps. These are:

1. Identify the appliances and energy using systems that account for the majority of overall electric consumption.

2. Use the end-use survey to determine the number of customers, or quantity of energy using devices identified in step 1. In some cases the DOE – 2004 Buildings Energy Data book was used as a reference for average typical commercial customers.

3. Use engineering calculations to determine the energy savings for the devices and quantities identified in steps 1 and 2 respectively.

The results of the analysis are summarized in Table V-3.

Table V-3
Estimated Maximum Potential Reductions
Commercial RPU Customers

Commercial			**Estimated Savings**		
			Energy		**Demand**
Efficiency conversions	**Quantity**	**Unit**	**Each (kWh)**	**Total (MWh)**	**(MW)**
Central Air more than 7 years old	936	Customers	3,948	3,695	5.3
Room Air more than 7 years old	226	each	121	27	0.1
Refrigerator more than 7 years old	2,214	each	143	315	0.2
Freezer more than 7 years old	858	each	120	103	0.0
No Compact FL	1,386	Customers	4,015	5,565	2.0
Washing Machine	515	Customers	722	372	0.1
Dishwasher-heated drying	67	Customers	78	5	0.0
Non electronic ballast flourescent	1,639	Customers	9,489	15,552	8.8
VSD on 3 HP AC unit fans	3,595	each	5,489	19,734	0.3
Computers	18,190	each	201	3,656	1.2
Printers	7,096	each	180	1,277	0.4
Copiers	5,103	each	324	1,653	0.5
				51,957	18.8

Other Options			**Total Use**		
Energy Using System/Device	**Quantity**	**Unit**	**Each (kWh)**	**Total (MWh)**	**Demand (MW)**
Electric heat-Main	118	Customers	86,348	10,189	n/a
Dryer	498	Customers	1,493	743	0.4
Range/Oven	44	Customers	384	17	n/a
Water Heater	568	Customers	9,622	5,465	2.4
				16,415	

Information for both the commercial and residential impacts determined above are included in Appendix IV.

Load Shape Modification Programs

Utilities have been controlling demand on the system since the late 1970's through the use of load management programs, interruptible rates and other programs that entice the customer to allow the utility to remove a portion of their load during high usage times. The economics of these programs are dependent on the cost of the marginal capacity on the system. As the utility moves between deficit and excess capacity conditions, the value of the program changes.

Another type of program which is gaining prominence is called a Demand Response Program. These programs are trying to bring the consumption side of the industry into the market to allow a demand response feedback to the hourly pricing. As wholesale markets move to day ahead pricing with load bidding into the market, these programs are becoming more useful.

The current wholesale market is discounting the value of capacity. Although the forward market (in the post 2010 time frame) is seeing the need for additional base load facilities which have high fixed cost, the current market is not pricing capacity above that for a combustion turbine, if that. However, the price for energy is increasing as more of the marginal energy produced is from natural gas-fired units. It is expected that this market will continue in this manner for several years at least. No significant structural change to this pricing on the wholesale markets operated by PJM and MISO is expected until base load units are added to the system beyond 2010.

Load Management

RPU has approximately 8,800 customers with load management switches installed. The evaluation of load management programs in the Benefit Cost Study revealed that there was no benefit from any perspective except for the Participant. This is due to the current capacity situation in RPU and the mild summer experienced in 2004. With the expected return of capacity from the Silver Lake Plant over the next several years, RPU has sufficient capacity to meet its obligations. Therefore, there is no cost avoided for the reduction in peak.

The primary benefit from the load management program will be from the opportunity to market excess capacity. Also, having the load management system provides some increased system security during times when the transmission capacity into RPU is constrained and load needs to be curtailed in the RPU area.

Another aspect of the load management program is that the appliances controlled are primarily central AC units and electric water heaters. Over the next several years, replacement units will be installed for the approximately 20,000 central air conditioning units with SEER ratings below 8. These units will be replaced with AC units with a SEER rating of 13 or better. These newer units have a lower demand than the older units. Also, since many of the units were installed oversized, smaller units may be used for the replacements. These two factors lead to the conclusion that the amount of reduction per point for the load management system will decline over the next five years. It is estimated that this reduction will be approximately .1 to .2 kW per central AC unit. Change out of electric water heaters to gas units would also reduce the amount of load under control.

Demand Response Programs

Demand response programs are gaining in popularity with utilities as markets move to the day ahead pricing structure used by the PJM, the MISO Day 2 market to start in March, 2005 and as promoted by the FERC in the Standard Market Design. These programs have a variety of definitions, but in general, entail using time-of-use metering or notification devices and rates to encourage consumers to reduce electric energy consumption during periods of high energy pricing. As the electric wholesale market moves to the day ahead of energy pricing, the knowledge of tomorrow's costs are more readily determined. These then can be shared with the customers to allow them to control their consumption during the periods when the pricing is above their threshold.

There are two broad categories of demand response programs. The first is applicable to markets where the load is bid into the market, such as will exist in the MISO area when its Day 2 operations are implemented. This conversion is expected to occur on or after March 1, 2005. In this program, qualifying customers are paid to reduce their demand by the level contracted with the utility. Verification of the amount of reduction is required. A set strike price for the capacity is often provided, such that there is no activity of the control unless the price exceeds a set level. In these programs, the customer is actually paid by the utility to reduce consumption at an agreed to rate. Qualifying customers are typically those that can reduce at least 100kW or more.

The other type of program incorporates the residential and small commercial customers. In this type of program, the customer is sent information on the time-of-use cost of the electricity. The customer then makes the choice on whether to shift usage away from the higher priced times to lower priced periods. This type of program simply results in the customer realizing a reduction in their bill due to avoiding the higher cost periods.

The first type of program could be used by RPU to release capacity for sale in the day ahead of the MISO market. Therefore, although the demand reduction has no specific value to RPU from an avoided capacity purchase, there may be value from the opportunity cost of potential sales and positioning for future years when capacity may be tighter. The development of the MISO Day 2 market on or after March 1, 2005 will need to be monitored to determine if this type of program would be of benefit and the revenues to the qualifying participants significant enough to gain a critical mass for participation.

The use of a demand response program by RPU for the residential and small commercial customers would require creating time-of-use pricing information for transmission to the customers who wish to participate. This pricing could be based on the MISO Day 2 market, which will provide the day ahead hourly pricing for the next day. Adjustments to this price for RPU costs would be made and forwarded to the participating customers.

Although time-of-use programs have been offered for several years, recent technology and communication changes have allowed the programs to be lower cost to implement. Savings resulting from the programs have been discussed in recent markets, such as California's during its crisis, and found to be significant when the price is above the customer's threshold. Although claims of 2kW per consumer in the program have been made by companies promoting the systems to support the programs, RPU would have to perform a pilot to determine what the level of pricing would need to be to influence the consumers in RPU's service territory to make any meaningful adjustment to their usage patterns.

Finally, it is important to note that from a customer's perspective, demand response strategies are effective only for those that are willing to change their energy usage habits. Contrarily, demand response strategies will not benefit those that are unwilling to change their usage habits. Therefore, selling DSM must be promoted as a conservation strategy and targeted to those that are willing to change their energy usage habits.

RPU DSM Program

The estimation of actual DSM impacts from various programs that have been or could be implemented by RPU allows a determination of the potential influence on the need for supply side resources. Since the DSM programs require acceptance by RPU customers, one unknown in the equation is the amount of participants in any program. The companion uncertainty to the level of participation is the amount per year who will participate.

In addition, natural replacement of appliances over time tends to reduce the average consumption since the replacement models have improved efficiencies. For instance, central AC unit efficiencies were increased to a minimum SEER of 10 in 1992. New standards are set to take affect in 2006 that increase the minimum SEER to 13. With this natural increase in efficiencies, the affect on RPU's load could be a reduction of approximately 30 percent of the energy over the approximately 20,000 central AC units that are older than five years. Major reductions would come from units that were installed prior to 1992. Similar improvements would come about from natural replacements of other appliances such as refrigerators and dishwashers.

In addition to the traditional impacts from DSM programs, RPU is also developing a cogeneration system with the Mayo Clinic's Franklin Heating Plant. This cogeneration effort will remove approximately 5MW (electric) from the system in 2008 and grows to approximately 15MW (electric) in 2015. This demand and its associated energy are removed from the electric system.

Using the information provided in Table V-2 and V-3 for the efficiency improvements and the benefit cost analysis Table V-1, estimates of reduction were developed. The resultant expected levels of reduction per year were identified to allow a determination of the impact on the load forecast as adjusted for DSM programs. A summary of the projections are shown in Table V-4. These projections include efforts to achieve reductions that are influenced by RPU and naturally occurring efficiency improvements in the existing appliance inventory. It is assumed that the naturally occurring efficiency savings would be achieved by 2015. Beyond 2015, the ongoing DSM activities of RPU would be the source of additional savings.

Due to the efficiency standards taking affect in 2006 and the need to develop the educational and incentive programs to be implemented to achieve savings, it was assumed that no savings would accrue in 2005 beyond the existing DSM program impacts. Starting in 2006, one third of the savings would accrue each year until the full savings of approximately 9,000 MWh annually would be achieved. It is estimated that these efficiency improvements would be completed after ten years and the savings from these areas would then remain constant after 2015. For purposes of estimating savings, one half of the Table V-4 projections are to be included in the RPU DSM future savings, while the remainder is considered to be an aggressive DSM alternative.

Table V-4
Estimated Additional DSM and Efficiency Impacts
To RPU Energy Forecast
(MWh)

Program	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential											
Central AC	0	236	475	709	709	709	709	709	709	709	709
Blower Motors	0	692	1,391	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076
CFLs	0	63	127	190	190	190	190	190	190	190	190
Refrigerators	0	42	84	125	125	125	125	125	125	125	125
Gas switched appliances	0	83	168	250	250	250	250	250	250	250	250
Commercial											
Central Air more than 7 years old	0	123	248	370	370	370	370	370	370	370	370
No Compact FL	0	185	373	556	556	556	556	556	556	556	556
Non electronic ballast flourescent	0	517	1,040	1,552	1,552	1,552	1,552	1,552	1,552	1,552	1,552
VSD on 3 HP AC unit fans	0	658	1,322	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973
Computers	0	122	245	365	365	365	365	365	365	365	365
Printers	0	43	86	128	128	128	128	128	128	128	128
Copiers	0	55	111	165	165	165	165	165	165	165	165
Gas switched appliances	0	250	503	750	750	750	750	750	750	750	750
Total	0	3,069	6,170	9,208	9,208	9,208	9,208	9,208	9,208	9,208	9,208
Cumulative Total	0	3,069	9,239	18,447	27,656	36,864	46,073	55,281	64,489	73,698	82,906

The estimated demand and energy impacts, including the Mayo cogeneration project, are shown in Table V-5. The Original Energy Forecast was the energy projection used for Phase I. The Existing DSM Impacts include the existing RPU DSM program estimated savings. The Future DSM impacts are one half of the saving shown in Table V-4. The Revised Energy Forecast is determined by subtracting the Future and Existing DSM Impacts from the Original Energy Forecast. The Aggressive Energy Forecast includes the remainder of the savings estimated in Table V-4.

Table V-5
Estimated DSM and Efficiency Improvement Impacts
Demand (MW) and Energy (MWh)

Year	Annual Peak	Demand Adjustments	Adjusted annual Peak	Original Energy Forecast	Future DSM Impacts	Existing DSM Impacts	Revised Energy Forecast	Aggressive Energy Forecast
2005	277	16.6	260	1,377,767	0	8,590	1,369,177	1,369,177
2006	284	21.8	262	1,414,967	1,535	56,310	1,357,122	1,355,588
2007	292	23.1	269	1,453,171	4,620	64,550	1,384,001	1,379,382
2008	300	25.1	275	1,495,732	9,224	72,650	1,413,858	1,404,635
2009	308	25.3	283	1,532,702	13,828	80,650	1,438,224	1,424,396
2010	316	26.9	289	1,574,085	18,432	88,500	1,467,153	1,448,721
2011	325	29.2	296	1,616,585	23,036	96,210	1,497,339	1,474,302
2012	334	31.8	302	1,663,932	27,641	103,790	1,532,501	1,504,861
2013	343	34.9	308	1,705,059	32,245	111,150	1,561,664	1,529,420
2014	352	38.4	314	1,751,096	36,849	118,450	1,595,797	1,558,948
2015	362	42.8	319	1,798,375	41,453	125,770	1,631,152	1,589,699

Renewable Energy Options

The state of Minnesota has implemented requirements for renewable energy under Minnesota Statute 2003 Chapter 216B. Retail electric utilities must offer customers an opportunity to purchase, at cost, renewable energy beginning July 1, 2002. RPU is offering customers the opportunity to purchase this energy under its Wind Power program in association with SMMPA.

Utilities are required to generate or procure renewable energy sufficient to ensure that by 2005, 1 percent of total retail sales are from renewable energy. This “Renewable Energy Objective” (REO) ramps up by 1 percent each year until 2015 when a total of 10 percent of retail sales must be from renewable energy. The REO also requires that, of the renewable generation required, in 2005 at least 0.5 percent be from biomass energy technology, increasing to 1.0 percent by 2010.

The integration of this energy into RPU’s resource mix will require adjustments to the dispatch determined in the traditional resource portfolios identified above.

There are several renewable energy options in commercial use. The most often considered include solar, wind, and biomass. In addition, the REO allows the use of electricity generated using municipal solid waste and existing hydro-electric generation to count towards the renewable requirement. The application of these options requires an assessment of their energy production capabilities, resultant power costs and the benefit to the RPU requirements. Following is a discussion of these alternatives.

Solar

The use of photovoltaic solar panels for electricity production is increasing annually. The largest increases are in those locations with high power costs coupled with net metering regulations, such as California, and remote from the grid applications. The Department of Energy has initiated a program to promote the use of solar through programs such as the Million Solar Roofs program. Probably the most advanced utility application of solar is in California and the leading utility is the Sacramento Municipal Utility District (SMUD) in Sacramento. For an idea of the size of an installation, a 2 MW array takes about 8100 square meters (about 2 acres). Costs of these installations are about $5000 per kW. Rooftop arrays provided under the SMUD program cost about $3500/kW and, on average for each kW produced, about 1800kWh of energy per year.

The output of the array is obviously dependent on the sun and the location of the array. In order to obtain specific information about the solar output in the RPU area, RPU assisted in the installation of an array on a residence in Rochester in the spring of 2004. The unit is a fixed plate array rated at 2.6kW and was installed in April 2004 at a residential customer. Information from the site is summarized in Table V-6. The cost of this array was $17,951 or approximately $6,900 per kW.

Table V-6
Solar Information from a 2.6kW Fixed Plate Array
Rochester, MN

Month	No. Days	Produced	Cap Factor	Max Output
April	17	156.047	0.1476711	2.096
May	31	276.071	0.14326763	2.216
June	30	300.097	0.16092718	2.084
July	31	310.481	0.16112478	2.108
August	31	248.101	0.12875254	2.04
September	30	194.925	0.10452864	1.3
October	31	91.791	0.04763514	1.88
November	7	37.111	0.08528912	
Yr. 2004	208	1614.624	0.1248812	

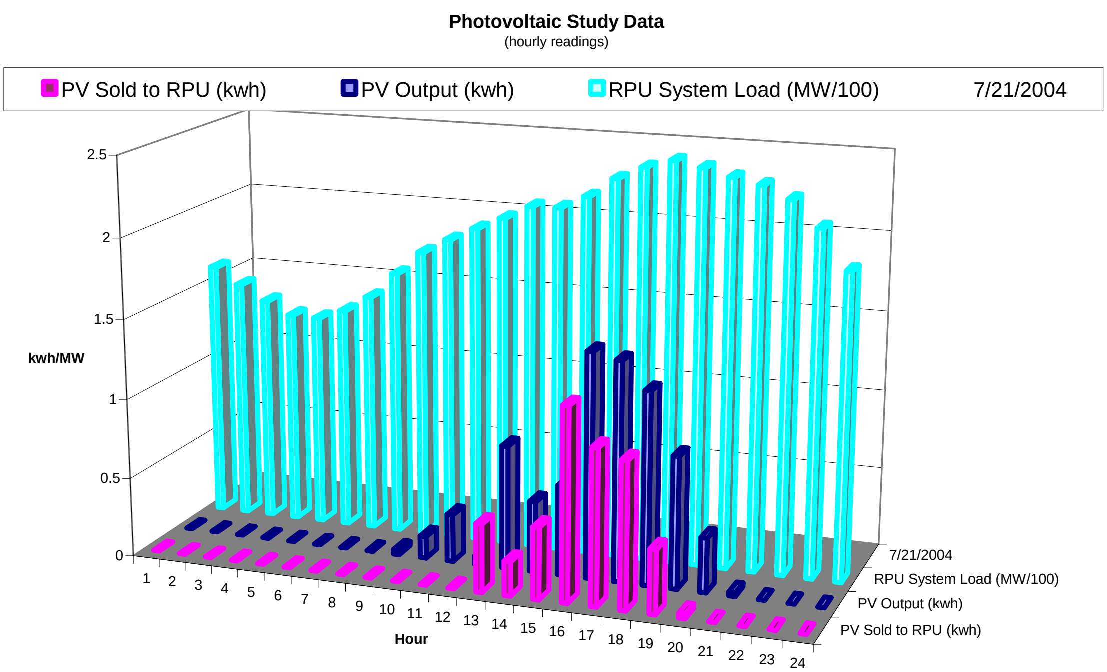
Legend:
Produced: The number of kWh produced by the PV array.
Capacity Factor: Based on a 2.59kW array rating
Max Output: The maximum kWh per hour measured

Note: Information from RPU's installation. Installed April, 2004.

The information from RPU is based on a flat plate array installed on a local residence. The output for the array was combined with the RPU system load for the same time period. The results are shown in Figures V-1 and V-2. Additional information was obtained for solar installations in the Minneapolis area.[1] A copy of the analysis is included in Appendix IV.

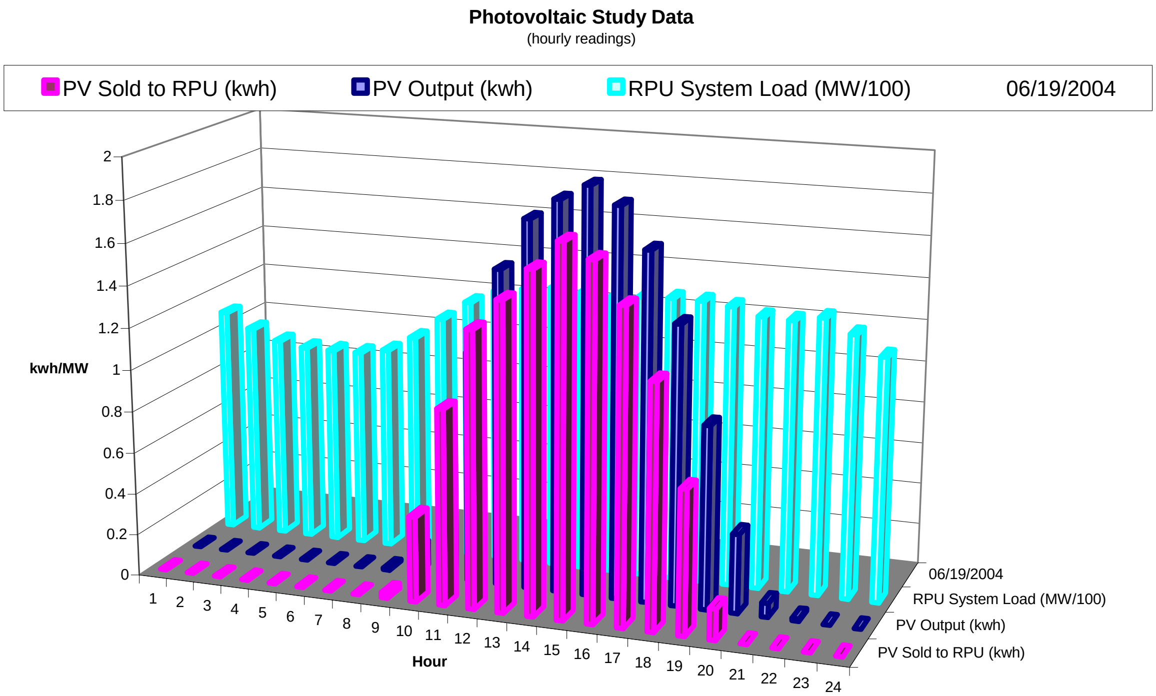
As shown in Figure V-1, the solar output drops to zero before the RPU system load declines significantly. This would require that RPU have sufficient generation available to meet its system needs in addition to having the solar output available. Also, the solar maximum output day is not coincident with the RPU peak day. This would require that RPU have capacity available for its peak day when the solar output was reduced from its maximum. The results from the RPU analysis are essentially the same as indicated in the referenced paper.

Figure V-1
Maximum RPU System Peak Day



[1] Statistical Relationship Between Photovoltaic Generation and Electric Utility Demand in Minnesota (1996-2002), Taylor, Mike, Minnesota Department of Commerce State Energy Office

Figure V-2
Maximum Solar Array Day



Wind

Wind power is being installed in several states with wind regimes suitable for their installation. In general, the units are in the 600kW to 750kW size range and are positioned in clusters of several machines. A 750kW machine has a rotor diameter of 164 feet and is mounted 164 feet above the ground. The output of the units is dependent on the average wind speed of the region. Table V-7 lists several operating projects, their average energy and capacity factor.

Table V-7
Wind Project Statistics

Site	Size of Unit	Average Output per Unit	Capacity Factor
Cedar Falls, IA	750kW	1,800MWh	30%
Searsburg, VT	550kW	1,220MWh	27%
NPPD	750kW	2,100MWh	32%
Glenmore, WI	600kW	1,630MWh	31%

From the list and other projects that Burns & McDonnell has evaluated in regions with similar wind regimes to Minnesota, the energy output from the machines results in an approximate 30 percent capacity factor. Operation and maintenance costs are estimated at $0.015 per kWh. Estimates of the energy cost from the machines for RPU considering capital and operating costs are in the range of $41to $53 per MWh. This assumes retirement of the debt in 15 years at an interest rate of 6 percent. Sales of output from wind power developments will be priced to include discounts for the energy credits from federal and state levels. In addition, green tags are being traded which provides another revenue stream for renewable projects.

Minnesota created a 1.5¢ per kilowatt-hour state renewable energy production incentive (REPI) for the first 100 MW of installed capacity of small wind generation projects. This state REPI was expanded by the 2003 Minnesota Legislature to be available to an additional 100 MW of small wind projects.

The energy produced by a wind generator is a non-dispatchable energy. Therefore, it has a limited capacity value. MAPP accreditation for wind resources is approximately 10 to 15 percent. Therefore, RPU would need to install approximately 8.5MW of traditional capacity for every 10MW of wind turbines installed to equal installation of a traditional resource to meet its MAPP capacity and reserve obligations.

Biomass

Biomass is typically used as a fuel stock for steam fired boilers in the production of electricity. Types of vegetation used for biomass fuel include wood waste, switchgrass, and certain forms of specific woody crops, such as bamboo. Biomass plants are typically rated below 50 MW due to the area required to acquire sufficient fuel for the plant. The lack of economies of scale pushes the capital cost of these plants up into the $1500 to $2000 per kW range for capital costs. Fuel for the biomass plants requires collection from dispersed areas by truck and delivery to the plant site.

There is an estimated 7000 MW of biomass fired power plants in the US in current operation. The plants produced approximately 39,000,000MWh of energy and consumed approximately 60 million tons of fuel. Reports from the Bioenergy group of Oak Ridge National Laboratories estimate the average cost of electricity from the plants is about $90 per MWh.

Under Minnesota Statute 2003, Chapter 216B, municipal waste is defined as a biomass fuel. RPU has access to energy derived from this biomass resource from the Olmsted Waste to Energy Facility (OWEF). The OWEF is a solid waste fueled unit that currently produces approximately 1.9MW. The plant has sufficient refuse available to support an estimated additional 5MW. RPU is in discussions with the county to purchase the output. The plant has operated with an historic 90 percent availability. A 5MW waste to energy plant would satisfy the renewable energy requirements of RPU under the Minnesota regulations until approximately 2023.

Fuel Cells

Although not strictly a renewable resource plant, fuel cells have been under development as a major alternative to traditional electrical generation methods. Fuel cells based on phosphoric acid have been in commercial operation for about ten years. These units are typically sized at a 200kW level. They are being deployed in certain high energy cost areas. Current phosphoric acid fuel cells are producing electricity with an efficiency of about 30-35 percent. An estimate of the stack life indicates that they will need to be replaced every 5 to 6 years. The estimated stack replacement cost is $100,000 for a 200kW unit, resulting in fixed maintenance cost of $83 to $100/kW-yr.

Fuel cells being considered for small commercial and residential application based on proton exchange membrane technology are entering the pre-commercial testing phase and have additional research required prior to being readily available as a commercially available technology. Combined heat and power concepts are working to increase the overall efficiency; however, they are in the early stages of development. Testing is indicating that reliability and the packaging approach for ease of repair and maintenance needs to be improved.

Molten carbonate (MC) fuel cells are currently being deployed on a pre-commercial test basis in several locations. These units operate at higher temperatures than the normal fuel cells and are being targeted for large utility and industrial applications. Units are being demonstrated on coal bed methane and land fill gas. The MC units are expected to operate at efficiencies approaching 60%.

The hope for fuel cells is their ability to operate on hydrogen and produce limited noxious emissions. Currently, almost all fuel cells operate on either methane gas from landfills or coal beds and pipeline natural gas due to the limited availability of hydrogen.

RPU is conducting fuel cell research with the University of Minnesota-Rochester (UMR). The Hybrid Energy System Study (HESS) project's primary objective is to complete the static and dynamic evaluation of fuel cell technology using a 1200-watt fuel cell system installed in the RPU headquarters building in Rochester. Phase I which was completed last October, acquainted RPU and UMR with the latest in fuel cell technology that is being used in the commercial market. The fuel cell system performance was analyzed and compared with respect to efficiency, reliability, availability and serviceability.

With the completion of the Phase I basic study on fuel cells, the RPU/UMR partnership will move early in 2005 to a project level that begins to make full use of fuel cell capabilities. Fuel cells typically run at an efficiency level of about 40% when generating electricity. A major part of the efficiency loss is in the heat generated during the fuel cells operation. Capturing this heat and making use of it as part of a system's energy solution is the focus of Phase II. In particular, we will integrate a fuel cell and a geothermal (GX) heating system, therefore, capturing the heat generated by the fuel cell and raising the efficiency of the system to over 80%. During summer time operation, this extra heat could be used to provide more energy to heat hot water, swimming pools, etc.

Renewable Portfolio Program

RPU is committed to not only providing its required portion of renewable energy to satisfy the requirements of the Minnesota Statute 216B, but to integrate renewable energy where it makes good business sense to do so. The energy above CROD amount provided by SMMPA is shown in Table V-8 for 2016 to the end of the study period. The growth in renewable energy required between 2005 and 2016 can be met through the energy from the Zumbro River hydro facility. Using the ten percent requirement from the Statute, the required amount of energy beyond 2015 can be determined. The amount of energy estimated to be available from the Zumbro River hydro facility is also shown. The resulting renewable energy required beyond that currently provided is shown in Table V-8.

Using the average capacity factors for the fixed plate solar arrays from Table V-6 and the average 30 percent capacity factor for wind units, the average amount of solar and wind capacity required to meet the RPU annual renewable energy requirements can be estimated. These estimates were derived from using the Revised Energy Forecast from Table V-5. Table V-8 provides the estimates. The energy above CROD requirements predicted in Table V-8 assumed the energy savings are evenly distributed across all hours of the year. To the degree the savings accrue more from programs reducing energy above or below the CROD level, the estimates in Table V-8 will vary actual results.

Table V-8
Estimated MW of Wind or Solar Required to Meet the RPU Renewable Energy Requirements Post 2015

Year	Energy Above CROD (MWh)	Renewable Requirement (10%)	From Zumbro River Hydro	Resultant Renewable Req.	Solar Capacity Required (MW)	Wind Capacity Required (MW)
2016	70,589	7,059	9,000	-1,941	0.0	0.0
2017	82,305	8,230	9,000	-770	0.0	0.0
2018	96,279	9,628	9,000	628	0.0	0.0
2019	112,425	11,243	9,000	2,243	2.0	0.9
2020	134,112	13,411	9,000	4,411	4.0	1.7
2021	159,422	15,942	9,000	6,942	6.3	2.6
2022	190,077	19,008	9,000	10,008	9.1	3.8
2023	224,847	22,485	9,000	13,485	12.3	5.1
2024	264,465	26,446	9,000	17,446	15.9	6.6
2025	305,705	30,570	9,000	21,570	19.7	8.2
2026	349,486	34,949	9,000	25,949	23.7	9.9
2027	396,145	39,614	9,000	30,614	28.0	11.6
2028	445,435	44,543	9,000	35,543	32.5	13.5
2029	496,336	49,634	9,000	40,634	37.1	15.5
2030	549,802	54,980	9,000	45,980	42.0	17.5

The solar and wind resources' ability to provide a certain amount of capacity relief was reviewed. The peak needs of RPU and the solar availability are shown in Figures V-1 and V-2. The figures indicate that the peak requirements extend beyond the time period when solar is available. Cloud cover can also significantly reduce the solar output below the demand required of RPU. Therefore, for supply reliability, additional resources are required to provide energy when the solar output is unavailable. The MAPP accreditation process for solar array output from the above paper indicates that for the Minneapolis solar arrays, the units were able to have capacity accredited between 8 percent and 44 percent of their AC ratings. Correlation of the specific RPU data will need to be made to determine the proper estimated accreditation for solar arrays in the RPU service territory.

Allowing wind the MAPP upper 15 percent capacity credit indicates that only a portion of the wind capacity may be available across the peak. Therefore, the renewable portfolio options may require the installation of peaking capacity to support them during times when they are unavailable and load demand is still higher than the existing resource capability. For the wind portfolio, approximately 85 percent of the capacity in the traditional options could be required.

If the OWEF increases its output to 5MW, the plant would produce approximately 32,850 MWh per year, assuming a 75 percent capacity factor. Since this unit counts as renewable energy and under the Statute utilities are to provide 1 percent of their energy from biomass, it could satisfy the RPU biomass renewable requirements through the study period. When combined with the Zumbro River hydro facility total renewable requirements could be satisfied until approximately 2027. Table V-9 provides an assumed purchase scenario. Due to the requirement in the REO of obtaining 1 percent of energy from biomass, the output of the OWEF will be required beginning in 2005.

Table V-9
RPU Estimated Annual Renewable Energy Requirements (MWh)

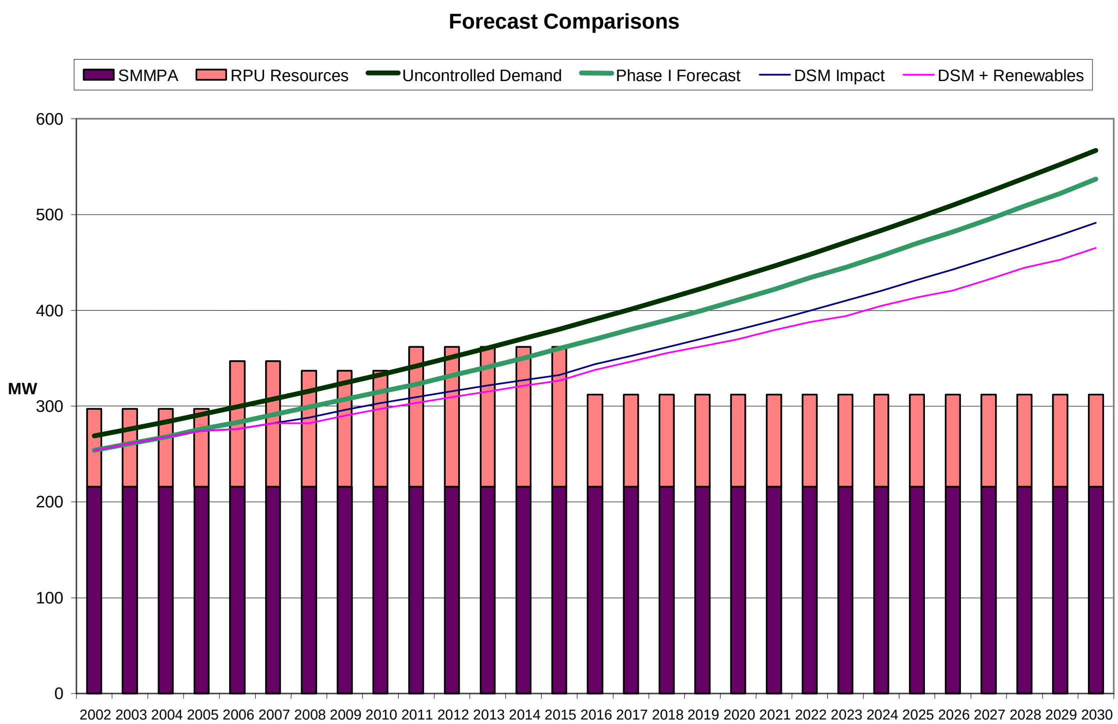
			Available from OWEF			
Year	Renewable Requirement (10%)	From Biomass	1.9MW @ 75%CF	5MW @ 75%CF	From Zumbro River	Total Hydro & Biomass
2016	7,059	71	12,483		9,000	21,483
2017	8,230	82	12,483		9,000	21,483
2018	9,628	96	12,483		9,000	21,483
2019	11,243	112	12,483		9,000	21,483
2020	13,411	134	12,483		9,000	21,483
2021	15,942	159	12,483		9,000	21,483
2022	19,008	190	12,483		9,000	21,483
2023	22,485	225		32,850	9,000	41,850
2024	26,446	264		32,850	9,000	41,850
2025	30,570	306		32,850	9,000	41,850
2026	34,949	349		32,850	9,000	41,850
2027	39,614	396		32,850	9,000	41,850
2028	44,543	445		32,850	9,000	41,850
2029	49,634	496		32,850	9,000	41,850
2030	54,980	550		32,850	9,000	41,850

Note: All energy values in MWh

DSM and Renewable Impacts on RPU Supply Needs

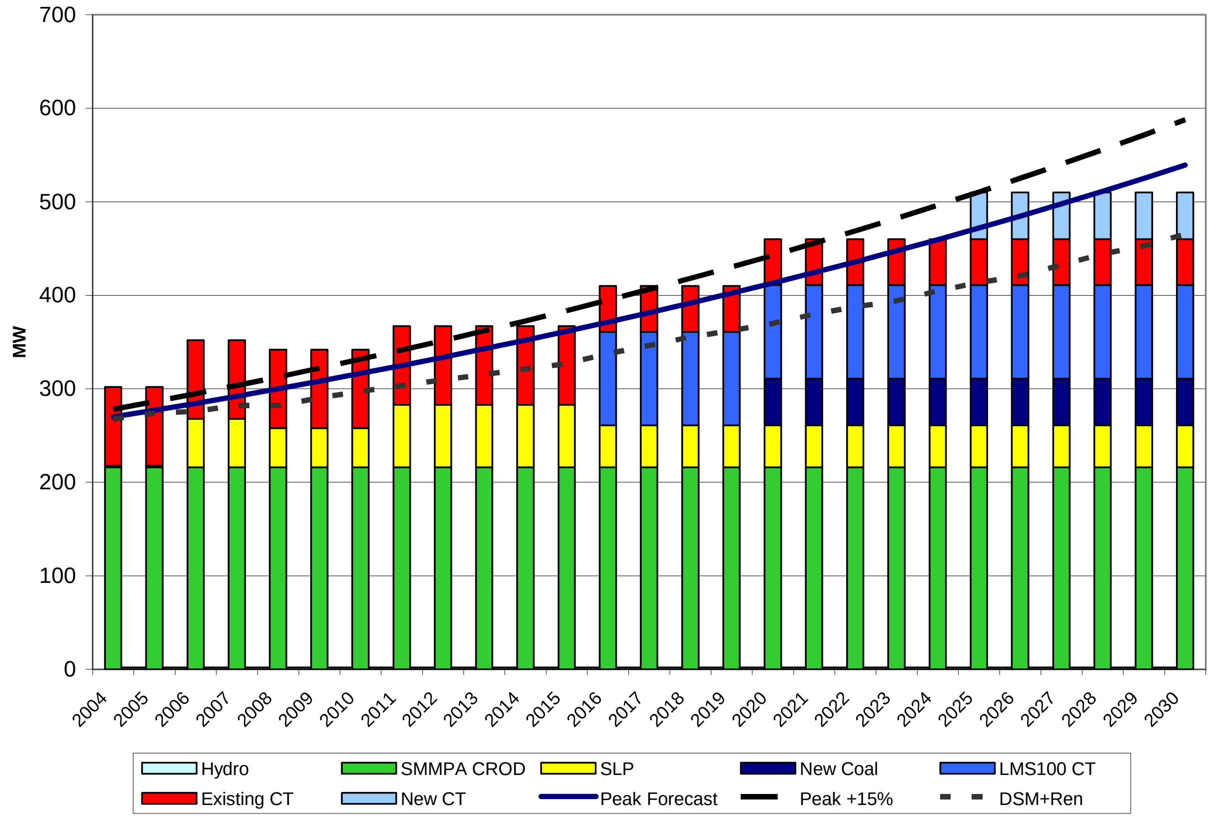
The balance of loads and resources using the DSM and renewable impacts was modified to include the above forecasts. The resulting impacts are shown in Figure V-3.

Figure V-3
Comparison of Base and Revised Forecasts
With DSM and Renewable Impacts



The impacts to the forecast indicate that the projected impacts of DSM and renewables do not delay the year when RPU becomes capacity deficit, however, they substantially reduce the amount of capacity needed. In addition, they delay the need for additional capacity in the future. Figure V-4 is the balance of loads and resources of the recommended traditional resource plan. As shown, the impact of the DSM and renewables on the forecast allows a delay in the installation of the LMS-100 combustion turbine by about 2 - 3 years. The impacts also allow a delay in the need for the coal unit by a similar period.

Figure V-4
Impact of DSM and Renewables
On Lowest Evaluated Traditional Resource Plan
Balance of Loads and Resources



Conclusions and Recommendations

Based on the review of the information provided by RPU and the analysis developed in this study, Burns & McDonnell has developed the following conclusions and recommendations about the DSM programs and renewable energy alternatives available to RPU.

1. The review of the DSM end use surveys and benefit cost ratios provided an indication of the amount and value of various conservation programs to the RPU customer base that is sufficient to use for planning purposes.

2. The estimates of energy and demand reductions from the programs with benefit cost ratios greater than one is sufficient to warrant study by RPU in determining the impact on rates for development of various programs and the impact on forecasts for energy and demand.

3. Considering the forecast, RPU has several years before it is in a capacity deficit condition due to load needs. Estimates of DSM and renewable impacts to the forecast provide the opportunity for RPU to delay the installation of resources by

two to three years, depending on the successful acceptance of the DSM programs by the RPU customers.

4. The development of the MISO Day 2 market will make day ahead pricing more predictable and potentially provide RPU with the opportunity to engage customers in demand adjustments based on the cost of energy. The current Partners program could see a decrease in the number of MW under control due to more efficient air conditioners being installed on the system and potential fuel switching of water heaters. These two developments are an indication that RPU should consider realigning its approach to demand reductions on the customer side of the meter. Because of this need, RPU should prepare a pilot program for implementation of demand response type programs across the residential, commercial and industrial classes in order to gain experience and begin shifting away from the direct control programs to market based programs.

5. RPU's renewable obligations under the Minnesota Statute Chapter 216B can be met for several years through purchase of energy from the OWEF and the Zumbro River hydro facility. If the OWEF facility is expanded, as is being considered, RPU renewable energy requirements could be satisfied until approximately 2027 with these two resources.

6. Discussions with the OWEF should proceed to determine if additional output is available. If it is not, then wind energy should be pursued as the next renewable option. Based on the cost and output of photovoltaic units, solar photovoltaic is the most expensive renewable option for the RPU to pursue.

7. Based on information from RPU, the SMMPA is in discussions on acquisition of additional resources which could affect the cost of capacity and energy under the CROD. At the current time, there is insufficient information to be able to determine how DSM programs could reduce the impact of these potential costs. If SMMPA moves ahead with resource acquisitions based on RPU impacts to the SMMPA resource mix, RPU should discuss with SMMPA the ability of DSM options to reduce the resource need impacts to SMMPA.

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Part VI

Financial Forecast

The results of the resource planning, demand side management and renewable assessments were reviewed on an incremental cost approach to determine lower evaluated options. In order to bring these options together to determine the recommended RPU future, a financial forecast model was developed by RPU to incorporate the total costs of RPU. This model allowed a complete evaluation of future costs, the impact to average rates and other financial factors of interest to RPU. This part of the report provides a discussion of the model and the results.

Financial Model

The model was developed by Bryan Blom of the RPU staff. It is a very flexible tool that will provide RPU with the capability to do scenario analysis rapidly, with a variety of measurements to gauge the benefits of certain futures. The model incorporates all of the RPU costs of operations, investments, and financial targets such as for cash balances and reserve accounts.

The financial model was used to analyze the following futures:

- The recommended expansion plan from Part IV with the forecast unaffected by demand side management,
- The recommended plan adjusted by using the normal demand side management forecast with SLP operating on coal and adjustments to the new resources,
- The recommenced plan adjusted by using the normal demand side management forecast with SLP operating on natural gas and the coal unit replaced with gas-fired capacity,
- The recommended plan adjusted by using the aggressive demand side management results with SLP operating on coal and adjustments to the new resources,
- The recommended plan adjusted by using the aggressive demand side management results with SLP operating on natural gas and the coal unit replaced with gas-fired capacity.

Input Assumptions

A variety of assumptions were made to the financial model. The main driver for the model is the energy forecast. The energy forecast for the three futures is summarized in Table VI-1. The demand forecast is also included.

Table VI-1
Financial Model Load Forecast

	System MWH Requirements		System KW Peaks	
Year	No DSM	Aggr DSM, Coal Gas Mix / Aggr DSM, All Gas	No DSM	Aggr DSM, Coal Gas Mix / Aggr DSM, All Gas
2005	1,377,188	1,369,244	275,532	273,943
2006	1,414,592	1,355,882	283,016	271,270
2007	1,452,466	1,379,800	290,593	276,055
2008	1,495,753	1,405,507	299,254	281,198
2009	1,532,736	1,424,557	306,653	285,009
2010	1,573,748	1,448,206	314,858	289,741
2011	1,615,858	1,473,719	323,283	294,845
2012	1,664,019	1,504,173	332,918	300,938
2013	1,705,167	1,529,146	341,151	305,934
2014	1,750,796	1,559,194	350,280	311,946
2015	1,797,648	1,589,834	359,653	318,076
2016	1,850,380	1,635,664	370,203	327,245
2017	1,897,159	1,672,869	379,562	334,689
2018	1,947,044	1,717,704	389,543	343,659
2019	2,000,216	1,762,000	400,181	352,521
2020	2,058,896	1,812,798	411,921	362,684
2021	2,108,877	1,857,723	421,920	371,672
2022	2,167,552	1,907,527	433,659	381,637
2023	2,225,664	1,958,667	445,286	391,868
2024	2,289,846	2,017,133	458,127	403,565
2025	2,346,599	2,067,127	469,481	413,568
2026	2,410,705	2,122,550	482,307	424,656
2027	2,475,342	2,180,536	495,239	436,257
2028	2,547,984	2,244,526	509,772	449,060
2029	2,612,433	2,301,298	522,666	460,418
2030	2,681,160	2,364,171	536,416	472,997
2031	2,753,599	2,426,667	550,909	485,500
2032	2,827,996	2,490,816	565,794	498,335
2033	2,904,405	2,556,663	581,081	511,508
2034	2,982,881	2,624,252	596,781	525,031

The load forecast was used to derive estimates for a variety of other assumptions, such as:

- Energy dispatch from RPU sources, including market sources, above the SMMPA supplied energy,
- Generation fuel expense,
- Purchased power expense for energy, capacity, and transmission,
- Administrative and general costs,
- Distribution and substation additions,
- Retail revenue forecasts.

Forecasts for investment in other projects, such as for transmission upgrades, capital investments in plant, and other improvements were provided by the respective operating divisions of RPU. The Silver Lake Plant was assumed to have the recommended environmental modifications from the Utility Engineering report “Rochester Public Utilities Emissions Control Feasibility Study, Silver Lake Plant,” Dec 2004 in the futures with coal. The budgets for the demand side management and marketing programs were included based on the level of DSM considered in the forecast. The list of input assumptions is included in Appendix V.

Methodology

The financial model uses the energy forecast and estimated energy price from the resources available to determine the amount of energy derived from each source. If the load level is at or below the 216MW level of the SMMPA contract, then the energy is assumed to come from SMMPA. If the load is above the 216MW level, then the lowest cost resource is dispatched to provide the energy with the exception that small load increments were dispatched first from peaking units until the point where the increment was high enough to feasibly dispatch baseload generation.

The economic impacts of resource additions were determined based on the estimated capital, fixed and variable operating and maintenance costs. The targeted financial goals for debt service coverage ratios, average cash balances and other targets based on capital investments were included. In-service years and the amount of capacity added were adjusted in the futures with demand side management included to reflect the benefits to delays in and amounts of capital investment.

Estimates of purchases from the market were made using a forecast market demand and energy price. For certain years, market capacity was purchased on a seasonal basis to provide the necessary capacity shortfall rather than install a new resource. Also, when market energy was estimated to be lower cost than an RPU resource’s energy cost, the market was used to provide the energy.

The operation of the SLP to meet wholesale energy and steam production contract obligations was modeled. The operations included estimated energy and steam production based on current discussions with counter parties to the contracts.

The operation and capital budgets of each RPU division were incorporated to provide a complete financial picture of the utility. The revenue requirements were then used to determine the amount of adjustment to rates necessary to meet those requirements. Average impact to retail rates and customer average bills were also estimated. The model covers a thirty year time period from 2005 to 2034.

Externalities

The values of externalities were included in this analysis. The values of externalities used by the Minnesota Public Utilities Commission (Rural) for utilities to evaluate externalities are shown in Table VI-2. These values were adjusted for the gross domestic price inflator (4.4%) for 2004. A midpoint range for the adjusted values was selected for use in the analysis. These values are also shown in Table VI-2.

Table VI-2
Externality Values

	Low Value		High Value		2004
	2003	2004	2003	2004	AVG
PM10	$645.00	$673.38	$981.00	$1,024.16	$848.77
CO	$ 0.24	$ 0.25	$ 0.47	$ 0.49	$ 0.37
Nox	$ 21.00	$ 21.92	$117.00	$122.15	$ 72.04
Pb	$461.00	$481.28	$514.00	$536.62	$508.95
CO2	$ 0.34	$ 0.35	$ 3.56	$ 3.72	$ 2.04

The emission rates from the resources considered in the financial model are summarized in Table VI-3. The emissions were placed on a dollar per MWh basis for use with the expected dispatch MWh determined from the financial model. Externalities on contract and market purchases were also included to reflect one half of the purchases from new coal units and one half from combined cycle gas units.

Table VI-3
Emission Rates
(lb/MWh)

			SLP			
Emission	LMS100	CC2	Coal	Gas	New Coal	Market
SO2	0	0	4.85	0.01	0.96	0
PM10	0.14	0.0166	0.21	0.07766	0.17	0.07
CO	5.85	2.96	0.28	0.924	1.44	0.117
Nox	0.87	1.52	1.60	3.08	0.67	0.084
Pb	0	0	0.000606	0.0000055	0.0002406	0
CO2	1125.48	1051.2	2,460.97	1126	2761.51	825

Renewable Options

The values for the average energy costs from the expected resources and certain renewable resources are shown in Table VI-4. The RPU currently purchases renewable energy from the Olmsted County Waste to Energy Facility, which counts towards the utilities biomass energy requirement. This facility is considering increasing the energy production which could provide additional biomass energy for RPU. Energy from a solar installation in the RPU service territory is currently being purchased at the net metered residential energy rate. Wind energy is purchased through the SMMPA. The amount of predominate renewable energy is from the Zumbro River hydro-electric facility.

Table VI-4
Average Energy Costs with Externalities
(2004$ per MWh)

Option	Fixed O&M	Var O&M	Purchase/ Fuel	Transmission	Externality	Total
SLP Coal	$13.85	$6.59	$25.34		$2.65	$48.43
New Coal	$ 3.01	$2.15	$11.07	$5.00	$2.91	$24.14
New Gas	$ 6.73	$4.01	$58.27		$1.13	$70.14
LMS 100	$ 3.75	$3.30	$53.79		$1.24	$62.08
Market			$35.88	$5.00	$1.89	$42.77
Solar PV			$75.10			$75.10
OWEF			$60.00	$5.00		$65.00
Wind			$33.44	$5.00		$38.44
Zumbro		$2.17				$2.17

Although it is acceptable to consider energy costs on a one for one basis between traditional and renewable resources, the capacity cannot always be considered in a comparable fashion. This is due to the non-dispatchability of most renewable options. For instance, the utility has to take energy from a wind turbine when the wind blows. The energy availability and the utility needs may not necessarily coincide. The line-up of solar energy with the RPU demand is shown in Part V and demonstrates this issue.

RPU operates in the Mid-Continent Area Power Pool (MAPP) reliability region. Utilities within this region must maintain a reserve margin of 15 percent or be assessed a penalty. In order to meet this requirement, resources must meet certain capacity tests. From past experience with wind turbine and solar array capacity, MAPP has established that wind capacity provides only 15 percent of the equivalent traditional resource capacity value and solar provides approximately 40 percent (summer season). This means that if RPU wanted to install wind or solar capacity to meet its MAPP reserve requirements, which for every MW of traditional resource considered either 6.67MW of wind or 2.5MW of solar would be needed. The impact of these requirements on the average cost of energy from the resources is shown in Table VI-5.

Table VI-5
Impacts of Equivalent Capacity on Energy Cost
(Average Annual Debt Service)

Option	$/MWh	Capacity Factor-%
SLP Coal	$11.73	40
New Coal	$16.99	80
New Gas	$32.48	20
LMS 100	$36.30	20
Solar PV	$852.50	20
Wind	$222.91	30

Based on the evaluation of the externalities and MAPP accreditation impacts, RPU has determined that renewable energy will be used to displace traditional resource energy where economic. However, renewable resources will not be considered to meet future capacity obligations.

Renewable energy from the Zumbro River facility was included in the financial model as the primary renewable resource, wind energy under the SMMPA program included at its historical average, and with OWEF assumed to be the biomass resource.

Results

Resource Plan

The impact of the demand side management efforts on the load forecast are shown in Part V, Figure V-1 and 2 for the demand and energy respectively. Figure V-4 provides the potential impacts the forecast could have to the resource needs in the traditional resource plan. The reduction in the demand and energy forecast provides an opportunity to delay the gas resource considered for 2016 and the in service year and amount of capacity for the coal resource considered in 2020. In the financial model, the combustion turbine considered for installation in 2016 was delayed two years and the coal unit was reduced to 25MW and its in service date delayed to 2025.

Rates

Figure VI-1 and 2 provide the results based on average retail rate impacts and average customer bills. As seen, there are significant advantages in the demand side management impacts on both rates and average bills. When considering the cost impacts due to the futures with and without coal, it is seen that the coal case provides economic benefits. The rate impacts determined from the analyses are summarized in Figure VI-3. RPU in any of the futures is expected to need rate increases of from 1 to 3 percent in almost each year of the assessment. The differences in the expected and aggressive demand side management scenarios were not significant and only the aggressive forecast is included here. The more detailed results of the financial model analyses are included in Appendix V.

Figure VI-1
Retail $/MWH-Major Customer Classes

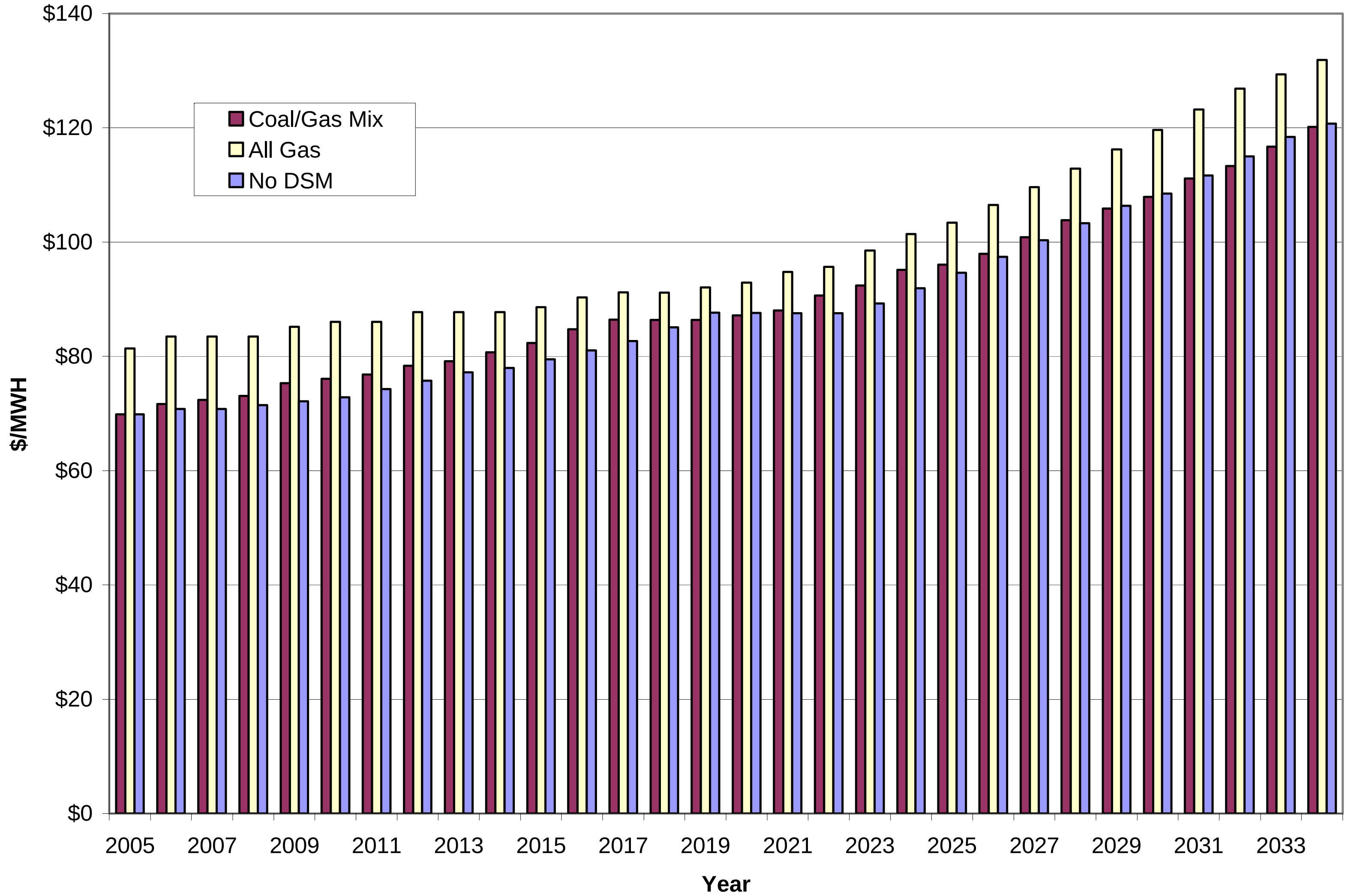


Figure VI-2
Average Annual Bill-Major Customer Classes

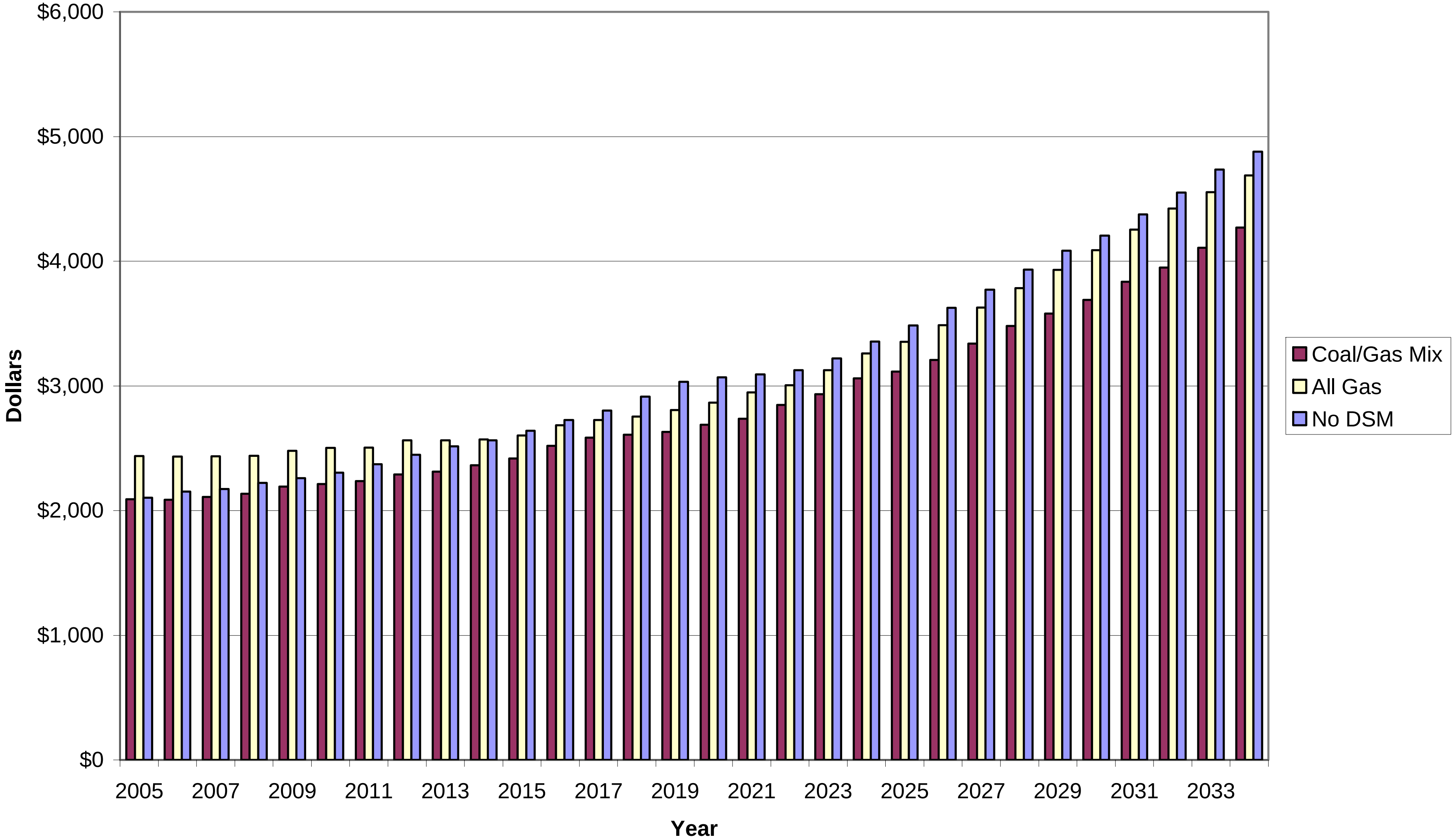
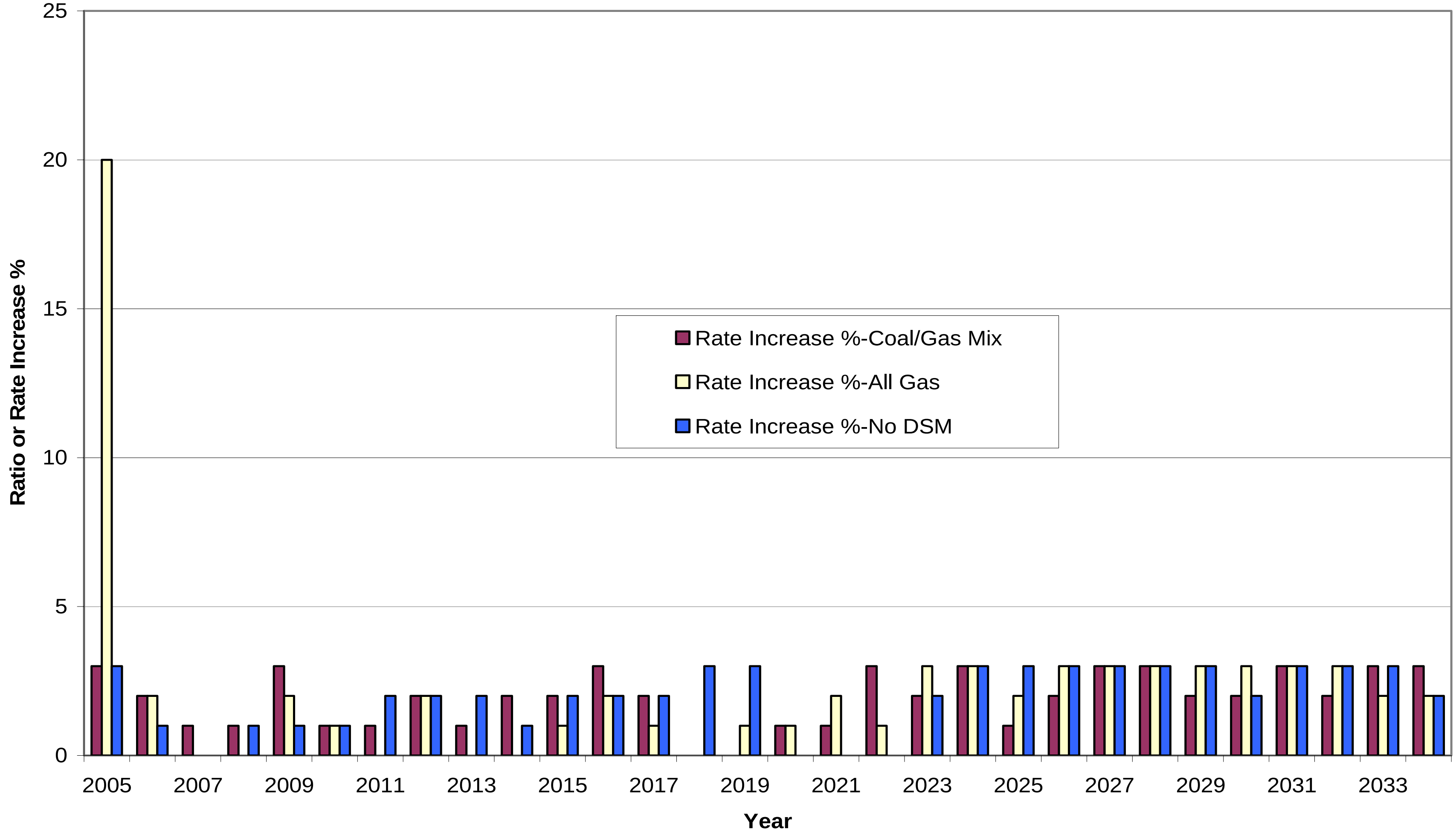


Figure VI-3
Percentage of Annual Retail Rate Increase



As seen from the above graphs, the DSM cases with the coal and gas fuel scenario are the only cases that help to reduce both the average rates and customer bills.

Emissions

The emissions from each of the futures were considered from both absolute tons per externality and the cost aspect using the Minnesota value for externalities. Table VI-6 provides the summary of tons emitted by externality based on the energy dispatch used for the RPU retail resource future over the thirty years of the analysis. As shown, there is a substantial advantage to the demand side reductions. The costs of the externalities and the total costs of the specific future are included in Table VI-7.

Table VI-6
Total Tons of Emissions by Scenario

Scenario	SO2	Nox	PM10	Pb	CO	CO2
Original Forecast	7,808	4,587	770	1.25	9,811	10,472,370
Normal DSM Coal & Gas	5,228	3,105	485	0.79	7,048	6,263,420
Normal DSM All Gas	379	5,086	296	0.10	8,341	3,784,419
Aggressive DSM Coal & Gas	4,931	2,886	448	0.73	6,504	5,720,385
Aggressive DSM All Gas	343	4,714	272	0.09	7,644	3,474,437

Table VI-7
Retail Portion of RPU Costs of Various Plans with Externalities
(2004$ 000's)

Scenario	Retail Revenue	Externalities	Total
Original Forecast	$ 5,649,613	$22,308	$ 5,671,921
Normal DSM Coal & Gas	$ 5,134,851	$13,390	$ 5,148,241
Normal DSM All Gas	$ 5,672,269	$ 8,325	$ 5,680,594
Aggressive DSM Coal & Gas	$ 5,104,864	$12,236	$ 5,117,100
Aggressive DSM All Gas	$ 5,569,761	$ 7,646	$ 5,577,408

Conclusions

Based on the analysis performed for this study, Burns & McDonnell has developed the following conclusions:

1. The uncertainty surrounding the conversion of the electricity wholesale market in the RPU region from its traditional operation to its new operation under MISO and the existing transmission limitations for importing power into the RPU area makes it necessary for RPU to continue to have capacity available within its service area for reliability and economic purposes.

2. The use of traditional resources to meet the RPU capacity obligations is lower cost than the use of wind or solar equivalent capacity. Energy costs from certain renewable options can be attractive when compared to the energy costs from coal, gas, or market resources.

3. The impacts of demand side management allow RPU to delay and reduce the amount of capacity required when compared to the forecast without significant demand side management effects included.

4. The future evaluated with coal and gas energy and aggressive demand side management was the only future that provided both lower average rates and lower average total bills when compared to the other futures. This ranking is not changed with the inclusion of externalities.

5. The emissions from the aggressive demand side management future with coal and gas are approximately one-half of the emissions from the traditional resource future.

Recommendations

Based on the above conclusions and the analyses performed, Burns & McDonnell provides the following recommendations for consideration by RPU.

1. Due to the need for future capacity additions internal to RPU, RPU should pursue the acquisition of property to install additional combustion turbine capacity. The property should be located in close proximity to high capacity electric and gas transmission lines.

2. RPU should pursue emission control upgrades to the SLP facility to allow continued operations while meeting ongoing environmental regulations and follow the general course of operations as modeled in the DSM futures with coal and gas fuels in the operating mix.

3. Improved transmission import capability should be reviewed with area utilities to allow increased access to market capacity. Although the plans anticipate future resource additions, there is also continued reliance on market purchases to meet future load growth.

4. RPU should monitor the operations of the MISO Day 2 market to determine how to participate in the market.

5. RPU should continue to design and market DSM programs to achieve the levels of forecast reductions for demand and energy. Periodic comparison of actual results to those forecasts should be made to determine if adjustments in the forecast results is necessary.

6. RPU should take advantage of renewable energy from the Zumbro River resource to the full extent of its output. The renewable energy from the OWEF should be considered to provide the RPU biomass energy requirements. Purchases above the requirements should be compared to the cost of other energy available.

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Appendix I – Load Forecast (Without DSM Impacts)

Annual Peak Demand and Energy Requirements

Year	Peak (MW)	Esc.	Energy (MWh)	Esc.	LF
2003	261.3	2.7%	1,306,276	9.6%	57.1%
2004	268.4	2.7%	1,344,534	2.9%	57.2%
2005	275.6	2.7%	1,377,767	2.5%	57.1%
2006	283.1	2.7%	1,414,967	2.7%	57.1%
2007	290.7	2.7%	1,453,171	2.7%	57.1%
2008	298.6	2.7%	1,495,732	2.9%	57.2%
2009	306.6	2.7%	1,532,702	2.5%	57.1%
2010	314.9	2.7%	1,574,085	2.7%	57.1%
2011	323.4	2.7%	1,616,585	2.7%	57.1%
2012	332.2	2.7%	1,663,932	2.9%	57.2%
2013	341.1	2.7%	1,705,059	2.5%	57.1%
2014	350.3	2.7%	1,751,096	2.7%	57.1%
2015	359.8	2.7%	1,798,375	2.7%	57.1%
2016	369.5	2.7%	1,851,046	2.9%	57.2%
2017	379.5	2.7%	1,896,798	2.5%	57.1%
2018	389.7	2.7%	1,948,012	2.7%	57.1%
2019	400.3	2.7%	2,000,608	2.7%	57.1%
2020	411.1	2.7%	2,059,202	2.9%	57.2%
2021	422.2	2.7%	2,110,100	2.5%	57.1%
2022	433.6	2.7%	2,167,072	2.7%	57.1%
2023	445.3	2.7%	2,225,583	2.7%	57.1%
2024	457.3	2.7%	2,290,766	2.9%	57.2%
2025	469.6	2.7%	2,347,559	2.5%	57.1%
2026	482.3	2.7%	2,410,943	2.7%	57.1%
2027	495.3	2.7%	2,476,038	2.7%	57.1%
2028	508.7	2.7%	2,548,370	2.9%	57.2%
2029	522.4	2.7%	2,611,549	2.5%	57.1%
2030	536.6	2.7%	2,682,061	2.7%	57.1%

Monthly Peak Demand and Energy Requirements

			Peak Demand (MW)			Total Energy Requirements (MWh)		
Month	Year		Annual Peak	Ratio	Peak	Total	Ratio	Total
Jan	2006		283.1	0.648	183.5	1,414,967	0.078	110,892
Feb	2006		283.1	0.645	182.6	1,414,967	0.071	100,341
Mar	2006		283.1	0.631	178.6	1,414,967	0.076	107,892
Apr	2006		283.1	0.687	194.5	1,414,967	0.073	103,354
May	2006		283.1	0.770	218.1	1,414,967	0.080	113,721
Jun	2006		283.1	0.966	273.5	1,414,967	0.091	128,980
Jul	2006		283.1	1.000	283.1	1,414,967	0.109	153,709
Aug	2006		283.1	0.984	278.7	1,414,967	0.102	144,845
Sep	2006		283.1	0.977	276.6	1,414,967	0.086	121,835
Oct	2006		283.1	0.694	196.6	1,414,967	0.079	111,608
Nov	2006		283.1	0.656	185.8	1,414,967	0.075	105,978
Dec	2006		283.1	0.687	194.5	1,414,967	0.079	111,812
Jan	2007		290.7	0.648	188.4	1,453,171	0.078	113,886
Feb	2007		290.7	0.645	187.5	1,453,171	0.071	103,050
Mar	2007		290.7	0.631	183.5	1,453,171	0.076	110,805
Apr	2007		290.7	0.687	199.8	1,453,171	0.073	106,145
May	2007		290.7	0.770	224.0	1,453,171	0.080	116,791
Jun	2007		290.7	0.966	280.9	1,453,171	0.091	132,462
Jul	2007		290.7	1.000	290.7	1,453,171	0.109	157,859
Aug	2007		290.7	0.984	286.2	1,453,171	0.102	148,756
Sep	2007		290.7	0.977	284.1	1,453,171	0.086	125,125
Oct	2007		290.7	0.694	201.9	1,453,171	0.079	114,622
Nov	2007		290.7	0.656	190.8	1,453,171	0.075	108,839
Dec	2007		290.7	0.687	199.8	1,453,171	0.079	114,831
Jan	2008		298.6	0.648	193.5	1,495,732	0.078	117,222
Feb	2008		298.6	0.645	192.6	1,495,732	0.071	106,068
Mar	2008		298.6	0.631	188.4	1,495,732	0.076	114,050
Apr	2008		298.6	0.687	205.2	1,495,732	0.073	109,253
May	2008		298.6	0.770	230.0	1,495,732	0.080	120,212
Jun	2008		298.6	0.966	288.5	1,495,732	0.091	136,342
Jul	2008		298.6	1.000	298.6	1,495,732	0.109	162,482
Aug	2008		298.6	0.984	293.9	1,495,732	0.102	153,113
Sep	2008		298.6	0.977	291.8	1,495,732	0.086	128,789
Oct	2008		298.6	0.694	207.3	1,495,732	0.079	117,979
Nov	2008		298.6	0.656	196.0	1,495,732	0.075	112,027
Dec	2008		298.6	0.687	205.2	1,495,732	0.079	118,195
Jan	2009		306.6	0.648	198.7	1,532,702	0.078	120,119
Feb	2009		306.6	0.645	197.8	1,532,702	0.071	108,690
Mar	2009		306.6	0.631	193.5	1,532,702	0.076	116,869
Apr	2009		306.6	0.687	210.7	1,532,702	0.073	111,954
May	2009		306.6	0.770	236.3	1,532,702	0.080	123,183
Jun	2009		306.6	0.966	296.3	1,532,702	0.091	139,711
Jul	2009		306.6	1.000	306.6	1,532,702	0.109	166,498
Aug	2009		306.6	0.984	301.8	1,532,702	0.102	156,897
Sep	2009		306.6	0.977	299.7	1,532,702	0.086	131,973
Oct	2009		306.6	0.694	212.9	1,532,702	0.079	120,895
Nov	2009		306.6	0.656	201.3	1,532,702	0.075	114,796
Dec	2009		306.6	0.687	210.7	1,532,702	0.079	121,116
Jan	2010		314.9	0.648	204.1	1,574,085	0.078	123,362
Feb	2010		314.9	0.645	203.1	1,574,085	0.071	111,625
Mar	2010		314.9	0.631	198.7	1,574,085	0.076	120,025
Apr	2010		314.9	0.687	216.4	1,574,085	0.073	114,976
May	2010		314.9	0.770	242.6	1,574,085	0.080	126,509
Jun	2010		314.9	0.966	304.3	1,574,085	0.091	143,484
Jul	2010		314.9	1.000	314.9	1,574,085	0.109	170,994
Aug	2010		314.9	0.984	310.0	1,574,085	0.102	161,133
Sep	2010		314.9	0.977	307.8	1,574,085	0.086	135,536
Oct	2010		314.9	0.694	218.7	1,574,085	0.079	124,159
Nov	2010		314.9	0.656	206.7	1,574,085	0.075	117,896
Dec	2010		314.9	0.687	216.4	1,574,085	0.079	124,386

Jan	2011		323.4	0.648	209.6	1,616,585	0.078	126,693
Feb	2011		323.4	0.645	208.6	1,616,585	0.071	114,639
Mar	2011		323.4	0.631	204.1	1,616,585	0.076	123,266
Apr	2011		323.4	0.687	222.3	1,616,585	0.073	118,081
May	2011		323.4	0.770	249.2	1,616,585	0.080	129,925
Jun	2011		323.4	0.966	312.5	1,616,585	0.091	147,358
Jul	2011		323.4	1.000	323.4	1,616,585	0.109	175,610
Aug	2011		323.4	0.984	318.4	1,616,585	0.102	165,484
Sep	2011		323.4	0.977	316.1	1,616,585	0.086	139,195
Oct	2011		323.4	0.694	224.6	1,616,585	0.079	127,511
Nov	2011		323.4	0.656	212.3	1,616,585	0.075	121,079
Dec	2011		323.4	0.687	222.3	1,616,585	0.079	127,745
Jan	2012		332.2	0.648	215.3	1,663,932	0.078	130,404
Feb	2012		332.2	0.645	214.3	1,663,932	0.071	117,996
Mar	2012		332.2	0.631	209.6	1,663,932	0.076	126,876
Apr	2012		332.2	0.687	228.3	1,663,932	0.073	121,539
May	2012		332.2	0.770	255.9	1,663,932	0.080	133,730
Jun	2012		332.2	0.966	320.9	1,663,932	0.091	151,674
Jul	2012		332.2	1.000	332.2	1,663,932	0.109	180,754
Aug	2012		332.2	0.984	327.0	1,663,932	0.102	170,331
Sep	2012		332.2	0.977	324.6	1,663,932	0.086	143,272
Oct	2012		332.2	0.694	230.7	1,663,932	0.079	131,246
Nov	2012		332.2	0.656	218.0	1,663,932	0.075	124,625
Dec	2012		332.2	0.687	228.3	1,663,932	0.079	131,486
Jan	2013		341.1	0.648	221.1	1,705,059	0.078	133,627
Feb	2013		341.1	0.645	220.0	1,705,059	0.071	120,913
Mar	2013		341.1	0.631	215.3	1,705,059	0.076	130,012
Apr	2013		341.1	0.687	234.4	1,705,059	0.073	124,543
May	2013		341.1	0.770	262.8	1,705,059	0.080	137,035
Jun	2013		341.1	0.966	329.6	1,705,059	0.091	155,423
Jul	2013		341.1	1.000	341.1	1,705,059	0.109	185,221
Aug	2013		341.1	0.984	335.8	1,705,059	0.102	174,541
Sep	2013		341.1	0.977	333.4	1,705,059	0.086	146,814
Oct	2013		341.1	0.694	236.9	1,705,059	0.079	134,490
Nov	2013		341.1	0.656	223.9	1,705,059	0.075	127,705
Dec	2013		341.1	0.687	234.4	1,705,059	0.079	134,736
Jan	2014		350.3	0.648	227.0	1,751,096	0.078	137,235
Feb	2014		350.3	0.645	226.0	1,751,096	0.071	124,177
Mar	2014		350.3	0.631	221.1	1,751,096	0.076	133,522
Apr	2014		350.3	0.687	240.8	1,751,096	0.073	127,906
May	2014		350.3	0.770	269.9	1,751,096	0.080	140,735
Jun	2014		350.3	0.966	338.5	1,751,096	0.091	159,619
Jul	2014		350.3	1.000	350.3	1,751,096	0.109	190,222
Aug	2014		350.3	0.984	344.9	1,751,096	0.102	179,253
Sep	2014		350.3	0.977	342.4	1,751,096	0.086	150,777
Oct	2014		350.3	0.694	243.3	1,751,096	0.079	138,121
Nov	2014		350.3	0.656	230.0	1,751,096	0.075	131,153
Dec	2014		350.3	0.687	240.7	1,751,096	0.079	138,374
Jan	2015		359.8	0.648	233.2	1,798,375	0.078	140,940
Feb	2015		359.8	0.645	232.1	1,798,375	0.071	127,530
Mar	2015		359.8	0.631	227.1	1,798,375	0.076	137,127
Apr	2015		359.8	0.687	247.3	1,798,375	0.073	131,359
May	2015		359.8	0.770	277.2	1,798,375	0.080	144,535
Jun	2015		359.8	0.966	347.6	1,798,375	0.091	163,929
Jul	2015		359.8	1.000	359.8	1,798,375	0.109	195,358
Aug	2015		359.8	0.984	354.2	1,798,375	0.102	184,093
Sep	2015		359.8	0.977	351.6	1,798,375	0.086	154,848
Oct	2015		359.8	0.694	249.8	1,798,375	0.079	141,850
Nov	2015		359.8	0.656	236.2	1,798,375	0.075	134,694
Dec	2015		359.8	0.687	247.2	1,798,375	0.079	142,110

Jan	2016		369.5	0.648	239.5	1,851,046	0.078	145,068
Feb	2016		369.5	0.645	238.4	1,851,046	0.071	131,265
Mar	2016		369.5	0.631	233.2	1,851,046	0.076	141,143
Apr	2016		369.5	0.687	253.9	1,851,046	0.073	135,207
May	2016		369.5	0.770	284.7	1,851,046	0.080	148,768
Jun	2016		369.5	0.966	357.0	1,851,046	0.091	168,730
Jul	2016		369.5	1.000	369.5	1,851,046	0.109	201,080
Aug	2016		369.5	0.984	363.7	1,851,046	0.102	189,485
Sep	2016		369.5	0.977	361.1	1,851,046	0.086	159,384
Oct	2016		369.5	0.694	256.6	1,851,046	0.079	146,005
Nov	2016		369.5	0.656	242.5	1,851,046	0.075	138,639
Dec	2016		369.5	0.687	253.9	1,851,046	0.079	146,272
Jan	2017		379.5	0.648	245.9	1,896,798	0.078	148,654
Feb	2017		379.5	0.645	244.8	1,896,798	0.071	134,510
Mar	2017		379.5	0.631	239.5	1,896,798	0.076	144,632
Apr	2017		379.5	0.687	260.8	1,896,798	0.073	138,549
May	2017		379.5	0.770	292.4	1,896,798	0.080	152,445
Jun	2017		379.5	0.966	366.6	1,896,798	0.091	172,900
Jul	2017		379.5	1.000	379.5	1,896,798	0.109	206,050
Aug	2017		379.5	0.984	373.6	1,896,798	0.102	194,168
Sep	2017		379.5	0.977	370.9	1,896,798	0.086	163,323
Oct	2017		379.5	0.694	263.5	1,896,798	0.079	149,613
Nov	2017		379.5	0.656	249.1	1,896,798	0.075	142,066
Dec	2017		379.5	0.687	260.8	1,896,798	0.079	149,887
Jan	2018		389.7	0.648	252.6	1,948,012	0.078	152,667
Feb	2018		389.7	0.645	251.4	1,948,012	0.071	138,141
Mar	2018		389.7	0.631	245.9	1,948,012	0.076	148,537
Apr	2018		389.7	0.687	267.8	1,948,012	0.073	142,289
May	2018		389.7	0.770	300.3	1,948,012	0.080	156,561
Jun	2018		389.7	0.966	376.5	1,948,012	0.091	177,569
Jul	2018		389.7	1.000	389.7	1,948,012	0.109	211,613
Aug	2018		389.7	0.984	383.6	1,948,012	0.102	199,411
Sep	2018		389.7	0.977	380.9	1,948,012	0.086	167,733
Oct	2018		389.7	0.694	270.6	1,948,012	0.079	153,653
Nov	2018		389.7	0.656	255.8	1,948,012	0.075	145,902
Dec	2018		389.7	0.687	267.8	1,948,012	0.079	153,934
Jan	2019		400.3	0.648	259.4	2,000,608	0.078	156,789
Feb	2019		400.3	0.645	258.2	2,000,608	0.071	141,871
Mar	2019		400.3	0.631	252.6	2,000,608	0.076	152,548
Apr	2019		400.3	0.687	275.1	2,000,608	0.073	146,131
May	2019		400.3	0.770	308.4	2,000,608	0.080	160,789
Jun	2019		400.3	0.966	386.7	2,000,608	0.091	182,363
Jul	2019		400.3	1.000	400.3	2,000,608	0.109	217,327
Aug	2019		400.3	0.984	394.0	2,000,608	0.102	204,795
Sep	2019		400.3	0.977	391.1	2,000,608	0.086	172,262
Oct	2019		400.3	0.694	277.9	2,000,608	0.079	157,802
Nov	2019		400.3	0.656	262.7	2,000,608	0.075	149,841
Dec	2019		400.3	0.687	275.0	2,000,608	0.079	158,091
Jan	2020		411.1	0.648	266.4	2,059,202	0.078	161,382
Feb	2020		411.1	0.645	265.2	2,059,202	0.071	146,026
Mar	2020		411.1	0.631	259.4	2,059,202	0.076	157,015
Apr	2020		411.1	0.687	282.5	2,059,202	0.073	150,411
May	2020		411.1	0.770	316.7	2,059,202	0.080	165,498
Jun	2020		411.1	0.966	397.1	2,059,202	0.091	187,704
Jul	2020		411.1	1.000	411.1	2,059,202	0.109	223,692
Aug	2020		411.1	0.984	404.6	2,059,202	0.102	210,793
Sep	2020		411.1	0.977	401.7	2,059,202	0.086	177,307
Oct	2020		411.1	0.694	285.4	2,059,202	0.079	162,423
Nov	2020		411.1	0.656	269.8	2,059,202	0.075	154,230
Dec	2020		411.1	0.687	282.5	2,059,202	0.079	162,721

Jan	2021		422.2	0.648	273.6	2,110,100	0.078	165,370
Feb	2021		422.2	0.645	272.3	2,110,100	0.071	149,636
Mar	2021		422.2	0.631	266.4	2,110,100	0.076	160,896
Apr	2021		422.2	0.687	290.1	2,110,100	0.073	154,129
May	2021		422.2	0.770	325.3	2,110,100	0.080	169,588
Jun	2021		422.2	0.966	407.9	2,110,100	0.091	192,343
Jul	2021		422.2	1.000	422.2	2,110,100	0.109	229,221
Aug	2021		422.2	0.984	415.6	2,110,100	0.102	216,003
Sep	2021		422.2	0.977	412.6	2,110,100	0.086	181,689
Oct	2021		422.2	0.694	293.2	2,110,100	0.079	166,438
Nov	2021		422.2	0.656	277.1	2,110,100	0.075	158,042
Dec	2021		422.2	0.687	290.1	2,110,100	0.079	166,743
Jan	2022		433.6	0.648	281.0	2,167,072	0.078	169,835
Feb	2022		433.6	0.645	279.7	2,167,072	0.071	153,676
Mar	2022		433.6	0.631	273.6	2,167,072	0.076	165,241
Apr	2022		433.6	0.687	298.0	2,167,072	0.073	158,290
May	2022		433.6	0.770	334.0	2,167,072	0.080	174,167
Jun	2022		433.6	0.966	418.9	2,167,072	0.091	197,537
Jul	2022		433.6	1.000	433.6	2,167,072	0.109	235,410
Aug	2022		433.6	0.984	426.8	2,167,072	0.102	221,835
Sep	2022		433.6	0.977	423.7	2,167,072	0.086	186,595
Oct	2022		433.6	0.694	301.1	2,167,072	0.079	170,932
Nov	2022		433.6	0.656	284.6	2,167,072	0.075	162,309
Dec	2022		433.6	0.687	297.9	2,167,072	0.079	171,245
Jan	2023		445.3	0.648	288.6	2,225,583	0.078	174,421
Feb	2023		445.3	0.645	287.2	2,225,583	0.071	157,825
Mar	2023		445.3	0.631	281.0	2,225,583	0.076	169,702
Apr	2023		445.3	0.687	306.0	2,225,583	0.073	162,564
May	2023		445.3	0.770	343.1	2,225,583	0.080	178,870
Jun	2023		445.3	0.966	430.2	2,225,583	0.091	202,870
Jul	2023		445.3	1.000	445.3	2,225,583	0.109	241,766
Aug	2023		445.3	0.984	438.3	2,225,583	0.102	227,825
Sep	2023		445.3	0.977	435.1	2,225,583	0.086	191,633
Oct	2023		445.3	0.694	309.2	2,225,583	0.079	175,547
Nov	2023		445.3	0.656	292.3	2,225,583	0.075	166,691
Dec	2023		445.3	0.687	306.0	2,225,583	0.079	175,868
Jan	2024		457.3	0.648	296.4	2,290,766	0.078	179,529
Feb	2024		457.3	0.645	295.0	2,290,766	0.071	162,447
Mar	2024		457.3	0.631	288.6	2,290,766	0.076	174,672
Apr	2024		457.3	0.687	314.3	2,290,766	0.073	167,325
May	2024		457.3	0.770	352.3	2,290,766	0.080	184,109
Jun	2024		457.3	0.966	441.8	2,290,766	0.091	208,812
Jul	2024		457.3	1.000	457.3	2,290,766	0.109	248,847
Aug	2024		457.3	0.984	450.1	2,290,766	0.102	234,497
Sep	2024		457.3	0.977	446.9	2,290,766	0.086	197,246
Oct	2024		457.3	0.694	317.5	2,290,766	0.079	180,688
Nov	2024		457.3	0.656	300.2	2,290,766	0.075	171,573
Dec	2024		457.3	0.687	314.2	2,290,766	0.079	181,019
Jan	2025		469.6	0.648	304.4	2,347,559	0.078	183,980
Feb	2025		469.6	0.645	302.9	2,347,559	0.071	166,475
Mar	2025		469.6	0.631	296.4	2,347,559	0.076	179,003
Apr	2025		469.6	0.687	322.7	2,347,559	0.073	171,474
May	2025		469.6	0.770	361.8	2,347,559	0.080	188,673
Jun	2025		469.6	0.966	453.7	2,347,559	0.091	213,989
Jul	2025		469.6	1.000	469.6	2,347,559	0.109	255,016
Aug	2025		469.6	0.984	462.3	2,347,559	0.102	240,311
Sep	2025		469.6	0.977	458.9	2,347,559	0.086	202,136
Oct	2025		469.6	0.694	326.1	2,347,559	0.079	185,168
Nov	2025		469.6	0.656	308.3	2,347,559	0.075	175,827
Dec	2025		469.6	0.687	322.7	2,347,559	0.079	185,507

Jan	2026		482.3	0.648	312.6	2,410,943	0.078	188,948
Feb	2026		482.3	0.645	311.1	2,410,943	0.071	170,970
Mar	2026		482.3	0.631	304.4	2,410,943	0.076	183,836
Apr	2026		482.3	0.687	331.5	2,410,943	0.073	176,103
May	2026		482.3	0.770	371.6	2,410,943	0.080	193,767
Jun	2026		482.3	0.966	466.0	2,410,943	0.091	219,766
Jul	2026		482.3	1.000	482.3	2,410,943	0.109	261,902
Aug	2026		482.3	0.984	474.8	2,410,943	0.102	246,799
Sep	2026		482.3	0.977	471.3	2,410,943	0.086	207,593
Oct	2026		482.3	0.694	334.9	2,410,943	0.079	190,168
Nov	2026		482.3	0.656	316.6	2,410,943	0.075	180,574
Dec	2026		482.3	0.687	331.4	2,410,943	0.079	190,516
Jan	2027		495.3	0.648	321.0	2,476,038	0.078	194,049
Feb	2027		495.3	0.645	319.5	2,476,038	0.071	175,586
Mar	2027		495.3	0.631	312.6	2,476,038	0.076	188,799
Apr	2027		495.3	0.687	340.4	2,476,038	0.073	180,858
May	2027		495.3	0.770	381.6	2,476,038	0.080	198,999
Jun	2027		495.3	0.966	478.6	2,476,038	0.091	225,700
Jul	2027		495.3	1.000	495.3	2,476,038	0.109	268,973
Aug	2027		495.3	0.984	487.6	2,476,038	0.102	253,463
Sep	2027		495.3	0.977	484.1	2,476,038	0.086	213,198
Oct	2027		495.3	0.694	344.0	2,476,038	0.079	195,302
Nov	2027		495.3	0.656	325.1	2,476,038	0.075	185,450
Dec	2027		495.3	0.687	340.4	2,476,038	0.079	195,660
Jan	2028		508.7	0.648	329.7	2,548,370	0.078	199,718
Feb	2028		508.7	0.645	328.1	2,548,370	0.071	180,715
Mar	2028		508.7	0.631	321.0	2,548,370	0.076	194,315
Apr	2028		508.7	0.687	349.6	2,548,370	0.073	186,142
May	2028		508.7	0.770	391.9	2,548,370	0.080	204,812
Jun	2028		508.7	0.966	491.5	2,548,370	0.091	232,294
Jul	2028		508.7	1.000	508.7	2,548,370	0.109	276,831
Aug	2028		508.7	0.984	500.8	2,548,370	0.102	260,867
Sep	2028		508.7	0.977	497.1	2,548,370	0.086	219,427
Oct	2028		508.7	0.694	353.3	2,548,370	0.079	201,007
Nov	2028		508.7	0.656	333.9	2,548,370	0.075	190,867
Dec	2028		508.7	0.687	349.6	2,548,370	0.079	201,375
Jan	2029		522.4	0.648	338.6	2,611,549	0.078	204,669
Feb	2029		522.4	0.645	337.0	2,611,549	0.071	185,195
Mar	2029		522.4	0.631	329.7	2,611,549	0.076	199,132
Apr	2029		522.4	0.687	359.0	2,611,549	0.073	190,756
May	2029		522.4	0.770	402.5	2,611,549	0.080	209,890
Jun	2029		522.4	0.966	504.7	2,611,549	0.091	238,052
Jul	2029		522.4	1.000	522.4	2,611,549	0.109	283,694
Aug	2029		522.4	0.984	514.3	2,611,549	0.102	267,335
Sep	2029		522.4	0.977	510.6	2,611,549	0.086	224,867
Oct	2029		522.4	0.694	362.8	2,611,549	0.079	205,991
Nov	2029		522.4	0.656	342.9	2,611,549	0.075	195,599
Dec	2029		522.4	0.687	359.0	2,611,549	0.079	206,368
Jan	2030		536.6	0.648	347.7	2,682,061	0.078	210,196
Feb	2030		536.6	0.645	346.1	2,682,061	0.071	190,196
Mar	2030		536.6	0.631	338.6	2,682,061	0.076	204,509
Apr	2030		536.6	0.687	368.7	2,682,061	0.073	195,907
May	2030		536.6	0.770	413.4	2,682,061	0.080	215,557
Jun	2030		536.6	0.966	518.4	2,682,061	0.091	244,480
Jul	2030		536.6	1.000	536.6	2,682,061	0.109	291,354
Aug	2030		536.6	0.984	528.2	2,682,061	0.102	274,553
Sep	2030		536.6	0.977	524.3	2,682,061	0.086	230,938
Oct	2030		536.6	0.694	372.6	2,682,061	0.079	211,553
Nov	2030		536.6	0.656	352.2	2,682,061	0.075	200,881
Dec	2030		536.6	0.687	368.7	2,682,061	0.079	211,940

Appendix II-Resource Operating Information and Other Modeling Assumptions

General Assumptions

- ✓ 15-year Net Present Value of incremental production expenses: January 2016 to December 2030 time frame, NPV in 2015 dollars

Financial Assumptions

- ✓ Interest Rate: 5.0% / 6.5% / 8.0% (min / likely / max)
- ✓ Financing Period: 30 Years
- ✓ Inflation Rate: 1.5% / 2.5% / 3.5% (min / likely / max)
- ✓ Discount Rate: 8.0%

Existing Resource Assumptions

Hydro Units:

- ✓ 2.68 MW capacity
- ✓ $0.98/MWh VO&M cost (2006$)
- ✓ Dispatched first after CROD up to maximum capacity each hour

Silver Lake Plant:

- ✓ 45 MW or 92 MW capacity
- ✓ Unit 4 assumed to be only unit to dispatch
- ✓ 10,500 Btu/kWh heat rate
- ✓ $1.88/MMBtu fuel cost (2004$) from EIA data for reported fuel receipts at plant
- ✓ $6.17/MWh VO&M cost (2006$) from O&M allocation file provided by RPU, escalating at 2.5% per year
- ✓ $4.3 million in 2006 to $6.0 million in 2030 total capital and FO&M for Unit 4

Existing TwinPac CT:

- ✓ 49 MW capacity
- ✓ 11,100 Btu/kWh heat rate, assumed at 80% average load based on info from RPU
- ✓ $3.89/MWh VO&M cost (2006$) from O&M allocation file provided by RPU, escalating at 2.5% per year
- ✓ No fixed costs (debt service, fixed O&M, etc.) included

New Resource Assumptions

New Coal Unit Purchase:

- ✓ 500 MW total capacity
- ✓ 9,622 Btu/kWh heat rate, PRB fuel
- ✓ $1,958/kW for 2015 online date - $149/kW-yr debt service cost
- ✓ $2.09/MWh VO&M cost (2004$)
- ✓ $20.47/kW-yr FO&M (2004$)
- ✓ 0.11 lb/MMBtu SO_2 at $1,122/ton, no escalation
- ✓ 0.05 lb/MMBtu NO_X at $1,491/ton, no escalation
- ✓ $3.732/kW-mo transmission cost for new unit, no escalation

New Combined Cycle Unit Purchase:
- ✓ 125 MW total capacity
- ✓ 7,763 Btu/kWh heat rate
- ✓ $1,136/kW for 2015 online date - $87/kW-yr debt service cost
- ✓ $2.81/MWh VO&M cost (2004$)
- ✓ $14.02/kW-yr FO&M (2004$)

New LMS100 High-Efficiency Combustion Turbine:
- ✓ 100 MW total capacity
- ✓ 9,379 Btu/kWh heat rate
- ✓ $629/kW for 2020 online date - $48/kW-yr debt service cost
- ✓ $3.30/MWh VO&M cost (2004$)

New FT8 TwinPac Combustion Turbines:
- ✓ 50 MW total capacity
- ✓ 11,100 Btu/kWh heat rate
- ✓ $789/kW for 2015 online date - $60/kW-yr debt service cost
- ✓ $3.89/MWh VO&M cost (2004$)
- ✓ $11.44/kW-mo FO&M cost (2004$)

On-Peak Non-Firm Market Energy:
- ✓ Historical Henry Hub natural gas prices used to calculate an implied heat rate for each day of historical MAIN market peak prices (2001-2003)
- ✓ Monthly implied heat rates used to calculate market price based on current monthly gas price:

Jan	8,300 Btu/kWh	Jul	11,400 Btu/kWh
Feb	7,590 Btu/kWh	Aug	9,870 Btu/kWh
Mar	8,300 Btu/kWh	Sep	6,970 Btu/kWh
Apr	7,590 Btu/kWh	Oct	6,860 Btu/kWh
May	5,810 Btu/kWh	Nov	7,170 Btu/kWh
Jun	6,480 Btu/kWh	Dec	6,260 Btu/kWh

Load Forecast

Year	MW	GWh
2016	369.5	1,851
2017	379.5	1,897
2018	389.7	1,948
2019	400.3	2,001
2020	411.1	2,059
2021	422.2	2,110
2022	433.6	2,167
2023	445.3	2,226
2024	457.3	2,291
2025	469.6	2,348

2026	482.3	2,411
2027	495.3	2,476
2028	508.7	2,548
2029	522.4	2,612
2030	536.6	2,682

✓ Monthly pattern applied to annual peak demand and total energy:

Month	Ratio to Annual Peak	Ratio to Annual Total Energy
Jan	0.648	0.0784
Feb	0.645	0.0709
Mar	0.631	0.0763
Apr	0.687	0.0730
May	0.770	0.0804
Jun	0.966	0.0912
Jul	1.000	0.1086
Aug	0.984	0.1024
Sep	0.977	0.0861
Oct	0.694	0.0789
Nov	0.656	0.0749
Dec	0.687	0.0790

Fuel Assumptions

Year	Henry Hub ($/MMBtu)	Gas Trans. ($/MMBtu)	PRB Coal, Minemouth ($/MMBtu)	PRB Coal Transportation ($/MMBtu)	FO#2 ($/MMBtu)
2016	7.39	0.54	0.58	0.83	6.96
2017	7.65	0.55	0.59	0.85	7.14
2018	7.92	0.56	0.61	0.87	7.31
2019	8.20	0.58	0.63	0.90	7.50
2020	8.49	0.59	0.65	0.92	7.69
2021	8.78	0.61	0.67	0.94	7.88
2022	9.09	0.62	0.69	0.97	8.07
2023	9.41	0.64	0.71	0.99	8.28
2024	9.75	0.66	0.73	1.01	8.48
2025	10.09	0.67	0.75	1.04	8.70
2026	10.45	0.69	0.77	1.07	8.91
2027	10.81	0.71	0.80	1.09	9.14
2028	11.19	0.72	0.82	1.12	9.36
2029	11.59	0.74	0.85	1.15	9.60
2030	12.00	0.76	0.87	1.18	9.84

✓ Monthly pattern applied to annual average natural gas price:

Month	Ratio to Annual Average
Jan	1.088
Feb	1.079
Mar	1.049
Apr	0.968
May	0.959
Jun	0.961
Jul	0.965
Aug	0.968
Sep	0.966
Oct	0.969
Nov	0.999
Dec	1.031

Case Assumptions

	Existing Capacity			Capacity Added - MW(year)				
Case	**CROD**	**Other**	**SLP**	**Coal**	**Combined Cycle**	**Twin Pac**		
None216-100Coal	216	51	0	100(15)		50(15)	50(20)	50(25)
None216-50Coal	216	51	0	50(15)		100(15)	50(20)	50(25)
None216-100CC	216	51	0		100(15)	50(15)	50(20)	50(25)
None216-LMS100	216	51	0		100(15)	50(15)	50(20)	50(25)
None216-SC	216	51	0			150(15)	50(20)	50(25)
45216-50Coal_CoalFirst	216	51	45	50(15)		50(15)	50(20)	50(25)
45216-50Coal_SLPfirst	216	51	45	50(15)		50(15)	50(20)	50(25)
45216-100CC	216	51	45		100(15)		50(20)	50(25)
45216-LMS100	216	51	45		100(15)		50(20)	50(25)
45216-SC	216	51	45			100(15)	50(20)	50(25)
All216-50Coal_CoalFirst	216	51	92	50(15)			50(20)	50(25)
All216-50Coal_SLPfirst	216	51	92	50(15)			50(20)	50(25)
All216-100CC	216	51	92		100(20)	50(20)		
All216-LMS100	216	51	92		100(20)	50(20)		
All216-SC	216	51	92			50(15)	50(20)	50(25)

None, 45, All refers to amount of Silver Lake Plant available
166 or 216 refers to CROD amount
MWCoal refers to amount of coal capacity added in case
MWCC refers to combined cycle added in case
SC refers to only simple cycle TwinPac units added

Appendix III – Production Cost Analysis Details

Financial Analysis

None216-100CC

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
SLP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New CC	74	85	93	102	110	115	122	128	135	142	150	158	166	175	183
Existing CT	0	1	4	8	0	4	8	16	27	11	24	42	60	84	113
New CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4
On-Peak Market Energy	47	60	78	100	138	170	203	236	266	326	359	389	422	449	473
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
SLP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
New CC	$4,708	$5,576	$6,329	$7,202	$8,060	$8,802	$9,620	$10,516	$11,496	$12,567	$13,727	$14,993	$16,372	$17,884	$19,340
Existing CT	$0	$68	$402	$780	$0	$418	$915	$1,781	$3,200	$1,322	$3,038	$5,445	$8,096	$11,754	$16,245
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$628
On-Peak Market Energy	$2,405	$3,182	$4,488	$6,141	$8,913	$11,594	$14,584	$17,738	$20,886	$26,505	$30,259	$33,893	$37,940	$41,621	$45,289
Total Variable Costs	$7,125	$8,840	$11,237	$14,143	$16,996	$20,839	$25,145	$30,061	$35,611	$40,425	$47,056	$54,364	$62,444	$71,296	$81,541
DEMAND/FIXED COST ($000)															
New CC	$14,591	$14,650	$14,710	$14,772	$14,836	$14,901	$14,968	$15,036	$15,106	$15,178	$15,251	$15,327	$15,404	$15,483	$15,564
New CT	$3,776	$3,795	$3,815	$3,835	$8,106	$8,149	$8,192	$8,237	$8,282	$13,138	$13,210	$13,284	$13,360	$13,438	$13,517
Total Fixed Costs	$18,367	$18,445	$18,525	$18,607	$22,942	$23,049	$23,160	$23,273	$23,388	$28,316	$28,462	$28,611	$28,764	$28,921	$29,082
TOTAL COST	**$25,492**	**$27,285**	**$29,762**	**$32,750**	**$39,938**	**$43,888**	**$48,304**	**$53,334**	**$59,000**	**$68,741**	**$75,517**	**$82,975**	**$91,208**	**$100,217**	**$110,623**

15-Year NPV (2015 $000): $435,755

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
SLP															
New CC	$260.22	$238.60	$226.79	$216.02	$208.72	$205.38	$202.32	$199.60	$197.22	$195.19	$193.58	$192.31	$191.38	$190.74	$191.16
Existing CT		$93.03	$96.19	$99.46		$106.34	$109.96	$113.79	$117.75	$121.58	$125.89	$130.26	$134.73	$139.38	$144.21
New CT															$3,240.01
On-Peak Market Energy	$50.92	$53.02	$57.49	$61.45	$64.52	$68.32	$71.83	$75.28	$78.41	$81.23	$84.30	$87.09	$89.98	$92.67	$95.74

Financial Analysis

45216-LMS100-50Coal

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
New Coal	0	0	0	0	169	195	222	249	273	292	308	320	331	340	349
SLP	87	99	116	134	65	71	78	86	97	111	130	153	180	206	228
LMS100	21	26	31	36	12	17	22	27	32	38	44	51	57	64	72
CTs	0	3	7	12	0	0	0	2	6	0	4	10	17	29	41
New CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
On-Peak Market Energy	13	17	21	28	2	5	10	16	20	38	47	55	63	70	83
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
New Coal	$0	$0	$0	$0	$3,230	$3,831	$4,472	$5,130	$5,771	$6,341	$6,846	$7,298	$7,742	$8,160	$8,605
SLP	$3,147	$3,697	$4,440	$5,277	$2,635	$2,974	$3,365	$3,782	$4,401	$5,208	$6,256	$7,586	$9,146	$10,794	$12,273
LMS100	$1,628	$2,048	$2,513	$3,033	$1,076	$1,526	$2,028	$2,591	$3,222	$3,925	$4,705	$5,573	$6,534	$7,588	$8,747
CTs	$0	$274	$687	$1,191	$0	$0	$0	$206	$769	$0	$537	$1,275	$2,343	$3,992	$5,877
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
On-Peak Market Energy	$935	$1,212	$1,460	$1,883	$139	$492	$938	$1,427	$1,714	$3,380	$4,184	$4,978	$5,734	$6,471	$7,817
Total Variable Costs	$5,721	$7,245	$9,118	$11,404	$7,103	$8,847	$10,829	$13,163	$15,906	$18,884	$22,561	$26,742	$31,534	$37,041	$43,358
DEMAND/FIXED COST ($000)															
New Coal (Including Transmission)	$0	$0	$0	$0	$12,196	$12,234	$12,273	$12,312	$12,353	$12,395	$12,438	$12,482	$12,527	$12,574	$12,621
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
LMS100	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,809	$4,833	$4,858	$4,883	$4,909	$4,935
Total Fixed Costs	$9,693	$9,764	$9,835	$9,909	$22,180	$22,296	$22,414	$22,535	$22,660	$27,596	$27,751	$27,909	$28,072	$28,238	$28,409
TOTAL COST	**$15,415**	**$17,009**	**$18,954**	**$21,314**	**$29,283**	**$31,143**	**$33,243**	**$35,699**	**$38,566**	**$46,480**	**$50,311**	**$54,651**	**$59,605**	**$65,279**	**$71,767**

15-Year NPV (2015 $000): $288,674

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
New Coal					$91.36	$82.25	$75.31	$70.14	$66.44	$64.11	$62.68	$61.86	$61.28	$61.01	$60.75
SLP	$92.43	$87.20	$81.74	$77.56	$120.36	$115.58	$111.12	$107.55	$102.35	$97.01	$91.84	$87.20	$83.63	$81.38	$80.58
LMS100	$300.87	$263.49	$237.07	$217.60	$475.65	$373.33	$313.56	$274.74	$247.96	$228.97	$215.19	$205.05	$197.62	$192.36	$188.72
Existing CT		$93.62	$96.80	$100.07				$114.43	$118.33		$126.53	$130.84	$135.21	$139.70	$144.40
New CT															
On-Peak Market Energy	$72.05	$70.46	$69.33	$68.23	$86.89	$89.90	$90.59	$87.75	$86.04	$89.98	$89.72	$89.97	$91.27	$92.86	$93.86

Financial Analysis
45216-LMS100

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
SLP	87	99	116	134	155	178	202	223	233	237	237	237	237	237	237
LMS100	21	26	31	36	41	47	53	59	66	72	74	74	74	74	74
CTs	0	3	7	12	4	9	15	25	35	22	33	47	64	75	87
On-Peak Market Energy	13	17	21	28	48	56	64	72	94	149	189	231	272	314	360
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
SLP	$3,147	$3,697	$4,440	$5,277	$6,273	$7,405	$8,648	$9,859	$10,603	$11,055	$11,376	$11,707	$12,047	$12,397	$12,757
LMS100	$1,628	$2,048	$2,513	$3,033	$3,610	$4,244	$4,942	$5,708	$6,543	$7,451	$7,934	$8,204	$8,484	$8,773	$9,072
CTs	$0	$274	$687	$1,191	$389	$922	$1,615	$2,805	$4,135	$2,639	$4,171	$6,158	$8,638	$10,533	$12,616
On-Peak Market Energy	$935	$1,212	$1,460	$1,883	$3,486	$4,087	$4,727	$5,424	$7,218	$11,889	$15,721	$20,077	$24,733	$29,758	$35,398
Total Variable Costs	$5,721	$7,245	$9,118	$11,404	$13,780	$16,682	$19,957	$23,823	$28,528	$33,064	$39,234	$46,179	$54,041	$62,558	$71,991
DEMAND/FIXED COST ($000)															
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
LMS100	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790
New CT	$0	$0	$0	$0	$4,251	$4,272	$4,294	$4,316	$4,339	$9,171	$9,219	$9,269	$9,319	$9,371	$9,424
Total Fixed Costs	$9,693	$9,764	$9,835	$9,909	$14,235	$14,334	$14,435	$14,539	$14,645	$19,563	$19,699	$19,838	$19,980	$20,126	$20,276
TOTAL COST	**$15,415**	**$17,009**	**$18,954**	**$21,314**	**$28,016**	**$31,016**	**$34,392**	**$38,362**	**$43,173**	**$52,627**	**$58,932**	**$66,017**	**$74,022**	**$82,684**	**$92,267**

15-Year NPV (2015 $000): $320,892

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
SLP	$92.43	$87.20	$81.74	$77.56	$74.05	$71.36	$69.44	$68.46	$69.05	$70.42	$72.15	$73.93	$75.76	$77.64	$79.57
LMS100	$300.87	$263.49	$237.07	$217.60	$202.97	$191.99	$183.67	$177.37	$172.73	$169.41	$171.02	$174.65	$178.41	$182.30	$186.32
Existing CT		$93.62	$96.80	$100.07	$103.50	$107.02	$110.62	$114.27	$118.10	$122.23	$126.31	$130.58	$135.00	$139.56	$144.29
New CT													$12,062.71	$1,377.23	$791.61
On-Peak Market Energy	$72.05	$70.46	$69.33	$68.23	$72.87	$73.33	$74.21	$75.13	$76.49	$79.82	$83.26	$87.08	$90.90	$94.64	$98.40

Financial Analysis

45216-50coal (Dispatch New Coal First)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
New Coal	86	101	120	143	169	195	222	249	273	292	308	320	331	340	349
SLP	31	37	42	48	54	60	68	77	90	108	130	157	185	212	236
CTs	0	0	0	0	0	0	0	0	0	0	0	0	1	7	13
On-Peak Market Energy	4	8	12	18	25	33	43	54	66	79	95	112	132	150	174
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
New Coal	$1,484	$1,790	$2,189	$2,676	$3,230	$3,831	$4,472	$5,130	$5,771	$6,341	$6,846	$7,298	$7,742	$8,160	$8,605
SLP	$1,127	$1,371	$1,625	$1,893	$2,184	$2,517	$2,903	$3,401	$4,092	$5,042	$6,274	$7,752	$9,400	$11,097	$12,721
CTs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$78	$924	$1,884
On-Peak Market Energy	$347	$613	$994	$1,511	$2,167	$2,964	$3,916	$5,030	$6,331	$7,854	$9,635	$11,722	$14,102	$16,278	$19,135
Total Variable Costs	$2,969	$3,789	$4,827	$6,100	$7,603	$9,337	$11,317	$13,588	$16,222	$19,267	$22,787	$26,805	$31,358	$36,497	$42,385
DEMAND/FIXED COST ($000)															
New Coal (Including Transmission)	$11,202	$11,237	$11,272	$11,308	$11,345	$11,383	$11,422	$11,462	$11,503	$11,545	$11,588	$11,632	$11,677	$11,723	$11,771
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
New CT	$3,828	$3,847	$3,867	$3,887	$8,217	$8,260	$8,303	$8,348	$8,394	$13,317	$13,389	$13,462	$13,538	$13,616	$13,695
Total Fixed Costs	$19,934	$20,057	$20,184	$20,314	$24,757	$24,915	$25,077	$25,243	$25,413	$30,463	$30,666	$30,873	$31,086	$31,305	$31,528
TOTAL COST	**$22,903**	**$23,847**	**$25,011**	**$26,414**	**$32,361**	**$34,252**	**$36,394**	**$38,831**	**$41,635**	**$49,730**	**$53,453**	**$57,678**	**$62,444**	**$67,801**	**$73,914**
15-Year NPV (2015 $000):	**$325,782**														
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
New Coal	$147.97	$129.13	$111.87	$97.50	$86.32	$77.90	$71.49	$66.72	$63.32	$61.20	$59.91	$59.20	$58.71	$58.50	$58.32
SLP	$193.40	$172.05	$157.02	$145.85	$136.87	$129.00	$121.97	$114.64	$106.66	$98.67	$91.71	$86.40	$82.75	$80.59	$79.64
Existing CT													$134.92	$139.53	$144.29
New CT															
On-Peak Market Energy	$77.33	$79.12	$81.49	$83.93	$86.39	$88.87	$91.36	$93.92	$96.57	$99.20	$101.82	$104.42	$106.93	$108.38	$109.76

Financial Analysis

45216-50Coal (Dispatch SLP First)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
New Coal	80	95	114	136	160	186	211	234	255	270	282	292	301	309	317
SLP	37	43	49	56	63	70	79	91	108	130	156	185	214	242	268
CTs	0	0	0	0	0	0	0	0	0	0	0	0	1	7	13
On-Peak Market Energy	4	8	12	18	25	33	43	54	66	79	95	112	132	150	174
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
New Coal	$1,389	$1,682	$2,066	$2,534	$3,065	$3,641	$4,242	$4,833	$5,385	$5,858	$6,275	$6,658	$7,051	$7,422	$7,820
SLP	$1,325	$1,597	$1,885	$2,192	$2,532	$2,920	$3,395	$4,035	$4,921	$6,082	$7,509	$9,138	$10,904	$12,708	$14,442
CTs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$78	$924	$1,884
On-Peak Market Energy	$347	$613	$994	$1,511	$2,167	$2,964	$3,916	$5,030	$6,331	$7,854	$9,635	$11,722	$14,102	$16,278	$19,136
Total Variable Costs	$3,073	$3,908	$4,963	$6,257	$7,787	$9,550	$11,578	$13,926	$16,665	$19,825	$23,451	$27,552	$32,171	$37,370	$43,321
DEMAND/FIXED COST ($000)															
New Coal (Including Transmission)	$11,202	$11,237	$11,272	$11,308	$11,345	$11,383	$11,422	$11,462	$11,503	$11,545	$11,588	$11,632	$11,677	$11,723	$11,771
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
New CT	$3,828	$3,847	$3,867	$3,887	$8,217	$8,260	$8,303	$8,348	$8,394	$13,317	$13,389	$13,462	$13,538	$13,616	$13,695
Total Fixed Costs	$19,934	$20,057	$20,184	$20,314	$24,757	$24,915	$25,077	$25,243	$25,413	$30,463	$30,666	$30,873	$31,086	$31,305	$31,528
TOTAL COST	**$23,007**	**$23,965**	**$25,147**	**$26,572**	**$32,545**	**$34,465**	**$36,655**	**$39,169**	**$42,078**	**$50,288**	**$54,116**	**$58,426**	**$63,257**	**$68,674**	**$74,849**

15-Year NPV (2015 $000): $328,750

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
New Coal	$156.92	$136.27	$117.47	$101.92	$89.93	$80.94	$74.28	$69.55	$66.35	$64.45	$63.34	$62.69	$62.18	$61.94	$61.70
SLP	$169.82	$152.96	$140.65	$131.29	$123.60	$116.94	$110.51	$103.57	$96.34	$89.79	$84.54	$80.80	$78.36	$77.02	$76.58
Existing CT													$134.92	$139.53	$144.29
New CT															
On-Peak Market Energy	$77.33	$79.12	$81.49	$83.93	$86.39	$88.87	$91.36	$93.92	$96.57	$99.20	$101.82	$104.42	$106.93	$108.38	$109.76

Financial Analysis

All216-50coal (Dispatch New Coal Unit First)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
New Coal	86	101	120	143	169	195	222	249	273	292	308	320	331	340	349
SLP	31	37	42	48	54	60	68	77	90	108	130	157	185	212	236
CTs	0	0	0	0	0	0	0	0	4	0	2	7	13	22	34
On-Peak Market Energy	4	8	12	18	25	33	43	54	61	79	93	105	119	135	153
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
New Coal	$1,484	$1,790	$2,189	$2,676	$3,230	$3,831	$4,472	$5,130	$5,771	$6,341	$6,846	$7,298	$7,742	$8,160	$8,605
SLP	$1,127	$1,371	$1,625	$1,893	$2,184	$2,517	$2,903	$3,401	$4,092	$5,042	$6,274	$7,752	$9,400	$11,097	$12,721
CTs	$0	$0	$0	$0	$0	$0	$0	$0	$524	$0	$237	$951	$1,751	$3,095	$4,930
On-Peak Market Energy	$347	$613	$994	$1,511	$2,167	$2,964	$3,916	$5,030	$5,822	$7,854	$9,404	$10,797	$12,473	$14,222	$16,332
Total Variable Costs	$2,969	$3,789	$4,827	$6,100	$7,603	$9,337	$11,317	$13,588	$16,237	$19,267	$22,794	$26,831	$31,402	$36,611	$42,628
DEMAND/FIXED COST ($000)															
New Coal (Including Transmission)	$11,202	$11,237	$11,272	$11,308	$11,345	$11,383	$11,422	$11,462	$11,503	$11,545	$11,588	$11,632	$11,677	$11,723	$11,771
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
SLP (Unit 1-3 FO&M)	$3,547	$3,636	$3,727	$3,820	$3,915	$4,013	$4,114	$4,216	$4,322	$4,430	$4,541	$4,654	$4,771	$4,890	$5,012
New CT	$0	$0	$0	$0	$4,310	$4,331	$4,353	$4,375	$4,398	$9,297	$9,345	$9,394	$9,445	$9,497	$9,550
Total Fixed Costs	$19,653	$19,846	$20,044	$20,247	$24,765	$25,000	$25,240	$25,486	$25,739	$30,874	$31,163	$31,460	$31,764	$32,075	$32,395
TOTAL COST	**$22,622**	**$23,636**	**$24,871**	**$26,347**	**$32,368**	**$34,336**	**$36,557**	**$39,074**	**$41,976**	**$50,141**	**$53,957**	**$58,290**	**$63,166**	**$68,686**	**$75,022**

15-Year NPV (2015 $000): $327,201

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
New Coal	$147.97	$129.13	$111.87	$97.50	$86.32	$77.90	$71.49	$66.72	$63.32	$61.20	$59.91	$59.20	$58.71	$58.50	$58.32
SLP	$193.40	$172.05	$157.02	$145.85	$136.87	$129.00	$121.97	$114.64	$106.66	$98.67	$91.71	$86.40	$82.75	$80.59	$79.64
Existing CT									$118.00		$126.17	$130.47	$134.92	$139.58	$144.39
New CT															
On-Peak Market Energy	$77.33	$79.12	$81.49	$83.93	$86.39	$88.87	$91.36	$93.92	$95.26	$99.20	$101.39	$102.86	$104.40	$105.62	$106.56

Financial Analysis

None216-50Coal

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
New Coal	86	101	120	143	169	195	222	249	273	292	308	320	331	340	349
SLP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CTs	0	0	0	0	0	0	0	0	3	0	2	9	16	27	41
On-Peak Market Energy	36	45	55	66	79	94	111	131	153	187	223	260	301	341	382
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
New Coal	$1,484	$1,790	$2,189	$2,676	$3,230	$3,831	$4,472	$5,130	$5,771	$6,341	$6,846	$7,298	$7,742	$8,160	$8,605
SLP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CTs	$0	$0	$0	$0	$0	$0	$0	$0	$360	$0	$310	$1,158	$2,110	$3,789	$5,902
On-Peak Market Energy	$2,662	$3,423	$4,313	$5,355	$6,571	$7,998	$9,669	$11,696	$13,893	$17,473	$21,177	$25,126	$29,676	$34,267	$39,181
Total Variable Costs	$4,157	$5,229	$6,521	$8,051	$9,824	$11,853	$14,167	$16,853	$20,052	$23,844	$28,365	$33,615	$39,564	$46,254	$53,727
DEMAND/FIXED COST ($000)															
New Coal (Including Transmission)	$11,073	$11,107	$11,142	$11,179	$11,216	$11,254	$11,293	$11,333	$11,373	$11,415	$11,458	$11,502	$11,548	$11,594	$11,641
New CT	$7,551	$7,590	$7,629	$7,670	$11,962	$12,025	$12,091	$12,157	$12,226	$17,105	$17,202	$17,300	$17,401	$17,504	$17,610
Total Fixed Costs	$18,624	$18,697	$18,772	$18,848	$23,177	$23,279	$23,383	$23,490	$23,599	$28,521	$28,660	$28,802	$28,948	$29,098	$29,252
TOTAL COST	**$22,781**	**$23,926**	**$25,292**	**$26,899**	**$33,001**	**$35,132**	**$37,551**	**$40,343**	**$43,651**	**$52,365**	**$57,025**	**$62,418**	**$68,512**	**$75,352**	**$82,979**

15-Year NPV (2015 $000): $342,102

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
New Coal	$146.46	$127.85	$110.79	$96.60	$85.55	$77.23	$70.91	$66.20	$62.85	$60.75	$59.49	$58.79	$58.32	$58.12	$57.95
Existing CT									$118.00		$126.17	$130.47	$134.92	$139.59	$144.39
New CT															
On-Peak Market Energy	$74.62	$76.71	$78.88	$81.04	$83.19	$85.32	$87.47	$89.55	$91.05	$93.41	$95.13	$96.64	$98.47	$100.38	$102.46

Financial Analysis

All216-50coal (Dispatch SLP First)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
New Coal	80	95	114	136	160	186	211	234	255	270	282	292	301	309	317
SLP	37	43	49	56	63	70	79	91	108	130	156	185	214	242	268
CTs	0	0	0	0	0	0	0	0	4	0	2	7	13	22	34
On-Peak Market Energy	4	8	12	18	25	33	43	54	61	79	93	105	119	135	153
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
New Coal	$1,389	$1,682	$2,066	$2,534	$3,065	$3,641	$4,242	$4,833	$5,385	$5,858	$6,275	$6,658	$7,051	$7,422	$7,820
SLP	$1,325	$1,597	$1,885	$2,192	$2,532	$2,920	$3,395	$4,035	$4,921	$6,082	$7,509	$9,138	$10,904	$12,708	$14,442
CTs	$0	$0	$0	$0	$0	$0	$0	$0	$524	$0	$237	$951	$1,751	$3,095	$4,930
On-Peak Market Energy	$347	$613	$994	$1,511	$2,167	$2,964	$3,916	$5,030	$5,822	$7,854	$9,404	$10,797	$12,473	$14,222	$16,333
Total Variable Costs	$3,073	$3,908	$4,963	$6,257	$7,787	$9,550	$11,578	$13,926	$16,680	$19,825	$23,457	$27,578	$32,215	$37,484	$43,563
DEMAND/FIXED COST ($000)															
New Coal (Including Transmission)	$11,202	$11,237	$11,272	$11,308	$11,345	$11,383	$11,422	$11,462	$11,503	$11,545	$11,588	$11,632	$11,677	$11,723	$11,771
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
SLP (Unit 1-3 FO&M)	$3,547	$3,636	$3,727	$3,820	$3,915	$4,013	$4,114	$4,216	$4,322	$4,430	$4,541	$4,654	$4,771	$4,890	$5,012
New CT	$0	$0	$0	$0	$4,310	$4,331	$4,353	$4,375	$4,398	$9,297	$9,345	$9,394	$9,445	$9,497	$9,550
Total Fixed Costs	$19,653	$19,846	$20,044	$20,247	$24,765	$25,000	$25,240	$25,486	$25,739	$30,874	$31,163	$31,460	$31,764	$32,075	$32,395
TOTAL COST	**$22,726**	**$23,754**	**$25,007**	**$26,505**	**$32,552**	**$34,550**	**$36,818**	**$39,412**	**$42,419**	**$50,698**	**$54,620**	**$59,038**	**$63,979**	**$69,559**	**$75,958**

15-Year NPV (2015 $000): $330,169

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
New Coal	$156.92	$136.27	$117.47	$101.92	$89.93	$80.94	$74.28	$69.55	$66.35	$64.45	$63.34	$62.69	$62.18	$61.94	$61.70
SLP	$169.82	$152.96	$140.65	$131.29	$123.60	$116.94	$110.51	$103.57	$96.34	$89.79	$84.54	$80.80	$78.36	$77.02	$76.58
Existing CT									$118.00		$126.17	$130.47	$134.92	$139.58	$144.39
New CT															
On-Peak Market Energy	$77.33	$79.12	$81.49	$83.93	$86.39	$88.87	$91.36	$93.92	$95.26	$99.20	$101.39	$102.86	$104.40	$105.62	$106.56

Financial Analysis

All216-LMS100

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
SLP	87	99	116	134	155	178	202	223	233	237	237	237	237	237	237
LMS100	0	0	0	0	41	47	53	59	66	72	74	74	74	74	74
Existing CT	0	1	6	11	4	9	15	25	35	50	66	77	88	104	141
New CT	0	0	0	0	0	0	0	0	0	0	0	7	13	23	36
On-Peak Market Energy	34	45	53	64	48	56	64	72	94	120	155	194	236	271	285
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
SLP	$3,147	$3,697	$4,440	$5,277	$6,273	$7,405	$8,648	$9,859	$10,603	$11,055	$11,376	$11,707	$12,047	$12,397	$12,757
LMS100	$0	$0	$0	$0	$3,610	$4,244	$4,942	$5,708	$6,543	$7,451	$7,934	$8,204	$8,484	$8,773	$9,072
Existing CT	$0	$131	$604	$1,138	$389	$922	$1,615	$2,805	$4,135	$6,141	$8,376	$10,043	$11,872	$14,526	$20,483
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$30	$864	$1,783	$3,171	$5,185
On-Peak Market Energy	$2,799	$3,660	$4,332	$5,246	$3,486	$4,087	$4,727	$5,424	$7,218	$9,493	$12,878	$16,915	$21,461	$25,729	$28,072
Total Variable Costs	$5,957	$7,503	$9,393	$11,681	$13,780	$16,682	$19,957	$23,823	$28,528	$34,171	$40,625	$47,767	$55,682	$64,632	$75,609
DEMAND/FIXED COST ($000)															
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
SLP (Unit 1-3 FO&M)	$3,547	$3,636	$3,727	$3,820	$3,915	$4,013	$4,114	$4,216	$4,322	$4,430	$4,541	$4,654	$4,771	$4,890	$5,012
LMS100	$0	$0	$0	$0	$5,109	$5,109	$5,109	$5,109	$5,109	$5,109	$5,109	$5,109	$5,109	$5,109	$5,109
New CT	$3,976	$3,995	$4,015	$4,035	$4,056	$4,077	$4,099	$4,121	$4,144	$4,168	$4,192	$4,216	$4,241	$4,267	$4,294
Total Fixed Costs	$12,427	$12,605	$12,787	$12,974	$18,275	$18,472	$18,673	$18,880	$19,092	$19,308	$19,531	$19,759	$19,992	$20,232	$20,477
TOTAL COST	**$18,384**	**$20,107**	**$22,181**	**$24,656**	**$32,056**	**$35,154**	**$38,630**	**$42,703**	**$47,619**	**$53,479**	**$60,156**	**$67,526**	**$75,674**	**$84,864**	**$96,086**

15-Year NPV (2015 $000): $347,789

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
SLP	$92.43	$87.20	$81.74	$77.56	$74.05	$71.36	$69.44	$68.46	$69.05	$70.42	$72.15	$73.93	$75.76	$77.64	$79.57
LMS100					$210.69	$198.77	$189.69	$182.77	$177.60	$173.83	$175.31	$178.94	$182.70	$186.59	$190.61
Existing CT		$93.36	$96.53	$99.82	$103.50	$107.02	$110.62	$114.27	$118.10	$122.10	$126.24	$130.51	$134.93	$139.51	$145.41
New CT											$17,836.07	$769.03	$457.07	$327.97	$264.09
On-Peak Market Energy	$81.57	$81.93	$82.18	$81.90	$72.87	$73.33	$74.21	$75.13	$76.49	$78.95	$82.95	$87.12	$91.06	$95.05	$98.50

Financial Analysis

45216-SC

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
SLP	87	99	116	134	155	178	202	223	233	237	237	237	237	237	237
Existing CT	0	0	0	0	0	0	4	10	16	11	17	30	44	58	71
New CT	0	0	0	0	0	0	0	0	0	0	0	0	0	3	10
On-Peak Market Energy	34	46	59	75	93	111	128	146	179	232	279	322	367	412	455
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
SLP	$3,147	$3,697	$4,440	$5,277	$6,273	$7,405	$8,648	$9,859	$10,603	$11,055	$11,376	$11,707	$12,047	$12,397	$12,757
Existing CT	$0	$0	$0	$0	$0	$0	$401	$1,122	$1,919	$1,282	$2,192	$3,955	$5,960	$8,053	$10,234
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$377	$1,495
On-Peak Market Energy	$2,799	$3,787	$4,917	$6,349	$7,954	$9,733	$11,342	$13,071	$16,002	$21,313	$25,914	$30,353	$35,262	$40,404	$45,830
Total Variable Costs	$5,957	$7,498	$9,374	$11,646	$14,249	$17,162	$20,416	$24,079	$28,553	$33,680	$39,513	$46,048	$53,304	$61,268	$70,355
DEMAND/FIXED COST ($000)															
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
New CT	$7,551	$7,590	$7,629	$7,670	$11,962	$12,025	$12,091	$12,157	$12,226	$17,105	$17,202	$17,300	$17,401	$17,504	$17,610
Total Fixed Costs	$12,455	$12,563	$12,675	$12,789	$17,156	$17,297	$17,442	$17,590	$17,742	$22,707	$22,891	$23,079	$23,272	$23,470	$23,673
TOTAL COST	**$18,412**	**$20,062**	**$22,049**	**$24,435**	**$31,406**	**$34,460**	**$37,858**	**$41,669**	**$46,295**	**$56,388**	**$62,404**	**$69,127**	**$76,576**	**$84,738**	**$94,028**

15-Year NPV (2015 $000): $347,544

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
SLP	$92.43	$87.20	$81.74	$77.56	$74.05	$71.36	$69.44	$68.46	$69.05	$70.42	$72.15	$73.93	$75.76	$77.64	$79.57
Existing CT							$110.35	$114.11	$118.00	$122.02	$126.17	$130.55	$135.03	$139.64	$144.37
New CT														$6,622.75	$1,844.19
On-Peak Market Energy	$81.57	$82.19	$83.38	$84.14	$85.54	$87.37	$88.86	$89.47	$89.54	$91.75	$92.93	$94.32	$96.05	$98.19	$100.75

Financial Analysis

None216-100Coal

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
New Coal	118	140	166	195	227	260	295	332	369	407	446	486	526	564	602
SLP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing CT	0	0	0	0	0	0	0	0	0	0	0	0	0	4	10
New CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
On-Peak Market Energy	3	6	9	15	21	29	38	48	59	72	87	103	122	140	161
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
New Coal	$2,045	$2,481	$3,012	$3,637	$4,339	$5,107	$5,939	$6,839	$7,812	$8,838	$9,930	$11,082	$12,309	$13,553	$14,818
SLP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Existing CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$534	$1,461
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
On-Peak Market Energy	$254	$455	$774	$1,225	$1,819	$2,558	$3,449	$4,501	$5,731	$7,168	$8,851	$10,820	$13,123	$15,353	$17,861
Total Variable Costs	$2,311	$2,951	$3,804	$4,882	$6,181	$7,689	$9,414	$11,367	$13,572	$16,037	$18,812	$21,935	$25,467	$29,477	$34,179
DEMAND/FIXED COST ($000)															
New Coal (Including Transmission)	$22,146	$22,214	$22,285	$22,357	$22,431	$22,507	$22,585	$22,665	$22,747	$22,831	$22,917	$23,005	$23,095	$23,188	$23,283
New CT	$3,776	$3,795	$3,815	$3,835	$8,106	$8,149	$8,192	$8,237	$8,282	$13,138	$13,210	$13,284	$13,360	$13,438	$13,517
Total Fixed Costs	$25,921	$26,009	$26,100	$26,192	$30,537	$30,656	$30,777	$30,902	$31,029	$35,969	$36,127	$36,289	$36,455	$36,625	$36,800
TOTAL COST	**$28,232**	**$28,960**	**$29,904**	**$31,074**	**$36,719**	**$38,345**	**$40,191**	**$42,269**	**$44,602**	**$52,006**	**$54,939**	**$58,224**	**$61,923**	**$66,102**	**$70,978**

15-Year NPV (2015 $000): $353,725

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
New Coal	$204.75	$176.66	$152.83	$133.34	$118.02	$106.06	$96.61	$88.99	$82.75	$77.74	$73.61	$70.20	$67.33	$65.09	$63.33
Existing CT														$139.53	$144.29
New CT															
On-Peak Market Energy	$77.96	$79.60	$81.65	$84.18	$86.64	$89.18	$91.70	$94.27	$96.93	$99.63	$102.30	$104.97	$107.64	$109.58	$111.02

Financial Analysis

All216-SC

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
SLP	87	99	116	134	155	178	202	223	233	237	237	237	237	237	237
Existing CT	0	1	6	11	4	10	17	29	41	29	42	57	69	83	100
New CT	0	0	0	0	0	0	0	0	0	0	0	0	8	15	25
On-Peak Market Energy	34	45	53	64	89	101	114	127	154	214	255	295	334	374	411
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
SLP	$3,147	$3,697	$4,440	$5,277	$6,273	$7,405	$8,648	$9,859	$10,603	$11,055	$11,376	$11,707	$12,047	$12,397	$12,757
Existing CT	$0	$131	$604	$1,138	$458	$1,078	$1,915	$3,298	$4,832	$3,499	$5,261	$7,441	$9,356	$11,600	$14,418
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$50	$1,031	$2,107	$3,597
On-Peak Market Energy	$2,799	$3,660	$4,332	$5,246	$7,510	$8,687	$9,891	$11,057	$13,360	$19,250	$23,125	$27,249	$31,623	$36,247	$41,035
Total Variable Costs	$5,957	$7,503	$9,393	$11,681	$14,263	$17,195	$20,480	$24,241	$28,824	$33,834	$39,794	$46,479	$54,093	$62,388	$71,847
DEMAND/FIXED COST ($000)															
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
SLP (Unit 1-3 FO&M)	$3,547	$3,636	$3,727	$3,820	$3,915	$4,013	$4,114	$4,216	$4,322	$4,430	$4,541	$4,654	$4,771	$4,890	$5,012
New CT	$3,776	$3,795	$3,815	$3,835	$8,106	$8,149	$8,192	$8,237	$8,282	$13,138	$13,210	$13,284	$13,360	$13,438	$13,517
Total Fixed Costs	$12,226	$12,404	$12,587	$12,774	$17,216	$17,434	$17,657	$17,886	$18,120	$23,170	$23,440	$23,718	$24,002	$24,293	$24,591
TOTAL COST	**$18,183**	**$19,907**	**$21,980**	**$24,455**	**$31,479**	**$34,628**	**$38,137**	**$42,127**	**$46,945**	**$57,004**	**$63,234**	**$70,197**	**$78,094**	**$86,681**	**$96,438**

15-Year NPV (2015 $000): $351,098

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
SLP	$92.43	$87.20	$81.74	$77.56	$74.05	$71.36	$69.44	$68.46	$69.05	$70.42	$72.15	$73.93	$75.76	$77.64	$79.57
Existing CT		$93.36	$96.53	$99.82	$103.21	$106.72	$110.38	$114.18	$118.10	$122.08	$126.27	$130.57	$135.00	$139.59	$144.34
New CT												$35,080.90	$1,883.25	$1,029.43	$686.59
On-Peak Market Energy	$81.57	$81.93	$82.18	$81.90	$84.81	$85.75	$86.82	$87.03	$86.72	$89.89	$90.84	$92.45	$94.60	$97.00	$99.76

Financial Analysis
None216-LMS100

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
SLP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LMS100	41	46	51	56	61	67	73	74	74	74	74	74	74	74	74
Existing CT	7	11	19	27	11	20	30	42	57	37	53	68	79	90	109
New CT	0	0	0	0	0	0	0	0	0	0	0	2	8	15	27
On-Peak Market Energy	73	88	105	126	175	202	230	262	297	368	406	445	486	528	563
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
SLP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LMS100	$3,161	$3,633	$4,152	$4,727	$5,362	$6,056	$6,815	$7,175	$7,419	$7,672	$7,934	$8,204	$8,484	$8,773	$9,072
Existing CT	$602	$1,061	$1,833	$2,701	$1,184	$2,163	$3,283	$4,841	$6,762	$4,484	$6,661	$8,855	$10,643	$12,617	$15,728
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$248	$1,146	$2,135	$3,848
On-Peak Market Energy	$4,377	$5,369	$6,593	$8,173	$11,804	$14,034	$16,525	$19,662	$23,208	$30,000	$34,376	$39,158	$44,474	$50,178	$55,391
Total Variable Costs	$8,151	$10,078	$12,596	$15,622	$18,373	$22,278	$26,649	$31,705	$37,419	$42,187	$49,002	$56,498	$64,781	$73,740	$84,077
DEMAND/FIXED COST ($000)															
LMS100	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790	$4,790
New CT	$3,776	$3,795	$3,815	$3,835	$8,106	$8,149	$8,192	$8,237	$8,282	$13,138	$13,210	$13,284	$13,360	$13,438	$13,517
Total Fixed Costs	$8,566	$8,585	$8,605	$8,625	$12,896	$12,939	$12,982	$13,027	$13,072	$17,928	$18,000	$18,074	$18,150	$18,228	$18,307
TOTAL COST	**$16,717**	**$18,663**	**$21,201**	**$24,247**	**$31,269**	**$35,216**	**$39,631**	**$44,731**	**$50,491**	**$60,115**	**$67,003**	**$74,572**	**$82,931**	**$91,968**	**$102,385**

15-Year NPV (2015 $000): $362,430

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
SLP															
LMS100	$191.96	$182.95	$175.70	$169.84	$165.15	$161.53	$158.81	$160.82	$164.11	$167.50	$171.02	$174.65	$178.41	$182.30	$186.32
Existing CT	$90.54	$93.58	$96.67	$99.91	$103.50	$106.89	$110.46	$114.19	$118.06	$122.13	$126.26	$130.54	$134.95	$139.52	$144.29
New CT												$7,143.26	$1,712.76	$1,020.41	$652.30
On-Peak Market Energy	$59.68	$60.92	$62.70	$64.65	$67.48	$69.59	$71.82	$74.90	$78.21	$81.48	$84.75	$88.09	$91.50	$94.98	$98.45

Financial Analysis
None216-SC

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
SLP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing CT	0	0	2	7	0	5	11	19	31	19	32	46	60	73	88
New CT	0	0	0	0	0	0	0	0	0	0	0	0	3	10	18
On-Peak Market Energy	121	146	173	203	248	284	322	360	397	460	501	543	585	625	666
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
SLP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Existing CT	$0	$0	$149	$667	$0	$576	$1,249	$2,221	$3,718	$2,347	$4,071	$5,964	$8,106	$10,163	$12,736
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$395	$1,449	$2,604
On-Peak Market Energy	$8,500	$10,400	$12,628	$14,989	$18,950	$22,124	$25,634	$29,346	$33,117	$39,951	$44,542	$49,571	$54,888	$60,403	$66,332
Total Variable Costs	$8,511	$10,415	$12,796	$15,677	$18,972	$22,723	$26,909	$31,595	$36,864	$42,329	$48,644	$55,568	$63,425	$72,053	$81,711
DEMAND/FIXED COST ($000)															
New CC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
New CT	$11,327	$11,385	$11,444	$11,504	$15,817	$15,902	$15,989	$16,078	$16,170	$21,073	$21,193	$21,316	$21,442	$21,571	$21,704
Total Fixed Costs	$11,327	$11,385	$11,444	$11,504	$15,817	$15,902	$15,989	$16,078	$16,170	$21,073	$21,193	$21,316	$21,442	$21,571	$21,704
TOTAL COST	**$19,838**	**$21,799**	**$24,239**	**$27,181**	**$34,790**	**$38,625**	**$42,898**	**$47,673**	**$53,034**	**$63,401**	**$69,837**	**$76,884**	**$84,867**	**$93,624**	**$103,414**

15-Year NPV (2015 $000): $387,146

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
SLP															
Existing CT			$96.53	$99.82		$106.72	$110.35	$114.14	$118.08	$122.03	$126.25	$130.58	$135.02	$139.60	$144.35
New CT													$7,454.01	$2,216.09	$1,346.86
On-Peak Market Energy	$70.01	$71.47	$72.80	$73.91	$76.46	$77.99	$79.72	$81.56	$83.43	$86.83	$88.99	$91.30	$93.86	$96.61	$99.54

Financial Analysis

All216-100CC

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
SLP	87	99	116	134	155	178	202	223	233	237	237	237	237	237	237
New CC	0	0	0	0	70	80	85	90	96	102	110	117	126	135	144
Existing CT	0	1	6	11	0	0	1	5	10	21	38	56	77	105	144
New CT	0	0	0	0	0	0	0	0	0	0	0	0	0	3	10
On-Peak Market Energy	34	45	53	64	23	32	46	60	89	120	149	179	208	229	237
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
SLP	$3,147	$3,697	$4,440	$5,277	$6,273	$7,405	$8,648	$9,859	$10,603	$11,055	$11,376	$11,707	$12,047	$12,397	$12,757
New CC	$0	$0	$0	$0	$5,045	$5,964	$6,562	$7,213	$7,967	$8,807	$9,838	$10,971	$12,213	$13,582	$15,096
Existing CT	$0	$131	$604	$1,138	$0	$0	$97	$625	$1,217	$2,550	$4,782	$7,248	$10,386	$14,707	$20,938
New CT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$376	$1,436
On-Peak Market Energy	$2,799	$3,660	$4,332	$5,246	$1,353	$1,937	$3,138	$4,467	$6,962	$9,904	$12,634	$15,658	$18,716	$21,172	$22,711
Total Variable Costs	$5,957	$7,503	$9,393	$11,681	$12,694	$15,331	$18,471	$22,192	$26,778	$32,346	$38,662	$45,618	$53,397	$62,272	$72,977
DEMAND/FIXED COST ($000)															
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
SLP (Unit 1-3 FO&M)	$3,547	$3,636	$3,727	$3,820	$3,915	$4,013	$4,114	$4,216	$4,322	$4,430	$4,541	$4,654	$4,771	$4,890	$5,012
New CC	$0	$0	$0	$0	$14,836	$14,901	$14,968	$15,036	$15,106	$15,178	$15,251	$15,327	$15,404	$15,483	$15,564
New CT	$3,776	$3,795	$3,815	$3,835	$3,856	$3,877	$3,898	$3,921	$3,944	$3,967	$3,991	$4,016	$4,041	$4,067	$4,093
Total Fixed Costs	$12,226	$12,404	$12,587	$12,774	$27,801	$28,063	$28,331	$28,606	$28,888	$29,176	$29,472	$29,776	$30,087	$30,405	$30,732
TOTAL COST	**$18,183**	**$19,907**	**$21,980**	**$24,455**	**$40,495**	**$43,394**	**$46,802**	**$50,798**	**$55,666**	**$61,522**	**$68,135**	**$75,393**	**$83,484**	**$92,677**	**$103,709**

15-Year NPV (2015 $000): $389,434

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
SLP	$92.43	$87.20	$81.74	$77.56	$74.05	$71.36	$69.44	$68.46	$69.05	$70.42	$72.15	$73.93	$75.76	$77.64	$79.57
New CC					$285.28	$261.90	$253.98	$246.93	$240.55	$235.23	$229.09	$223.84	$219.42	$215.69	$212.58
Existing CT		$93.36	$96.53	$99.82			$109.96	$113.70	$117.57	$121.71	$125.95	$130.28	$134.77	$139.41	$144.91
New CT														$1,642.15	$553.75
On-Peak Market Energy	$81.57	$81.93	$82.18	$81.90	$58.08	$61.04	$68.78	$74.05	$78.48	$82.61	$84.94	$87.48	$89.85	$92.48	$95.65

Financial Analysis
45216-100CC

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESOURCE DISPATCH (GWh)															
CROD	1,721	1,740	1,760	1,777	1,796	1,805	1,817	1,829	1,844	1,850	1,859	1,868	1,881	1,883	1,888
Hydro	9	11	13	15	16	16	17	17	18	18	19	19	20	20	21
SLP	87	99	116	134	155	178	202	223	233	237	237	237	237	237	237
New CC	32	41	50	60	70	80	85	90	96	102	110	117	126	135	144
CTs	0	0	0	0	0	0	1	5	10	3	9	19	38	56	81
On-Peak Market Energy	2	5	9	15	23	32	46	60	89	137	178	215	248	281	311
Total Energy	1,851	1,897	1,948	2,001	2,059	2,110	2,167	2,226	2,291	2,348	2,411	2,476	2,548	2,612	2,682
ENERGY/VARIABLE COST ($000)															
Hydro	$12	$15	$18	$21	$23	$24	$26	$27	$29	$30	$32	$33	$35	$37	$39
SLP	$3,147	$3,697	$4,440	$5,277	$6,273	$7,405	$8,648	$9,859	$10,603	$11,055	$11,376	$11,707	$12,047	$12,397	$12,757
New CC	$2,054	$2,686	$3,390	$4,174	$5,045	$5,964	$6,562	$7,213	$7,967	$8,807	$9,838	$10,971	$12,213	$13,582	$15,096
CTs	$0	$0	$0	$40	$0	$0	$97	$625	$1,217	$418	$1,098	$2,503	$5,054	$7,868	$11,620
On-Peak Market Energy	$93	$259	$473	$862	$1,353	$1,937	$3,138	$4,467	$6,962	$11,166	$15,147	$19,027	$22,560	$26,330	$30,007
Total Variable Costs	$5,305	$6,657	$8,320	$10,373	$12,694	$15,331	$18,471	$22,192	$26,778	$31,476	$37,490	$44,242	$51,909	$60,213	$69,519
DEMAND/FIXED COST ($000)															
SLP (Unit 4 Upgrade/FO&M)	$4,903	$4,974	$5,045	$5,119	$5,195	$5,272	$5,351	$5,433	$5,516	$5,602	$5,689	$5,779	$5,871	$5,965	$6,062
New CC	$14,591	$14,650	$14,710	$14,772	$14,836	$14,901	$14,968	$15,036	$15,106	$15,178	$15,251	$15,327	$15,404	$15,483	$15,564
New CT	$0	$0	$0	$0	$4,251	$4,272	$4,294	$4,316	$4,339	$9,171	$9,219	$9,269	$9,319	$9,371	$9,424
Total Fixed Costs	$19,495	$19,624	$19,756	$19,892	$24,281	$24,445	$24,613	$24,785	$24,961	$29,951	$30,160	$30,374	$30,594	$30,819	$31,050
TOTAL COST	**$24,800**	**$26,280**	**$28,076**	**$30,264**	**$36,975**	**$39,775**	**$43,083**	**$46,976**	**$51,739**	**$61,426**	**$67,650**	**$74,616**	**$82,503**	**$91,033**	**$100,569**

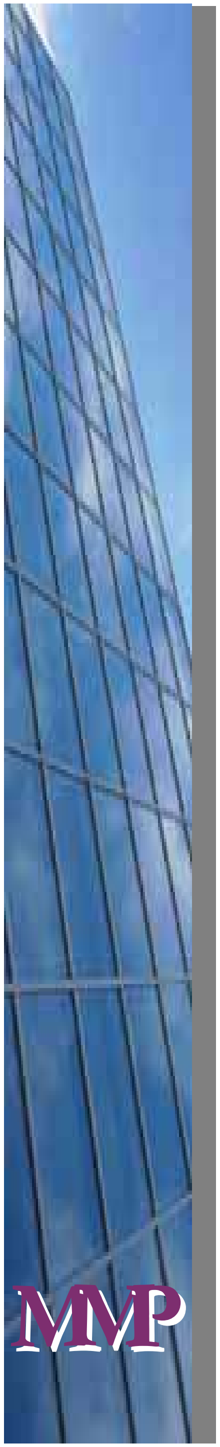
15-Year NPV (2015 $000): $396,788

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Resource Cost ($/MWh)															
Hydro	$1.32	$1.35	$1.38	$1.42	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.68	$1.73	$1.77	$1.81	$1.86
SLP	$92.43	$87.20	$81.74	$77.56	$74.05	$71.36	$69.44	$68.46	$69.05	$70.42	$72.15	$73.93	$75.76	$77.64	$79.57
New CC	$513.13	$422.60	$361.57	$317.83	$285.28	$261.90	$253.98	$246.93	$240.55	$235.23	$229.09	$223.84	$219.42	$215.69	$212.58
Existing CT				$99.46			$109.96	$113.70	$117.57	$121.58	$125.72	$130.14	$134.69	$139.32	$144.13
New CT															
On-Peak Market Energy	$49.47	$51.18	$53.14	$55.83	$58.08	$61.04	$68.78	$74.05	$78.48	$81.26	$85.10	$88.33	$91.02	$93.81	$96.39

Appendix IV -

- End Use Survey & Summary of Results
- End Use Survey Question Forms for Residential, Commercial and Industrial Customers
- "Next Level" Triad Report
- Task Force Recommendations
- Residential & Commercial End Use Information
- Statistical Relationship Photovoltaic Generation & Electric Utility Demand in Minnesota (1996 – 2002)

End Use Survey & Summary of Results



END USE CUSTOMER SURVEYS

Residential & Commercial/Industrial Customers

Presentation of Key Findings

October 18, 2004

Rick Morgan & Rick Tate

Morgan Marketing Partners

rpu we pledge, we deliver

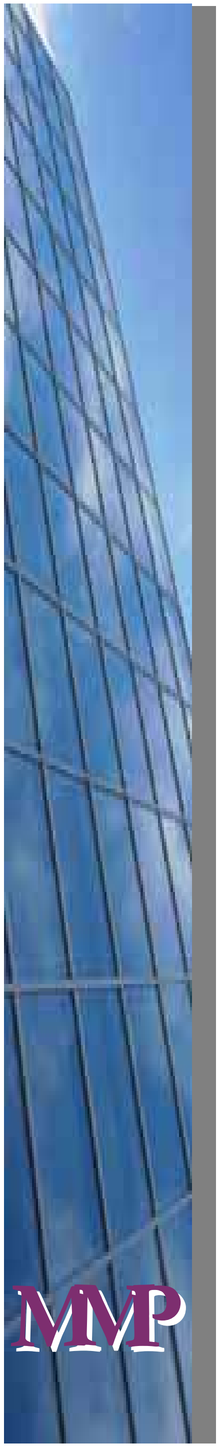
AUSTIN UTILITIES

OWATONNA PUBLIC UTILITIES

Strategic Marketing Consulting

Today’s Objective

- **Provide you with an overview of the study process**
- **Share Key Findings**
- **Provide Recommendations**
- **Discuss some uses of the information**
- **Questions**



Objectives

- Primarily for End-Use Facility Forecast and DSM Planning - Not Customer Satisfaction

- Inventory major appliances (gas and electric) and gather pertinent information about type, age, and usage.

- Gather information about homes and building characteristics such as age, number of rooms, number of residents, and current energy usage and practices.

- Inventory water using appliances and gather pertinent information about current usage and conservation practices.

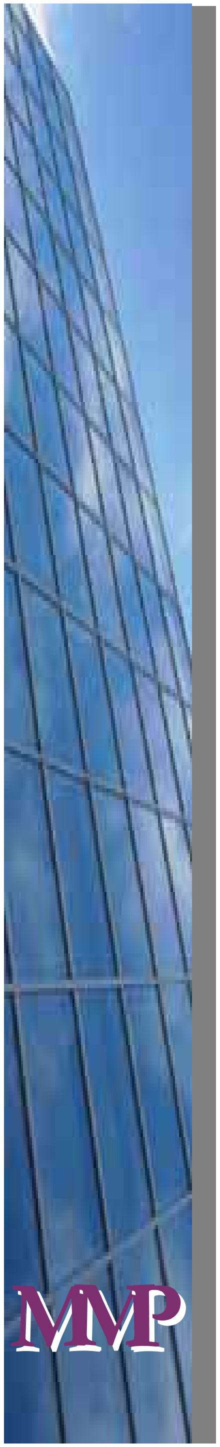
- Large Customers get some indication of services of interest.

Methodology

- MMP worked with AOR Utilities to develop a sampling plan to control for costs but produce reliable results

- MMP designed the survey instrument in conjunction with AOR. The primary issues covered in the surveys were:

  - ✓ Type/age of HVAC equipment
  - ✓ Number and sizes of refrigerators and freezers
  - ✓ Laundry appliances and usage
  - ✓ Food preparation appliances and usage
  - ✓ Compact fluorescent lighting
  - ✓ Energy management practices currently using
  - ✓ Water usage and conservation measures



Sample Question

- ***Central Air Conditioner***
- **20. What type of central air conditioner does this business have?**
  - 0 None ***(SKIP TO Q.24)*** 1 Central 2 Central (roof top) 3 Heat pump
- **21. Do you pay for your central air conditioning?**
  - 1 Yes 2 No, it is part of the lease
- **22. Was the central air conditioning unit purchased or replaced within the last seven years?**
  - 1 Yes 2 No 3 Don’t know
- **23. Please indicate how often the central air conditioner is used during the summer. (<u>Choose one</u> <u>for each time period</u>)**

	Never	Rarely (20% time)	Sometimes (40% time)	Often (70% time)	Always
a. Day	1	2	3	4	5
b. Evening	1	2	3	4	5
c. Night	1	2	3	4	5

Methodology - Continued

- AOR Utilities printed and mailed the surveys along with a cover letter and postage-paid return envelope. Completed surveys were batched to MMP on a weekly basis for data entry and processing.

- Response rates and statistical confidence

Utility	Population	Sample Mail Out	Responses	Response Rate	Confidence Level	Sampling Error
Austin	10,565	1,500	576	38.4%	95%	+/-3.97%
Owatonna	9,436	1,500	517	34.5%	95%	+/-4.19%
Rochester	39,414	1,497	520	34.7%	95%	+/-4.27%

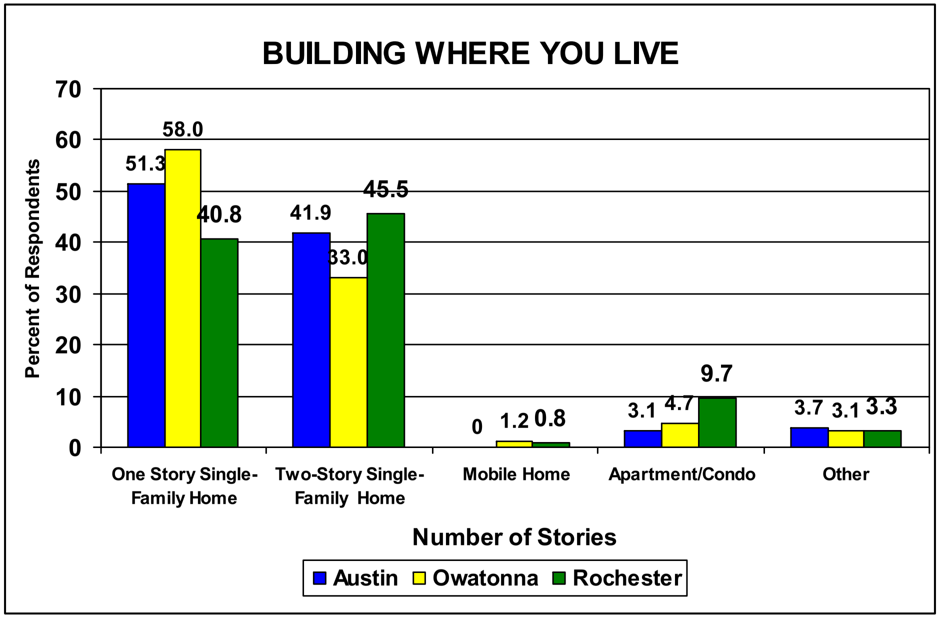
MMP

Methodology - Continued

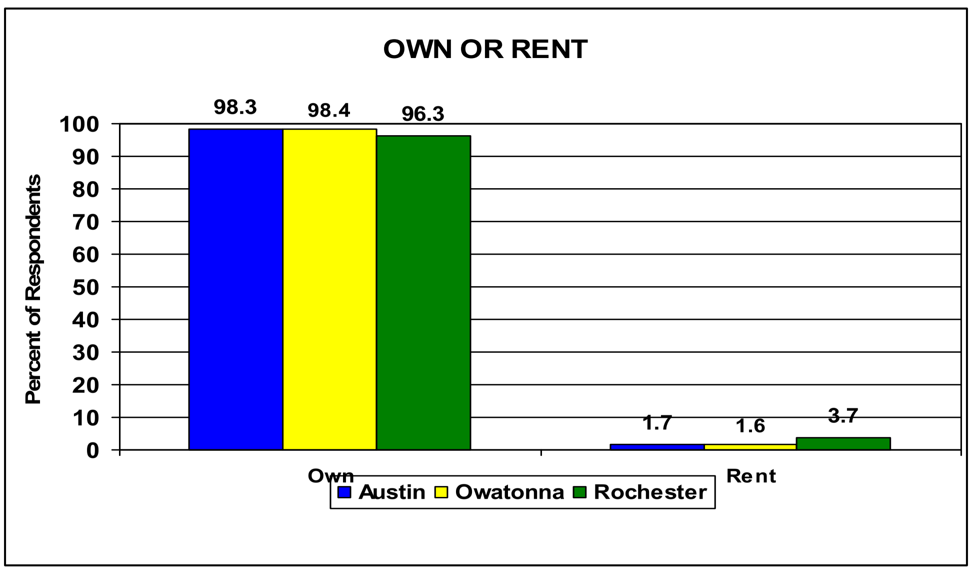
Utility	Population	Sample Mail Out	Responses	Response Rate	Confidence Level	Sampling Error
Austin						
Commercial	626	626	152	24.3%	95%	+/-6.92%
Large C&I	16	16	4	25.0%	NA	NA
Owatonna						
Commercial	941	941	202	21.5%	95%	+/-6.11%
Large C&I	62	62	14	22.6%	NA	NA
Rochester						
Commercial	2145	2145	381	17.8%	95%	+/-4.55%
Large C&I	48	48	7	14.6%	NA	NA

MMP

Key Findings - Home and Lifestyle

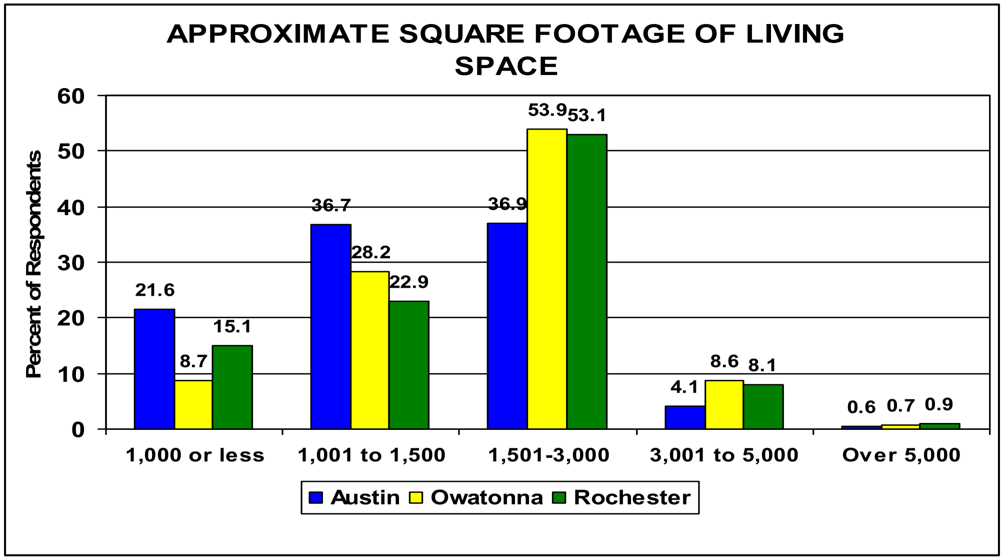


- One or two-story building.

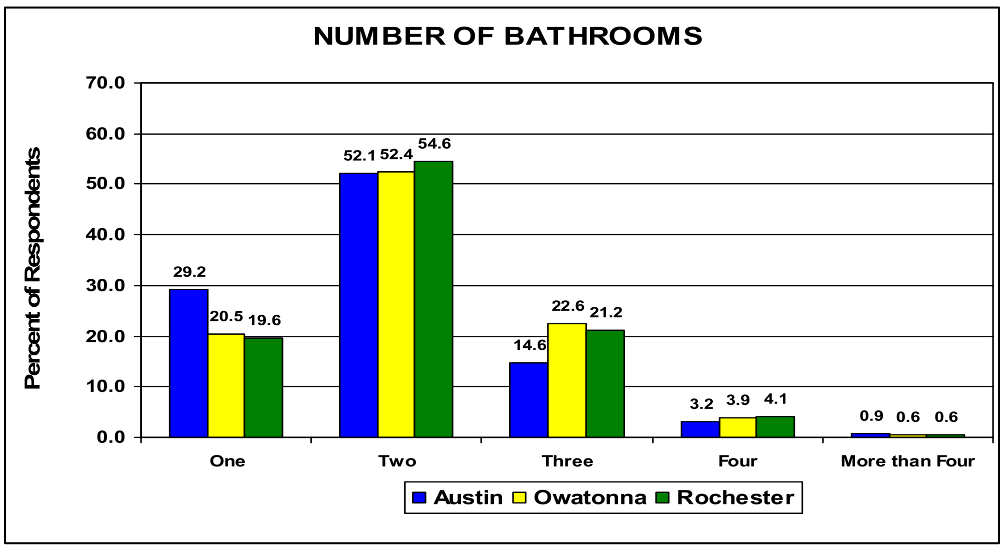


- Owner-occupied.

Key Findings - Home and Lifestyle

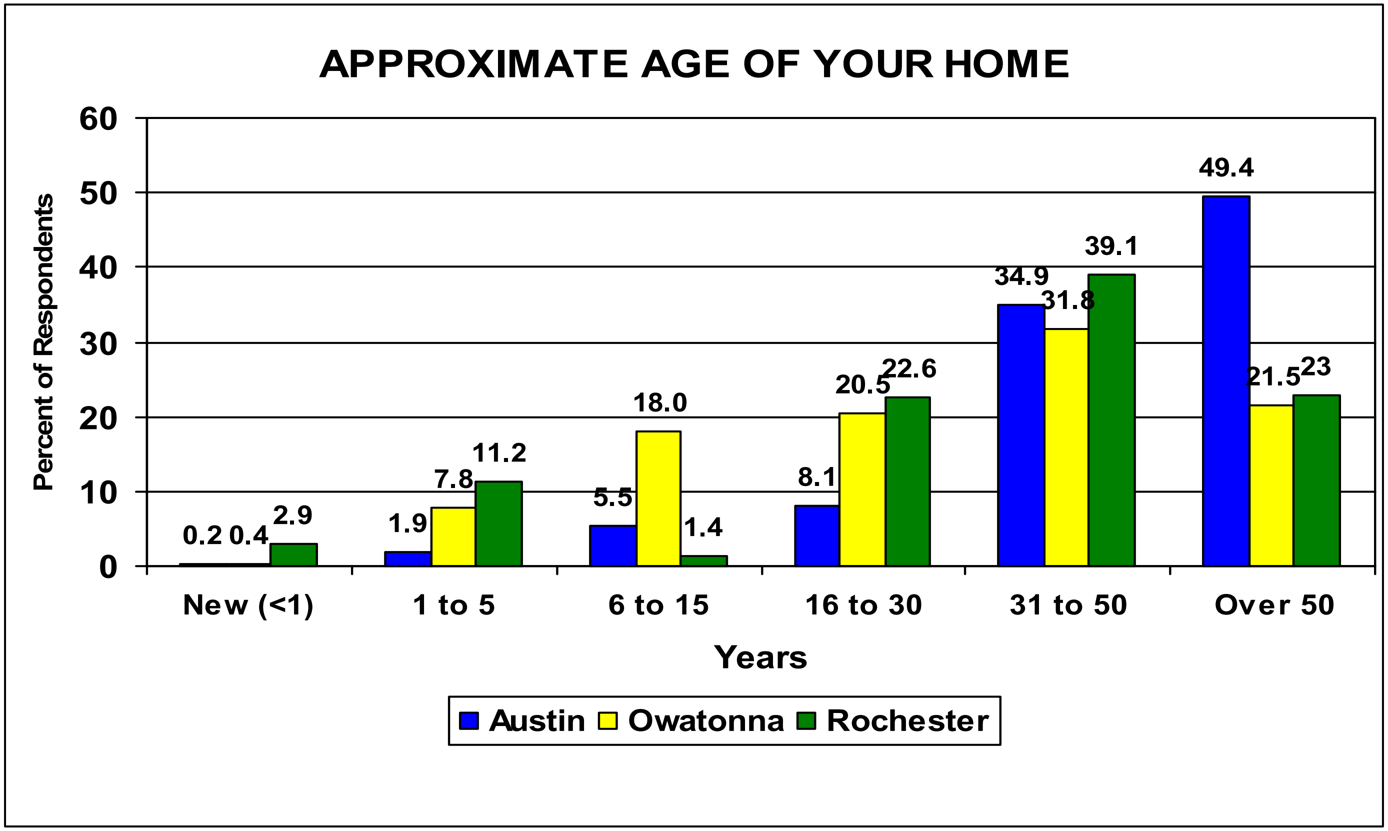


- Most homes are between 1,000 and 3,000 square feet.



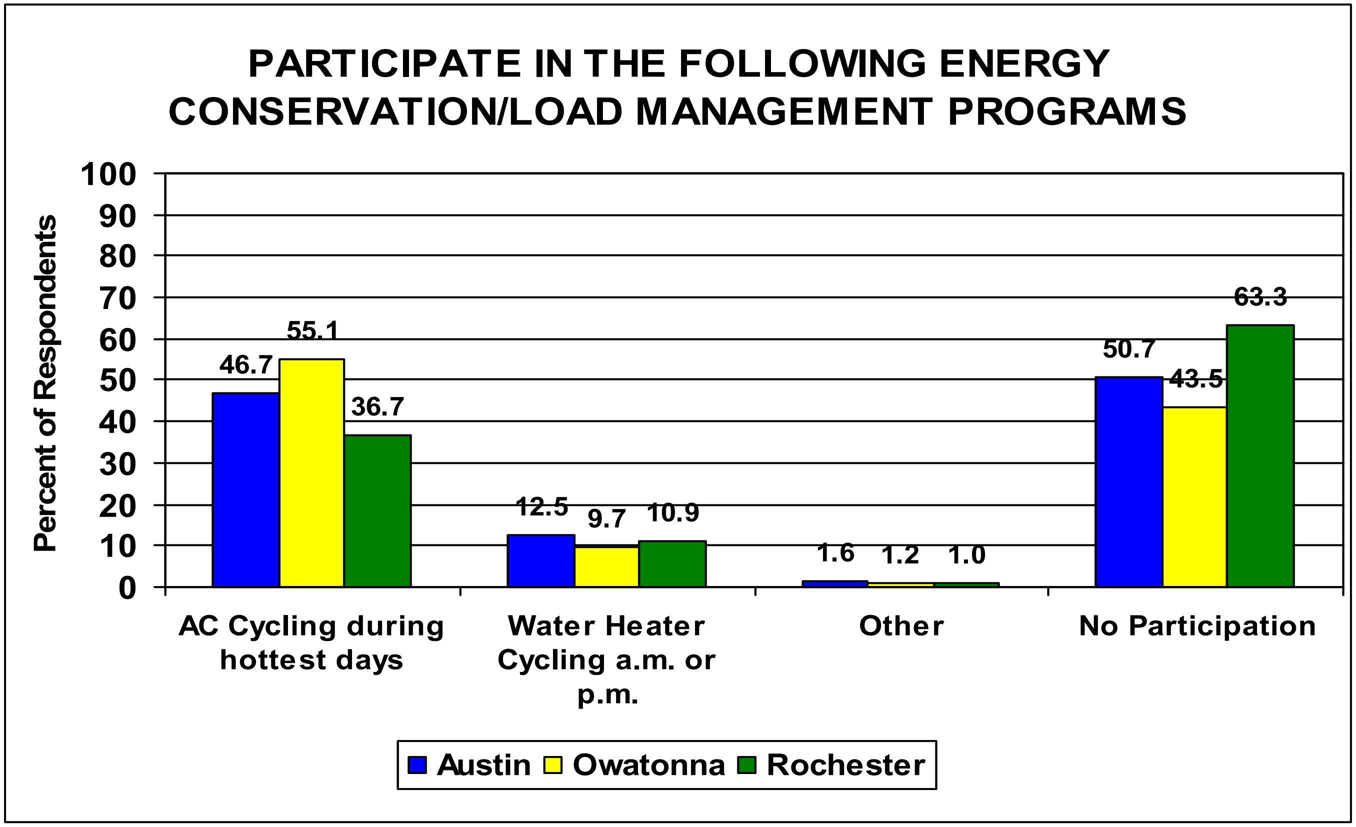
- Majority have two bathrooms.

Key Findings – Home and Lifestyle



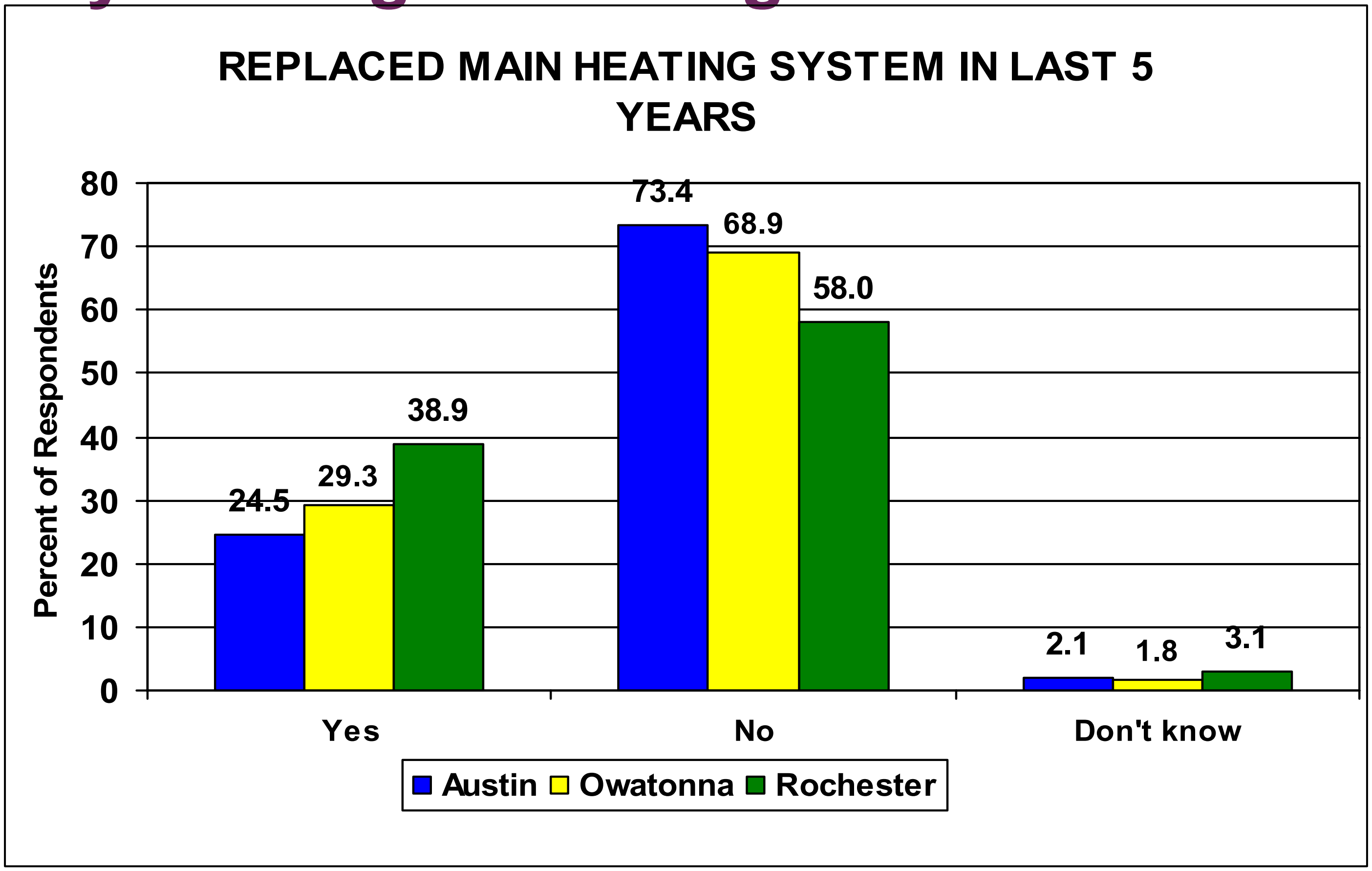
- In general, homes are older.

Key Findings - Home and Lifestyle



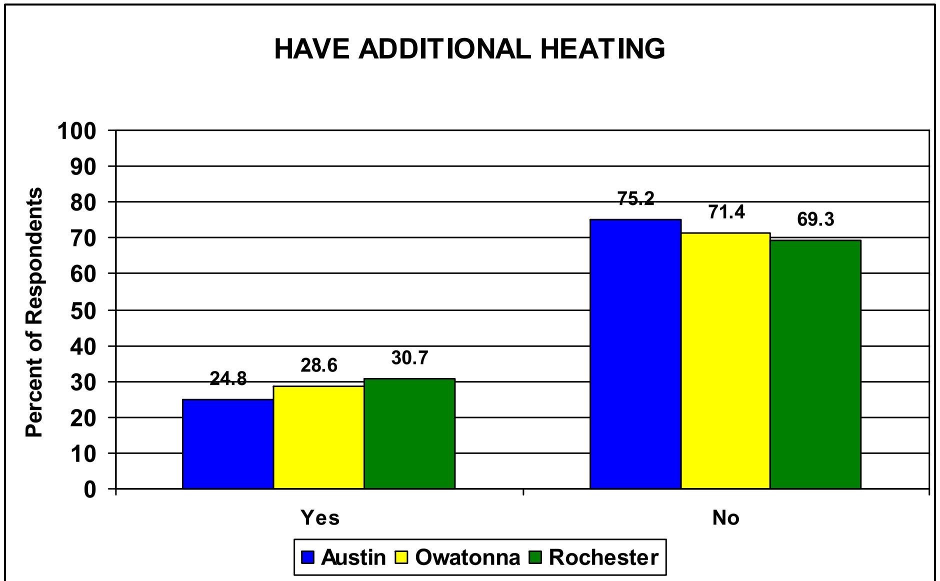
- A large percentage do not participate in conservation load/management programs.

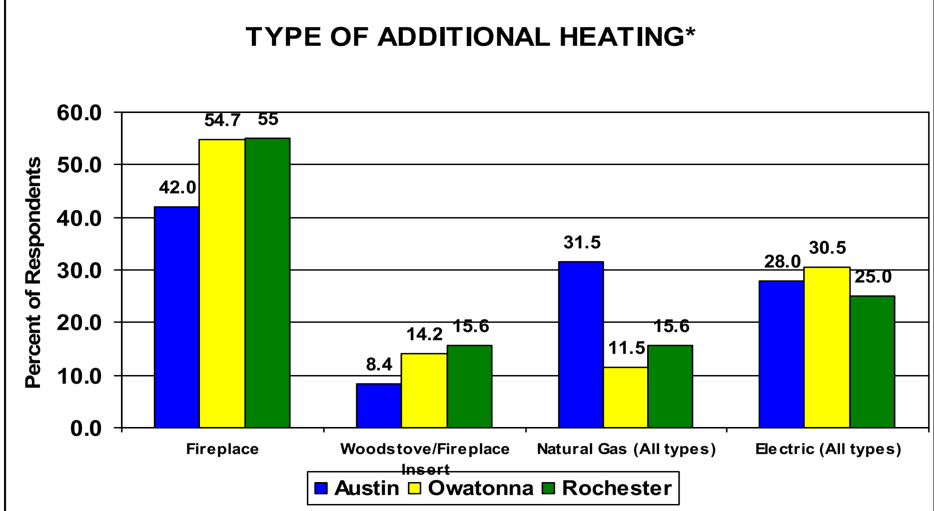
Key Findings - Heating



- Between one fourth and 39% have replaced system in past 5 years.

Key Findings - Heating

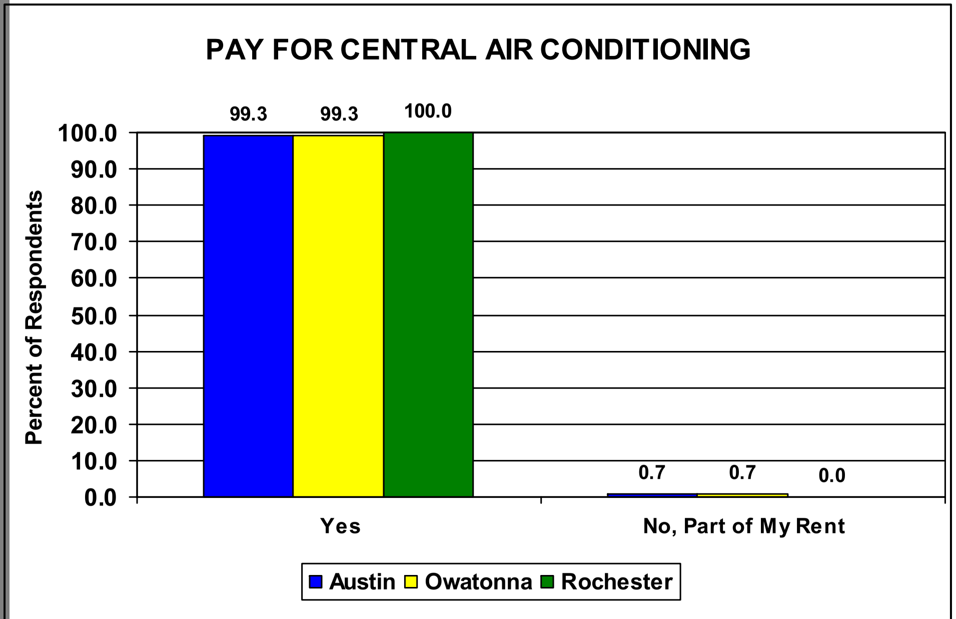


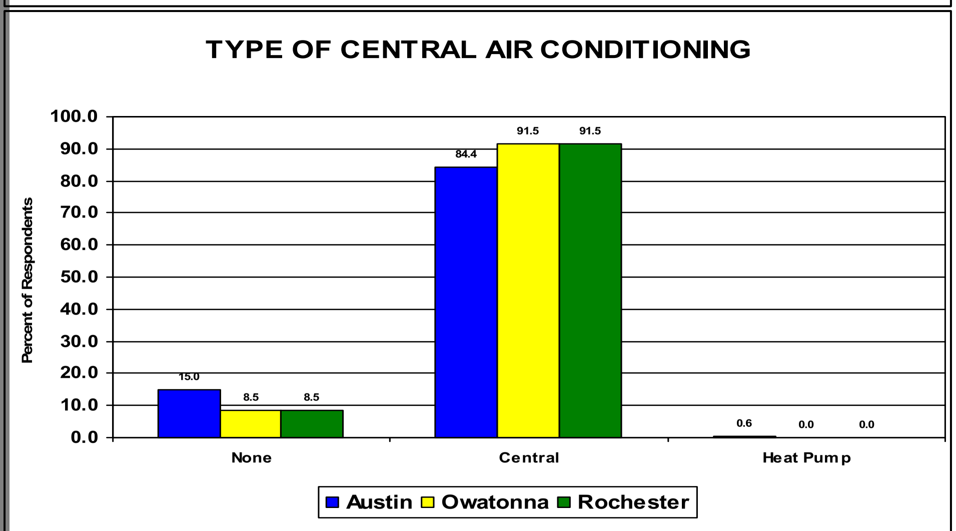


- 25% to 30% have some type of supplemental heating.

- A fireplace is the most common type and typically heats one room.

Key Findings - Air Conditioning

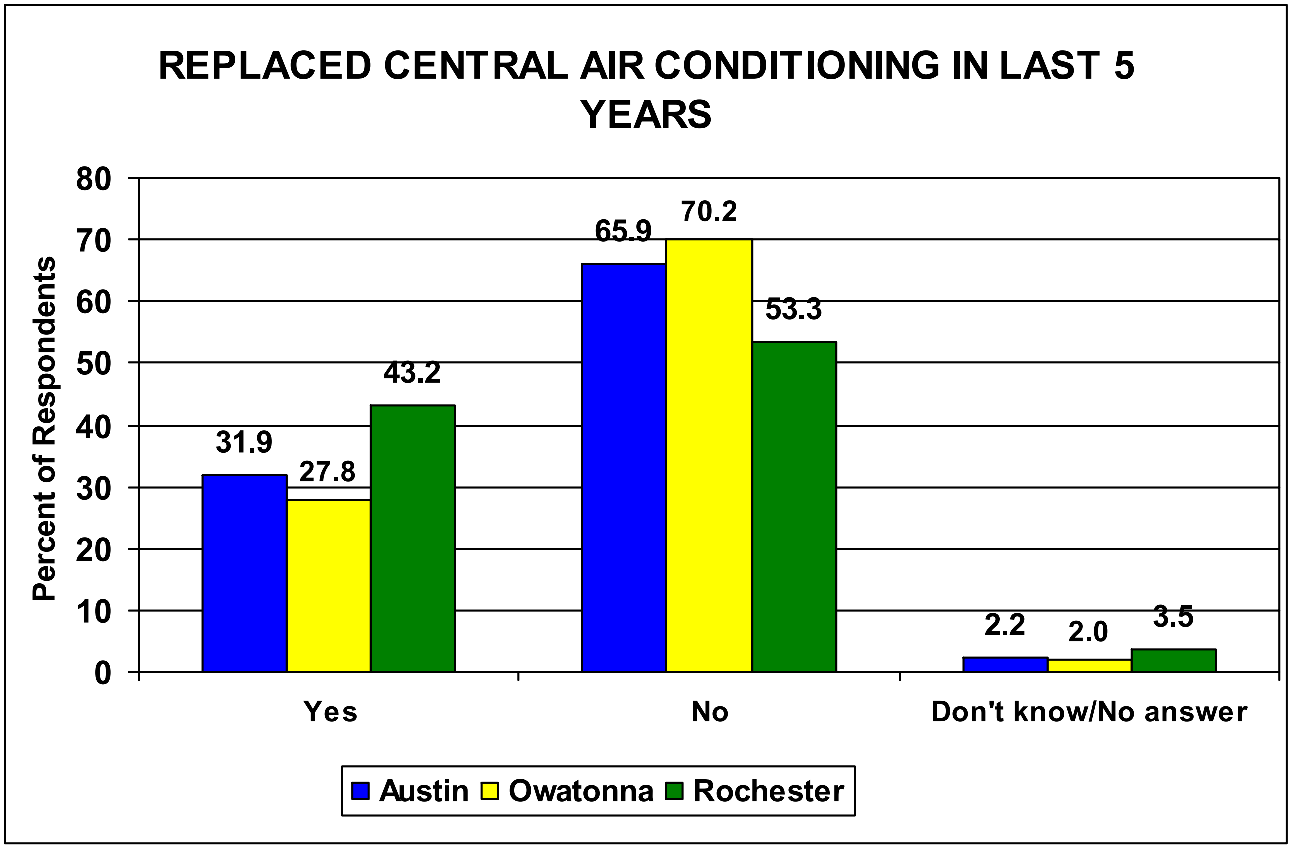




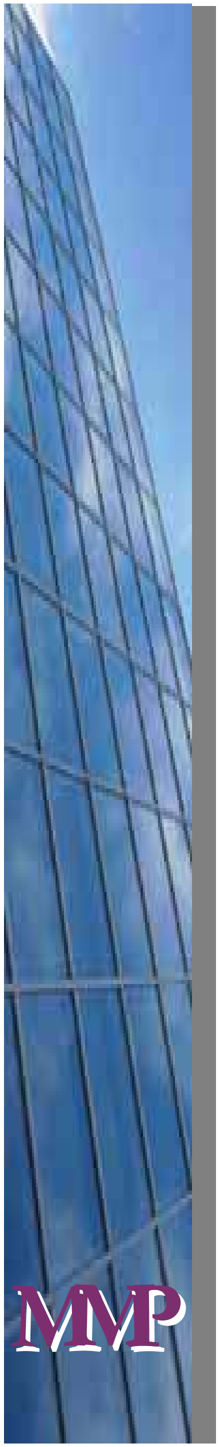
- Pay for air conditioning.

- Have a central AC system.

Key Findings - Air Conditioning



- A higher percentage of Rochester (43%) respondents have replaced their system in the last five years.



Key Findings - Air Conditioning

Frequency	Frequency of Central Air Conditioning Use During the Summer*								
	Austin			Owatonna			Rochester		
	Day	Evening	Night	Day	Evening	Night	Day	Evening	Night
Always	12.9%	13.7%	13.%	14.4%	14.0%	14.1%	11.7%	11.1%	10.2%
Often (70% of the time)	24.2%	24.1%	20.5%	28.5%	30.0%	24.8%	24.5%	24.7%	19.2%
Sometimes (40% of the time)	34.6%	35.6%	31.5%	32.9%	34.0%	31.8%	28.6%	32.9%	29.6%
Rarely (10% of the time)	25.8%	24.5%	26.0%	23.3%	20.0%	24.5%	32.2%	28.5%	35.1%
Never	2.5%	2.1%	8.6%	0.9%	1.9%	4.9%	2.9%	2.8%	5.9%

*Percentage of respondents that have central air conditioning

- Frequency of Summer use is moderate, mostly in the evenings.

Key Findings - Thermostat Setting

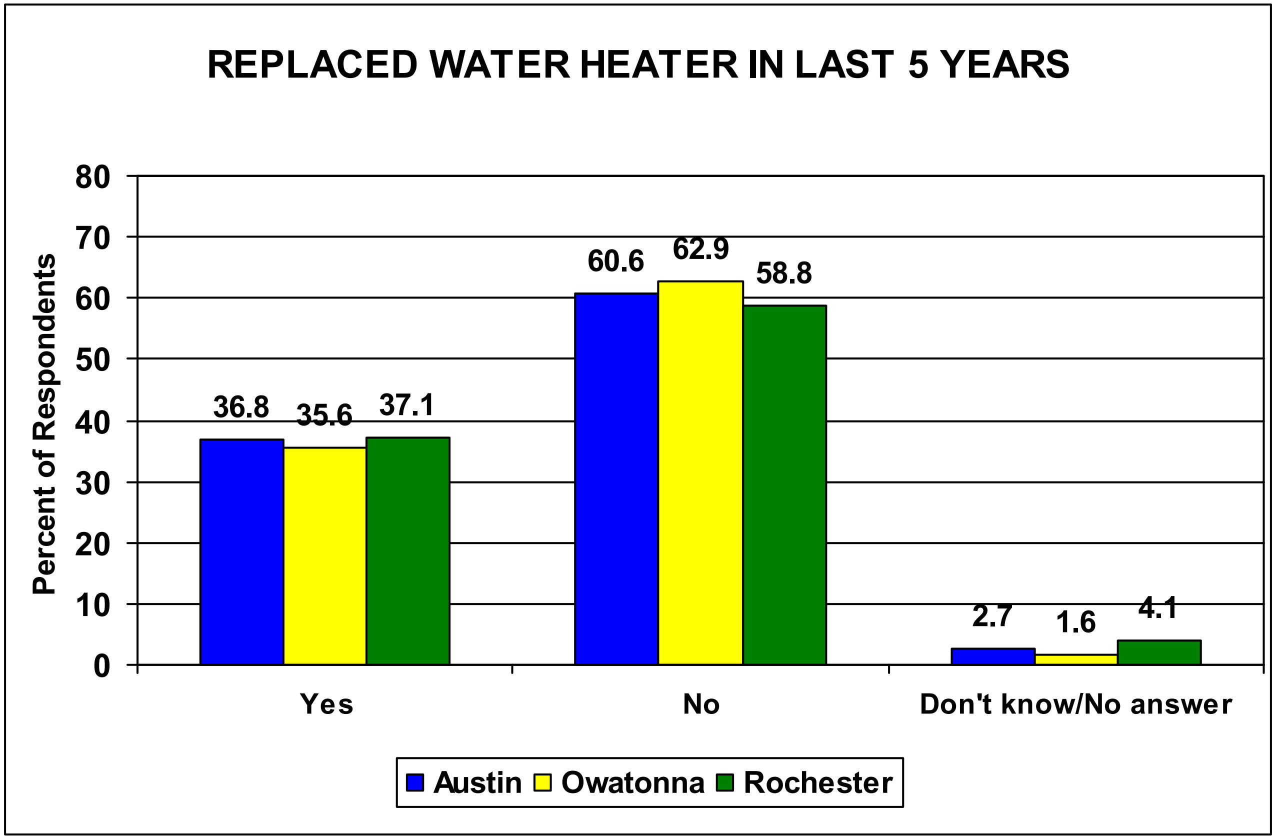
- Fan generally set to “auto” in all seasons.

	Thermostat Setting and Temperature For Operating Central Heating or Air Conditioning*											
	Austin				Owatonna				Rochester			
	Winter	Summer	Spring	Fall	Winter	Summer	Spring	Fall	Winter	Summer	Spring	Fall
Fan Set to Auto	89.6%	85.3%	88.3%	87.8 %	90.4%	82.5%	89.5%	89.5 %	84.0%	78.2%	82.3%	83.2%
Fan Set to On	10.4%	14.7%	11.7%	12.2 %	9.6%	17.5%	10.5%	10.5 %	16.0%	21.8%	17.8%	16.8%
65 to 68 degrees	30.2%	7.9%	30.0%	31.1 %	34.3%	4.5%	25.4%	32.7 %	33.8%	7.6%	24.5%	28.8%
69 to 72 degrees	54.2%	24.8%	41.1%	46.8 %	51.8%	20.1%	44.1%	45.0 %	49.3%	23.2%	42.3%	46.3%
73 to 75 degrees	12.6%	32.1%	18.7%	16.4 %	10.0%	35.5%	14.4%	12.1 %	14.0%	31.9%	18.9%	16.6%
76 degrees or higher	3.0%	35.1%	10.2%	5.6 %	3.8%	39.8%	16.1%	10.2 %	3.0%	37.3%	14.3%	8.3%

*Percentage of respondents that have central heating or air conditioning

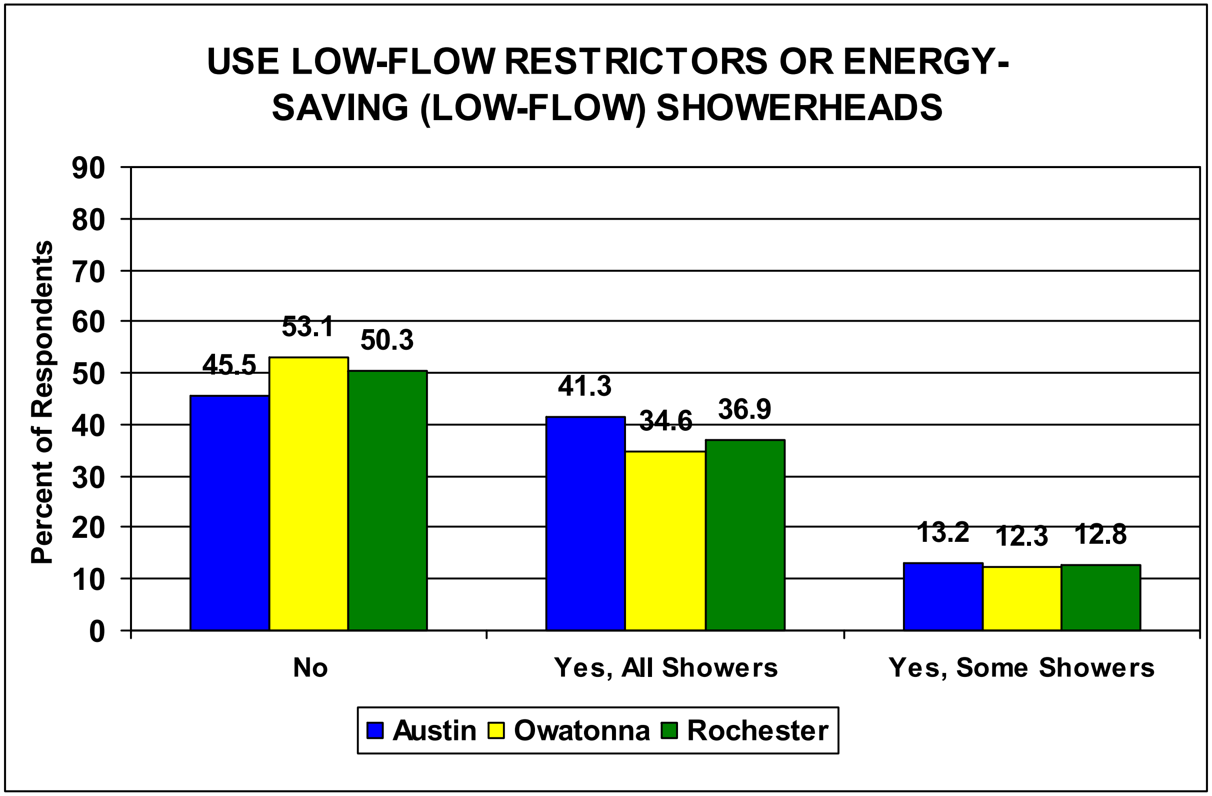
- Most prevalent Winter setting is 69 to 72 degrees and Summer setting is 76 degrees or higher.

Key Findings - Water Heating



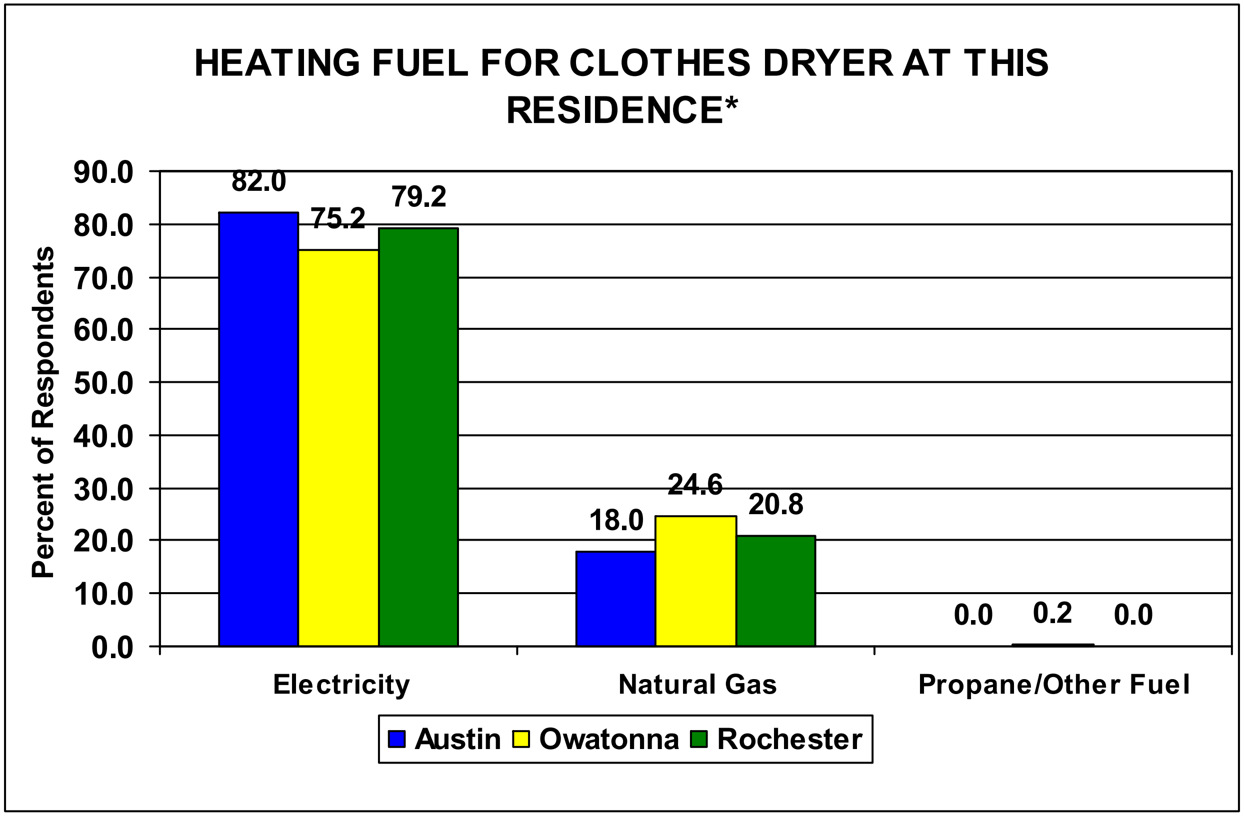
- A little over one-third have replaced unit in last five years.

Key Findings - Water Heating



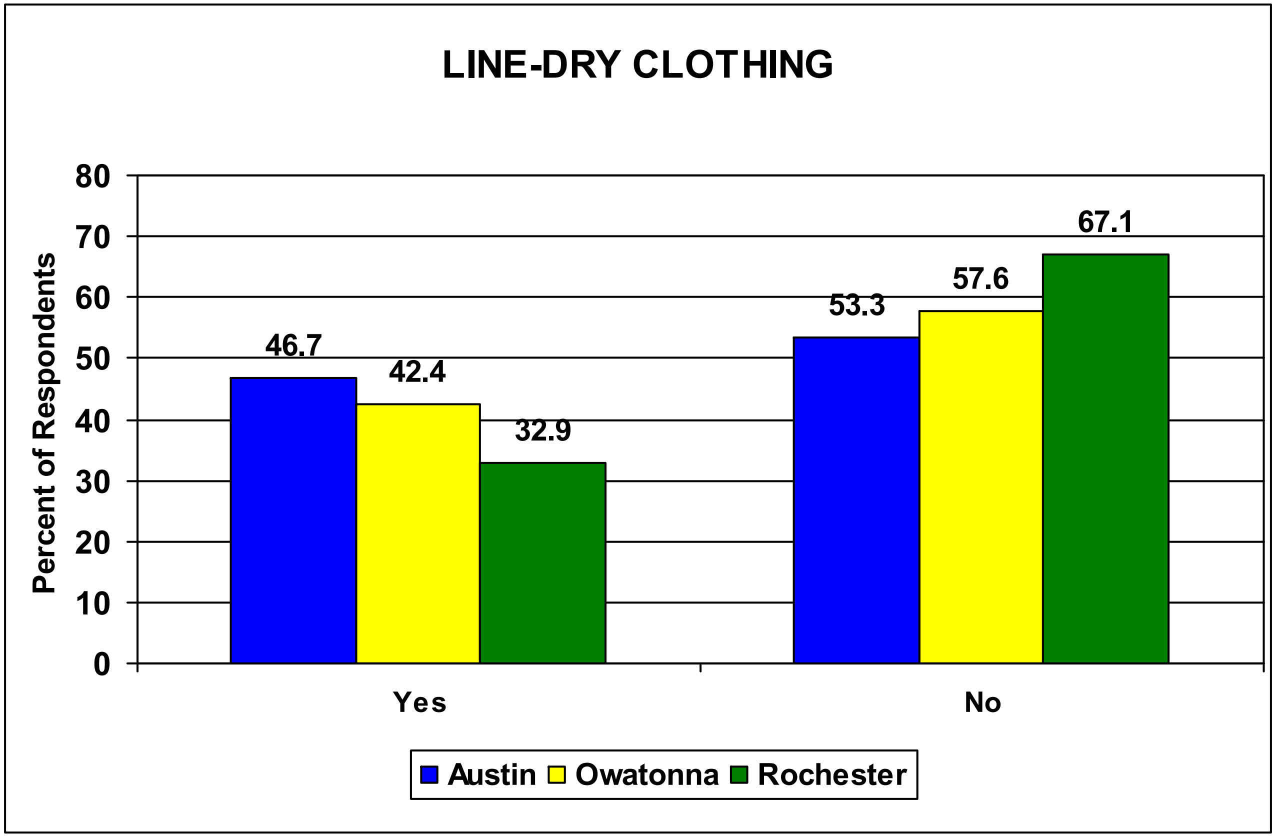
- Only about half of households use low-flow showerheads.

Key Findings - Laundry



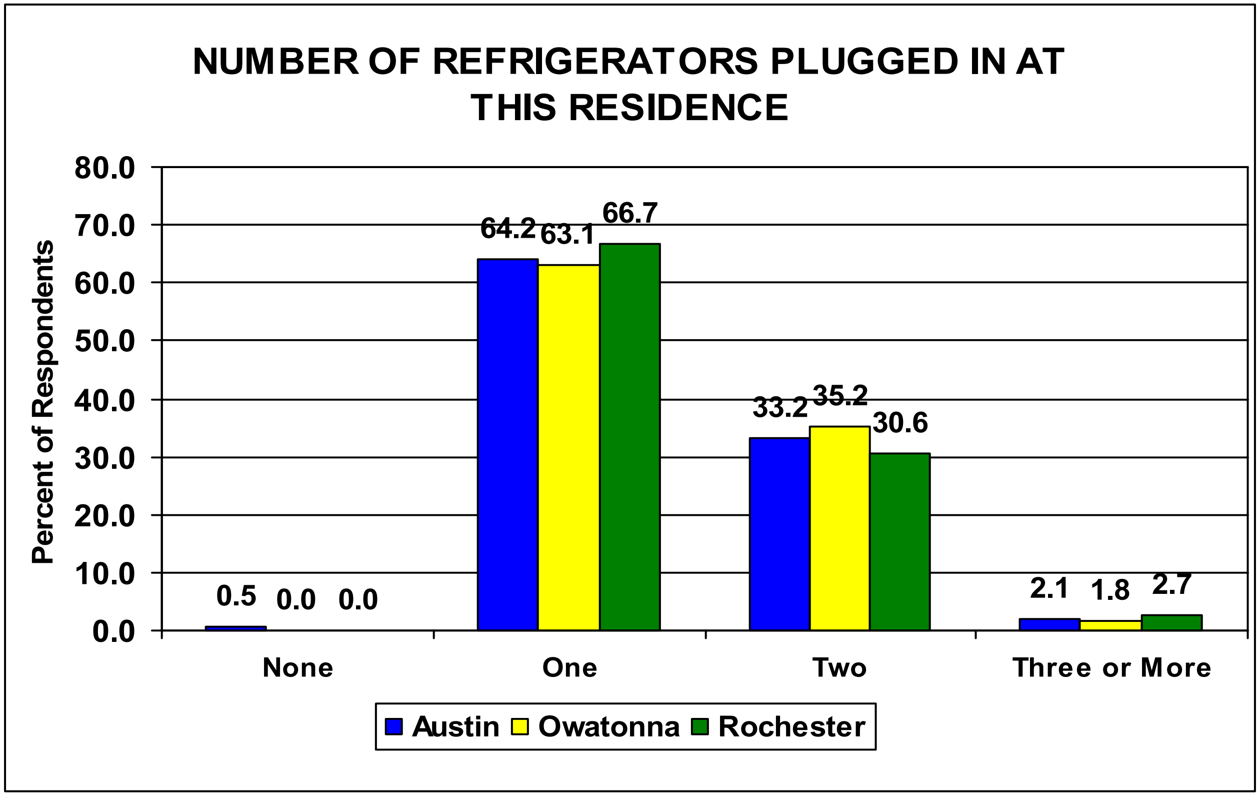
- Dryers are overwhelmingly electric.

Key Findings - Laundry



- Line drying is more prevalent with Austin customers.

Key Findings - Refrigerators



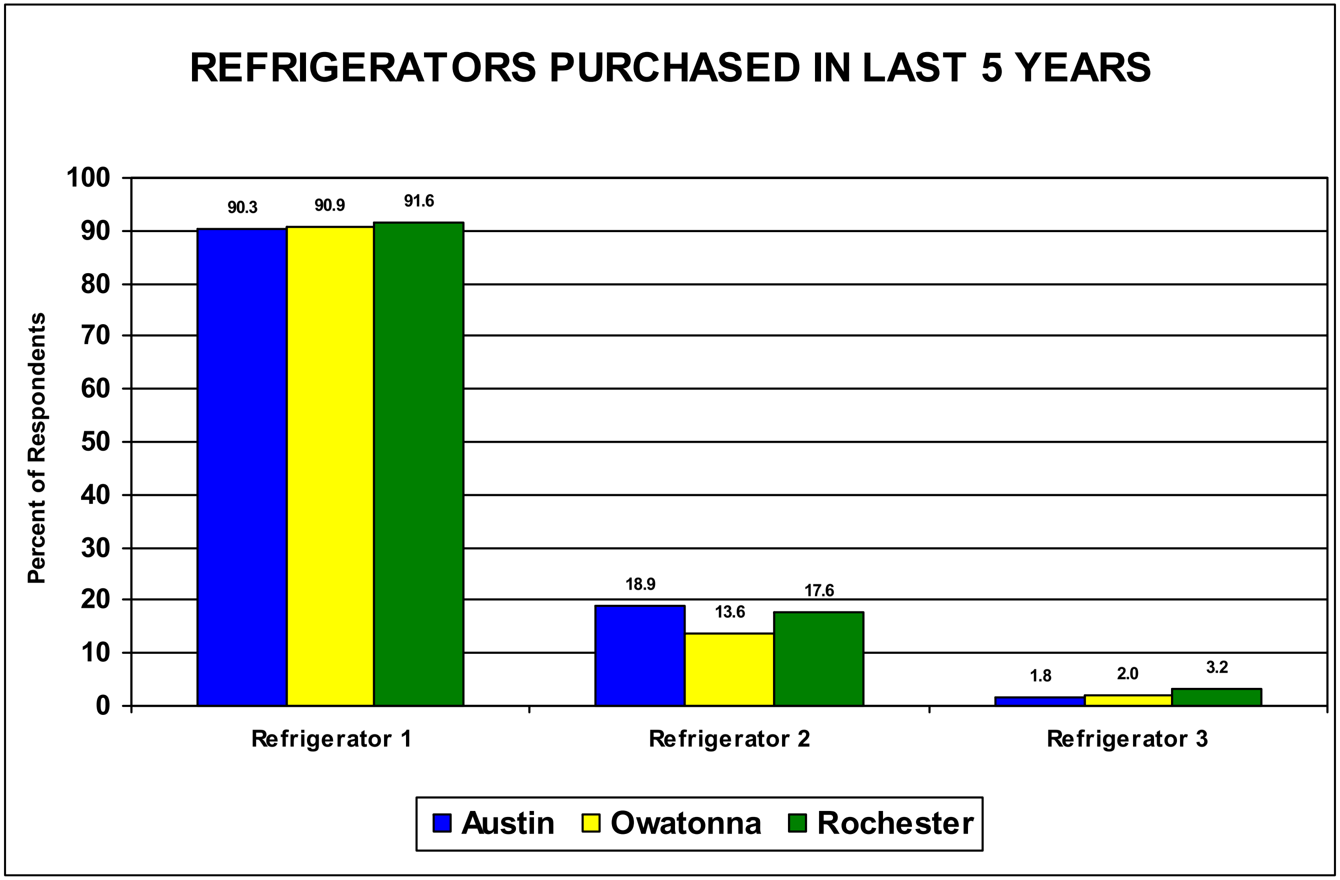
- About two-thirds of households have only one operating refrigerator.

Key Findings - Refrigerators

Characteristic	Overview of Refrigerators								
	Austin			Owatonna			Rochester		
	No. 1	No. 2	No. 3	No. 1	No. 2	No. 3	No. 1	No. 2	No. 3
Style: Top-Bottom	77.7%	84.6%	100.0%	72.2%	91.7%	100.0%	75.0%	89.8%	81.8%
Side-by-Side	22.3%	15.3%	0.0%	27.8%	8.3%	0.0%	25.0%	10.2%	18.2%
Size: Very Small (<13cu. ft)	3.0%	25.8%	54.5%	1.2%	17.3%	33.3%	2.2%	24.2%	53.8%
Small (13-16 cu. ft.)	9.5%	26.3%	9.1%	10.0%	25.1%	22.2%	7.2%	24.8%	15.4%
Medium (17-20 cu.ft.)	55.2%	34.2%	27.3%	52.2%	40.2%	11.1%	53.4%	35.8%	23.1%
Large (21-23 cu. Ft.)	29.5%	13.2%	9.1%	32.0%	16.2%	22.2%	32.2%	14.5%	7.7%
Very Large (over 23 cu. Ft)	2.8%	0.5%	0.0%	4.5%	1.1%	11.1%	5.0%	0.6%	0.0%
Defrost: Automatic (Frost Free)	92.3%	54.7%	18.2%	95.0%	59.6%	33.3%	95.0%	56.3%	23.1%
Manual	5.8%	40.6%	63.6%	3.4%	33.9%	55.5%	3.8%	37.1%	61.5%
Partial Automatic	2.0%	4.7%	18.2%	1.6%	6.6%	11.1%	1.2%	6.6%	15.4%

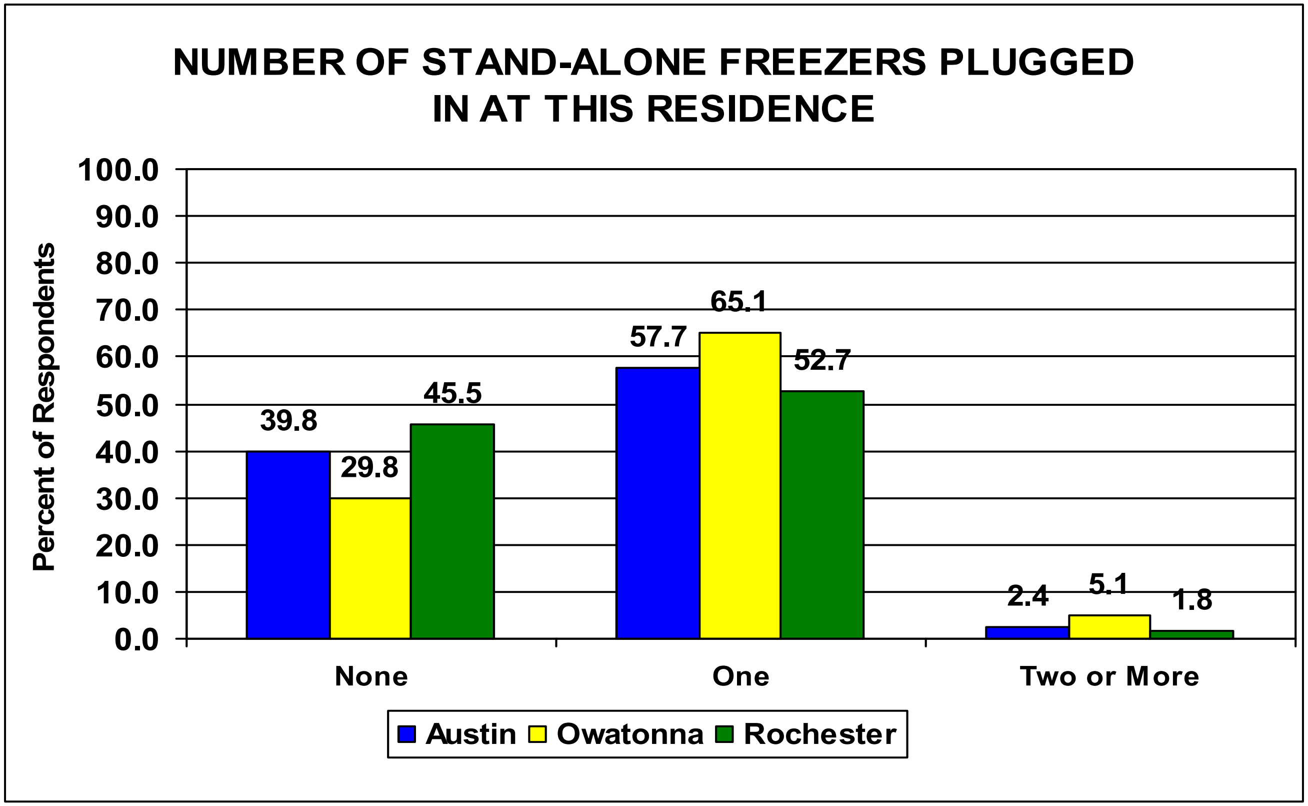
- The largest percentage of refrigerators and top-bottom models, medium-sized and frost free.

Key Findings - Refrigerators



- More than 90% indicated that Refrigerator 1 had been replaced in the last 5 years.

Key Findings - Stand-Alone Freezers



- Over half of households have one or more stand-alone freezers.

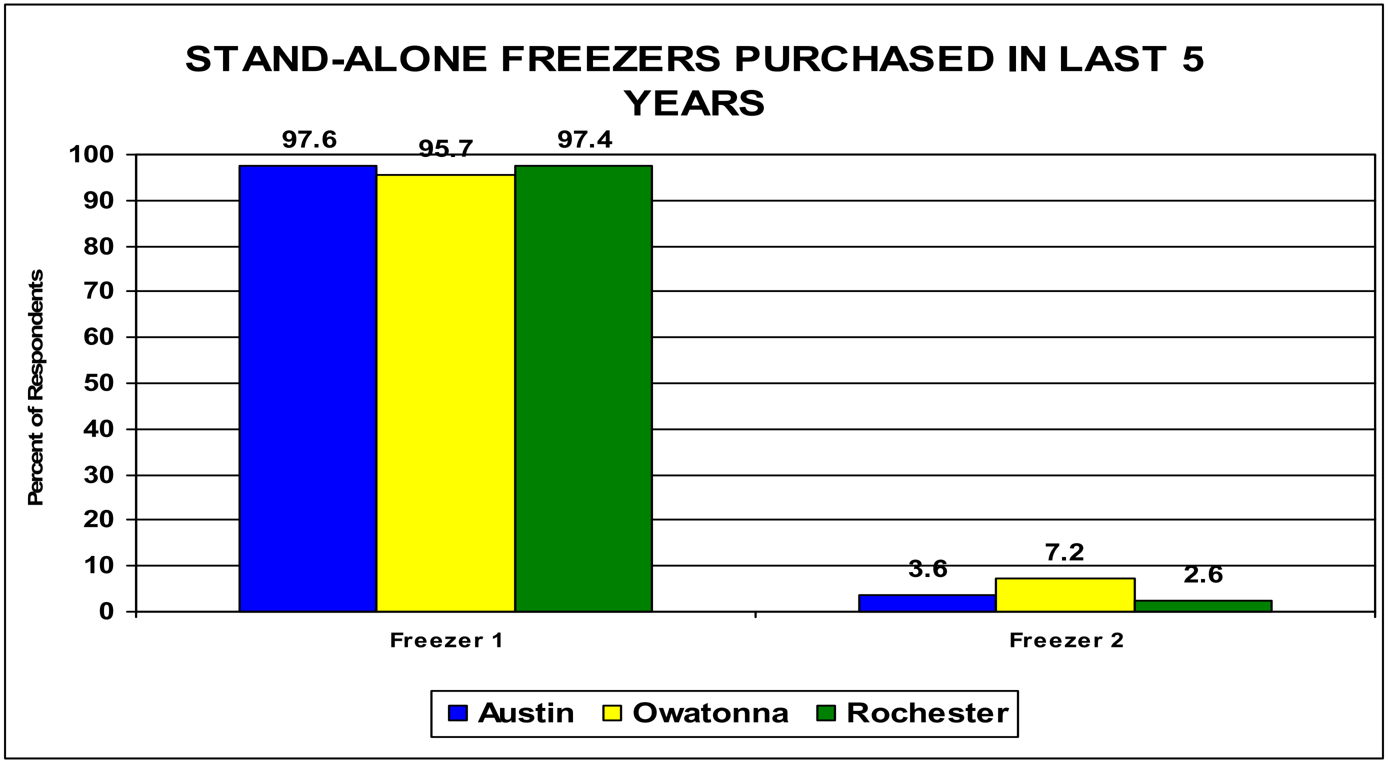
Key Findings - Stand-Alone Freezers

Characteristic	Overview of Stand-Alone Freezers*					
	Austin		Owatonna		Rochester	
	No. 1	No. 2	No. 1	No. 2	No. 1	No. 2
Style: Upright	44.5%	25.0%	42.3%	16.7%	47.2%	37.5%
Chest	55.5%	75.0%	57.6%	83.3%	52.8%	62.5%
Size: Very Small (<10cu. Ft)	15.9%	9.1%	13.5%	21.7%	13.5%	22.2%
Small (11-15 cu. ft.)	33.0%	27.3%	31.1%	34.8%	31.8%	33.3%
Medium (16-20 cu.ft.)	37.9%	18.2%	38.3%	39.1%	39.3%	44.4%
Large (21-25 cu. Ft.)	12.6%	45.5%	15.6%	4.3%	14.2%	0.0%
Very Large (over 25 cu. Ft)	0.6%	0.0%	1.5%	0.0%	1.1%	0.0%
Defrost: Automatic (Frost Free)	28.9%	25.0%	28.4%	12.5%	30.7%	50.0%
Manual	72.1%	75.0%	71.6%	87.5%	69.3%	50.0%

- Freezer 1 more likely to be upright, but freezer 2 is more likely to be larger.

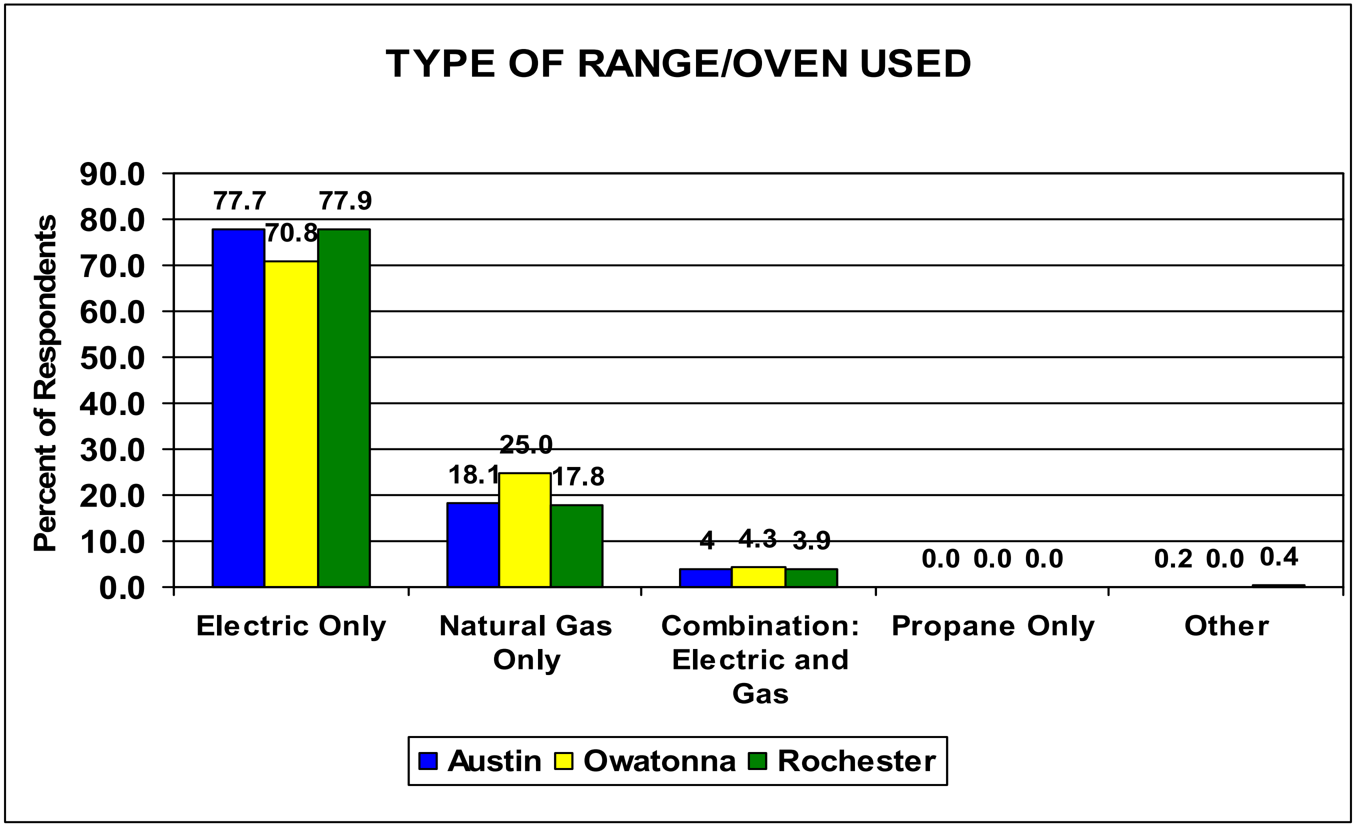
MVP

Key Findings - Stand-Alone Freezers



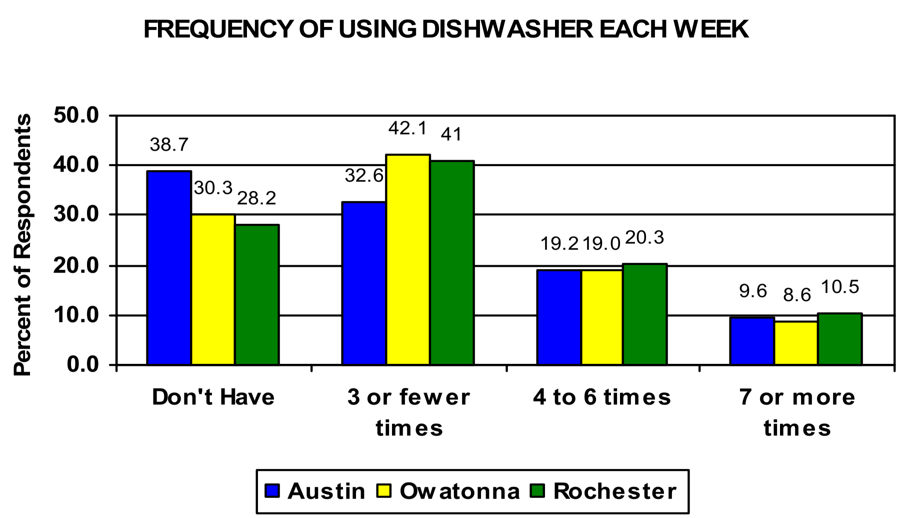
- More than 90% indicated that Freezer 1 had been replaced in the last 5 years.

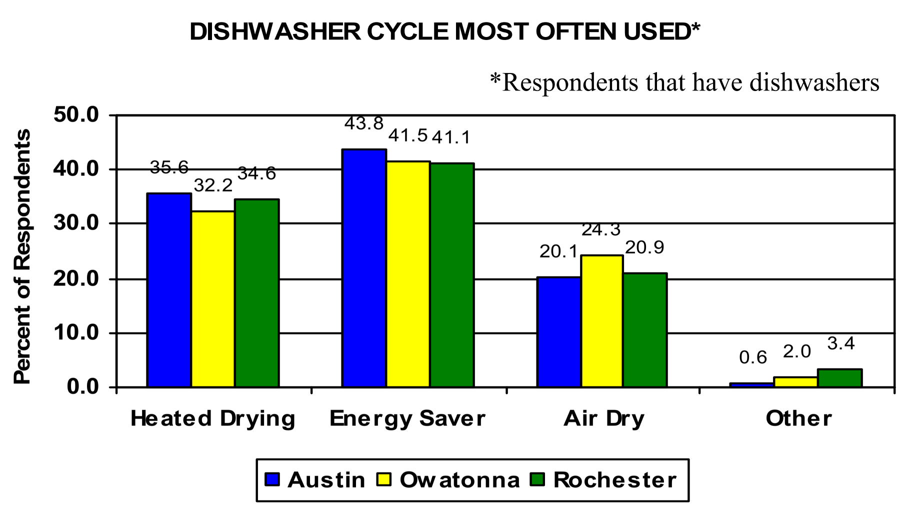
Key Findings - Food Preparation



- Electric ranges are prevalent.

Key Findings - Food Preparation

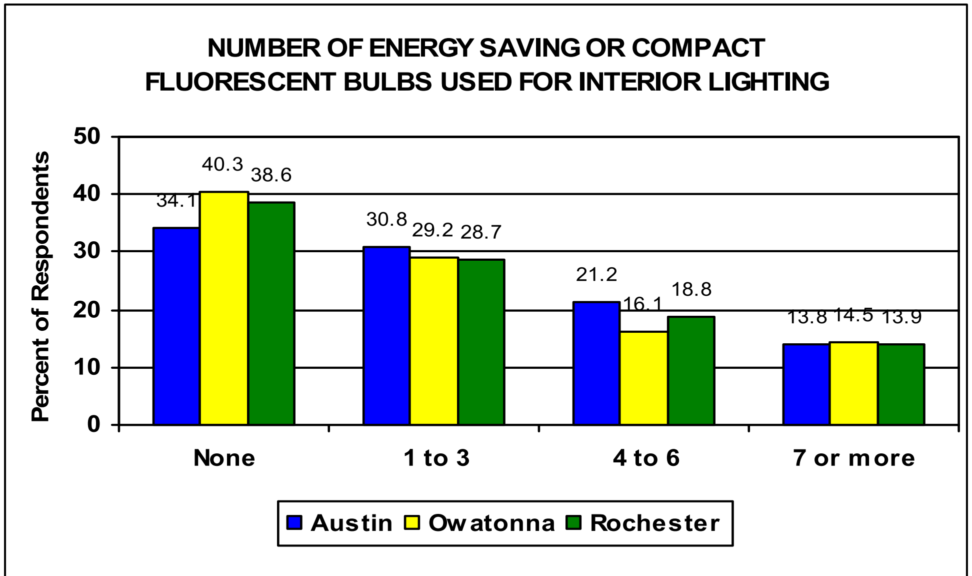


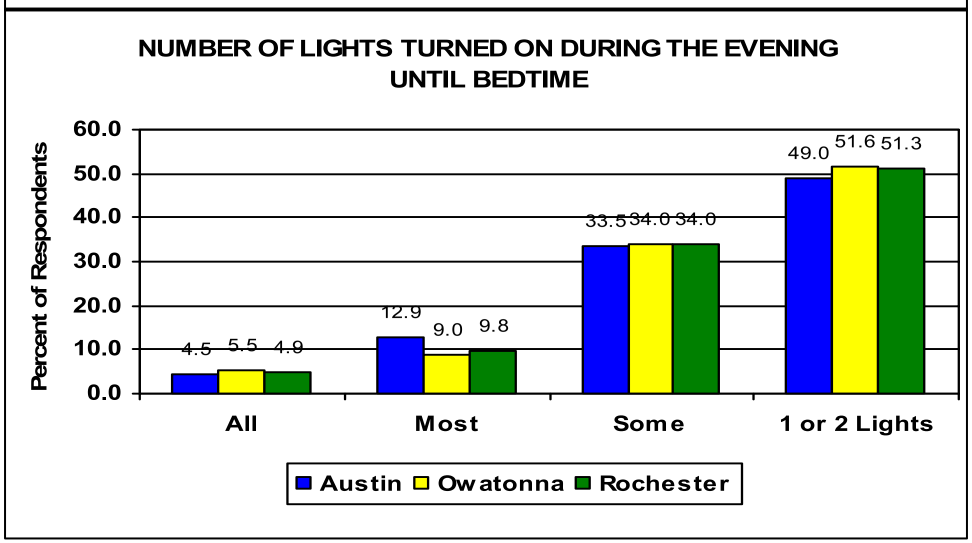


- At least one-fourth don't have a dishwasher.

- Energy saving cycle used slightly more than heated drying.

Key Findings - Lighting

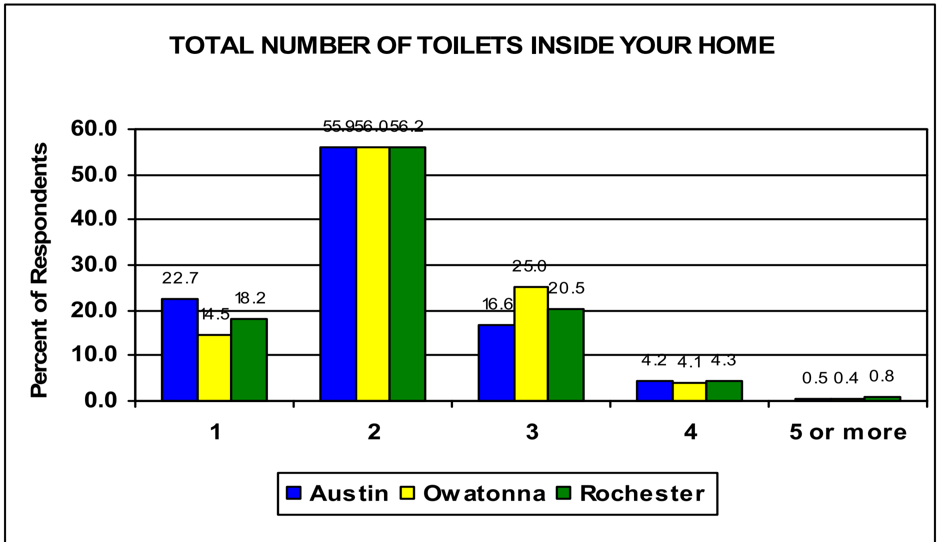


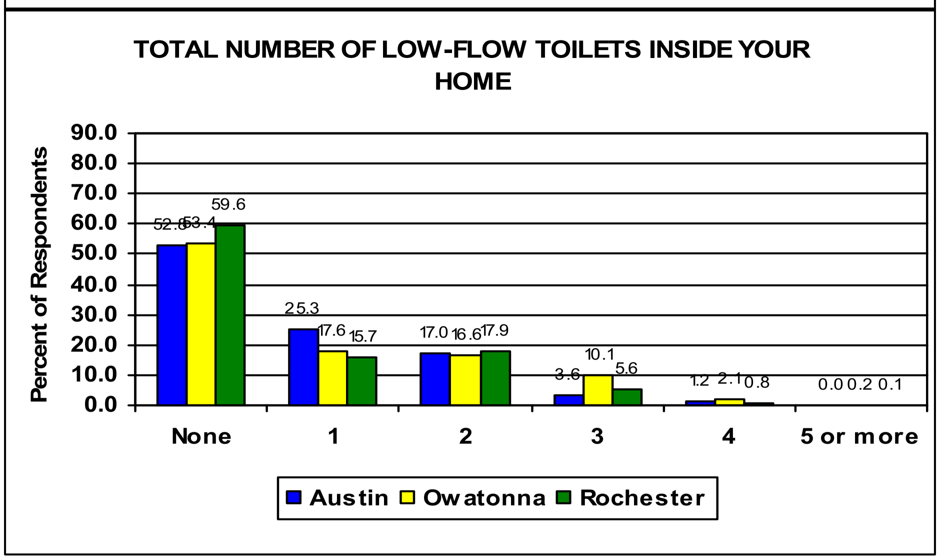


- The majority of households have at least one compact fluorescent bulb.

- The largest percentage indicated that 1 or 2 lights are turned on in the evening.

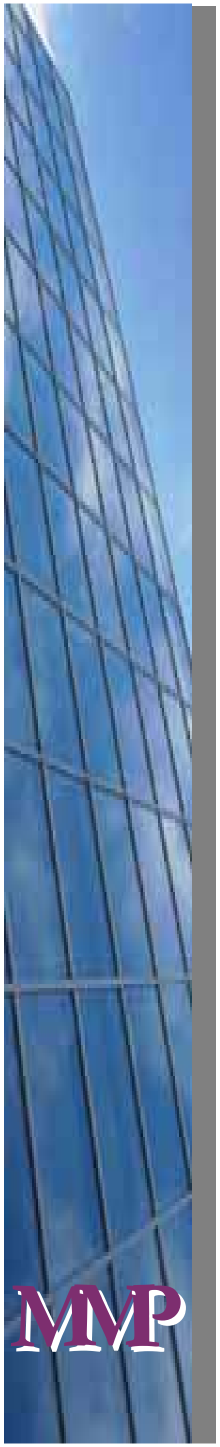
Key Findings - Water Usage/Conservation





- Two toilets are common.

- A majority of households have no low-flow toilets.



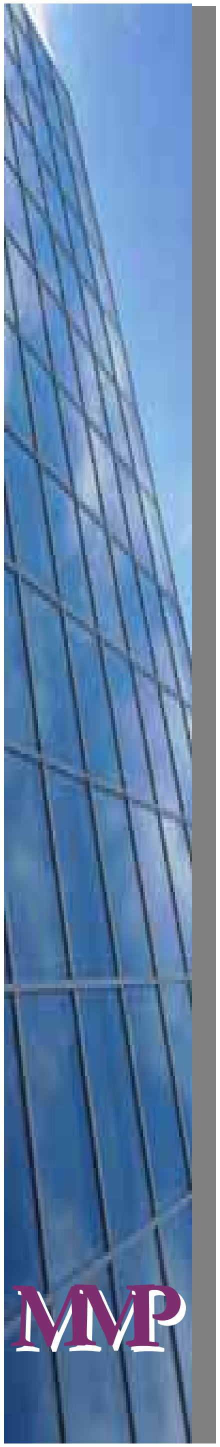
Recommendations - Residential

- Overall, residential customers do not clearly see the benefits of energy/load conservation management and the utilities will need to do more to promote and educate customers on the value.

- About half of residential customers indicated that some water conservation measures had been taken. Opportunities exist for the utilities to gain more participation.

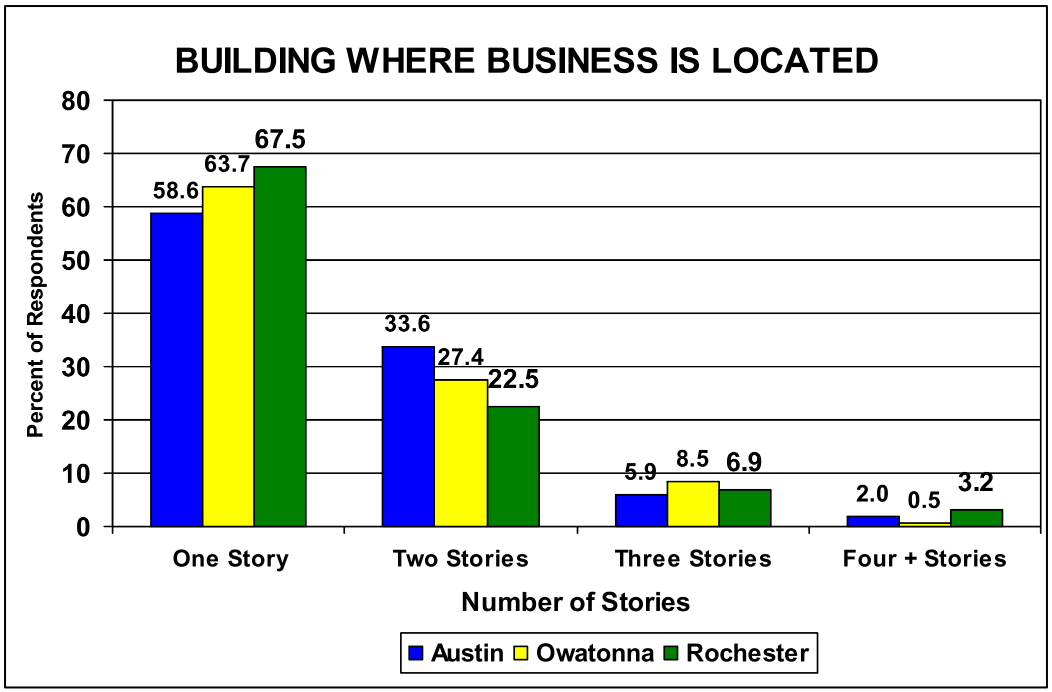
- The percentage of refrigerators and freezers purchased in the last five years seems unusually high. Even if the data is incorrect, the opportunity for DSM programs for this technology are limited.

- Lighting application of CFL technology shows good initial results with more than half using these bulbs. The utilities could expand this program to continue to increase application of this efficient technology.



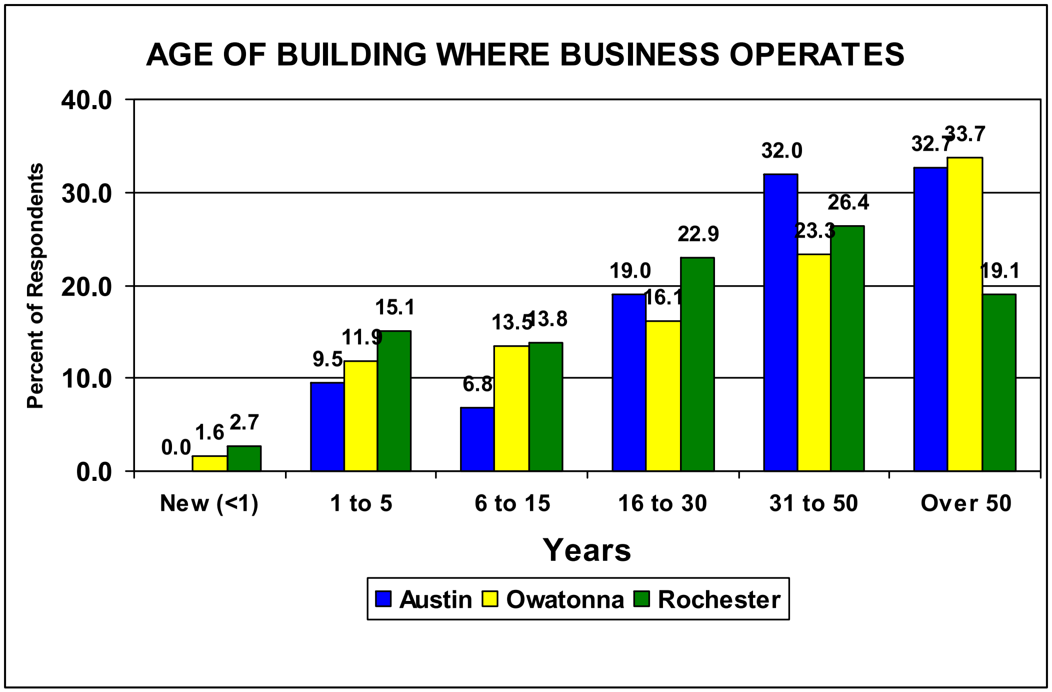
Summary of Findings: Small Commercial & Industrial Customers

Building and Firmographics



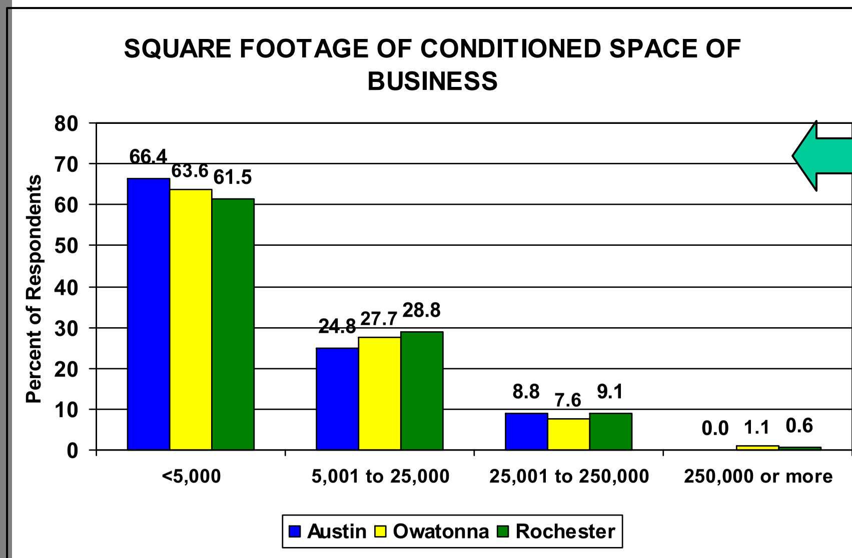
The majority of businesses are located in one story buildings.

Building and Firmographics - continued



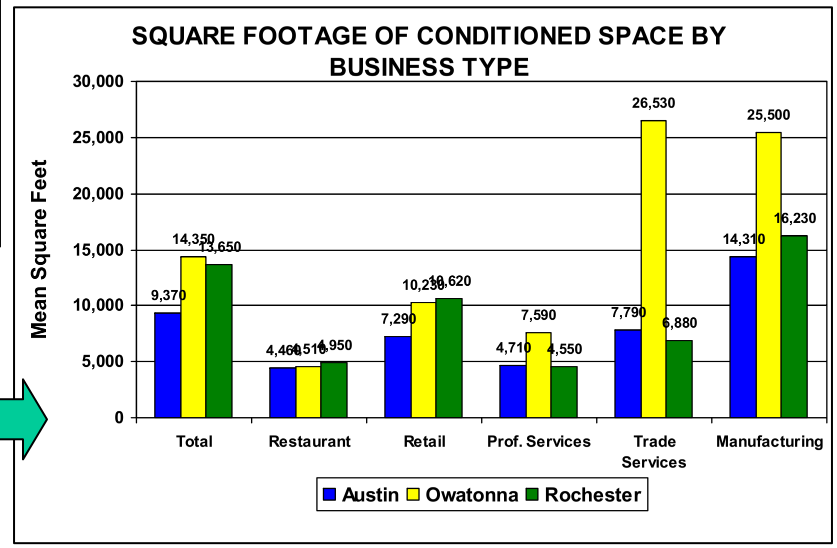
In general, buildings are old.

Building and Firmographics - continued

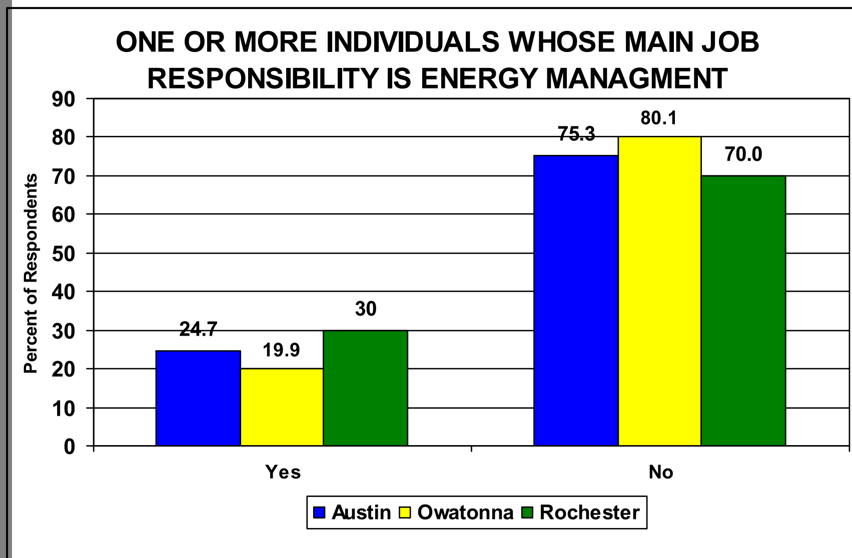


The majority of businesses occupy a conditioned space of less than 5,000 square feet.

However, as would be expected, size varies by type of business.

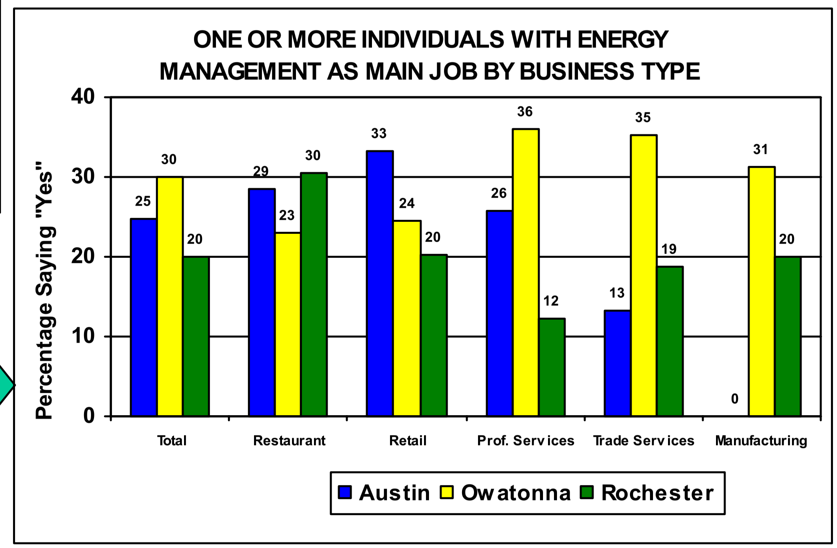


Building and Firmographics - continued

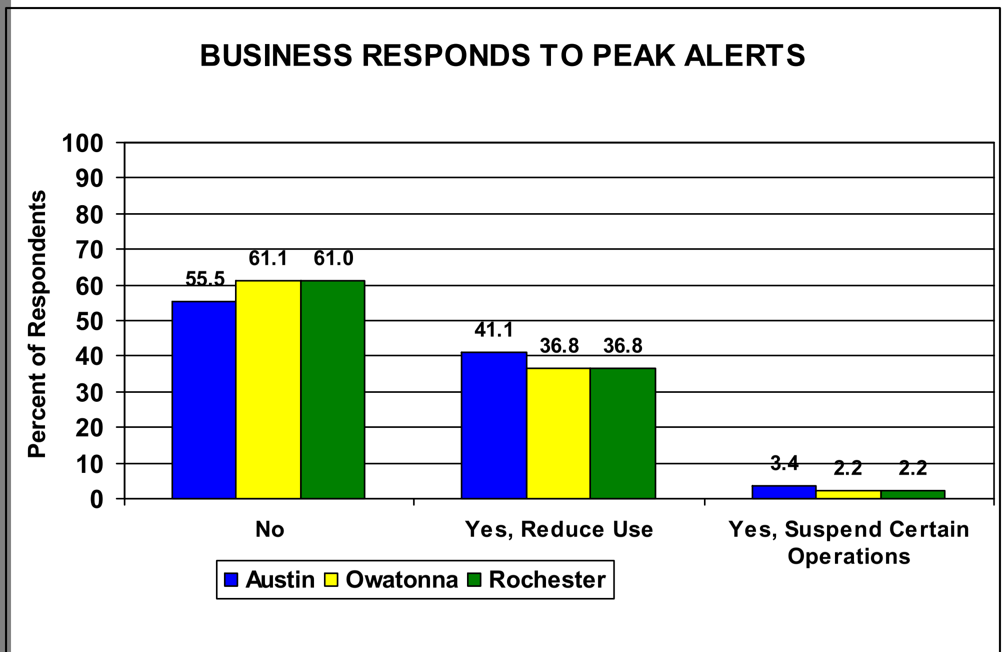


A minority of businesses have energy management.

Percentage varies by type of business

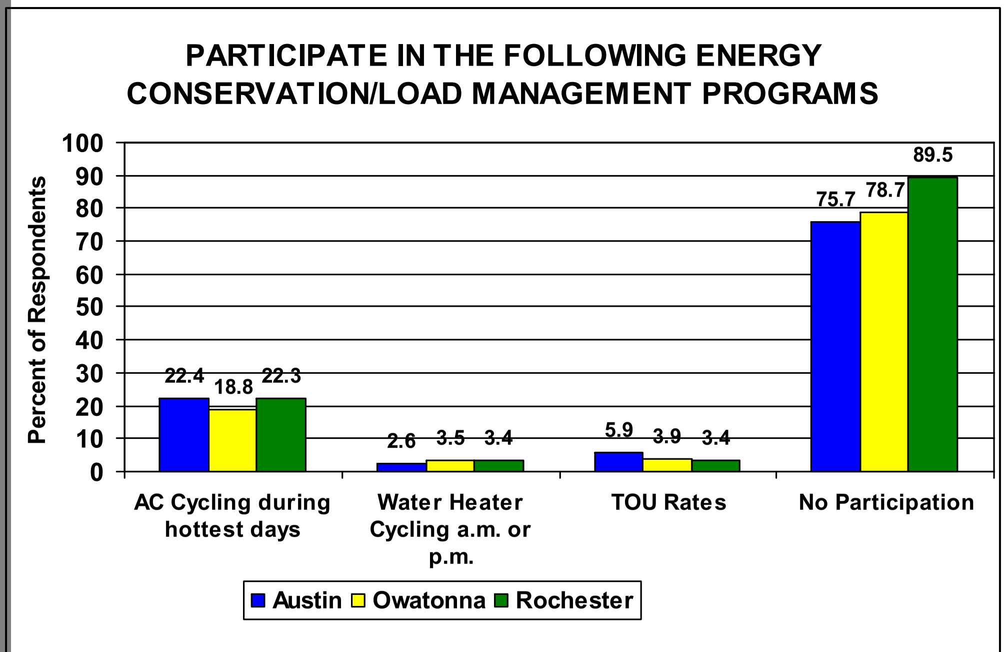


Building and Firmographics - continued



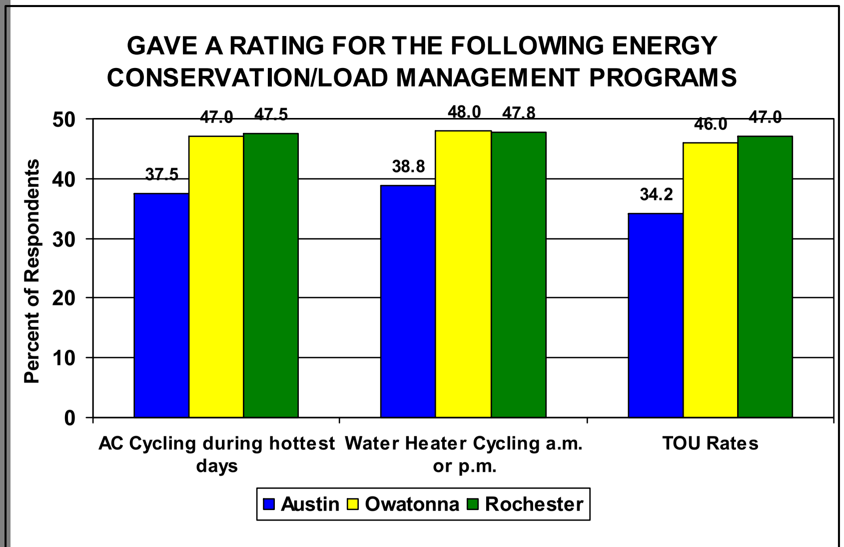
The majority of respondents indicated that they did not respond to peak alerts.

Building and Firmographics - continued



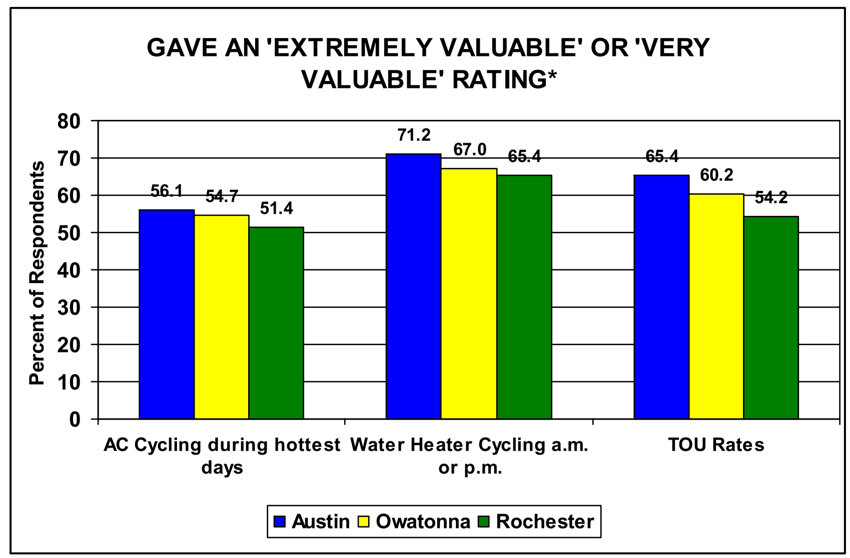
At least three-fourths do not participate in any of the three conservation load/management programs.

Building and Firmographics - continued



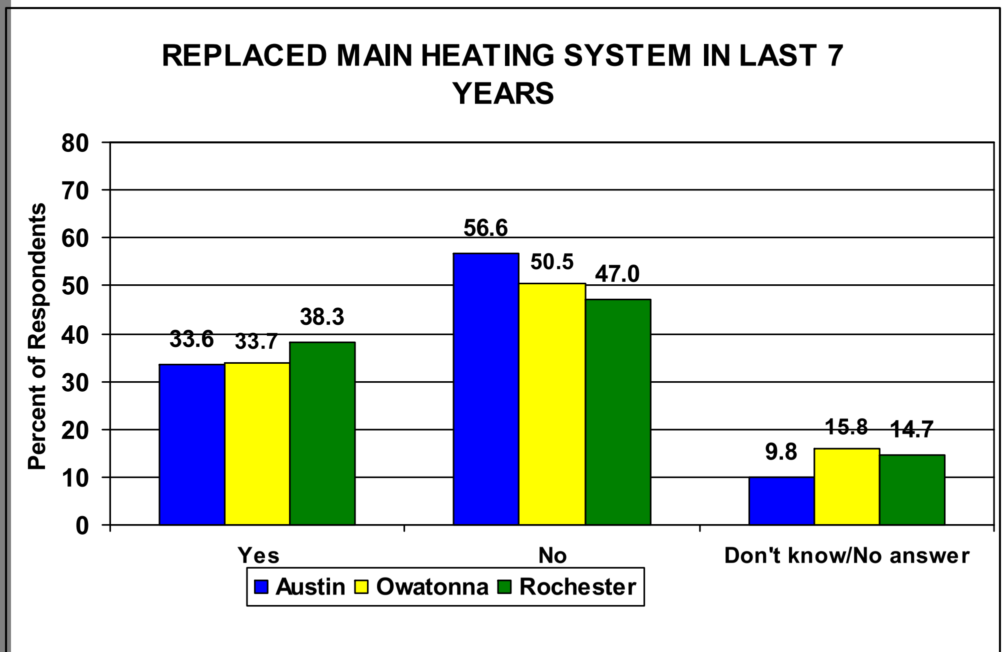
Only a little more than one-third of Austin respondents and just under a half of the Owatonna and Rochester respondents chose to rate the energy conservation/load management programs.

Of those who rated programs, water heater cycling was rated most valuable, followed by time-of-use rates and AC cycling during the hottest days.



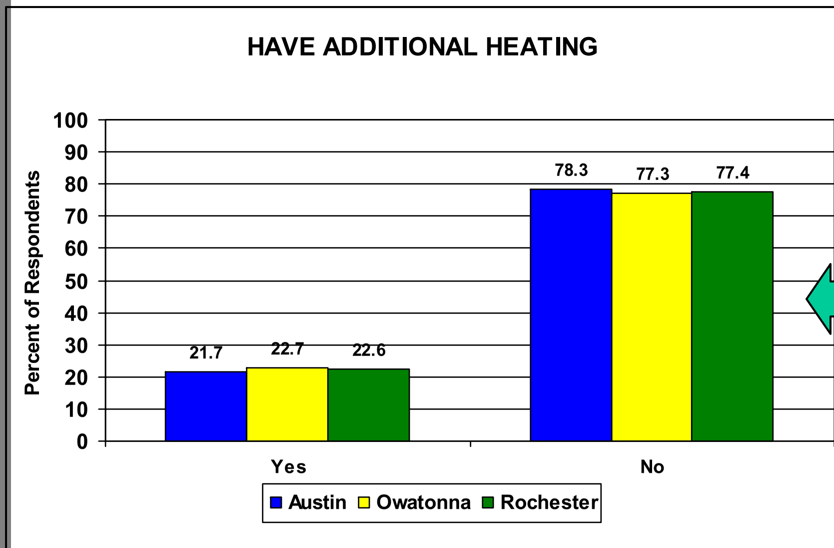
*Includes participants and non-participants. Too few participants gave a rating to show them separately.

Heating - continued



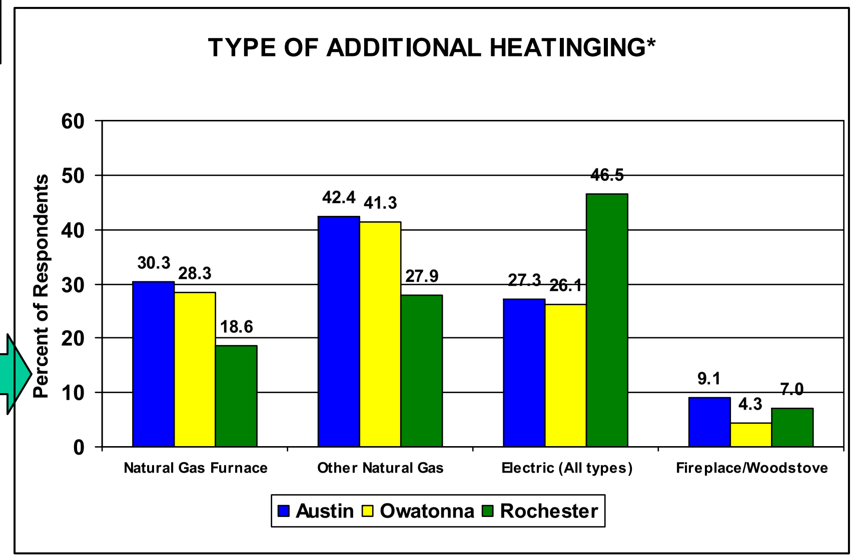
Just over a third replaced their main heating system in the last seven years.

Heating - continued



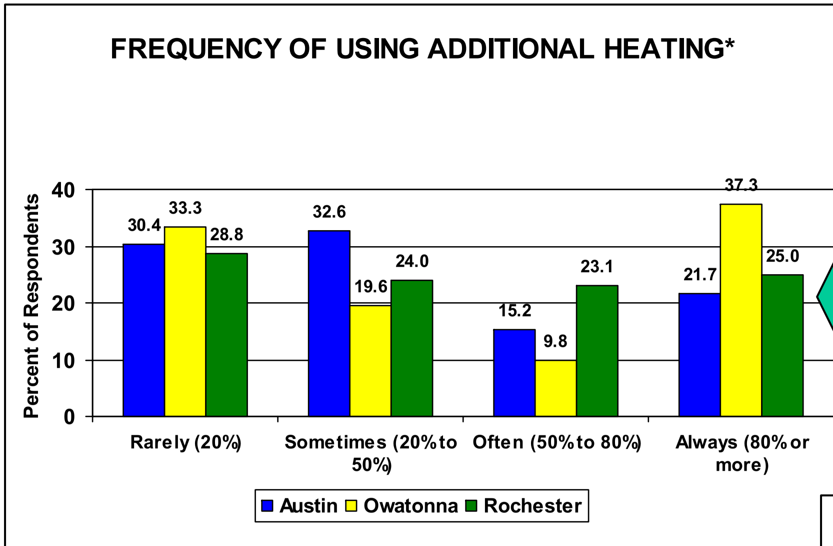
Just over one-fifth of businesses have some type of additional or supplemental heating.

While natural gas fueled additional heating is prevalent, electric heating has a larger percentage compared to main heating systems (particularly in Rochester).



*Respondents that have additional heating.

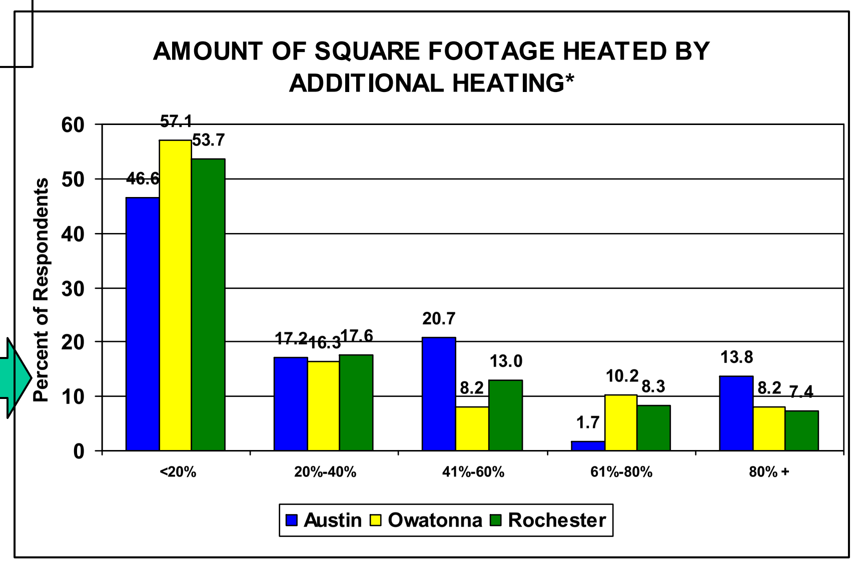
Heating - continued



*Respondents that have additional heating.

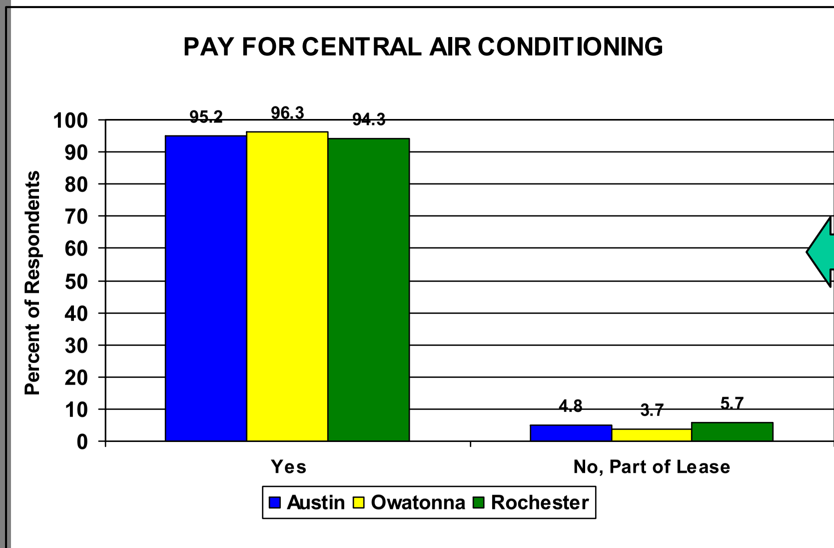
A larger percentage of Owatonna businesses indicate that they use their additional heating more than 80% of the time in Winter.

Additional heating covered less than 20% of their total square footage.

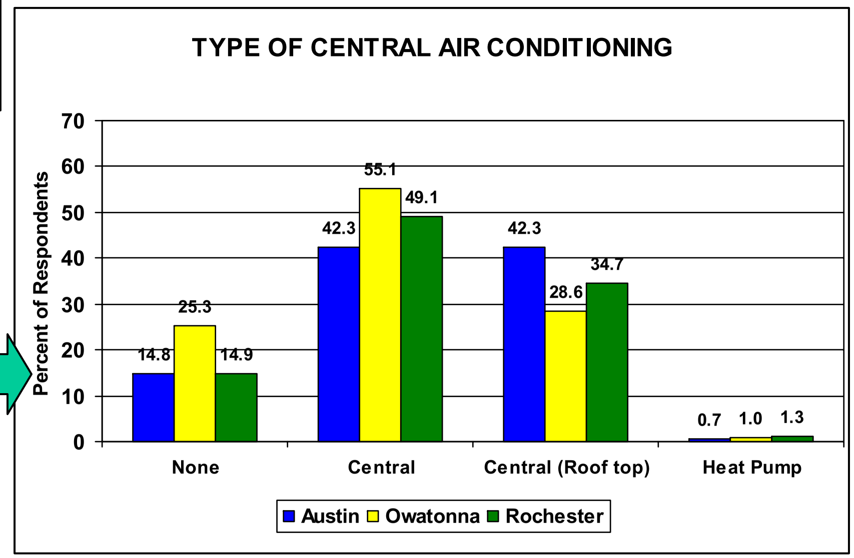


*Respondents that have additional heating.

Air Conditioning

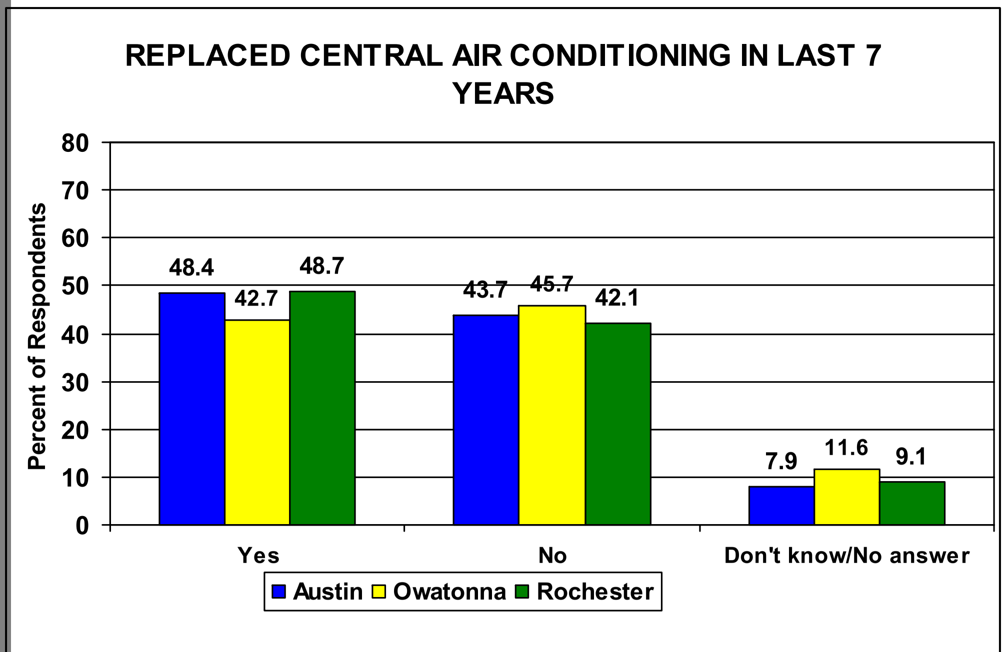


Businesses pay for central air conditioning.



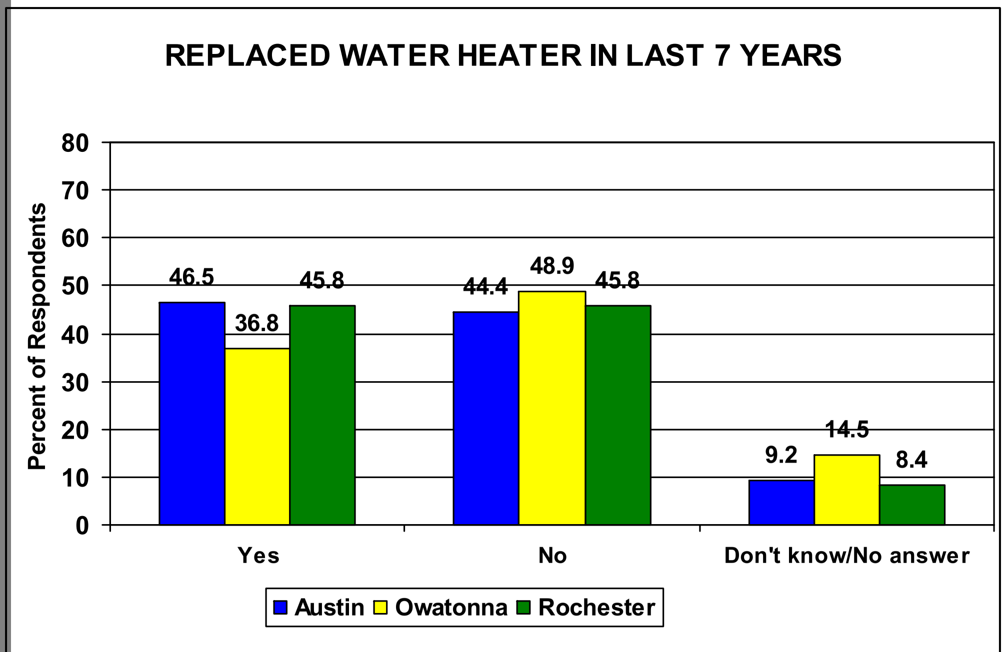
More Owatonna businesses reported having no central air conditioning. Few businesses report having heat pump systems.

Air Conditioning - continued



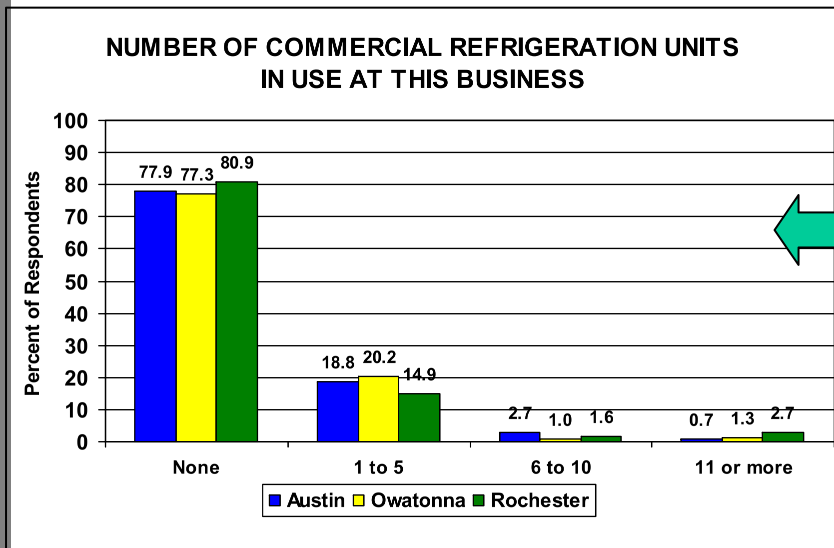
Just under one-half replaced their central air conditioning system in the last seven years.

Water Heating - continued



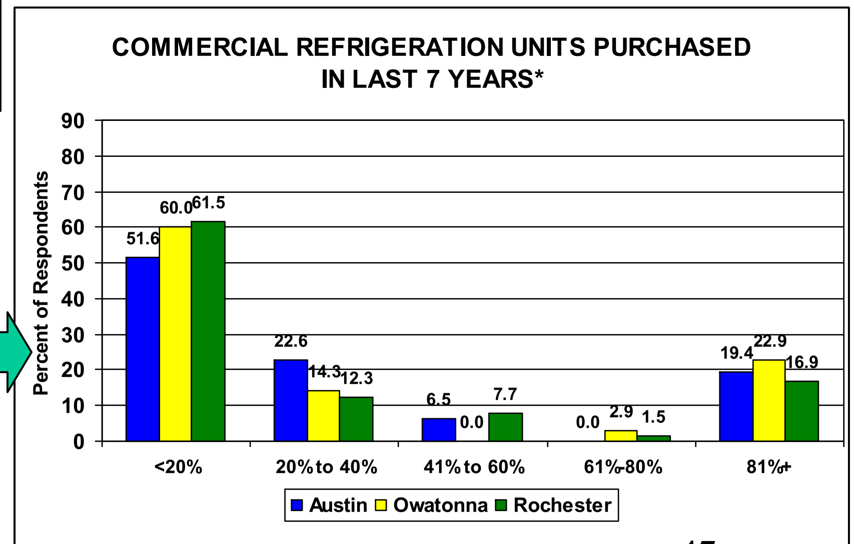
Just under one-half replaced their water heater in the last seven years.

Refrigerators - continued



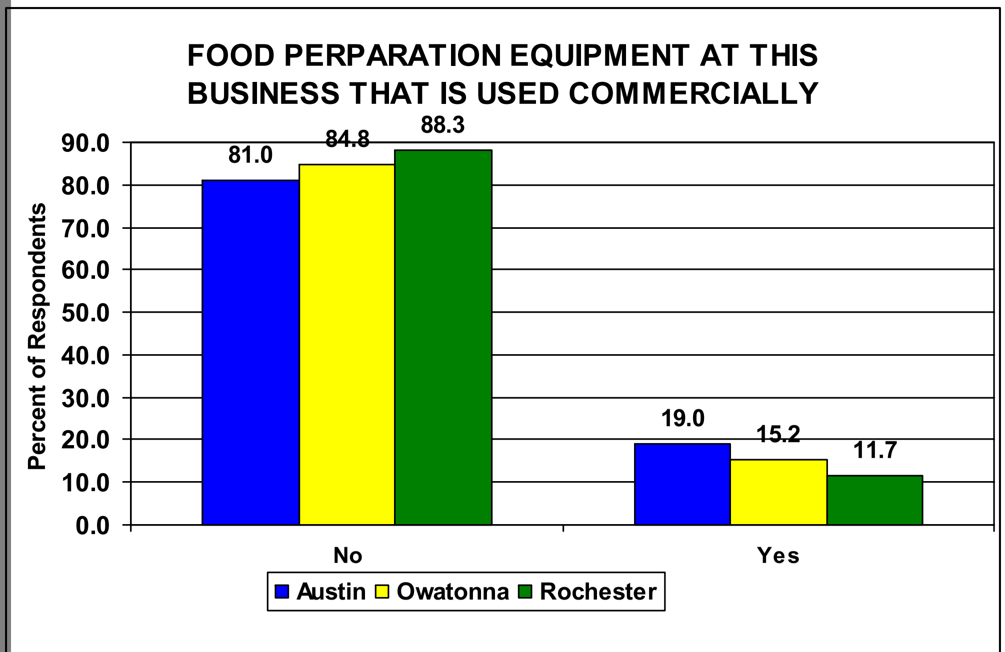
More than three-fourths indicated they had no commercial refrigeration units.

The majority indicated that less than 20% had been purchased in the last 7 years.



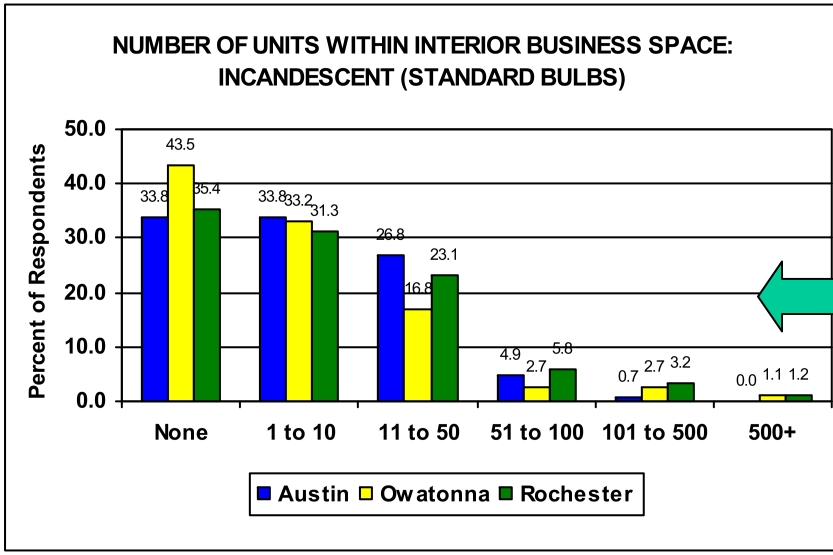
*Businesses that have commercial refrigeration units

Food Preparation

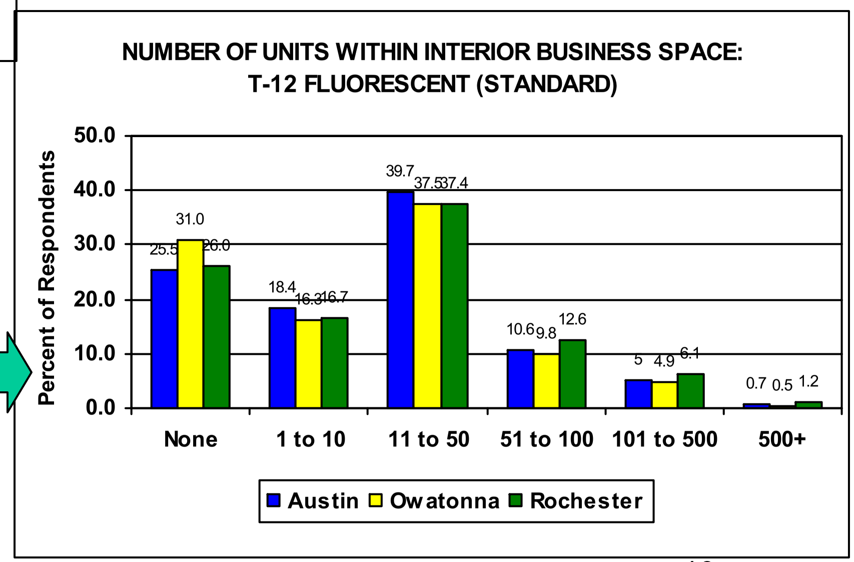


Less than 20% indicated that they have food preparation equipment that is used commercially.

Lighting

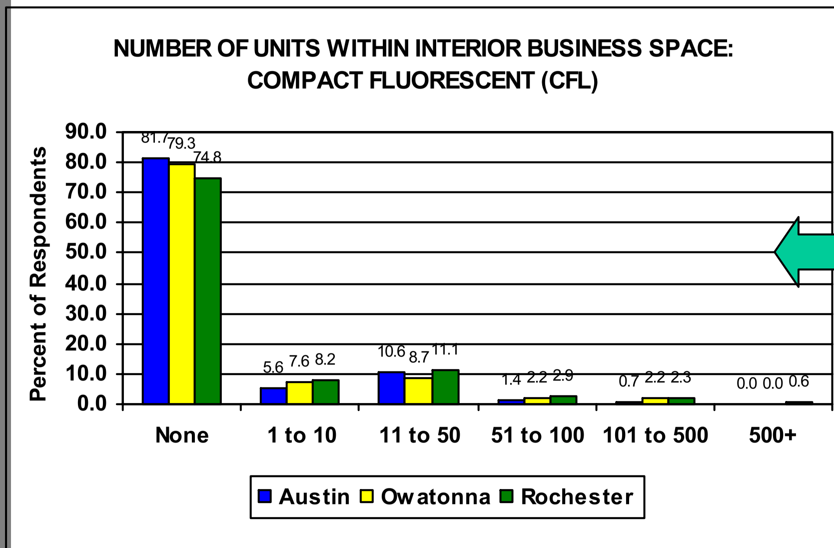


More than half indicated that their business has some incandescent bulbs. The largest percentage have 1 to 10 bulbs.

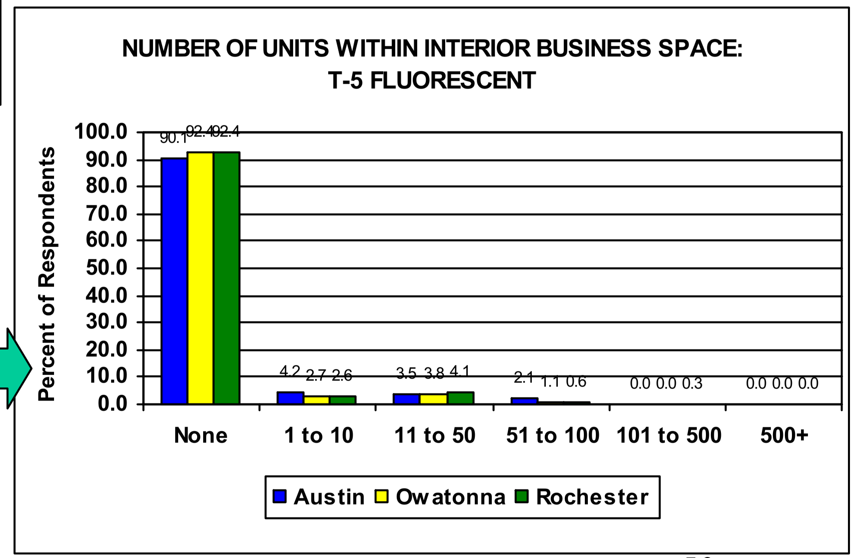


About three-fourths of businesses have T-12 Fluorescent bulbs. The largest percentage indicate having 11 to 50 bulbs.

Lighting - continued

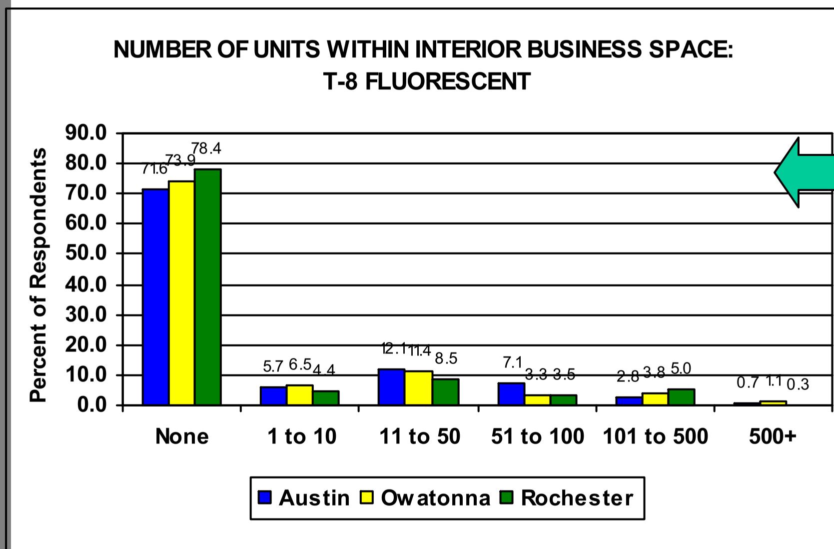


About one-fourth of Rochester and 20% of Austin and Owatonna businesses have some compact fluorescent. The largest percentage have 11 to 50 bulbs.



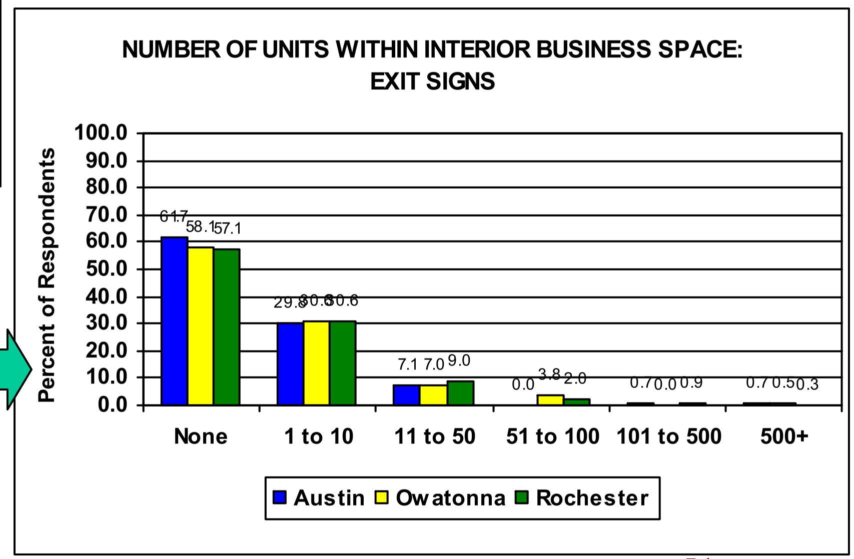
Less than 10% of businesses in all AOR Utilities indicated that they have T-5 Fluorescent bulbs.

Lighting - continued

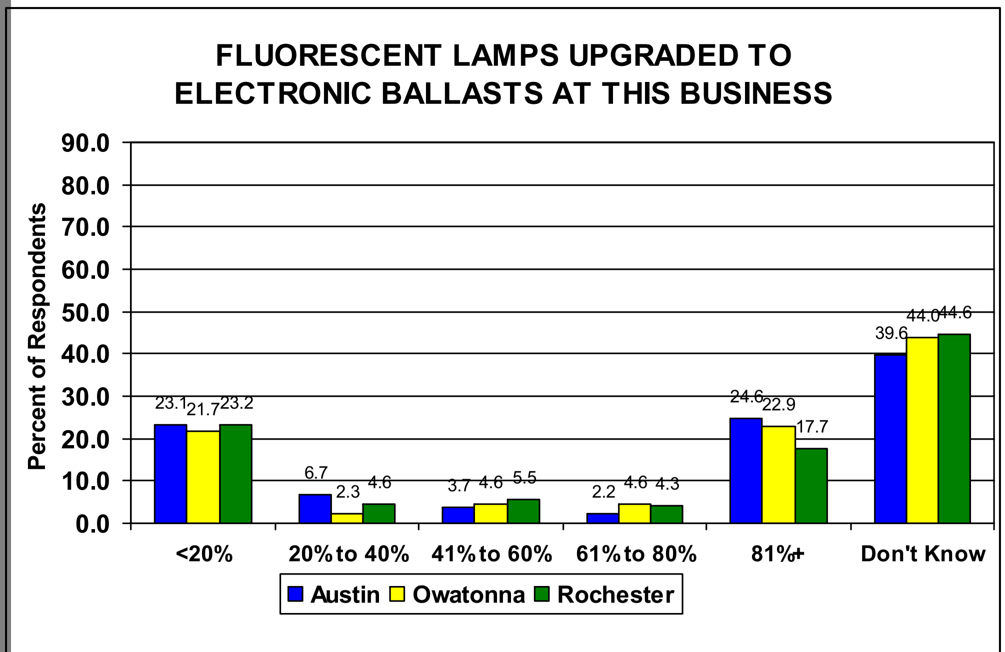


Between 20% and 30% of have some T-8 fluorescent units. The largest percentage have 11 to 50 bulbs.

Around 40% of businesses indicated that they have Exit Signs. The largest percentage have 1 to 10 signs.



Lighting - continued



The largest percentage didn’t know whether their fluorescent bulbs had been upgraded to electronic ballasts or not.

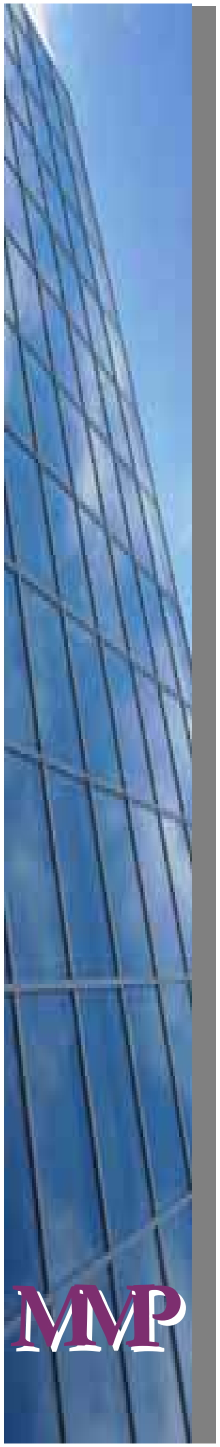
Other Equipment - continued

Number of Pieces	Overview of Office Equipment*			
	Rochester			
	Printers	Personal Computers	Copiers	Scanners
None	17.3%	15.2%	20.7%	52.0%
1 to 5	65.6%	51.4%	75.1%	47.5%
6 to 10	11.3%	17.6%	3.4%	0.3%
10 or more	5.8%	15.7%	0.8%	0.3%

*Percentage of all businesses

The table provides an overview of the number of pieces of office equipment for Rochester businesses. Personal computers have the highest saturation (85%) followed by printers (83%) and copiers (79%). About 48% indicated having one or more scanners.

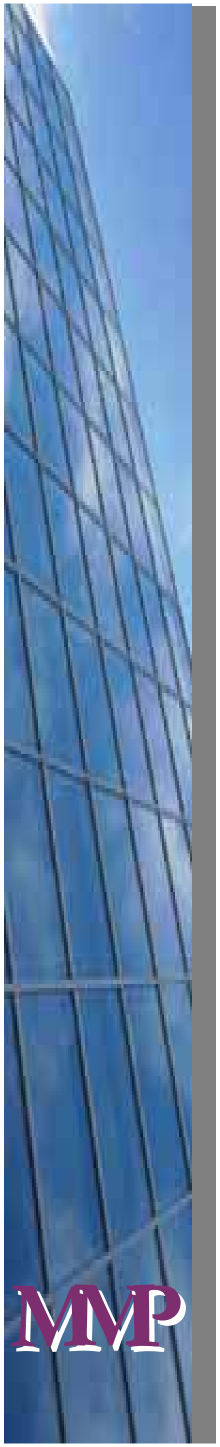
MMP



Summary of Findings:
Large Commercial & Industrial Customers

Note 25 Respondents - Indicators Only

Austin = 4 Owatonna = 14 RPU = 7



Building & Firmographics

The types of operations responding to study are:

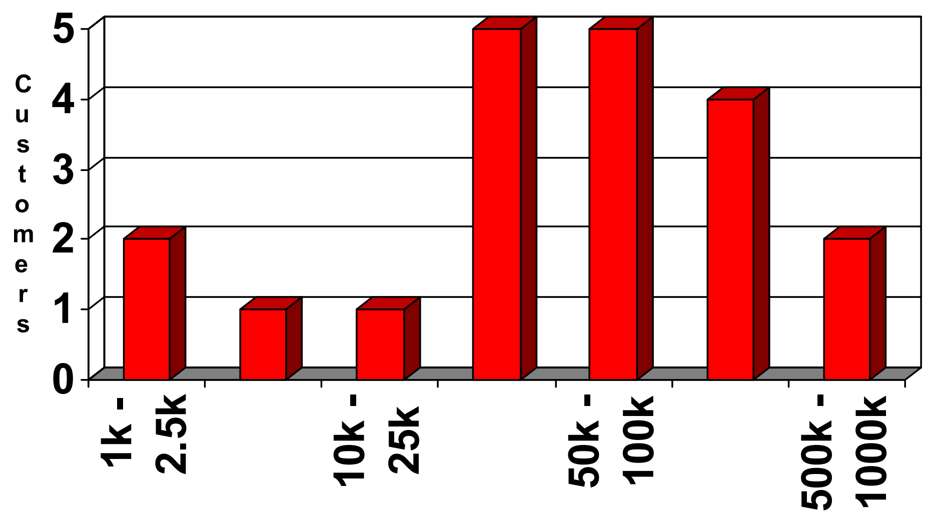
- Warehousing & Storage
- Health Care
- Food Processing - 3
- Shipping Containers
- Pet Food Manufacturer
- Steel Fabrication
- Fitness Equipment
- Metal Products
- Industrial Manufacturing
- Growing Tomatoes
- Sheet Metal Fabricator

Of these 25 customers all but two owned their facilities.

- Large Retail
- Retirement Nursing Care
- Laundry
- Hotel/Office/Condo
- Ice cream and Frozen Desserts
- Church - 2
- School
- Church & School
- Ice Arena/Convention Center
- Glass Fabrication
- Large Grocery

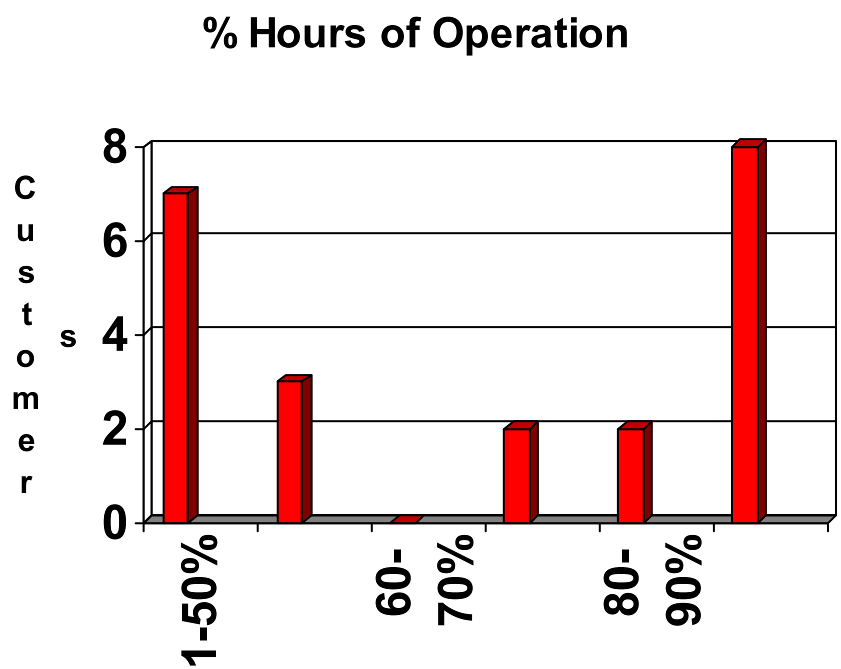
Building & Firmographics

Square Footage of Conditioned Space



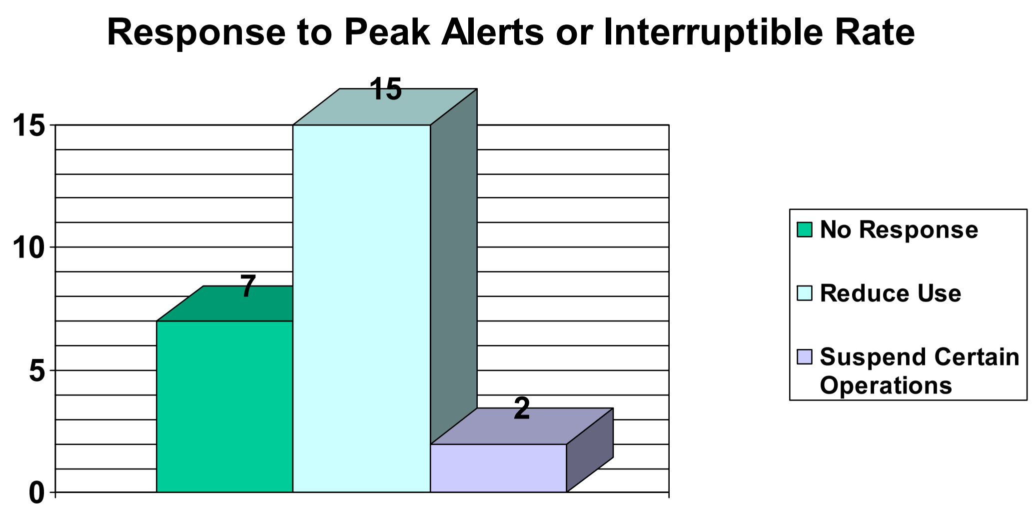
Half of the respondents were in facilities between 25,000 sq. ft. to 100,000 sq. ft.

Building & Firmographics

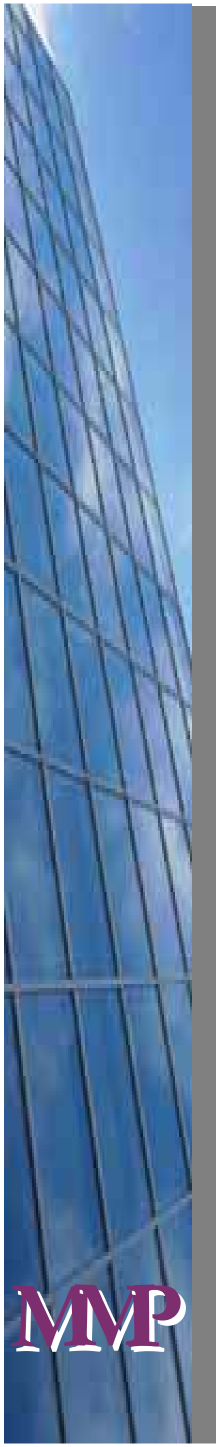


This table shows that almost half of this customer group operates 24/7 hours per week.

Energy & Water Management



70% of this customer group is responding in some manner to peak alerts or interruptible rates. There is no correlation to size of load or type of customer seen in the data.



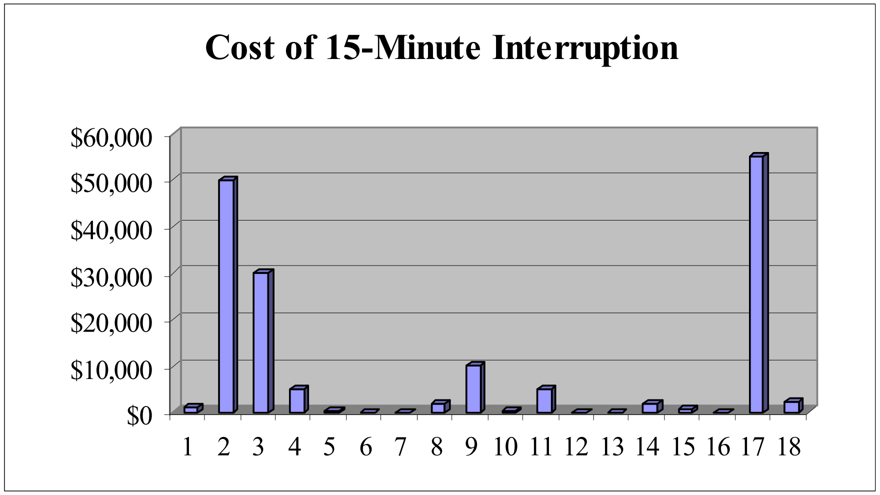
Energy & Water Management

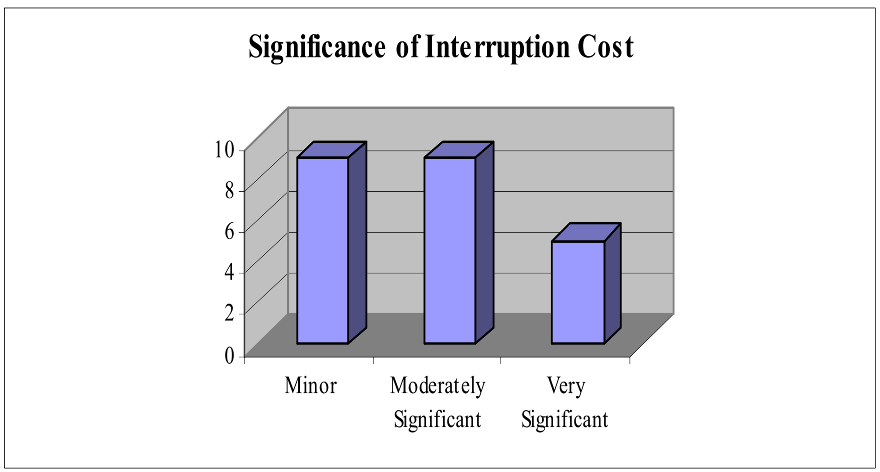
Capabilities/Knowledge on Site

High voltage electrical repairs	11	
Low voltage electrical work	19	
HVAC maintenance	14	
Mechanical maintenance		24
Plumbing maintenance		20
Full-time energy manager	4	
Part-time energy manager	7	

Skill levels usually follow size of operation. The large manufacturers have the highest skill levels. However it should be noted that only 4 customers have full time energy managers and 7 have part-time.

Energy & Water Management





As illustrated in the 18 responses some customers consider an outage of minor importance and not much value, to others where the cost can be up to $55,000 from a 15-minute interruption.

Energy Services - cont.

Billing Services	Currently Offered by Utility	Customer Currently Participating	Mean Value Score
1. Consolidated billing of multiple facilities	AOR	3	2.16
2. Monthly billing based on a calendar year		**8**	2.84
3. Monthly billing based on a fiscal year		1	2.11
4. Electronic interface for bills, meter reading, payments, electronic mail		**5**	**3.06**
5. Water reliability-based rates adjusted depending on your need for reliable or constant supply		3	2.83
6. Electricity reliability-based rates adjusted depending on your need for reliable or constant supply		3	**3.22**
7. Time of use rates at various time periods during the day and/or on weekends	AOR	3	2.83
8. Real time pricing rate that varies each hour to allow you to operate during the periods at low cost.		1	2.84
9. Direct access to your account information on the Internet		1	2.95

For the "Billing Services" there were no items of high interest to everyone.

Energy Services - cont.

Energy Evaluation Services	Currently Offered	Currently Participating	Mean Value Score
1. Graphic interval analysis of your energy usage pattern	AOR	3	3.1
2. Assistance in budgeting and forecasting energy usage	AOR	1	**3.21**
3. Sub-metering for electric processes	**OR**	**5**	3.05
4. Sub-metering for water processes		3	3.1
5. Sub-metering for gas processes		3	3.05
6. Tele-metering to a central monitoring location off-site		1	2.2

Energy evaluation services have some interest and some people getting these services elsewhere. Assistance in budgeting and forecasting usage has the highest score of this group of services.

Energy Services - cont.

Energy Evaluation Services cont.	Currently Offered	Currently Participating	Mean Value Score
7. Process energy audits	AOR	2	3.05
8. Metering input for EMS (energy management systems)	AOR	1	2.80
9. EMS reviews and assistance	AOR	1	2.95
10. GeoExchange (geothermal) heating and cooling consulting	AOR	0	2.38
11. Access to real-time energy consumption data		2	**3.15**
12. Total efficiency assessment covering energy, productivity and waste management	AOR	1	**3.19**

The balance of the energy evaluation services show that real-time energy consumption data has some interest as well as total efficiency assessments. Still these have limited interest.

MMP

Energy Services - cont.

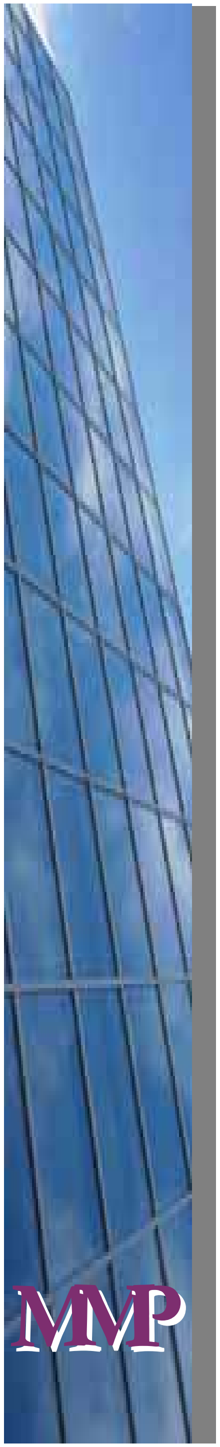
Energy Information & Management Services	Currently Offered	Currently Participating	Mean Value Score
1. Assistance in troubleshooting and resolving power quality problems	AOR	3	**3.43**
2. Education/training seminars on various technologies	AOR	3	**3.33**
3. Energy utility provided management of energy services such as fuel procurement, and boiler or generator operations	AOR	1	3.11
4. Technical information on new technologies related to your industry	AOR	1	**3.42**
5. Assistance in identifying suppliers of various technologies	AOR	1	3.1
6. Quarterly newsletters to provide updates on technologies, grants, new services, etc.	AOR	3	**3.3**
7. Turn-key engineering services for installation of efficiency improvements	AOR	1	3.11
8. Energy utility provided power quality monitoring 3.30 3.11 3.11 3.00 3.63	AOR	1	3.11
9. Energy utility provided environmental consulting services on generator permitting	OR	1	3
10. Energy utility provided services on lamp recycling	AOR	3	**3.63**

Energy Information Services is the only grouping of services in the survey where all offerings received a 3 or greater average rating.

Energy Services - cont.

Energy Operations Services	Currently Offered	Currently Participating	Mean Value Score
1. Locating customer-owned underground facilities (storage tanks, telephone, water, etc.)	AOR	3	3.15
2. Substation maintenance design, installation and/or maintenance	OR	1	2.53
3. Infra-red scanning of electrical systems and building components	**AOR**	**7**	**3.53**
4. Outdoor security lighting	**AOR**	**6**	**3.50**
5. Testing equipment for analysis of power quality problems	AOR	1	3.05
6. Purchase of power quality equipment from your energy utility		0	2.6
7. Lease transformers (includes maintenance and replacement)		0	2.25
8. Lease small back-up generators for your operations to be located on your site		0	2.53
9. Lease and maintain small back-up generators on your site		0	2.40
10. Buy/lease/rent water heating or HVAC equipment (includes maintenance and replacement)		2	2.65

Energy Operations services has two services with high scores above 3.5 and high participation.



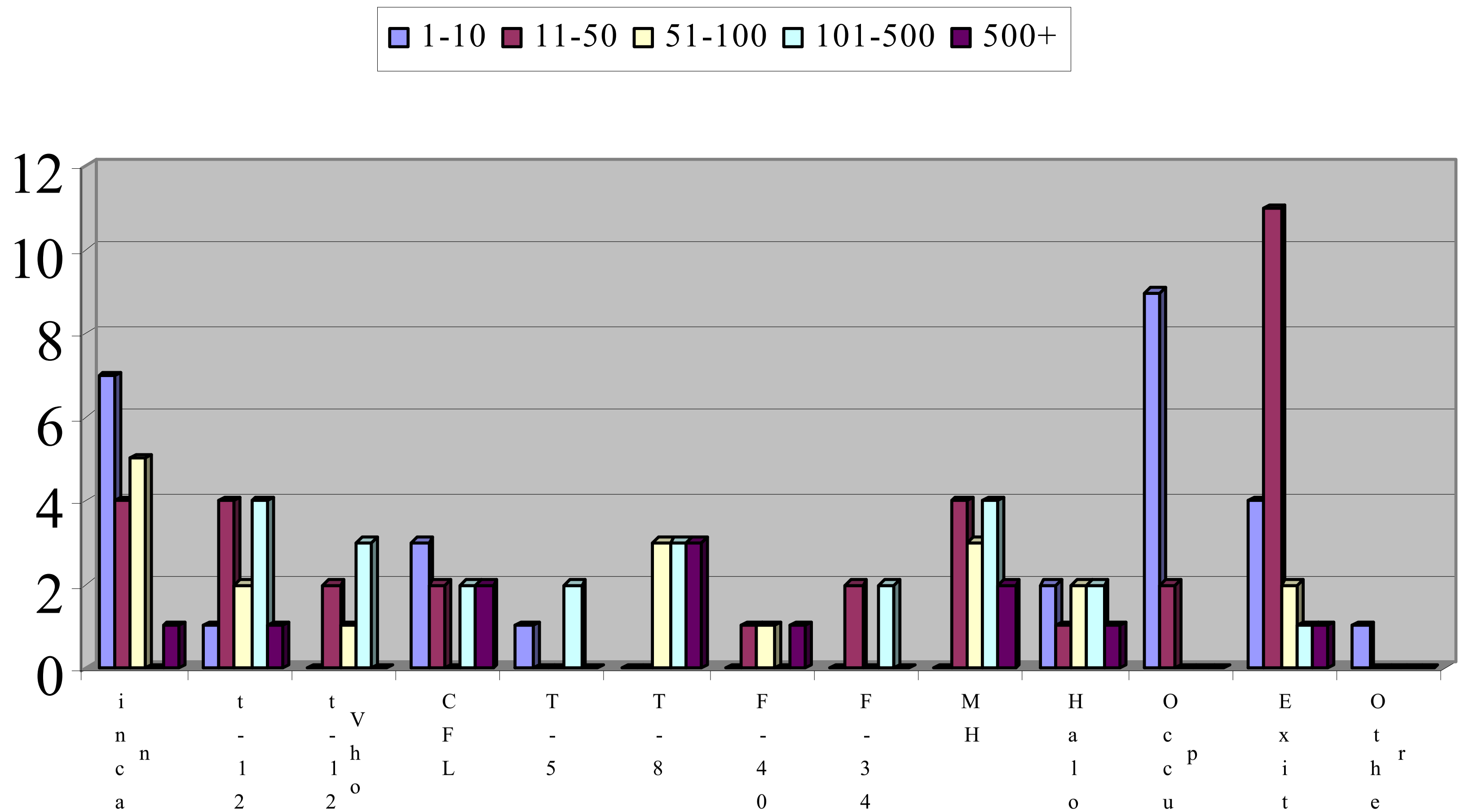
Energy Services - cont.

Energy Operations Services cont.	Currently Offered	Currently Participating	Mean Value Score
11. Maintenance services on HVAC owned by your company		3	2.94
12. Warranty or maintenance agreements for energy equipment and appliances		2	2.74
13. Energy utility provided wiring services within your facilities		0	2.55
14. Energy utility provided back-up generators for outages		0	**3.35**
15 Building maintenance and controls from your energy utility		1	2.68
16. Fuel cells from your energy utility		0	2.35
17. Lighting retrofit and new construction provided by your energy utility	AOR	2	2.94
18. Power factor correction services provided by your energy utility	AOR	1	**3.11**
19. Solar and wind power projects	OR	0	2.6

Continuing on the list of operations services, customers see value in providing back up generators for outages.

Technologies

Lighting



Technologies

Equipment Type	Electric 1-5 units	Electric 6-10	Electric 10+	Gas 1-5	Gas 6-10	Gas 10+
1. Kiln	1	1		2		
2. Medical equipment	1		1	1	1	
3. Well pump	2	1				
4. Fans		3	20			
5. Shop tools	3	4	15			
6. Irrigation pump	1		1			
7. Welding equipment	10	4	5	1		
8. Total motors			24			
9. Motors over 50 horsepower	7	5	6			
10. Motors older than 10 years	5	6	11			
11. Number of rewound motors	3	2	7			
12. Number of variable speed drives	5	4	10			

Every customer responding said they have more than ten motors at their facility. Six of these customers had more than ten motors over 50 horsepower.

Other non-listed equipment included:
- One customer with 6-10 gas paint ovens
- One customer with 6-10 gas engines to run NH4 compressors
- One customer with 10+ electric microwave generators
- One customer with 6-10 35-hour electric compressor motors

Other Technologies

- **Six customers had generators that are used for standby power and emergency lighting when there are outages.**
  - **One of these six also stated they used the generator for outages and peak shaving. This customer also plans on purchasing another generator within two years.**
  - **They sizes of these units are;**
    - **2 units over 100 kW,**
    - **two units between 51-100 kW**
    - **one unit between 10-25 kW.**

Future Energy & Water Use

Future Electric Use - 13 expected to increase.

- **Nine indicated the percentage of change and it ranged from 5% to 20% due primarily to increased business. Two customers indicated a decrease in energy use due to a lighting retrofit and phasing out an old building. The balance indicated no change.**

Gas Use - 12 expected an increase in use from 3% to 30%

- **Again two customers indicated a reduction in use but these were two different customers than the electric reduction and no reasons were provided**

Water Use - 11 expected an increase from 3% to 30%

- **Only one indicated a decrease in use and gave no reason.**

Recommendations

- **In general, small commercial customers do not clearly see the benefits of energy/load conservation management while most larger customers are participating**.

- **Only a small percentage of commercial and industrial customers indicated that water conservation measures had been taken. However, Low-flow showerheads or toilets applications are limited.**

- **There appears to be opportunities for lighting improvements.**

- **For large C&I customers there is interest in some energy services that could be expanded or offered as a new service.** Further research would need to be provided.

- **There appears to be an opportunity for an expanded motor program with the large C&I customers.**

Recommendations - continued

- **Interruptions are significant for some large customers and there appears to be an opportunity to provide backup services or special rates/service to this group.**

All these indicate that AOR Utilities need to do a better job of promoting the benefits to commercial and industrial customers of current energy/demand management programs and there are opportunities to expand or provide new additional DSM services.

Uses of Data

- Forecasting energy use by class
  - Growth of air conditioning - How many newer and more efficient, see change over time
- System demand forecast and facility forecasts
- DSM potential determination
  - Many old refrigerators out there
  - Program interest and opportunity

Thanks!

QUESTIONS

End Use Survey Question Forms for Residential, Commercial & Industrial Customers

RESIDENTIAL CUSTOMER APPLIANCE/EQUIPMENT SURVEY

Instructions: Thank you for your participation. Please check (✓) the appropriate box(s) that corresponds with your answer or write your response clearly in the space provided. **Your answers will remain strictly confidential.**

YOUR HOME AND LIFESTYLE

1. Choose the statement that best describes the building where you live.

1☐ One story single-family house
2☐ Two-story single-family house
3☐ Mobile home
4☐ Other
Apartment/Condo
5☐ High rise (4+ stories)
6☐ Low rise (1-3 stories)
7☐Townhouse or row house (Neighboring units on one or both sides, but not above or below)
1b. If apartment or condo, please indicate the number of units in your building. ___________

2. Do you own or rent?

1☐ Own 2 ☐ Rent

3. What portion of the year is this home occupied?

1☐ Year Round 2☐ Summer Only 3☐ Winter Only 4☐ Other seasons

4. What is the approximate age of your home?

1☐ New (less than one year) 2☐ 1-5 years 3☐ 6-10 years 4☐ 11-15 years
5☐16-30 years 6☐31-50 years 7☐ Over 50 years

5. How many rooms are in your home? (Only include areas used as living space, including finished and conditioned basements). Do NOT include bathrooms and hallways)

1☐ 1 Room 4☐ 4 Rooms 7☐ 7 Rooms 10☐ 10 Rooms 13☐ 13 Rooms
2☐ 2 Rooms 5☐ 5 Rooms 8☐ 8 Rooms 11☐ 11 Rooms 14☐ 14 Rooms
3☐ 3 Rooms 6☐ 6 Rooms 9☐ 9 Rooms 12☐ 12 Rooms 15☐ 15+ Rooms

6. How many bathrooms do you have in your home?

1☐ 1 2☐ 2 3☐ 3 4☐ 4 5☐ more than 4

7. What is the approximate square footage of the living space of your home? (Do not include unconditioned garage, attic, or basement space.)

1☐ Less than 600 4☐ 1501-2000 7☐ 3001-3500 10☐ 5001-7500
2☐ 601-1000 5☐ 2001-2500 8☐ 3501-4000 11☐ 7501-10000
3☐ 1001-1500 6☐ 2501-3000 9☐ 4001-5000 12☐ 10000+

8. Indicate the number or people that live in your home at least half of the year.

Number of People

1	2	3	4	5	6	7	8	9	10	11	12
☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

9. During a typical week, how often are people home on weekdays from 12 noon until 4 pm? How about from 4 pm until 8 pm? (<u>Check one for each time period</u>)

	Never	One or two weekdays	Three or four weekdays	Every weekday
a. 12 noon until 4pm	1☐	2☐	3☐	4☐
b. 4 pm until 8 pm	1☐	2☐	3☐	4☐

10. Do you have a home-based business?

1☐ No 2☐ Yes (Describe ____)

11. **Please indicate if you currently participate in the following energy conservation/load management programs. Also, indicate how valuable they are to you or would be if you do not currently participate. <u>(Check if participate and check value level for each program type)</u>**

	a	b				
	Currently Participate	**Not at all Valuable**	**Not Very Valuable**	**Somewhat Valuable**	**Very Valuable**	**Extremely Valuable**
1. AC cycling during hottest days	1☐	1☐	2☐	3☐	4☐	5☐
2. Water Heater cycling a.m. or p.m.	1☐	1☐	2☐	3☐	4☐	5☐
3. Other Specify ____________________	1☐	1☐	2☐	3☐	4☐	5☐

12. **What is the highest education level of the Head of Household?**
1☐ Less than high school graduate
2☐ High school graduate
3☐ Some college
4☐ College graduate
5☐ Post college graduate work or more

13. **What is the age of the Head of Household?**
1☐ Less than 30
2☐ 30-39
3☐ 40-49
4☐ 50-64
5☐ 65 or older

14. **What is the approximate total household income level?**
1☐ $20,000 per year or less
2☐ $20,001-$40,000 per year
3☐ $40,001-$60,000 per year
4☐ $60,001-$80,000 per year
5☐ $80,001-$100,000 per year
6☐ $100,000 per year or more

<u>HEATING</u>

15. **Do you pay to heat your residence?**
1☐ Yes
2☐ No, it is part of my rent

16. **What type of heating system do you use to heat your home? (If there is more than one heating system, describe the system that provides most of the heat as "Main Heating" and the other system(s) as "Additional Heating")**

	a. Main Heating (Check only one box below)	**b. Additional Heating (Check all boxes that apply)**
1. Natural gas central forced air furnace	1☐	1☐
2. Natural gas wall/floor Heater	2☐	2☐
3. Other natural gas system type	3☐	3☐
4. Electric resistance/baseboard/ceiling	4☐	4☐
5. Electric air source heat pump	5☐	5☐
6. Electric geo-thermal heat pump	6☐	6☐
7 Electric central forced air furnace	7☐	7☐
8. Electric wall/floor heater	8☐	8☐
9. Other electric system type	8☐	9☐
10. Central boiler	10☐	10☐
11. Woodstove/Fireplace Insert	11☐	11☐
12. Fireplace	12☐	12☐
13. Propane	13☐	13☐
14. Other Fuel	14☐	14☐

17. **Was your main heating system purchased or replaced in the last five years?**
1☐ Yes
2☐ No
3☐ Don't Know

18. **How often do you use your additional heating system(s) during the winter months?**
1☐ No additional heating
2☐ Rarely (20% of the time)
3☐ Sometimes (20-50% of the time)
4☐ Often (50-80% of the time)
5☐ Always (80% or more)

19. **How many rooms are heated by your additional heating system?**
1☐ All rooms 2☐ 1 room 3☐ 2-3 rooms 4☐4-7 rooms 5☐ 8-10 rooms 6☐ 10+ rooms

20. **How many portable electric heaters do you use?**
0☐ None 1☐ One 2☐ Two 3☐ Three or more

COOLING

Central Air Conditioner

21. **What type of central air conditioner do you use?**
0☐ None ***(SKIP TO Q.25)*** 1☐ Central 2☐ Heat pump

22. **Do you pay for your central air conditioning?**
1☐ Yes 2☐ No, it is part of my rent

23. **Was your central air conditioning unit purchased or replaced within the last five years?**
1☐ Yes 2☐ No 3☐ Don't Know

24. **Please indicate how often the central air conditioner is used during the summer. (Choose one for each time period)**

	Never	Rarely (20% of time)	Sometimes (40% of time)	Often (70% of time)	Always
a. Day	1☐	2☐	3☐	4☐	5☐
b. Evening	1☐	2☐	3☐	4☐	5☐
c. Night	1☐	2☐	3☐	4☐	5☐

Room Air Conditioning

25. **How many window/wall air conditioners do you use?**
0☐ None ***(SKIP TO Q.28)*** 1☐ 1 Unit 2☐ 2 Units 3☐ 3 Units 4☐ More than 3 units

26. **Have you purchased or replaced the window/wall air conditioner that is used most frequently in the last five years?**
1☐ Yes 2☐ No 3☐ Don't Know

27. **Please indicate how often the main room air conditioner is used during the summer. (Choose one for each time period)**

	Never	Rarely (20% of time)	Sometimes (40% of time)	Often (70% of time)	Always
a. Day	1☐	2☐	3☐	4☐	5☐
b. Evening	1☐	2☐	3☐	4☐	5☐
c. Night	1☐	2☐	3☐	4☐	5☐

THERMOSTAT SETTING

28. **When you operate your central heating or air conditioning systems, indicate below what setting you use for the fan operation as well as the typical temperature setting. (Choose a fan AND temperature setting for each season)**

	a. Fan Setting		b. Temperature Setting			
	Fan Set to AUTO	Fan Set to ON	65-68	69-72	73-75	76+
1. Winter	1☐	2☐	1☐	2☐	3☐	4☐
2. Summer	1☐	2☐	1☐	2☐	3☐	4☐
3. Spring	1☐	2☐	1☐	2☐	3☐	4☐
4. Fall	1☐	2☐	1☐	2☐	3☐	4☐

WATER HEATING

29. **Do you pay to heat your water?**
1☐ Yes 2☐ No it is included in my rent

30. Which of the following best describes the water heater? (Choose one box below)

Natural Gas	*Electric*	*Propane/Other fuel*
1☐ Standard separate tank	4☐ Standard separate tank	8☐ Any system type
2☐ Tank with solar collectors	5☐ Tank with solar collectors	
3☐ Other system type	6☐ Instantaneous (at sink)	
	7☐ Other system type	

31. Have you purchased or replaced your water heater in the last five years?

1☐ Yes 2☐ No 3☐ Don't Know

32. Consider the total number of people in your home and then check the total number of baths and showers taken during a typical week.

<5	6-10	11-15	16-20	21-25	26-30	30+
1☐	☐	☐	☐	☐	☐	☐

33. Do you use flow restrictors or energy-saving (low flow) showerheads?

1☐ Yes, all showers 2☐ Yes, some showers 3☐ No

LAUNDRY

Clothes Washer

34. Do you have a washing machine? (Do not include coin-operated machines or machines in apartment common areas)

1☐ Yes 2☐ No ***(SKIP TO Q.35)***

35. How many loads of laundry are washed each week in your home using this machine?

<1	1	2	3	4	5	6	7	8	9	10	10+
0☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	11☐

Clothes Drying

36. Do you have a clothes dryer? (Do not include coin-operated machines or machines in apartment common areas)

1☐ Yes 2☐ No ***(SKIP TO Q.39)***

37. What is the heating fuel for your clothes dryer?

1☐ Natural gas 2☐ Electricity 3☐ Propane/other fuel

38. Approximately how many loads does your household dry each week using this clothes dryer?

<1	1	2	3	4	5	6	7	8	9	10	10+
0☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	11☐

39. Do you line-dry clothing? (If so, choose one answer for each season)

a. 1☐ yes 2☐ no ***(SKIP TO Q.40)***

	Never	Rarely	Sometimes	Often	Always
b. Summer	1☐	2☐	3☐	4☐	5☐
c. Winter	1☐	2☐	3☐	4☐	5☐

REFRIGERATORS

40. How many refrigerators do you have plugged in?

0☐ 0 ***(SKIP TO Q.45)*** 1☐ 1 2☐ 2 3☐ 3 or more

41. What style best describes the refrigerator(s)? (Check one box for each refrigerator)

	a	b	c
	Refrigerator 1	Refrigerator 2	Refrigerator 3
Top-Bottom	1☐	1☐	1☐
Side-by-Side	2☐	2☐	2☐

42. What size, in cubic feet, best describes the above refrigerator(s)? (Refrigerator information is usually found on a nameplate just inside the door) (<u>Check one box for each refrigerator</u>)

	a Refrigerator 1	b Refrigerator 2	c Refrigerator 3
Very small (under 13 cubic feet)	1☐	1☐	1☐
Small (13-16 cubic feet)	2☐	2☐	2☐
Medium (17-20 cubic feet)	3☐	3☐	3☐
Large (21-23 cubic feet)	4☐	4☐	4☐
Extra Large (over 23 cubic feet)	5☐	5☐	5☐

43. What type of defrost does the above refrigerator(s) have? (<u>Check one box for each refrigerator</u>)

	a Refrigerator 1	b Refrigerator 2	c Refrigerator 3
Automatic (frost-free)	1☐	1☐	1☐
Manual	2☐	2☐	2☐
Partial Automatic*	3☐	3☐	3☐

*(These have a frost-free refrigerator and manual defrost freezer)

44. Please check each refrigerator that was purchased in the last five years.

	a Refrigerator 1	b Refrigerator 2	c Refrigerator 3
Purchased in last five years	1☐	1☐	1☐

<u>STAND-ALONE FREEZERS</u>

45. How many stand-alone freezers do you have plugged in? (<u>Do not include freezers that are part of your refrigerator unit</u>)

0☐ 0 ***(SKIP TO Q.50)*** 1☐ 1 2☐ 2 or more

46. What style best describes the freezer(s)? (<u>Check one box for each freezer</u>)

	a Freezer 1	b Freezer 2
Upright	1☐	1☐
Chest	2☐	2☐

47. What size, in cubic feet, best describes the above freezer(s)? (Freezer information is usually found on a nameplate just inside the door) (<u>Check one box for each freezer</u>)

	a Freezer 1	b Freezer 2
Very small (under 10 cubic feet)	1☐	1☐
Small (11-15 cubic feet)	2☐	2☐
Medium (16-20 cubic feet)	3☐	3☐
Large (21-25 cubic feet)	4☐	4☐
Extra Large (over 25 cubic feet)	5☐	5☐

48. What type of defrost does the above freezer(s) have? (<u>Check one box for each freezer</u>)

	a Freezer 1	b Freezer 2
Automatic (frost-free)	1☐	1☐
Manual	2☐	2☐

49. Please check each freezer that was purchased in the last five years.

	a Freezer 1	b Freezer 2
Purchased in last five years	1☐	1☐

FOUD PREPARATION

50. What type of range/oven do you use?

1☐ Combination: electric and gas
3☐ Natural gas only
2☐ Propane (bottled gas) only
4☐ Electric only
5☐ Other

51. How often do you use your microwave oven?

1☐ Never 2☐ Sometimes 3☐ Rarely 4☐ Often 5☐ We don't have a microwave oven

52. How often do you run your dishwasher each week?

0☐ We do not have or use a dishwasher ***(SKIP TO Q.53)***

1	2	3	4	5	6	7	8	9	10 or more
☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

53. Which dishwasher cycle do you <u>most often</u> use?

1☐ Heated Drying 2☐ Energy Saver 3☐ Air Dry 4☐ Other

SPAS, HOT TUBS, and POOLS

54. Do you have a spa or hot tub at your home? (Do not include whirlpool bathtubs)

1☐ Yes, and I pay to heat it
2☐ Yes, but I do not pay to heat it
3☐ No spa or hot tub ***(SKIP TO Q.59)***

55. How is the spa or hot tub heated?

1☐ Electric heat pump
3☐ Natural Gas
5☐ Propane (bottled gas)
2☐ Solar with electric backup
4☐ Electricity
6☐ Solar with gas backup

56. Do you use an insulated cover on your spa or hot tub?

1☐ Yes 2☐ No 3☐ No, but it is located indoors

57. Please indicate how often you use your spa or hot tub in both the summer and winter. <u>Choose one for each season</u>).

	a. Summer	b. Winter
Never	1☐	1☐
Rarely	2☐	2☐
Once a month	3☐	3☐
Once a week	4☐	4☐
2-4 times a week	5☐	5☐
5 or more times a week	6☐	6☐

58. How large is your spa or hot tub?

1☐ Small (3 people or less)
2☐ Medium (4-6 people)
3☐ Large (7 or more people)

59. Do you have a swimming pool?

1☐ Yes, and I pay for its energy use
2☐ Yes, but it is in a common area and I do not pay for its energy use
3☐ No ***(SKIP TO Q.61)***

60. How is the pool heated?

1☐ Pool is not heated
3☐ Electricity
5☐ Solar heated
7☐ Natural Gas
2☐ Electric heat pump
4☐ Solar cover
6☐ Propane (bottled gas)

61. Please indicate the number of hours per day the swimming pool filter operates. (<u>Choose one for each season</u>).

	a. Summer	b. Winter
Not operated	1☐	1☐
Up to 2 hours	2☐	2☐
3-4 hours	3☐	3☐
5-6 hours	4☐	4☐
7-8 hours	5☐	5☐
9-12 hours	6☐	6☐
13-23 hours	7☐	7☐
24 hours	8☐	8☐

LIGHTING

62. Please indicate the number of energy saving or compact fluorescent (CFL) bulbs that are used for interior lighting?

0	1	2	3	4	5	6	7	8	9	10 or more
☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

63. (SKIP TO Q.63 IF NO CFL BULBS) Which of the following best describes how many of these compact fluorescent bulbs lights are turned on in the evenings until bedtime?

1☐ All of the lights
2☐ Most of the lights
3☐ Some of the lights
4☐ 1or 2 lights

OTHER APPLIANCES

64. Indicate how many of the following appliances are used in your home.

(<u>Choose no more than one response for each appliance listed</u>)

	1	2	3 or more
a. Color television	1☐	2☐	3☐
b. Black & white television	1☐	2☐	3☐
c. VCR	1☐	2☐	3☐
d. Stereo system	1☐	2☐	3☐
e Personal computer	1☐	2☐	3☐
f. Humidifier	1☐	2☐	3☐
g. Dehumidifier	1☐	2☐	3☐
h. Well pump	1☐	2☐	3☐
i. Irrigation pump	1☐	2☐	3☐
j. Heated waterbed	1☐	2☐	3☐
k. Aquarium	1☐	2☐	3☐
l. Gas fireplace	1☐	2☐	3☐
m. Attic fan	1☐	2☐	3☐
n. Portable fan	1☐	2☐	3☐
o. Ceiling fan	1☐	2☐	3☐
p. Whole house fan	1☐	2☐	3☐

65. Please indicate how often the following fans are used during the summer.

	Never	Rarely	Sometimes	Often	Always
a. Portable Fan	1☐	2☐	3☐	4☐	5☐
b. Ceiling fan	1☐	2☐	3☐	4☐	5☐
c. Whole house fan	1☐	2☐	3☐	4☐	5☐

66. **How many total hours are your TVs on per day? (Include all TVs in your home)**

1☐ No TVs 3☐ 1-3 5☐ 7-10 7☐ 15-20 9☐27-35
2☐ Less than 1 4☐ 4-6 6☐ 11-14 8☐ 21-26 10☐ More than 35

67. **If you regularly use (3 or more hours per week) any other appliances not mentioned, please check them below.**

	Electric	Gas		Electric
a. Kiln	1☐	2☐	c. Shop tools	1☐
b. Medical equipment	1☐	2☐	d. Welding equipment	1☐
e. Other	1☐	2☐		

Describe Other: ____

OTHER WATER USAGE/CONSERVATION

68. **Please indicate total number of toilets in your home, and of these, the total number of low-flow toilets. (Choose one for each type)**

	1	2	3	4	4+
a. Total toilets	1☐	2☐	3☐	4☐	5☐
b. Total low-flow toilets	1☐	2☐	3☐	4☐	5☐

69. **Please indicate the total number of showers and bathtubs in your home. If your tub has a shower head, count it also as a shower. (Check one category for each type)**

	1	2	3	4	4+
a. Total bathtubs	1☐	2☐	3☐	4☐	5☐
b. Total showers	1☐	2☐	3☐	4☐	5☐

70. **Do you water your lawn with a garden hose? (If so, choose the frequency in each season)**

a. 1☐ yes 2☐ no (***SKIP TO Q.70)***

	Rarely	Sometimes	Often
b. Spring	1☐	2☐	3☐
c. Summer	1☐	2☐	3☐

71. **Do you have a lawn/shrub irrigation system? (If so, choose the level of usage for each season)**

a. 1☐ yes 2☐ no ***(SKIP TO conclusion)***

	Rarely	Sometimes	Often
b. Spring	1☐	2☐	3☐
c. Summer	1☐	2☐	3☐

72. **Write any other comments that you would like provide to us in the space below.**

____

____

____

That concludes our survey. Thank you for your time and cooperation. Your answers will be very helpful in our continuing efforts to better serve you. Please return your completed survey in the enclosed postage-paid envelope.

LARGE COMMERCIAL AND INDUSTRIAL CUSTOMER EQUIPMENT/APPLIANCE SURVEY

Instructions: Thank you for your participation. Please check (✓) the appropriate box(s) that corresponds with your answer or write your response clearly in the space provided. **Your answers will remain strictly confidential.**

BUILDING AND FIRMOGRAPHICS

1. **Is the space occupied by this business owned, leased or managed by the business?**
   1☐ Owned 2 ☐Leased 2 ☐ Managed

2. **What portion of the year does this business operate at this site?**
   1☐ Year Round 2☐ Summer Only 3☐ Winter Only 4☐ Other seasons

3. **What is the approximate square footage of the conditioned space of at this site? (Do not include unconditioned storage, warehouse, attic, or basement space.)**
   1☐ 1,000 or less 4☐ 5,001-7,500 7☐ 25,001-50,000 10☐ 250,001-500,000
   2☐ 1,001-2,500 5☐ 7,501-10,000 8☐ 50,001-100,000 11☐ 500,001-1,000,000
   3☐ 2,501-5,000 6☐ 10,001-25,000 9☐ 100,001-250,000 12☐ 1,000,000+

4. **How many full and part-time employees work at this location?**
   1☐ 10 or less 4☐ 51-100 7☐ 251-500 10☐ 1001-5000
   2☐ 11-50 5☐ 101-250 8☐ 501-1000 11☐ 5000+

5. **During a typical week, indicate the number hours the business is in operation by the time period and day type below (Fill in the number of hours for each as appropriate)**

	a 12:00a.m to 8:00a.m	b 8:00am. to 5:00p.m.	c 5:00p.m. to 9:00 p.m.	d 9:00p.m. to 12:00a.m.
1. Weekdays				
2. Weekends				

6. **Which <u>one</u> of the following best describes the <u>main</u> business activity at this location? (Check one)**
   1☐ Fast Food 2☐ Restaurant
   3☐ Small Grocery 4☐ Large Grocery (e.g. Kroger, Safeway)
   5☐ Small Retail 6☐ Large Retail (e.g., Kmart, Walmart, Best Buy)
   7☐ Prof. Services (e.g., doctor, lawyer, accountant) 8☐ Trade Services (e.g., auto repair, laundry)
   9☐ Warehousing/storage 10☐ Communications
   11☐ Transportation 12☐ Construction
   13☐ Real Estate 14☐ Banking/Finance/Insurance
   15☐ Wholesale-Durables 16☐ Wholesale-Non-durables
   17☐ Food Processing 18☐ Government
   19☐ Manufacturing (Describe ____)
   20☐ Other (Describe____)

ENERGY AND WATER MANAGEMENT

7. **Does this business respond to peak alerts or an interruptible rate?**
   1☐ No 2☐ Yes, reduce use 3☐ Yes, suspend certain operations

8. **Which of the following capabilities or knowledge do you have on site? (<u>Check one answer for each</u>)**

	Yes	No
a. High voltage (over 480 volt) electrical repairs	1☐	2☐
b. Low voltage electrical work	1☐	2☐
c. HVAC maintenance	1☐	2☐
d. Mechanical maintenance	1☐	2☐
e. Plumbing maintenance	1☐	2☐
f. Full-time energy manager	1☐	2☐
g. Part-time energy manager	1☐	2☐

9. **Please indicate if you currently participate in the following energy or water billing services products and services. Also, indicate how valuable they are to your business <u>or</u> would be if you do not currently participate. <u>(Check if participate AND check value level for each program type)</u>**

	a.			**b.**		
	Currently Participate	Not at all Valuable	Not Very Valuable	Somewhat Valuable	Very Valuable	Extremely Valuable
1. Consolidated billing of multiple facilities	1☐	1☐	2☐	3☐	4☐	5☐
2. Monthly billing based on a calendar year	1☐	1☐	2☐	3☐	4☐	5☐
3. Monthly billing based on a fiscal year	1☐	1☐	2☐	3☐	4☐	5☐
4. Electronic interface for bills, meter reading, payments, electronic mail, etc.	1☐	1☐	2☐	3☐	4☐	5☐
5. Water reliability-based rates adjusted depending on your need for reliable or constant supply	1☐	1☐	2☐	3☐	4☐	5☐
6. Electricity reliability-based rates adjusted depending on your need for reliable or constant supply	1☐	1☐	2☐	3☐	4☐	5☐
7. Time of use rates at various time periods during the day and/or on weekends	1☐	1☐	2☐	3☐	4☐	5☐
8. Real time pricing rate that varies each hour to allow you to operate during the periods at low cost.	1☐	1☐	2☐	3☐	4☐	5☐
9. Direct access to your account information on the Internet	1☐	1☐	2☐	3☐	4☐	5☐

10. **Please indicate if you currently participate in the following financial services related to your energy management. Also, indicate how valuable they are to your business or would be if you do not currently participate. <u>(Check if participate AND check value level for each program type)</u>**

	a.			**b.**		
	Currently Participate	Not at all Valuable	Not Very Valuable	Somewhat Valuable	Very Valuable	Extremely Valuable
1. Leasing options for energy utilization equipment	1☐	1☐	2☐	3☐	4☐	5☐
2. Low or discounted interest rates for ‘energy efficient structure’ mortgages or new construction	1☐	1☐	2☐	3☐	4☐	5☐
3. Assistance in obtaining funding for process improvement assess-ments or feasibility studies	1☐	1☐	2☐	3☐	4☐	5☐
4. Low-cost financing for purchase of energy efficient equipment	1☐	1☐	2☐	3☐	4☐	5☐
5. “Paid from savings” financing options for energy improvements	1☐	1☐	2☐	3☐	4☐	5☐
6. Payment of financing for energy improvement purchases on utility bills	1☐	1☐	2☐	3☐	4☐	5☐
7. Outage insurance	1☐	1☐	2☐	3☐	4☐	5☐

11. **Please indicate if you currently participate in the following energy evaluation services. Also, indicate how valuable they are to your business <u>or</u> would be if you do not currently participate. <u>(Check if participate AND check value level for each program type)</u>**

	a.	b.				
	Currently Participate	Not at all Valuable	Not Very Valuable	Somewhat Valuable	Very Valuable	Extremely Valuable
1. Graphic interval analysis of your energy usage pattern	1☐	1☐	2☐	3☐	4☐	5☐
2. Assistance in budgeting and forecasting energy usage	1☐	1☐	2☐	3☐	4☐	5☐
3. Sub-metering for electric processes	1☐	1☐	2☐	3☐	4☐	5☐
4. Sub-metering for water processes	1☐	1☐	2☐	3☐	4☐	5☐
5. Sub-metering for gas processes	1☐	1☐	2☐	3☐	4☐	5☐
6. Tele-metering to a central monitoring location off-site	1☐	1☐	2☐	3☐	4☐	5☐
7. Process energy audits	1☐	1☐	2☐	3☐	4☐	5☐
8. Metering input for EMS (energy management systems)	1☐	1☐	2☐	3☐	4☐	5☐
9. EMS reviews and assistance	1☐	1☐	2☐	3☐	4☐	5☐
10. GeoExchange (geothermal) heating and cooling consulting	1☐	1☐	2☐	3☐	4☐	5☐
11. Access to real-time energy consumption data	1☐	1☐	2☐	3☐	4☐	5☐
12. Total efficiency assessment covering energy, productivity and waste management	1☐	1☐	2☐	3☐	4☐	5☐

12. **Please indicate if you currently participate in the following energy information and management services. Also, indicate how valuable they are to your business <u>or</u> would be if you do not currently participate. <u>(Check if participate AND check value level for each program type)</u>**

	a.	b.				
	Currently Participate	Not at all Valuable	Not Very Valuable	Somewhat Valuable	Very Valuable	Extremely Valuable
1. Assistance in troubleshooting and resolving power quality problems	1☐	1☐	2☐	3☐	4☐	5☐
2. Education/training seminars on various technologies	1☐	1☐	2☐	3☐	4☐	5☐
3. Energy utility provided management of energy services such as fuel procurement, and boiler or generator operations	1☐	1☐	2☐	3☐	4☐	5☐
4. Technical information on new technologies related to your industry	1☐	1☐	2☐	3☐	4☐	5☐
5. Assistance in identifying suppliers of various technologies	1☐	1☐	2☐	3☐	4☐	5☐
6. Quarterly newsletters to provide updates on technologies, grants, new services, etc.	1☐	1☐	2☐	3☐	4☐	5☐
7. Turn-key engineering services for installation of efficiency improvements	1☐	1☐	2☐	3☐	4☐	5☐
8. Energy utility provided power quality monitoring	1☐	1☐	2☐	3☐	4☐	5☐
9. Energy utility provided environmental consulting services on generator permitting	1☐	1☐	2☐	3☐	4☐	5☐
10. Energy utility provided services on lamp recycling	1☐	1☐	2☐	3☐	4☐	5☐

13. **Please indicate if you currently participate in the following energy operations services. Also, indicate how valuable they are to your business or would be if you do not currently participate. <u>(Check if participate AND check value level for each program type)</u>**

	a.	b.				
	Currently Participate	Not at all Valuable	Not Very Valuable	Somewhat Valuable	Very Valuable	Extremely Valuable
1. Locating customer-owned underground facilities (storage tanks, telephone, water, etc.)	1☐	1☐	2☐	3☐	4☐	5☐
2. Substation maintenance design, installation and/or maintenance	1☐	1☐	2☐	3☐	4☐	5☐
3. Infra-red scanning of electrical systems and building components	1☐	1☐	2☐	3☐	4☐	5☐
4. Outdoor security lighting	1☐	1☐	2☐	3☐	4☐	5☐
5. Testing equipment for analysis of power quality problems	1☐	1☐	2☐	3☐	4☐	5☐
6. Purchase of power quality equipment from your energy utility	1☐	1☐	2☐	3☐	4☐	5☐
7. Lease transformers (includes maintenance and replacement)	1☐	1☐	2☐	3☐	4☐	5☐
8. Lease small back-up generators for your operations to be located on your site	1☐	1☐	2☐	3☐	4☐	5☐
9. Lease and maintain small back-up generators on your site	1☐	1☐	2☐	3☐	4☐	5☐
10. Buy/lease/rent water heating or HVAC equipment (includes maintenance and replacement)	1☐	1☐	2☐	3☐	4☐	5☐
11. Maintenance services on HVAC owned by your company	1☐	1☐	2☐	3☐	4☐	5☐
12. Warranty or maintenance agreements for energy equipment and appliances	1☐	1☐	2☐	3☐	4☐	5☐
13. Energy utility provided wiring services within your facilities	1☐	1☐	2☐	3☐	4☐	5☐
14. Energy utility provided back-up generators for outages	1☐	1☐	2☐	3☐	4☐	5☐
15 Building maintenance and controls from your energy utility	1☐	1☐	2☐	3☐	4☐	5☐
16. Fuel cells from your energy utility	1☐	1☐	2☐	3☐	4☐	5☐
17. Lighting retrofit and new construction provided by your energy utility	1☐	1☐	2☐	3☐	4☐	5☐
18. Power factor correction services provided by your energy utility	1☐	1☐	2☐	3☐	4☐	5☐
19. Solar and wind power projects	1☐	1☐	2☐	3☐	4☐	5☐

14. **Do you have an electric generator(s) on-site?**
1☐ Yes 2☐ No ***(SKIP TO Q.16)***

15. **What is the size of the largest electric generator you currently have?**
1☐ <10kW 2☐ 10-25KW 3☐ 26-50KW 4☐51-100KW 5☐ over 100kW

15a. How do you use existing generators (e.g., outages, peak demand, self-generation, other, etc,)?

____

____

16. **Do you plan to purchase an electric generator on in the next two years?**
1☐ Yes 2☐ No ***(SKIP TO Q.18)***

17. What would be the largest electric generator that you expect to purchase?

1☐ <10kW   2☐ 10-25KW   3☐ 26-50KW   4☐51-100KW   5☐ over 100kW

17a. How would you use these new generators (e.g., outages, peak demand, self-generation, other, etc,)?

____

____

18. What would you estimate the cost (in dollars) to be of a 15-minute power interruption to your company at this site? $__________________

19. How significant would this cost of the 15-minute power interruption be to your business?

1☐ minor   2☐ moderately significant   3☐ very significant

20. Do you currently have an energy management practices plan?

1☐ **Yes**   2☐ **No** ***(SKIP TO Q.21)***

20a. Briefly describe measures implemented?

____

____

____

20b. Briefly describe measures planned in the next two years (if any)?

____

____

____

21. Are there any other products and services that you would like your energy utility to offer?

1☐ **Yes**   2☐ **No** ***(SKIP TO Q.22)***

21a. Briefly describe them?

____

____

____

____

LIGHTING

22. Please indicate the number of units that you have for each type of light bulbs shown below. (Check one box for each type)

	none	1-10	11-50	51-100	101-500	500+
a. Incandescent (standard bulbs)	0☐	1☐	2☐	3☐	4☐	5☐
b. T-12 Fluorescent (standard)	0☐	1☐	2☐	3☐	4☐	5☐
c. T-12 Fluorescent (VHO or HO 1.5 inch)	0☐	1☐	2☐	3☐	4☐	5☐
d. Compact Fluorescent (CFL)	0☐	1☐	2☐	3☐	4☐	5☐
e. T-5 Fluorescent	0☐	1☐	2☐	3☐	4☐	5☐
f. T-8 Fluorescent	0☐	1☐	2☐	3☐	4☐	5☐
g. F-40 Fluorescent	0☐	1☐	2☐	3☐	4☐	5☐
h. F-34 Fluorescent	0☐	1☐	2☐	3☐	4☐	5☐
i. Metal halide lamps	0☐	1☐	2☐	3☐	4☐	5☐
j. Halogen lamps	0☐	1☐	2☐	3☐	4☐	5☐
k. Occupancy sensors	0☐	1☐	2☐	3☐	4☐	5☐
l. Exit signs	0☐	1☐	2☐	3☐	4☐	5☐
m. Other	0☐	1☐	2☐	3☐	4☐	5☐

Describe Other: ____

23. What percentage of your fluorescent lamps have been upgraded to electronic ballasts?

1☐ <20%   2☐ 20%-40%   3☐ 40%-60%   4☐60%-80%   5☐ 80%+   6☐ Don't know

24. Indicate the number of exterior lights and controls that you use? (Choose all that apply)

☐ a. No outdoor lighting or do not pay ***(SKIP TO Q.25)***

	1-2	3-4	5-7	8-10	11+
b. Motion sensors	1☐	2☐	3☐	4☐	5☐
c. Photo electric eye	1☐	2☐	3☐	4☐	5☐
d. Timers	1☐	2☐	3☐	4☐	5☐
e. Manual on/off switches	1☐	2☐	3☐	4☐	5☐
f. Flood/spot lights	1☐	2☐	3☐	4☐	5☐

PROCESSING EQUIPMENT

25. Indicate how many of the following kinds of equipment are used at this business site.

(Choose one response for each type and fuel listed)

	a. Electric			**b. Gas**		
Equipment Type	1-5	6-10	10+	1-5	6-10	10+
1. Kiln	1☐	2☐	3☐	1☐	2☐	3☐
2. Medical equipment	1☐	2☐	3☐	1☐	2☐	3☐
3. Well pump	1☐	2☐	3☐			
4. Fans	1☐	2☐	3☐			
5. Shop tools	1☐	2☐	3☐			
6. Irrigation pump	1☐	2☐	3☐			
7. Welding equipment	1☐	2☐	3☐	1☐	2☐	3☐
8. Total motors	1☐	2☐	3☐			
9. Motors over 50 horsepower	1☐	2☐	3☐			
10. Motors older than 10 years	1☐	2☐	3☐			
11. Number of rewound motors	1☐	2☐	3☐			
12. Number of variable speed drives	1☐	2☐	3☐			
13. Other	1☐	2☐	3☐	1☐	2☐	3☐

Describe Other: ____

26. Indicate how many of the following kinds of office equipment are used at this business.

(Choose one response for each type listed)

	1-5	6-10	11 -25	26-50	50+
a. Printers	1☐	2☐	3☐	4☐	5☐
b. Personal computers	1☐	2☐	3☐	4☐	5☐
c. Copiers	1☐	2☐	3☐	4☐	5☐
d. Scanners	1☐	2☐	3☐	4☐	5☐

27. Do you use steam or hot water for processes other than comfort heating at this site?

1☐ **Yes** 2☐ **No *(SKIP TO Q.28)***

27a. Briefly describe for what purposes used?

____

____

____

28. Do you use refrigeration for processes other than comfort cooling at this site?

1☐ **Yes** 2☐ **No *(SKIP TO Q.29)***

28a. Briefly describe for what purposes used?

____

____

____

OTHER WATER USAGE/CONSERVATION

29. Please indicate total number of toilets, and of those, the total number of low-flow toilets inside your business. (Choose one for each type)

	0	1	2	3	4	4+
a. Total toilets	0☐	1☐	2☐	3☐	4☐	5☐
b. Total low-flow toilets	0☐	1☐	2☐	3☐	4☐	5☐

30. Please indicate the total number of showers and bathtubs inside your business. If the tub has a shower head, count it also as a shower. (Check one category for each type)

	0	1	2	3	4	4+
a. Total bathtubs	0☐	1☐	2☐	3☐	4☐	5☐
b. Total showers	0☐	1☐	2☐	3☐	4☐	5☐

31. Does your business water a lawn area with a garden hose? (If so, choose the frequency in each season)

a. 1☐ yes 2☐ no (***SKIP TO Q.32)***

	Rarely	Sometimes	Often
b. Spring	1☐	2☐	3☐
c. Summer	1☐	2☐	3☐

32. Is there a lawn/shrub irrigation system that the business pays for the usage? (If so, choose the level of usage for each season)

a. 1☐ yes 2☐ no ***(SKIP TO Q.33)***

	Rarely	Sometimes	Often
b. Spring	1☐	2☐	3☐
c. Summer	1☐	2☐	3☐

THE FUTURE

33. Thinking about your use of electricity, natural gas and water at this business site <u>during the next five years</u>, would you expect usage to remain the same, increase or decrease? (<u>In the table below</u>, <u>check the appropriate box for each in column (1). If an increase or decrease is checked, estimate the percentage change in column (2) and the main reason(s) for the change in column (3)</u>.

	Expected Change (1)	Estimate Percentage Change (2)	Main reason(s) for change <u>if increase or decrease</u> (3)
a. **Electricity Usage**			
Remain the same	1☐		
Increase	2☐		
Decrease	3☐		
b. **Natural Gas Usage**			
Remain the same	1☐		
Increase	2☐		
Decrease	3☐		
c. **Water Usage**			
Remain the same	1☐		
Increase	2☐		
Decrease	3☐		

34. Write any other comments that you would like provide to us in the space below.

____

____

____

____

That concludes our survey. Thank you for your time and cooperation. Your answers will be very helpful in our continuing efforts to better serve you. Please return your completed survey in the postage-paid return envelope or see letter for further instructions.

(OPTIONAL): To help us better serve you, please provide the following optional information:

Name________________________________ Title ________________________________

Company______________________________ Business Phone:________________________

Address: ______________________________ Business Fax: __________________________

______________________________ Email: ________________________________

____

COMMERCIAL CUSTOMER APPLIANCE/EQUIPMENT SURVEY

Instructions: Thank you for your participation. Please check (✓) the appropriate box(s) that corresponds with your answer or write your response clearly in the space provided. **Your answers will remain strictly confidential.**

BUILDING AND FIRMOGRAPHICS

1. Choose the statement that best describes the building where this business is located.

1☐ One story
2☐ Two-story
3☐ Three-story
4☐ Four+ stories

2. Does this business occupy all or part of the building?

1☐ All 2 ☐ Part

3. Is the space occupied by this business owned, leased or managed by the business?

1☐ Owned 2 ☐Leased 2 ☐ Managed

4. What portion of the year does this business operate?

1☐ Year Round 2☐ Summer Only 3☐ Winter Only 4☐ Other seasons

5. What is the approximate age of the building?

1☐ New (less than one year) 2☐ 1-5 years 3☐ 6-10 years 4☐ 11-15 years
5☐16-30 years 6☐31-50 years 7☐ Over 50 years

6. What is the approximate square footage of the conditioned space of this business? (Do not include unconditioned storage/warehouse, attic, or basement space.)

1☐ 1,000 or less 4☐ 5,001-7500 7☐ 25,001-50,000 10☐ 250,001-500,000
2☐ 1,001-2,500 5☐ 7,501-10000 8☐ 50,001-100,000 11☐ 500,001-1,000,000
3☐ 2,501-5,000 6☐ 10,001-25000 9☐ 100,001-250,000 12☐ 1,000,000+

7. How many full and part-time employees work at this location?

1☐ 10 or less 4☐ 51-100 7☐ 251-500 10☐ 1001-5000
2☐ 11-50 5☐ 101-250 8☐ 501-1000 11☐ 5000+

8. During a typical week, indicate the number hours the business is in operation by the time period and day type below (<u>Fill in the number of hours for each as appropriate</u>)

	a 12:00a.m to 8:00a.m	b 8:00am. to 5:00p.m.	c 5:00p.m. to 9:00 p.m.	d 9:00p.m. to 12:00a.m.
1. Weekdays				
2. Weekends				

9. Does this business have at least one individual whose main job responsibility is energy management?

1☐ Yes 2☐ No

10. Do you have an on-going relationship with the following? (<u>Answer for each</u>)

	Yes	No
a. Electrical contractor	1☐	2☐
b. HVAC contractor	1☐	2☐
c. Plumbing contractor	1☐	2☐

11. Does this business respond to peak alerts from RPU?

1☐ No 2☐ Yes, reduce use 3☐ Yes, suspend certain operations

12. Please indicate if you currently participate in the following energy conservation/load management programs. Also, indicate how valuable they are to your business or would be if you do not currently participate. (Check if participate and check value level for each program type)

	a. Currently Participate	b. Not at all Valuable	Not Very Valuable	Somewhat Valuable	Very Valuable	Extremely Valuable
1. AC cycling during hottest days	1☐	1☐	2☐	3☐	4☐	5☐
2. Water Heater cycling a.m. or p.m.	1☐	1☐	2☐	3☐	4☐	5☐
3. Time-of-use rates at various time periods during the day and/or on weekends	1☐	1☐	2☐	3☐	4☐	5☐

13. Which one of the following best describes the main business activity at this location? (Check one)

1☐ Fast Food
2☐ Restaurant
3☐ Small Grocery
4☐ Large Grocery (e.g. Kroger, Safeway)
5☐ Small Retail
6☐ Large Retail (e.g., Kmart, Walmart, Best Buy)
7☐ Prof. Services (e.g., doctor, lawyer, accountant)
8☐ Trade Services (e.g., auto repair, laundry)
9☐ Warehousing/storage
10☐ Communications
11☐ Transportation
12☐ Construction
13☐ Wholesale-Durables
14☐ Wholesale-Non-durables
15☐ Banking/Finance/Insurance
16☐ Real Estate
17☐ Government
18☐ Manufacturing (Describe ____)
19☐ Other (Describe ____)

HEATING

14. Do you pay to heat this business?

1☐ Yes 2☐ No, it is part of the lease

15. What type of heating system do you use to heat this business? (If there is more than one heating system, describe the system that provides most of the heat as "Main Heating" and the other system(s) as "Additional Heating")

	a. Main Heating (Check only one box below)	b. Additional Heating (Check all boxes that apply)
1. Natural gas central forced air furnace	1☐	1☐
2. Natural gas wall/floor heater	2☐	2☐
3. Other natural gas system type	3☐	3☐
4. Electric resistance/baseboard/ceiling	4☐	4☐
5. Electric air source heat pump	5☐	5☐
6. Electric geo-thermal heat pump	6☐	6☐
7 Electric central forced air furnace	7☐	7☐
8. Electric wall/floor heater	8☐	8☐
9. Other electric system type	9☐	9☐
10. Central boiler	10☐	10☐
11. Woodstove/Fireplace Insert	11☐	11☐
12. Fireplace	12☐	12☐
13. Propane	13☐	13☐
14. Other Fuel	14☐	14☐

16. Was the main heating system purchased or replaced in the last seven years?

1☐ Yes 2☐ No 3☐ Don't know

17. **How often do you use your additional heating system(s) during the winter months?**
1☐ No additional heating
2☐ Rarely (20% of the time)
3☐ Sometimes (20-50% of the time)
4☐ Often (50-80% of the time)
5☐ Always (80% or more)

18. **How much of your total square footage is heated by your additional heating system?**
1☐ <20% 2☐ 20%-40% 3☐ 40%-60% 4☐60%-80% 5☐ 80%+

19. **How many portable electric heaters are used?**
0☐ None 1☐ 1-5 2☐ 6-10 3☐ 10 or more

COOLING

Central Air Conditioner

20. **What type of central air conditioner does this business have?**
0☐ None ***(SKIP TO Q.24)*** 1☐ Central 2☐ Central (roof top) 3☐ Heat pump

21. **Do you pay for your central air conditioning?**
1☐ Yes 2☐ No, it is part of the lease

22. **Was the central air conditioning unit purchased or replaced within the last seven years?**
1☐ Yes 2☐ No 3☐ Don't know

23. **Please indicate how often the central air conditioner is used during the summer. (<u>Choose one for each time period</u>)**

	Never	Rarely (20% of time)	Sometimes (40% of time)	Often (70% of time)	Always
a. Day	1☐	2☐	3☐	4☐	5☐
b. Evening	1☐	2☐	3☐	4☐	5☐
c. Night	1☐	2☐	3☐	4☐	5☐

Room Air Conditioning

24. **How many window/wall air conditioners do you use?**
0☐ None ***(SKIP TO Q.27)*** 1☐ 1 Unit 2☐ 2 Units 3☐ 3 Units 4☐ More than 3 units

25. **Have you purchased or replaced the window/wall air conditioner that is used most frequently in the last seven years?**
1☐ Yes 2☐ No 3☐ Don't know

26. **Please indicate how often the main room air conditioner is used during the summer. (<u>Choose one for each time period</u>)**

	Never	Rarely (20% of time)	Sometimes (40% of time)	Often (70% of time)	Always
a. Day	1☐	2☐	3☐	4☐	5☐
b. Evening	1☐	2☐	3☐	4☐	5☐
c. Night	1☐	2☐	3☐	4☐	5☐

WATER HEATING

27. **Do you pay to heat water at this business?**
1☐ Yes 2☐ No it is included the lease

28. **Which of the following best describes the water heater? (Choose <u>one</u> box below)**

<u>Natural Gas</u>
1☐ Standard separate tank
2☐ Tank with solar collectors
3☐ Other system type

<u>Electric</u>
4☐ Standard separate tank
5☐ Tank with solar collectors
6☐ Instantaneous water heater (at sink)
7☐ Other system type

<u>Propane/Other fuel</u>
7☐ Any system type

29. Have you purchased or replaced the water heater in the last seven years?
1☐ Yes　2☐ No　3☐ Don't know

30. Compared to an average residence, how much hot water would you estimate this business uses at this location?
1☐ Less　2☐ About the same　3☐ A little more
4☐ Considerably more　5☐ Many times more

31. What is the average temperature of the hot water?
1☐ <140° F)　2☐ 140° F-212° F (boiling)　3☐ Over 212° F

32. Do you use flow restrictors or energy-saving (low flow) showerheads?
1☐ Yes, all showers　2☐ Yes, some showers　3☐ No

LAUNDRY

Clothes Washer

33. Does this business have a washing machine?
1☐ Yes, residential type　2☐ Yes, commercial type　3☐ No ***(SKIP TO Q.36)***

34. How many washing machines?

1	2	3	4	5	6	7	8	9	10	10+
☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	11☐

35. How many loads of laundry are washed each week in <u>all machines</u> at this business?

<1	1	2	3	4	5	6	7	8	9	10	10+
0☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	11☐

Clothes Drying

36. Does this business have a clothes dryer?
1☐ Yes, residential type　2☐ Yes, commercial type　3☐ No ***(SKIP TO Q.40)***

37. How many dryers?

1	2	3	4	5	6	7	8	9	10	10+
☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	11☐

38. What is the heating fuel for the dryer(s) at this business?
1☐ Natural gas　2☐ Electricity　3☐ Propane/other fuel

39. Approximately how many loads are dried each week in all dryers at this business?

<1	1	2	3	4	5	6	7	8	9	10	10+
0☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	11☐

REFRIGERATORS

40. How many "residential-type" refrigerators do you have plugged in at this business?
0☐ 0 ***(SKIP TO Q.44)***　1☐ 1　2☐ 2　3☐ 3 or more

41. What style best describes the refrigerator(s)? (<u>Check one box for each refrigerator</u>)

	a	b	c
	Refrigerator 1	Refrigerator 2	Refrigerator 3
Top-Bottom	1☐	1☐	1☐
Side-by-Side	2☐	2☐	2☐

42. What size, in cubic feet, best describes the above refrigerator(s)? (Refrigerator information is usually found on a nameplate just inside the door) (<u>Check one box for each refrigerator</u>)

	a Refrigerator 1	b Refrigerator 2	c Refrigerator 3
Very small (under 13 cubic feet)	1☐	1☐	1☐
Small (13-16 cubic feet)	2☐	2☐	2☐
Medium (17-20 cubic feet)	3☐	3☐	3☐
Large (21-23 cubic feet)	4☐	4☐	4☐
Extra Large (over 23 cubic feet)	5☐	5☐	5☐

43. What type of defrost does the above refrigerator(s) have? (<u>Check one box for each refrigerator</u>)

	a Refrigerator 1	b Refrigerator 2	c Refrigerator 3
Automatic (frost-free)	1☐	1☐	1☐
Manual	2☐	2☐	2☐
Partial Automatic*	3☐	3☐	3☐

*(These have a frost-free refrigerator and manual defrost freezer)

44. How many units of commercial refrigeration do you have in use?

0☐ 0 ***(SKIP TO Q.46)*** 1☐ 1-5 2☐ 6-10 3☐ 10+

45. Please check the percentage of total commercial units purchased in the last seven years.

	<20%	20%-40%	40%-60%	60%-80%	80%+
Purchased in last seven years	1☐	2☐	3☐	4☐	5☐

<u>STAND-ALONE FREEZERS</u>

46. How many "residential type" stand-alone freezers do you have plugged in at this business? (<u>Do not include freezers that are part of your refrigerator unit</u>)

0☐ 0 ***(SKIP TO Q.51)*** 1☐ 1 2☐ 2 or more

47. What style best describes the freezer(s)? (<u>Check one box for each freezer</u>)

	a Freezer 1	b Freezer 2
Upright	1☐	1☐
Chest	2☐	2☐

48. What size, in cubic feet, best describes the above freezer(s)? (Freezer information is usually found on a nameplate just inside the door) (<u>Check one box for each freezer</u>)

	a Freezer 1	b Freezer 2
Very small (under 10 cubic feet)	1☐	1☐
Small (11-15 cubic feet)	2☐	2☐
Medium (16-20 cubic feet)	3☐	3☐
Large (21-25 cubic feet)	4☐	4☐
Extra Large (over 25 cubic feet) Specify size ___________________	5☐	5☐

49. What type of defrost does the above freezer(s) have? (<u>Check one box for each freezer</u>)

	a Freezer 1	b Freezer 2
Automatic (frost-free)	1☐	1☐
Manual	2☐	2☐

50. Please check each freezer that was purchased in the last seven years.

	a Freezer 1	b Freezer 2
Purchased in last seven years	1☐	1☐

51. How many units of commercial freezers do you have in use?

0☐ 0 ***(SKIP TO Q.53)*** 1☐ 1-5 2☐ 6-10 3☐ 10+

52. Please check the percentage of total commercial units purchased in the last seven years.

	<20%	20%-40%	40%-60%	60%-80%	80%+
Purchased in last seven years	1☐	2☐	3☐	4☐	5☐

FOOD PREPARATION

53. Does this business have any food preparation equipment that is used commercially?

1☐ Yes 2☐ No ***(SKIP TO Q.56)***

54. Please indicate the number of units that you have for each type of equipment below. (Check one box for each type)

	none	1	2	3	4	5	5+
a. Combination stove/range: electric and gas	0☐	1☐	2☐	3☐	4☐	5☐	6☐
b. Electric stove/range	0☐	1☐	2☐	3☐	4☐	5☐	6☐
c. Natural gas stove/range	0☐	1☐	2☐	3☐	4☐	5☐	6☐
d. Propane stove/range	0☐	1☐	2☐	3☐	4☐	5☐	6☐
e. Other stove/range	0☐	1☐	2☐	3☐	4☐	5☐	6☐
f. Microwave oven	0☐	1☐	2☐	3☐	4☐	5☐	6☐
g. Fryers	0☐	1☐	2☐	3☐	4☐	5☐	6☐
h. Griddles	0☐	1☐	2☐	3☐	4☐	5☐	6☐
i. Warmers	0☐	1☐	2☐	3☐	4☐	5☐	6☐
j. Dishwasher	0☐	1☐	2☐	3☐	4☐	5☐	6☐
k. Commercial dish rinsing unit	0☐	1☐	2☐	3☐	4☐	5☐	6☐
l. Commercial food sprayers	0☐	1☐	2☐	3☐	4☐	5☐	6☐

55. Please indicate the average number of hours per week that each type of unit is operated (Check one box for each type)

	<20	20-40	40-60	60-80	80+
a. Combination stove/range: electric and gas	1☐	2☐	3☐	4☐	5☐
b. Electric stove/range	1☐	2☐	3☐	4☐	5☐
c. Natural gas stove/range	1☐	2☐	3☐	4☐	5☐
d. Propane stove/range	1☐	2☐	3☐	4☐	5☐
e. Other stove/range	1☐	2☐	3☐	4☐	5☐
f. Microwave oven	1☐	2☐	3☐	4☐	5☐
g. Fryers	1☐	2☐	3☐	4☐	5☐
h. Griddles	1☐	2☐	3☐	4☐	5☐
i. Warmers	1☐	2☐	3☐	4☐	5☐
j. Dishwasher	1☐	2☐	3☐	4☐	5☐
k. Commercial dish rinsing unit	1☐	2☐	3☐	4☐	5☐
l. Commercial food sprayers	1☐	2☐	3☐	4☐	5☐

LIGHTING

56. Please indicate the number of units that you have for each type of light bulbs shown below within your interior business space. (Check one box for each type)

	none	1-10	11-50	51-100	101-500	500+
a. Incandescent (standard bulbs)	0☐	1☐	2☐	3☐	4☐	5☐
b. T-12 Fluorescent (standard)	0☐	1☐	2☐	3☐	4☐	5☐
c. Compact Fluorescent (CFL)	0☐	1☐	2☐	3☐	4☐	5☐
d. T-5 Fluorescent	0☐	1☐	2☐	3☐	4☐	5☐
e. T-8 Fluorescent	0☐	1☐	2☐	3☐	4☐	5☐
f. Exit signs	0☐	1☐	2☐	3☐	4☐	5☐
g. Other	0☐	1☐	2☐	3☐	4☐	5☐

57. What percentage of your fluorescent lamps have been upgraded to electronic ballasts?

1☐ <20% 2☐ 20%-40% 3☐ 40%-60% 4☐60%-80% 5☐ 80%+ 6☐ Don't know

58. Indicated the number of exterior lights and controls do you use? (Choose all that apply)

☐ a. No outdoor lighting or do not pay ***(SKIP TO Q.59)***

	1-2	3-4	5-7	8-10	11+
b. Motion sensors	1☐	2☐	3☐	4☐	5☐
c. Photo electric eye	1☐	2☐	3☐	4☐	5☐
d. Timers	1☐	2☐	3☐	4☐	5☐
e. Manual on/off switches	1☐	2☐	3☐	4☐	5☐
f. Flood/spot lights	1☐	2☐	3☐	4☐	5☐

OTHER WATER USAGE/CONSERVATION

59. Please indicate total number of toilets, and of those, the total number of low-flow toilets inside your business. (Choose one for each type)

	0	1	2	3	4	4+
a. Total toilets	0☐	1☐	2☐	3☐	4☐	5☐
b. Total low-flow toilets	0☐	1☐	2☐	3☐	4☐	5☐

60. Please indicate the total number of showers and bathtubs inside your business. If the tub has a shower head, count it also as a shower. (Check one category for each type)

	0	1	2	3	4	4+
a. Total bathtubs	0☐	1☐	2☐	3☐	4☐	5☐
b. Total showers	0☐	1☐	2☐	3☐	4☐	5☐

61. Does your business water a lawn area with a garden hose? (If so, choose the frequency in each season)

a. 1☐ yes 2☐ no (***SKIP TO Q.62)***

	Rarely	Sometimes	Often
b. Spring	1☐	2☐	3☐
c. Summer	1☐	2☐	3☐

62. Is their a lawn/shrub irrigation system that the business pays for the usage? (If so, choose the level of usage for each season)

a. 1☐ yes 2☐ no ***(SKIP TO Q.63)***

	Rarely	Sometimes	Often
b. Spring	1☐	2☐	3☐
c. Summer	1☐	2☐	3☐

OTHER EQUIPMENT

63. Indicate how many of the following kinds of office equipment are used at this business.

(Choose one response for each type listed)

	1-5	6-10	10 or more
a. Printers	1☐	2☐	3☐
b. Personal computers	1☐	2☐	3☐
c. Copiers	1☐	2☐	3☐
d. Scanners	1☐	2☐	3☐

64. Indicate how many of the following kinds of other equipment are used at this business.

(Choose one response for each type listed)

	a. Electric			b. Gas		
	1-5	6-10	10+	1-5	6-10	10+
1. Kilns	1☐	2☐	3☐	1☐	2☐	3☐
2. Medical equipment	1☐	2☐	3☐	1☐	2☐	3☐
3. Well pumps	1☐	2☐	3☐			
4. Fans	1☐	2☐	3☐			
5. Shop tools	1☐	2☐	3☐			
6. Irrigation pumps	1☐	2☐	3☐			
7. Welding equipment	1☐	2☐	3☐	1☐	2☐	3☐
8. Motors	1☐	2☐	3☐			
9. Variable speed drives	1☐	2☐	3☐			
10. Other	1☐	2☐	3☐	1☐	2☐	3☐

Describe Other: ____

65. Write any other comments that you would like provide to us in the space below.

____

____

____

____

That concludes our survey. Thank you for your time and cooperation. Your answers will be very helpful in our continuing efforts to better serve you. Please return your completed survey in the enclosed postage-paid envelope.

(OPTIONAL): To help us better serve you, please provide the following optional information:

Name____ Title ____

Company_____________________________________ Business Phone:________________________________

Address: ____________________________________ Business Fax: _________________________________

_____________________________________ Email: _______________________________________

____

“Next Level” Triad Report

Triad Conservation Improvement Programs

Plan for the "Next Level"

Prepared by: JD Crowley, Joe Green, Patty Hanson, Kelly Lady, Mike Smith, Roger Warehime, Stephanie Yrjo

Executive Summary

To date, the main thrust of CIP programs has been to use rebates to encourage customers to purchase more efficient equipment. As high efficiency equipment becomes standard in the market, the effectiveness of rebate programs declines. The Triad, therefore, seeks to transform its CIP programs so that they remain effective while at the same time drive toward our vision of the future utility industry. This vision includes demand/response pricing, distributed generation, increased renewable energy, and opportunities to provide non-traditional utility services.

The general strategy is to continuously improve the TRIAD CIP programs by focusing on: 1) cost effectiveness, 2) community involvement and development, 3) effective communications.

Having a written plan assures that all Triad members have the same understanding of the direction of future programs and provides a framework under which progress can be measured. Stipulating that the plan be updated and revised at least twice annually acknowledges the fact that conditions are continually changing and that achieving the "Next Level" is an on-going process.

The tactical portions of the plan are divided into near term (1-3 months), moderate term (3-6 months) and longer term (6-12 months) plans. There are also sections to capture non-CIP plans, tabled topics, and topics that were considered but not included in the plan.

The near term tactical plans include launching the Residential/Small Commercial Audit Program and making the following modifications to the residential Conserve & Save Program:

- Eliminate refrigerator and dishwasher rebates, effective June 30, 2005.
- Eliminate CFL rebates, effective March 31, 2005. Use special promotions to promote CFLs, rather than an on-going rebate program.
- Eliminate the rebate for 13 SEER air conditioners, effective June 30, 2005.
- Eliminate rebates for 92% efficient furnaces and all water heaters for new construction, effective June 30, 2005.

Moderate term tactical plans include:

- Builder programs,
- SNAP green-pricing program,
- Commercial & Residential Education through Community Ed,
- A strategy for improved communications,
- Re-evaluation of the Retail Support Coordinator position.

Longer term tactical plans include:

- Improved relationships with and management of trade allies,
- Evaluating evaporative coolers,
- Researching advanced metering & special billing,
- Researching residential demand controllers.

Introduction

CIP programs to date have focused primarily on achieving energy savings by encouraging the conversion to more efficient lighting, appliances, and equipment. The chief strategy has been to reduce market barriers, primarily in the form of a rebate paid to the customer in order to reduce the premium associated with higher efficiency products.

While these programs have been successful, the Triad believes that the time frame for which these programs will continue to be effective is limited. In large part due to CIP programs & government regulations, certain high efficiency equipment has become standard in the market. With this market transformation is the realization that CIP rebates will be paid to people who would have purchased the higher efficiency equipment without any incentives ("free riders"); thus, the program will have spent money without affecting change.

The vision of the future for the utility industry includes demand/response pricing, distributed generation, increased renewable energy opportunities, and an opportunity to provide additional, non-traditional services. The Triad's CIP strategy should be to continually transform the existing programs and create new programs in order to drive toward this vision of the future.

Such a transformation will not come easily. For one, it will require a cultural shift from administering programs to developing the skills necessary to create new, innovative ways of conducting business. Additionally, the Triad will be out ahead of most other utilities in the state and nation; thus, there will be little opportunity to implement programs that have already been proven elsewhere.

The purpose of this document is to lay out a general plan for getting to the *Next Level*. Having a written plan assures that all Triad members have the same understanding of the direction of future programs. It also provides a framework under which progress can be measured. It is intended to be a "living document" and will be updated at least twice annually.

Primary Objective

Transform CIP activities so that they drive toward our vision of the future.

Vision of the Future

The Triad will be nationally recognized for its innovation, customer satisfaction, and leadership in the areas of demand/response pricing, distributed energy, renewable energy, and energy related services.

Strategy

As municipal utilities, our mission is to enrich the quality of life in our communities by delivering reasonably priced, reliable, safe, customer-focused utility services. Among our guiding principles are Stewardship and Financial Soundness.

By *Stewardship* we mean we are committed to protecting the assets and natural resources entrusted to us, while taking responsibility for educating our communities about the efficient use of energy and water.

By *Financial Soundness* we mean we are dedicated to controlling cost and risk, achieving adequate revenue for future investment, maximizing the utilization of capital, and making decisions with the long-term financial interests of our communities in mind.

With our mission and guiding principles in mind, our strategy is one of continuously improving the value of our CIP offerings by focusing on:

- Cost Effectiveness
- Community Involvement and Development
- Effective Communications

Goals

- Improve the overall cost-effectiveness of our electric CIP program as measured by the Elecben model. (Specific numbers to be determined).
- Establish baseline cost-effectiveness of our gas CIP programs using Bencost.
- Launch at least 3 new CIP programs in 2005. Most likely candidates are:
    - Audit Program
    - SNAP Program
    - Builder Program
- Energy Solutions margin of $34,000 on sales of $340,000
- Launch Community Ed Programs in all three communities.
- Strengthen relationships and/or partnering with other groups such as MMUA, APPA, SMMPA, and trade allies.

This document provides the overall summary of all plans currently under consideration. Each specific program will have a detailed plan created before it is approved and put into action. Specific actions and milestones are tracked on a continuously updated Action Log.

<u>Near Term Tactical CIP Plans (Jan – March 2005)</u>

- **Residential Conserve and Save**
  - *Dishwasher Rebates:* Most dishwashers on the market today are Energy Star. Rebates will be discontinued effective June 30, 2005
  - *Refrigerator Rebates:* The energy savings between Energy Star and non-Energy Star models is small. Rebates will be discontinued effective June 30, 2005
  - *Central Air Conditioners:* The minimum SEER manufacturers will be allowed to produce in 2006 will be 13. We will raise the baseline for energy savings from 10 to 13 effective January 2006. The rebate for 13 SEER will be eliminated, effective June 30, 2005. The $300 rebate for 14 SEER will continue through 2005. As of January 1 2006, the rebate for 14 SEER will be reduced to $200; the rebate will be increased by $50 for each additional SEER (example $250 for 15 SEER).
  - *Geothermal:* Comment to be added to rebate application stating that for water-to-water GX without ARI approval, data must be provided from the manufacturer at the ARI test conditions.
  - *Clothes Washers:* No changes in 2005; re-evaluate fall of 2005 for 2006.
  - *CFL:* Eliminate rebates effective March 31, 2005. Will be removed from the large Conserve & Save Rebate form. CFL promotion after March will be through various special promotions throughout the rest of the year.
  - *Furnace Fan Motors*: Increase awareness. (<u>Patty</u>)
  - *Custom Electric*: <u>Roger</u> to develop standard formulas for determining rebate amounts. Formulas will not be published.
  - *Boilers:* No Changes
  - *Furnaces:* Effective June 30, 2005 there will be no rebate for 92% eff. for new construction. Rebates for retrofit will remain $100 for 92% and $150 for 95%. Rebate for 94% for new construction will be $50.
  - *Water Heaters:* Effective June 30, 2005 there will be no water heater rebate for new construction. For retrofit, rebate will remain $75 for .63 EF and greater.
  - *Custom Gas:* Same as custom electric.
  - *Attic Insulation:* Eliminate the requirement that beginning R Value must be R10 or less. Rebate determined by the net R Value added to get to at least R38.
  - *Load Management Requirement:* OPU's proposal to stipulate on rebate form that OPU customers need to be participating in load management to receive a rebate was evaluated and a decision was made to not make this a requirement. Other means of promotion will be used instead.

- **Residential, Commercial, and Industrial Audit Program**
  - Greg Earnst will be our primary auditor.
  - Carbon Copy Forms will be created for residential audits, so that the report can be left with the customer when the audit is finished.
  - A Triad template has been designed for commercial and industrial audits.
  - Residential customers will be charged $25 for an audit. They will receive approximately $25 worth of materials, or receive a blower test and furnace test. For an additional $25, they can receive both the materials and the tests.

- **Commercial Rebate Programs**
  - We will primarily follow SMMPA on changes they make.

Moderate Term Tactical CIP Plans (April –June 2005)

- **Builder Programs** - The plan is for a packaged program that encourages builders to use energy efficient equipment and practices. May include rebates to builders, but also information and exposure that may help them market themselves and their homes as being environmentally responsible. May go as far as achieving Energy Star Home or HERS ratings.

  The target launch date for the program is May 2005. Before the end of 2004, each utility will meet with builders in their area to hold an informal focus group to determine how the needs of the builders and the utility can both be met.

  RPU to meet with Aquila to see if they will share in the program so that the gas side is represented in Rochester.

- **SNAP** – This is a green-pricing program that encourages the development of small, local solar-electric electricity through a market based approach. OPU would like to launch by Earth Day (April 22 2005). There is concern that this may not be sufficient time, especially at RPU. Depending on the results of the NOD process at RPU, it may be decided to pilot this program at OPU in 2005, and have RPU and AU follow in 2006. Another option is to launch in all three cities in October to coincide with the national Solar Tour.

- **Commercial & Residential Education through Community Ed** – The title of the residential education program is "Home Energy Audits", and the title of the commercial program is "Where Do You Use Your Energy?" Carmel will develop the curriculum and teach the courses. A pilot course is scheduled for 2-Feb-05 in Austin and 9-Feb-05 in Owatonna. Courses to include a participant survey to gauge success and gather feedback for future education course.

- **Improved Communication** - Comments in customer satisfaction surveys indicate customers do not feel they are kept well enough advised of our programs. Kelly and Julie will develop a plan to improve communications. Ideas under consideration include developing a media plan for newsletters & having some section of the newsletters that are common to all three utilities. An issue to be addressed for this to be successful is the fact that AU & OPU publish a monthly newsletter, while RPU's is quarterly.

  Another objective is to determine a method of effectively communicating our DSM achievements to the communities without inundating them.

- **Retail Support Coordinator** – This position was vital when the Conserve & Save Program was first introduced. Now that the trade allies know about the programs, the time requirements are not as great and there may be an advantage to handling the interaction with trade allies by each individual utility.

  Related to this is developing a relationship directly with MEEA rather than through SMMPA. Additionally, a trade ally plan must be developed.

Longer Term Tactical CIP Plans (June – December 2005)

- **Evaporative Coolers**: JD will investigate this technology as an alternative to DX refrigeration air conditioning. Find where the technology has been proven to work in our climate.

- **Advanced Metering & Special Billing for Key Accounts:** Kelly will research availability and cost of equipment, software, etc.

- **Residential Demand Controller:** Roger will research the cost of the equipment, etc. as well as try to learn how customers have been enticed to participate in a pilot program.

- **Gas Radiant Garage Heaters:** Joe to research and make recommendation for rebate.

- **CSR "Audit-mation" Program:**

- **Tankless Water Heaters**

- **Air Source Heat Pumps**

- **Trade Ally Communication & Yearly Meeting**

Non-CIP Tactical Plans

- **Appliance Service Plan** – Explore subcontracting Aquila's *Service Guard* program. Issues to address are competing with local appliance stores. Joe to learn more about Aquila's program and determine if OPU or AU management will be concerned with using Aquila.
- **Surge Protection** – Determine if new technology is available that allows whole house protection of sensitive appliances such as TV's and computers. **(Needs Owner)**
- **Focus Groups** – Will be held in all 3 cities biannually (April & October). Stephanie is primary champion.

Tabled Topics (to be considered sometime in the Future)

- **Financing for Commercial Lighting Projects** – Greater participation by small commercial customers could be realized by providing 0% financing to qualifying businesses in lieu of a rebate. Loans would be structured such that the loan payment amount is approximately the same as the energy bill savings. The interest being covered by the utility would be recorded and filed as CIP expense.

  Concerns to be addressed include:
    - Will SMMPA reimbursements still be available
    - Conflict with Energy Solutions financing programs.
    - Billing and administration concerns; Mike Smith recommends that this would better be handled as turnkey projects through Energy Solutions.

- **Programs targeted specifically at multi-family dwellings.**
- **Rain Harvester**
- **On-site Generation**
- **GIS Maps**
- **Using the return side of the Mayo district heating line for GX**
- **Laundry ozonation for commercial launders.**

Topics Considered but not Included in the Plan

- **House Doctor -** This would have been a method to promote the energy audit program. One concern raised was that the name would not play well in Rochester which has a large medical community.
- **Utility Bill Round-up** – It was decided that this program is counter to the Low Income aspect of our CIP plan in that it pays for energy use rather than promoting the reduction of energy use.

Task Force Recommendations

Phase II Task Force Meeting
Tuesday, October 26, 2004
12:00pm – 2:00pm
RPU Training Room

Meeting Minutes

I. Greetings and Introductions

Mary Tompkins, RPU Manager of Customer Service, welcomed the group and especially thanked the Task Force members for attending.

II. Summary of End Use Survey and Cost Benefit Analysis

Kiah Harris from Burns & McDonnell explained the outline of the meeting. He will go through the summary of the End Use Survey and answer questions. Following his presentation, each Task Force member will have 5 minutes to give their responses to the seven questions given to them in their packets. Kiah also explained that the process and future of the Task Force on a going forward basis is questionable at this point.

Kiah began his presentation with the explanation of appliance and equipment inventory, or opportunities, in Rochester. One Task Force member expressed his objection of the term inventory and from here on, the term would be referred to as opportunities.

A comparison of Residential and Commercial estimated demand and energy impacts were discussed. On the Residential side, a comparison was made between the conversion to Energy Star appliances and the conversion to gas appliances. The Commercial side compared efficiency conversions to those converted to gas. There was a lot less opportunity on the Commercial side when converting to gas. Residential showed the opposite with more savings when converted to gas.

Kiah then reviewed the Benefit/Cost Analysis for Residential and Commercial while comparing Participant to Societal, or those that don't participate but are affected.

Florence Sandok, Task Force member, added that customers were not asked energy efficiency questions on the Commercial survey. There are other solutions besides appliances. She gave the example that Mayo has some lights that turn on when people enter the room and shut off when they exit.

Florence also expressed the idea that global warming may "skew" things – i.e. air conditioning and natural disasters. Insurance companies are now taking this into account with increased values of appliances.

Stephanie Yrjo, RPU Commercial Account Representative, further explained that the Cost/Benefit Analysis took specific motors and looked at the spectrum. We will look at costs and refine the numbers at a later date.

Keith Butcher, Manager of External Affairs – Center for Energy and Environment, supported these assumptions.

III. Sharing of Task Force Ideas and Recommendations

*****

Some questions to consider in anticipation of the last Task Force meeting on October 26, 2004….

1. What pricing conventions could RPU develop to make energy conservation efforts more effective?
2. What do you think is the largest hindrance to customer participation in programs? What role could RPU play in removing that hindrance?
3. Rank the importance of RPU's conservation programs (1 being most important, 5 being least important).
   - Pricing signals ______
   - Incentives ______
   - Education ______
   - Promotion ______
   - Other (please specify) ______
4. In your opinion, what is the best way for RPU to encourage participation in renewable energy programs?
   - Offer the customer a choice where they pay a premium to purchase renewable energy.
   - Subsidize (build into rate structure) some or all of the cost of a renewable program.
5. In your opinion, what is the most effective way for RPU to administer its conservation programs?
   - By customer choice – promoting rebates, special rates, education, etc.
   - By building into rates – all customers participate in conservation through the rate structures and/or required programs.
6. Please suggest any conservation programs not discussed at Task Force meetings that you feel would be of value for RPU to research.
7. Would you be willing to promote RPU's programs (e.g., energy efficient lighting for homes) through community groups or committees with which you are involved?

*****

Task Force Member 1

#1 Dual meters offering – peak vs. non-peak. Energy calculator on website would be good to have.
#3 Education is important and ongoing. Incentives are a good way to get people to act.

#5 Customer Choice
#6 Transfer coal on rail vs. trucks
#7 Yes – I would be willing to serve on a community group.

Task Force Member 2

#2 Pre and post-inspections for small dollar amount rebates make the biggest hindrances – the hassle factor.
#4 Encourage renewable energy participation – the big one is wind. Incentives will come naturally for wind as turbines are built and the cost drops below other power.
#5 Customer Choice.
#6 Air handling units waste energy. Do commissioning. Vending misers are a good savings.

Task Force Member 3

#1 Money saving on bills. Anything that can be credited on a bill (example: timers for A/C).
#2 The biggest hindrance is cutting out the UPC symbol for the rebate and mailing it in. Instead, just bring in a coupon. Make things easier.
#3 Education. Start with educating the elementary kids and they will educate the parents. Kids put great pressure on parents. Incentives is number 2 and promotion is number 3.
#4 Customer Choice.
#5 Customer Choice.
#6 Onsite exchange of working light bulbs for CFL's. This would be very little hassle. Turn off the lights! This is especially important in big buildings. Include store coupons in bills that customers could take with them to purchase CFL's and other energy efficient products. Lobby Congress for tax credits to providers of alternative energy choices. In lieu of off-peak storage capability and technology, manufacture hydrogen and oxygen for on-peak demand.

Task Force Member 4

This Task Force member would have liked to be involved from the beginning and been able to set the number of meetings. She also mentioned she had good ideas on how to structure the group and whether we want to continue its existence.

#1 Price incentives - Schedule rates on amounts of use and time of use.
#2 People don't know about the reward. Example: Paul Wellstone commercial. Do fun ads like his. Do more education and advertising.
#4 Subsidize the renewable rate program. This should include the WHOLE cost including health costs and externalities like pollution, etc. Penalize those not participating. Education is the key.
#5 Build into rates. All customers participate in conservation through the rate structures and/or required programs. Penalize those customers that don't participate.

#6 She wants to see more task forces.

How much has RPU paid consultants? Should hire a knowledgeable energy consultant to design the best program for a customized conservation program for the Rochester community. Teach Community Ed, tree planting, installing wind towers, student education programs, partner with builders, and install efficient home lighting systems.

#7 She would be willing to promote programs. She wants to be involved in the fine tuning. Keep it simple. Continue the process as we have just begun. Rebates for buying compact fluorescent light bulbs should be paid out where the light bulb is bought.

ADDITIONAL THOUGHTS: Send staff to green festival conferences. Have a tour of energy efficient homes in Rochester. City – wide contests for best energy efficient ideas with energy efficient award.

Task Force Member 5

This task force member explained that the rebates did not incent him to buy certain appliances. What is the motivation? Why buy a $700 refrigerator if you don't have $700?

RPU bill – Why is it that way? Why is it as high as it is? Can someone come to the house to say why it is so high? Be more proactive. Does RPU have a home auditor? (Stephanie confirmed that RPU can do this for a fee of approximately $50). $50 fee would be a roadblock in having that done.

Task Force Member 6

He sees comparable things. To capture the life cycle, it would take 20 to 25 years.

Partner with vendors for instant rebates.

Partner with builders and building/mechanical codes. Example is gas piping – the cost is high to put that in for a range.

Cost to conversion – minimum vs. maximum.

Pay 100% of difference or change the codes.

#3 Incentives is number 1. 70% of those that get a high efficiency furnace are free riders. The builder would have put them in anyway. The builder puts in a 92% efficient furnace to meet code and the customer gets the rebate.

Promotions is number 2. This includes education. Educate the kids and start young. Discontinue the bill inserts – most are discarded without being read.

#4 Customer Choice. Right now, it does not make financial sense.

#5 Build into the rates. Build the infrastructure into the rates.

#6 Work your partnerships. Work with vendor installers including appliance manufacturers.

Distributive generation. Larger companies are doing this out west. Partner with Mayo and IBM to do this. Incentives for this.

Energy Committee for Rochester Schools – Rory is involved with this group. The idea is to identify where you are wasting money. Who will manage the lights, remove refrigerators and heaters out of the classrooms, and removal of other teacher conveniences. Help facilities manage their energy and identify opportunities with an "audit for energy conservation".

Develop software program for auditing?

#7 Yes – he is willing to promote RPU programs.

Task Force Member 7

#1 Variable rates for peak – dual meters.
#2 Largest hindrance is cost effectiveness
#3 Incentives
#4 Subsidize/build into rates.
#5 Build into the rates – it will be easier.
#6 Night rates

Even out peak demand – energy storage.

How will we find more energy? Any power Ok – even nuclear which has no pollution and is cheap.

#7 Yes-if cost effective.

Task Force Member 8

#1 How much you use and when.

#2 The biggest hindrance is the lack of incentive. Change the rate structure to make customers more aware/ pay more attention. Residential participation is better than the commercial side. Put a greater emphasis on the commercial customer, where there is more potential for energy savings.

#3
1. Price
2. Incentives
3. Education/Promotion (Should be together)

#4 Wind is getting more competitive. Subsidize some or all of the cost. We need availability of transmission facilities for wind to get to the grid.

#5 The most effective way is to build into the rates. He doesn't want to subsidize someone else's power.

#6 Ground source heat pumps – work with developers to put in a community look. This is cheaper that each putting their own in. Partner with sewage treatment for heating. Educate sales people on advantages like energy savings of upgrading appliances.

#7 Yes, he is willing to promote RPU programs.

Task Force Member 9

The only complaint that others had about RPU was the severe tree trimming on the boulevard.

#1 According to this Task Force member, Big G is not supporting the purchase of the Energy Star ranges.

Did not like the hydrant fee.

Otherwise no complaints – RPU is #1.

#7 Yes, she is willing to promote RPU programs.

IV. ***Wrap Up***

- Florence suggested a poll of those who wanted to continue on the task force. Mary Tompkins took the poll and the majority (7-1) wanted to continue.
- Task force members would have liked to decide how many meetings and how they would have been structured, ongoing or not. They wanted to be involved from the beginning and to have more involvement.
- Florence informed the group that this is a public utility and if the community wants a task force, they should be able to have one.
- Kiah intercepted that everyone has a representative on the Board.
- Rory also supported this idea that RPU should make the decisions because of the level of expertise.
- Florence would still like to collaborate as partners.
- Bill explained that he had been involved with SLP pollution discussions and that RPU has become more open to community groups. He thinks we should keep on with the community task force. He is pleased with the forthcoming of RPU and the opportunity to get involved. Both would benefit from an ongoing citizens committee. He also suggested having terms assigned so others can get involved. Bill said this would not be unique in a city – other city and county departments have citizen task forces.
- Mary Tompkins confirmed that she would bring all this information back for discussion as the majority is interested in further participation of "citizen's advisory groups".
- Kiah summarized the process of RPU at this point. The suggestions will be put into a financial model to see the impact on the rates. This will be done over the next month or so.
- Stephanie inserted the fact that RPU is looking at conservation programs with Owatonna and Austin. RPU will definitely take the suggestions into account.

- Mary also informed the group that next year RPU is looking at doing pre-payment metering. This would be able to track usage and has been very successful in other cities.
- Kiah reminded the task force members to also send us their comments after the meeting too.
- Larry Koshire, RPU General Manager, closed the meeting thanking everyone for their participation.

Flipchart notes:
- Straw Pole: Majority interested in further participation. Citizen Advisory Groups.
- TOU rates
- Rebates – hassle free
- Customer choice – flexibility

Residential & Commercial End Use Information

Estimated Residential Demand Savings
Note: RPU summer peak is about 4pm
Air conditioner demand going to SEER 12

MWh saved = 7,087
Assume two thirds of energy used in July and August
Energy for July or August peak= 2338.86312 MWh per month
Assume half of the energy saved during 8 hours
Energy saved during 8 hours = 1169.43156 MWh
Energy saved per hour per day 4.71544984 MWh
Demand on peak = 4.71544984 MW

Demand reductions per ac are .6 to 1.2kW depending on if the same size or reduced size is installed. Based on the diversity on the RPU system, the average natural demand reduction would be .2 to .4kW.

Refrigerators

MWh saved = 1,252
Saved per day= 3
Assume half of energy used during 8 hours= 1.714685
Energy per hour 0.214336 MWh
Average Demand on peak 0.214336 MW

Freezers

MWh saved= 98
Assume averaged across the day
Ave MW= 0.011242 MW

Compact Flourescent

Energy savings based on 4 hours per day
Not coincident with RPU peak, therefore, no demand savings

Washing Machine

Assume same diversity as refrigerators
MWh saved = 13,973
Saved per day= 38.28084 MWh
Assume half of energy used during 8 hours= 19.14042
Energy per hour 2.392552 MWh
Average Demand on peak 2.392552 MW

Dishwasher

Not coincident with RPU peak

Water Heater

MWh used= 21,048
Average per day= 57.6661 MWh
Majority of energy is used in morning between 5 to 7 and evening from 7 to 10
Assume half is during this period
Average for rest of hours per hour = 1.517529 MW

Dryer

Assume same use as washing machine		
MWh used=	30,190	
Used per day=	82.71312	MWh
Half of energy in 8 hour period	41.3565616	
Energy per hour	5.16957021	MWh
Ave demand on peak	5.16957021	MW

Blower motor

From Ben cost study Average energy reduction =	570	kWh
Average demand reduction =	0.19	kW
Number of gas furnaces =	35867	
Number of electric furnaces =	552	
	36419	
Max Energy savings MWh	20758.83	

Summary demand reductions due to efficiencies

	)emand Reductions (MW
Appliance	Maximum
Air Conditioners	4.7
Rerigerators	0.22
Freezers	0.011
Washing Machine	2.35
	7.281
Conversion to gas appliances	
Water Heaters	1.52
Dryers	5.2
	6.72
Total	14.001

Load Management		Residential	Commercial
Total Central AC units		36064	1825
Current Partners		8461	
Reductions per AC kW	0.98		
Estimated current reductions kW		8292	
Estimated maximum reductions kW		35343	
Estimated max red when SEER 12		25245	
(assumes .7kW per point)			568
Total Water Heaters		4375	
Current Partners		905	
Reductions per AC kW	0.68		
Estimated current reductions kW		615	

Estimated Residential Energy Savings

Appliance summary				Estimated Energy Savings Each (kWh)	Estimated Energy Savings Total (MWh)	Source for savings		Maximum Estimated Demand Savings Coincident with RPU MW	
Energy Star or other Efficiency	Conversions								
Central Air more than	5 yrs	20484	(No. of customers)	346	7,087	calculator		4.7	
Room Air more than	5 yrs	2618	(No. of units)	58	152	calculator		0.1	
Refrigerator more than	5 yrs	13176	(No. of units)	95	1,252	calculator		0.2	
Freezer more than	5 yrs	1231	(No. of units)	80	98	calculator		0.0	
No Compact FL		15214	(No. of customers)	124	1,887	calculator		0.0	
Washing Machine		38705	(No. of customers)	361	13,973	calculator	Includes dryer savings	2.4	
Dishwasher-heated drying		9792	(No. of customers)	103	1,009	calculator		0.0	
HVAC Blower		36419	(No. of units)	570	20,759	Bencost study		6.9	Ben cost assumed .19kW per mot
				Total Usage Each (kWh)	Total Usage Total (MWh)				
Other Options									
Electric heat-Main		788	(No. of customers)	43174	34,021	energyguide.com web site		Not on summer peak	
Electric auxiliary heat		3035	(No. of customers)					Not on summer peak	
Dryer		30342	(No. of customers)	995	30,190	Cornhusker Power/Neb web sites		5.2	
Spa/Hot tub		585	(No. of customers)	1680	983	Cornhusker Power/Neb web sites		minimal demand	
Water Heater		4375	(No. of customers)	4811	21,048	Cornhusker Power/Neb web sites		1.5	
Range/Oven		30704	(No. of customers)	256	7,860	Cornhusker Power/Neb web sites		Not applicable to DSM	

Commercial Demand Side Management Energy Reduction Estimates
Rochester Public Utilities

Assumptions

There are a number of assumptions included in the DSM measure energy reduction estimates for commercial customers. These include:

- The survey population of 2,145 customers consists of small commercial properties. Most would have building areas of approximately 5,000 square feet or less. A larger customer in this group might include a 50,000 square office building.
- RPU commercial customers account for 50% of the SMMPA commercial customers' energy use.
- RPU commercial customers account for 50% of the SMMPA commercial customers' floor space (i.e., 50% of 67,210,000 sqft or 33,605,000 sqft).
- Use data from the US Department of Energy – 2004 Building Energy Databook when needed.
- The DSM measures will have 100% penetration. In other words all customers that are candidates for a given DSM measure will implement the measure.

References

References and calculation tools used include:

- ***End-use Survey of RPU Commercial Customers:*** A survey sent to 2,145 of RPU's commercial customers. Used to determine quantities customers and appliances.
- ***eQUEST:*** *A* computer simulation program that is a full implementation of the widely recognized DOE 2.2 calculation engine. It can perform hourly calculations for an entire year and incorporates local weather data.
- ***US Department of Energy – 2004 Buildings Energy Databook:***. This reference includes over 100 pages of data tables dealing directly with buildings and their energy use.
- ***Energy Star homepage:*** Web site with a variety of reference material and calculation tools for various technologies. Estimates that involved use of these calculation tools includes room air conditioners, freezers, washing machines, dishwashers, computers, printers, and copiers.
- ***SMMPA Integrated Resource Plan 2003-2018:*** In particular Table VII-8, *"SMMPA Sales Profile"*, which has an end-use breakdown of electricity use for commercial customers. The metric used is the Energy Use Indices (EUI) which has the units of kWh/yr/sqft.

Approach

The approach used to determine the potential energy savings for RPU's commercial customers included three basic steps. These include:

1. Identify the appliances and energy using systems that account for the majority of overall electric consumption.

2. Use the end-use survey to determine the number of customers, or quantity of energy using devices identified in step 1. In some cases the DOE – 2004 Buildings Energy Databook.
3. Use engineering calculations to determine the energy savings for the devices and quantities identified in steps 1 and 2 respectively.

1) Selecting Appliances and Energy Using Systems
The appliances and systems in the commercial customer electrical energy reduction estimates include:

- Central air Conditioning (AC) units more than 7 years old
- Room AC units more than 7 years old
- Refrigerators more than 7 years old
- Freezers more than 7 years old
- Use of incandescent lamps instead of compact fluorescents
- Washing machines
- Dishwashers with heated drying
- Non-electronic ballast fluorescent light fixtures
- Variable speed drives (VSD) on 3 HP AC unit fans
- Computers
- Printers
- Copiers

In addition estimates were provided of the total consumption of a number of electric appliances and systems that could be switched to natural gas. This group includes:

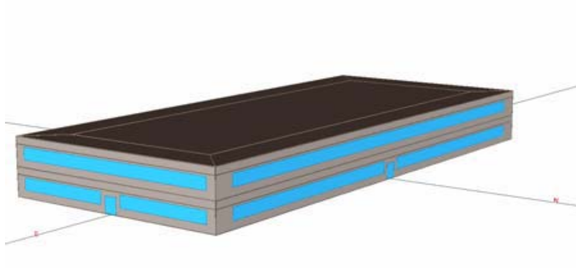
- Electric heat
- Dryers
- Range or oven
- Water heater

2) Determining Quantities
The end-use survey was the main source for determining the number of customers or quantity of appliances and systems. In most cases the number was derived my multiplying the percentage of positive respondents by the sample population size of 2,145 customers. Assumptions were used when the number could not be directly found. For instance, an average of 6 AC units was used if the customer answered positive to the item "*more than 3 room AC units*". In other cases the survey questions asked if the customer had one or more units of an item. Examples of assumptions used in these cases are 10 computers per customer, 3 printers per customer and 2 copiers per customer. The quantities used for the estimates can be found in Table ES-1.

3) Engineering Calculations
Engineering calculations included the use of hourly computer simulation programs, Energy Star EXCEL calculation templates, and device specific calculations. Examples of this work follow.

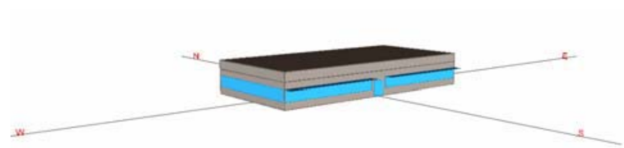
Central Air Conditioning Units

This estimate is based on the results of computer energy models using the eQUEST program. The models included two office buildings with areas of 5,000 and 45,000 square feet, and two retail buildings with areas of 5,000 and 45,000 square feet. There were a total of eight simulations. The first simulation for each model had an AC system



having an EER of 8.5, then with an EER of 9.7. An EER of 8.5 is typical for an older unit, while the EER of 9.7 represents a new, high efficiency unit. The results were used to determine the percent reduction in cooling power consumption expected with the newer units.

Results from the end-use survey indicate that 1,825 of the customer population have central AC systems and that 935 have been replaced within



the last 7 years. This leaves 936 customers (or 43.7% of the total population) with units older than 7 years. If 43.7% of the population can reduce their cooling power consumption by 14%, then the total reduction across the entire population is 6.11% (i.e., 43.7% * 14%).

Central AC Savings Estimate

eQUEST (DOE 2.2) simulation output for generic facilties in Rochester, MN

	Large Office ~ 45,000 sqft	**Small Office** ~ 5000 sq ft	**Small Retail** ~ 5000 sq ft	**Large Retail** ~ 45,000 sqft	**EER**
Base Cool (kWh)	48,230	95,630	6,840	12,980	8.5
Retrofit Cool (kWh)	41,540	82,370	5,800	11,180	9.7
Difference in Cool	6,690	13,260	1,040	1,800	
% Difference in Cool	***13.9%***	***13.9%***	***15.2%***	***13.9%***	

assume average reduction of 14% of cooling use by replacing older central AC systems

Table VII-8 of the SMMPA Integrated Resource Plan 2003-2018 (IRP) indicates that the EUI for cooling for commercial customers is 1.8 kWh/sqft/year for the entire population of 67,210,000 square feet. Assuming a 6.11% reduction in this EUI, and assuming RPU represents 50% of the SMMPA population

Savings (kWh/yr) = 50% * 67,210,000 sqft * 1.8 kWh/sqft/yr * 6.1%
= 3,697,016 kWh/yr

Savings per customer (kWh/yr/customer) = 3,697,016 kWh/yr / 936 customers
= 3,948 kWh/yr/customer

Commercial lighting
References used for lighting estimates include Table VII-8 of the SMMPA IRP and tables from the DOE 2004 Buildings Energy Databook. These include Table 5.9.1, *"2001 Total Lighting Technology Electricity Consumption by Sector"* and Table 5.9.10, *"Typical Efficacies and Lifetime of Lamps"*.

Table VII-8 lists an EUI of 4.2 kWh/yr/sqft for SMMPA commercial customers. The overall distribution of lighting energy use for buildings in the United States is listed in Table 5.9.1. The following table includes the commercial sector portion of Table 5.9.1. The right hand column lists the estimated breakdown of the SMMPA lighting EUI based on these percentages (i.e., Est EUI for incandescent = 26% * 4.2 kWh/yr/sqft = 1.11 kWh/yr/sqft).

Excerpt from Table 5.9.1
Commercial Sector

Lighting Type	(10^9 kWh/year)	Percent of Use	Estimated Breakdown of RPU Lighting EUI
Incandescent			
Standard	103	26%	1.11
Halogen	21	5%	0.23
Fluorescent			
T5	0	0%	0.00
T8	50	13%	0.53
T12	157	40%	1.69
Compact	13	3%	0.14
Miscellaneous	0	0%	0.00
HID			
Mercury Vapor	7	2%	0.07
Metal Halide	34	9%	0.36
HP Sodium	6	1%	0.06
LP Sodium	0	0%	0.00
Total	***391***	***100%***	***4.20***

Table 5.9.10 lists the efficacy for various lighting technologies. Efficacy is the ratio of light output to electric energy input (lumens/watt). A post retrofit EUI for a given lighting type can be estimated by taking the product of the existing EUI and the ratio of the old to new efficacy.

$$EUI_{retrofit} = EUI_{existing} * (\text{old efficacy/retrofit efficacy})$$

Replacing incandescent lamps with compact fluorescents gives the following results.

$$EUI_{cfl} = (1.11 \text{ kWh/yr/sqft}) * [(15 \text{ lumens/watt})/(65 \text{ lumens/watt})]$$
$$= 0.26 \text{ kWh/yr/sqft}$$

There were 1,386 respondents with incandescent lights. The savings resulting from retrofitting incandescent to compact fluorescents is calculated as follows:

$$\text{Savings (kWh)} = \text{(cust. w/ incan)/(population)} * \text{area} * (\text{EUI}_{\text{existing}} - \text{EUI}_{\text{retrofit)}}) * \%\text{area}$$
$$= (1{,}386/2145) * (33{,}605{,}000 \text{ sqft}) * [(1.1 - 0.26) \text{ kWh/yr/sqft}] * 30\%$$
$$= 5{,}565{,}000 \text{ kWh/yr}$$

$$\text{Savings per customer (kWh/cust)} = \text{Savings / Cust. with incan.}$$
$$= (5{,}565{,}000 \text{ kWh/yr}) / (1{,}386 \text{ customers})$$
$$= 4{,}015 \text{ kWh/yr}$$

Excerpt from Table 5.9.10
Typical Efficacies and Lifetimes of Lamps

Current Technology	Efficacy (lumens/watt)	Typical Rated Lifetime (hours)
Incandescent	6-24	750-2,000
Torchiere Halogen	2-14	2,000
Tungsten-Halogen	18-33	2,000-4,000
Mercury Vapor	25-50	24,000+
Fluorescent	50-100	7,500-24,000
Compact Fluorescent	50-80	10,000-20,000
Metal-Halide	50-115	6,000-20,000
High-Pressure Sodium	40-140	16,000-24,000
Low-Pressure Sodium	120-180	12,000-18,000

There were 1,587 customers with older fluorescent fixtures. Savings by retrofitting these fixtures with T-8 lamps and electronic ballasts is found in similar manner using the existing EUI of 1.69 kWh/yr/sqft, an existing efficacy of 55 lumens/watt and a retrofit efficacy of 85 lumens/watt and lighting area of just over 87%. The results follow:

Savings = 15,522,000 kWh/yr

Savings per customer = 9,489 kWh/yr/customer

Variable Speed Drives on 3 HP AC Unit Fans

There will be a variety of AC unit fans sizes in the commercial population. This analysis assumes an average size of 3 HP. The amount of energy consumed by a motor is a function of the loading of the motor and the run hours. A 3 HP motor, at a 70% motor load and running 24 hours a day would consume 13,723 kWh/year.

$$\text{Energy used (kWh/yr)} = \text{HP} * .746 \text{ kW/HP} * \% \text{ load} * \text{run time (hrs/yr)}$$
$$= (3 \text{ HP}) * (.746 \text{ kW/HP}) * (70\%) * (8{,}760 \text{ hrs/yr})$$
$$= 13{,}723 \text{ kWh/yr}$$

A variable speed drive (VSD) can easily reduce the power consumption of an AC unit fan by 40%. The annual energy savings by installing a VSD on these fans is 5,489 kWh/yr.

$$\text{Savings using VSD (kWh/yr)} = \text{Energy used (kWh/yr)} * \% \text{ reduction using VSD}$$
$$= (13{,}723 \text{ kWh/yr}) * (40\%)$$
$$= 5{,}489 \text{ kWh/yr}$$

Statistical Relationship Photovoltaic Generation & Electric Utility Demand in Minnesota (1996 – 2002)

STATISTICAL RELATIONSHIP BETWEEN PHOTOVOLTAIC GENERATION AND ELECTRIC UTILITY DEMAND IN MINNESOTA (1996-2002)

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ABSTRACT

Photovoltaics have an intuitively positive relationship with summer peak electricity demand periods. This study compared photovoltaic output with electric utility demand under various scenarios to determine photovoltaic capacity performance during periods of high electricity demand and certain months and times of day.

Three fixed-tilt and fixed-azimuth photovoltaic installations in the Minneapolis-St. Paul metropolitan area (Minnesota) were analyzed, comparing their electricity output's relationship to Xcel Energy's electrical demand from 1996 to 2002 using hourly output and coincident utility load data.

Using electric utility accreditation standards, two of the sites had capacity values ranging from 24% to 44% from June to September in the late afternoon, while the third site was lower due to shading of the panels. When the data were filtered for electrical demand exceeding 99% of annual peak, one of the sites produced at 62% of capacity, while the other two were less, again, likely due to shading.

1. PHOTOVOLTAIC INSTALLATIONS

1.1 Site Descriptions

Seventeen two to three kilowatt (kW) photovoltaic (PV) systems were installed in 1996 under Xcel Energy's (then Northern States Power) Solar Advantage Program in conjunction with the Solar Electric Power Association (SEPA). Three of the systems, located in Minnetonka (MTK), Rosemount (RMT), and White Bear Lake (WBL), were outfitted with data logging equipment (Figures 1, 2, and 3).

Fig. 1: Minnetonka (MTK) site picture (photo: SEPA).

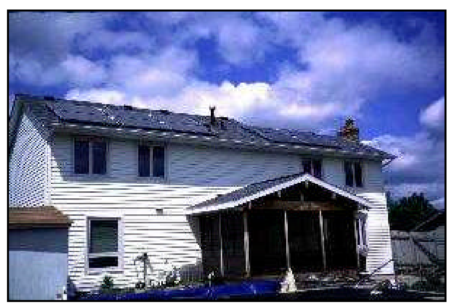

Fig. 2: Rosemount (RMT) site picture (photo: SEPA).

Fig. 3: White Bear Lake (WBL) site picture (photo: SEPA).

All three sites used ASE 50-volt, 285 watt panels and had fixed-tilt angles flush with the roof (Table 1). A solar pathfinder diagram was not available for the sites to determine the exact amount of shading. Elevation from ground level was not calculated but a comparative ranking would place them in order of lowest to highest as WBL, MTK, and RMT. Subjectively, the amount of shading from lowest to highest was RMT, WBL, and MTK.

TABLE 1: INSTALLATION SPECIFICATIONS

Site	Azimuth	Tilt	Inverter (kW)
MTK	179^o	39.8^o	Trace 4.0
RMT	180^o	33.7^o	Omnion 2.5
WBL	180^o	22.6^o	Trace 4.0

Source: Solar Electric Power Association, 2003 (1) (2).

1.2 Data Description

Averaged hourly Xcel Energy system electric load data for Minnesota was obtained from the Mid-Continent Area Power Pool (MAPP) and converted to a percentage of peak for each year (demand data for each year divided by peak demand number for that particular year) (3).

Fifteen minute photovoltaic site information was obtained from the SEPA website and data were filtered for hours corresponding to the Xcel Energy demand data by hour to provide a “snapshot” of photovoltaic performance from August 1996 to October 2002, sans September 2002, for which data was unavailable (1). Data was only available for the RMT site from August 1996 to December 2000 (2).

1.3 Calculating Total System Ratings

The direct current (DC) panel rating using standard test conditions (STC) was 2.85 kW for MTK and WBL and 2.28 kW for RMT. The peak DC output seen over the six year period for MTK was 2.68 kW and for WBL was 2.56 kW (RMT unavailable) or 6% and 10% less than STC rating respectively. Irradiance did exceed STC of 1000 watts/m^2 during the studied time period.

While photovoltaic panels themselves have a DC rating based on an industry accepted standard, photovoltaic systems do not have one for alternating-current (AC) rating. There are various methods for calculating an AC system rating, including the PVUSA Test Condition (PTC) and the Solar Electric Power Association (SEPA) derating methods (4) (5).

Under the PTC method, the combined DC rating of the solar panels in an array is derated for the normal operating conditions, as well as efficiency losses in the wiring and the inverter. Under the SEPA method, an AC rating is calculated using a regression analysis at modified PTC conditions. The PTC and SEPA methods were low in five of six cases when actual peak AC data was examined (Table 2). The PTC calculation was the closest to the actual peak AC values recorded. However, only roughly 1% of the data exceeded the SEPA rating.

TABLE 2: SYSTEM AC RATINGS (kW)

Site	DC Rating	Peak AC	PTC Rating	SEPA Rating
MTK	2.85	2.49	2.40	2.10
RMT	2.28	2.08	1.90	1.80
WBL	2.85	2.36	2.40	2.10

Determining the appropriate AC capacity is important in calculating the percentage of peak capacity. Dividing a 1.5 kW output during a peak demand period by 2.49 kW results in 60% of peak rating. Dividing it by 2.10 kW results in 71% of peak rating. The percentages, although in-exact, provide an easy to read format.

Unless noted, in the interest of a conservative analysis, the actual peak exhibited was used to determine the percentage of peak. For reference, the use of the PTC or SEPA ratings would increase the percentages roughly 3% to 10%.

2. PHOTOVOLTAIC PERFORMANCE

2.1 Average Annual Electricity Generation

The sites generated varying amounts of electricity in total over the study period and on an annual basis, but RMT was 0.57 kW (DC rating) smaller than MTK and WBL and had two less years of data. When the electricity generation is standardized on the DC system rating, RMT generated 1,042 kWh per DC kW, with MTK and WBL generating 3% and 16% less respectively (Table 3). When standardized, based on the peak AC current measured during the study period, WBL was again lower than MTK and RMT.

TABLE 3: ANNUAL ELECTRICITY GENERATION

Site	Total (kWh)	Annual (kWh/yr)	DC Annual (kWh/kW/yr)	AC Annual (kWh/kW/yr)
MTK	17,800	2,892	1,015	1,161
RMT	10,501	2,376	1,042	1,142
WBL	15,468	2,508	880	1,062

A previous study by the author calculated that 3% of electricity generation was compromised by snow loading on the WBL site, which has the lowest tilt angle of the three sites, and did not as readily shed snow (6). Site visits on March 8, 2001 showed the WBL site with snow on much of the roof and panels and the MTK site completely free of snow (Figures 4 and 5).

Fig. 4: White Bear Lake (WBL) site on March 8, 2001.

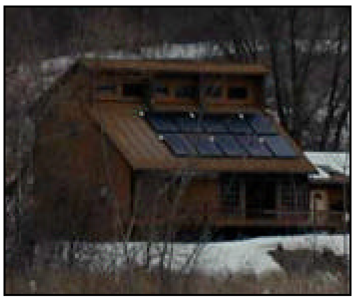

Fig. 5: Minnetonka (MTK) site on March 8, 2001.

2.2 Visual Relationship to Electricity Demand

The data can be looked at visually to provide a picture of the photovoltaic and electric demand relationship. The two peak demand days for 1999 and 2000 were selected to illustrate a sunny and a cloudy day.

The peak demand day for 1999 occurred on July 29 and the photovoltaic production was continuous and uninterrupted (Figure 6). MTK, RMT, and WBL peaked around noon, while the peak demand for the year occurred around 4 pm. Demand exceeded 95% of that year's peak from 10 am to 7 pm, so the sites' electricity production was valuable the majority of the day.

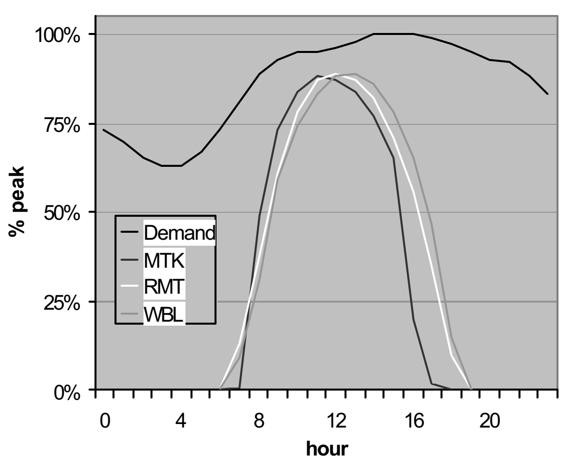

Fig. 6: Photovoltaic production and Xcel Energy electric demand on July 29, 1999.

The peak demand day for 2000 occurred on August 15 around 5 pm (Figure 7). Demand exceeded 95% of peak from 12 pm to 9 pm, a shift toward the evening that would tend to decrease the relationship between photovoltaic generation and demand. However, the photovoltaic sites did not exhibit a bell curve, as clouds affected MTK and RMT production during the noon hour. No AC electricity output was recorded for the WBL site, which was either not generating, the data logging equipment was malfunctioning, or both. The WBL site was recording erratic solar irradiance, indicating a data collection problem.

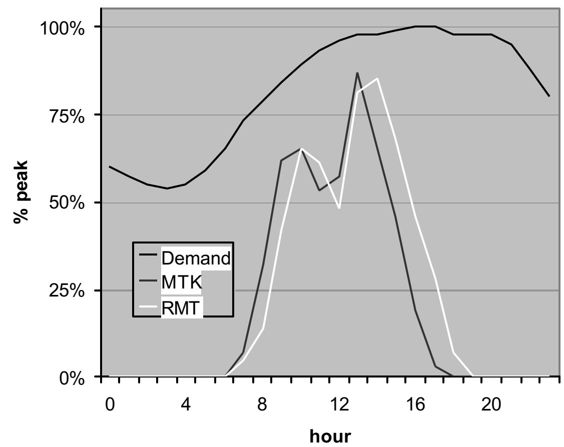

Fig. 7: Photovoltaic production and Xcel Energy electric demand on August 15, 2000.

These two scenarios are diametric snapshots of how photovoltaic production and electric demand interact. The next section calculates the statistical relationship over longer time periods.

2.3 Statistical Relationship to Electricity Demand

The statistical relationship between photovoltaic generation and electric demand can be studied under various scenarios to determine photovoltaic capacity performance during periods of high electricity demand and certain months and times of day.

The photovoltaic systems have azimuths facing due south, which optimizes annual electricity production. The WBL site has the lowest tilt angle of the three sites, in theory, optimizing it for summer electricity production, when the sun is higher in the sky. Xcel Energy's annual peak demand hour typically occurs in July around 4 pm so it is not expected that these sites are sited for optimal performance in relationship to electric demand. The systems' peak capacity performance during high demand periods could be increased if they were on active tracking mechanisms or if the system azimuths were directed more westerly. The latter case would decrease overall annual electricity production however.

2.3.1 General Capacity Performance

During daylight hours the systems' performance was 7% to 12% of peak capacity, which increased during Xcel Energy's general summer peak demand of June to September from 9 am to 9 pm, to 19% to 32% of peak (Table 5) (7). As would be expected, the noon hour window of 11 am to 1 pm from June to August exhibited very high peak percentages of 65% to 69%. All three sites performed very similarly during the noon hour summer analysis, indicating a robust data set across the three sites. When the data were filtered for a typical afternoon electric utility demand peak of June to August at 4 pm, the percent of peak ranged from 18% to 44%.

TABLE 4: PHOTOVOLTAIC PERFORMANCE DURING VARIOUS PHYSICAL AND TIME SCENARIOS (KW)

Site	Daylight hours	Jun-Sep, 9am-9pm	Jun-Aug, 11am-1pm	Jun-Aug, 4 pm
MTK	0.22 kW	0.48 kW	1.65 kW	0.44 kW
RMT	0.25 kW	0.66 kW	1.43 kW	0.88 kW
WBL	0.17 kW	0.69 kW	1.52 kW	1.05 kW

TABLE 5: PHOTOVOLTAIC PERFORMANCE DURING VARIOUS PHYSICAL AND TIME SCENARIOS (%)

Site	Daylight hours	Jun-Sep, 9am-9pm	Jun-Aug, 11am-1pm	Jun-Aug, 4pm
MTK	9%	19%	66%	18%
RMT	12%	32%	69%	42%
WBL	7%	29%	65%	44%

The MTK site dropped off appreciably during the June to August at 4 pm analysis, which may be indicative of late afternoon shading of the panels.

2.3.2 MAPP Capacity Performance

The MAPP organization accredits the rated capacity of various electricity generating technologies, including renewable technologies (8). Electric utilities need to have enough generating capacity to meet their anticipated demand each year and the sum of all of their purchased and owned capacity is counted toward this requirement.

Firm capacity generators, such as a natural gas power plant, have accredited capacities near their nameplate capacity. Renewable energy technologies, being variable in their output, have a specific MAPP protocol that involves calculating the median value of the generating technology's performance over a historical 4-hour peak electrical demand "window" by month for a particular electric utility over a ten year period. For example, Xcel Energy's historical peak demand window in August is from 3 pm to 6 pm.

During the MAPP accredited 4-hour window from June to September, the three sites studied ranged from a low of 8% for MTK during August to a high of 44% for RMT during July (Table 7). The four-hour window moves an additional hour into the evening in August, decreasing the capacity value for the photovoltaic systems, which are optimized around solar noon. For reference, the current MAPP accredited capacity value for wind turbines in Minnesota is roughly 10% to 15%.

TABLE 6: PHOTOVOLTAIC PERFORMANCE UNDER MAPP ACCREDITATION METHOD (KW)

Site	June 2-5 pm	July 2-5 pm	August 3-6 pm	September 2-5 pm
MTK	0.44 kW	0.50 kW	0.19 kW	0.30 kW
RMT	0.75 kW	0.92 kW	0.51 kW	0.78 kW
WBL	0.97 kW	0.95 kW	0.57 kW	0.73 kW

TABLE 7: PHOTOVOLTAIC PERFORMANCE UNDER MAPP ACCREDITATION METHOD (%)

Site	June 2-5 pm	July 2-5 pm	August 3-6 pm	September 2-5 pm
MTK	18%	20%	8%	12%
RMT	36%	44%	24%	38%
WBL	41%	40%	24%	31%

2.3.3 High Electric Demand Capacity Performance

A previous study determined that the actual peak demand for a day may or may not fall within the 4-hour accreditation window (6). An alternative measure of the relationship is to filter the data for demand thresholds that exceed 90%, 95%, and 99% of peak for each year. This pairs up photovoltaic generation with specific time periods of high demand.

The percent of peak ranged from 20% to 51% at 90% of demand and 21% to 54% and 19% to 62% at 95% and 99% of demand respectively. The RMT site consistently increased its percentage across the increasing demand thresholds, while the WBL site decreased performance with each threshold. The WBL site had the lowest elevation from ground-level and the lowest tilt angle, which may be indicative of shading during evening hours but not to the extent of the MTK site, which performed poorly relative to the other two sites.

TABLE 8: PHOTOVOLTAIC PERFORMANCE DURING PERIODS OF HIGH ELECTRIC UTILITY DEMAND (KW)

Site	Demand > 90%	Demand > 95%	Demand > 99%
MTK	0.44 kW	0.49 kW	0.44 kW
RMT	1.03 kW	1.06 kW	1.28 kW
WBL	0.90 kW	0.81 kW	0.55 kW

TABLE 9: PHOTOVOLTAIC PERFORMANCE DURING PERIODS OF HIGH ELECTRIC UTILITY DEMAND (%)

Location	Demand > 90%	Demand > 95%	Demand > 99%
MTK	18%	20%	18%
RMT	50%	51%	62%
WBL	38%	34%	23%

Electric utility demand exceeded 90% of annual peak when no measurable irradiance was occurring about 7% of the time, i.e. at night. Filtering the data for high demand periods during daylight hours only adds roughly 1% to 6% to the peak capacity values listed in Tables 7 and 9.

The RMT site is clearly the highest performer under all measurements of annual electricity generation and its electricity output's relationship to electric utility demand. Depending on the method of filtering, RMT produced a low of 24% capacity during August from 3 pm to 6 pm and a high of 62% when filtered for periods when electric demand exceeded 99% of annual peak.

MTK, while producing an equivalent amount of electricity to RMT on an annual basis, has lower peak capacity values than either RMT or WBL. This is likely due to shading during evening hours.

WBL, while producing less electricity than MTK and RMT on an annual basis, doesn't appear to be as affected by late afternoon shading in terms of peak capacity values. However, when the data is filtered for periods of demand greater than 90%, WBL actually decreases, but it is unclear why since all other data analysis produced similar results to RMT.

3. CONCLUSION

These photovoltaic sites were located in a metropolitan area with some degree of shading and technical difficulties that affected the annual electricity generation performance and the relationship with electric demand to some degree. They do represent real-world operational data however and in this conservative analysis one of the sites showed strong results across all measures of performance.

The RMT site had the least degree of shading and the fewest operational issues, producing the most annual electricity on a standardized basis (1042 kWh/kW/yr), the highest peak capacity using the MAPP accreditation method (24% to 44% from June to September), and the highest peak capacity at 90%, 95%, and 99% of annual peak demand (50%, 51%, and 62% respectively). The RMT site's performance under the alternative demand analysis to the MAPP accreditation method was significantly higher and may be a better method for calculating photovoltaic generating capacity during periods of high electrical demand.

Further investigation is needed to determine the economic benefits of a traditional net metering arrangement versus a time-of-day payment option that would increase the value of electricity generation during periods of peak demand.

4. ACKNOWLEDGEMENTS

The author wishes to thank the Minnesota Department of Commerce State Energy Office.

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Appendix V – Financial Forecast Details

30 Year Plan Model

Major Assumptions

Power Supply Assumptions

- RPU's power supply requirements are met in the following order
  - Hydro
  - SMMPA (up to CROD level)
  - Coal-fired generation
  - CT generation, subject to market price check of lower of market price or 90% of average CT Price.
  - Market purchases.
- Starting in 2005 1% of RPU's non-CROD power supply must come from renewable sources. The renewable requirement increases by 1% per year until 2014 when it reaches 10% where remains steady. Until 2010, 0.5% of the renewable requirement must come from biomass resources, 1.0% of renewable requirement thereafter. The Lake Zumbro Hydro is considered a renewable resource. The renewable energy beyond the Hydro production will be purchased.
- Silver Lake Plant (SLP) Units 1-3 are retired after 2015. SLP Unit 4 remains available throughout the forecast period.
- The amount of SLP capacity committed to Mayo steam supply grows over time from 5 mW's in 2005 to 15 mW's in 2009 staying at that level throughout the forecast period. The contract officially ends in April, 2022 but is expected to be extended at that time.
- The amount of SLP committed to MMPA changes from 100 mW's to 50 mW's in November, 2005, from 50 mW's to 25 mW's in November, 2010, and ends completely after October, 2015.
- CT#1 is retired after 2015.
- The Lake Zumbro Hydro facility remains available throughout the 30 year period.
- 95% of the Btu requirements for baseload generation are assumed to be provided by coal with the remaining 5% from natural gas; except in the All-Gas scenarios where 100% is provided by natural gas

Major Assumptions (continued)

- Generation dispatch is based on an hourly projection of self-generation requirements. Dispatch order is assumed as follows, subject to the market price check on the peaking units:

Self-Generation Demand Requirement	**Generation dispatch assumption**
Below 75% of smallest baseload capacity unit	Peaking units, the most efficient (newest) first
Above 75% of smallest baseload unit capacity.	Smallest baseload unit (SLP) first followed by peaking units up to 75% of next largest baseload unit (RPU's 50MW share of a new coal plant when it is projected) Above that point larger baseload unit is dispatched up to its capacity replacing smaller baseload unit and peaking units. Above that point peaking units are added to larger baseload unit up to point where 75% of next baseload unit (SLP) is reached. Above that point next baseload unit (SLP) is dispatched replacing peaking units up to its capacity. Larger baseload unit remains dispatched at capacity throughout this range. Above that point peaking units are dispatched until their capacity is reached. All baseload units remain dispatched at capacity throughout this range. Above that point market purchases are made.
NOTE REGARDING PRICE CHECK:	A price check is always done on peaking units and if market price is less than 110% of average peaking unit production price, market purchases will replace peaking unit capacity in the dispatch order.

Major Assumptions (continued)

Capital Expenditure Assumptions

- Every 50 mW's of new load requires a new distribution substation. A second transformer is also added to the substation between 50 mW increments. The cost of a substation including the second transformer is $4,250,000 in today's dollars.
- Every 5 mW's of new load requires a new distribution feeder at a cost of $400,000 in today's dollars
- The average cost to install a new service is $1,450 in today's dollars.
- Other capital spending (trucks, facilities, computer eqpt/software, etc.) is assumed to cost $100/customer in today's dollars.
- Internal costs such as labor, equipment, and overheads, add 25% to the external costs of a capital project, excluding the large projects such as generation additions, emissions control equipment, and transmission lines where it is assumed that a vendor will build the facility.

Number of Employees / Labor Expense

- Number of Operations employees is forecasted in proportion to the number of customers, 2.1 employees / 1,000 customers (2003 actual ratio)
- Number of Power Production employees is forecasted in proportion to installed kW's of generation with a weighting of 1 for RPU-operated coal-fired generation and a weighting of .05 for combustion turbine generation, which results in ~ .5 employees / weighted kW of generation (2003 actual ratio). However, when SLP Units 1-3 are retired, employee levels are held steady. Two additional power production employees are added in 2009 related to emissions control equipment additions.
- Number of Administration employees is forecasted in proportion to operating revenue, .33 employees / $1M operating revenue, indexed for rate increases (2003 actual ratio). In addition to operating revenues driving employee forecasts, one employee is added in 2006 and two in 2007 under the Aggressive DSM scenario to handle the additional DSM programs that are likely to be required.
- Annual wage inflation of 4%, annual payroll tax/benefits inflation of 5%.

Other Operating & Maintenance Expense Assumptions

- Other operating and maintenance expense, except for expenses related to transmission lines, will begin at 2004 levels and grow by inflation over the 30 year forecast term, unless specific inputs are made for significant changes, such as when new generation or emissions control facilities are added.
- Operating and maintenance expenses related to transmission lines will grow in proportion to the miles of transmission line installed, adjusted for inflation and a travel factor.
- Distribution system O&M and customer services/accounts O&M are indexed for customer base increases in addition to inflationary increases.

Major Assumptions (continued)

Steam Sales

- The contract runs from 11/2005 through 04/2022. However the steam sales forecast has been extended through all years of the forecast period under the assumption that the contract will be renewed when it expires.

Wholesale Sales

- The amount of SLP capacity sold to MMPA changes from 100 mW's to 50 mW's in November, 2005, from 50 mW's to 25 mW's in November, 2010, and ends completely after October, 2015. Additional spot market sales are forecast out of SLP, CT#2, and the new coal unit. Assumptions vary by generating unit as to how much of available output is assumed to be sold at wholesale.

Retail Sales & Revenue

- System losses are 2.5% across the entire forecast period
- Any forecasted rate increase is assumed to take effect at the beginning of the year.

Debt Service Assumptions

- All large capital projects such new generation facilities, new transmission lines and significant environmental control equipment will be debt financed.
- All new debt issued during the 30 forecast period will be at a rate of 6.5% and will be issued for a term that matches the economic life of the asset, not to exceed 30 years.

Reserve Requirement Assumptions

- 5.5% of retail revenues are available to finance capital projects.
- Debt-financed projects are excluded from the calculation of reserve requirements but debt principal payments are included.

Balance Sheet Assumptions

- Accounts Receivable balances grow in proportion to retail revenues
- Accounts Payable balances grow in proportion to operating expenses
- O&M Supplies Inventory balances grow in proportion to operating expenses
- Coal Inventory balances grow/shrink in proportion to tons of coal burned
- Due to City balances (ILOT, Sewer Rev) grow in proportion to number of customers.

Rochester Public Utilities
Financial Model Results
Scenario: No DSM
Scenario Description: Recommended expansion plan from Part IV with the forecast unaffected by demand side management
All dollar values in $1,000s

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1 Sales of Electricity - Retail	$ 94,278	$ 98,169	$ 100,761	$ 104,752	$ 108,387	$ 112,362	$ 117,636	$ 123,509	$ 129,063	$ 133,798	$ 140,081	$ 147,007	$ 153,692	$ 162,412	$ 171,790
2 Other Revenues	19,210	20,818	21,317	20,881	21,455	25,334	23,306	24,016	24,726	25,473	26,258	20,612	20,672	21,359	22,034
3 Total Operating Revenues	$ 113,488	$ 118,988	$ 122,078	$ 125,633	$ 129,842	$ 137,696	$ 140,942	$ 147,525	$ 153,789	$ 159,270	$ 166,339	$ 167,619	$ 174,365	$ 183,771	$ 193,823
4															
5 Power Supply Costs	69,738	70,091	71,632	73,036	74,851	79,946	79,455	81,351	82,946	84,886	87,147	84,930	87,655	90,687	94,233
6 Net Other Operating Expenses	27,169	29,430	30,854	32,029	34,667	37,187	38,685	40,606	42,979	45,864	49,193	51,498	53,560	56,807	61,121
7 Total Operating Expenses	$ 96,907	$ 99,521	$ 102,485	$ 105,065	$ 109,518	$ 117,132	$ 118,140	$ 121,958	$ 125,925	$ 130,750	$ 136,340	$ 136,428	$ 141,215	$ 147,494	$ 155,353
8															
9 Operating Income	16,581	19,467	19,593	20,568	20,324	20,563	22,802	25,567	27,864	28,521	29,998	31,191	33,149	36,277	38,470
10 Interest Expense, Incl AFUDC	(2,597)	(2,325)	(2,242)	(2,848)	(4,871)	(4,897)	(4,723)	(4,554)	(4,426)	(8,773)	(7,278)	(7,857)	(7,589)	(15,388)	(12,919)
11 Interest and Other Income	667	677	731	795	808	492	445	442	510	1,024	1,030	637	717	1,515	1,465
12 Income B4 Transfer/Cap Contribution	$ 14,651	$ 17,818	$ 18,082	$ 18,515	$ 16,261	$ 16,158	$ 18,524	$ 21,456	$ 23,948	$ 20,773	$ 23,750	$ 23,970	$ 26,277	$ 22,404	$ 27,016
13															
14 Net Transfers & Contributions In (Out)	(7,983)	(8,404)	(8,630)	(9,109)	(9,567)	(10,069)	(10,597)	(11,186)	(11,749)	(12,365)	(13,013)	(13,730)	(14,429)	(15,178)	(15,982)
15															
16 Change in Net Assets	$ 6,668	$ 9,414	$ 9,453	$ 9,406	$ 6,693	$ 6,089	$ 7,927	$ 10,270	$ 12,199	$ 8,408	$ 10,737	$ 10,241	$ 11,848	$ 7,226	$ 11,034
17															
18															
19															
20 01/01 Cash Balance	$ 14,217	$ 12,940	$ 14,825	$ 16,521	$ 19,030	$ 17,349	$ 14,951	$ 14,276	$ 14,755	$ 18,766	$ 48,504	$ 19,127	$ 22,672	$ 24,382	$ 75,105
21															
22 Change in Net Assets	6,668	9,414	9,453	9,406	6,693	6,089	7,927	10,270	12,199	8,408	10,737	10,241	11,848	7,226	11,034
23 Operating & Capital Activity	(11,265)	(5,769)	(5,922)	(15,686)	(40,651)	(5,621)	(5,585)	(6,606)	(4,830)	(37,300)	(36,297)	(2,661)	(5,873)	(62,765)	(60,028)
24 Bond Principle Payments	(1,681)	(1,760)	(1,835)	(2,211)	(2,724)	(2,866)	(3,017)	(3,185)	(3,358)	(4,270)	(3,817)	(4,035)	(4,265)	(4,738)	(5,028)
25 Bond Sale Proceeds	5,000	-	-	11,000	35,000	-	-	-	-	62,900	-	-	-	111,000	-
26															
27 Net Changes in Cash	$ (1,277)	$ 1,885	$ 1,696	$ 2,509	$ (1,681)	$ (2,398)	$ (675)	$ 479	$ 4,011	$ 29,738	$ (29,377)	$ 3,545	$ 1,711	$ 50,723	$ (54,022)
28															
29 12/31 Cash Balance	12,940	14,825	16,521	19,030	17,349	14,951	14,276	14,755	18,766	48,504	19,127	22,672	24,382	75,105	21,083
30 Reserve Minimum	10,364	10,393	10,744	12,077	13,887	12,675	12,933	13,214	14,212	16,401	17,036	16,012	16,864	20,381	21,283
31 Excess (Deficit) from Minimum	$ 2,576	$ 4,432	$ 5,777	$ 6,954	$ 3,462	$ 2,276	$ 1,343	$ 1,541	$ 4,554	$ 32,103	$ 2,090	$ 6,660	$ 7,519	$ 54,724	$ (200)
32															
33 Rate Change	3.0%	1.0%	0.0%	1.0%	1.0%	1.0%	2.0%	2.0%	2.0%	1.0%	2.0%	2.0%	2.0%	3.0%	3.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	$ 3,937	$ 4,759	$ 4,950	$ 4,014	$ 4,791	$ 5,047	$ 5,793	$ 6,127	$ 4,835	$ 5,955	$ 5,880	$ 5,836	$ 7,314	$ 7,659	$ 6,430
37 Transmission Line Additions	-	-	-	11,000	11,000	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	-	-	-	-	-	-	31,450	31,450	-	-	-	-
39 Baseload Generation Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	55,500	55,500
40 Emission Control Eqpt Major Additions	-	-	-	-	24,000	-	-	-	-	-	-	-	-	-	-
41 Other	12,315	7,063	7,422	7,758	8,920	8,477	9,067	9,560	9,619	11,164	11,610	11,303	12,238	14,268	14,497
42 Total Capital Expenditures	$ 16,252	$ 11,822	$ 12,373	$ 22,772	$ 48,711	$ 13,524	$ 14,860	$ 15,687	$ 14,454	$ 48,568	$ 48,940	$ 17,139	$ 19,552	$ 77,427	$ 76,428
43															
44															
45 Debt and Debt Service															
46 New Borrowings	$ 5,000	$ -	$ -	$ 11,000	$ 35,000	$ -	$ -	$ -	$ -	$ 62,900	$ -	$ -	$ -	$ 111,000	$ -
47 Debt Service Payments	$ 4,183	$ 4,187	$ 4,183	$ 5,189	$ 7,868	$ 7,867	$ 7,866	$ 7,872	$ 7,875	$ 12,695	$ 12,001	$ 12,007	$ 12,013	$ 19,461	$ 19,461
48 Debt Outstanding	$ 48,369	$ 46,610	$ 44,775	$ 53,564	$ 85,840	$ 82,975	$ 79,957	$ 76,772	$ 73,415	$ 132,045	$ 128,228	$ 124,193	$ 119,928	$ 226,191	$ 221,162
49 Debt Service Coverage Ratio	5.4	6.5	6.6	5.7	3.9	3.8	4.2	4.6	5.0	3.2	4.0	3.8	4.1	2.7	3.2

Rochester Public Utilities
Financial Model Results
Scenario: No DSM
Scenario Description: Recommended expansion p
All dollar values in $1,000s

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
1 Sales of Electricity - Retail	$ 176,752	$ 180,997	$ 185,962	$ 194,701	$ 206,240	$ 217,636	$ 230,209	$ 243,394	$ 257,947	$ 272,333	$ 285,002	$ 301,388	$ 318,716	$ 337,042	$ 352,962
2 Other Revenues	40,750	40,874	40,591	40,146	40,120	40,247	40,556	40,798	40,999	40,943	41,218	41,613	42,318	42,507	42,943
3 Total Operating Revenues	$ 217,502	$ 221,871	$ 226,553	$ 234,847	$ 246,360	$ 257,883	$ 270,765	$ 284,192	$ 298,946	$ 313,276	$ 326,221	$ 343,001	$ 361,034	$ 379,549	$ 395,905
4															
5 Power Supply Costs	105,357	108,329	111,895	115,885	120,746	125,823	131,700	137,151	144,166	151,536	159,937	169,473	179,602	190,986	202,818
6 Net Other Operating Expenses	66,660	69,763	72,707	76,094	80,070	84,284	88,566	92,337	96,865	101,300	105,474	111,029	116,064	121,312	127,639
7 Total Operating Expenses	$ 172,017	$ 178,092	$ 184,601	$ 191,979	$ 200,817	$ 210,107	$ 220,265	$ 229,489	$ 241,031	$ 252,836	$ 265,410	$ 280,502	$ 295,665	$ 312,297	$ 330,457
8															
9 Operating Income	45,485	43,779	41,951	42,867	45,544	47,776	50,500	54,703	57,916	60,440	60,810	62,499	65,368	67,251	65,448
10 Interest Expense, Incl AFUDC	(13,957)	(13,628)	(13,243)	(12,864)	(12,512)	(15,892)	(14,290)	(14,457)	(13,954)	(13,384)	(12,775)	(12,209)	(11,758)	(11,117)	(10,560)
11 Interest and Other Income	675	769	835	832	863	1,271	1,215	786	845	957	1,005	1,044	1,157	1,230	1,186
12 Income B4 Transfer/Cap Contribution	$ 32,203	$ 30,920	$ 29,544	$ 30,836	$ 33,894	$ 33,156	$ 37,424	$ 41,032	$ 44,806	$ 48,013	$ 49,040	$ 51,334	$ 54,768	$ 57,365	$ 56,074
13															
14 Net Transfers & Contributions In (Out)	(16,451)	(16,851)	(17,320)	(18,228)	(19,223)	(20,192)	(21,262)	(22,378)	(23,611)	(24,813)	(26,102)	(27,478)	(28,926)	(30,450)	(32,054)
15															
16 Change in Net Assets	$ 15,752	$ 14,069	$ 12,224	$ 12,608	$ 14,672	$ 12,964	$ 16,162	$ 18,654	$ 21,195	$ 23,200	$ 22,938	$ 23,856	$ 25,842	$ 26,915	$ 24,019
17															
18															
19															
20 01/01 Cash Balance	$ 21,083	$ 23,209	$ 27,269	$ 27,559	$ 27,107	$ 29,592	$ 53,880	$ 25,887	$ 25,731	$ 29,730	$ 33,099	$ 32,879	$ 35,682	$ 40,287	$ 40,502
21															
22 Change in Net Assets	15,752	14,069	12,224	12,608	14,672	12,964	16,162	18,654	21,195	23,200	22,938	23,856	25,842	26,915	24,019
23 Operating & Capital Activity	(8,287)	(4,345)	(5,918)	(6,674)	(5,401)	(33,913)	(35,852)	(9,991)	(8,828)	(10,946)	(13,725)	(13,499)	(13,192)	(18,132)	(18,012)
24 Bond Principle Payments	(5,338)	(5,664)	(6,016)	(6,386)	(6,785)	(7,818)	(8,304)	(8,819)	(8,369)	(8,885)	(9,433)	(7,554)	(8,045)	(8,568)	(9,125)
25 Bond Sale Proceeds	-	-	-	-	-	53,056	-	-	-	-	-	-	-	-	-
26															
27 Net Changes in Cash	$ 2,126	$ 4,060	$ 290	$ (452)	$ 2,485	$ 24,288	$ (27,993)	$ (156)	$ 3,999	$ 3,369	$ (221)	$ 2,803	$ 4,605	$ 216	$ (3,118)
28															
29 12/31 Cash Balance	23,209	27,269	27,559	27,107	29,592	53,880	25,887	25,731	29,730	33,099	32,879	35,682	40,287	40,502	37,384
30 Reserve Minimum	19,729	20,761	21,574	22,391	24,109	26,876	27,519	26,631	28,406	30,132	30,725	32,194	34,428	35,869	37,047
31 Excess (Deficit) from Minimum	$ 3,480	$ 6,508	$ 5,985	$ 4,716	$ 5,483	$ 27,005	$ (1,631)	$ (899)	$ 1,324	$ 2,967	$ 2,154	$ 3,489	$ 5,859	$ 4,633	$ 337
32															
33 Rate Change	0.0%	0.0%	0.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.0%	3.0%	3.0%	3.0%	2.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	$ 7,792	$ 7,878	$ 9,108	$ 9,439	$ 8,159	$ 9,803	$ 11,680	$ 11,162	$ 9,840	$ 11,669	$ 13,683	$ 13,248	$ 12,132	$ 16,074	$ 16,228
37 Transmission Line Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	-	-	26,528	26,528	-	-	-	-	-	-	-	-
39 Baseload Generation Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40 Emission Control Eqpt Major Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41 Other	14,097	14,760	15,777	16,578	16,961	18,872	20,226	20,286	20,829	22,309	23,891	24,838	25,650	27,945	29,237
42 Total Capital Expenditures	$ 21,889	$ 22,638	$ 24,885	$ 26,017	$ 25,121	$ 55,203	$ 58,434	$ 31,448	$ 30,669	$ 33,977	$ 37,575	$ 38,086	$ 37,782	$ 44,019	$ 45,465
43															
44															
45 Debt and Debt Service															
46 New Borrowings	$ -	$ -	$ -	$ -	$ -	$ 53,056	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47 Debt Service Payments	$ 19,461	$ 19,458	$ 19,460	$ 19,459	$ 19,463	$ 23,525	$ 23,525	$ 23,524	$ 22,526	$ 22,525	$ 22,523	$ 20,060	$ 20,060	$ 20,060	$ 20,060
48 Debt Outstanding	$ 215,824	$ 210,160	$ 204,143	$ 197,757	$ 190,971	$ 236,209	$ 227,905	$ 219,086	$ 210,718	$ 201,833	$ 192,400	$ 184,846	$ 176,801	$ 168,233	$ 159,108
49 Debt Service Coverage Ratio	3.3	3.3	3.2	3.3	3.5	3.0	3.4	3.4	3.7	3.9	3.9	4.5	4.7	4.9	4.9

Rochester Public Utilities
Financial Model Results
Scenario: Aggressive DSM, Coal & Gas Mix
Scenario Description: Recommended plan adjusted by using the aggressive demand side management results with SLP operating on coal and adjustments to the new resources
All dollar values in $1,000s

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1 Sales of Electricity - Retail	93,770	95,224	97,875	100,695	105,144	107,968	110,973	115,520	118,623	123,366	128,300	135,891	141,730	145,470	149,169
2 Other Revenues	19,117	20,615	21,131	20,668	21,261	25,151	23,169	23,906	24,643	25,417	26,226	20,683	20,927	21,671	22,446
3 Total Operating Revenues	112,887	115,839	119,006	121,363	126,405	133,118	134,141	139,426	143,265	148,784	154,526	156,574	162,657	167,141	171,616
4															
5 Power Supply Costs	69,442	68,037	69,126	69,873	71,030	75,337	74,480	75,818	76,986	78,372	79,895	78,679	80,456	81,165	83,004
6 Net Other Operating Expenses	27,338	29,754	31,486	32,895	35,516	38,069	39,755	41,593	43,567	45,558	47,618	49,178	52,621	55,240	57,597
7 Total Operating Expenses	96,780	97,792	100,612	102,768	106,546	113,406	114,235	117,411	120,553	123,930	127,513	127,857	133,077	136,405	140,601
8															
9 Operating Income	16,107	18,047	18,395	18,594	19,859	19,713	19,907	22,015	22,712	24,854	27,013	28,717	29,581	30,736	31,015
10 Interest Expense, Incl AFUDC	(2,601)	(2,345)	(2,249)	(2,858)	(4,882)	(4,916)	(4,780)	(4,612)	(4,442)	(4,254)	(4,046)	(8,668)	(7,112)	(7,747)	(7,510)
11 Interest and Other Income	664	670	714	750	749	445	410	405	414	446	521	1,054	1,028	553	598
12 Income B4 Transfer/Cap Contribution	14,170	16,373	16,859	16,487	15,727	15,241	15,538	17,808	18,684	21,045	23,488	21,104	23,497	23,541	24,102
13															
14 Net Transfers & Contributions In (Out)	(7,937)	(8,056)	(8,403)	(8,773)	(9,114)	(9,497)	(9,906)	(10,364)	(10,799)	(11,287)	(11,796)	(12,440)	(13,041)	(13,390)	(13,736)
15															
16 Change in Net Assets	6,233	8,317	8,457	7,713	6,612	5,744	5,631	7,444	7,885	9,759	11,691	8,664	10,456	10,151	10,367
17															
18															
19															
20 01/01 Cash Balance	14,217	12,734	14,600	15,613	16,973	15,534	13,696	13,259	13,339	13,839	15,443	18,742	50,487	17,034	19,249
21															
22 Change in Net Assets	6,233	8,317	8,457	7,713	6,612	5,744	5,631	7,444	7,885	9,759	11,691	8,664	10,456	10,151	10,367
23 Operating & Capital Activity	(11,036)	(4,691)	(5,608)	(15,143)	(40,327)	(4,717)	(3,051)	(4,179)	(4,027)	(4,613)	(5,350)	(39,677)	(39,702)	(4,544)	(6,031)
24 Bond Principle Payments	(1,681)	(1,760)	(1,835)	(2,211)	(2,724)	(2,866)	(3,017)	(3,185)	(3,358)	(3,542)	(3,042)	(3,981)	(4,208)	(3,392)	(3,595)
25 Bond Sale Proceeds	5,000	-	-	11,000	35,000	-	-	-	-	-	-	66,740	-	-	-
26															
27 Net Changes in Cash	(1,484)	1,867	1,013	1,359	(1,438)	(1,838)	(437)	80	499	1,604	3,299	31,745	(33,454)	2,215	740
28															
29 12/31 Cash Balance	12,734	14,600	15,613	16,973	15,534	13,696	13,259	13,339	13,839	15,443	18,742	50,487	17,034	19,249	19,989
30 Reserve Minimum	10,118	10,116	10,406	11,533	13,060	11,518	11,828	12,415	13,196	14,008	15,298	17,398	17,363	16,224	16,964
31 Excess (Deficit) from Minimum	2,615	4,485	5,207	5,440	2,475	2,178	1,431	925	643	1,435	3,444	33,089	(329)	3,025	3,025
32															
33 Rate Change	3.0%	2.0%	1.0%	1.0%	3.0%	1.0%	1.0%	2.0%	1.0%	2.0%	2.0%	3.0%	2.0%	0.0%	0.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	3,802	4,089	4,659	3,640	4,391	4,347	3,892	4,147	4,201	4,477	5,000	6,882	6,946	5,829	6,999
37 Transmission Line Additions	-	-	-	11,000	11,000	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	-	-	-	-	-	-	-	-	33,370	33,370	-	-
39 Baseload Generation Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40 Emission Control Eqpt Major Additions	-	-	-	-	24,000	-	-	-	-	-	-	-	-	-	-
41 Other	12,279	6,886	7,355	7,671	8,829	8,305	8,560	9,035	9,475	10,000	10,617	12,474	13,012	12,411	13,317
42 Total Capital Expenditures	16,080	10,976	12,013	22,311	48,219	12,652	12,452	13,181	13,676	14,477	15,617	52,725	53,328	18,240	20,315
43															
44															
45 Debt and Debt Service															
46 New Borrowings	5,000	-	-	11,000	35,000	-	-	-	-	-	-	66,740	-	-	-
47 Debt Service Payments	4,183	4,187	4,183	5,189	7,868	7,867	7,866	7,872	7,875	7,878	7,184	12,301	12,307	11,255	11,255
48 Debt Outstanding	48,369	46,610	44,775	53,564	85,840	82,975	79,957	76,772	73,415	69,873	66,831	129,590	125,382	121,990	118,394
49 Debt Service Coverage Ratio	5.3	6.1	6.3	5.3	3.8	3.7	3.8	4.1	4.2	4.6	5.4	3.3	4.0	4.1	4.2

Rochester Public Utilities
Financial Model Results
Scenario: Aggressive DSM, Coal & Gas Mix
Scenario Description: Recommended plan adjuste
All dollar values in $1,000s

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
1 Sales of Electricity - Retail	$ 154,931	$ 160,308	$ 169,477	$ 177,433	$ 188,115	$ 194,648	$ 203,787	$ 215,550	$ 228,425	$ 238,814	$ 250,151	$ 264,376	$ 276,698	$ 292,436	$ 309,069
2 Other Revenues	23,254	24,063	24,902	25,728	26,546	35,261	35,789	36,437	37,150	37,650	38,201	38,886	39,824	40,577	41,486
3 Total Operating Revenues	$ 178,184	$ 184,371	$ 194,380	$ 203,160	$ 214,661	$ 229,909	$ 239,576	$ 251,987	$ 265,575	$ 276,465	$ 288,352	$ 303,262	$ 316,522	$ 333,012	$ 350,555
4															
5 Power Supply Costs	85,190	87,633	90,856	94,450	98,729	105,134	109,618	114,733	120,492	125,399	132,017	139,321	147,249	156,456	166,210
6 Net Other Operating Expenses	60,453	63,535	66,245	70,283	74,893	79,699	83,199	86,161	91,086	97,478	101,393	106,224	110,972	117,289	122,825
7 Total Operating Expenses	$ 145,643	$ 151,168	$ 157,101	$ 164,733	$ 173,622	$ 184,833	$ 192,817	$ 200,894	$ 211,578	$ 222,877	$ 233,410	$ 245,545	$ 258,221	$ 273,746	$ 289,035
8															
9 Operating Income	32,541	33,202	37,279	38,428	41,040	45,076	46,759	51,093	53,997	53,587	54,942	57,717	58,301	59,267	61,520
10 Interest Expense, Incl AFUDC	(7,295)	(7,077)	(6,774)	(11,104)	(9,556)	(9,972)	(9,595)	(13,215)	(11,633)	(11,975)	(11,467)	(10,943)	(10,596)	(10,262)	(9,773)
11 Interest and Other Income	628	673	732	1,207	1,198	775	852	1,307	1,324	983	1,027	1,043	1,069	1,104	1,123
12 Income B4 Transfer/Cap Contribution	$ 25,875	$ 26,799	$ 31,237	$ 28,530	$ 32,682	$ 35,880	$ 38,016	$ 39,185	$ 43,688	$ 42,595	$ 44,503	$ 47,818	$ 48,774	$ 50,109	$ 52,870
13															
14 Net Transfers & Contributions In (Out)	(14,485)	(15,215)	(16,013)	(16,854)	(17,791)	(18,688)	(19,668)	(20,711)	(21,852)	(22,964)	(24,182)	(25,441)	(26,767)	(28,161)	(29,628)
15															
16 Change in Net Assets	$ 11,390	$ 11,584	$ 15,223	$ 11,676	$ 14,891	$ 17,192	$ 18,348	$ 18,474	$ 21,836	$ 19,631	$ 20,322	$ 22,376	$ 22,007	$ 21,948	$ 23,242
17															
18															
19															
20 01/01 Cash Balance	$ 19,989	$ 21,246	$ 22,962	$ 25,124	$ 54,104	$ 24,557	$ 26,360	$ 29,598	$ 56,217	$ 30,713	$ 33,821	$ 33,650	$ 34,871	$ 35,326	$ 37,176
21															
22 Change in Net Assets	11,390	11,584	15,223	11,676	14,891	17,192	18,348	18,474	21,836	19,631	20,322	22,376	22,007	21,948	23,242
23 Operating & Capital Activity	(6,321)	(5,828)	(8,777)	(40,826)	(38,834)	(9,443)	(8,801)	(40,258)	(40,546)	(9,314)	(12,846)	(15,503)	(15,533)	(13,687)	(17,012)
24 Bond Principle Payments	(3,812)	(4,039)	(4,285)	(5,277)	(5,604)	(5,946)	(6,309)	(7,341)	(6,794)	(7,208)	(7,647)	(5,652)	(6,019)	(6,410)	(6,827)
25 Bond Sale Proceeds	-	-	-	63,407	-	-	-	55,744	-	-	-	-	-	-	-
26															
27 Net Changes in Cash	$ 1,257	$ 1,717	$ 2,161	$ 28,980	$ (29,547)	$ 1,803	$ 3,238	$ 26,619	$ (25,504)	$ 3,109	$ (171)	$ 1,222	$ 454	$ 1,850	$ (597)
28															
29 12/31 Cash Balance	21,246	22,962	25,124	54,104	24,557	26,360	29,598	56,217	30,713	33,821	33,650	34,871	35,326	37,176	36,579
30 Reserve Minimum	17,824	19,047	20,110	22,485	23,700	23,393	24,871	27,136	28,016	28,293	29,247	30,269	31,426	33,662	35,699
31 Excess (Deficit) from Minimum	$ 3,421	$ 3,916	$ 5,013	$ 31,619	$ 857	$ 2,967	$ 4,727	$ 29,081	$ 2,697	$ 5,528	$ 4,403	$ 4,603	$ 3,900	$ 3,514	$ 880
32															
33 Rate Change	1.0%	1.0%	3.0%	2.0%	3.0%	1.0%	2.0%	3.0%	3.0%	2.0%	2.0%	3.0%	2.0%	3.0%	3.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	$ 7,061	$ 6,742	$ 8,704	$ 9,073	$ 7,818	$ 9,005	$ 9,517	$ 10,767	$ 11,366	$ 9,554	$ 11,858	$ 13,780	$ 13,265	$ 11,596	$ 14,038
37 Transmission Line Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	-	-	-	-	27,872	27,872	-	-	-	-	-	-
39 Baseload Generation Additions	-	-	-	31,704	31,704	-	-	-	-	-	-	-	-	-	-
40 Emission Control Eqpt Major Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41 Other	13,940	14,490	15,715	17,320	17,712	18,040	19,011	20,930	22,015	21,775	23,440	25,052	26,035	26,754	28,691
42 Total Capital Expenditures	$ 21,001	$ 21,232	$ 24,418	$ 58,097	$ 57,233	$ 27,045	$ 28,528	$ 59,569	$ 61,253	$ 31,329	$ 35,298	$ 38,832	$ 39,300	$ 38,350	$ 42,729
43															
44															
45 Debt and Debt Service															
46 New Borrowings	$ -	$ -	$ -	$ 63,407	$ -	$ -	$ -	$ 55,744	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47 Debt Service Payments	$ 11,255	$ 11,252	$ 11,254	$ 16,108	$ 16,112	$ 16,112	$ 16,111	$ 20,380	$ 19,381	$ 19,380	$ 19,378	$ 16,915	$ 16,915	$ 16,915	$ 16,915
48 Debt Outstanding	$ 114,582	$ 110,543	$ 106,258	$ 164,388	$ 158,784	$ 152,838	$ 146,529	$ 194,932	$ 188,138	$ 180,930	$ 173,283	$ 167,632	$ 161,612	$ 155,202	$ 148,375
49 Debt Service Coverage Ratio	4.4	4.5	4.9	3.5	4.1	4.1	4.3	3.6	4.2	4.1	4.2	5.0	5.1	5.2	5.4

Rochester Public Utilities
Financial Model Results
Scenario: Aggressive DSM, All Gas
Scenario Description: Recommended plan adjusted by using the aggressive demand side management results with SLP operating on natural gas and the coal unit replaced with gas-fired capacity
All dollar values in $1,000s

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1 Sales of Electricity - Retail	$ 109,247	$ 110,941	$ 112,900	$ 115,002	$ 118,918	$ 122,112	$ 124,268	$ 129,360	$ 131,519	$ 134,097	$ 138,092	$ 144,843	$ 149,585	$ 153,533	$ 159,011
2 Other Revenues	19,619	20,866	21,386	20,929	21,526	25,428	23,330	24,072	24,809	25,582	26,392	20,717	20,959	21,703	22,483
3 Total Operating Revenues	$ 128,866	$ 131,806	$ 134,286	$ 135,932	$ 140,445	$ 147,540	$ 147,598	$ 153,432	$ 156,328	$ 159,679	$ 164,484	$ 165,560	$ 170,545	$ 175,236	$ 181,495
4															
5 Power Supply Costs	86,254	82,792	84,298	84,451	86,019	92,626	88,749	90,565	92,205	94,111	96,432	89,337	91,648	92,947	95,425
6 Net Other Operating Expenses	27,019	29,418	31,155	32,569	34,698	37,245	38,889	40,706	42,634	44,564	46,578	48,029	51,427	54,011	56,348
7 Total Operating Expenses	$ 113,272	$ 112,209	$ 115,453	$ 117,020	$ 120,717	$ 129,872	$ 127,637	$ 131,271	$ 134,839	$ 138,674	$ 143,010	$ 137,366	$ 143,075	$ 146,958	$ 151,772
8															
9 Operating Income	15,594	19,597	18,832	18,911	19,728	17,668	19,961	22,161	21,489	21,004	21,474	28,194	27,470	28,278	29,722
10 Interest Expense, Incl AFUDC	(3,201)	(3,007)	(2,926)	(3,549)	(4,388)	(4,354)	(4,251)	(4,120)	(3,987)	(3,840)	(3,675)	(8,298)	(6,743)	(7,379)	(7,142)
11 Interest and Other Income	627	615	684	736	768	479	460	507	557	583	580	1,071	1,057	566	599
12 Income B4 Transfer/Cap Contribution	$ 13,019	$ 17,204	$ 16,591	$ 16,098	$ 16,109	$ 13,792	$ 16,169	$ 18,548	$ 18,059	$ 17,747	$ 18,379	$ 20,968	$ 21,785	$ 21,465	$ 23,179
13															
14 Net Transfers & Contributions In (Out)	(7,937)	(8,056)	(8,198)	(8,351)	(8,675)	(9,040)	(9,199)	(9,624)	(9,784)	(9,976)	(10,426)	(10,995)	(11,526)	(11,835)	(12,444)
15															
16 Change in Net Assets	$ 5,083	$ 9,149	$ 8,393	$ 7,748	$ 7,433	$ 4,753	$ 6,970	$ 8,925	$ 8,276	$ 7,771	$ 7,952	$ 9,973	$ 10,258	$ 9,630	$ 10,735
17															
18															
19															
20 01/01 Cash Balance	$ 14,217	$ 10,302	$ 13,385	$ 14,872	$ 16,800	$ 16,994	$ 14,458	$ 15,722	$ 17,588	$ 18,989	$ 19,298	$ 18,764	$ 51,582	$ 17,851	$ 19,319
21															
22 Change in Net Assets	5,083	9,149	8,393	7,748	7,433	4,753	6,970	8,925	8,276	7,771	7,952	9,973	10,258	9,630	10,735
23 Operating & Capital Activity	(22,515)	(4,516)	(5,294)	(14,847)	(20,000)	(4,940)	(3,238)	(4,460)	(4,140)	(4,585)	(5,456)	(39,926)	(39,795)	(4,784)	(6,450)
24 Bond Principle Payments	(1,484)	(1,550)	(1,612)	(1,973)	(2,239)	(2,349)	(2,468)	(2,599)	(2,734)	(2,877)	(3,030)	(3,969)	(4,194)	(3,378)	(3,580)
25 Bond Sale Proceeds	15,000	-	-	11,000	15,000	-	-	-	-	-	-	66,740	-	-	-
26															
27 Net Changes in Cash	$ (3,916)	$ 3,083	$ 1,487	$ 1,928	$ 195	$ (2,536)	$ 1,264	$ 1,865	$ 1,401	$ 309	$ (534)	$ 32,818	$ (33,731)	$ 1,468	$ 705
28															
29 12/31 Cash Balance	10,302	13,385	14,872	16,800	16,994	14,458	15,722	17,588	18,989	19,298	18,764	51,582	17,851	19,319	20,024
30 Reserve Minimum	11,180	10,472	10,758	11,745	12,231	11,978	12,115	12,755	13,590	14,610	15,957	17,723	17,690	16,551	17,304
31 Excess (Deficit) from Minimum	$ (878)	$ 2,913	$ 4,114	$ 5,055	$ 4,764	$ 2,480	$ 3,607	$ 4,833	$ 5,399	$ 4,688	$ 2,807	$ 33,859	$ 160	$ 2,768	$ 2,720
32															
33 Rate Change	20.0%	2.0%	0.0%	0.0%	2.0%	1.0%	0.0%	2.0%	0.0%	0.0%	1.0%	2.0%	1.0%	0.0%	1.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	$ 3,802	$ 4,089	$ 4,659	$ 3,640	$ 4,391	$ 4,347	$ 3,892	$ 4,147	$ 4,201	$ 4,477	$ 5,000	$ 6,882	$ 6,946	$ 5,829	$ 6,999
37 Transmission Line Additions	-	-	-	11,000	11,000	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	-	-	-	-	-	-	-	-	33,370	33,370	-	-
39 Baseload Generation Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40 Emission Control Eqpt Major Additions	10,000	-	-	-	4,000	-	-	-	-	-	-	-	-	-	-
41 Other	12,529	6,886	7,355	7,671	8,329	8,305	8,560	9,035	9,475	10,000	10,617	12,474	13,012	12,411	13,317
42 Total Capital Expenditures	$ 26,330	$ 10,976	$ 12,013	$ 22,311	$ 27,719	$ 12,652	$ 12,452	$ 13,181	$ 13,676	$ 14,477	$ 15,617	$ 52,725	$ 53,328	$ 18,240	$ 20,315
43															
44															
45 Debt and Debt Service															
46 New Borrowings	$ 15,000	$ -	$ -	$ 11,000	$ 15,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 66,740	$ -	$ -	$ -
47 Debt Service Payments	$ 4,636	$ 4,640	$ 4,636	$ 5,642	$ 6,789	$ 6,788	$ 6,788	$ 6,794	$ 6,796	$ 6,800	$ 6,801	$ 11,918	$ 11,924	$ 10,872	$ 10,872
48 Debt Outstanding	$ 58,566	$ 57,016	$ 55,404	$ 64,431	$ 77,193	$ 74,843	$ 72,376	$ 69,777	$ 67,043	$ 64,165	$ 61,135	$ 123,907	$ 119,712	$ 116,334	$ 112,754
49 Debt Service Coverage Ratio	4.8	5.9	5.8	4.9	4.3	4.0	4.4	4.8	4.7	4.7	4.9	3.4	3.9	4.0	4.2

Rochester Public Utilities
Financial Model Results
Scenario: Aggressive DSM, All Gas
Scenario Description: Recommended plan adjuste
All dollar values in $1,000s

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
1 Sales of Electricity - Retail	$ 165,153	$ 172,577	$ 178,905	$ 189,139	$ 200,527	$ 209,544	$ 221,534	$ 234,322	$ 248,318	$ 262,157	$ 277,294	$ 293,062	$ 309,729	$ 324,167	$ 339,279
2 Other Revenues	23,292	24,105	24,939	25,769	26,589	27,411	28,327	29,320	30,382	31,443	32,550	33,701	34,941	36,185	37,512
3 Total Operating Revenues	$ 188,444	$ 196,682	$ 203,844	$ 214,908	$ 227,116	$ 236,956	$ 249,862	$ 263,642	$ 278,700	$ 293,600	$ 309,844	$ 326,763	$ 344,670	$ 360,351	$ 376,791
4															
5 Power Supply Costs	98,375	101,624	105,840	110,732	116,714	121,946	128,405	135,472	143,381	150,938	160,197	169,974	180,136	191,835	204,074
6 Net Other Operating Expenses	59,167	62,229	64,872	68,601	72,887	76,242	79,716	82,626	87,505	93,890	97,811	102,616	107,339	113,589	119,051
7 Total Operating Expenses	$ 157,542	$ 163,853	$ 170,712	$ 179,334	$ 189,601	$ 198,188	$ 208,121	$ 218,099	$ 230,886	$ 244,828	$ 258,008	$ 272,590	$ 287,475	$ 305,424	$ 323,125
8															
9 Operating Income	30,902	32,829	33,132	35,575	37,515	38,767	41,741	45,543	47,814	48,772	51,836	54,173	57,195	54,927	53,666
10 Interest Expense, Incl AFUDC	(6,928)	(6,711)	(6,410)	(7,978)	(7,222)	(7,193)	(6,851)	(10,507)	(8,964)	(9,347)	(8,882)	(8,405)	(8,107)	(7,826)	(7,394)
11 Interest and Other Income	627	685	727	904	927	793	849	1,272	1,247	873	930	984	1,082	1,189	1,193
12 Income B4 Transfer/Cap Contribution	$ 24,601	$ 26,803	$ 27,448	$ 28,501	$ 31,220	$ 32,367	$ 35,739	$ 36,309	$ 40,098	$ 40,299	$ 43,884	$ 46,753	$ 50,170	$ 48,291	$ 47,465
13															
14 Net Transfers & Contributions In (Out)	(13,123)	(13,784)	(14,507)	(15,269)	(16,118)	(16,930)	(17,819)	(18,763)	(19,796)	(20,805)	(21,907)	(23,049)	(24,249)	(25,513)	(26,842)
15															
16 Change in Net Assets	$ 11,478	$ 13,019	$ 12,941	$ 13,233	$ 15,102	$ 15,437	$ 17,920	$ 17,546	$ 20,301	$ 19,494	$ 21,977	$ 23,704	$ 25,921	$ 22,778	$ 20,623
17															
18															
19															
20 01/01 Cash Balance	$ 20,024	$ 21,129	$ 23,852	$ 23,864	$ 35,526	$ 25,352	$ 26,739	$ 29,021	$ 54,506	$ 27,361	$ 29,991	$ 31,099	$ 33,534	$ 37,532	$ 40,539
21															
22 Change in Net Assets	11,478	13,019	12,941	13,233	15,102	15,437	17,920	17,546	20,301	19,494	21,977	23,704	25,921	22,778	20,623
23 Operating & Capital Activity	(6,577)	(6,274)	(8,662)	(22,054)	(20,163)	(8,628)	(9,885)	(41,057)	(41,284)	(10,328)	(13,938)	(16,380)	(16,716)	(14,226)	(17,486)
24 Bond Principle Payments	(3,796)	(4,021)	(4,267)	(4,816)	(5,113)	(5,423)	(5,753)	(6,748)	(6,162)	(6,536)	(6,931)	(4,889)	(5,207)	(5,545)	(5,906)
25 Bond Sale Proceeds	-	-	-	25,300	-	-	-	55,744	-	-	-	-	-	-	-
26															
27 Net Changes in Cash	$ 1,105	$ 2,723	$ 12	$ 11,662	$ (10,174)	$ 1,387	$ 2,282	$ 25,485	$ (27,145)	$ 2,630	$ 1,108	$ 2,435	$ 3,998	$ 3,007	$ (2,769)
28															
29 12/31 Cash Balance	21,129	23,852	23,864	35,526	25,352	26,739	29,021	54,506	27,361	29,991	31,099	33,534	37,532	40,539	37,770
30 Reserve Minimum	18,156	19,381	20,245	21,603	22,945	23,509	25,053	27,357	28,258	28,602	29,654	30,766	32,079	34,460	36,324
31 Excess (Deficit) from Minimum	$ 2,973	$ 4,471	$ 3,620	$ 13,924	$ 2,408	$ 3,230	$ 3,968	$ 27,149	$ (897)	$ 1,389	$ 1,445	$ 2,769	$ 5,453	$ 6,079	$ 1,446
32															
33 Rate Change	1.0%	2.0%	1.0%	3.0%	3.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.0%	2.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	$ 7,061	$ 6,742	$ 8,704	$ 9,073	$ 7,818	$ 9,005	$ 9,517	$ 10,767	$ 11,366	$ 9,554	$ 11,858	$ 13,780	$ 13,265	$ 11,596	$ 14,038
37 Transmission Line Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	12,650	12,650	-	-	27,872	27,872	-	-	-	-	-	-
39 Baseload Generation Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40 Emission Control Eqpt Major Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41 Other	13,940	14,490	15,715	16,844	17,236	18,040	19,011	20,930	22,015	21,775	23,440	25,052	26,035	26,754	28,691
42 Total Capital Expenditures	$ 21,001	$ 21,232	$ 24,418	$ 38,567	$ 37,704	$ 27,045	$ 28,528	$ 59,569	$ 61,253	$ 31,329	$ 35,298	$ 38,832	$ 39,300	$ 38,350	$ 42,729
43															
44															
45 Debt and Debt Service															
46 New Borrowings	$ -	$ -	$ -	$ 25,300	$ -	$ -	$ -	$ 55,744	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47 Debt Service Payments	$ 10,872	$ 10,869	$ 10,871	$ 12,807	$ 12,811	$ 12,811	$ 12,810	$ 17,079	$ 16,080	$ 16,079	$ 16,077	$ 13,614	$ 13,614	$ 13,614	$ 13,614
48 Debt Outstanding	$ 108,958	$ 104,937	$ 100,670	$ 121,154	$ 116,041	$ 110,617	$ 104,865	$ 153,861	$ 147,698	$ 141,163	$ 134,232	$ 129,343	$ 124,136	$ 118,591	$ 112,685
49 Debt Service Coverage Ratio	4.3	4.6	4.7	4.2	4.6	4.7	5.0	3.9	4.7	4.5	4.8	6.0	6.2	6.1	6.1

Rochester Public Utilities
Financial Model Results
Scenario: Normal DSM, Coal & Gas Mix
Scenario Description: Recommended plan adjusted by using the normal demand side management forecast with SLP operating on coal and adjustments to the new resources.
All dollar values in $1,000s

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1 Sales of Electricity - Retail	93,770	93,491	95,323	99,323	104,010	108,272	111,604	115,257	121,041	127,358	131,403	135,062	138,038	144,448	149,533
2 Other Revenues	19,211	20,865	21,378	20,920	21,510	25,402	23,412	24,141	24,879	25,649	26,447	20,784	20,877	21,630	22,400
3 Total Operating Revenues	112,981	114,357	116,702	120,243	125,520	133,673	135,015	139,398	145,920	153,008	157,850	155,846	158,915	166,078	171,933
4															
5 Power Supply Costs	69,442	68,104	69,292	70,186	71,500	76,034	75,345	76,820	78,201	79,659	81,279	79,160	80,691	82,517	84,445
6 Net Other Operating Expenses	27,177	29,413	30,688	31,815	34,413	36,930	38,605	40,409	42,366	45,300	48,176	50,217	52,835	54,456	57,120
7 Total Operating Expenses	96,619	97,517	99,980	102,001	105,913	112,964	113,950	117,228	120,567	124,959	129,455	129,377	133,527	136,973	141,566
8															
9 Operating Income	16,362	16,840	16,722	18,242	19,608	20,709	21,065	22,170	25,353	28,049	28,395	26,469	25,389	29,104	30,367
10 Interest Expense, Incl AFUDC	(2,601)	(2,345)	(2,248)	(2,856)	(4,879)	(4,913)	(4,777)	(4,610)	(4,439)	(8,802)	(7,258)	(7,820)	(7,643)	(7,364)	(7,163)
11 Interest and Other Income	668	665	676	687	681	390	391	413	468	993	1,012	542	510	486	497
12 Income B4 Transfer/Cap Contribution	14,429	15,160	15,150	16,074	15,409	16,187	16,679	17,972	21,382	20,240	22,150	19,191	18,255	22,226	23,701
13															
14 Net Transfers & Contributions In (Out)	(7,937)	(7,870)	(8,025)	(8,404)	(8,757)	(9,162)	(9,585)	(10,047)	(10,501)	(10,997)	(11,516)	(11,842)	(12,105)	(12,734)	(13,383)
15															
16 Change in Net Assets	6,492	7,289	7,124	7,670	6,652	7,025	7,094	7,925	10,881	9,243	10,634	7,349	6,150	9,492	10,319
17															
18															
19															
20 01/01 Cash Balance	14,217	12,981	14,000	13,701	14,778	13,250	12,387	13,257	13,831	16,892	48,332	18,109	17,474	15,988	15,908
21															
22 Change in Net Assets	6,492	7,289	7,124	7,670	6,652	7,025	7,094	7,925	10,881	9,243	10,634	7,349	6,150	9,492	10,319
23 Operating & Capital Activity	(11,048)	(4,510)	(5,589)	(15,382)	(40,456)	(5,023)	(3,207)	(4,166)	(4,463)	(36,433)	(37,040)	(3,950)	(3,371)	(6,118)	(5,828)
24 Bond Principle Payments	(1,681)	(1,760)	(1,835)	(2,211)	(2,724)	(2,866)	(3,017)	(3,185)	(3,358)	(4,270)	(3,817)	(4,035)	(4,265)	(3,453)	(3,660)
25 Bond Sale Proceeds	5,000	-	-	11,000	35,000	-	-	-	-	62,900	-	-	-	-	-
26															
27 Net Changes in Cash	(1,236)	1,019	(300)	1,077	(1,528)	(864)	870	574	3,061	31,440	(30,223)	(635)	(1,486)	(79)	831
28															
29 12/31 Cash Balance	12,981	14,000	13,701	14,778	13,250	12,387	13,257	13,831	16,892	48,332	18,109	17,474	15,988	15,908	16,739
30 Reserve Minimum	10,182	10,191	10,453	11,568	13,088	11,576	11,999	12,745	13,915	16,451	16,860	15,077	15,616	16,304	17,140
31 Excess (Deficit) from Minimum	2,799	3,809	3,248	3,210	162	811	1,258	1,086	2,977	31,882	1,249	2,396	371	(396)	(401)
32															
33 Rate Change	3.0%	0.0%	0.0%	2.0%	3.0%	2.0%	1.0%	1.0%	3.0%	3.0%	1.0%	0.0%	0.0%	2.0%	1.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	3,802	4,091	4,710	3,722	4,480	4,473	4,000	4,235	4,327	4,901	6,424	6,918	5,460	6,782	6,670
37 Transmission Line Additions	-	-	-	11,000	11,000	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	-	-	-	-	-	-	31,450	31,450	-	-	-	-
39 Baseload Generation Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40 Emission Control Eqpt Major Additions	-	-	-	-	24,000	-	-	-	-	-	-	-	-	-	-
41 Other	12,279	6,886	7,368	7,692	8,851	8,337	8,586	9,054	9,504	10,898	11,796	11,641	11,752	12,671	13,216
42 Total Capital Expenditures	16,080	10,977	12,078	22,414	48,331	12,810	12,587	13,289	13,831	47,249	49,670	18,560	17,212	19,453	19,886
43															
44															
45 Debt and Debt Service															
46 New Borrowings	5,000	-	-	11,000	35,000	-	-	-	-	62,900	-	-	-	-	-
47 Debt Service Payments	4,183	4,187	4,183	5,189	7,868	7,867	7,866	7,872	7,875	12,695	12,001	12,007	12,013	10,961	10,961
48 Debt Outstanding	48,369	46,610	44,775	53,564	85,840	82,975	79,957	76,772	73,415	132,045	128,228	124,193	119,928	116,476	112,816
49 Debt Service Coverage Ratio	5.4	5.8	5.9	5.2	3.8	3.8	3.9	4.1	4.6	3.1	3.8	3.4	3.4	4.0	4.2

Rochester Public Utilities
Financial Model Results
Scenario: Normal DSM, Coal & Gas Mix
Scenario Description: Recommended plan adjuste
All dollar values in $1,000s

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
1 Sales of Electricity - Retail	$ 158,311	$ 166,813	$ 174,644	$ 179,088	$ 186,186	$ 196,281	$ 207,513	$ 215,130	$ 227,982	$ 240,460	$ 251,876	$ 266,201	$ 281,342	$ 297,345	$ 311,209
2 Other Revenues	23,210	24,015	24,815	34,067	34,226	34,679	35,295	35,940	36,578	37,089	37,673	38,412	39,393	40,137	41,042
3 Total Operating Revenues	$ 181,520	$ 190,828	$ 199,459	$ 213,155	$ 220,412	$ 230,960	$ 242,809	$ 251,070	$ 264,560	$ 277,549	$ 289,549	$ 304,613	$ 320,735	$ 337,482	$ 352,250
4															
5 Power Supply Costs	86,934	89,766	93,185	100,022	103,673	107,611	112,404	117,090	122,764	128,637	135,699	143,429	151,743	161,315	171,407
6 Net Other Operating Expenses	59,981	63,326	67,051	72,220	75,370	79,812	84,048	87,403	91,793	96,072	100,071	105,462	110,402	115,741	121,356
7 Total Operating Expenses	$ 146,915	$ 153,092	$ 160,236	$ 172,242	$ 179,043	$ 187,422	$ 196,452	$ 204,493	$ 214,557	$ 224,709	$ 235,770	$ 248,891	$ 262,145	$ 277,057	$ 292,762
8															
9 Operating Income	34,606	37,736	39,223	40,913	41,369	43,538	46,357	46,577	50,003	52,840	53,779	55,723	58,590	60,425	59,488
10 Interest Expense, Incl AFUDC	(6,946)	(10,997)	(9,495)	(9,978)	(9,599)	(13,095)	(11,581)	(11,795)	(11,375)	(10,893)	(10,373)	(9,910)	(9,579)	(9,099)	(8,598)
11 Interest and Other Income	571	1,088	1,120	746	834	1,269	1,280	864	864	921	929	946	1,059	1,178	1,189
12 Income B4 Transfer/Cap Contribution	$ 28,231	$ 27,828	$ 30,848	$ 31,682	$ 32,604	$ 31,712	$ 36,056	$ 35,646	$ 39,492	$ 42,868	$ 44,335	$ 46,759	$ 50,070	$ 52,505	$ 52,079
13															
14 Net Transfers & Contributions In (Out)	(14,106)	(14,795)	(15,571)	(15,973)	(16,861)	(17,693)	(18,622)	(19,599)	(20,679)	(21,710)	(22,861)	(24,052)	(25,305)	(26,623)	(28,010)
15															
16 Change in Net Assets	$ 14,125	$ 13,033	$ 15,277	$ 15,709	$ 15,743	$ 14,019	$ 17,434	$ 16,047	$ 18,813	$ 21,158	$ 21,474	$ 22,707	$ 24,765	$ 25,882	$ 24,069
17															
18															
19															
20 01/01 Cash Balance	$ 16,739	$ 20,764	$ 50,685	$ 22,880	$ 26,127	$ 28,625	$ 54,679	$ 29,400	$ 27,369	$ 29,350	$ 31,159	$ 29,856	$ 32,250	$ 37,310	$ 40,061
21															
22 Change in Net Assets	14,125	13,033	15,277	15,709	15,743	14,019	17,434	16,047	18,813	21,158	21,474	22,707	24,765	25,882	24,069
23 Operating & Capital Activity	(6,220)	(38,075)	(37,982)	(7,052)	(7,499)	(34,309)	(35,588)	(10,515)	(9,800)	(11,888)	(14,861)	(14,374)	(13,380)	(16,395)	(18,928)
24 Bond Principle Payments	(3,881)	(4,804)	(5,100)	(5,411)	(5,746)	(6,712)	(7,125)	(7,564)	(7,032)	(7,461)	(7,916)	(5,939)	(6,325)	(6,736)	(7,174)
25 Bond Sale Proceeds	-	59,767	-	-	-	53,056	-	-	-	-	-	-	-	-	-
26															
27 Net Changes in Cash	$ 4,025	$ 29,921	$ (27,805)	$ 3,247	$ 2,498	$ 26,054	$ (25,279)	$ (2,031)	$ 1,981	$ 1,809	$ (1,303)	$ 2,394	$ 5,060	$ 2,751	$ (2,033)
28															
29 12/31 Cash Balance	20,764	50,685	22,880	26,127	28,625	54,679	29,400	27,369	29,350	31,159	29,856	32,250	37,310	40,061	38,028
30 Reserve Minimum	18,506	20,937	21,468	21,383	22,706	25,372	26,293	25,408	27,097	28,658	28,976	30,156	32,243	34,178	35,411
31 Excess (Deficit) from Minimum	$ 2,258	$ 29,748	$ 1,413	$ 4,744	$ 5,919	$ 29,307	$ 3,107	$ 1,960	$ 2,253	$ 2,501	$ 880	$ 2,094	$ 5,067	$ 5,883	$ 2,617
32															
33 Rate Change	3.0%	3.0%	2.0%	0.0%	1.0%	3.0%	3.0%	1.0%	3.0%	3.0%	2.0%	3.0%	3.0%	3.0%	2.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	$ 6,652	$ 8,248	$ 8,759	$ 7,321	$ 8,944	$ 9,005	$ 10,351	$ 10,797	$ 9,441	$ 11,215	$ 13,347	$ 12,774	$ 11,137	$ 13,509	$ 15,685
37 Transmission Line Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	-	-	26,528	26,528	-	-	-	-	-	-	-	-
39 Baseload Generation Additions	-	29,884	29,884	-	-	-	-	-	-	-	-	-	-	-	-
40 Emission Control Eqpt Major Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41 Other	13,817	15,653	16,469	16,026	17,228	18,695	19,901	20,234	20,769	22,234	23,851	24,761	25,428	27,283	29,145
42 Total Capital Expenditures	$ 20,468	$ 53,785	$ 55,112	$ 23,347	$ 26,172	$ 54,228	$ 56,779	$ 31,031	$ 30,210	$ 33,449	$ 37,198	$ 37,535	$ 36,565	$ 40,792	$ 44,831
43															
44															
45 Debt and Debt Service															
46 New Borrowings	$ -	$ 59,767	$ -	$ -	$ -	$ 53,056	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47 Debt Service Payments	$ 10,961	$ 15,534	$ 15,537	$ 15,535	$ 15,539	$ 19,602	$ 19,601	$ 19,601	$ 18,602	$ 18,601	$ 18,599	$ 16,137	$ 16,137	$ 16,137	$ 16,137
48 Debt Outstanding	$ 108,935	$ 163,898	$ 158,798	$ 153,388	$ 147,642	$ 193,986	$ 186,861	$ 179,297	$ 172,266	$ 164,805	$ 156,888	$ 150,949	$ 144,625	$ 137,888	$ 130,715
49 Debt Service Coverage Ratio	4.6	3.5	4.0	3.9	4.0	3.3	3.7	3.6	4.0	4.2	4.3	5.1	5.3	5.5	5.6

Rochester Public Utilities
Financial Model Results
Scenario: Normal DSM, All Gas
Scenario Description: Recommenced plan adjusted by using the normal demand side management forecast with SLP operating on natural gas and the coal unit replaced with gas-fired capacity
All dollar values in $1,000s

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1 Sales of Electricity - Retail	$ 110,157	$ 109,830	$ 111,982	$ 114,393	$ 116,302	$ 121,067	$ 124,793	$ 128,878	$ 132,718	$ 135,577	$ 141,267	$ 146,653	$ 152,883	$ 156,845	$ 160,758
2 Other Revenues	19,625	20,861	21,378	20,922	21,510	25,411	23,309	24,043	24,778	25,542	26,348	20,677	20,923	21,663	22,430
3 Total Operating Revenues	$ 129,782	$ 130,690	$ 133,360	$ 135,315	$ 137,812	$ 146,478	$ 148,102	$ 152,920	$ 157,496	$ 161,119	$ 167,615	$ 167,330	$ 173,806	$ 178,508	$ 183,188
4															
5 Power Supply Costs	86,254	82,862	84,475	84,786	86,525	93,377	89,704	91,682	93,567	95,591	98,056	91,065	93,321	94,498	97,127
6 Net Other Operating Expenses	26,837	29,112	30,538	31,640	33,744	36,264	37,926	39,715	41,641	43,458	45,254	48,017	51,748	53,787	56,421
7 Total Operating Expenses	$ 113,091	$ 111,974	$ 115,013	$ 116,425	$ 120,268	$ 129,641	$ 127,630	$ 131,397	$ 135,208	$ 139,048	$ 143,310	$ 139,082	$ 145,069	$ 148,286	$ 153,548
8															
9 Operating Income	16,691	18,716	18,347	18,890	17,544	16,838	20,472	21,523	22,287	22,071	24,305	28,248	28,737	30,222	29,640
10 Interest Expense, Incl AFUDC	(3,201)	(3,007)	(2,924)	(3,546)	(4,385)	(4,351)	(4,248)	(4,117)	(3,984)	(3,828)	(3,632)	(8,297)	(6,790)	(7,350)	(7,154)
11 Interest and Other Income	642	638	695	741	747	418	388	430	473	505	514	1,015	1,042	601	652
12 Income B4 Transfer/Cap Contribution	$ 14,133	$ 16,347	$ 16,118	$ 16,084	$ 13,905	$ 12,904	$ 16,612	$ 17,835	$ 18,776	$ 18,748	$ 21,188	$ 20,966	$ 22,989	$ 23,473	$ 23,139
13															
14 Net Transfers & Contributions In (Out)	(7,937)	(7,870)	(8,025)	(8,199)	(8,335)	(8,720)	(9,123)	(9,563)	(9,995)	(10,212)	(10,694)	(11,272)	(11,810)	(12,121)	(12,427)
15															
16 Change in Net Assets	$ 6,196	$ 8,476	$ 8,093	$ 7,885	$ 5,570	$ 4,184	$ 7,489	$ 8,272	$ 8,781	$ 8,536	$ 10,494	$ 9,695	$ 11,179	$ 11,352	$ 10,712
17															
18															
19															
20 01/01 Cash Balance	$ 14,217	$ 11,306	$ 13,944	$ 15,039	$ 16,965	$ 15,423	$ 11,998	$ 13,485	$ 14,725	$ 16,312	$ 16,847	$ 16,930	$ 49,733	$ 18,708	$ 20,737
21															
22 Change in Net Assets	6,196	8,476	8,093	7,885	5,570	4,184	7,489	8,272	8,781	8,536	10,494	9,695	11,179	11,352	10,712
23 Operating & Capital Activity	(22,624)	(4,288)	(5,385)	(14,987)	(19,873)	(5,261)	(3,534)	(4,433)	(4,460)	(5,124)	(7,381)	(39,664)	(38,009)	(5,946)	(5,777)
24 Bond Principle Payments	(1,484)	(1,550)	(1,612)	(1,973)	(2,239)	(2,349)	(2,468)	(2,599)	(2,734)	(2,877)	(3,030)	(3,969)	(4,194)	(3,378)	(3,580)
25 Bond Sale Proceeds	15,000	-	-	11,000	15,000	-	-	-	-	-	-	66,740	-	-	-
26															
27 Net Changes in Cash	$ (2,911)	$ 2,638	$ 1,095	$ 1,926	$ (1,542)	$ (3,426)	$ 1,487	$ 1,240	$ 1,587	$ 535	$ 84	$ 32,802	$ (31,024)	$ 2,028	$ 1,354
28															
29 12/31 Cash Balance	11,306	13,944	15,039	16,965	15,423	11,998	13,485	14,725	16,312	16,847	16,930	49,733	18,708	20,737	22,091
30 Reserve Minimum	11,221	10,530	10,826	11,823	12,287	12,036	12,245	12,979	13,926	14,935	15,819	17,405	17,890	16,631	17,469
31 Excess (Deficit) from Minimum	$ 85	$ 3,414	$ 4,214	$ 5,142	$ 3,136	$ (38)	$ 1,240	$ 1,746	$ 2,386	$ 1,912	$ 1,112	$ 32,328	$ 818	$ 4,105	$ 4,622
32															
33 Rate Change	21.0%	0.0%	0.0%	0.0%	0.0%	2.0%	1.0%	1.0%	1.0%	0.0%	2.0%	1.0%	2.0%	0.0%	0.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	$ 3,802	$ 4,091	$ 4,710	$ 3,722	$ 4,480	$ 4,473	$ 4,000	$ 4,235	$ 4,327	$ 4,901	$ 6,424	$ 6,918	$ 5,460	$ 6,782	$ 6,670
37 Transmission Line Additions	-	-	-	11,000	11,000	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	-	-	-	-	-	-	-	-	33,370	33,370	-	-
39 Baseload Generation Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40 Emission Control Eqpt Major Additions	10,000	-	-	-	4,000	-	-	-	-	-	-	-	-	-	-
41 Other	12,529	6,886	7,368	7,692	8,351	8,337	8,586	9,054	9,504	10,112	11,010	12,476	12,586	12,671	13,216
42 Total Capital Expenditures	$ 26,330	$ 10,977	$ 12,078	$ 22,414	$ 27,831	$ 12,810	$ 12,587	$ 13,289	$ 13,831	$ 15,013	$ 17,434	$ 52,764	$ 51,417	$ 19,453	$ 19,886
43															
44															
45 Debt and Debt Service															
46 New Borrowings	$ 15,000	$ -	$ -	$ 11,000	$ 15,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 66,740	$ -	$ -	$ -
47 Debt Service Payments	$ 4,636	$ 4,640	$ 4,636	$ 5,642	$ 6,789	$ 6,788	$ 6,788	$ 6,794	$ 6,796	$ 6,800	$ 6,801	$ 11,918	$ 11,924	$ 10,872	$ 10,872
48 Debt Outstanding	$ 58,566	$ 57,016	$ 55,404	$ 64,431	$ 77,193	$ 74,843	$ 72,376	$ 69,777	$ 67,043	$ 64,165	$ 61,135	$ 123,907	$ 119,712	$ 116,334	$ 112,754
49 Debt Service Coverage Ratio	5.0	5.7	5.7	4.9	4.0	3.8	4.4	4.6	4.8	4.9	5.3	3.4	4.0	4.2	4.2

Rochester Public Utilities
Financial Model Results
Scenario: Normal DSM, All Gas
Scenario Description: Recommenced plan adjuste
All dollar values in $1,000s

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
1 Sales of Electricity - Retail	$ 165,238	$ 172,422	$ 182,286	$ 192,532	$ 204,126	$ 213,105	$ 225,300	$ 238,194	$ 252,424	$ 266,240	$ 281,615	$ 294,741	$ 311,506	$ 329,224	$ 347,953
2 Other Revenues	23,229	24,032	24,836	25,640	26,437	27,295	28,246	29,249	30,306	31,357	32,457	33,611	34,861	36,115	37,447
3 Total Operating Revenues	$ 188,467	$ 196,453	$ 207,122	$ 218,173	$ 230,564	$ 240,400	$ 253,546	$ 267,443	$ 282,730	$ 297,597	$ 314,072	$ 328,353	$ 346,366	$ 365,340	$ 385,400
4															
5 Power Supply Costs	100,412	104,120	108,750	113,962	120,188	125,403	132,073	139,339	147,589	155,313	164,880	174,956	185,426	197,510	210,162
6 Net Other Operating Expenses	59,227	61,860	64,903	69,001	72,594	76,219	79,526	82,631	87,924	93,456	97,475	102,836	107,753	113,085	118,712
7 Total Operating Expenses	$ 159,639	$ 165,980	$ 173,653	$ 182,962	$ 192,783	$ 201,622	$ 211,599	$ 221,970	$ 235,513	$ 248,769	$ 262,355	$ 277,792	$ 293,179	$ 310,596	$ 328,874
8															
9 Operating Income	28,828	30,474	33,468	35,210	37,781	38,779	41,947	45,473	47,217	48,828	51,717	50,561	53,187	54,744	56,526
10 Interest Expense, Incl AFUDC	(6,942)	(6,665)	(6,409)	(8,033)	(7,187)	(7,194)	(6,826)	(10,507)	(9,025)	(9,296)	(8,836)	(8,437)	(8,175)	(7,767)	(7,343)
11 Interest and Other Income	675	663	651	868	915	781	843	1,272	1,294	939	960	979	1,050	1,115	1,107
12 Income B4 Transfer/Cap Contribution	$ 22,562	$ 24,471	$ 27,711	$ 28,045	$ 31,509	$ 32,366	$ 35,965	$ 36,238	$ 39,486	$ 40,472	$ 43,841	$ 43,102	$ 46,062	$ 48,093	$ 50,289
13															
14 Net Transfers & Contributions In (Out)	(12,779)	(13,403)	(14,107)	(14,832)	(15,657)	(16,430)	(17,292)	(18,200)	(19,202)	(20,160)	(21,229)	(22,335)	(23,498)	(24,722)	(26,010)
15															
16 Change in Net Assets	$ 9,783	$ 11,068	$ 13,604	$ 13,213	$ 15,852	$ 15,936	$ 18,673	$ 18,039	$ 20,284	$ 20,312	$ 22,612	$ 20,768	$ 22,564	$ 23,370	$ 24,279
17															
18															
19															
20 01/01 Cash Balance	$ 22,091	$ 22,266	$ 21,239	$ 21,543	$ 35,473	$ 24,643	$ 26,648	$ 28,738	$ 54,802	$ 30,139	$ 31,536	$ 31,515	$ 32,761	$ 36,184	$ 37,059
21															
22 Change in Net Assets	9,783	11,068	13,604	13,213	15,852	15,936	18,673	18,039	20,284	20,312	22,612	20,768	22,564	23,370	24,279
23 Operating & Capital Activity	(5,811)	(8,074)	(9,033)	(19,767)	(21,568)	(8,507)	(10,830)	(40,971)	(38,784)	(12,379)	(15,703)	(14,633)	(13,934)	(16,950)	(19,815)
24 Bond Principle Payments	(3,796)	(4,021)	(4,267)	(4,816)	(5,113)	(5,423)	(5,753)	(6,748)	(6,162)	(6,536)	(6,931)	(4,889)	(5,207)	(5,545)	(5,906)
25 Bond Sale Proceeds	-	-	-	25,300	-	-	-	55,744	-	-	-	-	-	-	-
26															
27 Net Changes in Cash	$ 175	$ (1,028)	$ 304	$ 13,930	$ (10,829)	$ 2,005	$ 2,090	$ 26,064	$ (24,663)	$ 1,397	$ (21)	$ 1,246	$ 3,423	$ 875	$ (1,442)
28															
29 12/31 Cash Balance	22,266	21,239	21,543	35,473	24,643	26,648	28,738	54,802	30,139	31,536	31,515	32,761	36,184	37,059	35,617
30 Reserve Minimum	18,556	19,299	20,003	22,026	23,209	23,741	25,051	27,286	28,938	29,002	29,447	30,679	32,802	34,781	35,825
31 Excess (Deficit) from Minimum	$ 3,711	$ 1,939	$ 1,539	$ 13,447	$ 1,434	$ 2,907	$ 3,687	$ 27,516	$ 1,201	$ 2,534	$ 2,068	$ 2,082	$ 3,382	$ 2,278	$ (209)
32															
33 Rate Change	0.0%	2.0%	3.0%	3.0%	3.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.0%	3.0%	3.0%	3.0%
34															
35 Breakdown of Capital Expenditures															
36 Distribution System Expansions	$ 6,652	$ 8,248	$ 8,759	$ 7,321	$ 8,944	$ 9,005	$ 10,351	$ 10,797	$ 9,441	$ 11,215	$ 13,347	$ 12,774	$ 11,137	$ 13,509	$ 15,685
37 Transmission Line Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38 Peaking Generation Additions	-	-	-	12,650	12,650	-	-	27,872	27,872	-	-	-	-	-	-
39 Baseload Generation Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40 Emission Control Eqpt Major Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41 Other	13,817	14,906	15,722	16,343	17,544	18,032	19,237	20,931	21,465	22,234	23,851	24,761	25,428	27,283	29,145
42 Total Capital Expenditures	$ 20,468	$ 23,154	$ 24,482	$ 36,314	$ 39,138	$ 27,037	$ 29,588	$ 59,600	$ 58,779	$ 33,449	$ 37,198	$ 37,535	$ 36,565	$ 40,792	$ 44,831
43															
44															
45 Debt and Debt Service															
46 New Borrowings	$ -	$ -	$ -	$ 25,300	$ -	$ -	$ -	$ 55,744	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47 Debt Service Payments	$ 10,872	$ 10,869	$ 10,871	$ 12,807	$ 12,811	$ 12,811	$ 12,810	$ 17,079	$ 16,080	$ 16,079	$ 16,077	$ 13,614	$ 13,614	$ 13,614	$ 13,614
48 Debt Outstanding	$ 108,958	$ 104,937	$ 100,670	$ 121,154	$ 116,041	$ 110,617	$ 104,865	$ 153,861	$ 147,698	$ 141,163	$ 134,232	$ 129,343	$ 124,136	$ 118,591	$ 112,685
49 Debt Service Coverage Ratio	4.2	4.4	4.7	4.2	4.7	4.7	5.0	3.9	4.6	4.6	4.8	5.7	5.9	6.1	6.4

Rochester Public Utilities
Emission Rates and Externality Cost Rates
All Scenarios

	CT #1	CT #2	SLP	NewCoal	Proposed CT #3	Proposed CT #4	Proposed CT #6	SMMPA	Market
Emsn Rt-SO2-lbs/MWH-Coal/Gas Mix	n/a	n/a	4.84966	0.96000	n/a	n/a	n/a	0.48000	0.48000
Emsn Rt-PM10-lbs/MWH-Coal/Gas Mix	n/a	n/a	0.21384	0.17000	n/a	n/a	n/a	0.15500	0.15500
Emsn Rt-CO-lbs/MWH-Coal/Gas Mix	n/a	n/a	0.28432	1.44000	n/a	n/a	n/a	3.64500	3.64500
Emsn Rt-Nox-lbs/MWH-Coal/Gas Mix	n/a	n/a	1.59879	0.67000	n/a	n/a	n/a	0.77000	0.77000
Emsn Rt-Pb-lbs/MWH-Coal/Gas Mix	n/a	n/a	0.00061	0.00024	n/a	n/a	n/a	0.00012	0.00012
Emsn Rt-CO2-lbs/MWH-Coal/Gas Mix	n/a	n/a	2,460.96981	2,761.51000	n/a	n/a	n/a	1,943.49500	1,943.49500
Emsn Rt-SO2-lbs/MWH-All Gas	-	-	0.01000	0.96000	-	-	-	n/a	n/a
Emsn Rt-PM10-lbs/MWH-All Gas	0.01660	0.01660	0.07766	0.17000	0.01660	0.01660	0.14000	n/a	n/a
Emsn Rt-CO-lbs/MWH-All Gas	2.96000	2.96000	0.92400	1.44000	2.96000	2.96000	5.85000	n/a	n/a
Emsn Rt-Nox-lbs/MWH-All Gas	1.52000	1.52000	3.08000	0.67000	1.52000	1.52000	0.87000	n/a	n/a
Emsn Rt-Pb-lbs/MWH-All Gas	-	-	0.00001	0.00024	-	-	-	n/a	n/a
Emsn Rt-CO2-lbs/MWH-All Gas	1,051.20000	1,051.20000	1,126.00000	2,761.51000	1,051.20000	1,051.20000	1,125.48000	n/a	n/a
Extrnlty Rt-SO2-$/ton	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Extrnlty Rt-PM10-$/ton	$ 848.770	$ 848.770	$ 848.770	$ 848.770	$ 848.770	$ 848.770	$ 848.770	$ 848.770	$ 848.770
Extrnlty Rt-CO-$/ton	$ 0.371	$ 0.371	$ 0.371	$ 0.371	$ 0.371	$ 0.371	$ 0.371	$ 0.371	$ 0.371
Extrnlty Rt-Nox-$/ton	$ 72.036	$ 72.036	$ 72.036	$ 72.036	$ 72.036	$ 72.036	$ 72.036	$ 72.036	$ 72.036
Extrnlty Rt-Pb-$/ton	$ 508.950	$ 508.950	$ 508.950	$ 508.950	$ 508.950	$ 508.950	$ 508.950	$ 508.950	$ 508.950
Extrnlty Rt-CO2-$/ton	$ 2.036	$ 2.036	$ 2.036	$ 2.036	$ 2.036	$ 2.036	$ 2.036	$ 2.036	$ 2.036

Resource List

Unit	Unit Description	Scenario*	Peak Period MW Capacity	Years available From:	Years available To:
CT #1	Combined Cycle Combustion Turbine, installed 1975	All scenarios	26	2005	2015
CT #2	Combined Cycle Combustion Turbine, installed 2002	All scenarios	47	2005	throughout
SLP	Silver Lake Plant	All scenarios	106	2005	2015
SLP		All scenarios	60	2016	throughout
NewCoal	Represents an ownership share in a baseload generating faciliy	1	50	2020	throughout
NewCoal		2	25	2025	throughout
NewCoal		4	25	2023	throughout
Proposed CT #3	FT8 TwinPac Combustion Turbine	1 and 4	50	2027	throughout
Proposed CT #3		2, 3, and 6	50	2029	throughout
Proposed CT #4	New Combined Cycle Combustion Turbine	6	25	2025	throughout
Proposed CT #6	LMS 100 High-Efficiency Combustion Turbine	1 and 4	100	2016	throughout
Proposed CT #6		2, 3, and 6	100	2018	throughout
SMMPA		All scenarios	216	2005	throughout

*See scenario descriptions below

Rochester Public Utilities
Emissions Cost and Tonnage for Retail Sales, 30 Yr Totals
Scenario #1: No DSM
Scenario Description: Recommended expansion plan from Part IV with the forecast unaffected by demand side management

	Resource	CT #1	CT #2	SLP	NewCoal	Proposed CT #3	Proposed CT #4	Proposed CT #6	SMMPA	Market	Grand Total
Retail MWH's		7,421	198,720	2,316,569	3,899,082	321,433	-	1,185,446	51,607,107	1,331,414	60,867,193
											-
Extrnlty Cost-SO2		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Extrnlty Cost-PM10		$ 52	$ 1,400	$ 210,228	$ 281,301	$ 2,264	$ -	$ 70,432	$ 3,394,699	$ 87,580	$ 4,047,956
Extrnlty Cost-CO		$ 4	$ 109	$ 122	$ 1,040	$ 176	$ -	$ 1,285	$ 34,858	$ 899	$ 38,495
Extrnlty Cost-Nox		$ 406	$ 10,879	$ 133,400	$ 94,093	$ 17,598	$ -	$ 37,147	$ 1,431,264	$ 36,925	$ 1,761,713
Extrnlty Cost-Pb		$ -	$ -	$ 357	$ 239	$ -	$ -	$ -	$ 1,580	$ 41	$ 2,216
Extrnlty Cost-CO2		$ 7,941	$ 212,634	$ 5,803,055	$ 10,960,090	$ 343,938	$ -	$ 1,358,078	$ 102,093,492	$ 2,633,914	$ 123,413,142
Extrnlty Cost-Total		$ 8,403	$ 225,022	$ 6,147,162	$ 11,336,763	$ 363,977	$ -	$ 1,466,942	$ 106,955,893	$ 2,759,360	$ 129,263,522
Tons of Emissions-SO2		-	-	5,617.3	1,871.6	-	-	-	12,385.7	319.5	20,194.1
Tons of Emissions-PM10		0.1	1.6	247.7	331.4	2.7	-	83.0	3,999.6	103.2	4,769.2
Tons of Emissions-CO		11.0	294.1	329.3	2,807.3	475.7	-	3,467.4	94,054.0	2,426.5	103,865.4
Tons of Emissions-Nox		5.6	151.0	1,851.9	1,306.2	244.3	-	515.7	19,868.7	512.6	24,456.0
Tons of Emissions-Pb		-	-	0.7	0.5	-	-	-	3.1	0.1	4.4
Tons of Emissions-CO2		-	-	-	-	-	-	-	-	-	-

Rochester Public Utilities
Emissions Cost and Tonnage for Retail Sales, 30 Yr Totals
Scenario #2: Aggressive DSM, Coal & Gas Mix
Scenario Description: Recommended plan adjusted by using the aggressive demand side management results with SLP operating on coal and adjustments to the new resources

	Resource	CT #1	CT #2	SLP	NewCoal	Proposed CT #3	Proposed CT #4	Proposed CT #6	SMMPA	Market	Grand Total
Retail MWH's		175	140,248	1,651,836	1,422,649	218,631	-	981,553	49,263,686	1,011,076	54,689,854
											-
Extrnlty Cost-SO2		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Extrnlty Cost-PM10		$ 1	$ 988	$ 149,904	$ 102,638	$ 1,540	$ -	$ 58,318	$ 3,240,549	$ 66,508	$ 3,620,446
Extrnlty Cost-CO		$ 0	$ 77	$ 87	$ 380	$ 120	$ -	$ 1,064	$ 33,275	$ 683	$ 35,686
Extrnlty Cost-Nox		$ 10	$ 7,678	$ 95,121	$ 34,331	$ 11,969	$ -	$ 30,758	$ 1,366,272	$ 28,041	$ 1,574,181
Extrnlty Cost-Pb		$ -	$ -	$ 255	$ 87	$ -	$ -	$ -	$ 1,508	$ 31	$ 1,881
Extrnlty Cost-CO2		$ 187	$ 150,068	$ 4,137,884	$ 3,998,981	$ 233,939	$ -	$ 1,124,493	$ 97,457,540	$ 2,000,196	$ 109,103,288
Extrnlty Cost-Total		$ 198	$ 158,811	$ 4,383,251	$ 4,136,417	$ 247,568	$ -	$ 1,214,632	$ 102,099,145	$ 2,095,459	$ 114,335,481
Tons of Emissions-SO2		-	-	4,005.4	682.9	-	-	-	11,823.3	242.7	16,754.2
Tons of Emissions-PM10		0.0	1.2	176.6	120.9	1.8	-	68.7	3,817.9	78.4	4,265.5
Tons of Emissions-CO		0.3	207.6	234.8	1,024.3	323.6	-	2,871.0	89,783.1	1,842.7	96,287.3
Tons of Emissions-Nox		0.1	106.6	1,320.5	476.6	166.2	-	427.0	18,966.5	389.3	21,852.7
Tons of Emissions-Pb		-	-	0.5	0.2	-	-	-	3.0	0.1	3.7
Tons of Emissions-CO2		-	-	-	-	-	-	-	-	-	-

Rochester Public Utilities
Emissions Cost and Tonnage for Retail Sales, 30 Yr Totals
Scenario #3: Aggressive DSM, All Gas
Scenario Description: Recommended plan adjusted by using the aggressive demand side management results with SLP operating on natural gas and the coal unit replaced with gas-fired capacity

Resource	CT #1	CT #2	SLP	NewCoal	Proposed CT #3	Proposed CT #4	Proposed CT #6	SMMPA	Market	Grand Total
Retail MWH's	175	140,248	2,101,143	-	265,579	200,745	1,110,130	49,263,686	1,387,061	54,468,767
										-
Extrnlty Cost-SO2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Extrnlty Cost-PM10	$ 1	$ 988	$ 69,249	$ -	$ 1,871	$ 1,414	$ 65,957	$ 3,240,549	$ 91,240	$ 3,471,270
Extrnlty Cost-CO	$ 0	$ 77	$ 360	$ -	$ 146	$ 110	$ 1,203	$ 33,275	$ 937	$ 36,108
Extrnlty Cost-Nox	$ 10	$ 7,678	$ 233,091	$ -	$ 14,540	$ 10,990	$ 34,787	$ 1,366,272	$ 38,469	$ 1,705,836
Extrnlty Cost-Pb	$ -	$ -	$ 3	$ -	$ -	$ -	$ -	$ 1,508	$ 42	$ 1,553
Extrnlty Cost-CO2	$ 187	$ 150,068	$ 2,408,236	$ -	$ 284,174	$ 214,800	$ 1,271,794	$ 97,457,540	$ 2,744,000	$ 104,530,799
Extrnlty Cost-Total	$ 198	$ 158,811	$ 2,710,939	$ -	$ 300,731	$ 227,315	$ 1,373,741	$ 102,099,145	$ 2,874,688	$ 109,745,567
Tons of Emissions-SO2	-	-	10.5	-	-	-	-	11,823.3	332.9	12,166.7
Tons of Emissions-PM10	0.0	1.2	81.6	-	2.2	1.7	77.7	3,817.9	107.5	4,089.8
Tons of Emissions-CO	0.3	207.6	970.7	-	393.1	297.1	3,247.1	89,783.1	2,527.9	97,426.8
Tons of Emissions-Nox	0.1	106.6	3,235.8	-	201.8	152.6	482.9	18,966.5	534.0	23,680.3
Tons of Emissions-Pb	-	-	0.0	-	-	-	-	3.0	0.1	3.1
Tons of Emissions-CO2	-	-	-	-	-	-	-	-	-	-

Rochester Public Utilities
Emissions Cost and Tonnage for Retail Sales, 30 Yr Totals
Scenario #4: Normal DSM, Coal & Gas Mix
Scenario Description: Recommended plan adjusted by using the normal demand side management forecast with SLP operating on coal and adjustments to the new resources.

Resource	CT #1	CT #2	SLP	NewCoal	Proposed CT #3	Proposed CT #4	Proposed CT #6	SMMPA	Market	Grand Total
Retail MWH's	531	112,756	1,718,855	1,663,208	285,682	-	1,035,546	49,706,665	1,090,275	55,613,517
										-
Extrnlty Cost-SO2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Extrnlty Cost-PM10	$ 4	$ 794	$ 155,985	$ 119,993	$ 2,013	$ -	$ 61,526	$ 3,269,688	$ 71,718	$ 3,681,721
Extrnlty Cost-CO	$ 0	$ 62	$ 91	$ 444	$ 157	$ -	$ 1,123	$ 33,575	$ 736	$ 36,187
Extrnlty Cost-Nox	$ 29	$ 6,173	$ 98,981	$ 40,137	$ 15,640	$ -	$ 32,450	$ 1,378,558	$ 30,238	$ 1,602,204
Extrnlty Cost-Pb	$ -	$ -	$ 265	$ 102	$ -	$ -	$ -	$ 1,521	$ 33	$ 1,922
Extrnlty Cost-CO2	$ 568	$ 120,650	$ 4,305,767	$ 4,675,180	$ 305,684	$ -	$ 1,186,349	$ 98,333,879	$ 2,156,872	$ 111,084,950
Extrnlty Cost-Total	$ 601	$ 127,680	$ 4,561,089	$ 4,835,856	$ 323,494	$ -	$ 1,281,446	$ 103,017,221	$ 2,259,598	$ 116,406,984
Tons of Emissions-SO2	-	-	4,167.9	798.3	-	-	-	11,929.6	261.7	17,157.5
Tons of Emissions-PM10	0.0	0.9	183.8	141.4	2.4	-	72.5	3,852.3	84.5	4,337.7
Tons of Emissions-CO	0.8	166.9	244.4	1,197.5	422.8	-	3,029.0	90,590.4	1,987.0	97,638.7
Tons of Emissions-Nox	0.4	85.7	1,374.0	557.2	217.1	-	450.5	19,137.1	419.8	22,241.7
Tons of Emissions-Pb	-	-	0.5	0.2	-	-	-	3.0	0.1	3.8
Tons of Emissions-CO2	-	-	-	-	-	-	-	-	-	-

Rochester Public Utilities
Emissions Cost and Tonnage for Retail Sales, 30 Yr Totals
Scenario #5: Normal DSM, All Gas
Scenario Description: Recommenced plan adjusted by using the normal demand side management forecast with SLP operating on natural gas and the coal unit replaced with gas-fired capacity

Resource	CT #1	CT #2	SLP	NewCoal	Proposed CT #3	Proposed CT #4	Proposed CT #6	SMMPA	Market	Grand Total
Retail MWH's	531	167,555	2,250,599	-	283,254	215,265	1,203,823	49,706,665	1,532,831	55,360,523
										-
Extrnlty Cost-SO2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Extrnlty Cost-PM10	$ 4	$ 1,180	$ 74,175	$ -	$ 1,995	$ 1,516	$ 71,524	$ 3,269,688	$ 100,829	$ 3,520,912
Extrnlty Cost-CO	$ 0	$ 92	$ 385	$ -	$ 155	$ 118	$ 1,305	$ 33,575	$ 1,035	$ 36,666
Extrnlty Cost-Nox	$ 29	$ 9,173	$ 249,671	$ -	$ 15,507	$ 11,785	$ 37,723	$ 1,378,558	$ 42,511	$ 1,744,958
Extrnlty Cost-Pb	$ -	$ -	$ 3	$ -	$ -	$ -	$ -	$ 1,521	$ 47	$ 1,571
Extrnlty Cost-CO2	$ 568	$ 179,286	$ 2,579,536	$ -	$ 303,086	$ 230,338	$ 1,379,131	$ 98,333,879	$ 3,032,374	$ 106,038,198
Extrnlty Cost-Total	$ 601	$ 189,732	$ 2,903,770	$ -	$ 320,744	$ 243,757	$ 1,489,683	$ 103,017,221	$ 3,176,797	$ 111,342,305
Tons of Emissions-SO2	-	-	11.3	-	-	-	-	11,929.6	367.9	12,308.7
Tons of Emissions-PM10	0.0	1.4	87.4	-	2.4	1.8	84.3	3,852.3	118.8	4,148.3
Tons of Emissions-CO	0.8	248.0	1,039.8	-	419.2	318.6	3,521.2	90,590.4	2,793.6	98,931.5
Tons of Emissions-Nox	0.4	127.3	3,465.9	-	215.3	163.6	523.7	19,137.1	590.1	24,223.4
Tons of Emissions-Pb	-	-	0.0	-	-	-	-	3.0	0.1	3.1
Tons of Emissions-CO2	-	-	-	-	-	-	-	-	-	-