AQUILA NETWORKS - MISSOURI
INTEGRATED RESOURCE PLAN

February 2007

Submitted to the
MISSOURI PUBLIC SERVICE COMMISSION

PART 4
RESOURCE INTEGRATION

PART 4
RESOURCE INTEGRATION

Table of Contents

		Page
4.1	INTRODUCTION	
	4.1.1 Objectives	1
	4.1.2 Performance Measures	2
	4.1.3 Resource Integration Process	3
4.2	RESOURCE INTEGRATION	
	4.2.1 Demand-Side Management Programs	4
	4.2.2 Wind Generation Power Purchase Agreements and Ownership	8
4.3	SUMMARY OF ALTERNATIVE RESOURCE PLANS WITH DSM	8
	4.3.1 No New Coal Generation	9
	4.3.2 Power Purchase Agreements Through 2012	9
	4.3.3 Power Purchase Agreements Through 2009	9
	4.3.4 No New Gas Generation	9
	4.3.5 Green	9
4.4	COMPARISON OF ALTERNATIVE RESOURCE PLANS	
	4.4.1 Generation Additions for Alternative Resource Plans	9
	4.4.2 Financial Comparison of ARPs	12
	4.4.3 Environmental Comparison of ARPs	14
4.5	CONCLUSIONS	16

APPENDICES	Number
Missouri Reporting Requirements	4-A
No New Coal Generation Plan Results	4-B
Power Purchase Agreements Through 2012 Plan Results	4-C
Power Purchase Agreements Through 2009 Plan Results	4-D
No New Gas Generation Plan Results	4-E
Green Generation Plan Results	4-F
Financials for Alternative Resource Plans	4-G

4.1 INTRODUCTION

4.1.1 Objectives

Resource integration of demand-side and supply-side resource options was performed by Aquila Networks - Missouri (ANM) as part of the 2007 Integrated Resource Plan. This volume is filed in compliance with the rules for Electric Utility Resource Planning (4 CSR 240-22.060) of the Missouri Public Service Commission. These rules require electric utilities to design resource plans to meet the planning objectives identified in 4 CSR 240-22.010(2), and set minimum standards for the scope and level of detail required in resource plan analysis, and for the logically consistent and economically equivalent analysis of resource plans. Appendix 4-A contains responses to each reporting requirement, referring to appropriate documentation within this report. Appendices 4-B through 4-F provide detailed results for the resource integration analysis.

ANM's 2007 Integrated Resource Plan is based on alternative energy resource plans that are designed to satisfy the objectives and priorities identified in 4 CSR 240-22.010(2), as follows:

> *(2) The fundamental objective of the resource planning process at electric utilities shall be to provide the public with energy services that are safe, reliable and efficient, at just and reasonable rates, in a manner that serves the public interest. This objective requires that the utility shall --*
>
> *(A) Consider and analyze demand-side efficiency and energy management measures on an equivalent basis with supply-side alternatives in the resource planning process;*
>
> *(B) Use minimization of the present worth of long-run utility costs as the primary selection criterion in choosing the preferred resource plan; and*
>
> *(C) Explicitly identify and, where possible, quantitatively analyze any other considerations which are critical to meeting the fundamental objective of the resource planning process, but which may constrain or limit the minimization of the present worth of expected utility costs . . .*

As required by the Commission's rules, the primary objective utilized by ANM in developing the optimal energy plan was minimization of the present value of revenue requirements over the 2007-2026 planning period. In addition to this objective, alternative resource plans (ARPs) were also developed for other important planning objectives, as follows:

- Minimize CO_2 production – The “No New Coal Generation” ARP prohibits the addition of new coal-fired resources and thus lowers the systemwide production of CO_2. The “Green” ARP examines the cost impact of ANM unilaterally setting its own CO_2 emission rate limit at 6.5 million tons per year beginning in 2015, equivalent to the ANM level of CO_2 emissions in the year 2000.

- Minimize dependence on natural gas – The “No New Gas Generation” ARP provides an alternative plan for ANM to not increase its exposure to the volatile natural gas market in the generation of electricity.

4.1.2 Performance Measures

The alternative resource plans contained in Part 4, Resource Integration, were evaluated based on several performance measures. These performance measures were developed over the 2007-2026 planning period in accordance with 4 CSR 240-22.060(2), and other sections of the Commission’s rules, as follows:

Customer Value Measures (Rate Impacts)

- Present value of Utility Revenue Requirements
- Present value of Probable Environmental Costs
- Present value of DSM Program Participant Costs
- Average Rates (annual, levelized and maximum increase)

Environmental Impacts (Annual emissions: Tons, $Cost)

- Sulfur dioxide (SO_2)
- Nitrogen oxide (NOx)
- Mercury (Hg)
- Carbon dioxide (CO_2)

The above performance measures were calculated over the 2007-2026 planning period for each alternative resource plan using Global Energy Decisions’ MIDAS Gold™ software package. Probable environmental costs were included in the resource integration process to determine the selection of demand-side and supply-side resources in the Alternative Resource Plans.

4.1.3 Resource Integration Process

The resource integration process is automated in the MIDAS Gold™ software to comply with the requirement in 4 CSR 240-22.010(2)(A) of the rules. This section of the rules states that the utility shall consider and analyze demand-side efficiency and energy management measures on an equivalent basis with supply-side alternatives in the resource planning process. In addition, section 4 CSR 240-22.060(4)(D) requires that:

> *The modeling procedure shall treat supply-side and demand-side resources on a logically consistent and economically equivalent basis. This means than the same types or categories of costs, benefits and risks shall be considered, and that these factors shall be quantified in a similar level of detail and precision for all resource types.*

The energy planning process for electric utilities includes the following basic steps:

(1) Prepare a baseline load forecast without demand-side programs.

(2) Develop an optimal supply-side plan, as a reference plan, without demand-side programs, based on a desired planning objective. (Part 2 of the IRP)

(3) Develop avoided cost estimates using the system planning method for use in evaluating demand-side measures.

(4) Evaluate the cost-effectiveness of demand-side resources and develop an initial demand-side plan, based on the avoided costs from the optimal supply-side plan developed in step #2.

(5) Subtract the effects of cost-effective demand-side resources, identified in step #4, from the baseline load forecast to arrive at a net load forecast.

(6) Re-optimize the supply-side resources to meet the net load forecast from step #5, considering the load impacts of cost-effective demand-side programs

(7) Conduct a risk analysis to determine the optimal energy plan with the greatest flexibility in coping with uncertainties. (Part 5 of the IRP)

This section of the IRP details the results of steps 5, 6, and 7 from above.

4.2 RESOURCE INTEGRATION

4.2.1 Demand-Side Management Programs

The Demand-Side Management Programs identified in Part 2 were evaluated against the supply-side resources using the MIDAS Gold production cost model. The programs were modeled individually to determine the impact of each program on the net present value of revenue requirements. The model allowed for the delay or elimination of supply-side resource additions as a result of the DSM impact. The only DSM program that was not determined to be cost effective was the direct load control (DLC) program. Table 4-2 provides an overview of the DSM program impacts on ANM-system demand and energy along with the total costs of the cost-effective programs.

Table 4-1
Impact of Demand-Side Management Programs

	Energy Efficiency			Demand Response			Total		
Year	Total Non-Coincident Demand Impact (MW)	Energy Reduction (MWh)	Total Cost ($)	Total Non-Coincident Demand Impact (MW)	Energy Reduction (MWh)	Total Cost ($)	Total Coincident Peak Demand Impact (MW) [1]	Energy Reduction (MWh)	Total Cost ($)
2007	3.7	9,050	4,152,436	7.8	480	2,422,580	10.2	9,530	6,575,016
2008	11.5	28,390	7,510,036	15.7	950	1,613,628	23.1	29,340	9,123,663
2009	25.0	62,020	11,692,454	23.5	1,100	1,761,812	39.5	63,120	13,454,267
2010	38.6	95,750	11,752,850	24.1	1,490	967,394	48.8	97,240	12,720,244
2011	52.4	130,040	12,164,206	24.8	1,700	1,000,302	58.2	131,740	13,164,507
2012	66.4	164,830	12,483,859	25.4	1,970	1,041,767	67.8	166,800	13,525,627
2013	80.6	200,560	12,854,347	26.0	2,190	1,084,073	77.4	202,750	13,938,420
2014	95.0	236,720	13,485,491	26.7	2,410	1,128,192	87.2	239,130	14,613,683
2015	109.5	273,580	14,207,839	27.4	2,610	1,174,326	97.2	276,190	15,382,165
2016	124.3	310,360	14,969,457	28.0	2,920	1,222,249	107.3	313,280	16,191,706
2017	139.3	348,150	15,692,767	28.8	3,190	1,273,755	117.5	351,340	16,966,522
2018	154.5	386,530	16,412,567	29.5	3,150	1,327,139	127.9	389,680	17,739,706
2019	170.0	425,920	17,355,025	30.2	3,480	1,382,230	138.5	429,400	18,737,254
2020	185.7	466,470	17,852,616	31.0	3,830	1,441,090	149.3	470,300	19,293,707
2021	201.6	506,370	18,679,284	31.8	3,660	1,501,429	160.3	510,030	20,180,714
2022	217.9	547,170	19,991,271	32.6	3,870	1,565,525	171.4	551,040	21,556,796
2023	234.5	589,060	21,544,204	33.4	4,400	1,632,852	182.8	593,460	23,177,057
2024	251.3	631,980	23,050,903	34.3	3,650	1,703,235	194.5	635,630	24,754,138
2025	268.6	675,950	23,739,358	35.2	3,900	1,777,352	206.4	679,850	25,516,710
2026	285.7	719,950	24,051,420	36.1	3,840	1,854,635	218.3	723,790	25,906,055

[1] The sum of Energy Efficiency and Demand Response Demand Impact do not equal the total peak reduction due to non-coincidence of the program impacts.

The costs and benefits that would be realized by the program participants are shown in Table 4-2. It should be noted that this table does not include the benefit of incentives paid to participants by ANM in the curtailable rates programs.

Table 4-2
DSM Program Participant Costs and Benefits

	Total Participant	
	Costs	Benefits
2007	$1,111,736	$575,676
2008	$2,331,236	$1,860,234
2009	$4,053,554	$4,194,115
2010	$4,107,250	$6,724,466
2011	$4,262,524	$9,525,536
2012	$4,430,287	$12,631,984
2013	$4,628,848	$16,129,700
2014	$5,082,402	$20,073,788
2015	$5,623,168	$24,500,914
2016	$6,198,781	$29,263,328
2017	$6,737,932	$34,415,116
2018	$7,264,990	$39,999,019
2019	$8,001,587	$46,132,297
2020	$8,293,867	$52,447,196
2021	$8,905,839	$58,980,893
2022	$9,996,808	$65,453,642
2023	$11,312,567	$72,575,036
2024	$12,579,695	$80,313,251
2025	$13,016,445	$88,621,784
2026	$13,199,630	$97,311,759
NPV	**$55,577,713**	**$256,151,725**

The summer and winter peak demand impacts of the cost-effective demand-side management programs are shown in Figures 4-1 and 4-2. The impact represents an average annual peak demand growth reduction from 2.0% to 1.6% over the study period. Figure 4-3 shows the summer peak demand impact by DSM program. The demand impact grows from 0.5% of forecasted peak demand in 2007 to 8.0% of peak demand in 2026.

Figure 4-4 shows the system annual energy impacts of the cost-effective demand-side management programs and Figure 4-5 provides the annual energy impact by program. The energy impact increases from 0.1% of forecasted energy requirements in 2007 to 5.4% in 2026.

Figure 4-1
DSM Summer Peak Demand Impact

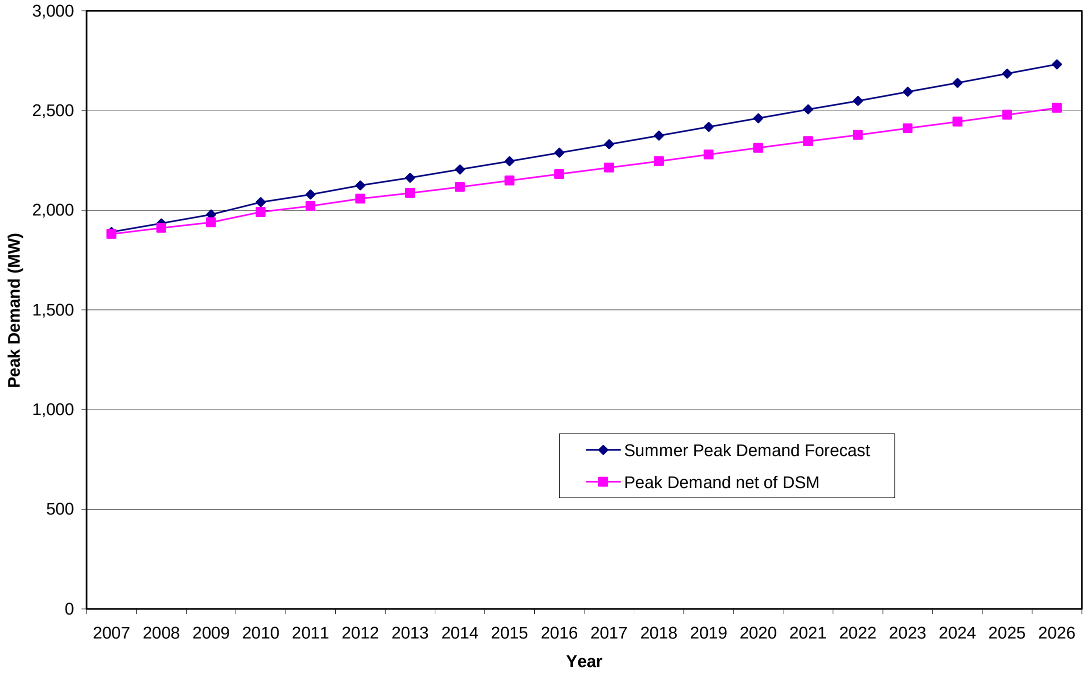


Figure 4-2
DSM Winter Peak Demand Impact

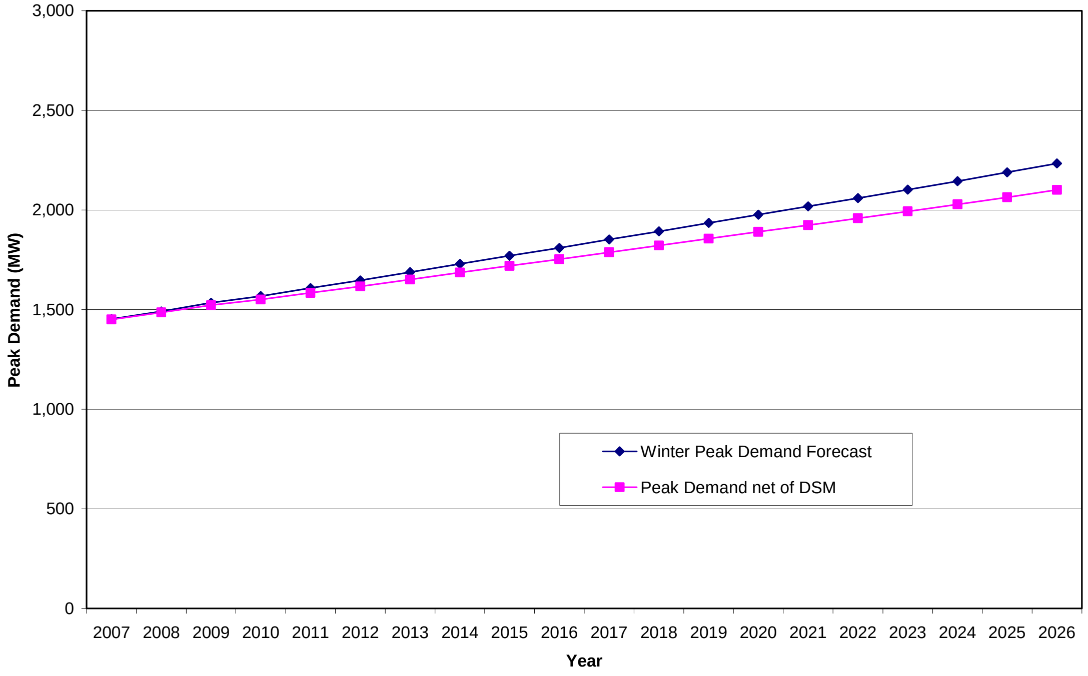


Figure 4-3
Summer Peak Demand Impact of DSM by Program

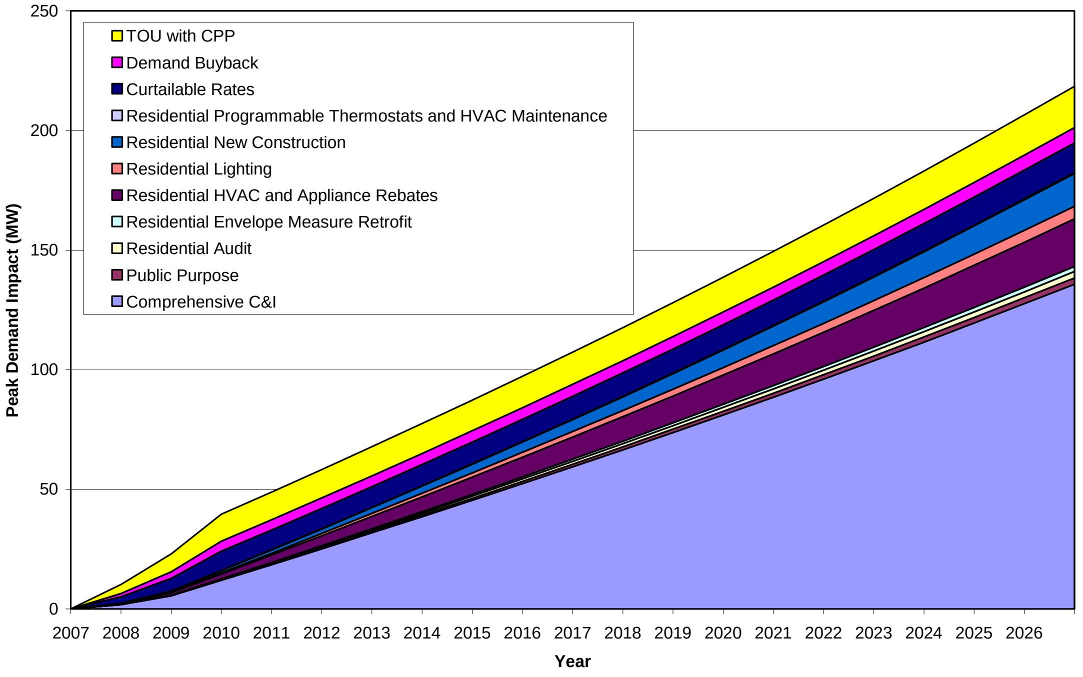


Figure 4-4
DSM Energy Impact

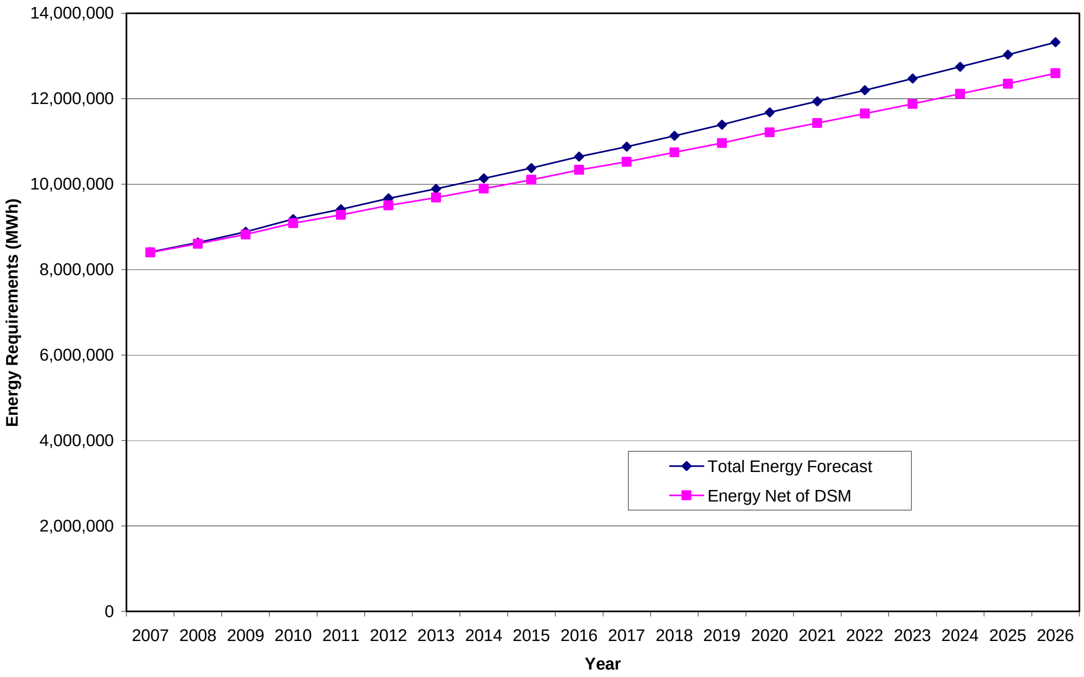
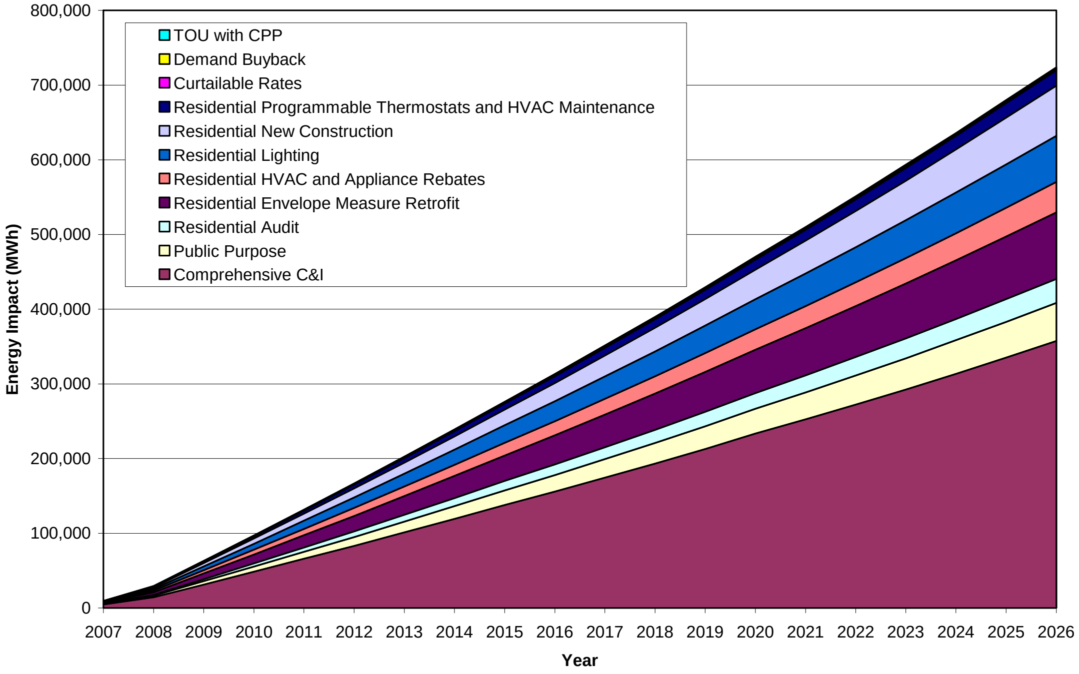


Figure 4-5
Energy Impacts of DSM by Program



4.2.2 Wind Generation Power Purchase Agreements and Ownership

Wind generation was analyzed in a manner similar to the demand-side management programs because of the methodology of modeling non-dispatchable resources in the MIDAS Gold model. The costs of wind PPAs and generation ownership were modeled based on recent proposals from wind project developers. Neither wind option was cost effective when modeled against the dispatchable power supply resource options. However, the wind PPA was only marginally higher cost and new wind generation proposals will be requested when ANM issues a request for power supply proposals in the spring of 2006.

4.3 SUMMARY OF ALTERNATIVE RESOURCE PLANS WITH DSM

The Alternative Resource Plans (ARPs) developed for Aquila Networks - Missouri as a result of the resource integration process described above are based on the Commission's required planning objective of minimizing utility costs (revenue requirements) on a present value basis at the utility's cost of capital of 7.97% over the 20-year planning horizon (2007-2026).

Each ARP assumes that a different mix of generation types is available or constrained by environmental limits. The MIDAS capacity expansion module was used to determine the least cost capacity expansion plan using the limitations specific to each plan. A description of the ARPs is included in the following paragraphs.

4.3.1 No New Coal Generation

The “No New Coal Generation” ARP assumes that PPAs are available through 2012 to meet all capacity requirements and also assumes no coal-fired generation additions are available during the study period. The financial and operating data output from the modeling of this plan are included as Appendix 4-B.

4.3.2 Power Purchase Agreements Through 2012

The “PPAs Through 2012” ARP assumes that PPAs are available through 2012 and no other generation types are excluded during the entire study period. This plan was the least-cost supply-side only plan and remains the least cost plan with the integration of demand-side management programs. The financial and operating data output from the modeling of this plan are included as Appendix 4-C.

4.3.3 Power Purchase Agreements Through 2009

The “PPAs Through 2009” ARP assumes that PPAs are available through 2009 and no other generation types are excluded during the entire study period. The financial and operating data output from the modeling of this plan are included as Appendix 4-D.

4.3.4 No New Gas Generation

The “No New Gas Generation” ARP assumes that PPAs are available through 2012 and also assumes no gas-fired generation additions are available during the study period. The financial and operating data output from the modeling of this plan are included as Appendix 4-E.

4.3.5 Green

The “Green” ARP assumes that PPAs are available through 2012 and also assumes that Aquila will self-impose a CO_2 emissions limit of 6.5 million tons beginning in 2015. This limit is equal to ANM’s CO_2 emissions level in the year 2000. The generation additions in this plan are the least cost alternatives that allow ANM to meet the CO_2 limit. The financial and operating data output from the modeling of this plan are included as Appendix 4-F.

4.4 COMPARISON OF ALTERNATIVE RESOURCE PLANS

4.4.1 Generation Additions for Alternative Resource Plans

Table 4-3 summarizes the generation additions and net present value of revenue requirements (NPVRR) for each of the ARPs with DSM integrated. The table shows that the “PPAs through 2012” alternative resource plan is the lowest cost among these six ARPs when comparing 20-year net present value of revenue requirements and the “No Coal” ARP is the lowest cost using a 10-year NPVRR. All references to PPAs in Table 4-3 represent the total PPA resource in that year. The PPA amounts are not additive from one year to the next.

Table 4-3
Generation Additions and Capacity Purchases for Alternative Resource Plans

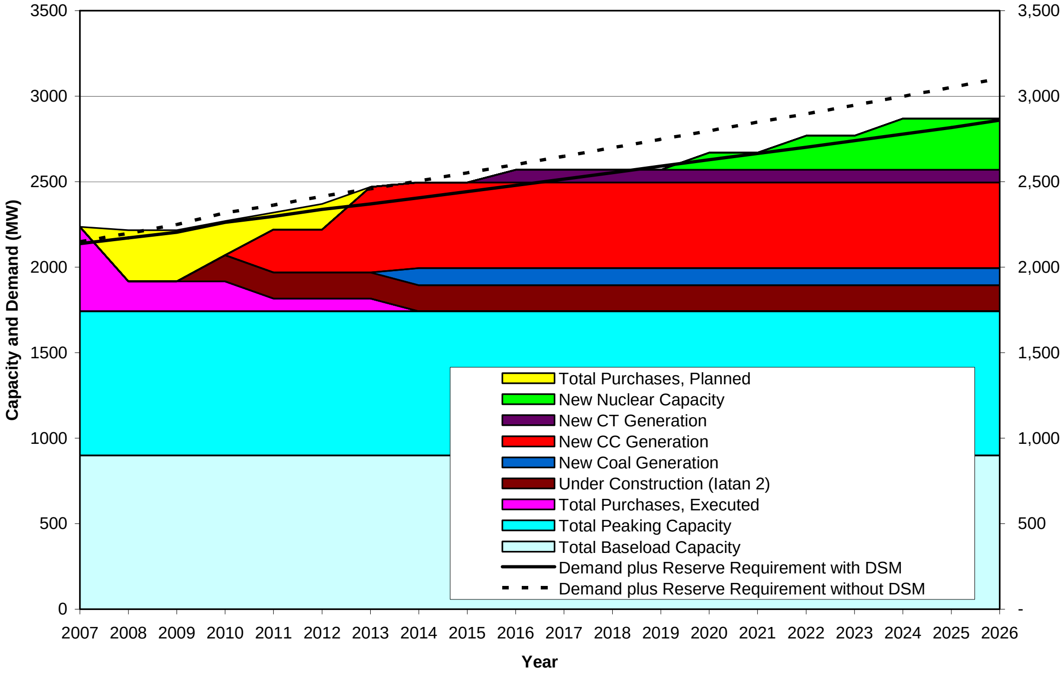
	Alternative Resource Plans				
Year	No Coal	PPAs through 2012	PPAs through 2009	No Gas	Green
2007					
2008	300 MW PPA	300 MW PPA	300 MW PPA	300 MW PPA	300 MW PPA, 100 MW Wind PPA
2009	300 MW PPA	300 MW PPA	300 MW PPA	300 MW PPA	300 MW PPA
2010	200 MW PPA	200 MW PPA	225 MW CT	200 MW PPA	200 MW PPA
2011	250 MW CC, 100 MW PPA	250 MW CC, 100 MW PPA	250 MW CC		250 MW CC, 100 MW PPA, 100 MW Wind PPA
2012	150 MW PPA	150 MW PPA		400 MW PPA	150 MW PPA
2013	250 MW CC	250 MW CC		400 MW Coal Participation	100 MW Coal w/ CO_2 Capture Participation, 75 MW CT
2014	75 MW CT	100 MW Coal Participation	100 MW Coal Participation	100 MW Coal Participation	100 MW Coal w/ CO_2 Capture Participation
2015			100 MW Coal Participation	100 MW Coal Participation	100 MW Coal w/ CO_2 Capture Participation, 100 MW Wind PPA
2016	150 MW CT	75 MW CT			100 MW Coal w/ CO_2 Capture Participation
2017				100 MW Coal Participation	
2018			75 MW CT		100 MW Wind PPA
2019					
2020	200 MW Nuclear Participation	100 MW Nuclear Participation	100 MW Nuclear Participation	100 MW Nuclear Participation	100 MW Nuclear Participation
2021					
2022		100 MW Nuclear Participation	100 MW Nuclear Participation	100 MW Nuclear Participation	100 MW Nuclear Participation
2023					100 MW Wind PPA
2024		100 MW Nuclear Participation	100 MW Nuclear Participation		
2025	100 MW Nuclear Participation			100 MW Nuclear Participation	75 MW CT
2026					50 MW Wind PPA

20-Year NPVRR ($M)	$10,034	$10,029	$10,065	$10,148	$10,236
% Above Min	0.1%	0.0%	0.4%	1.2%	2.1%

10-Year NPVRR ($M)	$5,507	$5,522	$5,555	$5,585	$5,654
% Above Min	0.0%	0.3%	0.9%	1.4%	2.7%

Figure 4-6 is a plot of the loads and resources for the “PPAs through 2012” Expansion Plan. New capacity is supplied from Iatan 2 in 2010, new gas-fired combined cycle (CC) units in 2011 and 2013, 100 MW coal generation participation in 2014, 75 MW combustion turbine (CT) unit in 2016, and nuclear unit capacity participation in 2020, 2022, and 2024.

Figure 4-6
Loads and Resources with PPAs through 2012 Expansion Plan



4.4.2 Financial Comparison of ARPs

This section compares key shareholder value performance measures for the Alternative Resource Plans. Table 4-4 shows the annual revenue requirements for the ARPs, Table 4-5 shows the annual average rates (cents/kWh) including the levelized rates over the study period and Figure 4-7 shows the annual average rates graphically.

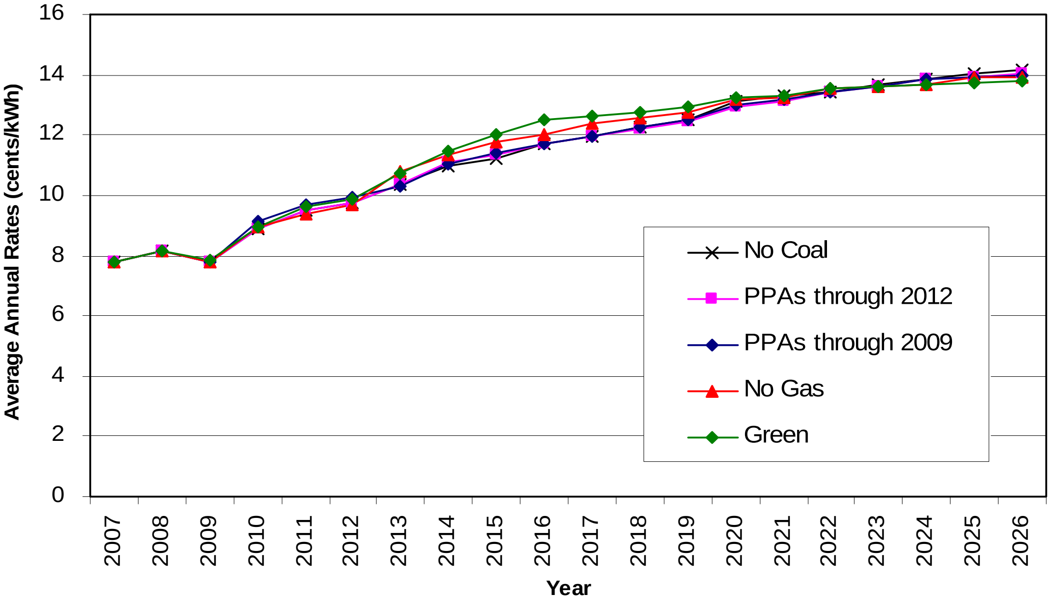
Table 4-4
Revenue Requirement Comparison

	No Coal		PPAs through 2012		PPAs through 2009		No Gas		Green	
Year	Annual Revenue Requirements ($M)	% Increase	Annual Revenue Requirements ($M)	% Increase	Annual Revenue Requirements ($M)	% Increase	Annual Revenue Requirements ($M)	% Increase	Annual Revenue Requirements ($M)	% Increase
2007	609.33		609.33		609.33		609.33		609.32	
2008	654.44	7.4%	654.44	7.4%	654.93	7.5%	655.18	7.5%	654.92	7.5%
2009	641.41	-2.0%	641.42	-2.0%	643.33	-1.8%	644.08	-1.7%	646.15	-1.3%
2010	758.66	18.3%	759.36	18.4%	777.52	20.9%	763.64	18.6%	764.41	18.3%
2011	829.57	9.3%	831.17	9.5%	847.62	9.0%	820.15	7.4%	840.42	9.9%
2012	873.79	5.3%	875.98	5.4%	891.02	5.1%	868.25	5.9%	889.33	5.8%
2013	951.55	8.9%	953.98	8.9%	947.88	6.4%	989.84	14.0%	983.56	10.6%
2014	1,034.26	8.7%	1,043.20	9.4%	1,038.78	9.6%	1,068.87	8.0%	1,081.91	10.0%
2015	1,080.00	4.4%	1,090.78	4.6%	1,098.22	5.7%	1,136.88	6.4%	1,160.53	7.3%
2016	1,158.57	7.3%	1,160.46	6.4%	1,157.63	5.4%	1,185.62	4.3%	1,238.62	6.7%
2017	1,205.99	4.1%	1,206.53	4.0%	1,205.67	4.1%	1,253.39	5.7%	1,275.39	3.0%
2018	1,266.53	5.0%	1,263.28	4.7%	1,269.80	5.3%	1,299.23	3.7%	1,319.88	3.5%
2019	1,323.57	4.5%	1,318.97	4.4%	1,326.34	4.5%	1,351.49	4.0%	1,366.51	3.5%
2020	1,423.98	7.6%	1,404.96	6.5%	1,409.18	6.2%	1,431.08	5.9%	1,439.89	5.4%
2021	1,472.46	3.4%	1,458.59	3.8%	1,460.93	3.7%	1,471.19	2.8%	1,477.78	2.6%
2022	1,522.45	3.4%	1,521.18	4.3%	1,521.58	4.2%	1,535.41	4.4%	1,537.56	4.0%
2023	1,585.08	4.1%	1,579.69	3.8%	1,577.64	3.7%	1,579.60	2.9%	1,579.65	2.7%
2024	1,639.42	3.4%	1,641.24	3.9%	1,637.47	3.8%	1,621.71	2.7%	1,619.24	2.5%
2025	1,699.38	3.7%	1,686.17	2.7%	1,683.23	2.8%	1,686.69	4.0%	1,666.19	2.9%
2026	1,751.54	3.1%	1,737.92	3.1%	1,733.16	3.0%	1,724.00	2.2%	1,704.77	2.3%
Maximum Single-Year Increase ($M)	117.25		117.94		134.19		121.59		118.26	

Table 4-5
Average Annual Rate Comparison

	No Coal		PPAs through 2012		PPAs through 2009		No Gas		Green	
	Average Annual Rates (cents/kWh)	% Increase	Average Annual Rates (cents/kWh)	% Increase	Average Annual Rates (cents/kWh)	% Increase	Average Annual Rates (cents/kWh)	% Increase	Average Annual Rates (cents/kWh)	% Increase
2007	7.795¢		7.795¢		7.795¢		7.795¢		7.795¢	
2008	8.158¢	4.7%	8.158¢	4.7%	8.164¢	4.7%	8.168¢	4.8%	8.164¢	4.7%
2009	7.770¢	-4.8%	7.770¢	-4.8%	7.793¢	-4.6%	7.802¢	-4.5%	7.827¢	-4.1%
2010	8.892¢	14.4%	8.900¢	14.5%	9.113¢	16.9%	8.950¢	14.7%	8.959¢	14.5%
2011	9.485¢	6.7%	9.503¢	6.8%	9.691¢	6.3%	9.377¢	4.8%	9.609¢	7.2%
2012	9.726¢	2.5%	9.751¢	2.6%	9.918¢	2.3%	9.664¢	3.1%	9.899¢	3.0%
2013	10.357¢	6.5%	10.383¢	6.5%	10.317¢	4.0%	10.774¢	11.5%	10.705¢	8.1%
2014	10.985¢	6.1%	11.080¢	6.7%	11.033¢	6.9%	11.353¢	5.4%	11.492¢	7.3%
2015	11.201¢	2.0%	11.313¢	2.1%	11.390¢	3.2%	11.791¢	3.9%	12.036¢	4.7%
2016	11.714¢	4.6%	11.733¢	3.7%	11.704¢	2.8%	11.987¢	1.7%	12.523¢	4.0%
2017	11.936¢	1.9%	11.941¢	1.8%	11.933¢	2.0%	12.405¢	3.5%	12.623¢	0.8%
2018	12.245¢	2.6%	12.214¢	2.3%	12.277¢	2.9%	12.561¢	1.3%	12.761¢	1.1%
2019	12.504¢	2.1%	12.461¢	2.0%	12.530¢	2.1%	12.768¢	1.6%	12.910¢	1.2%
2020	13.120¢	4.9%	12.945¢	3.9%	12.984¢	3.6%	13.185¢	3.3%	13.266¢	2.8%
2021	13.274¢	1.2%	13.149¢	1.6%	13.170¢	1.4%	13.263¢	0.6%	13.322¢	0.4%
2022	13.430¢	1.2%	13.419¢	2.1%	13.423¢	1.9%	13.545¢	2.1%	13.563¢	1.8%
2023	13.680¢	1.9%	13.633¢	1.6%	13.616¢	1.4%	13.632¢	0.6%	13.633¢	0.5%
2024	13.842¢	1.2%	13.858¢	1.6%	13.826¢	1.5%	13.693¢	0.4%	13.672¢	0.3%
2025	14.036¢	1.4%	13.927¢	0.5%	13.903¢	0.6%	13.931¢	1.7%	13.762¢	0.7%
2026	14.152¢	0.8%	14.042¢	0.8%	14.003¢	0.7%	13.929¢	0.0%	13.774¢	0.1%
Levelized Rates	10.505¢		10.503¢		10.545¢		10.625¢		10.720¢	
Maximum Single-Year Rate Increase (cents/kWh)	1.122¢		1.130¢		1.320¢		1.148¢		1.132¢	

Figure 4-7
Average Annual Rates



All plans show a large increase in revenue requirements and the resulting rates in the year 2010 due to the additions of Iatan 2 and planned environmental projects. The decrease in revenue requirements in the year 2009 is largely the result of forecasted natural gas price decreases which leads to lower forecasted spot market energy prices. The No Coal and PPA alternative resource plans do not vary significantly in the levelized rates as shown in Table 4-5 with all three plans within 0.5% of each other.

The pretax interest coverage ratio (including allowance for funds used during construction (AFUDC)), ratio of total debt to total capital, and ratio of net cash flow to capital expenditures for the ARPs are included in Appendix 4-G.

4.4.3 Environmental Comparison of ARPs

Table 4-6 shows the annual emission levels of NOx, SO_2, Hg, and CO_2 for each of the ARPs and Table 4-7 shows the annual emission cost comparison. The annual costs are largely driven by the forecast of CO_2 emissions costs as described in Part 2 of the IRP.

Table 4-6
Emission Level Comparison

	No Coal				PPAs through 2009				PPAs through 2012				No Gas				Green			
	NO_X	SO_2	Hg	CO2	NO_X	SO_2	Hg	CO2	NO_X	SO_2	Hg	CO2	NO_X	SO_2	Hg	CO2	NO_X	SO_2	Hg	CO2
Year	(tons)	(tons)	(lbs)	(tons)	(tons)	(tons)	(lbs)	(tons)	(tons)	(tons)	(lbs)	(tons)	(tons)	(tons)	(lbs)	(tons)	(tons)	(tons)	(lbs)	(tons)
2007	1,053	17,109	71	5,708,574	1,053	17,109	71	5,708,574	1,053	17,109	71	5,708,574	1,053	17,109	71	5,708,574	1,053	17,109	71	5,708,554
2008	1,062	16,697	69	5,576,739	1,062	16,697	69	5,576,739	1,062	16,697	69	5,576,739	1,062	16,697	69	5,576,739	1,051	16,503	69	5,515,963
2009	1,065	17,553	72	5,781,230	1,065	17,553	72	5,781,230	1,065	17,553	72	5,781,230	1,065	17,553	72	5,781,230	1,037	17,149	71	5,660,362
2010	1,224	17,519	79	6,401,310	1,239	17,473	79	6,457,296	1,224	17,519	79	6,401,310	1,224	17,519	79	6,401,310	1,191	17,084	77	6,259,323
2011	1,362	17,784	84	7,100,587	1,363	17,758	84	7,145,906	1,362	17,784	84	7,100,587	1,324	17,772	84	6,865,998	1,315	17,137	82	6,864,250
2012	1,380	18,274	87	7,335,520	1,392	18,227	87	7,379,615	1,380	18,274	87	7,335,520	1,338	18,266	87	7,047,632	1,315	17,477	84	7,038,372
2013	1,431	18,351	87	7,614,820	1,424	18,367	87	7,500,826	1,431	18,351	87	7,614,820	1,588	15,574	105	8,574,328	1,465	16,800	92	6,979,704
2014	1,480	18,864	89	8,003,302	1,535	18,596	96	8,263,446	1,542	18,571	96	8,402,332	1,692	15,738	113	9,277,186	1,620	16,579	105	7,032,268
2015	1,502	18,870	88	8,111,477	1,611	18,279	102	8,735,470	1,563	18,616	95	8,509,393	1,738	15,255	117	9,551,961	1,689	15,244	111	6,524,850
2016	1,515	18,987	89	8,208,856	1,620	18,546	103	8,869,143	1,574	18,849	97	8,633,878	1,761	15,581	119	9,738,778	1,780	14,419	119	6,259,442
2017	1,527	18,958	89	8,242,700	1,650	18,658	103	8,901,336	1,595	18,869	96	8,671,592	1,814	15,095	122	10,000,217	1,809	14,803	121	6,399,868
2018	1,545	19,038	89	8,380,226	1,669	18,862	104	9,049,550	1,615	19,013	97	8,831,356	1,841	15,475	125	10,201,492	1,813	14,887	121	6,468,388
2019	1,556	19,041	89	8,440,559	1,684	18,960	104	9,082,290	1,627	19,075	97	8,885,848	1,872	15,824	126	10,324,421	1,822	14,990	121	6,471,802
2020	1,455	18,360	87	7,982,962	1,635	18,473	102	8,892,190	1,586	18,747	96	8,712,022	1,784	15,071	121	9,917,283	1,732	14,184	116	6,114,311
2021	1,472	18,467	87	8,014,903	1,647	18,636	102	8,925,275	1,594	18,818	95	8,718,792	1,813	15,409	123	10,064,478	1,758	14,482	118	6,227,156
2022	1,484	18,628	88	8,132,372	1,589	18,150	101	8,719,784	1,549	18,443	94	8,524,031	1,733	14,663	118	9,646,658	1,683	13,825	114	5,897,224
2023	1,500	18,706	87	8,174,232	1,603	18,368	101	8,766,512	1,564	18,574	94	8,583,273	1,760	15,007	120	9,808,945	1,669	13,935	113	5,920,817
2024	1,522	18,851	88	8,295,826	1,559	17,855	99	8,561,490	1,515	18,194	93	8,380,113	1,798	15,293	122	10,004,886	1,695	14,053	114	6,018,233
2025	1,529	19,869	92	8,433,605	1,627	19,156	104	8,984,220	1,587	19,590	98	8,799,956	1,757	15,298	120	9,838,929	1,775	15,273	120	6,436,565
2026	1,538	19,956	92	8,506,108	1,640	19,307	105	9,056,006	1,592	19,675	99	8,858,304	1,784	15,620	122	9,987,520	1,772	15,247	119	6,430,906

Table 4-7
Total Emission Cost Comparison ($M)

	No Coal	PPAs through 2012	PPAs through 2009	No Gas	Green
2007	$17.19	$17.19	$17.19	$17.19	$17.19
2008	$15.93	$15.93	$15.93	$15.93	$15.76
2009	$17.71	$17.71	$17.71	$17.71	$17.33
2010	$52.72	$52.72	$52.99	$52.72	$51.55
2011	$70.10	$70.10	$70.40	$68.37	$67.76
2012	$86.28	$86.28	$86.66	$83.59	$82.74
2013	$104.22	$104.22	$102.96	$113.54	$96.28
2014	$125.38	$130.71	$128.90	$140.80	$111.82
2015	$143.36	$149.51	$152.97	$163.67	$117.93
2016	$161.71	$169.23	$173.34	$186.70	$126.69
2017	$179.14	$187.67	$192.27	$211.46	$142.75
2018	$199.05	$208.99	$213.87	$236.61	$157.52
2019	$217.71	$228.49	$233.36	$260.81	$171.16
2020	$222.75	$242.06	$246.75	$270.78	$174.61
2021	$232.57	$251.92	$257.59	$285.83	$184.85
2022	$244.90	$255.81	$261.24	$284.36	$182.01
2023	$255.22	$267.09	$272.45	$299.90	$189.43
2024	$268.13	$270.15	$275.52	$316.79	$199.25
2025	$282.64	$293.87	$299.39	$322.42	$220.37
2026	$293.45	$304.59	$310.81	$337.36	$226.56
20-Year NPV	$1,185	$1,230	$1,249	$1,350	$975
10-Year NPV	$461	$470	$473	$493	$414

4.3 CONCLUSIONS

ANM has identified six Alternative Resource Plans which attempt to meet the objective of minimizing revenue requirements while addressing other important planning objectives. The No Coal, PPAs through 2009, and PPAs through 2012 ARPs are very similar from a financial and emissions standpoint. All of these plans will be further evaluated in Part 5 – Risk Analysis and Strategy Selection.