BLACK HILLS/COLORADO ELECTRIC UTILITY COMPANY, LP

2008 RESOURCE PLAN

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ES. Executive Summary

Introduction - The First Priority – Keeping the Customers' Lights On

On July 14, 2008, the electric utility assets and operations in Colorado of Aquila, Inc., doing business as Aquila Networks-WPC, were transferred to a subsidiary of Aquila, Inc. (Aquila) named Aquila Colorado Electric Opco, LP (Electric Opco) followed by the immediate transfer of the general and limited partnership interests in Electric Opco to subsidiaries of Black Hills Utility Holdings, Inc. and the change of the name of Electric Opco to Black Hills/Colorado Electric Utility Company, LP. All necessary approvals for these transfers were obtained including approval from the Colorado Public Utilities Commission (Commission) by Decision No. 08-0204 in Docket No. 07A-108EG and from local franchise authorities.

This resource plan (Resource Plan or Plan) is being filed by Black Hills/Colorado Electric Utility Company, LP which will be referred to in this Plan as "the Company." The Company has filed with the Commission an Application for Approval of this Resource Plan and Petition for Waivers of Portions of the Resource Planning Rules of the Commission.

This Resource Plan must be filed at a time in history when events outside the control of the Company make it impossible for the Company to propose its preferred plan; a plan that would include a broader mixture of generation fuel sources such as coal.

Unlike the typical resource plan that is concerned with the additional resources required to address normal customer growth, this Resource Plan must address the unique situation in which a utility faces an abrupt loss of the majority of the capacity, associated energy and reserves used to serve its customers. The Company has an existing Restated Power Sales Agreement with Public Service Company of Colorado (PSCo) that terminates on December 31, 2011 (PSCo PPA).[1] The PSCo PPA supplies approximately 75% of the Company's capacity, including associated energy, and the majority of the Company's reserve margin. Thus, the most immediate task that the Company faces is addressing this capacity deficit in order to "keep the lights on" in 2012 and beyond.

Black Hills Corporation (Black Hills), the ultimate parent corporation of the Black Hills organization, through its utility subsidiaries and their predecessors, has been serving retail electric customers since 1883. Black Hills understands that customers want safe, reliable, and economic electric service. Black Hills has extensive and current experience with the construction, ownership and operation of generation and transmission assets; resource planning; and the process to competitively bid and negotiate purchased power agreements. The owners of the Company know how to keep the lights on.

[1] See the Coordination Letters in Appendix C.

In addition, the Company understands and appreciates the necessity for just and reasonable rates for our customers. However, the measures that the Company would ordinarily take to achieve a least cost plan – a balanced portfolio of baseload, intermediate and peaking resources that utilize a diversified fuel mix of coal, natural gas, and renewable resources – are limited by new environmental laws, rules and governmental directives, many of which did not exist in February 2007 when Black Hills announced its agreement to acquire the assets of Aquila, Inc. in Colorado and three other states. These include:

November 2004	Colorado voters pass Amendment 37 renewable energy standard with a 50 cent residential retail rate impact cap[2]
2005 Legislature	Increases Amendment 37's retail rate impact cap to 1%; Commission adopts implementing rules
2007 Legislature	Increases Amendment 37's renewable standard requirements to 20% by 2020 and doubles the retail rate impact cap to 2%; Commission amends rules
November 5, 2007	Governor issues the Colorado Climate Action Plan that includes a goal to reduce greenhouse gas emissions in the utility sector by 20% by 2020
2008 Legislature	Adopts HB08-1164 which requires that the Commission give consideration to the likelihood of new environmental regulation and the risk of higher future costs associated with greenhouse gas emissions when it considers utility proposals to acquire resources
April 22, 2008	Governor issues Executive Order D 004 08 which requests the Commission to require utilities to submit electric resource plans for meeting greenhouse gas reduction goals and directs the Colorado Department of Public Health and Environment and the Governor's Energy Office to evaluate alternatives for addressing greenhouse gas emissions from new coal-fired power plants and to submit a report to the Governor within 12 months.

[2] Approximately 58% of the customers who voted in the Company's service territory, voted against Amendment 37.

There have been other developments as well that have affected this Resource Plan. In 2007, there were at least 52 announced coal project cancellations or delays (see Table D-1 in Appendix D). Perhaps the most well-known of these is the Sunflower Electric Power Cooperative Holcomb plant that was scheduled to be built in Garden City, Kansas with an in-service date of 2012. In October 2007, the air permit application was denied by the Kansas Department of Health and Environment. Sunflower filed an appeal and, on November 30, 2007, the Kansas Supreme Court decided to hear the appeal. The Kansas legislature attempted to override the decision of the Department but Governor Sebelius twice vetoed the legislature's measures. The legislature ended its 2008 session on May 29, 2008. The latest development is that the Kansas Supreme Court has put the appeal on hold pending determinations by the Kansas Department of Health and Environment and the District Court. The future of the project remains uncertain at this time.

Environmental groups are also appealing environmental permits for other coal-fired power plants. For example, on November 1, 2007, the Sierra Club, the Powder River Basin Cooperative, and the Wyoming Outdoor Council filed an appeal before the Wyoming Environmental Quality Council of Basin Electric Power Cooperative's final permit to construct the 365 MW Dry Fork Station near Gillette. Similarly, in 2004, PSCo applied for permits from the Colorado Department of Health and Environment for construction of a new coal-fired electrical generation unit (Comanche 3). The permits were issued but an appeal was filed by Citizens for Clean Air &Water in Pueblo and Southern Colorado and Clean Energy Action. The Pueblo County District Court dismissed the case and the environmental groups appealed. On February 7, 2008, the Colorado Court of Appeals affirmed the dismissal. In July 2008, a Motion was filed with the Commission asking it to review whether Comanche 3 is in the public interest. Construction is underway for both projects after significant delays amid ongoing regulatory risk associated with the appeals.

On December 5, 2007, the United States' Senate Environment and Public Works Committee marked up and voted 11-8 to report S.2191, the Lieberman-Warner Climate Security Act to the full Senate. This was the first time a greenhouse gas cap-and-trade bill has ever been voted out of a congressional committee. The bill was brought to the Senate floor in 2008. While the Act is not expected to pass Congress in 2008, future carbon regulation remains a possibility. Colorado's House Bill 08-1164, effective June 2, 2008, requires the Commission to give consideration to the likelihood of new environmental regulation and the risk of higher future costs associated with the emission of greenhouse gases when it considers utility proposals to acquire resources.

The first priority of this Resource Plan must be to address the capacity deficit in 2012 and beyond. The Company is proposing what it believes to be the best plan to address the capacity deficit and provide the most reliable and efficient resources consistent with that need. It is not the plan the Company would have preferred to propose because it does not include any coal resources even though coal resources have historically been the least cost baseload resources due to low fuel costs and low to medium operation and maintenance costs. The regulatory uncertainty around permitting coal resources at this point in time, particularly in Colorado (with the investigation under Executive Order D

004 08 pending), means that it is not prudent in this Resource Plan for the Company to rely on coal resources being available to address the capacity deficit. In addition, it is now not certain that the long-term transmission projects required for Wyoming-based generation to serve Colorado loads will be built in a timely manner. The Company cannot wait 12 months for the results of the policy evaluation ordered by the Governor on April 22, 2008, to propose its resource plan and cannot wait for transmission to be built; it must act now to address the 2012 capacity deficit.

The Company had to choose between two paths: (1) a proposal that relies on coal as a baseload resource by no later than 2013 and 2014 (with bridging purchased power starting in 2012), or (2) a proposal that does not rely on coal. If the Company started down the permitting road for new coal resources in Colorado or Wyoming and encountered delays, it would be too late for the Company to pursue the alternative option proposed in this plan. The Company and customers would be at risk for whatever price the market could demand for power in that situation and the more significant risk that purchased power would not be available, leading to a lack of resource supply.

These realities caused the Company, in May 2008, to model a no coal resource plan (the Proposed Plan). The Proposed Plan relies on the only resources available in the current environment to ensure the adequacy of resources to address the capacity deficit (after demand side management (DSM) and the amount of renewable resources to be added to meet the Renewable Energy Standard (RES)). Those resources are natural gas-fired combustion turbines.

The Company is very aware of and concerned about natural gas price volatility. It is that volatility that has historically made coal-fired resources for baseload the least cost resources. It is unknown at this time what impact future carbon regulation may have on that paradigm. Purchased power resources would also be natural-gas fired resources. This includes wholesale power purchased from other utilities (not expected to be available) which would in all likelihood be priced at incremental cost (i.e., the cost of natural-gas fired units) and not at system average cost. This Resource Plan contemplates steps to reduce the impact of natural gas prices including state of the art, lower heat rate units which will be sited in areas of the State with greater and more reliable natural gas supplies (and thus lower-cost supplies). The units being proposed in the plan are particularly well suited to support wind integration at a lower cost.

Additionally, this Resource Plan does not reflect the end of the Company's planning; it is only an interim step. At the time this Resource Plan is filed, the Company will have been owned by Black Hills for less than a month. It is now possible for Black Hills to pursue options that could not be pursued prior to the closing of the transaction with Aquila. While Black Hills has been working on this Resource Plan for almost a year, the plan has had to evolve as events have unfolded and represents where the Company is at this point. The Company will continue to look for options that will provide greater fuel diversity and/or employ new technologies that can reduce costs for customers. The Company will also investigate options to participate in regional activities to give customers the benefits of economies of scale that are not available to the Company acting alone. If viable

options become available that the Company believes are better for customers, the Company will make the appropriate regulatory filings. In the interim, the Company is proposing the plan that will ensure the adequacy of resources to address the capacity deficit.

If other options become available, the resources the Company is proposing in this Resource Plan may not be constructed. The assets that the Company will actually seek to have added to rate base will be only those assets that serve the customers and those may or may not be all of the assets being proposed in this Resource Plan or the same assets as proposed in this Resource Plan.

What is needed at this point in time is a focus on the customers: how they can best be served while the Company complies with all of the local, state, regional, and federal legal, regulatory, and other constraints. For example, since the Company does not already have the resources to back up wind in 2012, the cost of wind resources will be incremental to, rather than in lieu of, the cost of the natural gas-fired turbines. The wind resources will add value not by avoiding capacity costs but by reducing the consumption of natural gas.

It is also not realistic to believe that DSM alone can solve the capacity deficit. The Resource Plan assumes success in achieving the 5% DSM reduction goals in HB07-1037. However, to assume greater or faster success at DSM than what is set forth in HB07-1037 and underbuild capacity would put the customers at risk. If, in fact, greater DSM is achieved, there will be savings in reduced consumption of natural gas.

Arguing for technologies that are not currently viable or available is not helpful. For example, integrated gasification combined cycle (IGCC) with carbon capture and carbon sequestration, and nuclear are not feasible resource alternatives to meet the January 1, 2012 capacity deficit. Similarly, arguing for technology that is cost-effective only on a scale too large for the size of the Company's load, such as large combined cycle units which are most efficient in the 500 to 600 MW size, is not helpful.

This Resource Plan must deal with the facts that are presented, not the facts as we wish they were. The Company is open to suggestions for viable alternatives that can be successfully implemented in time to address the capacity deficit in 2012 and beyond.

ES.1 The Resource Acquisition Period and Planning Period

The Resource Acquisition Period has been identified as 2008-2013, the first six years of the Resource Plan. This Resource Plan covers the twenty-year planning period of 2008-2027. The Company is scheduled to file its next resource plan in 2011.

ES.2 The Service Territory

The Company provides electric service to 21 communities in Colorado with more than 90,150 customers. The largest communities served include Pueblo, Cañon City, and

Rocky Ford. The Company's generating stations are located in these three largest communities. The Company's service territory encompasses all or part of Crowley, Custer, Fremont, Otero, Pueblo, and Teller counties.

The median household income and median home/condo values in the Company's service territory are substantially below the State average and the averages in the two largest cities served by Xcel Energy Inc. (d/b/a Public Service Company of Colorado), the other Commission-jurisdictional utility in Colorado.

ES.3 Need For Replacement Resources to Address Capacity Deficit in 2012

As discussed in Section ES.1., this Resource Plan must address the unique situation in which a utility faces an abrupt loss of the majority of the capacity, associated energy and reserves used to serve its customers. The Company's PSCo PPA terminates on December 31, 2011. The PSCo PPA supplies approximately 75% of the Company's capacity, including associated energy, and the majority of the Company's reserve margin.

The termination of the PSCo PPA creates a significant capacity deficit beginning on January 1, 2012. Because of the expiration of the PSCo PPA at the end of 2011, the necessary and primary focus of this Resource Plan is the resources needed to address the capacity deficit in a timely and cost effective manner so that reliable resources are in place on or before January 1, 2012.

ES.4 Need for Additional Resources to Address Customer Growth

This plan also addresses the resources needed to meet customer growth. The expected annual peak demand growth rate is 2.2%, less than the recent actual growth rate. The expected annual energy growth rate is 2.4% which is comparable to the recent actual growth rate. The low, base and high growth forecasts for the resource acquisition period (2008-2013) are shown in Table ES-1:

Table ES-1
Low, Base, and High Load Forecasts Before DSM

	Low Case		Base Case		High Case	
Year	Peak Demand (MW)	Annual Energy (000 MWh)	Peak Demand (MW)	Annual Energy (000 MWh)	Peak Demand (MW)	Annual Energy (000 MWh)
2008	367	1,985	369	2,004	373	2,079
2009	372	2,008	378	2,067	385	2,154
2010	377	2,033	388	2,124	397	2,233
2011	383	2,064	397	2,200	410	2,319
2012	388	2,093	406	2,255	422	2,406
2013	393	2,116	415	2,307	435	2,486

ES.5 Existing Resources

ES.5.1 Conventional

The Company's generation resources consist of two coal-fired steam units, two natural gas-fired steam units, and three diesel plants. The total existing generation owned by the Company is 101.5 MW or about 25% of the Company's resource supply requirements.

ES.5.2 Renewable

The Company's existing renewable resources include the utilization of small amounts of wood chips at the Cañon City units and bio-diesel at the Pueblo and Rocky Ford diesel units. Modest amounts of on-site solar in the form of photovoltaics (PV) have been installed by small and large customers. The Company purchases Renewable Energy Credits (REC) from these customers over the first twenty years of operation. The Company also purchases non-solar RECs. These non-solar RECs do not provide any capacity or energy to the Company.

ES.5.3 Purchased Power

The primary PPA in place for the Company is the one with PSCo that expires December 31, 2011. The PSCo PPA provides for incremental annual increases in capacity from 2007 through 2011 and the option to increase or decrease the contract capacity by 10 MW annually starting with 2007 with at least one-year's notice for each change. The agreement effectively provides its own reserves. The resources of the PSCo system that provide power under the PSCo PPA to the Company are primarily coal and natural gas.

ES.6 Reserve Margin Assumptions

The Company has used a minimum 15% reserve margin for planning purposes for this Resource Plan and a maximum reserve margin of 25% with a goal of staying between these two values. The 15% minimum reserve margin is based on reserve margins required for other utilities by state regulatory commissions and regional transmission organizations.[3] The addition of resources is "lumpy" because resources are available in specific size increments. This is why a resource margin range is needed. The 25% maximum reserve margin ensures that units that are of appropriate size, not too large, for the Company's load are selected.

[3] North American Electric Reliability Corporation, *2008 Summer Reliability Assessment*, May 2008: ERCOT – 12.5% minimum reserve margin; FRCC – 15% reserve margin; MRO – 17.5% summer reserve margin; MAPP GRSP – 15% reserve capacity obligation; MAIN – approximately 14% minimum short-term planning reserve margin; NYISO – 15% Installed Reserve Margin; MISO – 12% default reserve requirement; PJM – 15% reserve margin; SPP – 12% capacity margin requirement.

ES.7 Resource Needs on January 1, 2012

Immediately upon expiration of the existing PSCo PPA on December 31, 2011, the Company must have resources to replace the capacity, associated energy and reserves provided by the PSCo PPA. The Company must also have additional resources due to growth. Table ES-2 indicates that the Company's total need for replacement and additional capacity to maintain a minimum 15% reserve margin increases from 342 MW in 2012, when the PSCo PPA expires, to over 537 MW in 2027. These resource needs are prior to the implementation of the DSM program portfolio discussed in ES.11.3 and Table ES-3 and prior to the addition of new renewable energy resources required to meet the state's RES.

Table ES-2
Load and Capacity Resource Balance (Excess or Deficit)

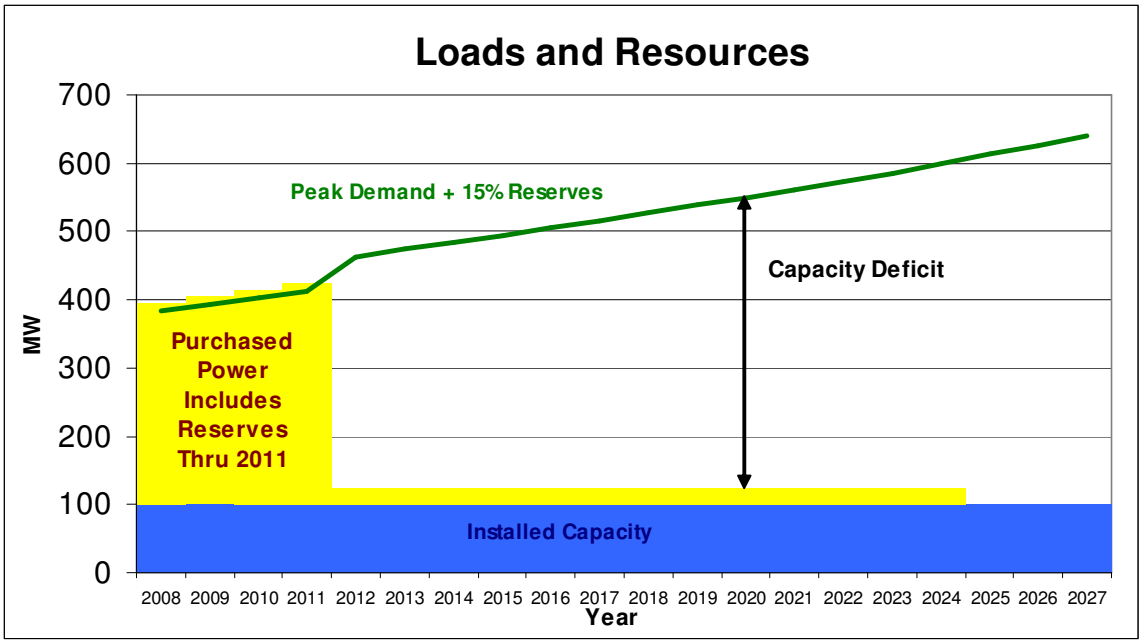
Year	Peak Demand (MW)[1] (1)	PSCO PPA (MW)[2] (2)	15% Reserves (MW)[3] (3) ((1)-(2))*.15	Peak + 15% Reserves (4) (1) + (3)	Installed Capacity (MW) (5)	Purchased Capacity (MW)[(4)] (6)	Total Capacity (MW) (7) (5) + (6)	Excess (Deficit) (MW) (8) (7) –(3)
2008	369	270	14.9	383.9	101.5	293	394.5	10.7
2009	378	280	14.7	392.7	101.5	303	404.5	11.8
2010	388	290	14.7	402.7	101.5	313	414.5	11.8
2011	397	300	14.6	411.6	101.5	323	424.5	13.0
2012	406	0	60.9	466.9	101.5	23	124.5	(342.4)
2013	415	0	62.3	477.3	101.5	23	124.5	(352.8)
2014	424	0	63.6	487.6	101.5	23	124.5	(363.1)
2015	433	0	65.0	498.0	101.5	23	124.5	(373.5)
2016	442	0	66.3	508.3	101.5	23	124.5	(383.8)
2017	452	0	67.8	519.8	101.5	23	124.5	(395.3)
2018	461	0	69.2	530.2	101.5	23	124.5	(405.7)
2019	471	0	70.7	541.7	101.5	23	124.5	(417.2)
2020	481	0	72.2	553.2	101.5	23	124.5	(428.7)
2021	491	0	73.7	564.7	101.5	23	124.5	(440.2)
2022	501	0	75.2	576.2	101.5	23	124.5	(451.7)
2023	512	0	76.8	588.8	101.5	23	124.5	(464.3)
2024	522	0	78.3	600.3	101.5	0	101.5	(498.8)
2025	533	0	80.0	613.0	101.5	0	101.5	(511.5)
2026	544	0	81.6	625.6	101.5	0	101.5	(524.1)
2027	556	0	83.4	639.4	101.5	0	101.5	(537.9)

1. Peak Demand before Demand-Side Management mandate
2. The PSCo PPA brings reserves
3. The significant increase in required reserves in 2012 reflects the loss of reserves that were associated with the PSCo PPA.
4. The 23 MW of purchased power reflects the two swaps with the Western Area Power Administration.

To appreciate the significance of the expiration of the PSCo PPA as compared to the significance of growth in customer demand, note that for the capacity deficit for 2012 only 9 MW is attributable to growth in peak demand (2012 peak demand of 406 minus 2011 peak demand of 397) which is less than 3% of the 2012 capacity deficit.

Figure ES.1 presents the capacity deficit in 2012 when the PPA with PSCo terminates and the Company faces a need to replace approximately three-quarters of its resources and most of its reserve margin.

Figure ES.1



ES.8 Significant Changes Since the Company's 2003 Least Cost Plan Filing

Since the Company's last resource plan was filed in February 2004 by Aquila, there have been significant changes in the legal requirements affecting electric utilities in Colorado. These changes include:

ES.8.1 Renewable Energy Standard (RES)

The Renewable Energy Standard was first adopted by the Colorado voters as Amendment 37 and then modified by the legislature in 2005 and 2007. This is a significant change that requires the Company to generate or cause to be generated eligible energy in the following minimum amounts as a percent of its retail sales:

- 3% for 2007
- 5% for 2008 – 2010
- 10% for 2011 – 2014
- 15% for 2015 – 2019
- 20% for 2020 and thereafter

These eligible energy resources are to be provided with a retail rate impact not exceeding 2% of the total electric retail bill annually for each customer.[4] The retail rate impact must be determined net of new alternative sources of electricity supply from non-eligible energy resources that are reasonably available at the time of the determination.

ES.8.2 Demand Side Management (DSM)

A new statutory requirement was passed in 2007 (HB07-1037) that requires the Company to achieve a reduction of at least 5% of its retail system peak demand measured in MW in 2006 and at least 5% of its retail energy sales measured in MWh in 2006. These goals must be met in 2018, counting savings in 2018 from DSM measures installed starting in 2006. DSM is defined as one of or any combination of energy efficiency, conservation, load management, and demand response programs. The statute provides that utilities must be allowed an opportunity for their investments in cost-effective DSM programs to be more profitable than any other utility investment that is not already subject to special incentives.

ES.8.3 Section 123 Resources

Another statute, §40-2-123, C.R.S., requires the Commission to "give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities, bearing in mind the beneficial contributions such technologies make to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases." The Commission's rules require utilities to include in their resource plan descriptions of three alternate scenarios that can be used to represent the costs and benefits from increasing amounts of Section 123 resources included in a cost-effective resource plan. The Commission clarified in a recent Decision that "Section 123 resources" as used in the resource planning rules are "to represent a wide range of resources that are not selected as least-cost resources, but that have other attributes, such as societal or environmental benefits, that may be considered by the Commission." [5]

ES.8.4 Colorado Climate Action Plan

On November 5, 2007, Governor Ritter unveiled the Colorado Climate Action Plan which includes goals for reductions in carbon dioxide (CO_2) emissions. The Colorado Climate Action Plan sets forth expectations for all of the electric utilities in Colorado. Specifically, the Colorado Climate Action Plan:

- Articulates a goal of reducing greenhouse gas emissions in the utility sector by 20% from 2005 levels by the year 2020.

[4] §40-2-124, C.R.S. and 4 CCR 723-3-3650-3665
[5] Decision No. C08-0185.

- Outlines specific actions that can be taken including planning for new energy resources by using 50% energy efficiency, 33% renewable energy and 17% clean coal technology which the Colorado Climate Action Plan anticipates will be developed within 10 years.

- Identifies five key ways to achieve energy efficiency including increases in lighting performance, expanded DSM programs, industrial efficiency measures, greening of state government, and updating building codes.

- Identifies natural gas as a key element in a bridge strategy to a cleaner energy future for Colorado because it is a plentiful and reliable energy source that generates 43 percent less CO_2 than coal and can serve as a primary fuel source for electrical energy generation and as backup power for intermittent renewable technologies such as photovoltaics and wind.

ES.8.5 Executive Order D 004 08

On April 22, 2008, the Governor issued Executive Order D 004 08 (Executive Order). As to public utilities, the Executive Order:

- Requests the Commission require from each utility within its jurisdiction (including the Company) an electric resource plan for achieving a 20% reduction in its greenhouse gas emissions from 2005 levels by 2020.

- Directs the Governor's Energy Office and the Department of Regulatory Agencies to identify regulatory and legislative changes that may be needed to provide investor-owned utilities with the appropriate incentives to reduce greenhouse gas emissions, and to reduce financial barriers to investments in renewable energy sources, energy efficiency, carbon credits, and clean coal technologies and to provide their suggestions to the Governor within 12 months of the date of the Executive Order.

- Directs the Colorado Department of Public Health and Environment and the Governor's Energy Office to evaluate policy options to address future demand for new coal-fired power plants considering, at a minimum, development of alternative sources of energy and options for reducing or mitigating greenhouse gas emissions from new plants and making a recommendation to the Governor within 12 months of the date of the Executive Order.

ES.8.6 Resource Planning Rules

The current Commission resource planning rules[6] became effective on March 1, 2008, and significantly amended the former least cost planning rules. The purpose of the amended rules is to result in "cost-effective resource portfolios, taking into consideration

[6] 4 CCR 723-3, Rules 3600-1615.

projected system needs, reliability of proposed resources, beneficial contributions of new clean energy and energy-efficient technologies, expected generation load characteristics, and various risk factors." The amended rules define a "cost-effective resource plan" as "a designated combination of new resources that the Commission determines can be acquired at a reasonable cost and rate impact."

Under the rules, it is the Commission and not the utility that decides what is a cost-effective resource plan. The utility's responsibility is to file a resource plan for review and approval or disapproval by the Commission. The utility must include in the plan a baseline case that describes the costs and benefits of the new utility resources required to meet the utility's needs during the planning period that minimize the net present value of revenue requirements consistent with reliability considerations, financial and development risks, and the evaluation criteria approved by the Commission under rule 3613 and that complies with the RES discussed in Section ES.8.1 as well as with the DSM resource requirements discussed in Section ES.8.2. The utility must also include two other scenarios that represent alternative combinations of resources that meet the same resource needs as the baseline case but that include proportionately more section 123 resources.

ES.8.7 Future Greenhouse Gas Regulation

The 2008 legislature adopted House Bill 08-1164 which amends Section 123 to provide that the Commission may give consideration to the likelihood of new environmental regulation and the risk of higher future costs associated with the emission of greenhouse gases such as CO_2 when it considers utility proposals to acquire resources. This Bill was signed into law by the Governor on June 2, 2008.

ES.9 Other Uncertainties

In addition to new legal requirements, the Company has had to propose this Resource Plan notwithstanding a number of uncertainties including the uncertainty regarding future carbon regulation and natural gas price volatility. Additionally, costs of concrete and steel have soared in recent years as a result of the reconstruction of New Orleans subsequent to Hurricane Katrina and very significant growth in world demand caused by emerging economies such as China, India and Brazil. These conditions have led to rising costs of materials and a shortage in the availability of equipment. Not only are the costs of materials increasing, but the availability of labor has decreased resulting in cost increases associated with decreases in productivity. For example, Duke Energy's cost estimate to build its coal-fired Cliffside 6 unit increased by $1 billion; Duke Energy now expects its 800 MW unit will cost $2.4 billion, an increase of 70% in just over two years.[7]

[7] NCWARN, "Basics: Duke Energy's Cliffside Power Plant," http://www.ncwarn.org/HansenEvent11-07/BasicsDukeEnergy'sCliffsidePowerPlant.htm.

ES.10 Utility's Obligation to Serve

Notwithstanding the current environment of uncertainty and the legal changes that have occurred since the Company filed its last least cost resource plan, Colorado law requires that, "every public utility shall furnish, provide, and maintain such service, instrumentalities, equipment, and facilities as shall promote the safety, health, comfort, and convenience of its patrons, employees, and the public, and as shall in all respects *be adequate*, efficient, just and reasonable" (emphasis added).[8]

ES.11 Resource Alternatives Examined to Meet Customer Growth and the Capacity Deficit by January 1, 2012

A variety of conventional supply-side resources were examined and considered in preparing the Resource Plan. These include natural gas-fired simple cycle combustion turbines, natural gas-fired combined cycle units, and coal (located either in Wyoming or Colorado). The modeled conventional resources were limited to sizes appropriate for the Company's load. Integrated gasification combined cycle (IGCC) with carbon sequestration and nuclear were also considered as potential resource options but both were determined to not be viable options during the resource acquisition period.

The initial modeling also assumed that purchased power in two 100 MW blocks in 2012 and one in 2013 was available. The capacity component of purchased power was priced at the same level as the existing PSCo PPA escalated to the appropriate years. The energy component was priced at the level of the market.

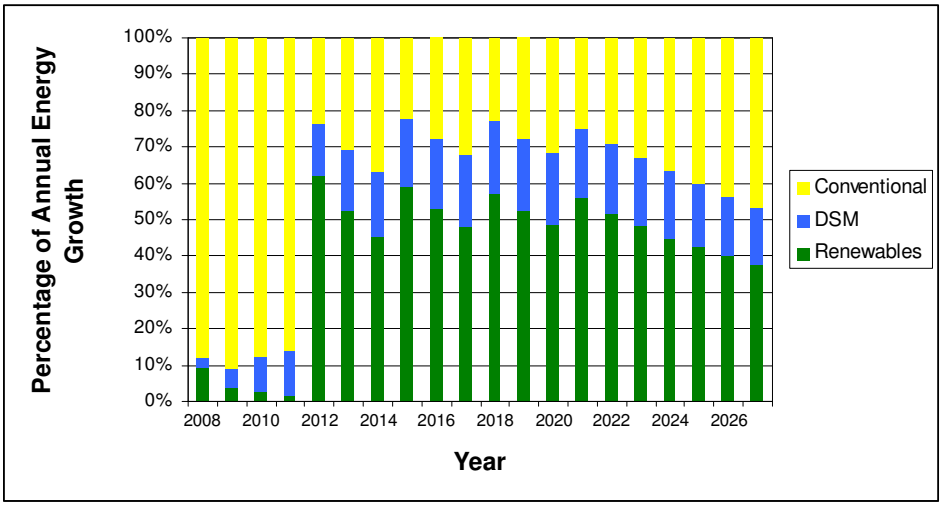
Finally, the renewable energy resource technologies that were modeled in this Resource Plan include wind, solar, thermal, biomass co-firing, and biomass stand-alone.

ES.11.1 Resources to Meet Customer Growth

DSM and the use of renewable energy will meet the majority of the expected growth of customer energy consumption over the planning period as shown in Figure ES.2.

[8] Section 40-3-101(b)

Figure ES.2
Resources Providing the Company's Energy Growth By 2020



The Resource Plan assumes that the Company will be successful in achieving the DSM goals established by the legislature. An advisory group consisting of representatives from the Colorado Public Utilities Commission staff, Colorado Office of Consumer Counsel, Colorado Governor's Energy Office, Colorado Energy Science Center, Southwest Energy Efficiency Project (SWEEP), and Built Green Colorado has been assisting the Company in the planning process. The DSM plan and cost recovery proposal will be filed by the Company in the fall of 2008.

The modeling for the Resource Plan included the amount of renewable resources that can be added without exceeding the statutory 2% retail rate impact cap during the resource acquisition period. The capital costs of renewable resources are in addition to, not in lieu of, the natural gas-fired generation resources.

ES.11.2 Resources to Provide Replacement Capacity for the PSCo PPA

This Resource Plan proposes to replace the capacity and reserves currently provided by the PSCo PPA through conventional supply-side resources. The size of the capacity deficit resulting from expiration of the PSCo PPA (approximately 75% of capacity, including associated energy, and the majority of the Company's reserves) cannot be met through DSM. Additionally, while renewable energy resources supply energy, they only make a nominal contribution to capacity because they are intermittent in nature. The conventional supply-side resources considered included IGCC, nuclear, coal, and natural gas.

ES.11.2.1 Integrated Gasification Combined Cycle

IGCC with carbon capture and carbon sequestration is not a mature technology. The expected cost of FutureGen (the IGCC demonstration project planned in Illinois) increased so significantly since 2003 when the facility was originally announced that the

U.S. Department of Energy decided in January 2008 to withdraw from the project.[9] *This technology cannot meet the capacity deficit by 2012.*

ES.11.2.2 Nuclear

Although there are 104 operating nuclear units in the U.S., no nuclear generating unit has been built in this country for over twenty years. However, in 2007, four license applications were filed for seven new nuclear units and another 15 applications for 22 new units are expected to be filed with the U.S. Nuclear Regulatory Commission in 2008. A utility with the size of the Company's load could participate in a nuclear unit only as a partner with a minority share. At present, no nuclear units are planned or under construction within a geographic footprint for which it is prudent utility practice for the Company to consider participating. *This technology cannot meet the capacity deficit by 2012.*

ES.11.2.3 Coal

An Initial Base Case was developed that contained coal-fired power plants in the resource mix to come on line in 2013 and 2014 and assumed that purchased power in two 100 MW blocks in 2012 and one in 2013 would be available. The Initial Base Case did not achieve the RES in the timeframe required by the RES because of the statutory 2% retail rate impact cap. (The Initial Base Case achieved the 20% renewable standard in 2027 instead of 2020.)

The regulatory uncertainty around permitting coal resources at this point in time, particularly in Colorado (with the investigation under Executive Order D 004 08 pending), means that it is not prudent in this Resource Plan for the Company to rely on coal resources being available to address the capacity deficit. In addition, it is now not certain that the long-term transmission projects required for Wyoming-based generation to serve Colorado loads will be built in a timely manner.

If the Company pursued the Initial Base Case and encountered delays, it would be too late for the Company to pursue other options. This would put the Company and customers at risk for whatever price the market could demand for power in that situation and the more significant risk that purchased power would not be available, leading to a lack of resource supply.

Accordingly, in May 2008, the Company performed additional modeling (constraining the model for no coal availability during the planning period) and developed a base case

[9] Mercer, David and Jim Suhr, Associated Press, "FutureGen developers propose cost restructuring," *Chicago Tribune*, January 11, 2008, http://www.chicagotribune.com/business/chi-ap-il-futuregen,0,2025985.story. Barber, Wayne, "FutureGen charges DOE reversal will slow carbon capture development," SNL Energy Electric Utility Report, February 4, 2008, pp. 1-12.

referred to as the Proposed Plan which does not include the construction of any coal-fired generation.

ES.11.2.4 Natural Gas

With the unavailability of IGCC, nuclear and viable carbon sequestration alternatives, the Company's Proposed Plan relies on five natural gas-fired combustion turbines, appropriately sized for the Company's load, three 76 MW LMS-100 or similar units for baseload and two 59 MW Frame 7EA's or similar units for peaking. No other resources are available in the current regulatory climate to serve the Company's load. Additionally, natural gas-fired resources are required in order to be able to integrate renewable resources (wind and solar) which are intermittent in nature because natural gas-fired generation can be ramped up and down quickly. To the extent wind and solar resources are operating, the Company will be able to reduce its purchases of natural gas because natural gas-fired generation can be ramped down. This will result in savings in natural gas costs.

Note, however, that because wind and solar are intermittent resources, the addition of these resources does **not** significantly reduce the amount of conventional capacity that is required to serve the Company's load. For purposes of this Resource Plan, it was assumed that solar energy does not contribute to capacity needs at all and wind energy only contributes 10% of its rated capacity. For this reason, the addition of wind and solar resources, to meet the RES requirement, will be in addition to, not in lieu of, the Company's existing resources and the new natural gas-fired generation required to meet the projected need. The addition of renewable resources will not reduce capacity costs; however, they will serve to reduce energy costs by offsetting the consumption of natural gas.

The responsiveness (ability to ramp up and down quickly) and efficiency of the LMS-100 units makes them particularly well suited for responding to, and offsetting, the intermittent characteristics of wind resources when integrating them into a system. The relatively low partial load heat rate of the LMS-100 makes it more cost-effective to back up intermittent wind resources than with less efficient, higher heat rate units.

A sensitivity analysis on the Company's natural gas price forecast was run for the Proposed Plan. At higher gas prices, the initial model run still selects simple cycle gas-fired units but additional renewable resources are possible before reaching the retail rate impact cap. Again, however, the capital costs of these renewable resources are in addition to, not in lieu of, the natural gas-fired generation resources. The Company will continue to evaluate additional renewable resource additions as a means to cost effectively provide additional energy and to offset the consumption of natural gas and, as necessary, will make appropriate filings with the Commission.

ES.11.3 The DSM Portfolio Results.

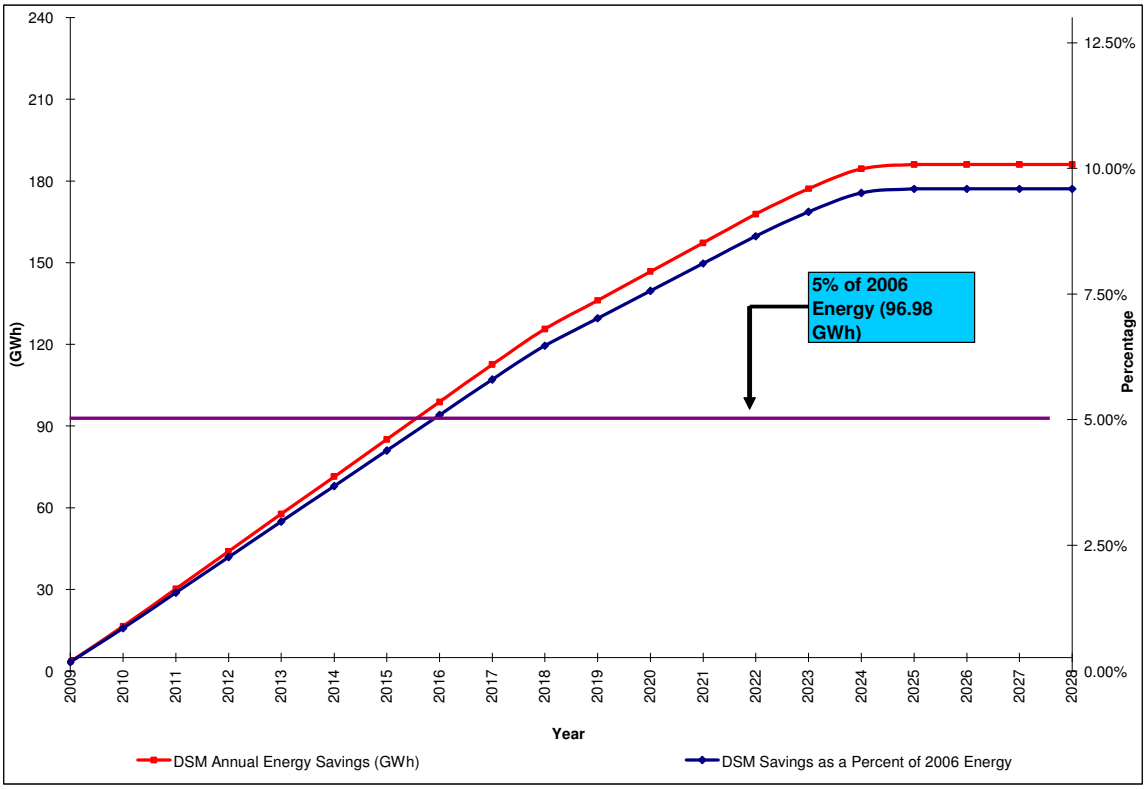
The assumption was made in the modeling that the DSM portfolio to be filed in the fall of 2008 will result in MW reductions of load that range from just over 2 MW in 2009 to over 64 MW by 2027 as shown in Table ES-3 and corresponding energy savings. The achievement of the DSM energy reduction requirements to comply with HB07-1037[10] is shown in Figure ES.3. This portfolio of DSM programs achieves the stated goals of HB07-1037 of a 5% reduction from 2006 peak demand and energy by 2018.

Table ES-3
DSM Program Portfolio Effects on Peak Demand and Annual Energy

Year	Peak (MW)	DSM Savings in Peak (MW)	Net Peak (MW)	Annual Energy (GWh)	DSM Savings in Energy (GWh)	Net Energy (GWh)
2009	378	(2.30)	376	2,067	(5.6)	2,061
2010	388	(6.00)	382	2,124	(16.5)	2,108
2011	397	(10.30)	387	2,200	(30.2)	2,170
2012	406	(14.60)	391	2,255	(43.9)	2,211
2013	415	(18.90)	396	2,307	(57.6)	2,249
2014	424	(23.30)	401	2,362	(71.3)	2,291
2015	433	(27.60)	405	2,416	(85.1)	2,331
2016	442	(31.90)	410	2,474	(98.8)	2,375
2017	452	(36.90)	415	2,529	(112.5)	2,417
2018	461	(39.60)	421	2,587	(125.6)	2,461
2019	471	(44.90)	426	2,645	(136.1)	2,509
2020	481	(47.40)	434	2,708	(146.7)	2,561
2021	491	(54.50)	437	2,768	(157.2)	2,611
2022	501	(58.40)	443	2,831	(167.8)	2,663
2023	512	(61.10)	451	2,897	(177.2)	2,720
2024	522	(62.50)	460	2,962	(184.4)	2,778
2025	533	(63.20)	470	3,029	(186.0)	2,843
2026	544	(64.10)	480	3,096	(186.0)	2,910
2027	556	(64.10)	492	3,165	(186.0)	2,979

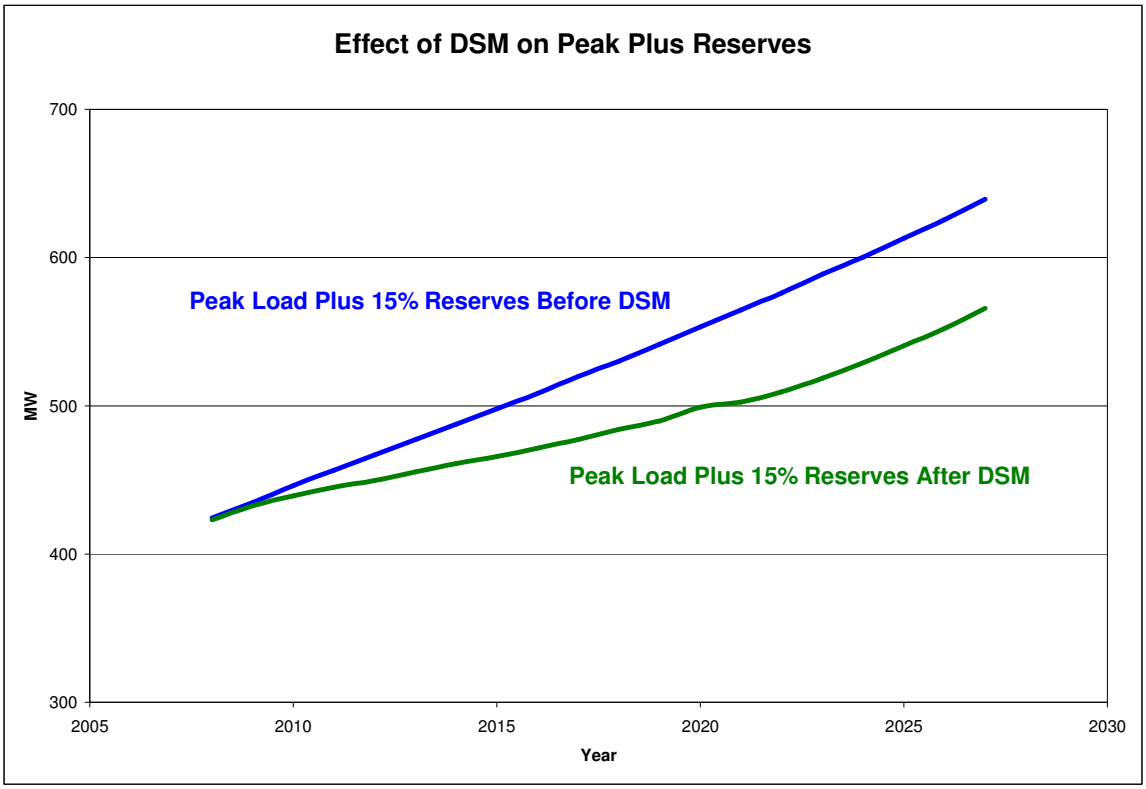
[10] Not codified in a single reference. Amended §40-3-102(5), C.R.S. and §40-3.2-101, C.R.S. Added new sections §40-3.2-103, C.R.S.; §40-3.2-104, C.R.S., and §40-3.2-105, C.R.S.

Figure ES.3
DSM Program Portfolio Reductions



Because DSM reduces the peak demand, the amount of reserves required is also reduced. This effect is shown in Figure ES.4. In addition to meeting the DSM requirements of HB07-1037, this DSM Program Portfolio reduces the amount of capacity required to meet load growth (as distinct from the abrupt capacity deficit) through 2020 by over 40%, correlating well with the recommendations of the Colorado Climate Action Plan.

Figure ES.4



ES.11.4 Proposed Plan Resource Additions

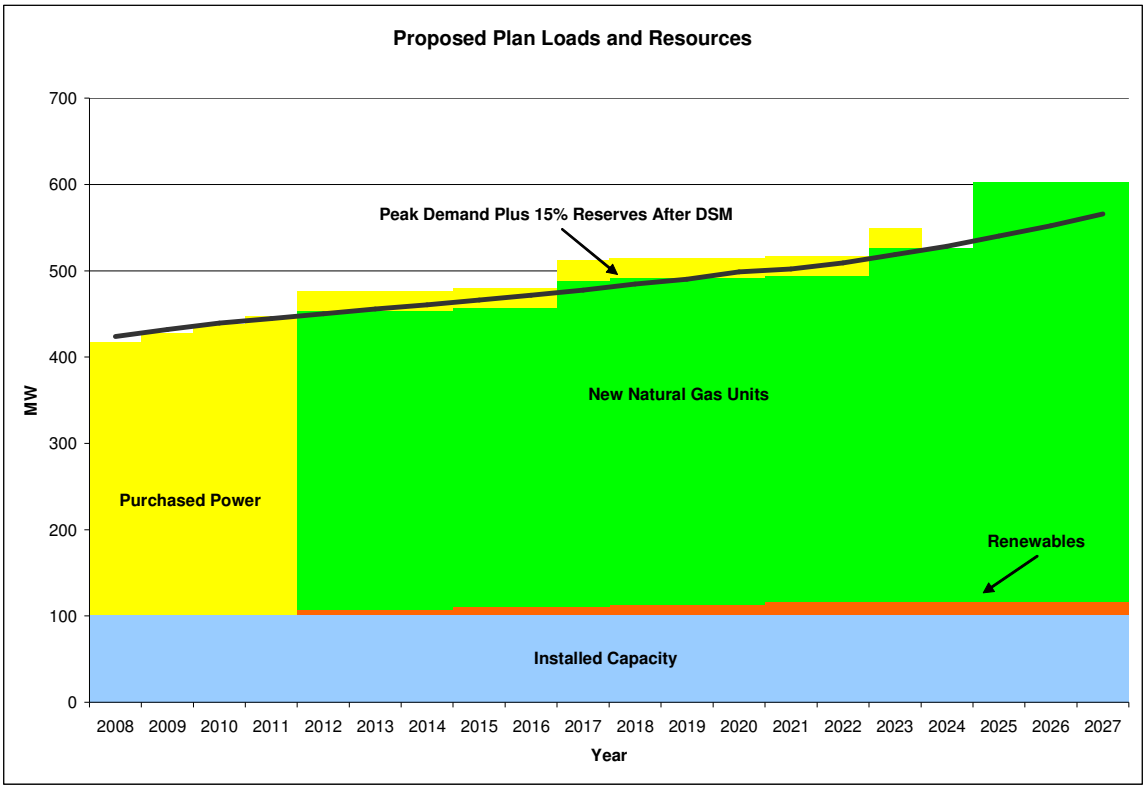
Only natural gas, DSM, and renewable resource additions are reflected in the Company's Proposed Plan. As shown in Table ES-4 and on Figure ES.5, the Proposed plan is to acquire at least 60 MW of wind energy resources (in blocks of 30 MW or less) to be on line on or before January 1, 2012, 2 MW of solar (installed and RECs purchased) in 2008 and 2 MW of solar installed in 2012, and 346 MW of natural gas-fired combustion turbine capacity (three 76 MW LMS 100 or comparable combustion turbines and two 59 MW Frame 7EA or comparable combustion turbines) that will enter commercial operation on or before January 1, 2012. This Proposed Plan meets the state's RES requirements and the modeling for the Proposed Plan assumed that the DSM mandates of HB07-1037 would be met as well. Additionally, because the Company's Proposed Plan replaces the coal-fired resources under the PSCo PPA with natural gas-fired resources, it meets the Colorado Climate Action Plan goal of reducing greenhouse gas emissions by 20% from 2005 levels by the year 2020.

Table ES-4
Proposed Plan Resource Additions

Year	Net Peak (MW)[1]	Installed Capacity (MW)	Purchased Power[2] (MW)	New Resources (MW)[3]	Total Capacity (MW)	Reserve Margin (%)
2008	368	101.5	293	Solar (2 MW)	435	18.2
2009	376	101.5	303		447	18.8
2010	382	101.5	313		458	19.9
2011	387	101.5	323		470	21.3
2012	391	101.5	23	Wind (60 MW), 5 CTs (346 MW), Solar (2 MW)	477	21.9
2013	396	101.5	23		477	20.3
2014	401	101.5	23		477	18.8
2015	405	101.5	23	Wind (30 MW)	480	18.4
2016	410	101.5	23	Solar (2 MW)	480	17.0
2017	415	101.5	23	CT (32 MW)	512	23.3
2018	421	101.5	23	Wind (30 MW)	515	22.2
2019	426	101.5	23		515	20.8
2020	434	101.5	23	Solar (2 MW)	515	18.5
2021	437	101.5	23	Wind (30 MW)	518	18.4
2022	443	101.5	23		518	16.8
2023	451	101.5	23	CT (32 MW)	550	21.8
2024	460	101.5	23		550	19.5
2025	470	101.5	0	CT (59 MW), Solar (2 MW)	586	24.6
2026	480	101.5	0		586	22.0
2027	492	101.5	0		586	19.0

Notes:
1. Net peak is the peak demand after DSM
2. PSCo PPA brings associated 15% reserves
3. Ten percent of installed wind capacity counts as capacity (capacity credit). Solar receives no capacity credit.

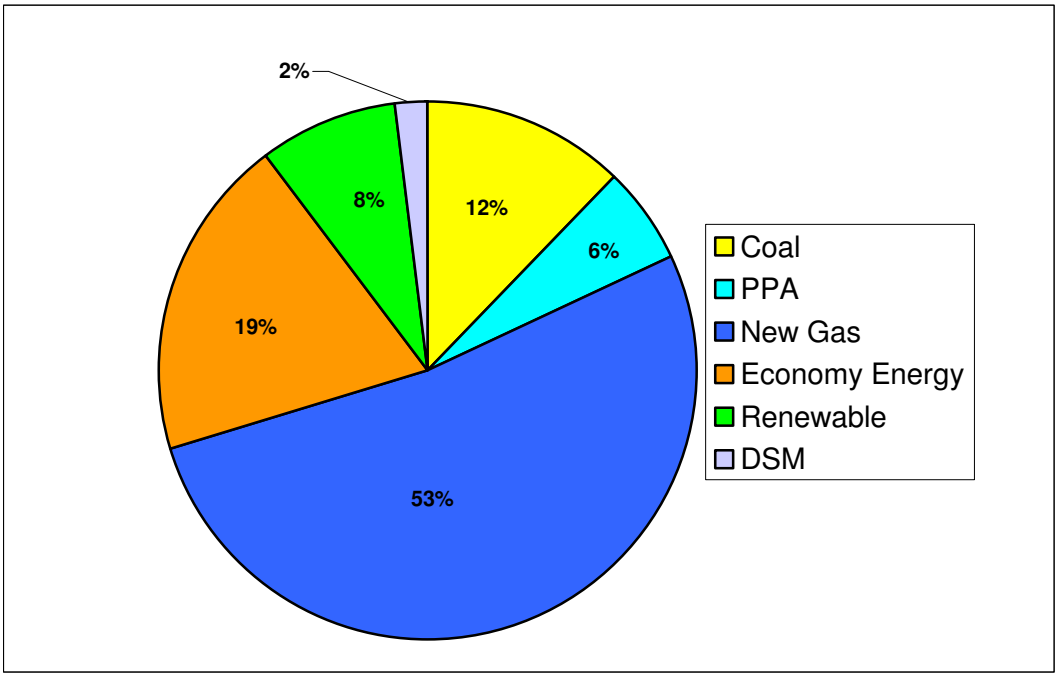
Figure ES.5



The Company's goal in this Resource Plan is to ensure the adequacy of resources to address the capacity deficit. If customers do not have access to adequate, reliable electric supplies, this will cause economic harm. The challenge that has to be addressed by this Resource Plan is to balance all of the economic and social concerns associated with resource planning in the current regulatory environment.

The Company will utilize the least cost resources available to serve its customers. It is assumed that non-firm or economy energy will be available in the market place. To the extent possible, the Company will purchase lower cost energy from the market in lieu of dispatching potentially higher cost resources. For example, the modeling for the proposed plan included on-peak and off-peak purchased power from the market. On-peak market energy prices are typically based on intermediate or peaking resource costs. Off-peak market energy prices are typically based on intermediate or base load resource costs. In 2012, it is expected that the energy required to serve the Company's load will be, 6% from existing purchased power agreements, 8% from renewable resources, 12% from existing coal resources, 19% from market energy purchases, and 53% from the new gas-fired combustion turbines. No energy is expected to be provided by the two less efficient existing gas-fired steam units but they will continue to provide capacity and reserves. It is also assumed that there will be a 2% contribution (savings) from DSM programs by 2012. This distribution is illustrated in the following energy pie chart from Figure 8.1 of this Resource Plan:

Figure ES.6
2012 Energy From Expected Resources



ES.12 Plan for Acquiring the Needed Resources

The Resource Planning Rules provide that a utility shall meet the resource need identified in the plan through a competitive acquisition process. The Commission may approve an alternative method of resource acquisition for a maximum of the lesser of 250 MW or 10% of the highest base case forecast peak requirement identified for the resource acquisition period. In the Company's case, 10% would be equal to approximately 40 MW, which is not sufficient to address the capacity deficit. However, Rule 3610(b) of the Commission's Rules of Practice and Procedure also give it authority to grant a waiver of its rules.

ES.12.1 Conventional Resources

The Company faces a situation outside an ordinary resource plan. The Company must successfully replace approximately 75% of its existing capacity, including associated energy, and the majority of the Company's reserve margin by January 1, 2012. It must also start over in 2012 on compliance with the non-solar requirements of the RES. The Company's plan for acquiring the conventional resources is through competitive procurement of the major components and construction and ownership by the Company.

The Company is not proposing competitive bidding for purchased power from conventional resources for the following reasons:

- Continued reliance on purchased power puts the customers at risk for a reoccurrence of the current capacity deficit problem and does not provide long-term security of resource supply.

- Equipment availability is tight and subject to constantly changing world demand. Costs of materials and labor are rising rapidly and will continue to rise while this Resource Plan is being reviewed.

- The size of the capacity deficit is so significant that it is not prudent to take any risks of project failure.

- The Company is in the best position to manage and assume the risk that the needed facilities are in service on time.

- Utility ownership of the capacity provides operational benefits and security and will result in a more financially sound utility which benefits customers.

For these reasons, the Company's application includes a request that the Commission waive its rules to enable the Company to address the substantial capacity deficit by constructing and owning the natural gas-fired units in the Proposed Plan.

ES.12.2 Renewable Resources

The Company also believes it is in the best interest of customers that it own renewable resources. However, with the Company's primary focus on addressing the capacity deficit, the Company believes that it should leverage the market to build and supply the renewable resources. It is expected that the size of these resources will be in blocks of 30 MW or less each and, therefore, the Company will not be acquiring these resources through a Phase 2 in this Resource Plan docket. HB07-1281 encourages utility rate-based ownership of new renewable resources (up to 50%) and the Company may seek to acquire equity positions as permitted by the RES rules.

ES.13 Proposed Plan Projected Emissions

The projected emissions for the new utility resources expected to be acquired during the planning period for each of sulfur dioxide, nitrogen oxides, particulate matter, mercury and CO_2 are shown in Table ES-5.

Table ES-5
Projected Emissions for New Utility Resources

Type of emission	LMS 100	LM 6000	7EA
Size of Unit (MW)	86	40	68
SO_2 – lb/MWh	0.01	0.01	0.01
SO_2 – tons/year	<1	<1	<1
NO_x – lb/MWh	0.07	0.07	0.10-0.25
NO_x – tons/year	1-15	0.5-1.5	0.3-1.1
PM – lb/MWh	0.07	0.02	0.17
PM – tons/year	0.5-15	1.4-4.0	0.7-2.6
Hg – lb/MWh	0	0	0
Hg – tons/year	0	0	0
CO_2 – lb/MWh	1035	1159	1582
CO_2 – tons/year	8,000-220,000	7,000-22,000	4,500-17,500

Note that the new utility resources actually acquired during the planning period could change as a result of other options that become available during the planning period.

ES.14 RFPs and Model Contracts

Because the Company does not intend to solicit bids for conventional resources, an RFP and associated model contract for conventional resources have not been developed. Because it is expected that the size of the renewable resources in the Proposed Plan will each be in blocks of 30 MW or less, the Company will not be acquiring these resources through a Phase 2 in this Resource Plan docket. Therefore, no RFPs or model contracts for renewable resources are included in this Resource Plan.

ES.15 Rate Design

The current rate design is consistent with Resource Plan contents. The Company is not currently proposing during the resource acquisition period any interruptible service, non tariff wind provisions, or other rate designs. During the resource acquisition period, the Company will be filing an Electric DSM Proposal under §40-3.2-104, C.R.S.

ES.16 Section 123 Plan

The Company is not presenting in this Resource Plan a medium or high Section 123 resources scenario and has requested a waiver of the requirement to do so. The focus of the Proposed Plan must be to acquire the resources necessary to address the 2012 capacity deficit while meeting the RES and DSM requirements. Additional Section 123 resources will not impact the need for the five combustion turbines identified in this Resource Plan because they will not provide sufficient capacity to meet the capacity deficit.

Furthermore, the Company does not currently own appropriate resources to back-up wind and has, instead, been purchasing non-solar renewable energy credits. Therefore, the Company has no experience with integrating wind. Black Hills will get its first experience with wind integration when the Happy Jack wind farm becomes commercial in September 2008.[11] The modeling for this Resource Plan showed that 60 MW of wind could be acquired during the resource acquisition period without exceeding the retail rate impact cap. The Company does not believe it would be prudent for it to propose additional renewable resources in this Resource Plan until it has acquired some experience with wind integration.

Therefore, the Company did not evaluate additional Section 123 resources as part of this Resource Plan but will be addressing them in its 2011 Resource Plan as a means to provide additional energy and offset the consumption of natural gas.

[11] Cheyenne Light, Fuel and Power has a PPA for 30 MW of wind from Happy Jack.

Introduction

On July 14, 2008, the electric utility assets and operations in Colorado of Aquila, Inc., doing business as Aquila Networks-WPC were transferred to a subsidiary of Aquila, Inc. named Aquila Colorado Electric Opco, LP. ("Electric Opco") followed by the immediate transfer of the general and limited partnership interests in Electric Opco to subsidiaries of Black Hills Utility Holding Company, Inc. and the change of the name of Electric Opco to Black Hills/Colorado Electric Utility Company, LP. All necessary approvals for these transfers were obtained including approval from the Colorado Public Utilities Commission (Commission) by Decision No. 08-0204 in Docket No. 07A-108EG and from local franchise authorities.

This Resource Plan is being filed by Black Hills/Colorado Electric Utility Company, LP which will be referred to in this plan as the "Company."

1.0 Rule 3604(a) – Statement of the Resource Acquisition Period and Planning Period

1.1 Resource Acquisition Period

The Resource Acquisition Period has been identified as 2008-2013, the first six years of the Resource Plan.

1.2 Planning Period

This Resource Plan covers the twenty-year planning horizon of 2008-2027.

1.3 Rationale for Selection

The stated purpose of the Commission's Resource Planning Rules is to "establish a process to determine the need for *additional* electric resources by Commission jurisdictional electric utilities." (emphasis added)[12] The typical resource plan considers the additional resources required to address normal customer growth. However, unlike the typical resource plan, this Resource Plan must also address the unique situation in which a utility faces an abrupt loss of the majority of the capacity, associated energy, and reserves used to serve its customers. The Company has an existing Restated Power Sales Agreement with Public Service Company of Colorado (PSCo) that terminates on December 31, 2011 (PSCo PPA). The PSCo PPA supplies approximately 75% of the Company's capacity, including associated energy, and the majority of the Company's reserve margin.

[12] Rule 3601, 4 CCR 723-3.

The termination of the PSCo PPA creates a significant "capacity deficit" beginning on January 1, 2012. By that date, the Company must acquire approximately 350 MW of conventional resources to ensure that sufficient capacity and energy are available to serve the customers with adequate reserves.

Because of the termination of the PSCo PPA at the end of 2011, the primary focus of this Resource Plan is the resources needed to address the capacity deficit in a timely and cost effective manner so that reliable resources are in place on or before January 1, 2012. Accordingly, it was decided to propose a resource acquisition period that was no longer than necessary to get the resources in place to address the capacity deficit. By selecting only a six-year resource acquisition period, the Company will be able to keep the options open for addressing future growth and will be able to review and speak to these in its next resource plan to be filed in 2011. This will allow the Company to have the benefit of the investigations that have been ordered by Executive Order D 004 08.[13] In addition, by that time, there may be more certainty regarding carbon legislation and advances in clean coal technology as well as carbon capture and carbon sequestration technology. Renewable energy compliance plans will continue to be filed annually on July 1.

The twenty-year planning period was selected to enable the Company and the Commission to have a preview of what resources might be required over the long term. The long-term resource needs will be reviewed and addressed again in the Company's next resource plan to be filed in 2011.

1.4 Next Resource Plan

The next Resource Plan is scheduled to be filed in October 2011.

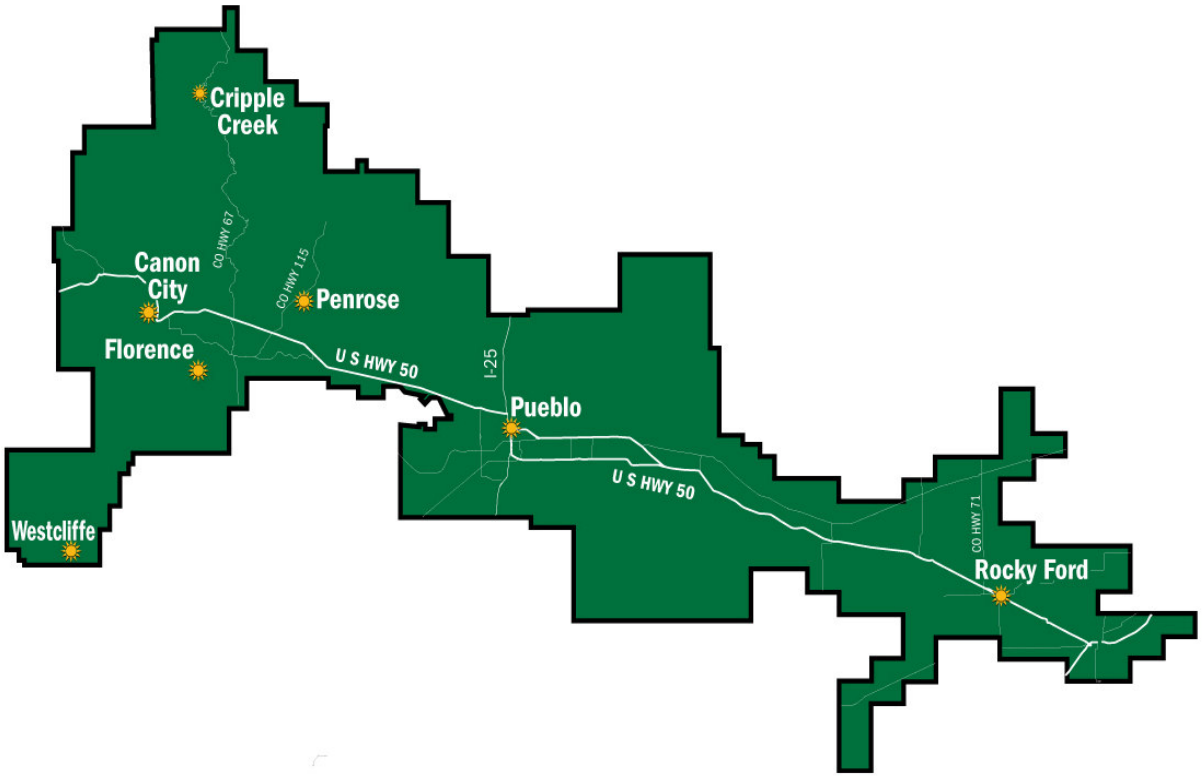
2.0 Rule 3604(b) – Annual Electric Demand and Energy Forecast

2.1 The Service Territory

The Company provides electric service to 21 communities in Colorado with more than 90,150 customers. The largest communities served include Pueblo, Cañon City, and Rocky Ford. The Company's generating stations are located in these three largest communities. The Company's service territory, which encompasses all or part of Crowley, Custer, Fremont, Otero, Pueblo, and Teller counties, is shown in Figure 2.1.

[13] Executive Order D 004 08 – Reducing Greenhouse Gas Emissions in Colorado, April 22, 2008.

Figure 2.1
The Company Service Territory



Energy forecasts for residential, commercial, industrial, other, and wholesale classes were developed using MS-Excel and Itron MetrixND econometric models. System and class hourly loads were weather normalized using Itron MetrixND based on 1971-2000 normals for the Pueblo, CO airport. Regional economic forecasts for the Company's service territory were used to forecast growth in energy sales, based on 1996-2007 actual data through August 2007. Moody's Economy.com developed the regional Colorado County economic forecast dated July 2007 for base, high, and low economic growth scenarios. These economic scenarios were used to drive energy sales forecasts of the Company's service territory, which were, in turn, used to drive hourly load forecasts for the Company to 2030, although the resource planning analysis only examined resources needed to meet the hourly load forecast through 2027 (2008-2027 is the planning period).

Actual energy sales for the Company increased at 2.9% annually during 1996 to 2006. Actual summer peak demand for the Company in August 2007 was 372 MW. Energy sales growth for the Company is forecast in the base case without demand side management (DSM) at 2.4% annually during 2008 to 2030. Summer peak demand growth without DSM is forecast at 2.2% annually from 2008 to 2030 with an annual system load factor of 61.8% in 2008 increasing to 65.3% in 2030.

2.2 Economic and Demographic Outlook

Economy.com's July 2007 long-term U.S. and regional economic forecast for Colorado counties was an input into the regional analysis which provided growth assumptions for customers, households, personal income, commercial employment, industrial manufacturing employment, and real GDP. A comparison of the 2005 median household income and median home/condo values for the major cities in the Company's service territory are contrasted with those same values for Denver and Boulder and the state in Table 2-1.

Table 2-1
Comparison of 2005 Median Household Income and Median Home/Condo Values

City/Area	Median Household Income	Median Home/Condo Value
Pueblo	$31,261	$108,800
Rocky Ford	$23,400	$70,000
Cañon City	$31,800	$113,100
City of Denver*	$42,370	$231,900
Boulder	$46,002	$457,400
State of Colorado	$50,652	$223,300
*Denver proper and not the Denver metropolitan area.		

As these data illustrate, the median household income and median home/condo values in the Company's service territory are substantially below the State average and the averages in the two largest cities served by Xcel Energy Inc. (d/b/a PSCo), the other Commission-jurisdictional utility in Colorado,

The county forecasts for base, high, and low economic growth scenarios were aggregated for the counties served by the Company, as shown in Table 2-2.

Table 2-2
Economic Growth Outlook – Compound Annual Growth Rate (CAGR), 2007-2030
(Colorado Counties: Crowley, Custer, Fremont, Otero, Pueblo, Teller)

Scenario	Real GDP	Households	Com. Empl.	Ind. Empl.	Per. Inc.
Base	1.80%	1.15%	1.34%	-0.62%	4.69%
High	3.52%	1.16%	2.70%	2.08%	5.81%
Low	0.30%	1.13%	0.18%	-2.95%	3.74%
Source: Economy.com, WPC Colorado Economic Forecast, July 2007					

Growth in the Company's service territory is dependent on other economic factors, several of which are summarized in Table 2-3.

Table 2-3
Economic Growth Trends for the Company's Service Territory

Class	Res	Com	Ind	Total	Year	Res	Com	Ind	Total
Sales (MWh)									
1996-2006	2.1%	3.2%	5.1%	**3.0%**	2006	572.0	665.9	544.4	**1,824.8**
2007-2010	1.8%	2.7%	3.1%	**2.5%**	2010	625.7	744.5	583.3	**1,994.2**
2007-2030	2.4%	2.5%	2.3%	**2.4%**	2030	1028.4	1,200.8	902.9	**3,174.2**
Customers									
1996-2006	1.7%	2.5%	6.6%	**1.8%**	2006	79,507	11,365	101	**91,423**
2007-2010	1.4%	1.7%	-0.1%	**1.4%**	2010	83,977	12,069	98	**96,606**
2007-2030	1.4%	1.7%	0.0%	**1.4%**	2030	110,897	16,908	98	**128,364**
Sales/Customer									
					2006	7.19	58.60	5,390	**19.96**
					2010	7.45	61.69	5,952	**20.64**
					2030	9.27	71.02	9,213	**24.73**
Service Territory Ratio Econ	**2.1**	**1.8**	**(3.8)**	**1.3**		**0.0**	**0.0**	**0.2**	**0.3**
Economic Growth	**HH**	**Emp_Com**	**Emp_Ind**	**GDP**		**HH**	**Emp_Com**	**Emp_Ind**	**GDP$M96**
1996-2006	1.29%	1.46%	-1.86%	**3.11%**	2006	94,446	83,879	5,662	**6,271**
2007-2010	1.44%	1.65%	-0.25%	**2.41%**	2010	100,255	90,048	5,603	**6,910**
2007-2030	1.15%	1.34%	-0.62%	**1.80%**	2030	124,847	116,451	4,895	**9,691**
Source: Economy.com, Colorado Economic Forecast, WPC Counties, July 2007									

The Company's total energy sales are projected to grow slightly faster than service territory real GDP over the 2007-2030 period. Customers in each of the residential, commercial, and industrial classes are projected to grow slightly faster than economic/demographic growth in households (HH), commercial employment, and industrial (manufacturing) employment. Growth in energy use per customer, plus customer growth, drives overall energy sales growth.

The Company serves the majority of Fremont, Custer, Pueblo, Crowley, Teller, and Otero Counties of Colorado. Although not all of the economic activity in these six counties is within the Company's service territory, the service territory does experience a major portion of the economic activity. Residential customer growth in the Company's service territory is projected to grow at 2.4% annually, higher than the expected growth in households as shown in Table 2-2. Table 2-4 shows individual county household growth rates for the Company service territory.

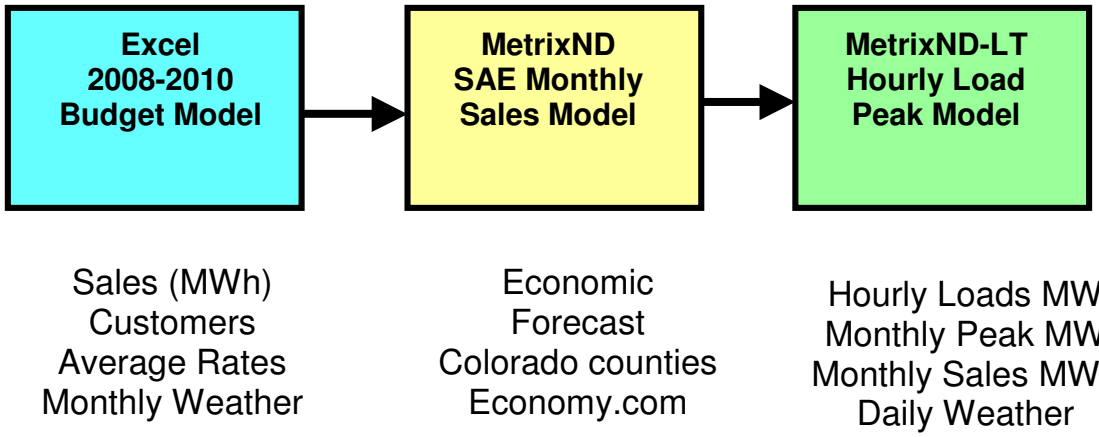
Table 2-4
Company Service Territory Household Growth by County

	08025 Crowley	08027 Custer	08043 Fremont	08089 Otero	08101 Pueblo	08119 Teller
Households – 2006	1,330	1,640	15,790	7,630	58,460	8,530
% Total – 2006	1.4%	1.8%	16.9%	8.2%	62.6%	9.1%
CAGR: 1991-2000	1.5%	7.2%	3.0%	0.6%	1.5%	5.8%
CAGR: 2001-2006	-0.5%	2.0%	0.6%	-0.7%	1.3%	1.2%
CAGR: 2007-2035	1.1%	2.1%	1.4%	-0.4%	1.0%	1.7%
Counties shown with their FIPS code. Source: July 2007 Economy.com, Economic Forecast (Base Case)						

2.3 Load Forecast Methodology

The Company used the ITRON MetrixND and MetrixND-LT models (see Appendix B), historical hourly data, historical weather data, and long-term economic projections to develop the load forecast. Figure 2.2 depicts an overview of the process.

Figure 2.2
Load Forecasting Methodology



Energy sales models by revenue class were developed in MS-Excel monthly econometric models to produce short-term (three-year) forecasts based on historical monthly sales, customers, use per customer, weather – heating degree days (HDD) and cooling degree days (CDD), and seasonal variables. Historical weather normalized use per customer by revenue class was multiplied by customer forecasts to produce energy sales forecasts. Use per customer and customer forecasts by class are based on historical trends. Energy sales are weather normalized based on NOAA 1971-2000 calendar month normals for weather at the Pueblo, Colorado airport (PUB). Adjustments for large customer loads were made for the 2008-2010 budget forecast period.

Itron MetrixND Statistically-Adjusted End-Use (SAE) forecast models were calibrated to historical data and short-term 2008-2010 monthly forecasts for the Company by class, using Economy.com economic forecasts for the Company's service territory to 2030 to produce long-term energy sales forecasts by class. These MetrixND SAE forecast models were based on regional end-use data underlying the *Annual Energy Outlook* for the Rocky Mountain Region (produced by the U.S. Energy Information Administration).[14] No sales to other utilities are included in the 2008-2030 forecast. Energy sales forecasts are before any future energy-efficiency or conservation program impacts. All of the Company's previously approved Colorado electric DSM programs have been fully implemented and completed.

[14] *Annual Energy Outlook*, Energy Information Administration, Report #DOE/EIA-0383 (2007). http://www.eia.doe.gov/oiaf/archive/aeo07/index.html

Itron MetrixND models were used to weather normalize historical hourly loads through August 2007, which were then driven by the overall energy sales forecasts for the base, high, and low growth scenarios to produce hourly load forecasts for 2008-2030. The MetrixND models are based on daily loads with explanatory variables for Average Daily Temperature (ADT), days of the week, holidays, months of the year, and time trends. Monthly peak forecasts were driven by monthly energy forecasts from MetrixND SAE models, and long-term hourly load forecasts were produced by MetrixLT.

Weather normal ADTs for PUB for the 1971-2000 period were used to weather normalize system and class hourly loads. Historical ADTs were sorted by month in descending order, averaged over 1971-2000 by rank, and then normal values were resorted by actual historical patterns of ADTs. Weather normal ADTs were simulated in the MetrixND model.

2.4 Large Customer Growth Changes

Table 2-5 shows anticipated large customer loads over the period 2008-2010 with future peak load changes greater than 250 kW. This information was compiled based on information from the Company's economic development personnel. These annual changes in large customer loads are reflected in the base load forecast.

Table 2-5
Large Customer Loads 2008-2010

Customer	Load Factor	MW 2008	MW 2009	MW 2010	MWh 2008	MWh 2009	MWh 2010
Large Customer A	63%	32.6	32.6	32.6	178,735	178,735	178,735
Large Customer B	85%	8.2	8.6	9.3	60,960	63,835	69,561
Large Customer C	51%	2.0	2.0	2.0	8,766	8,766	8,766
Large Customer D	80%	-	1.0	1.0	-	7,008	7,008
Large Customer E	75%	-	0.8	0.8	-	4,928	4,928
Large Customer F	70%	0.6	0.6	0.6	3,679	3,679	3,679
Large Customer G	80%	0.3	0.3	0.3	1,752	1,752	1,752
Large Customer H	75%	0.8	0.8	0.8	5,256	5,256	5,256
Large Customer I	80%	0.5	1.0	1.0	3,329	6,658	6,658
Large Customer J	75%	0.3	0.3	0.3	1,643	1,643	1,643
TOTAL	68%	45.1	47.7	48.4	264,120	282,259	287,984
Annual Change		-	2.6	0.8	-	18,139	5,736

Certain large customers could temporarily or permanently experience load increases after 2010 in the range of 1 to 20 MW; however, the load increases are highly uncertain. Those customers with potentially large load increases have been informed that a one-year notice is required for load increases above 3 MW and a two-year notice is required for load increases above 10 MW. These loads could also require special contracts.

Compared to the base load forecast, the high load forecast reflects an additional 10 MW of peak load by 2010, 30 MW of additional peak load by 2015, and 50 MW of additional peak load by 2020. The high load forecast covers potential additional but highly uncertain large customer load increases to the Company's summer peak load.

2.5 Historical Peak Demand and Annual Energy

The Company has historically experienced annual peaks in the summer. Table 2-6 shows the historical peak demand and annual energy from 1996 through 2006. The summer peak demand has experienced an annual growth rate of approximately 3.75%. Figure 2.3 shows the historical peak demand as well as the forecast peak demand through 2027. The historical annual energy experienced a growth rate of 2.93% and is shown on Figure 2.4. Monthly historical peak demand and energy values are contained in Appendix A in Tables A-10 and A-11.

Table 2-6
Historical Peak Demand and Annual Energy

	Peak Demand		Annual Energy		Load Factor
Year	(MW)	% Change	MWh	% Change	(%)
1996	247		1,453		67.1
1997	263	6.48	1,539	5.95	66.8
1998	272	3.42	1,595	3.59	66.9
1999	280	2.94	1,628	2.11	66.4
2000	292	4.29	1,715	5.32	67.0
2001	297	1.71	1,663	-3.04	63.9
2002	319	7.41	1,757	5.66	62.9
2003	345	8.15	1,830	4.14	60.5
2004	347	0.58	1,887	3.14	62.1
2005	366	5.48	1,915	1.45	59.7
2006	357	-2.46	1,939	1.27	62.0
Average Annual Growth (%)		3.75		2.93	

Annual energy is the sum of the hourly energy sales by customer class plus transmission and distribution losses.

Figure 2.3
Historical and Forecast Peak Demand

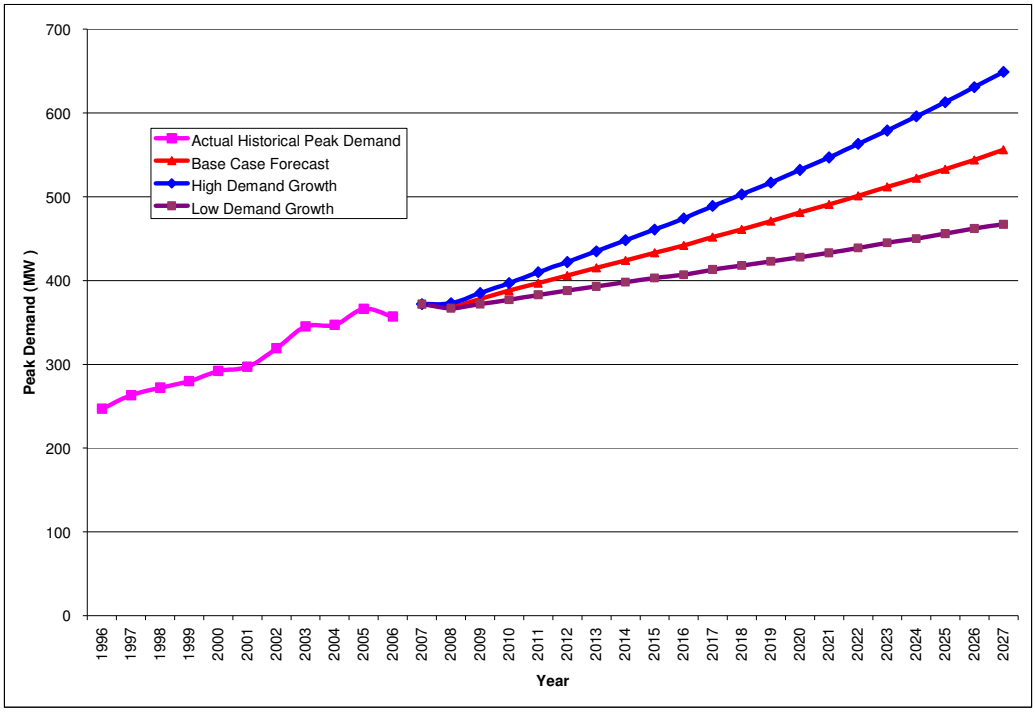
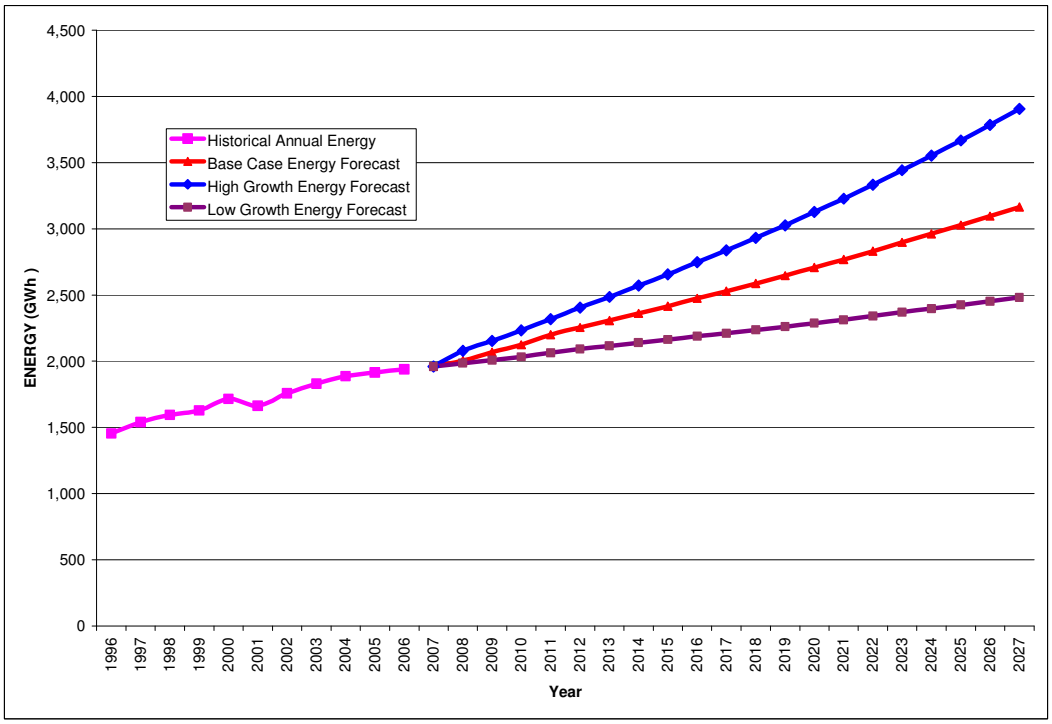


Figure 2.4
Historical and Forecast Annual Energy



2.6 Peak Demand and Energy Forecasts Before DSM

Base Case. The peak demand and energy forecast for the base case is shown in Table 2-7. The expected annual peak demand growth rate is 2.2%, less than the recent actual growth rate. The expected annual energy growth rate is 2.4% which is comparable to the recent actual growth rate.

Low Growth Case. A forecast was developed for a low growth case scenario reflecting the potential for a weak economy in the future. In this case, the peak demand is expected to grow at a rate of 1.3% while the expected annual energy growth rate would be 1.2%.

High Growth Case. The forecast for the high growth case reflects extreme temperatures as well as a strong economy in the future. The peak demand is expected to grow annually at a rate of 3.0% while annual energy experiences a growth rate of 3.4%.

Figures 2.3 and 2.4 show the historical peak demand and annual energy data as well as each of the low, base and high growth forecasts for peak demand and annual energy, respectively.

Tables A-1, A-2, and A-3 (in Appendix A) show historical and forecast annual sales by customer class, transmission and distribution (T&D) losses, total energy, the summer and winter peaks, and the annual load factor through the load forecast period of 2030 for each of the base, low, and high growth cases.

Table 2-7
Low, Base, and High Forecasts Before DSM

Year	Low Case		Base Case		High Case	
	Peak Demand (MW)	Annual Energy (000 MWh)	Peak Demand (MW)	Annual Energy (000 MWh)	Peak Demand (MW)	Annual Energy (000 MWh)
2008	367	1,985	369	2,004	373	2,079
2009	372	2,008	378	2,067	385	2,154
2010	377	2,033	388	2,124	397	2,233
2011	383	2,064	397	2,200	410	2,319
2012	388	2,093	406	2,255	422	2,406
2013	393	2,116	415	2,307	435	2,486
2014	398	2,140	424	2,362	448	2,571
2015	403	2,163	433	2,416	461	2,656
2016	407	2,188	442	2,474	474	2,748
2017	413	2,212	452	2,529	489	2,837
2018	418	2,237	461	2,587	503	2,930
2019	423	2,261	471	2,645	517	3,026
2020	428	2,288	481	2,708	532	3,128
2021	433	2,312	491	2,768	547	3,227
2022	439	2,341	501	2,831	563	3,333
2023	445	2,371	512	2,897	579	3,443
2024	450	2,397	522	2,962	596	3,552
2025	456	2,425	533	3,029	613	3,667
2026	462	2,453	544	3,096	631	3,785
2027	467	2,481	556	3,165	649	3,905
Average Growth Rate (%)	1.3%	1.2%	2.2%	2.4%	3.0%	3.4%

Figure A.1 provides weather normalized hourly loads for a peak summer day. Table A-4 shows the data associated with Figure A.1. Figure A.2 provides weather normalized hourly loads for a peak winter day. Table A-5 shows the data associated with Figure A.2. Summer and winter class load profiles for average weekdays, average weekends, and system peak days, based on load research data, are provided in Appendix A.

Tables A-6 and A-7 provide coincident peak demand forecasts for the base case by class for the summer and winter peaks.

2.7 Comparison to Prior Forecasts

A comparison of the peak demand and annual energy forecasts made in the 2003 Least Cost Plan (2003 LCP) and this Electric Resource Plan (2008 ERP) for the base case is shown in Table 2-8. Figures 2.5, 2.6, and 2.7 present this comparison graphically for annual energy, summer peak, and winter peak, respectively.

In the 2003 LCP, the annual energy growth was projected at 3.7% over the 2008-2025 period, compared to the 2.4% growth rate projection in the current plan. The annual summer and winter peak demand growth over the 2008-2025 period was forecasted at 3.3% in the 2003 LCP compared to the summer and winter 2008 ERP growth rates projected to be 2.2% and 2.3%, respectively, as shown in Table 2-8.

In the 2003 LCP, long-term energy sales were driven by the real GDP growth of the Colorado counties, which was projected to average 3.7% annually over the 2006-2018 period. The current comparable economic forecast for those Colorado counties is 1.7% annual real GDP growth for 2010-2030. Based on historical experience from 1996-2007, the current load forecast also assumes gradually rising monthly and annual load factors; thus peak demand growth is lower than energy sales growth.

Figure 2.5
Annual Energy (GWh) Forecasts, 2003 LCP vs. 2008 ERP

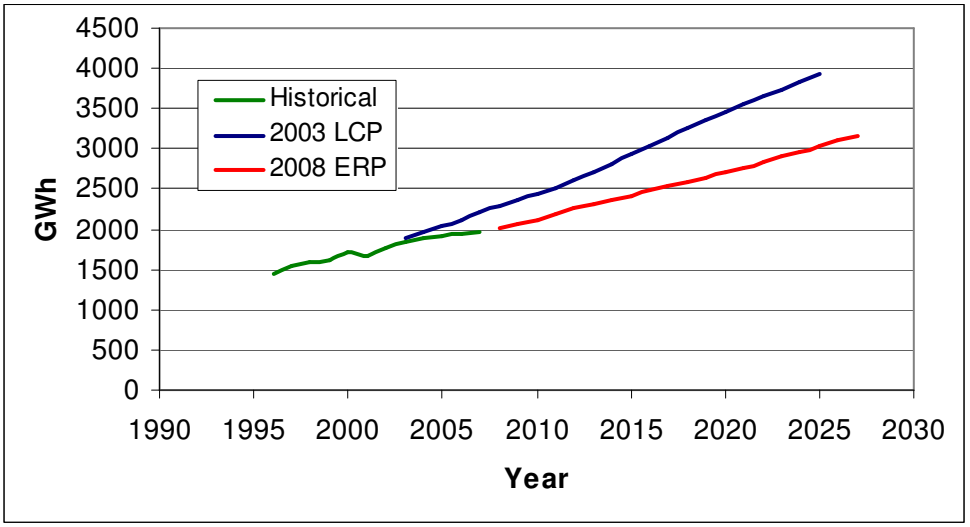


Table 2-8
Forecast Comparison

Year	Annual Energy (GWh)		Summer Peak Demand (MW)		Winter Peak Demand (MW)	
	2003 LCP	2008 ERP	2003 LCP	2008 ERP	2003 LCP	2008 ERP
1996	1,453*	1,453*	247*	247*	242*	242*
1997	1,539*	1,539*	263*	263*	236*	236*
1998	1,595*	1,595*	272*	272*	260*	260*
1999	1,628*	1,628*	280*	280*	257*	257*
2000	1,715*	1,715*	292*	292*	268*	272*
2001	1,663*	1,663*	297*	297*	258*	258*
2002	1,757*	1,757*	319*	319*	278*	278*
2003	1,885	1,830*	350	345*	296	283*
2004	1,970	1,887*	365	347*	309	289*
2005	2,045	1,915*	380	366*	322	310*
2006	2,122	1,939*	394	357*	334	300*
2007	2,202	1,960*	409	372*	347	316*
2008	2,277	2,004	422	369	358	325
2009	2,354	2,067	438	378	371	334
2010	2,432	2,124	452	388	383	341
2011	2,517	2,200	468	397	396	350
2012	2,607	2,255	483	406	409	359
2013	2,710	2,307	503	415	426	368
2014	2,819	2,362	523	424	443	376
2015	2,928	2,416	543	433	460	385
2016	3,036	2,474	561	442	476	394
2017	3,143	2,529	582	452	494	403
2018	3,248	2,587	601	461	510	412
2019	3,350	2,645	620	471	526	421
2020	3,448	2,708	637	481	540	430
2021	3,546	2,768	657	491	557	440
2022	3,644	2,831	675	501	572	450
2023	3,740	2,897	693	512	587	460
2024	3,836	2,962	709	522	600	470
2025	3,934	3,029	729	533	617	480
2026		3,096		544		491
2027		3,165		556		502
Average Annual Growth						
2008 – 2025	3.3%	2.5%	3.3%	2.2%	3.3%	2.3%
2008 – 2027		2.4%		2.2%		2.3%
*Actual						

Figure 2.6
Summer Coincident Peak (MW) Forecasts, 2003 LCP vs. 2008 ERP

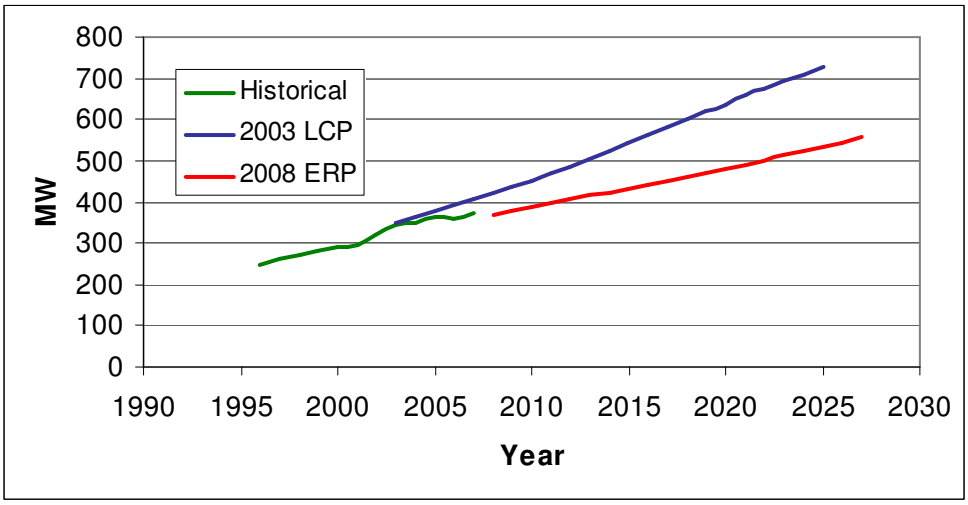
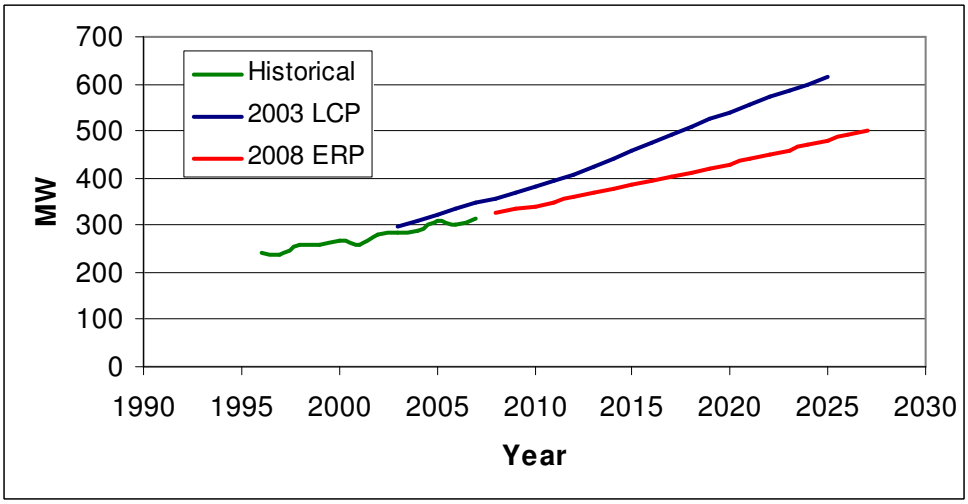


Figure 2.7
Winter Coincident Peak (MW) Forecasts, 2003 LCP vs. 2008 ERP



3.0. Rule 3604(c) - Evaluation of Existing Resources

3.1 Existing Conventional Supply-Side Resources

The Company's generation resources consist of two coal-fired steam units, two natural gas-fired steam units, and three diesel plants. The data used for modeling these units are shown in Table 3-1. The total existing generation owned by the Company is 101.5 MW.

Currently, the Company purchases approximately 75% of its energy requirements from PSCo under a PPA that expires on December 31, 2011. No unit retirements are planned for the resource acquisition period because of the large capacity deficit starting in 2012. However, the retirement plans for each of these units will be reviewed again as part of the Company's 2011 resource plan.

Table 3-1 provides information on unit operating parameters for each of the generating facilities. The dependable capacity is the same as the rated capacity shown. The annual availability is projected to range between 80% and 90% for all units and will be a function of the major overhaul scheduled for each unit as well as actual forced outages. The Cañon City units are baseload units. The Pueblo gas-fired steam units have been run as intermediate units in the summer. The diesel units are used for peaking, to support the transmission system, and to provide system reserves.

Table 3-1
Existing Generating Facilities

Unit Name	Year Installed	Rated Capacity (MW)	Forced Outage Rate (%)	Scheduled Outage rate (%)	Fuel Type	Average Heat Rate (Btu/kWh)
Cañon City 1	1955	17.6	6.47	8.0	Coal	13,597
Cañon City 2	1959	24.9	6.47	8.0	Coal	11,523
Pueblo 5	1941	9.0	13.06	5.8	Nat Gas Steam	14,900
Pueblo 6	1949	20.0	13.06	5.8	Nat Gas Steam	13,613
Pueblo Diesels[1]	1963	10.0	9.46	4.0	#2 Oil	10,626
Airport Diesels[1]	1964	10.0	9.46	4.0	#2 Oil	10,200
RF Diesels[1]	1964	10.0	9.46	4.0	#2 Oil	10,626
Total Capacity		**101.5**				

Notes: 1. There are five 2 MW diesel units at each of Pueblo and Rocky Ford. There are four 2.5 MW diesel units at the Airport.

Table 3-2 summarizes the estimated emission rates of nitrogen oxides (NO_x), carbon dioxide (CO_2), sulfur dioxide (SO_2), and mercury (Hg) for the existing units. The only facility with an hourly limitation is the Airport Diesels (1,181 hrs/year) which is based on its NO_x emission rate to maintain Prevention of Significant Deterioration (PSD) synthetic minor status.

Table 3-2
Emission Rates (HHV)

Unit	NO_x (lb/MMBtu)	CO_2 (lb/MMBtu)	SO_2 (lb/MMBtu)	Hg (lb/TBtu)
Cañon City 1[1]	0.49	210	1.2	6[2]
Cañon City 2[1]	0.49	210	1.2	6[2]
Pueblo 5	0.034	115	0.00071	N/A
Pueblo 6	0.329	115	0.00071	N/A
Pueblo Diesels	3.221	155	0.0407	N/A
Airport Diesels	3.3	155	0.186	N/A
RF Diesels	0.589	155	0.0401	N/A

Notes:
1. NO_x and SO_2 emission rates for Cañon City 1 and 2 assume 100% coal firing.
2. Estimated uncontrolled Hg emission rate when burning bituminous coal.

3.2 Existing Renewable Resources

The Company's existing renewable resources include the utilization of small amounts of wood chips at the Cañon City units and bio-diesel at the Pueblo and Rocky Ford diesel units. Modest amounts of on-site solar in the form of photovoltaics (PV) have been installed by small and large customers. The Company purchases Renewable Energy Credits (REC) from these customers over the first twenty years of operation. The Company also purchases non-solar RECs. These non-solar RECs do not provide any capacity or energy to the Company.

3.3 Existing Purchased Power Resources

The primary PPA in place for the Company is the one with PSCo. The PSCo PPA terminates on December 31, 2011. It provides for incremental annual increases in capacity from 2007 through 2011 and the option to increase or decrease the contract capacity by 10 MW annually starting with 2007 with at least one-year's notice for each change. The agreement effectively provides its own reserves. Coordination letters for the PSCo PPA are found in Appendix C.

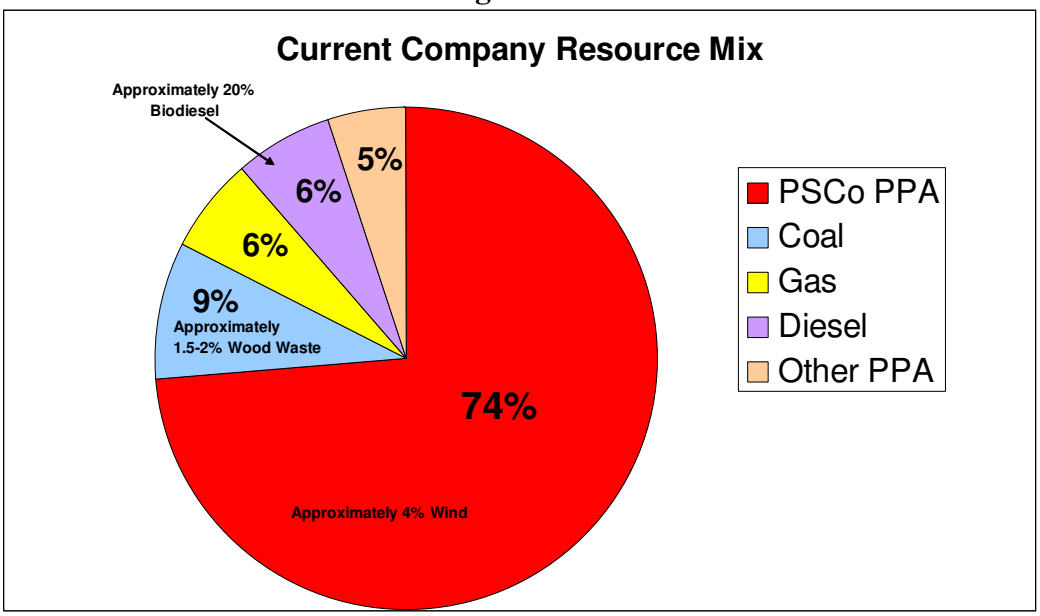
The Western Area Power Administration (Western) has two swaps in place with the Company between the western and eastern transmission grids to facilitate the delivery of capacity and energy. Western has generation resources on the western grid. In addition, Western has wholesale customers connected to the eastern grid that are accessible from Sunflower Electric and a Missouri operating unit of Great Plains, Missouri Public Service (MPS). Sunflower and MPS entered into contracts with the Company whereby Sunflower and MPS supply capacity and energy to the Company which is delivered to Western on the eastern grid. In exchange, Western supplies an equivalent amount of capacity and energy to the Company in the western grid.

The Western swap contract utilizing a purchase from Sunflower expires on December 31, 2024 and provides 18 MW of firm capacity and energy to the Company. The amount of energy to be provided annually under the contract is approximately 105,900 MWh. The contract pricing is subject to wholesale tariff changes.

The Western swap contract utilizing a purchase from MPS expires on December 31, 2024 and provides 5 MW of firm capacity and energy to the Company. The amount of energy to be provided annually under the contract is approximately 26,480 MWh. The contract pricing is subject to wholesale tariff changes.

The composition of the Company's current resource mix is shown in Figure 3.1.

Figure 3.1



3.4 Expiration of the PSCo PPA and Resulting Capacity Deficit in 2012

The PSCo PPA terminates on December 31, 2011. As a result of the termination of the PSCo PPA, as of December 31, 2011, the Company will lose approximately 75% of the capacity, including associated energy, and the majority of the reserve margin used to serve our customers. This results in a capacity deficit that will require the Company to replace 300 MW of capacity and 45 MW of reserves on or before January 1, 2012, in order to continue to provide service. Addressing the capacity deficit in as cost effective a manner as possible, subject to the legal mandates described in Section 5.0 of this Resource Plan, is the primary focus of this Resource Plan. The normal focus of a Resource Plan, meeting customer growth, is also addressed and will be revisited again in the next resource plan filing in 2011.

3.5 Transmission Resources

The Company's service territory generally follows the Arkansas River Valley from the Royal Gorge, west of Cañon City, to La Junta, east of Pueblo. The major load centers are the cities of Pueblo and Cañon City with significant smaller load centers in the Victor/Cripple Creek area and the area near Rocky Ford.

The Company's transmission system also follows the Arkansas River and consists of 194 miles of 115-kV and 314 miles of 69-kV transmission lines. The location and capacities of the major components of the Company's transmission system are shown on Figure 3.2.

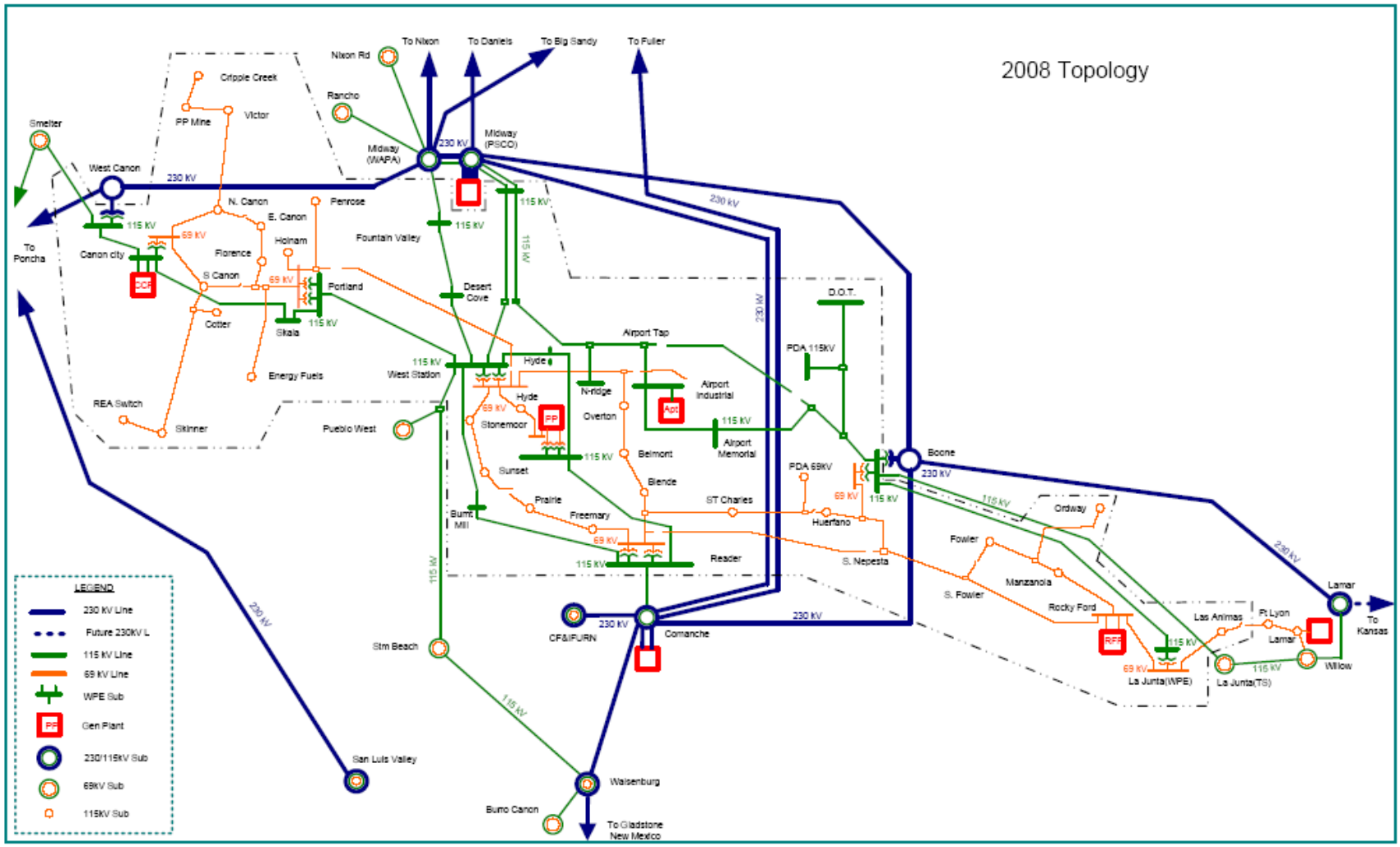
Transmission interconnections with neighboring transmission systems and the capacities between these systems are shown in Table 3-3. Total capacities shown in the table do not account for committed or existing uses.

Table 3-3
Transmission Interconnections

Name	Utility	Voltage (kV)	Total Import Capacity (MVA)	Total Export Capacity (MVA)
Reader	PSCo	115	216	216
Boone	PSCo	115	150	150
West Station	Western	115	77	77
Midway 1	PSCo	115	100	100
Midway 2	Western	115	115	115
Cañon West	Western	115	100	100
Cañon West	PSCo	115	135	135
La Junta	ARPA	69	20	0

The Company's transmission planning staff has performed studies on the existing transmission grid. These studies indicate that five areas exist within the Company's service territory that have adequate transmission facilities to support the existing resource and energy imports. These areas include the Cañon City West substation area, the valley area west of Pueblo to Cañon City, the Pueblo north to Midway area, the valley area east of Pueblo, and the La Junta area on the eastern edge of the system.

Figure 3.2 Service Territory Transmission Map



Generation injection capabilities can be described as follows:

- The West Cañon City area has the capability to support 144 MW of future generation connected to the Cañon West 230/115 kV facilities.
- The valley area west of Pueblo to Cañon City has the capability to support up to 150 MW of future generation on the Portland 115-kV facilities.
- The Pueblo to Midway area has the capability to accept 105 MW of future generation at either the Desert Cove or Fountain Valley 115-kV facilities.
- The valley area east of Pueblo currently has the capability to accept 117 MW of future generation on the Airport 115/69 kV facilities, with a potential of 180 MW if additional transmission from the airport area to southern Pueblo were installed.
- The La Junta area on the eastern edge of the Company's system has the capability to support 25 MW of future generation on the La Junta 115-kV facilities. By interconnecting with neighboring La Junta facilities owned by Tri-State Generation and Transmission (Tri-State), generation capability could be increased from 25 MW to 75 MW.

The generation injection capabilities for these areas are summarized on Table 3-5. The generation injections may require voltage support and transmission up-rates or rebuilds.

Table 3-4
Generation Injection Capability

Area	Voltage (kV)	Capacity (MW)
West Cañon	230/115	144
Portland	115	150
Desert Cove	115	105
Airport	115	117/180
La Junta	115	25/75

The *Long Range Planning Study 2005-2015*, completed by the Company in February 2005 and reviewed in August 2007, assessed the high voltage transmission system (69 kV and above) and identified the improvements required to reliably serve projected load through 2017.

Facilities recently placed into service such as the PDA 115-kV Substation and the Burnt Mill 115-kV Substation were included as part of the base cases. The additional 20 MVA load at the PDA 115-kV Substation planned for 2012 and other planned additions were also included in the base cases.

The study recommended improvements for Cañon City, which include the installation of a Cañon West to Arequa Gulch 115-kV line and an Arequa Gulch 115/69 KV Substation. Both are planned for 2010 and will provide for future load growth in the Cripple Creek area.

The improvement recommendations for the Pueblo Region include installation of a 115-kV line between the Reader Substation and the Airport Memorial Substation in 2009-2010, a new Freemary 115/69 kV Substation in 2011, a new Overton 115/69 KV Substation in 2010, and a second 115-kV tie line between the Comanche and Reader Substations. This second tie line will

provide needed support to the Pueblo and Cañon City area during certain contingency conditions and will provide an additional interconnection between the Company and PSCo.

The proposal for the Rocky Ford area is for the Company to form a partnership with Tri-State to build a 69-kV and a 115-kV tie between the two La Junta Substations. There are also plans to upgrade the 115/69 kV La Junta transformer. These facilities will provide additional voltage support as well as additional generation injection capabilities at La Junta.

The Company is a member of the Western Electricity Coordinating Council (WECC), the Rocky Mountain Reserve Group (RMRG), and the Colorado Coordinated Planning Group (CCPG), all of which engage in transmission planning activities.

The Company does not have any proposed transmission additions that are the result of Section 210 of the Federal Power Act or other federal open access transmission requirements.

3.6 Senate Bill 07-100

The Company filed an application on November 1, 2007, in Docket No. 07A-422E which was treated by the Commission as an information filing. In that filing, the Company described the process it followed to designate an energy resource zone and evaluate the adequacy of electric transmission facilities in that zone. The evaluation included input from the public.. After evaluating all of the input, it was determined that a single Energy Resource Zone would be sufficient to address transmission adequacy as it relates to the Company and designated an Energy Resource Zone consisting of all of the Company's certificated service territory and any contiguous territory required to satisfy any request to connect to the Company's transmission infrastructure. The Company concluded that, with one exception, the existing facilities and environment were capable of supporting potential energy resource needs and that the existing transmission infrastructure, augmented by current improvement plans, provides adequate transmission facilities for local ownership of renewable energy facilities. The one exception was a pending need in the transmission facilities serving the Cripple Creek and Victor areas. This need is being addressed by the system improvements described above for the Canon City area.

4.0 Rule 3604(d) - Assessment of Planning Reserve Margins and Contingency Plans

4.1 Assessment of Planning Reserve Margins

Prudent utility practices require a utility to plan for sufficient capacity resources to meet its peak demand and to maintain an additional margin of capacity to accommodate unforeseen events that result in higher system demand due to weather more extreme than projected or lower than anticipated available capacity due to generating unit forced outages.

The Company will use a minimum 15% reserve margin for planning for this Resource Plan and a maximum reserve margin of 25% with a goal of staying between these two values. The 15% minimum reserve margin is based on reserve margins required for other utilities by state

regulatory commissions and regional transmission organizations.[15] The addition of resources is "lumpy" because resources are available in specific size increments. This is why a resource margin range is needed. The 25% maximum reserve margin ensures that units that are of appropriate size, not too large, for the Company's load are selected.

4.2 Contingency Plan

Rule 3605 of the resource planning rules requires a resource plan to contain contingency plans for the acquisition of additional resources. Contingency plans have been used by PSCo in the past when PPAs have failed.[16] However, the size of the capacity deficit is too large to take any risks of project failure. For this and other reasons described in detail in Section 9 of this Resource Plan, the Company is not proposing to enter into any new PPAs to replace the PSCo PPA. Instead, the Company, is proposing to acquire the conventional resources through competitive procurement of the major components and construction and ownership by the Company. Furthermore, the Company is proposing in this Resource Plan what it believes to be the only feasible plan to have the resources in place to timely address the capacity deficit. Therefore, the Company is not proposing a contingency plan and will be requesting a waiver of this requirement.

5.0 Rule 3604(e) - Assessment of Need for Additional Resources

5.1 Need for Replacement Resources and Additional Resources

Immediately upon expiration of the existing PSCo PPA on December 31, 2011, the Company will need resources to replace the capacity, associated energy and reserves provided by the PSCo PPA. The Company will also need additional resources due to growth. Table 5-1 indicates that the Company's total need for replacement and additional capacity to maintain a minimum 15% reserve margin increases from 342 MW in 2012 when the PPA with PSCo expires to over 537 MW in 2027. These resource needs are prior to the implementation of the proposed DSM program portfolio and prior to the addition of new renewable energy resources required to meet the state's RES. Figure 5.1 presents the 2012 capacity deficit when the PSCo PPA terminates and the Company faces a need to replace approximately 75% of the Company's capacity, including associated energy, and the majority of the Company's reserve margin.

[15] North American Electric Reliability Corporation, *2008 Summer Reliability Assessment*, May 2008: ERCOT – 12.5% minimum reserve margin; FRCC – 15% reserve margin; MRO – 17.5% summer reserve margin; MAPP GRSP – 15% reserve capacity obligation; MAIN – approximately 14% minimum short-term planning reserve margin; NYISO – 15% Installed Reserve Margin; MISO – 12% default reserve requirement; PJM – 15% reserve margin; SPP – 12% capacity margin requirement.

[16] For example, the Commission has recently approved a CPCN for PSCo to construct two combustion turbines at the Fort St. Vrain Generating Station because of the termination of a PPA between PSCo and Squirrel Creek Energy. Decision No. C08-0369. The project had been selected as a result of competitive bidding in PSCo's 2005 All Source Solicitation.

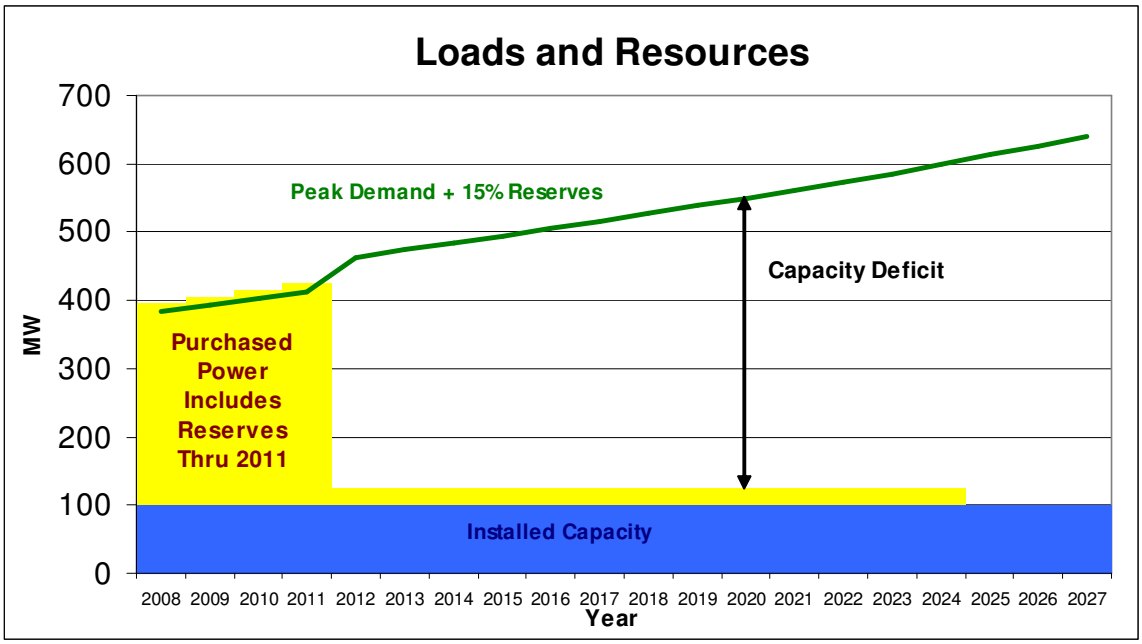
To appreciate the significance of the expiration of the PSCo PPA as compared to the significance of growth in customer demand, note that the capacity deficit for 2012 is 339 MW of which 9 MW is attributable to growth in peak demand (2012 peak demand of 406 minus 2011 peak demand of 397).

Table 5-1
Load and Capacity Resource Balance (Excess or Deficit)

Year	Peak Demand (MW)[1] (1)	PSCO PPA (MW)[2] (2)	15% Reserves (MW)[3] (3) ((1)-(2))*.15	Peak + 15% Reserves (4) (1) + (3)	Installed Capacity (MW) (5)	Purchased Capacity (MW)[(4)] (6)	Total Capacity (MW) (7) (5) + (6)	Excess (Deficit) (MW) (8) (7) –(3)
2008	369	270	14.9	383.9	101.5	293	394.5	10.7
2009	378	280	14.7	392.7	101.5	303	404.5	11.8
2010	388	290	14.7	402.7	101.5	313	414.5	11.8
2011	397	300	14.6	411.6	101.5	323	424.5	13.0
2012	406	0	60.9	466.9	101.5	23	124.5	(342.4)
2013	415	0	62.3	477.3	101.5	23	124.5	(352.8)
2014	424	0	63.6	487.6	101.5	23	124.5	(363.1)
2015	433	0	65.0	498.0	101.5	23	124.5	(373.5)
2016	442	0	66.3	508.3	101.5	23	124.5	(383.8)
2017	452	0	67.8	519.8	101.5	23	124.5	(395.3)
2018	461	0	69.2	530.2	101.5	23	124.5	(405.7)
2019	471	0	70.7	541.7	101.5	23	124.5	(417.2)
2020	481	0	72.2	553.2	101.5	23	124.5	(428.7)
2021	491	0	73.7	564.7	101.5	23	124.5	(440.2)
2022	501	0	75.2	576.2	101.5	23	124.5	(451.7)
2023	512	0	76.8	588.8	101.5	23	124.5	(464.3)
2024	522	0	78.3	600.3	101.5	0	101.5	(498.8)
2025	533	0	80.0	613.0	101.5	0	101.5	(511.5)
2026	544	0	81.6	625.6	101.5	0	101.5	(524.1)
2027	556	0	83.4	639.4	101.5	0	101.5	(537.9)

1. Peak Demand before Demand-Side Management mandate
2. The PSCo PPA brings reserves
3. The significant increase in required reserves in 2012 reflects the loss of reserves that were associated with the PSCo PPA.
4. The 23 MW of purchased power reflects the two swaps with the Western Area Power Administration.

Figure 5.1



5.2 Legal Requirements Affecting Resource Planning

5.2.1 Statutory Requirement for Just and Reasonable Rates

Section 40-3-101(a) provides that, "all charges made, demanded, or received by any public utility for any rate, fare, product, or commodity furnished or to be furnished or any service rendered or to be rendered shall be *just and reasonable*." (Emphasis added.) The public utilities commission is entrusted with regulation of the rates of public utilities. Determination of what is a just and reasonable rate is a matter of judgment or discretion on the part of the public utilities commission.[17]

5.2.2 Statutory Requirement for Adequate Service

Section 40-3-101(b) provides that, "every public utility shall furnish, provide, and maintain such service, instrumentalities, equipment, and facilities as shall promote the safety, heal, comfort, and convenience of its patrons, employees, and the public, and as shall in all respects *be adequate*, efficient, just and reasonable" (emphasis added).

5.2.3 Legal Requirement to Maintain the Utility's Financial Integrity

The Colorado Supreme Court has held that the Commission must protect two interests when setting rates: (1) the right of the public utility company and its investors to earn a return

[17] *Mountain States Tel. & Tel. Co. v. Pub. Utils. Comm'n*, 182 Colo. 269, 513 P.2d 721 (1973).

reasonably sufficient to maintain the utility's financial integrity; and (2) the right of consumers to pay a rate which accurately reflects the cost of service rendered.[18]

5.2.4 Renewable Energy Standard Requirements

The Colorado voters passed Amendment 37 in November 2004 which required the legislature to adopt an amendment to the Colorado Revised Statutes for large providers of retail electric service (including the Company) mandating that a percentage of their retail electricity sales be derived from renewable resources, starting with 3% in the year 2007 and increasing to 10% by 2015 and limiting the retail rate impact of renewable energy resources to 50 cents per month for residential customers. The legislature adopted a new statute, §40-2-124 C.R.S., effective December 1, 2004.

In 2005, the legislature adopted Senate Bill 05-143 which, among other things, increased the retail rate impact cap to 1% of the total annual electric bill for each customer. During the 2007 session, the Colorado legislature adopted House Bill 07-1281 which doubled the percentages of retail electricity sales that a qualifying retail utility (including the Company) must generate or cause to be generated from eligible energy resources through 2015, added a renewable energy standard of 20% by 2020, and increased the retail rate impact cap to 2% of the total annual electric bill for each customer. Eligible energy resources include recycled energy and facilities that generate electricity by means of solar radiation, wind, geothermal, biomass, hydropower and fuel cells using hydrogen from eligible energy resources. The renewable energy standard now facing the Company, which is also the case for PSCo, is as shown in Table 5-2.

These eligible energy resources are to be provided with a retail rate impact not exceeding 2% of the total electric bill annually for each customer.[19] The retail rate impact must be determined net of new alternative sources of electricity supply from non-eligible energy resources that are reasonably available at the time of the determination.

[18] *Pub. Serv. Co. v. Pub. Utils. Comm'n*, 644 P.2d 933 (Colo. 1982).
[19] §40-2-124, C.R.S. and 4 CCR 723-3-3650-3665.

Table 5-2
Regulatory Requirements – Renewable Energy Standard

Years	% of Retail Electricity Sales
2007	3%
2008-2010	5%
2011-2014	10%
2015-2019	15%
2020	20%
Note: 4% of the energy requirements are to be provided by solar generation technologies and half of this 4% must be on-site solar systems located at customer facilities.	

Renewable energy compliance plans and reports are required to be filed annually. The Company has an approved 2008 compliance plan. (Decision No. R08-0385 in Docket No. 07A-356E, was issued April 10, 2008 and became the Commission's effective decision by operation of law on May 1, 2008.) The Company's 2009 compliance plan will be filed on or before September 3, 2008.

5.2.5 Demand Side Management Requirement

The Company is subject to the DSM provisions of regulatory mandates as enumerated in HB07-1037.[20] The Commission is required to establish energy savings and peak demand reduction goals to be achieved by investor-owned electric utilities (the Company and PSCo), taking into account the utility's cost-effective DSM potential, the need for electricity resources, the benefits of DSM investments, and other factors as determined by the Commission. The energy savings and peak demand reduction goals shall be at least 5% of the utility's retail system peak demand measured in MW in the base year and at least 5% of the utility's retail energy sales measured in MWh in the base year. The base year shall be 2006. The goals shall be met in 2018, counting savings in 2018 from DSM measures installed starting in 2006. DSM is defined as one of or any combination of energy efficiency, conservation, load management, and demand response programs. In addition, compliance plans and reports must be filed annually.

5.2.6 Section 123 Resources

Section 40-2-123, C.R.S. requires the Commission to "give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities, bearing in mind the beneficial contributions such technologies make to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases. The commission shall consider utility investments in energy efficiency to be an acceptable use of ratepayer moneys."

The Commission's resource planning rules use the term "Section 123 resources" and require utilities to include in their resource plan descriptions of three alternate scenarios that can be used to represent the costs and benefits from increasing amounts of Section 123 resources included in

[20] Not codified in a single reference. Amended §40-1-102, C.R.S. and §40-3.2-101, C.R.S. Added new sections §40-3.2-103, C.R.S.; §40-3.2-104, C.R.S., and §40-3.2-105, C.R.S.

a cost-effective resource plan. The Commission clarified the term "Section 123 resources" as used in the resource planning rules "to represent a wide range of resources that are not selected as least-cost resources, but that have other attributes, such as societal or environmental benefits, that may be considered by the Commission." It is not limited to only those resources that qualify under §40-2-123 but includes other resources as well.[21]

The 2008 legislature adopted House Bill 08-1164 which amends Section 123 to provide that the Commission may give consideration to the likelihood of new environmental regulation and the risk of higher future costs associated with the emission of greenhouse gases such as CO_2 when it considers utility proposals to acquire resources. The Commission may also consider whether acquisition of utility-scale solar resources is in the public interest, taking into account the associated costs and benefits. This Bill was signed into law by the Governor on June 2, 2008.

5.2.7 The Colorado Climate Action Plan

On November 5, 2007, Governor Ritter unveiled the Colorado Climate Action Plan which includes goals for reductions in carbon dioxide (CO_2) emissions. The Colorado Climate Action Plan sets forth expectations for all of the electric utilities in Colorado. Specifically, the Colorado Climate Action Plan:

- Articulates a goal of reducing greenhouse gas emissions in the utility sector by 20% from 2005 levels by the year 2020.

- Outlines specific actions that can be taken including planning for new energy resources by using 50% energy efficiency, 33% renewable energy and 17% clean coal technology which the Colorado Climate Action Plan anticipates will be developed within 10 years.

- Identifies five key ways to achieve energy efficiency including increases in lighting performance, expanded DSM programs, industrial efficiency measures, greening of state government, and updating building codes.

- Identifies natural gas as a key element in a bridge strategy to a cleaner energy future for Colorado because it is a plentiful and reliable energy source that generates 43 percent less CO_2 than coal and can serve as a primary fuel source for electrical energy generation and as backup power for intermittent renewable technologies such as photovoltaics and wind.

5.2.8 Executive Order D 004 08

On April 22, 2008, the Governor issued Executive Order D 004 08 (Executive Order). As to public utilities, the Executive Order:

- Requests the Commission require from each utility within its jurisdiction (including the Company) an electric resource plan for achieving a 20% reduction in its greenhouse gas emissions from 2005 levels by 2020.

[21] Decision No. C08-0185.

- Directs the Governor's Energy Office and the Department of Regulatory Agencies to identify regulatory and legislative changes that may be needed to provide investor-owned utilities with the appropriate incentives to reduce greenhouse gas emissions, and to reduce financial barriers to investments in renewable energy sources, energy efficiency, carbon credits, and clean coal technologies and to provide their suggestions to the Governor within 12 months of the date of the Executive Order.

- Directs the Colorado Department of Public Health and Environment and the Governor's Energy Office to evaluate policy options to address future demand for new coal-fired power plants considering, at a minimum, development of alternative sources of energy and options for reducing or mitigating greenhouse gas emissions from new plants and making a recommendation to the Governor within 12 months of the date of the Executive Order.

The Company recognizes the complexity of the climate change issue and its impact on our customers. The need to supply energy in a cost-effective manner must be balanced with the high costs of possible mandates for reducing greenhouse gas emissions. Legislative compliance dates must be coordinated with the projected availability of technologies needed to make meaningful reductions. It is essential that climate legislation include an effective economic safeguard to limit the potential impacts of carbon policy on customers and on U.S. jobs and economic growth.

5.2.9 Energy Independence and Security Act of 2007

The Company acknowledges the energy efficiency and research and development provisions of The Energy Independence and Security Act of 2007. Under the provisions of the Act related to energy security, and primarily affecting the transportation sector, are incentives for the development of plug-in hybrid vehicles. Increased standards for appliances and lighting will effectively ban the sale of most incandescent light bulbs by 2014. Conservation in buildings and industry will be promoted through new initiatives. New and renovated federal buildings must significantly reduce their use of fossil fuels. Additional research for solar, geothermal, and ocean renewable resources will be encouraged. Carbon sequestration research will be expanded at the federal level. Loans will be provided to small businesses to make energy efficiency improvements.[22]

[22] H.R.6, Public Law No. 110-140, THOMAS (Library of Congress), http://thoms.loc.gov/cgi-bin/bdquery/z?d110:HR00006. Fact Sheet: Energy Independence and Security Act of 2007, The White House, December 19, 2007, www.whitehouse.gov/news/releases/2007/12/20071219-1.html

5.2.10 Resource Planning Rules Requirements

The current Commission resource planning rules became effective on March 1, 2008,[23] and significantly amended the former least cost planning rules. The purpose of the amended rules is to result in "cost-effective resource portfolios, taking into consideration projected system needs, reliability of proposed resources, beneficial contributions of new clean energy and energy-efficient technologies, expected generation loading characteristics, and various risk factors."

The amended rules define a "cost-effective resource plan" as "a designated combination of new resources that the Commission determines can be acquired at a reasonable cost and rate impact." Under the rules, it is the Commission and not the utility that decides what is a cost-effective resource plan. The utility's responsibility is to file a resource plan for review and approval or disapproval by the Commission. The utility must include in the plan a baseline case that describes the costs and benefits of the new utility resources required to meet the utility's needs during the planning period minimizing the net present value of revenue requirements consistent with reliability considerations, financial and development risks, and the evaluation criteria approved by the Commission under Rule 3613. The baseline plan must also comply with the RES and with the DSM resource requirements. The utility must also include two other scenarios that represent alternative combinations of resources that meet the same resource needs as the baseline case but that include proportionately more section 123 resources.

5.3 Other Resource Planning Considerations

5.3.1 Transmission Issues

Transmission additions across the U.S. have historically occurred in conjunction with the construction of generating resources. As most utilities throughout the U.S. stopped self-building additional resources over the past twenty years, construction of transmission also slowed or stopped. Thus, the backlog of needed transmission projects has grown at the same time that consumer resistance to those projects has increased. With the Energy Policy Act of 2005, the federal government is empowered to designate transmission corridors of national interest. However, the pace of transmission additions is still very slow, the siting and permitting process is long and arduous, and resistance to construction is greater than ever.

5.3.2 Equipment Availability and Increasing Costs of Material and Labor

Costs of concrete and steel have soared in recent years as a result of the reconstruction of New Orleans subsequent to Hurricane Katrina and very significant growth in world demand caused by emerging economies such as China, India and Brazil. These conditions have led to rising costs of materials and a shortage in the availability of equipment. Not only are the cost of materials increasing at a very significant annual rate, but the availability of labor has decreased resulting in cost increases and decreased productivity. The expected cost of FutureGen (the integrated gasification combined cycle unit demonstration project planned in Illinois) increased so significantly since 2003 when the facility was originally announced that the U.S. Department of

[23] 4 CCR 723-3, Rules 3600 – 3615.

Energy decided in January 2008 to withdraw from the project.[24] Duke Energy's cost estimate to build its coal-fired Cliffside 6 unit increased by $1 billion; Duke Energy now expects its 800 MW unit will cost $2.4 billion, an increase of 70% in just over two years. These cost increases are due to a number of factors including increases in the costs of materials. However, with the aging of the Baby Boomer Generation and the lack of interest by younger workers in trade jobs, the labor shortage issues are expected to become more intense.

5.3.3 Electricity and Natural Gas Markets

The Company will continue to participate in the electricity markets on an hourly basis in an effort to provide our customers with the least cost resources available. This type of optimization is illustrated in the energy pie chart that is part of Figure 8.1 in this Resource Plan. Price fluctuations occur and have occurred historically due to classic economic supply and demand – typically prices are higher during on-peak periods and lower during off-peak periods. The price of electricity in the Company's market is currently driven, and will be driven over the planning horizon, by the price of natural gas (as natural gas units are the predominant unit on the margin in any hour) and the ability of neighboring utilities to ensure adequate generation and transmission resources.

6.0 Modeling Parameters

A wide variety of modeling parameters must be developed in order to prepare a meaningful and comprehensive Resource Plan. These parameters include availability of resources, economic assumptions, fuel and market price forecasts, and emission costs (including potential CO_2 taxes which represent either a tax or a cap and trade system). The Global Energy Decisions (GED) *Power Market Advisory Service: Electricity and Fuel Price Outlook – WECC Fall 2007* (GED Fall 2007 Reference Case) was used for the long-term natural gas and electric price forecasts as well as for the estimates of a possible future CO_2 tax and the prices for other emissions.

6.1 Purchased Power Agreement with PSCo

The most significant issue facing the Company is the capacity deficit caused by the expiration of the PSCo PPA on December 31, 2011. The necessary and primary focus of this Resource Plan is the resources needed to address the capacity deficit in a timely and cost effective manner so that reliable resources are in place on or before January 1, 2012.

[24] Mercer, David and Jim Suhr, Associated Press, "FutureGen developers propose cost restructuring," *Chicago Tribune*, January 11, 2008, http://www.chicagotribune.com/business/chi-ap-il-futuregen,0,2025985.story. NCWARN, "Basics: Duke Energy's Cliffside Power Plant," http://www.ncwarn.org/HansenEvent11-07/BasicsDukeEnergy'sCliffsidePowerPlant.htm. Barber, Wayne, "FutureGen charges DOE reversal will slow carbon capture development," SNL Energy Electric Utility Report, February 4, 2008, pp. 1-12.

6.2 Economic Parameters

Table 6-1 presents the assumed economic parameters, including interest rate, return of equity, rate of return, weighted average cost of capital, income tax rate, and rate of escalation.

Table 6-1
Economic Assumptions

Component	Annual Rate (percent)
Interest Rate	6.85
Weighted Average Cost of Capital (WACC)	7.3359
Income Tax Rate	38.0
Rate of Escalation	3.0
Capital Structure Equity Debt	 47.50 52.50
Wyoming Property Tax Rate	0.27
Colorado Property Tax Rate	0.82
Colorado Fixed Charge Rate (Simple Cycle)	11.52
Colorado Fixed Charge Rate	11.95
Wyoming Fixed Charge Rate	11.40

The Wyoming property tax rate of 0.27% is for original cost of gross plant. The Colorado property tax rate of 0.82% is for original cost of gross plant.

6.3 Fuel Price Forecasts

Fuel price forecasts were developed for natural gas, oil, and coal.

6.3.1 Natural Gas Price Forecasts

The price of natural gas is volatile and difficult to accurately forecast due to a variety of factors. As a result, high and low price sensitivities were evaluated for natural gas and market clearing prices. The base case natural gas price forecast is contained in the GED Fall 2007 Reference Case. The monthly price forecasts associated with the base case are shown on Figure 6.1. The average annual prices for natural gas were calculated from this monthly price forecast and are presented in Table 6-2.

The high and low case natural gas price forecasts were developed by GED. GED performed stochastic analysis of historical power and gas price data and Monte Carlo iterations of the forecast price series. The high and low natural gas price cases are the 75^{th} percentile and 25^{th} percentile prices, respectively. The values for these forecasts are also shown on Table 6-2.

Figure 6.1
Natural Gas Price Forecast – Base Case (Nominal Year $/MMBtu)

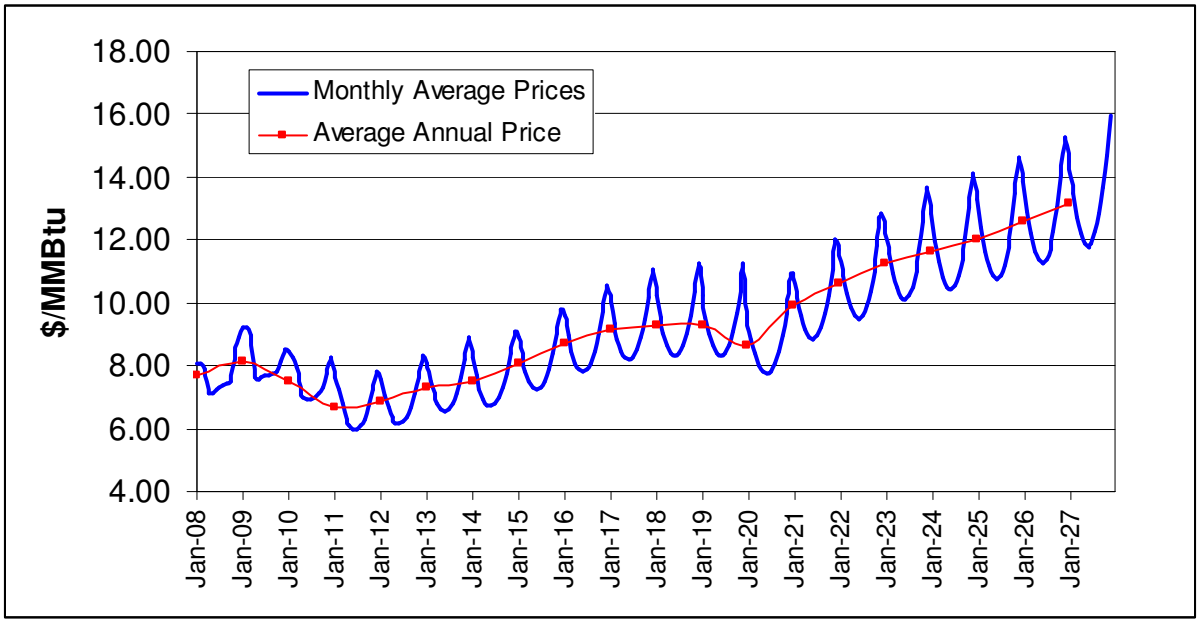


Table 6-2
Natural Gas Price Forecasts
(Nominal Year $/MMBtu – Annual Average)

Year	Base Case	Low Case	High Case
2008	7.72	6.43	9.86
2009	8.15	6.29	10.31
2010	7.49	5.63	9.55
2011	6.68	4.71	8.62
2012	6.86	4.79	8.95
2013	7.33	4.87	9.62
2014	7.50	4.88	9.87
2015	8.08	5.22	10.38
2016	8.70	5.49	11.19
2017	9.13	5.61	11.75
2018	9.28	5.57	12.13
2019	9.29	5.41	12.11
2020	8.64	5.06	11.22
2021	9.90	5.53	12.69
2022	10.61	5.70	13.61
2023	11.28	5.90	14.48
2024	11.66	5.98	15.11
2025	12.04	6.05	15.61
2026	12.59	6.21	16.45
2027	13.15	6.13	17.32

6.3.2 Fuel Oil Price Forecast

The monthly fuel oil price forecast is contained in the GED Fall 2007 Reference Case. The monthly price forecasts are shown on Figure 6.2. The average annual prices for fuel oil were calculated from this monthly price forecast and are presented in Table 6-3.

Figure 6.2
No. 2 Fuel Oil Price Forecast (Nominal Year $/MMBtu)

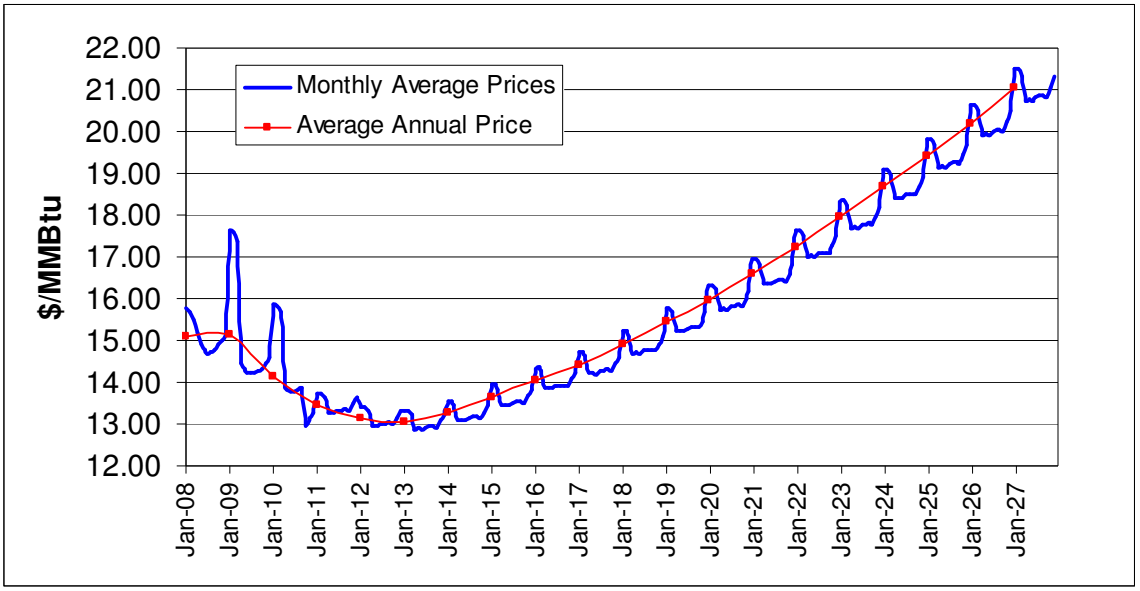


Table 6-3
No. 2 Fuel Oil Price Forecast
(Nominal Year $/MMBtu – Annual Average)

Year	No. 2 Fuel Oil
2008	15.09
2009	15.14
2010	14.14
2011	13.45
2012	13.12
2013	13.05
2014	13.27
2015	13.64
2016	14.04
2017	14.41
2018	14.89
2019	15.44
2020	15.96
2021	16.58
2022	17.25
2023	17.94
2024	18.66
2025	19.41
2026	20.20
2027	21.02

6.3.3 Coal Price Forecast

The primary sources of coal for the power plants examined in this analysis were the Powder River Basin (PRB) in Wyoming (subbituminous coal) and the Rocky Mountain region (bituminous coal) in Colorado. The coal price forecast for coal delivered to an undetermined location in the Company's service territory was obtained by adding the rail transportation cost component to the mine price forecast provided in the GED Fall 2007 Reference Case. The resulting coal price forecast is shown on Figure 6-3 and Table 6-4.

Figure 6.3
Coal Price Forecast (Nominal Year $/MMBtu)

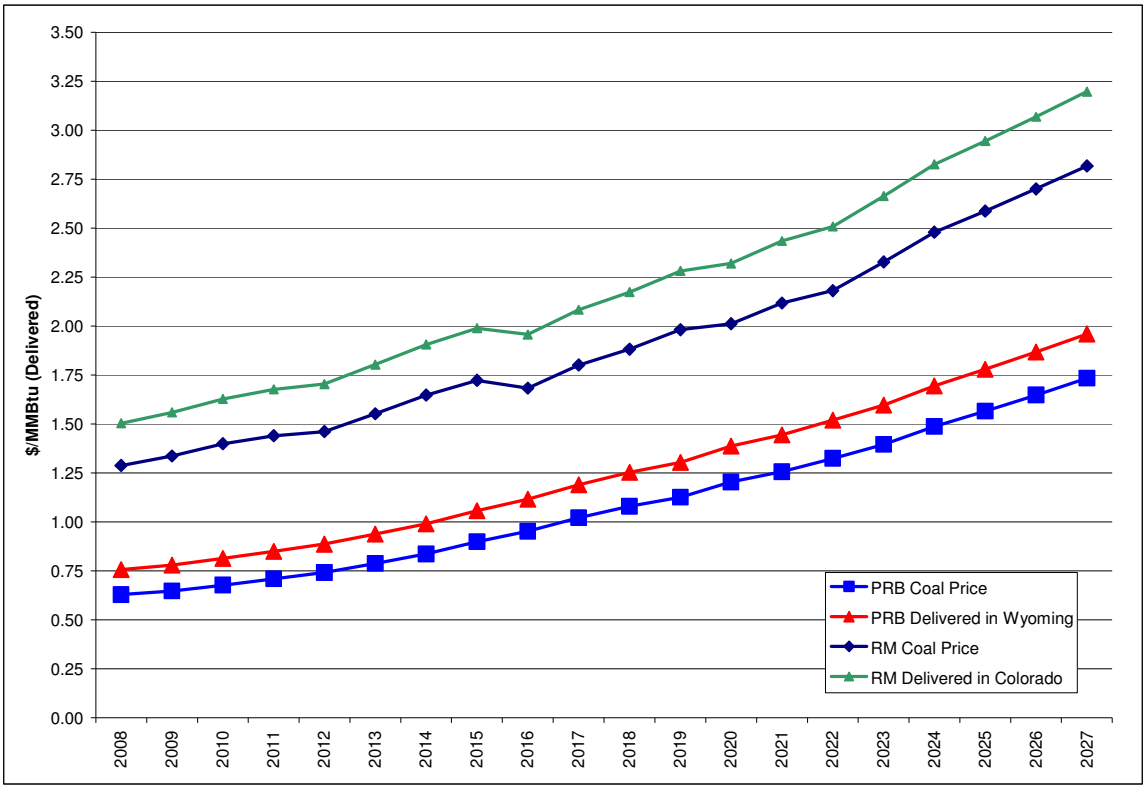


Table 6-4
Coal Price Forecast (Nominal Year $/MMBtu – Annual Average)

	Powder River Basin			Rocky Mountain Region		
Year	Mine-mouth price	Infrastructure Costs	Total Delivered	Mine Price	Transportation	Total Delivered
2008	0.63	0.129	0.76	1.29	0.22	1.50
2009	0.65	0.133	0.78	1.34	0.22	1.56
2010	0.68	0.137	0.81	1.40	0.23	1.63
2011	0.71	0.141	0.85	1.44	0.24	1.68
2012	0.74	0.145	0.89	1.46	0.24	1.70
2013	0.79	0.149	0.94	1.55	0.25	1.80
2014	0.84	0.154	0.99	1.65	0.26	1.91
2015	0.90	0.158	1.06	1.72	0.27	1.99
2016	0.95	0.163	1.12	1.68	0.27	1.96
2017	1.02	0.168	1.19	1.80	0.28	2.08
2018	1.08	0.173	1.25	1.88	0.29	2.17
2019	1.13	0.178	1.30	1.98	0.30	2.28
2020	1.20	0.184	1.39	2.01	0.31	2.32
2021	1.26	0.189	1.44	2.12	0.32	2.44
2022	1.32	0.195	1.52	2.18	0.33	2.51
2023	1.40	0.201	1.60	2.33	0.34	2.66
2024	1.49	0.207	1.69	2.48	0.35	2.83
2025	1.57	0.213	1.78	2.59	0.36	2.95
2026	1.65	0.219	1.87	2.70	0.37	3.07
2027	1.73	0.226	1.96	2.82	0.38	3.20

6.4 Emission Allowance Price Forecast

GED provided forecasts of sulfur dioxide (SO_2), mercury (Hg), and CO_2 allowance prices that correspond to its base case fuel forecasts. Although CO_2 emissions are not currently regulated, this forecast assumes that some form of regulation will be in place by 2012. GED also postulates a high CO_2 forecast of $40/ton for the entire planning period. The SO_2, Hg, and CO_2 allowance price forecasts presented in Table 6-5 correspond to the base case fuel forecasts.

Table 6-5
Annual Emission Allowance Costs (Nominal Year Dollars)

Year	SO_2 ($/ton)	Hg ($/lb)	CO_2 ($/ton)
2008	501.25	0	0
2009	509.29	0	0
2010	517.35	6,696	0
2011	525.44	6,897	0
2012	533.35	7,104	3.06
2013	527.62	7,317	3.51
2014	532.62	7,537	4.03
2015	527.07	7,763	4.61
2016	521.66	7,996	5.28
2017	516.41	8,236	6.05
2018	511.32	8,483	6.92
2019	506.37	8,737	7.91
2020	501.58	8,999	9.03
2021	496.92	9,269	10.32
2022	492.40	9,547	11.78
2023	488.01	9,834	13.45
2024	483.74	10,129	15.34
2025	479.59	10,433	17.50
2026	475.59	10,745	19.96
2027	388.31	11,068	22.74

7.0 Resource Alternatives Examined

The resources required to fill the gap caused by the 2012 capacity deficit and to meet the growing electricity needs of the Company's customers were selected from a range of DSM, conventional, and renewable resources examined for the 20-year planning period in this Resource Plan.

7.1 Demand Side Management Resources

The Company is involved in a new DSM evaluation effort that started with an efficiency potential analysis. The purpose of this analysis was to determine the technical, economic, and achievable potential for electric energy efficiency programs in the Company's service territory. As part of this effort, a DSM advisory group was formed to review preliminary results and provide feedback. The outside members of the advisory group included representatives from the following organizations:

1. Colorado Public Utilities Commission staff
2. Colorado Office of Consumer Counsel
3. Colorado Governor's Energy Office

4. Colorado Energy Science Center
5. Southwest Energy Efficiency Project (SWEEP)
6. Built Green Colorado

Based on the technical, economic and achievable potentials as well as input from the DSM advisory group, a portfolio of DSM programs was developed. The proposed DSM Programs include:

- Low Income Weatherization Program
- Residential High Efficiency Lighting Program
- Residential High Efficiency Cooling Program
- Commercial Prescriptive Rebate Program
- Commercial Custom Rebate Program
- Commercial Retro-Commissioning Program
- Commercial LEED Buildings Program
- Industrial Energy Efficiency Program

Final review of this portfolio is underway and the Company expects to file a DSM plan and cost recovery proposal in the fall of 2008.

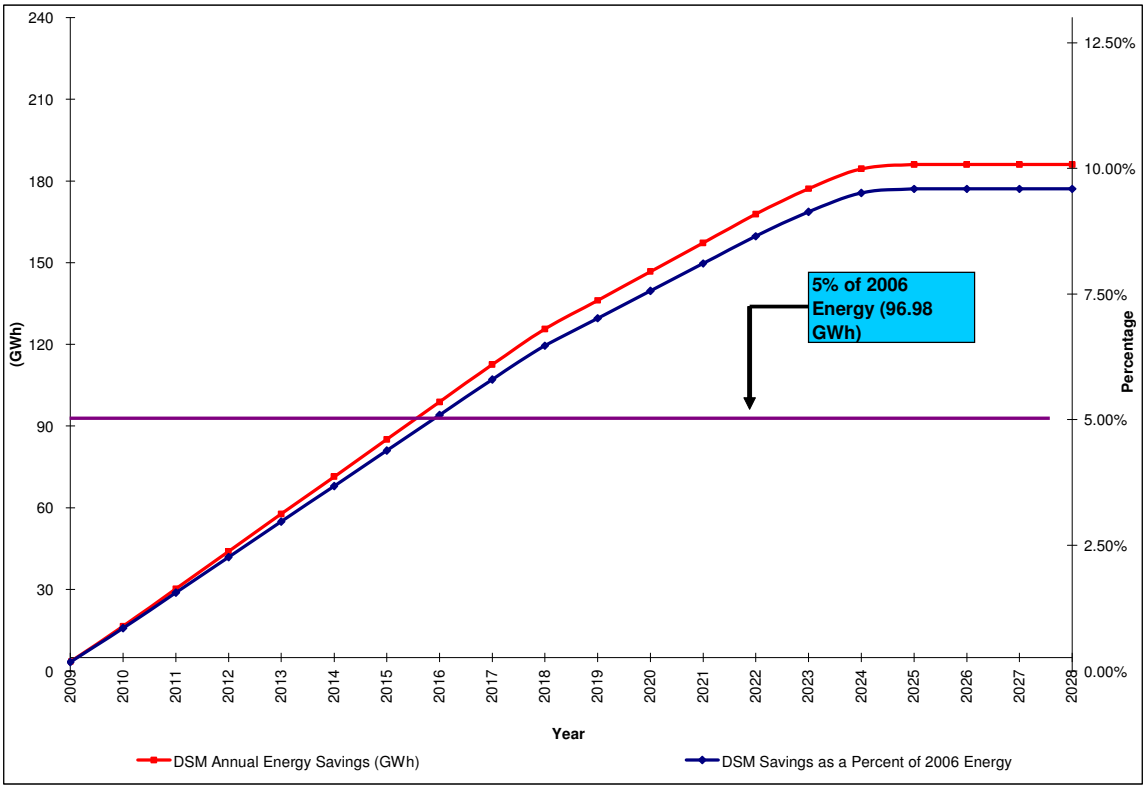
The assumption was made in the modeling that the DSM portfolio to be filed in the fall of 2008 will result in MW reductions of load that range from just over 2 MW in 2009 to over 64 MW by 2027 as shown in Table 7-1 and corresponding energy savings. The achievement of the DSM energy reduction requirements to comply with HB07-1037[25] is shown in Figure 7.1. This achieves the stated goals of HB07-1037 of a 5% reduction from 2006 peak demand and energy by 2018.

[25] Not codified in a single reference. Amended §40-3-102(5), C.R.S. and §40-3.2-101, C.R.S. Added new sections §40-3.2-103, C.R.S.; §40-3.2-104, C.R.S., and §40-3.2-105, C.R.S.

Table 7-1
DSM Program Portfolio Effects on Peak Demand and Annual Energy

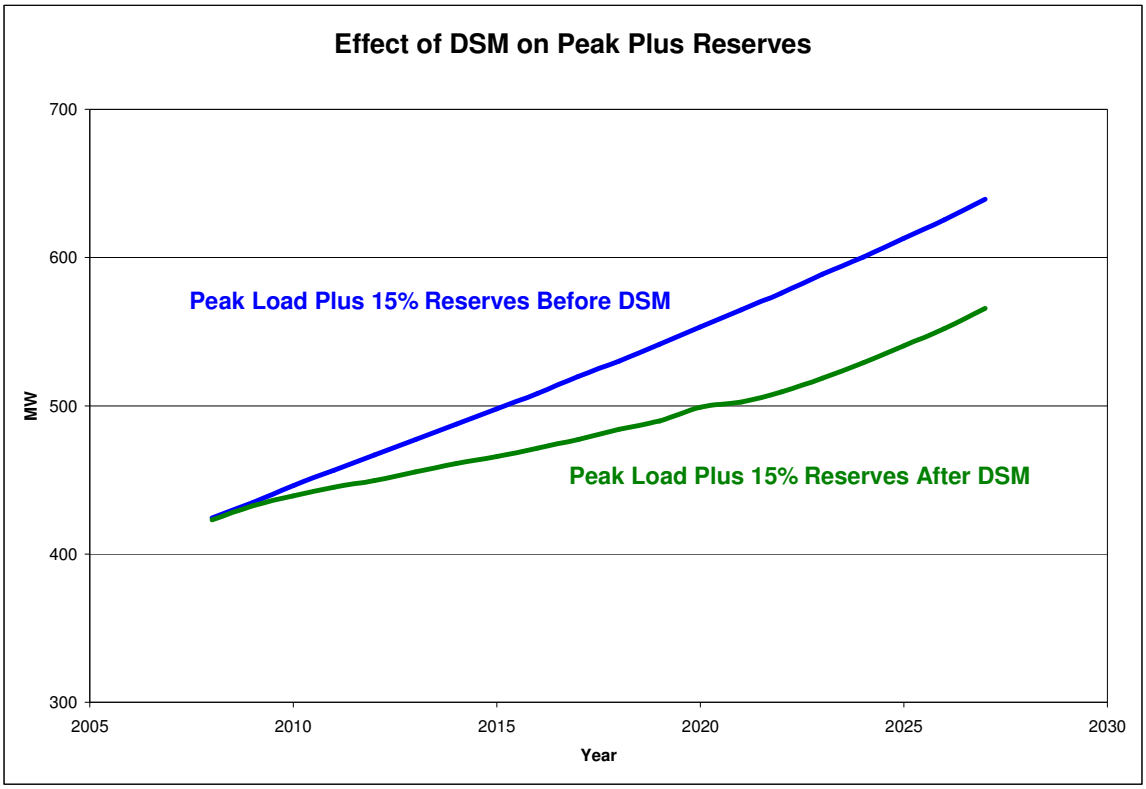
Year	Peak (MW)	DSM Savings in Peak (MW)	Net Peak (MW)	Annual Energy (GWh)	DSM Savings in Energy (GWh)	Net Energy (GWh)
2009	378	(2.30)	376	2,067	(5.6)	2,061
2010	388	(6.00)	382	2,124	(16.5)	2,108
2011	397	(10.30)	387	2,200	(30.2)	2,170
2012	406	(14.60)	391	2,255	(43.9)	2,211
2013	415	(18.90)	396	2,307	(57.6)	2,249
2014	424	(23.30)	401	2,362	(71.3)	2,291
2015	433	(27.60)	405	2,416	(85.1)	2,331
2016	442	(31.90)	410	2,474	(98.8)	2,375
2017	452	(36.90)	415	2,529	(112.5)	2,417
2018	461	(39.60)	421	2,587	(125.6)	2,461
2019	471	(44.90)	426	2,645	(136.1)	2,509
2020	481	(47.40)	434	2,708	(146.7)	2,561
2021	491	(54.50)	437	2,768	(157.2)	2,611
2022	501	(58.40)	443	2,831	(167.8)	2,663
2023	512	(61.10)	451	2,897	(177.2)	2,720
2024	522	(62.50)	460	2,962	(184.4)	2,778
2025	533	(63.20)	470	3,029	(186.0)	2,843
2026	544	(64.10)	480	3,096	(186.0)	2,910
2027	556	(64.10)	492	3,165	(186.0)	2,979

Figure 7.1
DSM Program Portfolio Reductions



Because DSM reduces the peak demand, the amount of reserves required is also reduced. This effect is shown in Figure 7.2. In addition to meeting the DSM requirements of HB07-1037, this DSM Program Portfolio reduces the amount of capacity required to meet load growth through 2020 by over 40%, correlating well with the recommendations of the Colorado Climate Action Plan.

Figure 7.2



7.2 Conventional Resources

A variety of conventional supply-side resources were examined and considered in preparing the Resource Plan. These include natural gas-fired simple cycle combustion turbines, natural gas-fired combined cycle units, and coal (located either in Wyoming or Colorado). An important consideration for siting any plant is accessibility to transmission. For natural gas-fired units, additional consideration needs to be given to accessibility to and availability from natural gas pipelines. Both integrated gasification combined cycle (IGCC), which included 60% carbon capture, and nuclear power were considered as potential resource options but both were determined to not be viable options during the resource acquisition period. IGCC and nuclear are not considered viable due to the size of the units, the estimated cost of construction, the lead time to complete construction, and the need to partner with other utilities. A brief description of each type of resource and the cost and other parameters used for modeling are described below.

7.2.1 Combustion Turbine

Combustion turbines (CT) typically burn natural gas and/or No. 2 fuel oil and are available in a wide variety of sizes and configurations. CTs are generally used for peaking and reserve purposes because of their relatively low capital costs, higher full load heat rate, and the higher cost of fuel when compared to conventional baseload capacity. Many CTs have the added benefit of providing quick-start and black-start capability in certain configurations. In this

analysis, three different technology options were modeled for CTs: LMS-100, LM-6000, and a Frame 7EA. Parameters used to model each of these CT options are shown on Table 7-2.

Table 7-2
Combustion Turbine Data Parameters

Parameter	LMS-100	LM-6000	Frame 7EA
Size, MW (gross)	86	40	68
Full load heat rate (Btu/kWh)	8,922	9,789	12,051
Capital Cost, $/kW (2008 $)	1,012	1,167	838
Fixed O&M, $/kW-year (2008 $)	8.59	6.86	4.57
Variable O&M, $/MWh (2008 $)	3.59	4.20	12.80
Equivalent Forced Outage Rate, %	3	2	2
Average number of weeks of maintenance per year	2.1	2.1	2.1
First available year	2010	2010	2010
Construction time, months	18	12	12

7.2.2 Combined Cycle

In a combustion turbine combined cycle (CC) facility, the hot exhaust gases from the combustion turbine pass through a heat recovery steam generator (HRSG). The steam generated by the HRSG is expanded through a steam turbine which, in turn, drives an additional generator. CCs typically burn natural gas and are available in a wide variety of sizes and configurations. Parameters used to model a CC facility (two different configurations were analyzed) as a resource are shown on Table 7-3.

Table 7-3
Combined Cycle Data Parameters

Parameter	2 X 1 LM 6000[1]	1 X 1 6FA
Size, MW	136	93
Full load heat rate (Btu/kWh)	8,701	7,371
Capital Cost, $/kW (2008 $)	1,309	1,947
Fixed O&M, $/kW-year (2008 $)	19.45	28.44
Variable O&M, $/MWh (2008 $)	5.70	5.30
Equivalent Forced Outage Rate, %	3	3
Average number of weeks of maintenance per year	2.4	2.4
First available year	2012	2011
Construction time, months	24	24
Notes: 1. Includes duct firing.		

7.2.3 Coal

New pulverized coal-fired units were assumed to be located either in the Gillette, Wyoming area or within the Company's service territory in Colorado (but at an undetermined site). The Company evaluated coal units located in Wyoming and Colorado, assuming such units could be timely permitted and that short-term purchased power would be available as a bridge until coal units, if selected by the model, could be brought on-line. Data used for modeling new coal-fired

units in the Initial Base Case are shown in Table 7-4. The coal-fired unit in Colorado shown on Table 7-2 is assumed to burn coal from Colorado. During the modeling, a sensitivity analysis was performed using PRB coal in the Colorado coal unit.

Table 7-4
Coal-Fired Power Plant Data Parameters

Parameter	Coal Plant located in Wyoming	Coal Plant located in Colorado with Colorado Coal
Size, MW	100[1]	100
Full load heat rate (Btu/kWh)	11,038	10,862
Capital Cost, $/kW (2008 $)	2,676	3,228
Fixed O&M, $/kW-year (2008 $)	62.23	86.80
Variable O&M, $/MWh (2008 $)	12.23[2]	4.37
Equivalent Forced Outage Rate, %	5	5
Average number of weeks of maintenance per year	2.4	2.4
First available year[3]	2013	2013
Construction time, months	32 or 42	42
Source of coal	Wyoming, PRB	Colorado Bituminous

Notes:
1. The effective capacity is 96 MW after accounting for transmission losses.
2. Includes cost of transmission to move power from the Gillette, Wyoming area to the PSCo network
3. The earliest availability for one coal unit is 2013. The earliest availability for a second coal unit is 2014.

7.2.4 Integrated Gasification Combined Cycle

Integrated gasification combined cycle (IGCC) with carbon capture and carbon sequestration is not a mature technology. There are commercial-scale IGCC units in North America that have demonstrated several years of successful operation, however, none has employed carbon capture technology. There are at least 15 suppliers of commercial gasification, but three main gasification technologies have emerged in the industry. The main gasification technologies are offered by GE Energy (originally known as the Chevron/Texaco process), Shell, and ConocoPhillips (E Gas). These are all entrained-flow, slagging gasifiers.

An IGCC unit is comprised of four major subsystems: gasification, oxygen supply, gas cleanup, and the power block. The gasifier reacts coal, oxygen from an air separation unit (ASU), and steam at high pressure (400 to 1000 psi) to produce a medium Btu fuel gas (200-300 Btu/scf). Slag is removed from the gasifier through a slag tap, and the remaining particulates are removed from the raw gas stream. Fly ash is typically recycled back to the coal feed to maximize carbon utilization.

Emissions control for IGCC plants is generally done in the raw gas stream and at the combustion turbine combustor rather than the flue gas. The volumetric flow of raw gas is much smaller than that of flue gas at this point, reducing the size of the gas cleanup systems. Also, the partial pressures of pollutants are much higher than in flue gas, making the absorption processes more efficient.

An IGCC unit dubbed "FutureGen" was to be built in Illinois as a collaboration with the U.S. Department of Energy (DOE). However, significantly increased costs led the DOE to withdraw its support of (and funding for) the facility in early 2008.

The parameters used to model IGCC in this Resource Plan are contained in Table 7-5. These parameters represent participation in a larger IGCC unit with 60% carbon capture owned by a utility other than the Company. The modeling assumed that the Company could participate in up to 50 MW, available in 25 MW blocks.

Table 7-5
IGCC Data Parameters

Parameter	IGCC[1]
Size, MW	615
Full load heat rate (Btu/kWh)	11,300
Capital Cost, $/kW (2008 $)	5,596
Fixed O&M, $/kW-year (2008 $)	81.06
Variable O&M, $/MWh (2008 $)	6.70
Equivalent Forced Outage Rate, %	15
Average number of weeks of maintenance per year	3.0
First available year	2016
Construction time, months	42
Notes: 1. Assumes 60% carbon capture.	

7.2.5 Nuclear

Although there are 104 operating nuclear units in the U.S., no nuclear generating units have been built in this country for over twenty years. However, in 2007, four license applications were filed for seven new nuclear units and another 15 applications for 22 new units are expected to be filed with the U.S. Nuclear Regulatory Commission in 2008. All of the applications filed in 2007 and expected to be filed in 2008 represent additional units at existing nuclear power plant sites.

Impetus for new nuclear units is coming from a variety of areas. Much work has been done in the industry to standardize the design of units, making the licensing process more straightforward, and many nuclear units have been built and are operational overseas. As nuclear units do not emit carbon dioxide or other greenhouse gases, the increasing emphasis nationwide on global warming and climate change is starting to make nuclear units look like an attractive option for power generation again.

A utility with the size of the Company's load could participate in a nuclear unit only as a partner with a minority share. At present, no nuclear units are planned or under construction within a geographic footprint for which it is prudent utility practice for the Company to consider participation. The Company will continue to monitor plans of utilities in the region for new resources and will report in subsequent Resource Plans of any plans for unit participation.

7.3 Purchased Power

The initial modeling also assumed that purchased power in two 100 MW blocks in 2012 and one in 2013 was available. The capacity component of the product was priced at the same level as the existing PSCo PPA escalated to the appropriate years. The energy component was priced at the level of the market. This initial modeling was done in connection with the Initial Base Case described in Section 8 below.

7.4 Renewable Resources

Eligible energy resources as defined in the Code of Colorado Regulations include solar radiation, wind, geothermal, biomass, hydropower (facility size needs to be less than 10 MW for new resources), and fuel cells using hydrogen derived from eligible energy resources. The regulations further define biomass as nontoxic plant matter consisting of agricultural crops or their byproducts, urban wood waste, mill residue, slash, or brush; animal wastes and products of animal wastes; or methane produced at landfills or as a by-product of the treatment of wastewater residuals.

The renewable energy resource technologies that were modeled in this Resource Plan include wind, solar thermal, biomass co-firing, and biomass stand-alone. The data parameters used in the modeling are provided in Table 7-6.

Table 7-6
Renewable Energy Resource Data Parameters

Parameter	Wind	Solar Thermal	Biomass co-firing[3]	Biomass standalone
Size, MW	1.5	1	5	35
Full load heat rate (Btu/kWh)	N/A	N/A	11,400	15,000
Capital Cost, $/kW (2008 $)	2,600	5,005	645	3,913
Fixed O&M, $/kW-year (2008 $)	46.67	54.30	9.60	106.70
Variable O&M, $/MWh (2008 $)	0	0	1.00	7.40
Equivalent Forced Outage Rate, %	N/A	N/A	5	5
Average number of weeks of maintenance per year	1.5	2[2]	2.4	2.4
First available year	2010	2008	2010	2012
Construction time, months	18[1]	20	12	42

Notes:
1. From Notice to Proceed to Commercial Operation Date if turbines are ready to be installed.
2. In a six year schedule, years 1-2 and 4-5 – 0 weeks, year 3 – 3 weeks, year 6 – 6 weeks.
3. Reflects incremental costs to an existing unit.

8.0 Results of Modeling - Additional Resources Needed

The combination of resources that can be available to meet the capacity deficit in 2012 and that provides the lowest net present value of revenue requirements to the Company's customers, subject to the DSM and RES requirements, while satisfying the reliability criteria, is referred to

as the Initial Base Case. The modeling identified an Initial Base Case which contained coal-fired power plants in the resource mix to come on line in 2013 and 2014. The Initial Base Case did not achieve the RES in the timeframe required by the standard because its lower cost affected the calculation of the statutory 2% retail rate impact cap. In addition, it would leave the customers with the future burden of complying with any laws mandating reduction of greenhouse gas emissions.

Furthermore, numerous regulatory developments in the last two years make it unlikely that a coal-fired power plant could be timely permitted in the current environment and an effort to do so would put the customers at risk. These developments include: the permit denial in Kansas for the coal-fired Holcomb plant, Xcel Energy's and PacifiCorp's publicly stated moves away from coal, cancellations of coal units around the country (see Appendix D), the inability of PSCo to commit to availability of purchased power in either 2012 or 2013, issuance of the Colorado Climate Action Plan and Executive Order D 004 08, and the unavailability of commercially demonstrated carbon capture and sequestration technology or other clean coal technologies. Accordingly, the Company performed additional modeling and developed a base case referred to as the Proposed Plan, which does not include the construction of any coal-fired generation. The Initial Base Case is briefly described below. The discussion of the Proposed Plan follows after that.

All of the modeling was performed by Black & Veatch using PROMOD IV and Strategist® (see Appendix B).

8.1 Initial Base Case

Significant resources are added in 2012 to address the capacity deficit caused by the termination of the PSCo PPA. The resources that are added in the Initial Base Case are shown in Table 8-1. These resources include two combustion turbines (LMS-100), purchased power to serve as a bridge until additional generating capacity can be constructed, and some wind energy. The net present value of revenue requirements for the Initial Base Case is $3,341,115,000.

Table 8-1
Initial Base Case Resource Additions

Year	Net Peak (MW)[1]	Installed Capacity (MW)	Purchased Power[2] (MW)	New Resources (MW)[3]	Total Capacity (MW)	Reserve Margin (%)
2008	368	101.5	293	Solar (2 MW)	435	18.2
2009	376	101.5	303		447	18.8
2010	382	101.5	313	Wind (18 MW)	460	20.4
2011	387	101.5	323		471	21.8
2012	391	101.5	23	Wind (9 MW), 2 CTs (152 MW), Purchased Power (200 MW), Solar (2 MW)	479	22.6
2013	396	101.5	23	Wyoming Coal (96 MW), Purchased Power (100 MW)	475	20.0
2014	401	101.5	23	Wyoming Coal (96 MW), Wind (8 MW)	472	17.8
2015	405	101.5	23	Wind (6 MW)	473	16.8
2016	410	101.5	23	CT (59 MW), Wind (3 MW), Solar (2 MW)	532	29.7[4]
2017	415	101.5	23	Wind (6 MW)	533	28.3[4]
2018	421	101.5	23	Wind (7 MW)	533	26.7[4]
2019	426	101.5	23	Wind (3 MW)	534	25.2[4]
2020	434	101.5	23	Solar (2 MW)	534	22.9
2021	437	101.5	23	Wind (24 MW)	536	22.6
2022	443	101.5	23	Wind (18 MW)	538	21.4
2023	451	101.5	23	Wind (8 MW)	539	19.4
2024	460	101.5	23	Wind (24 MW)	541	17.6
2025	470	101.5	0	CT (32 MW), Wind (24 MW), Solar (2 MW)	552	17.4
2026	480	101.5	0	CT (32 MW), Wind (18 MW)	587	22.3
2027	492	101.5	0	Wind (18 MW)	589	19.7

Notes:
1. Net peak is the peak demand after DSM
2. PSCo PPA brings associated 15% reserves
3. Ten percent of installed wind capacity counts as capacity (capacity credit). Solar receives no capacity credit.
4. Maximum reserve margin was capped at 30%.

Sensitivity and risk analysis were conducted for the Initial Base Case. Sensitivity analysis included: high and low energy and demand forecasts, high and low natural gas price forecasts, higher CO_2 taxes, no coal availability until 2014, high capital cost, high sulfur dioxide allowances, high mercury compliance costs, higher transmission costs from Wyoming to Colorado, and two Section 123 renewables cases. Risk analysis for higher and lower load forecasts, higher and lower natural gas price forecasts, higher CO_2 taxes, and higher capital costs were performed for three of the scenarios examined in the sensitivity analysis: the Initial Base Case, Natural Gas Only, and Higher Carbon Tax. The risk and sensitivity analyses indicated that if coal were available to meet the capacity deficit in 2012, it would be the resource of choice.

8.2 Proposed Plan

The measures that the Company would ordinarily take to achieve a least cost plan – a balanced portfolio of baseload, intermediate and peaking resources that utilize a diversified fuel mix of coal, natural gas, and renewable resources – are limited by new environmental laws, rules and governmental directives, many of which did not exist in February 2007 when Black Hills announced its agreement to acquire the assets of Aquila, Inc. in Colorado and three other states. These are set forth in detail in Section 5 of this Resource Plan and include:

November 2004	Colorado voters pass Amendment 37 renewable energy standard with a 50 cent residential retail impact cap[26]
2005 Legislature	Increases Amendment 37's retail rate impact cap to 1%; Commission adopts implementing rules
2007 Legislature	Increases Amendment 37's renewable standard requirements to 20% by 2020 and doubles the retail rate impact cap to 2%; Commission amends rules
November 5, 2007	Governor issues the Colorado Climate Action Plan that includes a goal to reduce greenhouse gas emissions in the utility sector by 20% by 2020
2008 Legislature	Adopts HB08-1164 which requires that the Commission give consideration to the likelihood of new environmental regulation and the risk of higher future costs associated with greenhouse gas emissions when it considers utility proposals to acquire resources

[26] Approximately 58% of the customers who voted in the Company's service territory, voted against Amendment 37.

April 22, 2008	Governor issues Executive Order D 004 08 which requests the Commission to require utilities to submit electric resource plans for meeting greenhouse gas reduction goals and directs the Colorado Department of Public Health and Environment and the Governor's Energy Office to evaluate alternatives for addressing greenhouse gas emissions from new coal-fired power plants and to submit a report to the Governor within 12 months.

There have been other developments as well that have affected this Resource Plan. In 2007, there were at least 52 announced coal project cancellations or delays (see Table D-1 in the Appendix). Perhaps the most well-known of these is the Sunflower Electric Power Cooperative Holcomb plant that was scheduled to be built in Garden City, Kansas with an in-service date of 2012. In October 2007, the air permit application was denied by the Kansas Department of Health and Environment. Sunflower filed an appeal and, on November 30, 2007, the Kansas Supreme Court decided to hear the appeal. The Kansas legislature attempted to override the decision of the Department but Governor Sebelius twice vetoed the legislature's measures. The legislature ended its 2008 session on May 29, 2008. The latest development is that the Kansas Supreme Court has put the appeal on hold pending determinations by the Kansas Department of Health and Environment and the District Court. The future of the project remains uncertain at this time.

Environmental groups are also appealing environmental permits for other coal-fired power plants. For example, on November 1, 2007, the Sierra Club, the Powder River Basin Cooperative, and the Wyoming Outdoor Council filed an appeal before the Wyoming Environmental Quality Council of Basin Electric Power Cooperative's final permit to construct the 365 MW Dry Fork Station near Gillette. Similarly, in 2004, PSCo applied for permits from the Colorado Department of Health and Environment for construction of a new coal-fired electrical generation unit (Comanche 3). The permits were issued but an appeal was filed by Citizens for Clean Air &Water in Pueblo and Southern Colorado and Clean Energy Action. The Pueblo County District Court dismissed the case and the environmental groups appealed. On February 7, 2008, the Colorado Court of Appeals affirmed the dismissal. In July 2008, a Motion was filed with the Commission asking it to review whether Comanche 3 is in the public interest. Construction is underway for both projects after significant delays amid ongoing regulatory risk associated with the appeals.

On December 5, 2007, the United States' Senate Environment and Public Works Committee marked up and voted 11-8 to report S.2191, the Lieberman-Warner Climate Security Act to the full Senate. This was the first time a greenhouse gas cap-and-trade bill has ever been voted out of a congressional committee. The bill was brought to the Senate floor in 2008. While the Act is not expected to pass Congress in 2008, future carbon regulation remains a possibility. Colorado's House Bill 08-1164, effective June 2, 2008, requires the Commission to give consideration to the likelihood of new environmental regulation and the risk of higher future costs associated with the emission of greenhouse gases when it considers utility proposals to acquire resources.

The first priority of this Resource Plan must be to address the capacity deficit in 2012 and beyond. The Company is proposing what it believes to be the best plan to address the capacity deficit in 2012 and provide the most reliable and efficient resources consistent with that need. It is not the plan the Company would have preferred to propose because it does not include any coal resources even though coal resources have historically been the least cost baseload resources due to low fuel costs and low to medium operation and maintenance costs. The regulatory uncertainty around permitting coal resources at this point in time, particularly in Colorado (with the investigation under Executive Order D 004 08 pending), means that it is not prudent in this Resource Plan for the Company to rely on coal resources being available to address the capacity deficit. In addition, it is now not certain that the long-term transmission projects required for Wyoming-based generation to serve Colorado loads will be built in a timely manner. The Company cannot wait 12 months for the results of the policy evaluation ordered by the Governor on April 22, 2008, to propose its resource plan and cannot wait for transmission to be built; it must act now to address the 2012 capacity deficit.

The Company had to choose between two paths: (1) a proposal that relies on coal as a baseload resource by no later than 2013 and 2014 (with bridging purchased power starting in 2012), or (2) a proposal that does not rely on coal. If the Company started down the permitting road for new coal resources in Colorado or Wyoming and encountered delays, it would be too late for the Company to pursue the alternative option proposed in this plan. The Company and customers would be at risk for whatever price the market could demand for power in that situation and the more significant risk that purchased power would not be available, leading to a lack of resource supply.

These realities caused the Company, in May 2008, to model a no coal resource plan (the Proposed Plan). The Proposed Plan relies on the only resources available in the current environment to ensure the adequacy of resources to address the capacity deficit (after DSM and the amount of renewable resources to be added to meet the RES). Those resources are natural gas-fired combustion turbines.

As shown in Table 8-2 and on Figure 8.1, combustion turbines and wind energy resources are installed in 2012 to fill the capacity deficit left by the expiration of the PSCo PPA. During the rest of the planning period, additional renewables and natural gas-fired combustion turbines are the resources selected. This Proposed Plan meets the state's RES requirements as well as the DSM mandates of HB07-1037. Additionally, because the Company's Proposed Plan replaces the coal-fired resources under the PSCo PPA with natural gas-fired resources, it meets the Colorado Climate Action Plan goal of reducing greenhouse gas emissions by 20% from 2005 levels by the year 2020.[27] The net present value of revenue requirements for the Proposed Plan is $3,628,434,000.

[27] The Company's calculation of its 2005 carbon footprint is set forth in Appendix E.

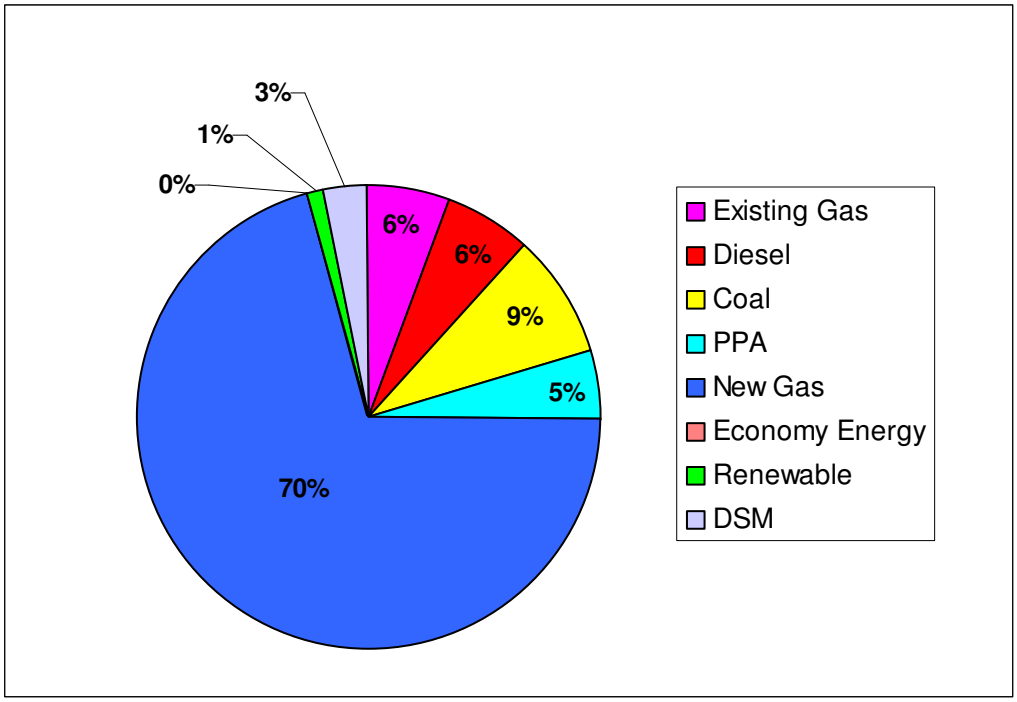
Table 8-2
Proposed Plan Resource Additions

Year	Net Peak (MW)[1]	Installed Capacity (MW)	Purchased Power[2] (MW)	New Resources (MW)[3]	Total Capacity (MW)	Reserve Margin (%)
2008	368	101.5	293	Solar (2 MW)	435	18.2
2009	376	101.5	303		447	18.8
2010	382	101.5	313		458	19.9
2011	387	101.5	323		470	21.3
2012	391	101.5	23	Wind (60 MW), 5 CTs (346 MW), Solar (2 MW)	477	21.9
2013	396	101.5	23		477	20.3
2014	401	101.5	23		477	18.8
2015	405	101.5	23	Wind (30 MW)	480	18.4
2016	410	101.5	23	Solar (2 MW)	480	17.0
2017	415	101.5	23	CT (32 MW)	512	23.3
2018	421	101.5	23	Wind (30 MW)	515	22.2
2019	426	101.5	23		515	20.8
2020	434	101.5	23	Solar (2 MW)	515	18.5
2021	437	101.5	23	Wind (30 MW)	518	18.4
2022	443	101.5	23		518	16.8
2023	451	101.5	23	CT (32 MW)	550	21.8
2024	460	101.5	23		550	19.5
2025	470	101.5	0	CT (59 MW), Solar (2 MW)	586	24.6
2026	480	101.5	0		586	22.0
2027	492	101.5	0		586	19.0

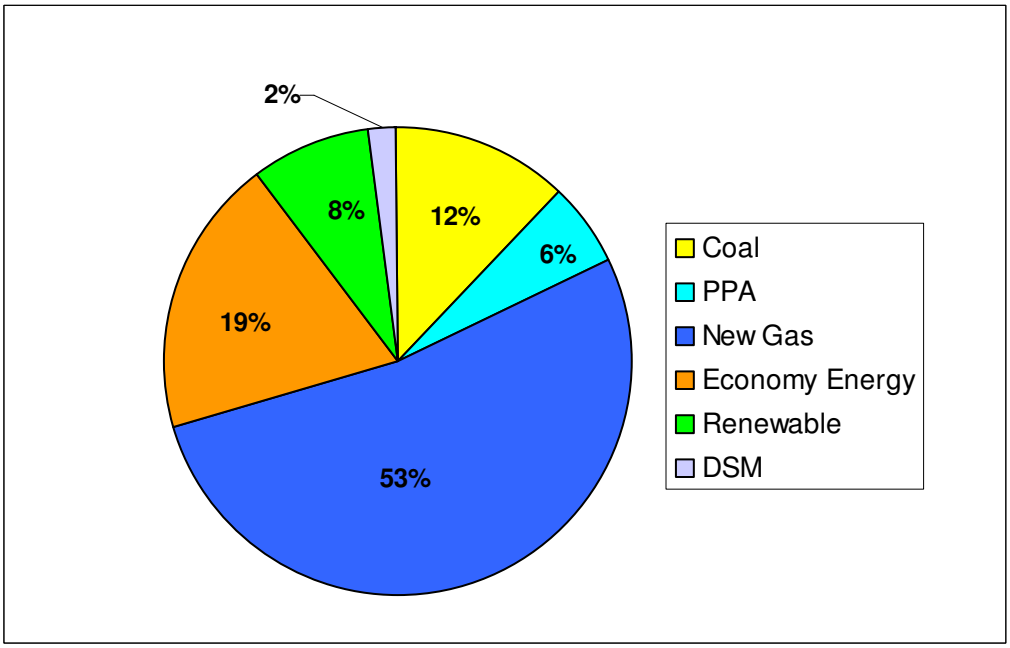
Notes:
1. Net peak is the peak demand after DSM
2. PSCo PPA brings associated 15% reserves
3. Ten percent of installed wind capacity counts as capacity (capacity credit). Solar receives no capacity credit.

Figure 8.1
2012 Expected Resources

Capacity

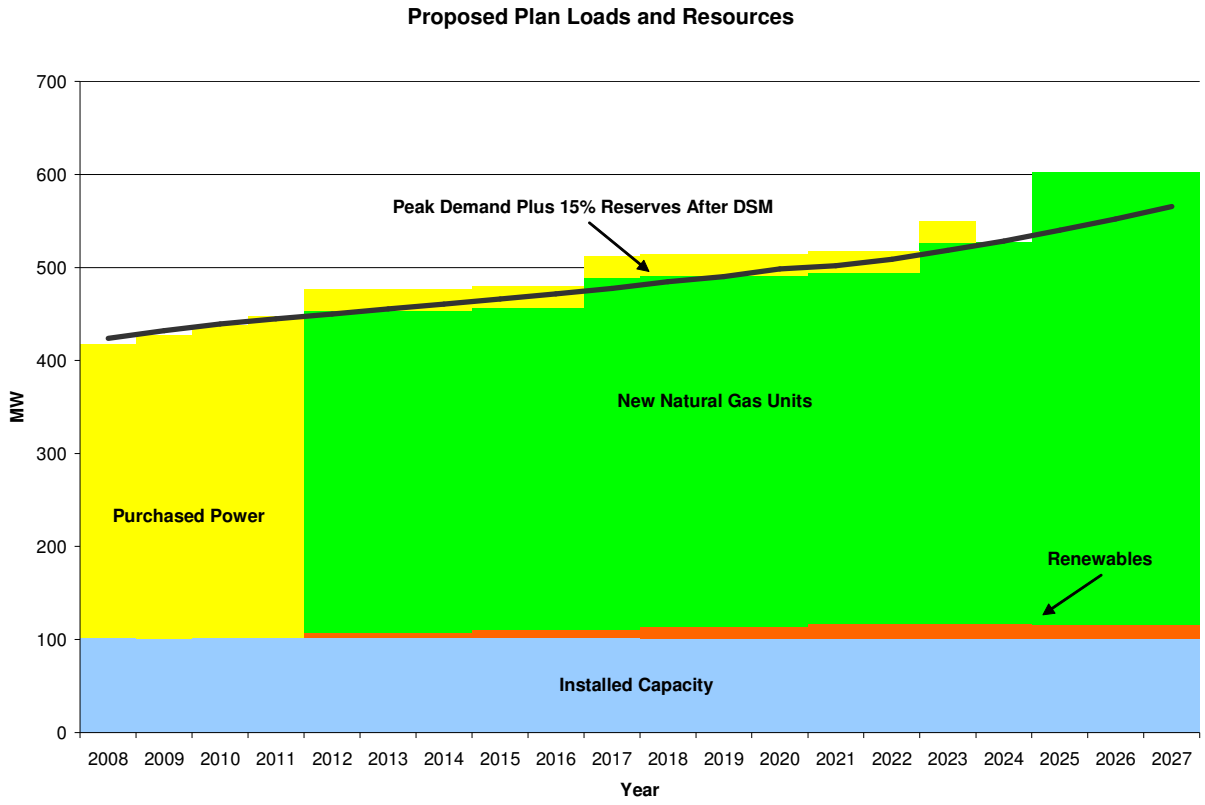


Energy



The manner in which the capacity deficit is filled and then needed resources are added over the planning period is demonstrated graphically in Figure 8.2.

Figure 8.2



The Proposed Plan relies on natural gas-fired combustion turbines to provide baseload in excess of the Company's existing coal-fired resources and to provide peaking resources. No other resource is available in the current regulatory climate to serve the Company's load. Additionally, natural gas-fired resources are required in order to be able to integrate renewable resources which are intermittent in nature (wind and solar) because natural gas-fired generation can be ramped up and down quickly. To the extent wind and solar resources are operating, the Company will be able to reduce its purchases of natural gas because natural gas-fired generation can be ramped down. This will result in savings in natural gas costs. This is illustrated in the energy pie chart that is part of Figure 8.1.

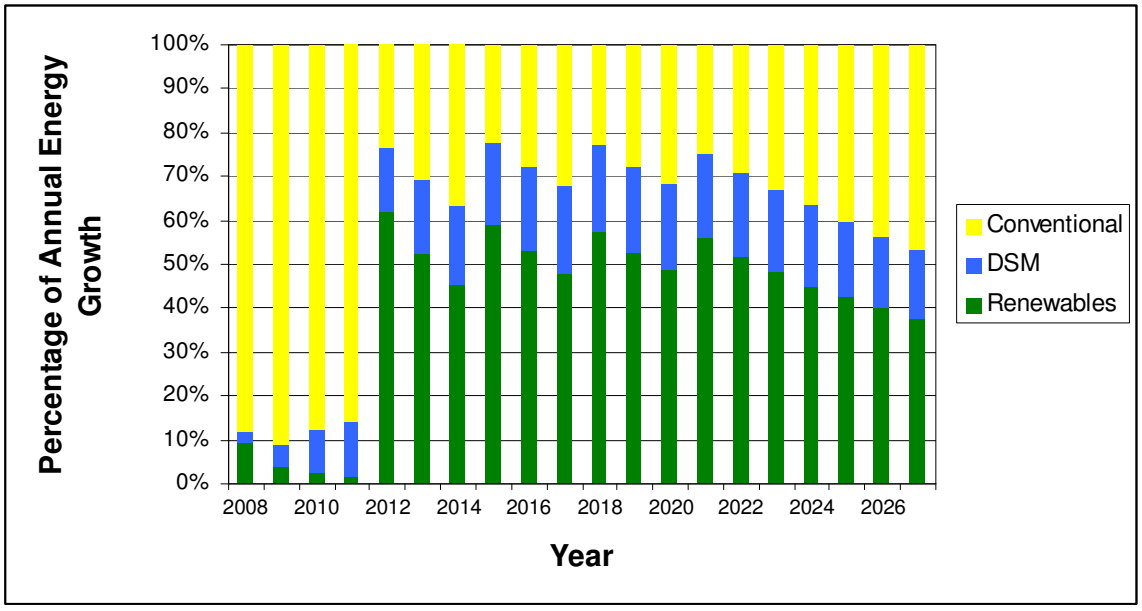
Additionally, because wind and solar are intermittent resources, the addition of these resources does **not** significantly reduce the amount of capacity that is required to serve the Company's load. For purposes of this Resource Plan, it was assumed that solar energy does not contribute to capacity needs at all and wind energy only contributes 10% of its rated capacity. For this reason, the addition of wind and solar resources, up to the statutory 2% retail rate impact cap, will be in addition to the Company's existing resources and the natural gas-fired generation required to meet the projected need. The addition of renewable resources will not reduce capacity costs; they will reduce energy costs.

The only types of resources that are available for selection to address the capacity deficit are natural gas-fired resources. However, a sensitivity analysis was performed with 50% higher natural gas prices to examine what the results of the Resource Plan would have been with higher natural gas prices. This analysis revealed that the price of natural gas does not affect the selection of resources needed to address the capacity deficit as of January 1, 2012; simple cycle natural gas-fired combustion turbines are still selected over natural gas-fired combined cycle plants. Advances in technology may make IGCC available in the future; a nuclear facility might be proposed in the future in which the Company could participate; and the current uncertainty surrounding permitting coal-fired generation and transmission access might be resolved. If so, these changes can be considered in the Company's next resource plan. However, for the current resource planning period, the Proposed Plan meets the forecasted need, including the capacity deficit, and complies with all existing regulatory requirements. Simple cycle units are selected over natural gas-fired combined cycle units. Due to the relatively small size of the Company's load, only smaller combined cycle units can be considered. The initial cost of a smaller sized combined cycle unit is significantly higher than for a simple cycle unit and the efficiency gains are not enough (in this size range) to compensate for this.

8.2.1 Resources to Meet Customer Growth

DSM and the use of renewable energy will meet the majority of the expected growth of customer energy consumption over the planning period as shown in Figure 8.3.

Figure 8.3
Resources Providing the Company's Energy Growth By 2020



The Resource Plan assumes that the Company will be successful in achieving the DSM goals established by the legislature. The modeling for the Resource Plan included the amount of renewable resources that need to be added to meet the RES.

9.0 Rule 3604(f) - Description of the Plan for Acquiring Needed Additional Resources

The Company has examined its need for resources during the resource acquisition period taking into consideration the significant capacity deficit that occurs as a result of the expiration of the PSCo PPA and the legal requirements and other considerations discussed in detail in Section 5.0 of this Plan.

The Resource Planning Rules provide that the utility shall meet the resource need identified in the plan through a competitive acquisition process.[28] The Commission may approve an alternative method of resource acquisition for a maximum of the lesser of 250 MW or 10% of the highest base case forecast peak requirement identified for the Resource Acquisition Period. In the Company's case, 10% would be equal to approximately 40 MW, which is not sufficient to address the capacity deficit. However, the Commission's Rules of Practice and Procedure also give it authority to grant a waiver of its rules[29] and the Company has filed a Petition for Waiver of Portions of the Resource Planning Rules that includes the rules pertaining to resource acquisition.

9.1 Plan to Acquire the Conventional Resources

The Company is facing a situation outside the typical resource plan. By January 1, 2012, the Company must successfully replace the approximately 75% of capacity, including associated energy, and majority of the reserve margin currently supplied by the PSCo PPA. The Company considered competitive bidding for purchased power for the replacement capacity but is not proposing this method because:

- Continued reliance on purchased power for the replacement capacity puts the customers at risk for a reoccurrence of the current capacity deficit problem and does not provide long-term security of resource supply.

- Equipment availability is tight and subject to constantly changing world demand. Costs of materials and labor are rising rapidly and will continue to rise while this Resource Plan is being reviewed.

- The size of the capacity deficit is so significant that it is not prudent to take any risks of project failure.

- The Company is in the best position to manage and assume the risk that the needed facilities are in service on time.

- Utility ownership of the capacity will provide operational benefits and security and will result in a more financially sound utility which benefits customers.

[28] Rule 3610(b).
[29] 4 CCR 723-1003.

Based upon these considerations, the Company's plan for acquiring the conventional resources is through competitive procurement of the major components and construction and ownership by the Company. The Company's application for approval of this Resource Plan includes a request that the Commission waive its competitive procurement rules to enable the Company to address the substantial capacity deficit by constructing the natural gas-fired units in the Proposed Plan.

9.1.1 Long-Term Security of Resource Supply

PPAs are contracts between an electric service provider (such as the Company) and wholesale electricity producers such as PSCo or independent power producers (IPP) (non-utility power producers). The pricing provisions under a PPA typically include a capacity charge (fixed component) and an energy charge (variable component). The Federal Energy Regulatory Commission (FERC) regulates the rates for some wholesalers, such as PSCo, but does not regulate the rates for IPPs. Alternatively, IPPs may obtain an exempt wholesale generator certificate from FERC and sell power at market-based rates.

Capacity is the amount of electric power committed to under a PPA in kW or MW. The capacity charge, characterized as a fixed cost, is assessed on the amount of capacity which a seller has committed to provide the purchaser and must be paid whether or not all of the capacity is actually used, although for IPPs, capacity payments may be subject to the achievement of specific levels of availability. The capacity charge enables the seller under a PPA to recoup some or all of its investment, including a return on that investment, whether or not its facility is dispatched or run.

The energy charge under a PPA is a payment that is made based upon the electric energy (kWh) consumed or billed. It generally includes escalators for O&M components such as labor and consumables. Fuel costs may also be a component of the energy charge and are subject to fuel cost adjustment provisions. Alternatively, the purchaser of the power may provide the fuel. In either circumstance, the purchaser assumes the price risk associated with the fuel. Unlike the capacity charge which is owed whether or not a facility is run, the energy charge is incurred only if and to the extent a facility is dispatched or run.

Typically, both capacity and energy charges escalate over the term of a PPA. PSCo recently completed a rate case at the FERC in which it raised its base rates (both capacity and energy) charged to six wholesale customers including the Company.[30] PSCo noted that its base rates have increased due to added purchased capacity costs and other costs. The increased energy charges will flow through the Company's fuel adjustment clause. Since the capacity charge under PSCo's PPA is in the Company's base rates, the Company will have to file a rate case in order to recoup the increased capacity charge under the PSCo PPA.

At the end of the term of a PPA, the seller has typically recouped all or part of its investment and earned a return from the capacity charges paid by the buyer under the PPA. At the end of the term of a PPA, the buyer has a capacity deficit and has to start over to acquire capacity to replace

[30] ER08-527-000-004

the capacity that had been purchased under the PPA. That is the situation facing the Company with the expiration of the PSCo PPA at the end of 2011.

Because many IPPs hold authorizations from the FERC to charge market-based rates, IPPs whose original PPAs have expired are free to charge market-based rates even though they have already recouped their entire investment and a return on that investment. Thus, in constrained markets, a buyer of purchased power cannot have any expectation of lower purchased power costs at the end of the term of a PPA.

In contrast, with utility-owned rate-based assets, the prudently incurred costs of property used by a utility to provide service are included in the utility's rate base. If the utility owns a generation asset (instead of entering into a PPA for the capacity and energy from a third-party's generation facility), the prudently incurred costs of the utility's generation asset are included in rate base. The utility is allowed an annual depreciation expense, with a depreciation rate that is fairly consistent over the useful life of the asset, and the opportunity to earn a specified rate of return on the undepreciated portion of its investment in the asset. The book value of the asset declines over time due to depreciation.

In order to compare a utility self-build proposal with a PPA, it is necessary to consider the net present value of the revenue requirement over the life of the asset. A utility's expenses are highest in the first year an asset is placed in service (because the asset is depreciating) and declines annually thereafter until the return earned on the investment is reduced to zero when the asset is fully depreciated. In contrast, capacity charges under PPAs often escalate over the term of the contract so that the lowest prices are at the beginning of the term. As previously stated, energy charges are typically subject to escalators and fuel is subject to fuel cost adjustments or has to be provided by the purchaser.

Continued reliance on purchased power puts customers at risk for a reoccurrence of the current capacity deficit problem every time contracts expire. Replacement of the capacity and energy from expired contracts or construction of new resources will be subject to market forces at the time contracts expire. This does not lead to security of resource supply and does not allow customers to benefit from utility rate-basing of assets. These problems are magnified for the Company by the size of the capacity deficit relative to the peak demand requirements of the Company.

Acquiring the replacement capacity through purchased power will continue to put customers at risk for ever-increasing costs. The capacity payments that are made for purchased power do not result in a depreciated asset base for customer rates. In contrast, utility ownership of generation assets for the replacement capacity results in a ratebased asset that depreciates over time. This translates into lower costs for customers over the long term.

9.1.2 Equipment Availability and Rising Costs of Materials and Labor

There are numerous risks associated with power plant construction including, but not limited to, equipment availability and increasing costs of material and labor. These concerns are discussed in Section 5.3.2 of this plan. The time required for a normal Phase 1 and Phase 2 process under

the Resource Planning Rules can total 500 days or more. In order for new natural gas-fired combustion turbines in the Proposed Plan to be in service by January 1, 2012, the major milestones shown in Table 9-1 will have to be met.

Table 9-1
Milestones for Plant Completion

Year	Milestone
2008	Site selection and equipment specifications
2008	File air permit application
2008	File CPCN application
Jan 2009	Upon approval of the resource plan: Payment of a nonrefundable deposit for the turbines to secure turbine production slots
Feb 2009	Obtain Certificate of Public Convenience and Necessity
2009	Obtain other permits (National Pollutant Discharge Elimination System (NPDES), etc.)
2009	Negotiate purchase and construction contracts
2010	Turbine and equipment fabrication
2010	Commence construction
12/1/2011	Commercial operation date

9.1.3 The Size of the Capacity Deficit is So Significant That It Is Not Prudent to Take Any Risks of Project Failure

The Commission has recently approved a CPCN for PSCo to construct two combustion turbines at the Fort St. Vrain Generating Station because of the termination of a PPA between PSCo and Squirrel Creek Energy resulting in a 383 MW capacity shortfall for the projected peak load in summer 2009. The termination of the PPA was the result of negotiations between PSCo and the parent company of Squirrel Creek Energy over PSCo's uncertainty regarding Squirrel Creek Energy's ability to adhere to the terms of the PPA and to meet its contract deadlines for providing capacity to meet the Company's 2009 system peak demand. The project had been selected as a result of competitive bidding in PSCo's 2005 All Source Solicitation.

The Squirrel Creek failed PPA represented approximately 4% of PSCo's 2009 summer peak.

In contrast, the Company's capacity deficit represents approximately 75% of the Company's capacity, including associated energy, and the majority of the Company's reserve margin. The Company's Proposed Plan provides for five new natural gas-fired facilities to be in service on or before January 1, 2012 and 60 MW of wind. **It is the Company's position that the size of the capacity deficit is too significant to place the risk of project failure in the hands of bidders who do not have the obligation to serve.**

9.1.4 The Company is in the Best Position to Manage and Assume the Risk that the Needed Facilities Are In Service On Time

Black Hills Corporation has a proven track record in constructing coal and natural gas-fired power plants and is in the best position to manage and assume the risk that the natural gas-fired facilities in the Proposed Plan are available in time to meet the capacity deficit. Subsidiaries of Black Hills Corporation have constructed the power plants shown in Table 9-2 on time and all within the budgets approved by the Board of Directors:

Table 9-2
Black Hills Corporation – Power Plants Constructed

Plant	State	Fuel Type	Total Capacity (MW)	Situation	Construction Method
Neil Simpson II – 1995 (BHP)	WY	Coal	80		Self-Performance with multiple fixed price contracts
Neil Simpson CT – 2000 (BHP)	WY	Gas	40		Self-Performance with multiple fixed price contracts
Harbor Expansion CC – 2000 (BHG)	CA	Gas	98		EPC
Valmont 7 CT-2000 (BHG)	CO	Gas	40	Acquired by BHC after a failed third-party PPA	
Gillette CT – 2001 (BHW)	WY	Gas	40		Self-Performance with multiple fixed price contracts
Valmont 8 CT– 2001 (BHG)	CO	Gas	40	Site expansion by BHC	EPC
Lange CT – 2002 (BHP)	SD	Gas	40		Self-Performance with multiple fixed price contracts
Arapahoe CC – 2000/2002 (BHG)	CO	Gas	130	Acquired as CTs by BHC after a failed third-party PPA; later expanded to CC by BHC	EPC/Self-Performance expansion
Las Vegas II CC – 2002 (BHG)	NV	Gas	224		EPC
Wygen I – 2003 (BHW)	WY	Coal	85		EPC
Wygen II – 2008 (CLF&P)	WY	Coal	90		Self-Performance with multiple fixed price contracts
Valencia CT – 2008 (BHG)	NM	Gas	149	Acquired by BHC after utility unable to get a CPCN	Self-Performance with multiple fixed price contracts
Wygen III – under construction (BHP)	WY	Coal	100		Self-Performance with multiple fixed price contracts

9.1.5 Operational Benefits and Security and the Financial Benefits of Utility-Owned Assets

Utility ownership of generation assets provides operational benefits and security that relate to outage management, dispatch, ramp rates, unit commitments, and capital additions for increased efficiency and life extension and to comply with new regulation. When a utility owns a generating unit, that utility has the ability to maximize the availability of the unit subject to various economic considerations and taking into account the outages and availability of the other units on its system. A utility can directly control the ramping up and down of utility-owned assets in a manner that is most cost effective for the customers. A utility-owned asset can be examined within the context of the entire utility system to determine if its unit commitment or dispatch needs to be handled differently in order to optimize the operation of the entire system. Utility ownership can result in capital additions to increase unit efficiency or additional maintenance to improve a unit's performance as these investments are vetted through the regulatory process and borne by the customers providing the utility can demonstrate that the benefits exceed the costs.

Generation assets are going to earn a return for someone. If an IPP owns the assets, the return is earned by a party that does not have an obligation to serve and that is not in need of cash flow to reinvest back into the utility. Since IPPs may charge market-based rates, the only limit on the size of that return is the market for purchased power. In the current environment of rising need for power from natural gas-fired facilities, the returns on IPP assets may far exceed utility authorized returns. If the utility owns the assets, the Commission sets the authorized rate of return and the utility has an opportunity to earn that return and thereby generate new funds for investment, thus allowing better debt management.

Finally, to the extent FASB lease accounting guidance requires utilities to recognize long-term fixed obligations under PPAs and other contracts as on-balance-sheet liabilities, this will require significantly greater equity contributions to counterbalance the "debt." This increases costs to customers and dilutes earnings.

9.2 Plan to Acquire the Renewable Resources

The Company also believes it is in the best interest of customers that it own renewable resources. However, with the Company's primary focus on addressing the capacity deficit, the Company believes that it should leverage the market to build and supply the renewable resources. The impact of failed wind projects will not be significant because 60 MW of wind energy translates into only 6 MW of capacity. Therefore, the Company proposes to acquire these resources through competitive bidding. However, HB07-1281 encourages utility rate-based ownership of new renewable resources (up to 50%) and the Company proposes, in the Renewable RFP, to require all bidders to give the Company the option to acquire part or all of their facilities for utility ownership.

10.0 Rule 3605(g) - Projected Emissions for New Utility Resources

10.1 Proposed Plan Projected Emissions

The projected emissions for the new utility resources expected to be acquired during the planning period for each of sulfur dioxide, nitrogen oxides, particulate matter, mercury and CO_2 are shown in Table 10-1.

Table 10-1
Projected Emissions for New Utility Resources

Type of emission	LMS 100	LM 6000	7EA
Size of Unit (MW)	86	40	68
SO_2 – lb/MWh	0.01	0.01	0.01
SO_2 – tons/year	<1	<1	<1
NO_x – lb/MWh	0.07	0.07	0.10-0.25
NO_x – tons/year	1-15	0.5-1.5	0.3-1.1
PM – lb/MWh	0.07	0.02	0.17
PM – tons/year	0.5-15	1.4-4.0	0.7-2.6
Hg – lb/MWh	0	0	0
Hg – tons/year	0	0	0
CO_2 – lb/MWh	1035	1159	1582
CO_2 – tons/year	8,000-220,000	7,000-22,000	4,500-17,500

The new utility resources actually acquired during the planning period could change as a result of other options that become available during the planning period. Because the Company's proposed plan replaces the coal-fired resources under the PSCo PPA with natural gas-fired resources, it meets the Colorado Climate Action Plan goal of reducing greenhouse gas emissions by 20% from 2005 levels by the year 2020. The Company's calculation of its 2005 carbon footprint is set forth in Appendix D.

11.0 Rule 3604(h) – Proposed RFPs including Model Contracts

Rule 3604(h) requires a plan to include the proposed RFP(s) the utility intends to use to solicit bids for the resources to be acquired through a competitive acquisition process, including model contracts, pursuant to rule 3612. Because the Company does not intend to solicit bids for conventional resources, an RFP for conventional resources has not been developed. Because the Company expects to procure renewable resources in 30 MW blocks or less, no renewable RFP or model contract are included with this plan.

12.0 Rule 3604(i) - Consistency of Current Rate Design With Plan Contents

The current rate design is consistent with plan contents. The Company is not proposing during the resource acquisition period any interruptible service, non tariff wind provisions, or other rate designs. During the resource acquisition period, the Company will be filing an Electric DSM Proposal under §40-3.2-104, C.R.S.

13.0 Rule 3604(j) - Section 123 Resources

The Company is not presenting in this Resource Plan a medium or high Section 123 resources scenario and has requested a waiver of the requirement to do so. The focus of the Proposed Plan must be to acquire the resources necessary to address the 2012 capacity deficit while meeting the RES requirements and the DSM mandates. Additional Section 123 resources will not impact the need for the five combustion turbines identified in this Resource Plan because they will not provide sufficient capacity to meet the capacity deficit.

Furthermore, the Company does not currently own appropriate resources to backup wind and has, instead, been purchasing non-solar renewable energy credits. Therefore, the Company has no experience with integrating wind. Black Hills will get its first experience with wind integration when the Happy Jack wind farm becomes commercial in September 2008.[31] The modeling for this Resource Plan showed that 60 MW of wind could be acquired during the resource acquisition period without exceeding the retail rate impact cap. The Company does not believe it would be prudent for it to propose additional renewable resources in this Resource Plan until it has acquired some experience with wind integration.

Therefore, the Company did not evaluate additional Section 123 resources as part of this Resource Plan but will be addressing them in its 2011 Resource Plan as a means to provide additional energy and offset the consumption of natural gas.

[31] Cheyenne Light, Fuel and Power has a PPA for 30 MW of wind from Happy Jack.

List of Abbreviations

ADT – Average Daily Temperature
ARPA – Arkansas River Power Authority
ASU – Air Separation Unit
BHG – Black Hills Generation
BHP – Black Hills Power
BHW – Black Hills - Wyoming
Btu – British Thermal Unit
CAGR – Compound Annual Growth Rate
CC – Combined Cycle
CCPG – Colorado Coordinated Planning Group
CDD – Cooling Degree Days
CLF&P – Cheyenne Light, Fuel & Power
CO – Carbon Monoxide
CO_2 – Carbon Dioxide
CPCN – Certificate of Public Convenience and Necessity
CPUC – Colorado Public Utilities Commission
CT – Combustion Turbine
DOE – U.S. Department of Energy
DSM – Demand-Side Management
ERP – Electric Resource Plan
FERC – Federal Energy Regulatory Commission
GDP – Gross Domestic Product
GED – Global Energy Decisions
GHG – Greenhouse Gases
GWh – Gigawatthour
HDD – Heating Degree Days
Hg – Mercury
HH – Households
HHV – Higher Heating Value
HRSG – Heat Recovery Steam Generator
IGCC – Integrated Gasification Combined Cycle
IPP – Independent Power Producer
kW – Kilowatt
kWh – Kilowatthour
LCP – Least Cost Plan
LNG – Liquefied Natural Gas
MMBtu – Millions of Btus
MPS – Missouri Public Service
MW - Megawatt
MWh – Megawatthour
NO_x – Nitrogen Oxides
NPDES – National Pollutant Discharge Elimination System
O&M – Operating and Maintenance
PPA – Power Purchase Agreement

PRB – Powder River Basin
PSCo – Public Service Company of Colorado
PSD – Prevention of Significant Deterioration
PUB – Pueblo, Colorado airport
PV - Photovoltaics
PVRR – Present Value of Revenue Requirements
RAP – Resource Acquisition Period
REC – Renewable Energy Credit
RES – Renewable Energy Standard
RFP – Request for Proposals
RMRG – Rocky Mountain Reserve Group
SAE – Statistically-adjusted end-use
SO_2 – Sulfur Dioxide
TBtu – Trillions of Btus
Tri-State – Tri-State Generation and Transmission Association
WECC – Western Electricity Coordinating Council
WPK – Aquila's Kansas operating utility (West Plains – Kansas)

Appendix A – Load Forecast Information and Class Load Profiles

Table A-1
Peak Demand and Annual Energy Forecast – Base Case

Year	RES (GWh)	COM (GWh)	IND (GWh)	WHO (GWh)	OTH (GWh)	Total Sales (GWh)	Sales Growth (GWh)	T&D Losses (GWh)	Total Energy (GWh)	T&D Losses	Summer Peak (MW)	Winter Peak (MW)	Annual Load Factor
1996	466.7	487.7	330.4	2.7	64.9	1352.4		100.5	1452.9	6.9%	247.0	242.0	67.0%
1997	468.6	520.6	355.1	0.4	77.6	1422.3	69.9	117.1	1539.4	7.6%	263.0	236.0	66.8%
1998	481.0	552.7	383.9	0.5	63.8	1481.8	59.5	112.8	1594.6	7.1%	272.0	260.0	66.9%
1999	484.1	561.7	406.4	0.6	65.6	1518.4	36.6	109.9	1628.3	6.7%	280.0	257.0	66.4%
2000	507.4	587.4	417.2	0.5	71.9	1584.3	65.9	130.6	1714.9	7.6%	292.0	268.0	66.9%
2001	517.0	587.2	372.3	0.5	80.9	1557.8	-26.5	105.0	1662.8	6.3%	297.0	258.0	63.9%
2002	542.9	604.3	410.1	0.1	85.8	1643.1	85.4	113.7	1756.9	6.5%	319.0	278.0	62.9%
2003	545.9	610.8	505.5	0.2	66.7	1729.1	85.9	100.6	1829.7	5.5%	345.0	274.0	60.5%
2004	535.2	623.6	512.1	0.1	63.8	1734.9	5.8	152.3	1887.1	8.1%	347.0	289.0	61.9%
2005	569.4	636.3	539.2	0.1	46.7	1791.6	56.8	122.9	1914.6	6.4%	366.0	297.0	59.7%
2006	572.0	665.9	544.4	0.6	41.8	1824.8	33.1	114.1	1938.9	5.9%	357.0	297.0	62.0%
2007	593.7	686.4	532.5	0.4	40.0	1853.1	28.3	106.6	1959.6	5.4%	372.0	316.0	60.1%
2008	598.9	701.4	541.0	0.4	39.9	1881.7	28.6	122.7	2004.3	6.1%	369.0	325.0	61.8%
2009	612.2	722.6	565.6	0.4	40.1	1940.9	59.2	126.5	2067.4	6.1%	378.0	334.0	62.4%
2010	625.7	744.5	583.3	0.4	40.3	1994.2	53.4	130.0	2124.2	6.1%	388.0	341.0	62.5%
2011	656.9	758.0	608.2	0.4	41.8	2065.2	71.0	134.6	2199.9	6.1%	397.0	350.0	63.3%
2012	672.5	780.4	622.0	0.4	41.6	2117.0	51.8	138.0	2255.0	6.1%	406.0	359.0	63.2%
2013	687.0	798.8	638.0	0.4	41.6	2165.8	48.8	141.2	2307.0	6.1%	415.0	368.0	63.5%
2014	702.5	819.8	652.8	0.4	41.6	2217.1	51.3	144.5	2361.7	6.1%	424.0	376.0	63.6%
2015	718.6	839.9	667.4	0.4	41.6	2267.9	50.8	147.8	2415.8	6.1%	433.0	385.0	63.7%
2016	736.1	862.8	681.8	0.4	41.6	2322.7	54.8	151.4	2474.1	6.1%	442.0	394.0	63.7%
2017	752.4	881.9	697.6	0.4	41.6	2374.0	51.3	154.8	2528.8	6.1%	452.0	403.0	63.9%
2018	770.0	904.1	712.3	0.4	41.6	2428.5	54.4	158.3	2586.8	6.1%	461.0	412.0	64.1%
2019	788.1	926.8	726.3	0.4	41.6	2483.2	54.8	161.9	2645.1	6.1%	471.0	421.0	64.1%
2020	807.7	952.2	740.3	0.4	41.6	2542.3	59.0	165.7	2708.0	6.1%	481.0	430.0	64.1%
2021	827.1	974.2	754.9	0.4	41.6	2598.2	55.9	169.4	2767.6	6.1%	491.0	440.0	64.3%
2022	846.8	997.2	772.0	0.4	41.6	2658.1	59.9	173.3	2831.4	6.1%	501.0	450.0	64.5%
2023	867.4	1021.0	789.4	0.4	41.6	2719.8	61.7	177.3	2897.1	6.1%	512.0	460.0	64.6%
2024	888.6	1044.9	804.9	0.4	41.6	2780.5	60.6	181.3	2961.7	6.1%	522.0	470.0	64.6%
2025	910.5	1069.5	821.3	0.4	41.6	2843.3	62.8	185.3	3028.7	6.1%	533.0	480.0	64.9%
2026	932.9	1094.6	837.2	0.4	41.6	2906.8	63.4	189.5	3096.2	6.1%	544.0	491.0	65.0%
2027	955.8	1120.2	853.1	0.4	41.6	2971.2	64.4	193.7	3164.9	6.1%	556.0	502.0	65.0%
2028	979.4	1146.3	869.2	0.4	41.6	3036.9	65.7	198.0	3234.9	6.1%	567.0	513.0	65.0%
2029	1003.6	1173.2	885.5	0.4	41.6	3104.3	67.4	202.4	3306.7	6.1%	579.0	524.0	65.2%
2030	1028.4	1200.8	902.9	0.4	41.6	3174.2	69.8	206.9	3381.1	6.1%	591.0	535.0	65.3%
Growth:													
1996-2006	2.1%	3.2%	5.1%	-13.9%	-4.3%	3.0%		6.8%	2.9%	6.8%	3.8%	2.1%	-0.8%
2007-2010	1.8%	2.7%	3.1%	0.0%	0.3%	2.5%		5.9%	2.7%	5.9%	1.4%	2.6%	1.3%
2008-2030	2.5%	2.5%	2.4%	0.0%	0.2%	2.4%		2.4%	2.4%	0.0%	2.2%	2.3%	0.2%

** Actual 1996-2007, Forecast 2008-2030*

Table A-2
Peak Demand and Annual Energy Forecast – Low Case

Year	RES (GWh)	COM (GWh)	IND (GWh)	WHO (GWh)	OTH (GWh)	Total Sales (GWh)	Sales Growth (GWh)	T&D Losses (GWh)	Total Energy (GWh)	T&D Losses	Summer Peak (MW)	Winter Peak (MW)	Annual Load Factor
1996	466.7	487.7	330.4	2.7	64.9	1352.4		100.5	1452.9	6.9%	247.0	242.0	67.0%
1997	468.6	520.6	355.1	0.4	77.6	1422.3	69.9	117.1	1539.4	7.6%	263.0	236.0	66.6%
1998	481.0	552.7	383.9	0.5	63.8	1481.8	59.5	112.8	1594.6	7.1%	272.0	260.0	66.9%
1999	484.1	561.7	406.4	0.6	65.6	1518.4	36.6	109.9	1628.3	6.7%	280.0	257.0	66.2%
2000	507.4	587.4	417.2	0.5	71.9	1584.3	65.9	130.6	1714.9	7.6%	292.0	268.0	66.9%
2001	517.0	587.2	372.3	0.5	80.9	1557.8	-26.5	105.0	1662.8	6.3%	297.0	258.0	63.7%
2002	542.9	604.3	410.1	0.1	85.8	1643.1	85.4	113.7	1756.9	6.5%	319.0	278.0	62.9%
2003	545.9	610.8	505.5	0.2	66.7	1729.1	85.9	100.6	1829.7	5.5%	345.0	274.0	60.4%
2004	535.2	623.6	512.1	0.1	63.8	1734.9	5.8	152.3	1887.1	8.1%	347.0	289.0	61.9%
2005	569.4	636.3	539.2	0.1	46.7	1791.6	56.8	122.9	1914.6	6.4%	366.0	297.0	59.6%
2006	572.0	665.9	544.4	0.6	41.8	1824.8	33.1	114.1	1938.9	5.9%	357.0	297.0	62.0%
2007	593.7	686.4	532.5	0.4	40.0	1853.1	28.3	106.6	1959.6	5.4%	372.0	316.0	60.0%
2008	602.8	696.1	524.6	0.4	39.9	1863.8	10.8	121.5	1985.3	6.1%	367.0	320.0	61.6%
2009	612.1	707.6	524.5	0.4	40.1	1884.7	20.9	122.9	2007.6	6.1%	372.0	325.0	61.4%
2010	621.3	718.7	528.3	0.4	40.3	1909.0	24.3	124.4	2033.4	6.1%	377.0	330.0	61.6%
2011	630.8	730.2	532.7	0.4	43.3	1937.4	28.4	126.3	2063.7	6.1%	383.0	335.0	61.3%
2012	641.0	743.0	536.8	0.4	43.2	1964.4	27.0	128.1	2092.5	6.1%	388.0	340.0	61.4%
2013	650.3	752.6	540.0	0.4	43.2	1986.5	22.0	129.5	2115.9	6.1%	393.0	345.0	61.3%
2014	660.1	763.2	542.1	0.4	43.2	2008.9	22.5	131.0	2139.9	6.1%	398.0	349.0	61.4%
2015	670.4	772.8	543.9	0.4	43.2	2030.7	21.8	132.4	2163.1	6.1%	403.0	354.0	61.1%
2016	681.5	783.8	545.3	0.4	43.2	2054.2	23.5	133.9	2188.1	6.1%	407.0	359.0	61.2%
2017	691.7	793.0	548.0	0.4	43.2	2076.3	22.1	135.4	2211.7	6.1%	413.0	364.0	61.0%
2018	702.7	803.5	549.9	0.4	43.2	2099.6	23.3	136.9	2236.5	6.1%	418.0	369.0	61.1%
2019	714.0	813.8	551.1	0.4	43.2	2122.4	22.8	138.4	2260.7	6.1%	423.0	374.0	60.8%
2020	726.1	825.5	552.4	0.4	43.2	2147.6	25.2	140.0	2287.6	6.1%	428.0	379.0	60.8%
2021	737.9	835.2	554.2	0.4	43.2	2170.9	23.3	141.5	2312.4	6.1%	433.0	384.0	60.8%
2022	749.9	846.6	557.8	0.4	43.2	2197.9	27.0	143.3	2341.2	6.1%	439.0	389.0	60.9%
2023	762.3	858.3	561.4	0.4	43.2	2225.5	27.7	145.1	2370.6	6.1%	445.0	395.0	60.6%
2024	775.0	868.7	563.4	0.4	43.2	2250.7	25.1	146.7	2397.4	6.1%	450.0	400.0	60.7%
2025	788.0	879.7	565.7	0.4	43.2	2277.0	26.3	148.4	2425.4	6.1%	456.0	405.0	60.6%
2026	801.1	890.5	567.6	0.4	43.2	2302.8	25.9	150.1	2453.0	6.1%	462.0	411.0	60.6%
2027	814.5	901.3	569.4	0.4	43.2	2328.8	25.9	151.8	2480.6	6.1%	467.0	416.0	60.5%
2028	828.1	912.2	571.1	0.4	43.2	2355.0	26.2	153.5	2508.5	6.1%	473.0	422.0	60.4%
2029	842.0	923.2	572.8	0.4	43.2	2381.6	26.7	155.3	2536.9	6.1%	479.0	427.0	60.3%
2030	856.1	934.9	575.1	0.4	43.2	2409.7	28.1	157.1	2566.8	6.1%	485.0	433.0	60.4%
Growth:													
1996-2006	2.1%	3.2%	5.1%	-13.9%	-4.3%	3.0%		6.8%	2.9%	6.8%	3.8%	2.1%	-0.8%
2007-2010	1.5%	1.5%	-0.3%	0.0%	0.3%	1.0%		5.9%	1.2%	5.9%	0.4%	1.5%	0.9%
2008-2030	1.6%	1.3%	0.4%	0.0%	0.4%	1.2%		1.2%	1.2%	0.0%	1.3%	1.4%	-0.1%

** Actual 1996-2007, Forecast 2008-2030*

Table A-3
Peak Demand and Annual Energy Forecast – High Case

Year	RES (GWh)	COM (GWh)	IND (GWh)	WHO (GWh)	OTH (GWh)	Total Sales (GWh)	Sales Growth (GWh)	T&D Losses (GWh)	Total Energy (GWh)	T&D Losses	Summer Peak (MW)	Winter Peak (MW)	Annual Load Factor
1996	466.7	487.7	330.4	2.7	64.9	1352.4		100.5	1452.9	6.9%	247.0	242.0	67.0%
1997	468.6	520.6	355.1	0.4	77.6	1422.3	69.9	117.1	1539.4	7.6%	263.0	236.0	66.8%
1998	481.0	552.7	383.9	0.5	63.8	1481.8	59.5	112.8	1594.6	7.1%	272.0	260.0	66.9%
1999	484.1	561.7	406.4	0.6	65.6	1518.4	36.6	109.9	1628.3	6.7%	280.0	257.0	66.4%
2000	507.4	587.4	417.2	0.5	71.9	1584.3	65.9	130.6	1714.9	7.6%	292.0	268.0	66.9%
2001	517.0	587.2	372.3	0.5	80.9	1557.8	-26.5	105.0	1662.8	6.3%	297.0	258.0	63.9%
2002	542.9	604.3	410.1	0.1	85.8	1643.1	85.4	113.7	1756.9	6.5%	319.0	278.0	62.9%
2003	545.9	610.8	505.5	0.2	66.7	1729.1	85.9	100.6	1829.7	5.5%	345.0	274.0	60.5%
2004	535.2	623.6	512.1	0.1	63.8	1734.9	5.8	152.3	1887.1	8.1%	347.0	289.0	61.9%
2005	569.4	636.3	539.2	0.1	46.7	1791.6	56.8	122.9	1914.6	6.4%	366.0	297.0	59.7%
2006	572.0	665.9	544.4	0.6	41.8	1824.8	33.1	114.1	1938.9	5.9%	357.0	297.0	62.0%
2007	593.7	686.4	532.5	0.4	40.0	1853.1	28.3	106.6	1959.6	5.4%	372.0	316.0	60.1%
2008	613.5	717.6	580.5	0.4	39.9	1951.8	98.8	127.2	2079.1	6.1%	373.0	328.0	63.5%
2009	629.3	746.5	606.1	0.4	40.1	2022.4	70.5	131.8	2154.2	6.1%	385.0	340.0	63.9%
2010	644.9	776.7	634.1	0.4	40.3	2096.5	74.1	136.7	2233.1	6.1%	397.0	351.0	64.2%
2011	661.3	808.5	663.5	0.4	43.3	2176.9	80.4	141.9	2318.8	6.1%	410.0	363.0	64.6%
2012	678.5	843.6	693.1	0.4	43.2	2258.8	81.9	147.2	2406.0	6.1%	422.0	375.0	64.9%
2013	695.0	873.4	722.1	0.4	43.2	2334.0	75.2	152.1	2486.1	6.1%	435.0	388.0	65.2%
2014	712.4	907.2	750.6	0.4	43.2	2413.8	79.8	157.3	2571.1	6.1%	448.0	400.0	65.5%
2015	730.5	940.0	779.5	0.4	43.2	2493.5	79.8	162.5	2656.1	6.1%	461.0	413.0	65.8%
2016	750.0	977.2	809.2	0.4	43.2	2580.0	86.5	168.2	2748.2	6.1%	474.0	425.0	66.0%
2017	768.7	1009.6	841.1	0.4	43.2	2663.0	82.9	173.6	2836.5	6.1%	489.0	439.0	66.2%
2018	788.6	1046.6	872.4	0.4	43.2	2751.1	88.2	179.3	2930.5	6.1%	503.0	453.0	66.5%
2019	809.2	1084.6	903.4	0.4	43.2	2840.8	89.6	185.2	3026.0	6.1%	517.0	466.0	66.8%
2020	831.3	1127.0	935.1	0.4	43.2	2937.0	96.2	191.5	3128.5	6.1%	532.0	481.0	66.9%
2021	853.3	1164.7	968.0	0.4	43.2	3029.6	92.6	197.5	3227.1	6.1%	547.0	495.0	67.3%
2022	875.9	1204.8	1004.6	0.4	43.2	3128.8	99.2	204.0	3332.8	6.1%	563.0	510.0	67.6%
2023	899.4	1246.5	1042.5	0.4	43.2	3231.9	103.1	210.7	3442.6	6.1%	579.0	526.0	67.9%
2024	923.7	1288.6	1079.2	0.4	43.2	3335.1	103.1	217.4	3552.5	6.1%	596.0	542.0	67.9%
2025	948.8	1332.6	1117.9	0.4	43.2	3442.9	107.8	224.4	3667.3	6.1%	613.0	558.0	68.3%
2026	974.7	1377.7	1157.2	0.4	43.2	3553.2	110.3	231.6	3784.8	6.1%	631.0	575.0	68.5%
2027	1001.3	1424.2	1197.4	0.4	43.2	3666.4	113.2	239.0	3905.4	6.1%	649.0	592.0	68.7%
2028	1028.7	1472.2	1238.7	0.4	43.2	3783.2	116.8	246.6	4029.8	6.1%	667.0	609.0	68.8%
2029	1057.0	1521.9	1281.6	0.4	43.2	3904.1	120.9	254.5	4158.6	6.1%	686.0	627.0	69.2%
2030	1086.1	1573.8	1327.0	0.4	43.2	4030.4	126.3	262.7	4293.2	6.1%	706.0	646.0	69.4%
Growth:													
1996-2006	2.1%	3.2%	5.1%	-13.9%	-4.3%	3.0%		6.8%	2.9%	6.8%	3.8%	2.1%	-0.8%
2007-2010	2.8%	4.2%	6.0%	0.0%	0.3%	4.2%		5.9%	4.5%	5.9%	2.2%	3.6%	2.2%
2008-2030	2.6%	3.6%	3.8%	0.0%	0.4%	3.4%		3.4%	3.4%	0.0%	2.9%	3.1%	0.4%

** Actual 1996-2007, Forecast 2008-2030*

Figure A.1
Summer Peak Day Class Load Profile – July 2006

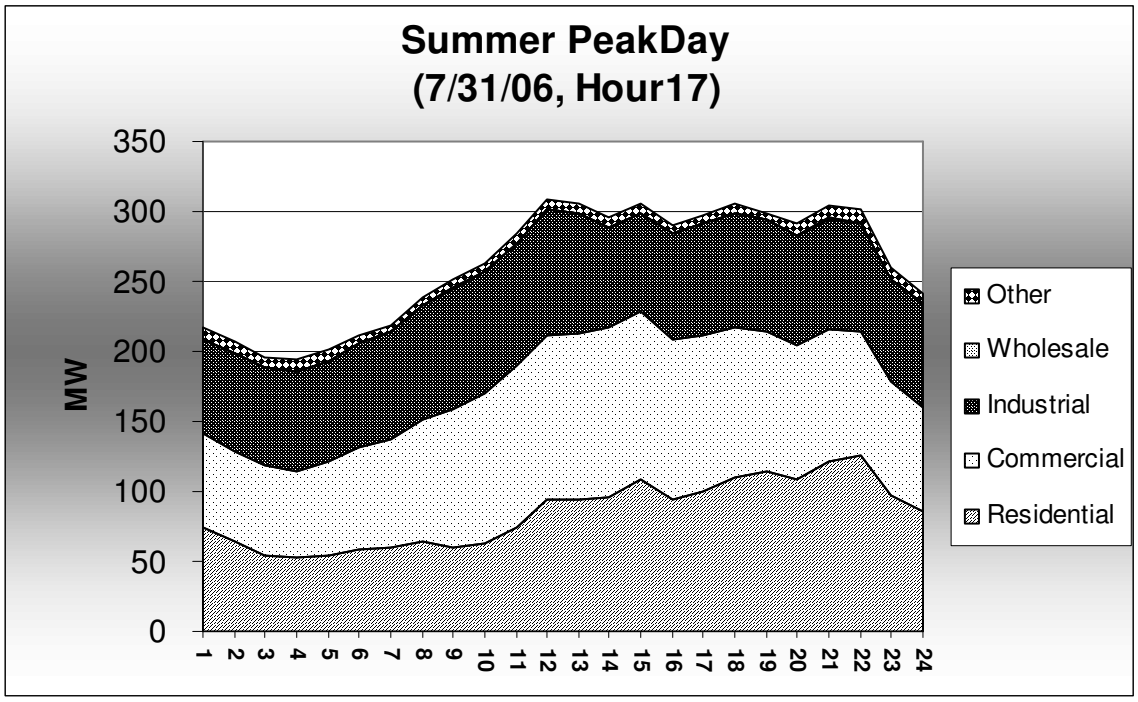


Table A-4
Typical Daily Class Hourly Load Profiles (MW) – July 2006

Typical Daily Class Hourly Load Research Profiles (MW) **JULY 2006**
WestPlains Energy-Colorado

AVERAGE WEEKDAY			Hour																							
YearMoDT	Days		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	DayMWh	PeakMW
200607WD	21	RES	62	54	51	49	49	51	56	58	57	63	71	81	84	90	92	93	96	101	101	99	99	96	88	73	1,813	101
200607WD	21	COM	66	64	62	60	62	68	74	83	94	102	108	111	113	114	114	111	106	101	94	89	86	81	75	70	2,108	114
200607WD	21	IND	65	64	64	64	65	66	68	70	72	73	74	75	74	73	71	70	70	70	70	69	71	69	66	65	1,659	75
200607WD	21	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.31	0.02
200607WD	21	OTH	8	8	8	7	7	4	5	5	6	6	6	6	6	6	6	6	6	5	5	7	9	8	8	8	156	9
200607WD	**21**	**System**	**209**	**200**	**194**	**192**	**192**	**200**	**208**	**227**	**247**	**266**	**282**	**294**	**303**	**310**	**314**	**316**	**317**	**311**	**299**	**288**	**286**	**273**	**249**	**227**	**6,206**	**317**
AVERAGE WEEKEND			Hour																							
YearMoDT	Days		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	DayMWh	PeakMW
200607WE	10	RES	66	57	53	50	49	49	53	55	62	69	78	88	94	94	102	103	100	100	102	100	103	102	93	79	1,900	103
200607WE	10	COM	67	64	62	60	61	62	63	67	73	78	82	85	87	87	88	88	87	85	81	78	78	76	71	67	1,794	88
200607WE	10	IND	64	64	63	63	64	64	64	65	67	68	70	71	72	71	71	71	70	71	70	69	68	65	65	64	1,611	72
200607WE	10	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.33	0.02
200607WE	10	OTH	8	8	8	8	7	4	4	4	4	4	5	5	5	5	5	5	5	5	5	7	8	8	8	8	140	8
200607WE	**10**	**System**	**213**	**203**	**195**	**193**	**190**	**191**	**192**	**203**	**223**	**241**	**259**	**274**	**287**	**292**	**299**	**302**	**301**	**297**	**289**	**280**	**278**	**271**	**248**	**226**	**5,943**	**302**
SYSTEM PEAKDAY			Hour																							
Mo/Da/Year	DW		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	DayMWh	PeakMW
7/31/2006	2	RES	74	64	55	53	55	59	60	65	60	63	75	94	94	96	109	94	100	110	114	109	121	126	97	86	2,033	126
7/31/2006	2	COM	67	65	64	62	66	72	77	87	99	107	115	118	119	121	119	115	112	107	100	96	95	89	81	74	2,227	121
7/31/2006	2	IND	68	70	69	71	72	75	77	81	86	87	87	89	85	72	71	75	79	82	80	78	79	77	74	74	1,858	89
7/31/2006	2	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.38	0.02
7/31/2006	2	OTH	8	8	8	8	8	5	5	6	6	6	7	7	7	7	7	6	6	6	5	9	9	9	8	8	169	9
7/31/2006	**2**	**System**	**231**	**221**	**212**	**212**	**207**	**221**	**230**	**252**	**280**	**304**	**323**	**339**	**345**	**339**	**340**	**351**	**357**	**351**	**335**	**322**	**320**	**301**	**270**	**243**	**6,906**	**357**

Figure A.2
Winter Peak Day Class Load Profile – December 2006

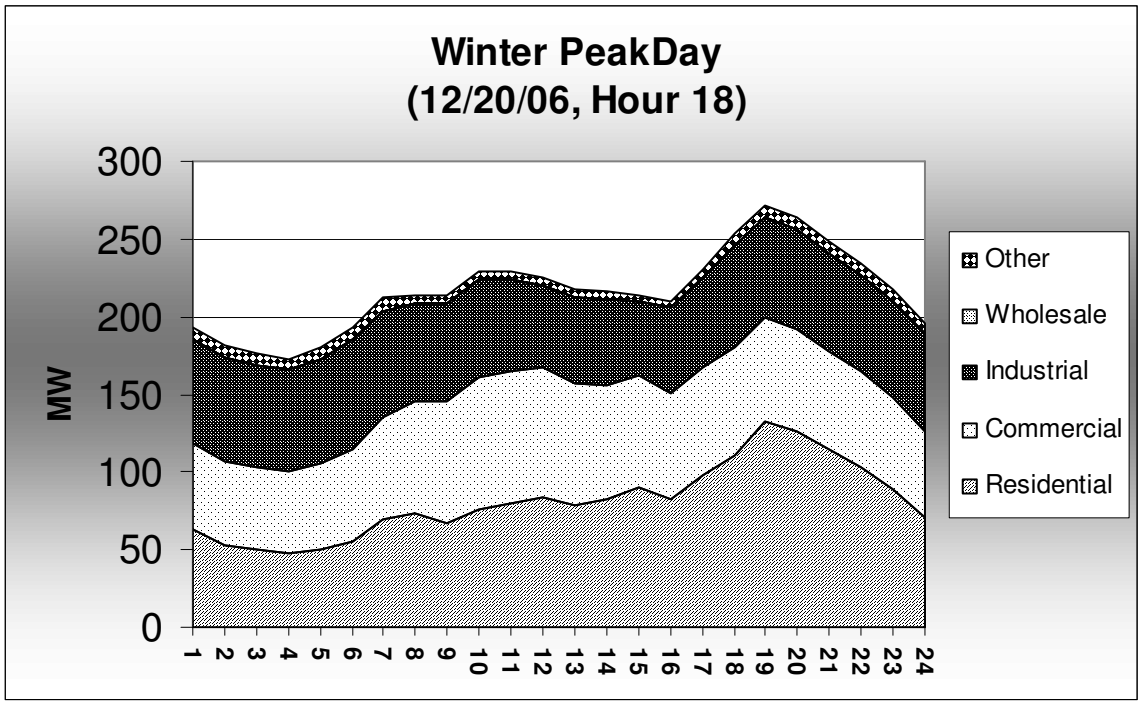


Table A-5
Typical Daily Class Hourly Load Profiles (MW) – December 2006

Typical Daily Class Hourly Load Research Profiles (MW) **DECEMBER 2006**
WestPlains Energy-Colorado

AVERAGE WEEKDAY			Hour																							
YearMoDT	Days		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	DayMWh	PeakMW
200612WD	21	RES	66	60	55	53	55	59	68	73	71	70	71	72	68	69	65	63	68	90	99	101	98	93	85	74	1,745	101
200612WD	21	COM	54	54	53	53	55	58	65	71	77	82	84	84	83	82	81	79	77	76	73	71	69	66	61	57	1,663	84
200612WD	21	IND	61	60	60	60	61	61	62	61	63	63	63	62	63	63	63	63	62	64	63	62	63	63	62	61	1,487	64
200612WD	21	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.27	0.01
200612WD	21	OTH	7	7	7	7	7	8	8	5	5	5	5	5	5	5	5	5	6	8	8	8	8	8	7	7	152	8
200612WD	**21**	**System**	**199**	**194**	**191**	**190**	**196**	**207**	**225**	**233**	**238**	**241**	**240**	**238**	**235**	**231**	**230**	**231**	**244**	**272**	**273**	**267**	**263**	**250**	**228**	**210**	**5,523**	**273**
AVERAGE WEEKEND			**Hour**																									
YearMoDT	**Days**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
200612WE	10	RES	66	62	57	56	58	59	62	70	73	78	81	81	82	79	74	74	74	90	104	103	106	101	91	81	1,863	106
200612WE	10	COM	54	53	53	53	53	54	57	57	59	61	64	64	64	63	63	62	64	66	65	63	62	60	57	54	1,424	66
200612WE	10	IND	61	62	62	61	62	62	62	60	61	62	62	61	61	62	61	61	62	64	63	61	62	63	62	61	1,480	64
200612WE	10	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.25	0.01
200612WE	10	OTH	7	7	7	7	7	7	7	4	3	3	3	4	4	4	3	4	5	8	7	7	7	7	7	7	136	8
200612WE	**10**	**System**	**202**	**198**	**195**	**192**	**196**	**200**	**210**	**214**	**223**	**229**	**230**	**229**	**227**	**224**	**223**	**223**	**238**	**267**	**268**	**262**	**258**	**249**	**230**	**215**	**5,404**	**268**
SYSTEM PEAKDAY			**Hour**																									
Mo/Da/Year	**DW**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
12/20/2006	4	RES	63	53	50	48	50	56	70	74	67	76	80	84	78	82	90	82	98	111	132	126	114	103	89	71	1,947	132
12/20/2006	4	COM	55	54	53	52	55	59	65	72	79	85	85	84	79	74	72	69	69	69	67	66	64	62	59	55	1,603	85
12/20/2006	4	IND	68	67	66	66	68	70	69	63	63	63	59	52	56	55	48	55	58	66	65	64	63	62	62	63	1,491	70
12/20/2006	4	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.27	0.02
12/20/2006	4	OTH	7	7	7	7	7	8	8	5	5	5	5	5	4	5	4	4	5	8	8	8	7	7	7	7	150	8
12/20/2006	**4**	**System**	**208**	**202**	**195**	**198**	**204**	**219**	**235**	**242**	**249**	**261**	**258**	**252**	**251**	**247**	**236**	**251**	**266**	**297**	**291**	**281**	**270**	**257**	**235**	**218**	**5,823**	**297**

Note: Class load research hourly load profiles exclude losses vs. system loads which include losses.

Table A-6
Class Peak Demand Forecast - Base Case
Summer (July) Peak MW (including losses)

Year	Res	Com	Ind	Who	Other	System	Loss%
1996	104	87	54	1.39	8	253	7%
1997	91	117	51	0.05	17	276	8%
1998	106	105	65	0.07	8	284	7%
1999	118	104	60	0.09	9	291	7%
2000	99	118	65	0.07	10	292	8%
2001	110	121	48	0.06	14	293	6%
2002	115	127	61	0.01	12	316	6%
2003	139	105	73	0.01	6	324	5%
2004	145	114	74	0.02	7	340	8%
2005	135	120	81	0.01	6	342	6%
2006	133	134	74	0.08	6	347	6%
2007	144	150	60	0.07	6	361	5%
2008	147	153	64	0.08	6	369	6%
2009	149	157	66	0.08	6	378	6%
2010	152	161	68	0.08	6	388	6%
2011	163	151	77	0.08	6	397	6%
2012	166	155	79	0.08	6	406	6%
2013	170	158	81	0.08	6	415	6%
2014	173	162	82	0.08	6	424	6%
2015	177	166	84	0.08	6	433	6%
2016	181	170	86	0.08	6	442	6%
2017	185	173	87	0.08	6	452	6%
2018	188	177	89	0.07	6	461	6%
2019	193	181	90	0.07	6	471	6%
2020	197	185	92	0.07	6	481	6%
2021	201	189	94	0.07	6	491	6%
2022	206	193	96	0.07	6	501	6%
2023	210	198	97	0.07	6	512	6%
2024	215	202	99	0.07	6	522	6%
2025	220	206	101	0.07	6	533	6%
2026	225	211	103	0.07	6	544	6%
2027	230	215	104	0.07	6	556	6%
2028	235	220	106	0.07	6	567	6%
2029	241	224	108	0.07	6	579	6%
2030	246	229	110	0.07	6	591	6%
Growth/Yr:							
2008-2030	4	3	2	0.00	0	10	

Growth:						
1996-2006	2.5%	4.5%	3.2%	-13.1%	-3.1%	3.2%
2007-2010	1.9%	2.4%	4.0%	0.1%	-0.2%	2.4%
2008-2030	2.4%	1.9%	2.5%	0.0%	0.1%	2.2%

Note: Weather Normalized (1971-2000, Pueblo, CO-PUB)

Table A-7
Class Peak Demand Forecast - Base Case
Winter (December) Peak MW (including losses)

Year	Res	Com	Ind	Who	Other	System	Loss%
1996	111	64	47	0.06	7	231	7%
1997	115	67	48	0.06	8	239	8%
1998	106	86	52	0.05	4	251	7%
1999	100	91	57	0.05	9	259	7%
2000	105	91	58	0.05	13	269	8%
2001	128	73	48	0.05	10	261	6%
2002	118	93	59	0.02	11	284	6%
2003	111	99	72	0.02	5	289	5%
2004	146	84	61	0.01	6	298	8%
2005	127	95	76	0.01	4	304	6%
2006	137	96	68	0.02	4	307	6%
2007	147	87	75	0.02	4	316	5%
2008	150	90	78	0.02	4	325	6%
2009	153	93	82	0.02	4	334	6%
2010	157	96	83	0.02	4	341	6%
2011	173	95	77	0.02	3	350	6%
2012	176	98	80	0.02	4	359	6%
2013	180	100	82	0.02	4	368	6%
2014	184	103	84	0.02	4	376	6%
2015	188	105	86	0.02	4	385	6%
2016	192	108	87	0.02	4	394	6%
2017	197	111	90	0.02	4	403	6%
2018	201	114	91	0.02	4	412	6%
2019	206	117	93	0.02	4	421	6%
2020	210	119	95	0.02	4	430	6%
2021	215	122	97	0.02	4	440	6%
2022	220	125	99	0.02	4	450	6%
2023	225	128	101	0.02	4	460	6%
2024	230	131	103	0.02	3	470	6%
2025	235	134	106	0.02	3	480	6%
2026	241	137	108	0.02	3	491	6%
2027	246	140	110	0.02	3	502	6%
2028	252	144	112	0.02	3	513	6%
2029	258	147	114	0.02	3	524	6%
2030	263	150	116	0.02	3	535	6%
Growth/Yr:							
2008-2030	5	3	2	(0.00)	(0)	10	

Growth:						
1996-2006	2.1%	4.2%	3.7%	-0.4%	-5.0%	2.9%
2007-2010	2.2%	3.0%	3.3%	0.0%	0.8%	2.7%
2008-2030	2.6%	2.4%	1.8%	0.0%	-0.7%	2.3%

Note: Weather Normalized (1971-2000, Pueblo, CO-PUB)

Table A-8

WPC Class and System Loads **WestPlains Energy-Colorado**
2006 Load Research Actual Hourly Load Profiles

Monthly Class Energy Sales (excluding losses)

Mwh	1	2	3	4	5	6	7	8	9	10	11	12	Year	Loss%	NEL
RES	49,175	46,134	44,480	39,679	42,958	52,776	57,071	54,347	41,307	44,472	45,270	55,283	**572,952**	5.7%	607,409
COM	50,506	46,541	49,963	48,321	56,269	59,270	62,202	62,986	54,744	50,582	48,184	49,157	**638,725**	5.7%	677,138
IND	36,395	41,510	46,475	45,558	48,285	52,203	50,957	53,188	48,258	48,635	45,828	46,031	**563,323**	5.7%	597,201
OTH	4,578	4,102	4,351	4,218	4,608	4,669	4,665	4,914	4,413	4,438	4,314	4,552	**53,822**	5.7%	57,059
WHO	16	13	10	7	8	9	10	8	8	8	8	8	**113**	5.7%	120
Total	**140,670**	**138,300**	**145,279**	**137,783**	**152,128**	**168,927**	**174,905**	**175,443**	**148,730**	**148,135**	**143,604**	**155,031**	**1,828,935**	**5.7%**	**1,938,927**
Losses	7,878	8,405	9,380	7,015	6,010	10,702	14,855	7,635	3,301	8,534	11,284	14,993	109,992		
System	**148,548**	**146,705**	**154,659**	**144,798**	**158,138**	**179,629**	**189,760**	**183,079**	**152,031**	**156,669**	**154,888**	**170,024**	**1,938,927**		

Monthly Class Coincident Peak Demand (excluding losses)

Mw_Peak	1	2	3	4	5	6	7	8	9	10	11	12	Summer	Annual LF%
RES	66	91	112	62	65	102	100	102	81	49	109	111	**102**	64.1%
COM	71	70	72	105	110	115	112	114	110	100	80	69	**115**	63.4%
IND	70	71	72	85	82	80	79	71	73	78	71	66	**80**	80.4%
OTH	8	8	8	6	6	7	6	6	6	6	8	8	**7**	
WHO	0.020	0.019	0.013	0.009	0.010	0.009	0.019	0.014	0.011	0.011	0.009	0.011	**0.02**	67.7%
Total	**215**	**240**	**264**	**258**	**263**	**304**	**297**	**293**	**270**	**233**	**268**	**254**	**304**	**68.7%**
Losses	42	37	(2)	3	33	45	60	48	10	32	32	43	**53**	
System	**257**	**277**	**262**	**261**	**296**	**349**	**357**	**341**	**280**	**265**	**300**	**297**	**357**	**62.0%**
Cp_Date	1/2	2/18	3/21	4/17	5/26	6/19	7/31	8/8	9/1	10/2	11/29	12/20		
Cp-Hour	18	19	20	15	16	16	17	17	16	16	19	18		

Table A-9

Aquila Networks-Colorado
Colorado (WPC)
Electric Rates and Load Research Classes
2006

			Class Weights							Hour 17 7/31/2006 System Coincident	Hour 17 7/31/2006 System Coincident	Annual Energy Sales
RateID	Load Research	RateClass	RES	COM	IND	OTH	Description	Class	Notes	Load Factor	Peak MW	MWH
CO860,CO861	**RES**	**RES**	1.000				**Res_Total**	**Residential**	**Total Residential**	**65.1%**	**100.48**	**572,951**
CO710	SGSNDC	SGS		0.997	0.000	0.003	Com_SGS_Sec	Com/Ind/Oth	Sm. Gen. Service-Secondary	54.2%	12.50	59,408
CO711	SGSDC	SGP		0.979	0.004	0.017	Com_SGS_Pri	Com/Ind/Oth	Sm. Gen. Service-Primary	55.8%	29.87	146,086
CO720	LGSSSC	LGS		0.817	0.151	0.032	Com_LGS_Sec	Com/Ind/Oth	Lg. Gen. Service-Secondary	69.6%	77.89	474,702
CO725,CO770	LGSSTC	LGST		0.575	0.386	0.039	Com_LGS_Pri	Com/Ind/Oth	Lg. Gen. Service-Primary-tou	76.0%	5.83	38,803
	COM	**COM**					**Com_Total**	**Commercial**	**Total Commercial**	**65.1%**	**126.09**	**718,999**
CO730	LGSPC	LPP			0.725	0.275	Ind_LPS_Sec	Ind/Oth	Lg. Power Service-Secondary	70.1%	10.39	63,856
CO735,CO779	LGSPTC	LPPT		0.108	0.892		Ind_LPS_Pri	Com/Ind	Lg. Power Service-Primary-tou	82.3%	33.92	244,672
CO736	TOUCMC	CMC			1.000		Ind_TOU_Cement	Industrial	Holcim Cement Plant	88.1%	27.42	211,528
	IND	**IND**					**Ind_Total**	**Industrial**	**Total Industrial**	**82.8%**	**71.73**	**520,056**
COM26	**Lites**	**LT**				1.000	**Street Lights**	**Other**	**Street Lights**		-	16,876
	PRCLJC	WHO					Who_LJC	Wholesale	Wholesale		0.02	113
	TOTAL LR							**Total LR**	**Class Loads (excl. losses)**		**298.30**	**1,828,883**
								Losses	6.5%		61.70	127,868
	SYS	**SYS**					**Sys_WPC**	**System**	**System Net Load**	**62.0%**	**360.00**	**1,956,751**

Class	Wtd. by Rate Codes	Load Factor	Peak MW	Sales MWH
Residential	860,861,875	65.1%	100.48	572,951
Commercial	710,711,720,725,735,770,779	64.9%	112.34	638,721
Industrial	710,711,720,725,735,736	81.1%	79.34	563,301
Other	710,711,720,725,730,LT	0.0%	6.14	53,910
Wholesale			-	-
Total	**Class Loads**	**70.0%**	**298.30**	**1,828,883**
Losses	6.5%		61.70	127,868
System	**System Load**	**62.0%**	**360.00**	**1,956,751**

Table A-10

Aquila-CO WPC Monthly Coincident System Peak MW. Weather Normalized (PUB, 1971-2000)

Sum of M_SysMW	Month											
Year	1	2	3	4	5	6	7	8	9	10	11	12
1996	207.0	209.6	196.2	181.6	220.1	252.1	**253.5**	255.5	222.4	200.0	215.2	**231.2**
1997	217.9	213.4	206.0	195.9	225.7	259.3	**275.6**	265.1	237.5	205.0	224.8	**238.9**
1998	219.2	219.8	212.5	199.3	238.3	280.0	**283.8**	274.6	250.9	216.3	236.1	**250.6**
1999	237.6	228.3	226.8	213.8	236.9	287.1	**290.9**	297.1	261.7	219.7	240.6	**259.1**
2000	239.2	242.8	229.6	215.6	253.1	279.1	**292.4**	280.6	270.2	234.7	252.5	**268.9**
2001	249.7	242.1	236.5	221.8	260.3	294.3	**293.4**	289.4	257.0	227.9	247.9	**261.5**
2002	251.0	241.1	236.6	226.5	265.3	283.9	**315.8**	310.2	280.5	250.4	265.8	**283.5**
2003	263.8	263.2	259.8	240.4	273.8	314.1	**324.5**	322.4	285.7	261.3	269.1	**289.1**
2004	284.1	271.3	267.5	257.4	288.9	328.7	**339.9**	329.2	291.2	257.0	279.8	**298.1**
2005	277.6	264.7	265.2	252.7	295.6	335.2	**342.2**	337.3	300.3	259.9	287.7	**303.7**
2006	267.3	278.0	273.2	255.5	294.0	338.2	**346.7**	342.5	305.4	270.9	291.6	**307.5**
2007	283.0	281.6	270.2	264.3	287.8	330.7	**360.6**	355.5	304.3	268.8	295.3	**315.6**
2008	283.6	284.7	287.0	262.7	301.3	342.7	**369.3**	352.3	312.9	277.1	303.7	**324.6**
2009	292.3	293.2	295.9	271.1	309.9	351.7	**378.4**	361.3	322.0	286.1	312.7	**334.2**
2010	301.5	302.3	305.3	280.1	319.2	360.8	**387.7**	369.7	328.8	292.5	319.4	**341.4**
2011	323.3	318.0	313.7	296.9	318.7	368.8	**397.3**	377.2	339.5	301.3	326.6	**350.4**
2012	329.3	328.6	321.4	304.7	326.6	377.0	**406.2**	385.7	347.7	309.4	334.6	**359.0**
2013	337.7	332.7	329.5	312.7	334.6	385.3	**415.2**	394.2	356.0	317.4	342.7	**367.6**
2014	346.0	340.6	337.7	320.8	342.6	393.6	**424.1**	402.7	364.2	325.5	350.8	**376.2**
2015	354.3	348.4	345.8	328.8	350.5	401.9	**433.1**	411.2	372.4	333.5	358.9	**384.8**
2016	362.7	360.6	354.0	336.9	358.5	410.3	**442.2**	419.8	380.8	341.6	367.0	**393.6**
2017	371.4	364.7	362.6	345.3	366.9	419.1	**451.7**	428.9	389.5	350.1	375.6	**402.7**
2018	380.2	373.0	371.3	353.8	375.4	427.9	**461.3**	437.9	398.2	358.6	384.1	**411.8**
2019	389.1	381.4	380.0	362.4	383.9	436.8	**470.9**	447.1	407.0	367.2	392.7	**421.1**
2020	398.1	394.6	388.8	371.0	392.5	445.8	**480.7**	456.3	415.9	375.9	401.5	**430.4**
2021	407.2	403.3	397.6	379.8	401.1	454.8	**490.6**	465.7	424.9	384.7	410.3	**439.9**
2022	416.7	412.5	407.0	389.0	410.3	464.4	**501.0**	475.5	434.4	393.9	419.5	**449.8**
2023	426.5	421.9	416.6	398.4	419.6	474.2	**511.7**	485.6	444.1	403.4	429.0	**460.0**
2024	436.2	431.2	426.1	407.8	428.9	484.0	**522.4**	495.7	453.7	412.8	438.5	**470.1**
2025	446.2	440.7	435.8	417.4	438.5	494.0	**533.3**	506.0	463.6	422.4	448.1	**480.5**
2026	456.3	450.4	445.7	427.1	448.1	504.2	**544.4**	516.5	473.6	432.2	457.9	**491.0**
2027	466.6	460.3	455.7	437.0	457.9	514.5	**555.7**	527.1	483.8	442.1	467.9	**501.7**
2028	477.0	470.3	465.9	447.0	467.9	525.0	**567.2**	537.9	494.2	452.1	478.0	**512.6**
2029	487.7	480.5	476.4	457.3	478.1	535.7	**579.0**	549.0	504.8	462.4	488.4	**523.7**
2030	498.6	491.0	487.1	467.9	488.6	546.7	**591.0**	560.3	515.7	473.1	499.0	**535.2**
1996-06	2.6%	2.9%	3.4%	3.5%	2.9%	3.0%	**3.2%**	3.0%	3.2%	3.1%	3.1%	**2.9%**
2007-30	2.5%	2.4%	2.6%	2.5%	2.3%	2.2%	**2.2%**	2.0%	2.3%	2.5%	2.3%	**2.3%**

Table A-11

Aquila-CO WPC Monthly Net System Energy MWH. Weather Normalized (PUB, 1971-2000), including losses.

Sum of M_SysMWH	Month												
Year	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
1996	122,637	111,445	114,766	109,640	116,610	123,266	137,124	135,848	118,222	118,730	118,376	129,161	1,455,824
1997	130,041	114,054	121,824	117,449	122,400	130,167	148,253	143,845	128,528	123,089	124,518	134,820	1,538,988
1998	132,658	117,539	126,811	119,345	131,100	141,304	152,924	147,713	135,454	129,340	129,863	140,583	1,604,632
1999	138,442	121,820	133,388	124,960	129,213	140,597	151,648	152,907	135,542	130,461	133,313	146,412	1,638,703
2000	144,254	133,906	137,045	129,929	137,968	145,107	158,727	155,703	140,210	137,325	136,645	148,108	1,704,928
2001	143,382	126,766	136,703	129,337	135,338	143,100	154,612	156,396	134,416	129,344	129,947	140,369	1,659,711
2002	141,918	123,461	132,396	128,364	136,586	144,669	169,007	166,673	147,280	143,777	142,149	156,172	1,732,453
2003	150,097	140,228	147,772	140,293	141,987	154,949	174,525	172,887	148,775	152,684	145,226	159,044	1,828,467
2004	166,423	145,592	157,230	150,122	160,299	166,160	185,548	175,040	154,927	147,303	149,827	163,482	1,921,953
2005	158,084	137,315	148,865	146,177	155,873	170,823	187,197	181,136	159,290	148,125	156,568	166,943	1,916,394
2006	152,529	145,814	155,069	147,414	155,885	170,626	185,162	184,065	159,380	155,683	156,725	171,278	1,939,629
2007	161,861	148,437	149,995	150,565	156,965	162,714	195,260	191,976	156,407	151,830	157,654	175,943	1,959,607
2008	160,263	148,930	161,867	147,143	166,053	170,620	200,316	187,216	161,384	156,649	162,570	181,325	2,004,337
2009	165,362	153,881	167,051	152,004	171,124	175,898	205,758	192,544	166,808	161,908	167,918	187,160	2,067,415
2010	170,905	159,220	172,680	157,279	176,655	181,320	211,311	197,366	170,234	165,068	171,278	190,934	2,124,252
2011	186,800	170,089	177,481	169,013	174,061	185,729	217,073	201,323	176,919	170,170	175,008	196,199	2,199,866
2012	189,582	176,657	181,628	173,282	178,383	190,351	222,241	206,149	181,510	174,615	179,486	201,109	2,254,994
2013	194,252	177,839	186,140	177,689	182,743	194,973	227,405	210,951	186,068	179,027	183,933	206,003	2,307,023
2014	198,875	182,102	190,608	182,057	187,064	199,552	232,522	215,705	190,588	183,401	188,337	210,855	2,361,666
2015	203,445	186,313	195,018	186,365	191,327	204,094	237,638	220,440	195,057	187,711	192,685	215,665	2,415,758
2016	208,089	194,073	199,495	190,735	195,649	208,690	242,810	225,225	199,584	192,086	197,102	220,557	2,474,094
2017	213,000	195,116	204,236	195,367	200,234	213,581	248,322	230,322	204,391	196,722	201,776	225,722	2,528,786
2018	217,894	199,619	208,955	199,978	204,798	218,462	253,837	235,413	209,184	201,338	206,431	230,875	2,586,785
2019	222,831	204,152	213,710	204,619	209,385	223,356	259,368	240,514	213,998	205,984	211,120	236,078	2,645,116
2020	227,815	212,607	218,514	209,314	214,029	228,317	264,976	245,683	218,875	210,685	215,860	241,338	2,708,012
2021	232,841	217,309	223,352	214,032	218,698	233,316	270,653	250,903	223,780	215,408	220,629	246,644	2,767,565
2022	238,215	222,367	228,535	219,097	223,713	238,679	276,719	256,496	229,041	220,477	225,745	252,309	2,831,394
2023	243,747	227,572	233,869	224,311	228,876	244,206	282,978	262,262	234,462	225,697	231,011	258,142	2,897,132
2024	249,177	232,687	239,095	229,422	233,935	249,640	289,166	267,940	239,783	230,813	236,176	263,888	2,961,722
2025	254,812	237,965	244,522	234,721	239,180	255,276	295,583	273,828	245,300	236,116	241,529	269,835	3,028,667
2026	260,493	243,299	249,992	240,067	244,471	260,965	302,068	279,774	250,869	241,467	246,929	275,842	3,096,238
2027	266,265	248,717	255,547	245,497	249,846	266,746	308,661	285,815	256,528	246,903	252,415	281,948	3,164,889
2028	272,145	254,255	261,207	251,037	255,329	272,644	315,389	291,977	262,300	252,448	258,010	288,177	3,234,917
2029	278,187	259,908	267,022	256,717	260,950	278,690	322,287	298,292	268,219	258,135	263,747	294,562	3,306,716
2030	284,433	265,776	273,039	262,605	266,778	284,953	329,419	304,828	274,351	264,030	269,691	301,179	3,381,082
1996-06	2.2%	2.7%	3.1%	3.0%	2.9%	3.3%	3.0%	3.1%	3.0%	2.7%	2.8%	2.9%	2.9%
2007-30	2.5%	2.6%	2.6%	2.4%	2.3%	2.5%	2.3%	2.0%	2.5%	2.4%	2.4%	2.4%	2.4%

Tables A12-A14

Typical Daily Class Hourly Load Research Profiles (MW) **JANUARY 2006**

WestPlains Energy-Colorado

AVERAGE WEEKDAY			Hour																							
YearMoDT	Days		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	DayMWh	PeakMW
200601WD	23	RES	55	50	49	47	48	52	64	67	62	62	60	59	56	54	55	55	60	72	84	86	85	81	76	65	1,505	86
200601WD	23	COM	51	50	50	50	51	55	63	71	79	85	87	87	87	86	85	82	79	77	73	70	67	62	57	54	1,658	87
200601WD	23	IND	45	45	45	45	46	48	50	51	52	53	53	53	53	52	52	50	49	49	48	46	47	46	45	44	1,165	53
200601WD	23	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.48	0.02
200601WD	23	OTH	7	7	7	7	7	7	8	5	5	5	5	5	5	5	5	5	4	7	8	8	8	7	7	7	147	8
200601WD	**23**	**System**	**165**	**161**	**160**	**160**	**165**	**177**	**198**	**206**	**208**	**208**	**209**	**206**	**204**	**202**	**199**	**197**	**202**	**223**	**227**	**222**	**217**	**205**	**187**	**172**	**4,679**	**227**
AVERAGE WEEKEND			**Hour**																							
YearMoDT	**Days**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
200601WE	8	RES	68	61	55	55	53	57	66	70	73	74	77	75	79	77	75	75	79	89	107	103	99	94	86	75	1,821	107
200601WE	8	COM	58	58	57	56	56	58	60	62	64	67	70	72	72	70	69	69	69	72	71	69	67	64	60	57	1,547	72
200601WE	8	IND	49	49	48	48	48	49	51	49	49	49	50	51	50	50	50	50	51	52	52	52	52	51	50	50	1,200	52
200601WE	8	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.56	0.03
200601WE	8	OTH	8	8	8	8	8	8	8	5	4	4	4	4	4	4	4	4	4	8	8	8	8	8	8	8	150	8
200601WE	**8**	**System**	**193**	**186**	**182**	**182**	**183**	**189**	**200**	**203**	**211**	**217**	**221**	**221**	**219**	**215**	**213**	**212**	**220**	**249**	**255**	**250**	**245**	**234**	**217**	**201**	**5,117**	**255**
SYSTEM PEAKDAY			**Hour**																							
Mo/Da/Year	**DW**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
1/2/2006	2	RES	63	50	50	48	48	51	75	64	57	60	55	61	55	58	73	60	56	66	74	85	75	91	78	57	1,510	91
1/2/2006	2	COM	47	47	47	48	49	51	59	63	68	73	75	77	77	77	76	73	70	71	69	68	66	60	55	51	1,517	77
1/2/2006	2	IND	65	65	65	65	66	68	70	67	69	72	72	72	72	73	72	70	70	70	71	69	70	69	67	67	1,656	73
1/2/2006	2	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.49	0.02
1/2/2006	2	OTH	7	7	7	7	7	7	7	5	4	4	4	4	4	4	4	4	5	8	8	7	8	7	7	7	143	8
1/2/2006	**2**	**System**	**188**	**183**	**179**	**182**	**184**	**191**	**207**	**209**	**217**	**226**	**227**	**228**	**229**	**225**	**220**	**221**	**229**	**257**	**256**	**251**	**245**	**233**	**211**	**193**	**5,191**	**257**

Note: Class load research hourly load profiles exclude losses vs. system loads which include losses.

Typical Daily Class Hourly Load Research Profiles (MW) **FEBRUARY 2006**

WestPlains Energy-Colorado

AVERAGE WEEKDAY			Hour																							
YearMoDT	Days		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	DayMWh	PeakMW
200602WD	20	RES	58	53	51	52	53	57	73	77	68	68	67	64	65	61	58	57	61	72	86	90	89	85	78	66	1,608	90
200602WD	20	COM	54	53	53	53	55	59	67	75	83	90	92	93	92	92	90	87	83	80	77	74	72	67	62	57	1,759	93
200602WD	20	IND	58	58	58	58	60	62	64	65	66	65	65	65	65	65	65	63	61	62	63	62	62	62	61	59	1,493	66
200602WD	20	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.46	0.02
200602WD	20	OTH	7	7	7	7	7	8	7	5	5	5	5	5	5	5	5	5	4	6	8	8	8	8	7	7	152	8
200602WD	**20**	**System**	**188**	**184**	**184**	**184**	**190**	**204**	**225**	**231**	**234**	**234**	**232**	**232**	**228**	**226**	**224**	**221**	**222**	**236**	**250**	**247**	**244**	**232**	**216**	**199**	**5,265**	**250**
AVERAGE WEEKEND			**Hour**																							
YearMoDT	**Days**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
200602WE	8	RES	64	59	56	56	56	58	68	70	76	81	80	75	72	68	69	69	71	80	85	96	96	89	82	73	1,747	96
200602WE	8	COM	54	54	53	52	53	54	57	57	60	63	65	66	65	64	63	63	63	63	64	63	61	58	54	52	1,419	66
200602WE	8	IND	60	60	59	60	60	61	63	62	62	62	62	63	63	62	60	61	61	61	62	61	60	59	58	58	1,456	63
200602WE	8	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.45	0.02
200602WE	8	OTH	7	7	7	7	7	7	7	3	4	4	4	4	4	4	4	4	4	5	8	7	7	7	7	7	133	8
200602WE	**8**	**System**	**200**	**196**	**193**	**193**	**196**	**201**	**209**	**213**	**221**	**226**	**228**	**225**	**222**	**217**	**212**	**211**	**215**	**229**	**247**	**243**	**238**	**229**	**214**	**200**	**5,177**	**247**
SYSTEM PEAKDAY			**Hour**																							
Mo/Da/Year	**DW**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
2/18/2006	7	RES	66	63	62	61	61	67	74	77	91	104	107	105	104	102	110	98	91	74	91	109	104	103	101	91	2,116	110
2/18/2006	7	COM	60	59	58	57	57	58	62	64	67	69	71	73	69	68	68	68	69	69	70	70	67	63	60	57	1,553	73
2/18/2006	7	IND	68	68	61	67	69	70	70	70	70	70	70	70	70	70	68	72	71	72	71	72	71	67	61	64	1,652	72
2/18/2006	7	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.45	0.02
2/18/2006	7	OTH	7	7	7	7	7	7	6	3	4	4	4	4	4	4	4	4	4	5	8	8	7	7	7	7	136	8
2/18/2006	**7**	**System**	**225**	**225**	**210**	**219**	**220**	**225**	**235**	**241**	**250**	**254**	**256**	**256**	**253**	**245**	**239**	**246**	**245**	**261**	**277**	**273**	**268**	**256**	**237**	**226**	**5,842**	**277**

Note: Class load research hourly load profiles exclude losses vs. system loads which include losses.

Typical Daily Class Hourly Load Research Profiles (MW) **MARCH 2006**

WestPlains Energy-Colorado

AVERAGE WEEKDAY			Hour																							
YearMoDT	Days		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	DayMWh	PeakMW
200603WD	23	RES	53	45	44	44	44	49	60	65	60	59	58	57	52	51	50	48	53	61	75	83	84	81	76	62	1,412	84
200603WD	23	COM	53	52	51	51	52	57	64	72	80	86	89	90	90	90	88	86	81	76	74	73	70	65	60	55	1,706	90
200603WD	23	IND	62	62	61	61	62	63	64	66	68	68	68	68	67	67	66	65	65	64	64	64	64	64	63	62	1,546	68
200603WD	23	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.33	0.02
200603WD	23	OTH	7	7	7	7	7	7	5	5	5	5	5	5	5	5	5	5	4	4	7	8	8	8	7	7	146	8
200603WD	**23**	**System**	**183**	**179**	**178**	**178**	**182**	**194**	**207**	**219**	**225**	**227**	**228**	**226**	**223**	**221**	**219**	**219**	**219**	**224**	**240**	**242**	**236**	**225**	**208**	**192**	**5,095**	**242**
AVERAGE WEEKEND			**Hour**																							
YearMoDT	**Days**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
200603WE	8	RES	53	46	45	44	43	46	53	57	63	67	72	68	68	64	62	62	59	64	74	88	86	81	72	64	1,499	88
200603WE	8	COM	50	49	49	48	48	49	51	52	55	59	61	63	62	62	62	61	61	61	61	61	59	56	53	50	1,341	63
200603WE	8	IND	54	54	53	54	55	56	57	57	57	57	58	58	58	58	57	58	57	59	59	59	59	58	57	56	1,364	59
200603WE	8	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.32	0.02
200603WE	8	OTH	7	7	7	7	7	7	4	3	3	3	3	4	4	4	4	4	3	3	7	7	7	7	7	7	125	7
200603WE	**8**	**System**	**176**	**169**	**169**	**168**	**171**	**177**	**180**	**188**	**197**	**201**	**204**	**204**	**203**	**199**	**197**	**198**	**201**	**210**	**228**	**228**	**223**	**213**	**198**	**183**	**4,684**	**228**
SYSTEM PEAKDAY			**Hour**																							
Mo/Da/Year	**DW**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
3/21/2006	3	RES	64	49	51	50	48	58	63	60	60	64	61	65	47	63	55	56	67	76	92	112	94	94	101	81	1,631	112
3/21/2006	3	COM	55	55	52	53	54	59	66	73	81	87	88	89	88	88	86	84	81	76	74	72	70	65	60	56	1,712	89
3/21/2006	3	IND	69	68	62	62	63	65	66	68	69	69	69	68	69	70	69	68	66	70	69	72	74	71	69	69	1,634	74
3/21/2006	3	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.27	0.01
3/21/2006	3	OTH	7	7	7	7	7	8	4	4	5	5	5	5	5	5	5	5	5	4	7	8	8	7	7	7	144	8
3/21/2006	**3**	**System**	**202**	**197**	**188**	**192**	**193**	**204**	**213**	**228**	**232**	**232**	**233**	**233**	**229**	**229**	**225**	**227**	**231**	**241**	**257**	**262**	**257**	**246**	**225**	**212**	**5,388**	**262**

Note: Class load research hourly load profiles exclude losses vs. system loads which include losses.

Tables A15-A17

Typical Daily Class Hourly Load Research Profiles (MW) **APRIL 2006**

WestPlains Energy-Colorado

AVERAGE WEEKDAY			Hour																							
YearMoDT	Days		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	DayMWh	PeakMW
200604WD	20	RES	47	41	39	38	38	43	53	56	57	53	55	55	54	50	49	48	51	59	63	65	77	80	72	59	1,298	80
200604WD	20	COM	53	52	51	51	52	56	64	72	81	87	91	92	93	93	93	90	85	80	74	72	72	67	61	56	1,737	93
200604WD	20	IND	61	61	59	59	60	60	62	64	65	67	66	67	67	68	67	65	64	63	63	63	65	64	62	62	1,525	68
200604WD	20	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.24	0.01
200604WD	20	OTH	7	7	7	7	7	5	4	5	5	5	5	5	6	6	6	5	5	5	6	8	8	8	8	8	148	8
200604WD	**20**	**System**	**174**	**169**	**165**	**163**	**167**	**178**	**195**	**206**	**214**	**220**	**222**	**223**	**223**	**224**	**224**	**221**	**221**	**219**	**217**	**223**	**233**	**223**	**204**	**186**	**4,914**	**233**
AVERAGE WEEKEND			**Hour**																							
YearMoDT	**Days**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
200604WE	10	RES	51	44	36	38	38	41	46	49	56	65	65	63	65	64	62	53	59	56	62	66	78	83	72	60	1,372	83
200604WE	10	COM	51	51	45	48	48	49	50	52	55	58	61	62	63	63	64	64	63	63	61	60	61	59	55	52	1,358	64
200604WE	10	IND	62	62	56	61	61	62	63	62	62	63	64	64	63	63	63	63	63	65	65	65	65	64	63	62	1,507	65
200604WE	10	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.26	0.01
200604WE	10	OTH	7	7	7	7	7	5	3	3	4	4	4	4	4	4	4	4	4	4	5	8	8	7	7	7	126	8
200604WE	**10**	**System**	**174**	**172**	**168**	**165**	**167**	**173**	**175**	**181**	**191**	**199**	**204**	**206**	**204**	**204**	**202**	**203**	**203**	**209**	**210**	**216**	**226**	**216**	**200**	**186**	**4,653**	**226**
SYSTEM PEAKDAY			**Hour**																							
Mo/Da/Year	**DW**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
4/17/2006	2	RES	50	45	36	37	40	40	50	56	52	48	50	60	47	47	62	46	48	63	67	61	78	88	73	62	1,306	88
4/17/2006	2	COM	50	49	49	49	53	59	65	73	82	89	94	98	101	104	105	105	97	90	81	76	74	69	64	59	1,835	105
4/17/2006	2	IND	67	67	66	66	69	71	73	76	80	81	82	83	83	84	85	82	78	75	73	72	73	76	67	72	1,801	85
4/17/2006	2	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.24	0.01
4/17/2006	2	OTH	7	7	7	7	8	5	5	5	6	6	6	6	6	6	6	6	6	5	6	9	9	8	8	8	158	9
4/17/2006	**2**	**System**	**179**	**171**	**167**	**165**	**173**	**185**	**199**	**213**	**228**	**235**	**249**	**251**	**253**	**258**	**261**	**260**	**259**	**251**	**239**	**244**	**253**	**244**	**214**	**199**	**5,350**	**261**

Note: Class load research hourly load profiles exclude losses vs. system loads which include losses.

Typical Daily Class Hourly Load Research Profiles (MW) **MAY 2006**

WestPlains Energy-Colorado

AVERAGE WEEKDAY			Hour																							
YearMoDT	Days		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	DayMWh	PeakMW
200605WD	23	RES	50	43	41	39	40	42	51	52	51	52	54	53	53	54	57	55	58	66	72	70	79	79	71	58	1,341	79
200605WD	23	COM	58	56	55	54	55	60	67	77	87	95	100	102	103	104	104	100	95	90	83	79	78	73	67	62	1,901	104
200605WD	23	IND	62	60	60	60	61	62	64	67	69	70	70	70	70	69	69	68	67	66	65	65	66	65	63	63	1,573	70
200605WD	23	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.25	0.01
200605WD	23	OTH	8	7	7	7	7	4	5	5	6	6	6	6	6	6	6	6	5	5	5	8	8	8	8	8	154	8
200605WD	**23**	**System**	**179**	**171**	**168**	**166**	**169**	**178**	**191**	**209**	**220**	**228**	**233**	**238**	**238**	**241**	**242**	**242**	**242**	**241**	**236**	**233**	**242**	**233**	**213**	**192**	**5,144**	**242**
AVERAGE WEEKEND			**Hour**																							
YearMoDT	**Days**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
200605WE	8	RES	54	48	46	43	41	43	45	48	54	64	73	65	67	72	75	70	71	73	80	80	88	81	72	63	1,514	88
200605WE	8	COM	58	57	55	54	53	55	57	59	63	68	72	74	76	75	76	75	75	74	71	69	68	66	62	58	1,568	76
200605WE	8	IND	61	60	59	59	60	59	62	62	63	64	66	67	66	67	66	65	65	65	64	63	64	63	62	61	1,513	67
200605WE	8	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.27	0.01
200605WE	8	OTH	8	7	7	7	6	4	4	4	4	4	4	5	5	5	5	5	5	4	4	7	8	8	8	7	133	8
200605WE	**8**	**System**	**184**	**175**	**169**	**167**	**167**	**168**	**172**	**183**	**196**	**209**	**219**	**226**	**230**	**232**	**235**	**236**	**236**	**236**	**234**	**230**	**238**	**231**	**212**	**194**	**4,978**	**238**
SYSTEM PEAKDAY			**Hour**																							
Mo/Da/Year	**DW**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
5/26/2006	6	RES	55	47	44	41	41	44	54	59	59	55	59	58	57	64	65	65	75	84	86	82	98	88	77	60	1,517	98
5/26/2006	6	COM	65	63	61	60	60	65	72	81	93	103	110	113	115	115	113	110	103	99	92	89	86	80	72	66	2,086	115
5/26/2006	6	IND	69	72	71	59	67	71	73	76	74	78	82	84	86	82	84	82	80	79	77	76	73	75	73	72	1,815	86
5/26/2006	6	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.27	0.01
5/26/2006	6	OTH	8	8	8	7	7	4	5	6	6	6	7	7	7	7	7	6	6	6	5	8	9	9	8	8	165	9
5/26/2006	**6**	**System**	**200**	**197**	**191**	**174**	**183**	**191**	**205**	**227**	**236**	**255**	**271**	**285**	**290**	**294**	**294**	**296**	**290**	**291**	**285**	**274**	**272**	**265**	**245**	**219**	**5,930**	**296**

Note: Class load research hourly load profiles exclude losses vs. system loads which include losses.

Typical Daily Class Hourly Load Research Profiles (MW) **JUNE 2006**

WestPlains Energy-Colorado

AVERAGE WEEKDAY			Hour																							
YearMoDT	Days		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	DayMWh	PeakMW
200606WD	22	RES	60	54	50	48	48	49	57	59	54	59	66	73	81	86	89	90	90	97	102	100	98	97	88	74	1,767	102
200606WD	22	COM	64	62	61	59	61	65	72	82	93	102	107	111	113	115	114	110	105	100	92	87	85	81	74	69	2,085	115
200606WD	22	IND	70	69	69	69	70	70	71	74	77	79	79	79	79	79	77	75	75	75	75	74	74	74	71	70	1,773	79
200606WD	22	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.28	0.01
200606WD	22	OTH	8	8	8	8	6	4	5	6	6	6	6	7	7	7	7	6	6	6	5	8	9	9	9	8	162	9
200606WD	**22**	**System**	**209**	**200**	**194**	**190**	**192**	**196**	**205**	**224**	**245**	**262**	**277**	**289**	**297**	**305**	**308**	**308**	**308**	**303**	**294**	**286**	**284**	**276**	**251**	**227**	**6,130**	**308**
AVERAGE WEEKEND			**Hour**																							
YearMoDT	**Days**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
200606WE	8	RES	65	55	50	47	46	45	47	48	54	63	69	74	77	89	89	85	89	97	98	98	98	96	86	73	1,737	98
200606WE	8	COM	62	60	58	56	56	58	60	63	68	73	77	80	80	81	81	81	80	80	77	73	72	71	66	62	1,675	81
200606WE	8	IND	68	67	66	65	66	66	67	67	68	70	73	74	72	72	72	72	71	70	69	68	68	68	66	67	1,649	74
200606WE	8	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.29	0.01
200606WE	8	OTH	8	8	8	8	6	4	4	4	4	4	5	5	5	5	5	5	5	5	4	7	8	8	8	8	138	8
200606WE	**8**	**System**	**205**	**194**	**186**	**182**	**181**	**180**	**183**	**193**	**211**	**226**	**242**	**254**	**260**	**268**	**274**	**279**	**280**	**280**	**273**	**266**	**265**	**260**	**237**	**217**	**5,595**	**280**
SYSTEM PEAKDAY			**Hour**																							
Mo/Da/Year	**DW**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
6/19/2006	2	RES	66	55	51	49	49	51	58	61	53	66	81	69	84	99	102	102	103	118	130	125	114	113	90	73	1,962	130
6/19/2006	2	COM	60	58	57	58	59	64	69	82	93	104	112	116	117	119	120	115	111	108	100	94	89	85	78	72	2,140	120
6/19/2006	2	IND	66	70	71	71	72	73	77	82	85	87	88	89	89	89	84	80	77	70	68	70	70	69	67	66	1,830	89
6/19/2006	2	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.25	0.01
6/19/2006	2	OTH	8	8	8	8	6	4	5	6	6	6	7	7	7	7	7	7	6	6	6	8	9	9	9	8	168	9
6/19/2006	**2**	**System**	**207**	**201**	**195**	**193**	**194**	**198**	**212**	**235**	**259**	**278**	**295**	**314**	**329**	**340**	**344**	**349**	**343**	**331**	**323**	**315**	**308**	**293**	**269**	**234**	**6,559**	**349**

Note: Class load research hourly load profiles exclude losses vs. system loads which include losses.

Tables A18-A20

AVERAGE WEEKDAY			Hour																							
YearMoDT	Days		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	DayMWh	PeakMW
200607WD	21	RES	62	54	51	49	49	51	56	58	57	63	71	81	84	90	92	93	96	101	101	99	99	96	88	73	1,813	101
200607WD	21	COM	66	64	62	60	62	68	74	83	94	102	108	111	113	114	114	111	106	101	94	89	86	81	75	70	2,108	114
200607WD	21	IND	65	64	64	64	65	66	68	70	72	73	74	75	74	73	71	70	70	70	70	69	71	69	66	65	1,659	75
200607WD	21	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.31	0.02
200607WD	21	OTH	8	8	8	7	7	4	5	5	6	6	6	6	6	6	6	6	6	5	5	7	9	8	8	8	156	9
200607WD	**21**	**System**	**209**	**200**	**194**	**192**	**192**	**200**	**208**	**227**	**247**	**266**	**282**	**294**	**303**	**310**	**314**	**316**	**317**	**311**	**299**	**288**	**286**	**273**	**249**	**227**	**6,206**	**317**
AVERAGE WEEKEND			**Hour**																							
YearMoDT	**Days**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
200607WE	10	RES	66	57	53	50	49	49	53	55	62	69	78	88	94	94	102	103	100	100	102	100	103	102	93	79	1,900	103
200607WE	10	COM	67	64	62	60	61	62	63	67	73	78	82	85	87	87	88	88	87	85	81	78	78	76	71	67	1,794	88
200607WE	10	IND	64	64	63	63	64	64	64	65	67	68	70	71	72	71	71	71	70	71	70	69	68	65	65	64	1,611	72
200607WE	10	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.33	0.02
200607WE	10	OTH	8	8	8	8	7	4	4	4	4	4	5	5	5	5	5	5	5	5	5	7	8	8	8	8	140	8
200607WE	**10**	**System**	**213**	**203**	**195**	**193**	**190**	**191**	**192**	**203**	**223**	**241**	**259**	**274**	**287**	**292**	**299**	**302**	**301**	**297**	**289**	**280**	**278**	**271**	**248**	**226**	**5,943**	**302**
SYSTEM PEAKDAY			**Hour**																							
Mo/Da/Year	**DW**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
7/31/2006	2	RES	74	64	55	53	55	59	60	65	60	63	75	94	94	96	109	94	100	110	114	109	121	126	97	86	2,033	126
7/31/2006	2	COM	67	65	64	62	66	72	77	87	99	107	115	118	119	121	119	115	112	107	100	96	95	89	81	74	2,227	121
7/31/2006	2	IND	68	70	69	71	72	75	77	81	86	87	87	89	85	72	71	75	79	82	80	78	79	77	74	74	1,858	89
7/31/2006	2	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.38	0.02
7/31/2006	2	OTH	8	8	8	8	8	5	5	6	6	6	7	7	7	7	7	6	6	6	5	9	9	9	8	8	169	9
7/31/2006	**2**	**System**	**231**	**221**	**212**	**212**	**207**	**221**	**230**	**252**	**280**	**304**	**323**	**339**	**345**	**339**	**340**	**351**	**357**	**351**	**335**	**322**	**320**	**301**	**270**	**243**	**6,906**	**357**

Note: Class load research hourly load profiles exclude losses vs. system loads which include losses.

Typical Daily Class Hourly Load Research Profiles (MW) **AUGUST 2006**

WestPlains Energy-Colorado

AVERAGE WEEKDAY			Hour																							
YearMoDT	Days		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	DayMWh	PeakMW
200608WD	23	RES	60	53	50	48	48	50	59	58	55	59	65	68	77	81	83	86	93	99	102	102	101	101	93	73	1,763	102
200608WD	23	COM	67	65	63	61	63	69	75	85	95	103	109	113	115	116	117	114	109	102	95	91	89	84	77	71	2,148	117
200608WD	23	IND	68	67	67	66	67	69	70	72	75	76	77	78	78	78	79	76	75	74	72	72	73	72	70	70	1,740	79
200608WD	23	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.27	0.01
200608WD	23	OTH	8	8	8	8	8	5	5	5	6	6	6	6	6	7	7	6	6	6	6	9	9	9	8	8	165	9
200608WD	**23**	**System**	**206**	**196**	**192**	**189**	**191**	**200**	**213**	**226**	**243**	**257**	**269**	**282**	**292**	**301**	**307**	**307**	**306**	**300**	**288**	**280**	**283**	**267**	**243**	**221**	**6,057**	**307**
AVERAGE WEEKEND			**Hour**																							
YearMoDT	**Days**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
200608WE	8	RES	59	55	49	48	46	47	49	52	60	66	72	73	75	80	89	92	92	95	95	92	95	96	82	69	1,726	96
200608WE	8	COM	64	62	60	59	60	62	63	65	70	74	78	81	82	82	83	82	81	78	73	71	72	70	66	62	1,697	83
200608WE	8	IND	67	66	66	66	65	66	68	68	70	71	72	71	72	74	73	72	71	68	68	66	68	67	67	66	1,646	74
200608WE	8	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.26	0.01
200608WE	8	OTH	8	8	8	8	8	5	4	4	4	4	4	4	5	5	5	5	5	4	5	8	8	8	8	8	139	8
200608WE	**8**	**System**	**202**	**192**	**189**	**183**	**184**	**187**	**192**	**198**	**214**	**230**	**241**	**251**	**256**	**267**	**268**	**267**	**267**	**262**	**251**	**246**	**253**	**242**	**226**	**206**	**5,472**	**268**
SYSTEM PEAKDAY			**Hour**																							
Mo/Da/Year	**DW**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
8/8/2006	3	RES	73	54	52	50	48	48	54	52	58	62	75	80	107	93	98	100	102	94	108	113	117	133	106	85	1,962	133
8/8/2006	3	COM	71	68	66	64	67	71	77	85	97	106	112	116	118	118	118	117	114	108	101	96	97	92	83	76	2,238	118
8/8/2006	3	IND	69	69	69	69	69	62	61	62	70	72	73	77	72	71	78	73	71	73	71	75	79	77	75	74	1,711	79
8/8/2006	3	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.31	0.02
8/8/2006	3	OTH	8	8	8	8	8	5	5	5	6	6	6	6	7	6	7	6	6	6	5	9	9	9	9	8	166	9
8/8/2006	**3**	**System**	**213**	**206**	**205**	**200**	**200**	**197**	**205**	**221**	**250**	**269**	**282**	**303**	**312**	**319**	**337**	**334**	**341**	**337**	**326**	**319**	**326**	**309**	**276**	**250**	**6,537**	**341**

Note: Class load research hourly load profiles exclude losses vs. system loads which include losses.

Typical Daily Class Hourly Load Research Profiles (MW) **SEPTEMBER 2006**

WestPlains Energy-Colorado

AVERAGE WEEKDAY			Hour																							
YearMoDT	Days		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	DayMWh	PeakMW
200609WD	22	RES	45	39	37	37	38	41	49	51	51	51	51	54	54	54	52	57	62	64	66	69	74	75	69	55	1,294	75
200609WD	22	COM	57	56	54	53	54	58	65	73	83	89	94	97	99	101	101	99	94	88	82	81	78	73	65	60	1,854	101
200609WD	22	IND	61	61	60	60	61	61	63	63	64	65	66	67	68	69	69	67	66	66	66	66	66	64	62	61	1,541	69
200609WD	22	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.25	0.01
200609WD	22	OTH	7	7	7	7	7	6	4	5	5	5	5	5	6	6	6	5	5	5	8	8	8	8	8	7	147	8
200609WD	**22**	**System**	**171**	**165**	**162**	**160**	**163**	**172**	**190**	**199**	**206**	**212**	**219**	**223**	**226**	**231**	**233**	**233**	**234**	**231**	**227**	**235**	**234**	**219**	**198**	**182**	**4,926**	**235**
AVERAGE WEEKEND			**Hour**																							
YearMoDT	**Days**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
200609WE	8	RES	58	51	47	46	46	45	49	57	66	68	70	69	68	75	76	76	75	79	81	85	87	84	80	65	1,604	87
200609WE	8	COM	65	64	63	62	61	64	66	67	70	74	78	81	82	82	83	83	83	81	78	78	77	74	68	63	1,744	83
200609WE	8	IND	72	71	71	71	73	74	75	73	74	76	76	77	78	78	78	78	78	77	76	76	76	74	72	72	1,795	78
200609WE	8	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.31	0.02
200609WE	8	OTH	8	8	8	8	8	7	4	4	4	4	4	4	4	4	4	5	4	5	8	9	8	8	8	8	146	9
200609WE	**8**	**System**	**202**	**196**	**190**	**189**	**190**	**196**	**203**	**208**	**220**	**231**	**238**	**243**	**246**	**247**	**248**	**251**	**251**	**253**	**252**	**262**	**261**	**246**	**226**	**209**	**5,456**	**262**
SYSTEM PEAKDAY			**Hour**																							
Mo/Da/Year	**DW**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
9/1/2006	6	RES	51	48	43	40	41	48	55	57	51	53	57	50	57	68	71	81	77	77	110	85	83	80	80	66	1,529	110
9/1/2006	6	COM	67	67	65	62	64	69	76	85	94	102	107	110	113	116	116	110	103	95	87	85	83	78	71	65	2,090	116
9/1/2006	6	IND	72	72	67	68	72	72	73	71	70	72	74	68	66	66	67	73	76	76	75	75	75	73	72	71	1,716	76
9/1/2006	6	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.24	0.01
9/1/2006	6	OTH	8	8	8	7	7	6	4	5	5	6	6	6	6	6	6	6	5	5	7	8	8	8	8	8	157	8
9/1/2006	**6**	**System**	**206**	**195**	**189**	**185**	**188**	**200**	**215**	**224**	**227**	**240**	**250**	**250**	**258**	**264**	**272**	**280**	**275**	**266**	**250**	**247**	**251**	**234**	**218**	**202**	**5,586**	**280**

Note: Class load research hourly load profiles exclude losses vs. system loads which include losses.

Tables A21-A23

Typical Daily Class Hourly Load Research Profiles (MW) **OCTOBER 2006**

WestPlains Energy-Colorado

AVERAGE WEEKDAY			Hour																							
YearMoDT	Days		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	DayMWh	PeakMW
200610WD	23	RES	50	46	43	43	44	48	56	58	54	55	56	56	55	54	51	51	53	62	69	73	74	75	68	57	1,352	75
200610WD	23	COM	51	50	50	49	49	53	61	68	76	80	84	85	87	87	87	84	81	75	72	72	69	64	58	54	1,648	87
200610WD	23	IND	59	59	59	59	59	60	61	64	66	67	67	66	66	66	66	65	63	63	63	63	64	63	62	61	1,511	67
200610WD	23	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.26	0.01
200610WD	23	OTH	7	7	7	7	7	7	4	4	5	5	5	5	5	5	5	5	4	7	8	8	8	7	7	7	143	8
200610WD	**23**	**System**	**171**	**167**	**163**	**163**	**167**	**177**	**199**	**211**	**216**	**219**	**222**	**221**	**220**	**219**	**221**	**220**	**218**	**221**	**229**	**233**	**229**	**216**	**198**	**182**	**4,903**	**233**
AVERAGE WEEKEND			**Hour**																							
YearMoDT	**Days**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
200610WE	8	RES	60	53	51	48	50	51	52	58	61	71	68	74	70	77	75	73	79	84	91	98	95	90	78	66	1,672	98
200610WE	8	COM	60	59	58	57	57	59	61	62	64	67	71	73	74	75	75	74	74	72	72	71	69	66	61	58	1,586	75
200610WE	8	IND	72	70	70	71	71	73	73	72	73	74	75	76	75	75	75	74	73	72	73	73	71	69	69	68	1,734	76
200610WE	8	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.28	0.01
200610WE	8	OTH	8	8	8	8	8	8	4	4	4	4	4	4	4	4	4	4	4	7	8	8	8	8	8	8	144	8
200610WE	**8**	**System**	**207**	**198**	**194**	**193**	**195**	**200**	**208**	**215**	**226**	**237**	**242**	**245**	**244**	**243**	**244**	**243**	**243**	**247**	**261**	**267**	**258**	**246**	**226**	**210**	**5,488**	**267**
SYSTEM PEAKDAY			**Hour**																							
Mo/Da/Year	**DW**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
10/2/2006	2	RES	52	43	41	37	37	39	54	53	43	45	50	50	45	42	47	49	52	60	69	74	80	63	58	48	1,231	80
10/2/2006	2	COM	53	52	52	52	53	60	67	75	84	91	96	99	102	103	104	100	95	89	85	85	81	74	65	60	1,877	104
10/2/2006	2	IND	56	55	55	56	58	65	71	73	68	70	71	72	72	78	77	78	78	75	75	74	74	72	69	68	1,660	78
10/2/2006	2	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.24	0.01
10/2/2006	2	OTH	7	7	7	7	7	7	4	5	5	6	6	6	6	6	6	6	5	6	9	8	8	8	8	8	158	9
10/2/2006	**2**	**System**	**171**	**162**	**157**	**160**	**165**	**181**	**208**	**216**	**220**	**227**	**240**	**242**	**246**	**258**	**259**	**265**	**262**	**259**	**260**	**264**	**260**	**240**	**214**	**196**	**5,332**	**265**

Note: Class load research hourly load profiles exclude losses vs. system loads which include losses.

Typical Daily Class Hourly Load Research Profiles (MW) **NOVEMBER 2006**

WestPlains Energy-Colorado

AVERAGE WEEKDAY			Hour																							
YearMoDT	Days		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	DayMWh	PeakMW
200611WD	22	RES	55	51	49	48	49	52	60	64	61	64	61	62	59	57	56	56	62	70	79	79	80	80	76	64	1,493	80
200611WD	22	COM	54	53	52	52	53	56	63	71	78	83	86	87	87	87	85	83	80	78	75	73	70	65	60	56	1,685	87
200611WD	22	IND	61	60	60	60	61	62	63	65	66	66	66	66	65	64	64	62	62	64	64	64	64	62	60	60	1,511	66
200611WD	22	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.26	0.01
200611WD	22	OTH	7	7	7	7	7	7	7	4	5	5	5	5	5	5	5	5	5	8	8	8	8	8	7	7	149	8
200611WD	**22**	**System**	**184**	**180**	**178**	**179**	**184**	**197**	**215**	**224**	**228**	**231**	**231**	**231**	**228**	**224**	**222**	**220**	**229**	**251**	**254**	**247**	**242**	**228**	**208**	**194**	**5,210**	**254**
AVERAGE WEEKEND			**Hour**																							
YearMoDT	**Days**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
200611WE	8	RES	52	49	48	49	49	48	51	58	66	69	66	68	65	72	72	65	71	81	83	84	81	76	70	60	1,554	84
200611WE	8	COM	51	50	50	50	51	52	54	54	57	60	63	64	64	64	63	63	64	67	65	62	60	58	54	50	1,390	67
200611WE	8	IND	64	64	64	64	64	65	67	66	65	66	66	66	65	65	66	66	66	67	67	67	68	66	65	65	1,573	68
200611WE	8	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.28	0.01
200611WE	8	OTH	7	7	7	7	7	7	6	3	3	3	3	4	4	3	4	4	4	7	7	7	7	7	7	7	130	7
200611WE	**8**	**System**	**187**	**183**	**180**	**182**	**183**	**190**	**197**	**202**	**210**	**215**	**217**	**218**	**215**	**213**	**212**	**214**	**223**	**245**	**245**	**242**	**237**	**224**	**208**	**195**	**5,035**	**245**
SYSTEM PEAKDAY			**Hour**																							
Mo/Da/Year	**DW**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
11/29/2006	4	RES	61	51	50	47	46	60	76	69	61	59	67	74	75	73	73	77	90	113	109	105	99	95	85	75	1,790	113
11/29/2006	4	COM	57	56	55	55	56	59	68	77	86	90	91	93	92	91	90	87	85	84	80	77	75	71	65	61	1,801	93
11/29/2006	4	IND	67	67	67	66	68	70	73	76	70	67	66	66	67	67	66	64	63	66	71	73	72	70	70	70	1,642	76
11/29/2006	4	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.23	0.01
11/29/2006	4	OTH	7	7	7	7	7	7	8	5	5	5	5	5	5	5	5	5	6	8	8	8	8	8	7	7	155	8
11/29/2006	**4**	**System**	**201**	**198**	**195**	**195**	**201**	**215**	**241**	**251**	**247**	**249**	**255**	**253**	**254**	**252**	**252**	**251**	**262**	**291**	**300**	**292**	**280**	**265**	**242**	**227**	**5,869**	**300**

Note: Class load research hourly load profiles exclude losses vs. system loads which include losses.

AVERAGE WEEKDAY			Hour																							
YearMoDT	Days		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	DayMWh	PeakMW
200612WD	21	RES	66	60	55	53	55	59	68	73	71	70	71	72	68	69	65	63	68	90	99	101	98	93	85	74	1,745	101
200612WD	21	COM	54	54	53	53	55	58	65	71	77	82	84	84	83	82	81	79	77	76	73	71	69	66	61	57	1,663	84
200612WD	21	IND	61	60	60	60	61	61	62	61	63	63	63	62	63	63	63	62	64	63	62	63	63	62	61	61	1,487	64
200612WD	21	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.27	0.01
200612WD	21	OTH	7	7	7	7	7	8	8	5	5	5	5	5	5	5	5	6	8	8	8	8	8	7	7	7	152	8
200612WD	**21**	**System**	**199**	**194**	**191**	**190**	**196**	**207**	**225**	**233**	**238**	**241**	**240**	**238**	**235**	**231**	**230**	**231**	**244**	**272**	**273**	**267**	**263**	**250**	**228**	**210**	**5,523**	**273**
AVERAGE WEEKEND			**Hour**																							
YearMoDT	**Days**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
200612WE	10	RES	66	62	57	56	58	59	62	70	73	78	81	81	82	79	74	74	74	90	104	103	106	101	91	81	1,863	106
200612WE	10	COM	54	53	53	53	53	54	57	57	59	61	64	64	64	63	63	62	64	66	65	63	62	60	57	54	1,424	66
200612WE	10	IND	61	62	62	61	62	62	62	60	61	62	62	61	61	62	61	61	62	64	63	61	62	63	62	61	1,480	64
200612WE	10	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.25	0.01
200612WE	10	OTH	7	7	7	7	7	7	7	4	3	3	3	4	4	4	3	4	5	8	7	7	7	7	7	7	136	8
200612WE	**10**	**System**	**202**	**198**	**195**	**192**	**196**	**200**	**210**	**214**	**223**	**229**	**230**	**229**	**227**	**224**	**223**	**223**	**238**	**267**	**268**	**262**	**258**	**249**	**230**	**215**	**5,404**	**268**
SYSTEM PEAKDAY			**Hour**																							
Mo/Da/Year	**DW**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**DayMWh**	**PeakMW**
12/20/2006	4	RES	63	53	50	48	50	56	70	74	67	76	80	84	78	82	90	82	98	111	132	126	114	103	89	71	1,947	132
12/20/2006	4	COM	55	54	53	52	55	59	65	72	79	85	85	84	79	74	72	69	69	69	67	66	64	62	59	55	1,603	85
12/20/2006	4	IND	68	67	66	66	68	70	69	63	63	63	59	52	56	55	48	55	58	66	65	64	63	62	62	63	1,491	70
12/20/2006	4	WHO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.27	0.02
12/20/2006	4	OTH	7	7	7	7	7	8	8	5	5	5	5	5	4	5	4	4	5	8	8	8	7	7	7	7	150	8
12/20/2006	**4**	**System**	**208**	**202**	**195**	**198**	**204**	**219**	**235**	**242**	**249**	**261**	**258**	**252**	**251**	**247**	**236**	**251**	**266**	**297**	**291**	**281**	**270**	**257**	**235**	**218**	**5,823**	**297**

Note: Class load research hourly load profiles exclude losses vs. system loads which include losses.

Appendix B - Computer Models Used in the Resource Plan

MetrixND®

MetrixND is a flexible modeling tool, widely used by the top energy forecasters at leading utilities and energy providers throughout the world. MetrixND puts the power of the most advanced modeling techniques at your fingertips, enabling you to develop accurate forecasts and apply them to business decisions with confidence. These techniques include:

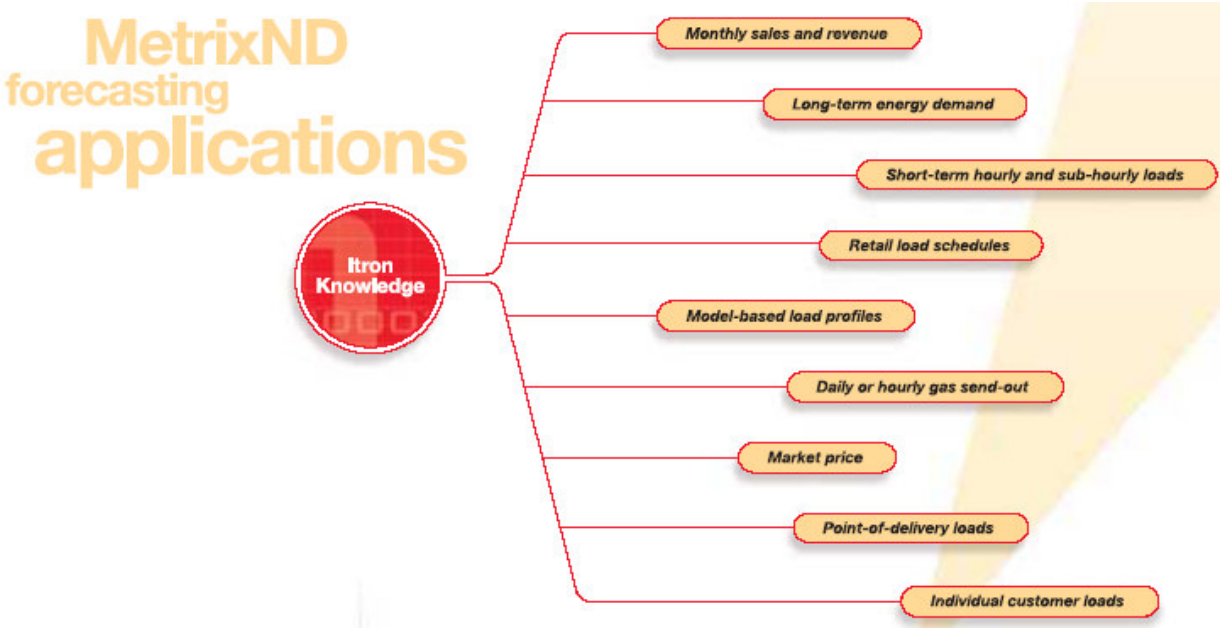
Exponential Smoothing
Ideal for projecting customer growth trends that support monthly sales and peak forecasting applications.

ARIMA
For seasoned time series professionals who want to visualize how historical data patterns extend into the future.

Regression
The workhorse of the energy forecasting professional. No other tool lets you build multi-variate models faster.

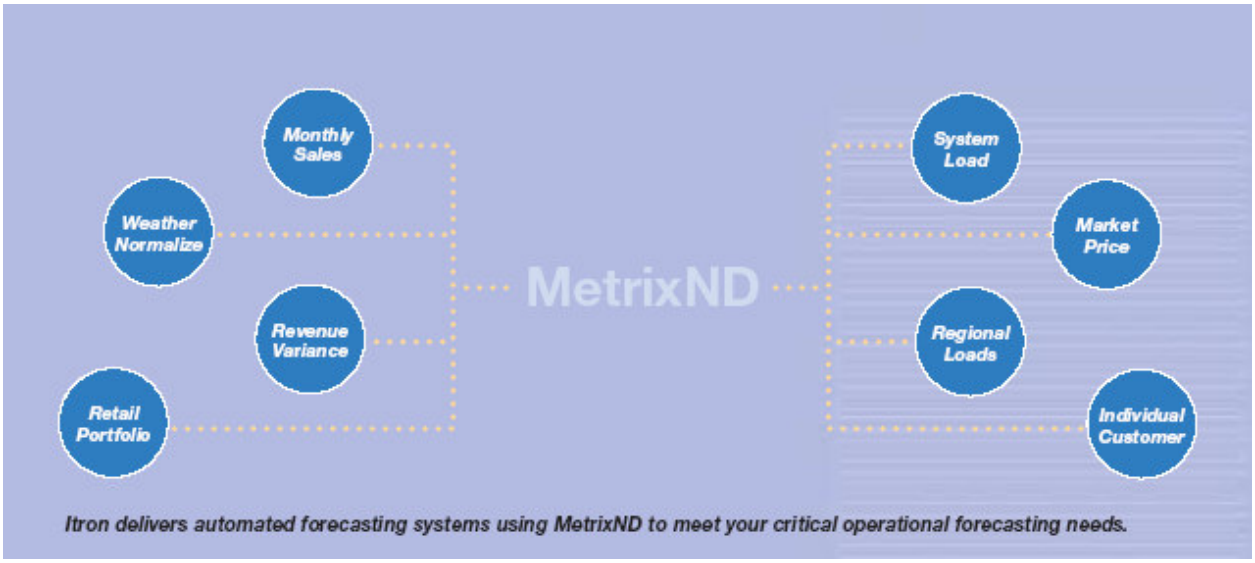
Neural Networks
Essential for short-term forecasting where modeling the nonlinear response between loads and weather matters the most.

You choose the method that works best for your data and MetrixND will deliver accurate results, quickly and easily. Or, use a combination of methods to provide optimal forecast accuracy.



Designed to take advantage of advanced Windows capabilities, MetrixND's intuitive user interface and drag-and-drop architecture streamlines the development of forecasting variables and models. Evaluation graphs, diagnostic statistics, and reports are readily available to assist in developing and analyzing forecasts. This interactive design strategy allows the forecast analyst to quickly evaluate alternative models and select the model that works the best for their particular data.

More than 100 utilities, ISOs, municipals, cooperatives and other energy service providers use Itron's MetrixND. Licensed users have unique access to industry experts in energy forecasting. Additional benefits include a quarterly newsletter that keeps you abreast of the latest forecasting techniques, and an annual meeting that covers the nuts and bolts of energy forecasting and brings you together to network with industry peers.



Itron delivers automated forecasting systems using MetrixND to meet your critical operational forecasting needs.

Short- and Long-Term Hourly Forecasting Applications

Hourly load forecasting applications typically use a combination of neural networks, time series, and regression approaches. No other package provides the modeling power and flexibility that MetrixND delivers. Models are customized to optimize accuracy for each location. The MetrixND modeling system allows you to quickly and efficiently evaluate load data and weather relationships, and compare the relative accuracy and stability of alternative model specifications.

Financial Forecasting

Financial forecast applications cover a range of topics, including customer, sales volume, peak, revenue, variance analyses, normalized sales and revenues. MetrixND allows you to estimate forecast models, generate sector sales forecasts, and calculate weather impacts. Results can be easily exported for generating forecast and variance analysis reports.

Retail and Delivery Point Forecasting

MetrixND supports Itron's retail and delivery point systems with sub-hourly, hourly or daily forecasts. Forecasts are created for profiles of portfolios of retail customers or lists of delivery points, where a portfolio can change on a daily basis. For individual customers or delivery points, the system provides a set of templates that are assigned based on the properties of the load. This allows simple models to be used for calendar-driven loads, while more complex models are used for loads driven by weather, price or other factors.

MetrixLT™

Itron MetrixLT is designed specifically for developing hourly and sub-hourly load shape forecasts to support utility generation, transmission and distribution planning. With MetrixLT, it's easy to create "bottom-up" system load forecasts that build from the end-use, rate class, or revenue class level. Built-in functionality allows you to calibrate load shape profiles or day-type load shapes to annual or monthly energy forecasts. MetrixLT provides functionality for calibrating a long-run forecast consistent with actual system loads or with short-run load forecasts, while robust reporting capabilities allow the user to summarize hourly data or forecasts into daily, monthly, or annual tables.

MetrixLT supports the following types of functionality:

- Import monthly, daily, hourly, and sub-hourly data and forecasts
- Import day-type load shapes
- Scale load shape data or forecasts to agree with sales and peak inputs
- Adjust load shape data or forecasts for losses
- Aggregate load shape components to the system level
- Scale one load shape to be consistent with another based on an overlap period
- Create annual or monthly reports that summarize sales and peaks for a load shape

MetrixLT can import energy forecasts and load shape data directly from the MetrixND® forecasting engine, providing unlimited modeling flexibility.

STRATEGIST®

STRATEGIST® includes an automatic expansion planning module, which can determine the optimal demand and supply plan for a utility system under a prescribed set of constraints and assumptions. STRATEGIST® evaluates all combinations of generating unit alternatives and purchased power options in conjunction with existing capacity resources to satisfy forecast capacity requirements while maintaining user-defined reliability criteria. STRATEGIST® simulates the operation of a utility system to determine the cost and reliability effects of adding resources to the system or modifying the load through demand side management (DSM) programs. The simulation of the utility system operation is accomplished using dynamic programming, a mathematical technique useful for making a sequence of interrelated decisions for determining the combination of decisions that optimizes the desired outcome.

PROMOD IV

PROMOD IV is a comprehensive computer software program (developed by NewEnergy) for detailed chronological hourly production costing simulations for various generation expansion scenarios or operational strategies.

Appendix C – Coordination Letters

October 10, 2007

Mr. Kevin Noblet
Vice President, Energy Resources
Aquila Networks
20 W. 9th Street
Kansas City, MO 64105

Subject: PSCo 2007 Resource Plan Information

Dear Kevin:

As you know, according to the Colorado Public Utilities Commission Resource Planning Rules that apply to all jurisdictional electric utilities in the state, PSCo is required to coordinate their reporting of purchases and sales between the companies. With this letter, Public Service Company is requesting that Aquila confirm that the transaction information listed below is consistent with that which Aquila plans to use in its resource plan filing for Aquila Networks-WPC.

Specifically, our request relates to LCRP rule 3607(b), which states:

> "Utilities required to comply with these rules shall coordinate their plan filings such that the amount of electricity purchases and sales between utilities during the planning period is reflected uniformly in their respective plans. Disputes regarding the amount, timing, price, or other terms and conditions of such purchases and sales shall be fully explained in each utility's plan. If a utility files an interim plan as specified in rule 3603, the utility is not required to coordinate that filing with other utilities."

Currently, PSCo and Aquila Networks-WPC are counter-parties in one purchased power agreement (PPA), under which Aquila purchases system firm power from Xcel Energy through the end of December 2011. Specifically, the PPA between our companies provides for the sale and delivery of the following quantities of firm capacity.

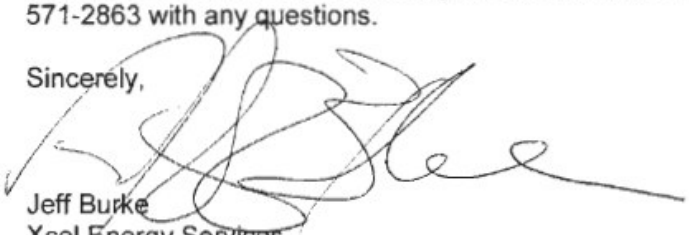
Year	Summer Capacity (MW)
2007	260
2008	270
2009	280
2010	290
2011	300

Of course, the capacity amounts shown are subject to all of the other terms and conditions of the specific contract between PSCo and Aquila Networks-WPC. This letter is not intended to limit Public Service or Aquila in any manner regarding future administration of this or other contracts.

If you agree with this contract information, please reply with a letter of acknowledgement to my attention. We anticipate that we will include your reply letter, as well as this letter of request, in our plan filing to demonstrate compliance with the rule cited.

Thank you in advance for reviewing this information. Please contact me at (303) 571-2863 with any questions.

Sincerely,



Jeff Burke
Xcel Energy Services
Resource Planning and Bidding
550 15th Street
Suite 1000
Denver, CO 80202

October 11, 2007

Jeff Burke
Xcel Energy Services
Resource Planning and Bidding
550 15th Street; Suite 1000
Denver, CO 80202

Dear Mr. Burke:

Kevin Noblet forwarded to me your letter dated October 10, 2007. Your letter requests confirmation of the contract information contained in that letter. The request for confirmation is in order to comply with certain Colorado Public Utilities Commission Resource Planning Rules.

As noted in your letter, the capacity amounts shown are subject to all of the other terms and conditions of the specific contract between PSCo and Aquila Networks-WPC. This letter is not intended to limit Public Service or Aquila in any manner regarding future administration of this or other contracts.

Currently, PSCo and Aquila Networks-WPC are counter-parties in one purchased power agreement (PPA), under which Aquila purchases system firm power from Xcel Energy through the end of December 2011. Specifically, the PPA between our companies provides for the sale and delivery of the following quantities of firm capacity.

Year	Summer Capacity (MW)
2007	260
2008	270
2009	280
2010	290
2011	300

If I can provide additional assistance, you may contact me at (816) 467-3222.

Sincerely,

Davis Rooney
Aquila, Inc.
Director, Resource Planning
20 W. Ninth Street
Kansas City, MO 64105

Appendix D

Table D-1
2007 Coal-Fired Power Plant Cancellations/Delays

Utility	Name of Facility	Size (MW)	Technology	Expected In-Service Date	Location	Date Cancelled/Delayed
PacifiCorp	Hunter 4	575	PC	TBD	Utah	January 2007
TXU	Big Brown 3	858	Coal	TBD	Texas	February 2007
TXU	Future Gen	275	Experimental Carbon Capture	2012	Illinois	February 2007
TXU	Lake Creek 3	858	Coal	TBD	Texas	February 2007
TXU	Martin Lake 4	858	Coal	TBD	Texas	February 2007
TXU	Morgan Creek 7	858	Coal	TBD	Texas	February 2007
TXU	Monticello 4	858	Coal	TBD	Texas	February 2007
TXU	Tradinghouse 3 & 4	1716	Coal	TBD	Texas	February 2007
TXU	Valley 4	858	Coal	TBD	Texas	February 2007
Duke Energy	Cliffside	800	PC	2011	North Carolina	March 2007
Associated Electric Cooperative	Norborne Base load	660	Super Critical	2013	Missouri	March 2007
Corn Belt Energy	Elkhart	91	Low Emission Boiler System (LEBS)	TBD	Illinois	March 2007
Turris Coal Company	Elkhart	25-35	Circulating fluidized bed	TBD	Illinois	May 2007
Illinois Energy Group	Benton	1500	coal	TBD	Illinois	May 2007
Dynegy	Baldwin Energy Complex	1300	coal	2007	Illinois	May 2007
Clean Coal Power Resources	Fayette County Econ Dev Project	2400	IGCC		Illinois	May 2007
Colorado Springs Utilities	Ray D Dixon	150	Circulating fluidized bed	2008	Colorado	2007
Xcel Energy	Rosemount	550			Minnesota	2007

Utility	Name of Facility	Size (MW)	Technology	Expected In-Service Date	Location	Date Cancelled/Delayed
Nuvista Power and Light	Bethel Power Plant	100	coal	2010	Alaska	2007
NRG	Indian River	630	IGCC		Delaware	May 2007
Tondu Corp	Nueces	600	IGCC	2012	Texas	June 2007
Florida Power & Light	Glades	980	Ultra-supercritical	2012	Florida	July 2007
Florida Municipal Power Agency	Taylor Energy Center	800	Super Critical	2012	Florida	July 2007
Tenaska Energy	Sallisaw	660-880	Pulverized Coal	TBD	Oklahoma	July 2007
Excelsior Energy	Mesaba	600	IGCC	TBD	Minnesota	August 2007
Great North Power	South Heart Power Project	500	Coal-to-gas	TBD	North Dakota	August 2007
Great North Power	Nelson Creek	500	Circulating fluidized bed	TBD	Montana	August 2007
Seminole Electric Power Cooperative	Seminole 3	750	coal	2012	Florida	August 2007
Peabody Coal	Thoroughbred Generating Station	1500	Pulverized Coal	TBD	Kentucky	August 2007
Southwestern Power Group	Bowie	600	IGCC	2012	Arizona	September 2007
Bull Mountain Power Project	Roundup	780	PC	TBD	Montana	September 2008
American Electric Power/OGE	Red Rock	950	Ultra-supercritical	2011	Oklahoma	September 2007
Rochester Gas and Electric	Russell Station II	300	Circulating fluidized bed	TBD	New York	September 2007
Xcel Energy	Unnamed	300-350	IGCC	TBD	Colorado	October 2007
Tampa Electric	Polk Power Station Unit 6	630	IGCC	2013	Florida	October 2007
Dynergy/LS Power	West Deptford	500	Pulverized Coal	TBD	New Jersey	October 2007
Sunflower Electric Power Cooperative	Holcomb	2100	Super Critical	2012	Kansas	October 2007, Governor's Third Veto Upheld May 1, 2008
Buffalo Energy	Glenrock	1100	IGCC	2009	Wyoming	October 2007
Matanuska Electric Association	Matanuska Power Plant	100	Circulating fluidized bed	2015	Alaska	October 2007
Madison Power	Marion Gasification	500	IGCC	TBD	Illinois	October 2007
RE/Sources	Twin River Energy Center	700	IGCC	TBD	Maine	November 2007

Utility	Name of Facility	Size (MW)	Technology	Expected In-Service Date	Location	Date Cancelled/Delayed
PacifiCorp	Intermountain Power Project 3	900	Pulverized Coal	2012	Utah	December 2007
Idaho Power	Pocatello/Soda Springs	250	IGCC	2014	Idaho	November 2007
Energy Northwest	Pacific Mountain Energy	600	IGCC	2012	Washington	November 2007
Orlando Utilities Commission	Stanton Energy Center	285	IGCC	2010	Florida	November 2007
Point East	Twin River Energy Center	700	IGCC	TBD	Maine	November 2007
PacifiCorp	Sweetwater	450	IGCC	TBD	Wyoming	December 2007
PacifiCorp	Jim Bridger 5	600-800	PC	TBD	Wyoming	December 2007
Mountain Island Energy	Soda Springs	250	Pressurized fluidized bed	2013	Idaho	December 2007
Kansas City, Kansas Board of Public Utilities	Nearman Creek	235	PC	TBD	Kansas	December 2007
Steelhead Energy	Southern Illinois Clean Energy Center	545	IGCC	TBD	Illinois	December 2007
Indeck Energy	Elmwood Energy Center	660	Circulating fluidized bed	2007	Illinois	December 2007

Primary Sources: "Coal plants cancelled in 2007," SourceWatch, http://www.sourcewatch.org/index.php?title=Coal_plants_cancelled_in_2007. "$45.3 Billion in U.S. Coal-Fired Power Plants Cancelled in 2007: Rising Costs Force Energy Firms to Ditch Plans for 31 New Plants – Fact Sheet by Resource Media," January 8, 2008, www.scribacrc.org/uploads/24_45.3_Billion_in_Coal_Plants_Canceled_in_07.pdf. "Progress Towards a Coal Moratorium: 59 Coal Plants Cancelled or Shelved in 2007", Coal Moratorium NOW!, cmnow.org/59plants.pdf.

Appendix E - Calculation of Black Hills/Colorado Electric Utility Company, LP 2005 CO_2 Footprint

2005 Generating Resource CO_2 Contribution	
Unit/Fuel Type	Tons of CO_2
Cañon City 1/Coal	151,786.21
Cañon City 2/Coal	238,308.42
Pueblo 5/Gas	10,730.38
Pueblo 6/Gas	5,912.40
Pueblo Diesels	1,519.11
Pueblo Airport Diesels	876.55
Rocky Ford Diesels	1,817.30
Total	410,932.38

2005 PSCo PPA CO_2 Contribution	
PSCo 2005 Total CO_2 Emissions	31.9 (Million Tons)
PSCo 2005 Total MWh Sales	33,920,956 (MWh)
CO_2 per MWh	0.94 (Tons per MWh)

2005 Total PPA CO_2 Contribution	
MWh Purchased from PSCo	1,788,901
CO_2 Contribution (0.94 x MWh)	1,681,567
MWh from WAPA Swap Agreements	135,600
CO_2 Contribution (0.94 x MWh)	127,464
Total PPA CO_2 Contribution	1,809,031

2005 Company Total CO_2 Emissions	
Tons of CO_2 from Generation	410,932.38
Tons of CO_2 from Purchased Power	1,809,031.00
2005 Total Tons of CO_2	2,219,963.38

The Company's customers have been using energy provided by PSCo under the PSCo PPA for many years. Greenhouse gas emissions associated with that energy and the other energy consumed by the customers were produced as a result of the resource needs of the customers. Thus, the 2005 carbon footprint is based on a pro rata share of PSCo's system carbon dioxide (CO_2) emissions in 2005, along with the 2005 CO_2 emissions associated with purchased power from other entities, and the 2005 actual CO_2 emissions of the Company's owned resources.