Electricity Supply and Demand in Montana

The electricity industry is not in the crisis it was four years ago. The price spikes and supply disruptions of 2000 and 2001 are gone, though the investigations and court cases continue. Sweeping changes in the electricity industry appear to have slowed almost to a stop. Still, the industry has not returned to where it was before. The deregulation of the wholesale electricity markets through the federal Energy Policy Act (1992) and deregulation of the Montana retail market by SB390 (1997) have not been repealed. NorthWestern Energy, the successor to Montana Power Company, should emerge from bankruptcy this fall. The first new generation in eight years came on-line in 2003. Several more moderate-size plants will be on-line this year and next. Larger ones are in the planning stages. Industrial consumption has dropped dramatically, but loads are growing in other sectors. The electricity industry continues to change.

This chapter provides historical supply and demand information needed to put this change in context. Transmission, which affects access to out-of-state markets by Montana suppliers and consumers, is covered in a separate chapter.

1. Necessary Definitions

Certain terms are used throughout this chapter and are explained here. Electricity is measured in kilowatt-hours (kWh) or megawatt-hours (MWh). A MWh is 1,000 kWh. One MWh is produced when a 1 MW generator runs for one hour. A 1 MW generator running for all the 8,760 hours in a year produces 1 average Megawatt (aMW). As one illustration of electricity use, residential customers without electric heat use typically use 10-30 kWh per day. As another, the Helena and the Helena Valley at the beginning of the decade used around 80 aMW (700 million kWh), with a peak around 140 MW (Data request MCC-8, PSC Docket No. D2001.10.144).

Montana Power Company (MPC) sold most of its generating units to PPL Montana at the end of 1999. The remainder of the generating units, contracts, and leases, as well as the entire distribution utility, was sold to NorthWestern Energy (NWE) in February 2002. Data from the period of MPC ownership are labeled PPL Montana or NWE to be more useful for today's reader.

2. Montana in Perspective

Montana generates more electricity than it consumes. Even so, it is a small player in the western electricity market. Montana generating plants have the capacity to produce 5,100 MW of electricity in the summer. Primarily because hydro generators depend on the rise

Key Electricity Facts for Montana		
Generation capability	-	5,100 MW
Average generation	-	3,000 aMW
Average load	-	1,600 aMW

and fall of river flows, but also because any plant needs downtime for refurbishing and repairs, Montana produced an annual average of 3,000 aMW (1999-2003). This is down about 6 percent from the previous period, primarily because of drought reducing production at hydro facilities. During that time, Montana sales and transmission losses accounted for slightly more than half of production, or less than 1,600 aMW.

Montana straddles the two major electric interconnections in the country. Most of Montana is in the western interconnection, which covers all or most of 11 states and two Canadian provinces; it also includes small portions of one Mexican and three other US states. Only about 7 percent of Montana's load and about 2 percent of the electricity generated in Montana is in the eastern interconnection. The 2003 Montana load (sales plus transmission losses) was equivalent to less than 2 percent of the 90,772 aMW load in the western interconnection. Montana generation accounted for over 3 percent of total west-wide generation that year.

3. Generation

Average Generation by Company, 1999-2003

Company	aMW	Percent
PPL Montana[1,2]	914	30.5%
Puget Sound Power & Light[2]	546	18.2
Avista[2]	360	12.0
Bonneville Power Administration[3]	312	10.4
Portland General Electric[2]	239	8.0
Western Area Power Administration[3]	197	6.6
NorthWestern Energy[2,4]	181	6.0
PacificCorp[2]	122	4.1
Yellowstone Energy Partnership	47	1.6
Other	77	2.6
TOTAL	2,994	100.0%

[1] PPL Montana plants were owned by MPC until mid-December 1999.
[2] Public data on output for Colstrip 1-4 are reported for the entire facility, not individual units. In this table, the output was allocated among the partners on the basis of their ownership percentages. NWE actually leases its portion of Colstrip.
[3] Distributes power generated at U.S. Corps of Engineers and U.S. Bureau of Reclamation dams.
[4] MPC sold its plant, contracts, and leases to NWE in February 2002.
Source: Table E2.

There are 44 generating facilities in Montana reported in Table E1. (Over 1 MW of small commercial and residential wind turbines are known to be in operation but aren't formally reported.) The oldest is Madison Dam near Ennis, built in 1906. The largest facility is the four privately owned coal-fired plants at Colstrip, which have a combined capability of 2,094 MW. (Capability is the maximum amount of power a plant can be counted on to deliver to the grid, net of in-plant use.) The largest hydroelectric plant is U.S. Corps of Engineers' Libby Dam with 598 MW. The smallest commercial plants supplying the grid in Montana are a micro-hydro plant at 60 kW and several wind turbines at 65 kW.

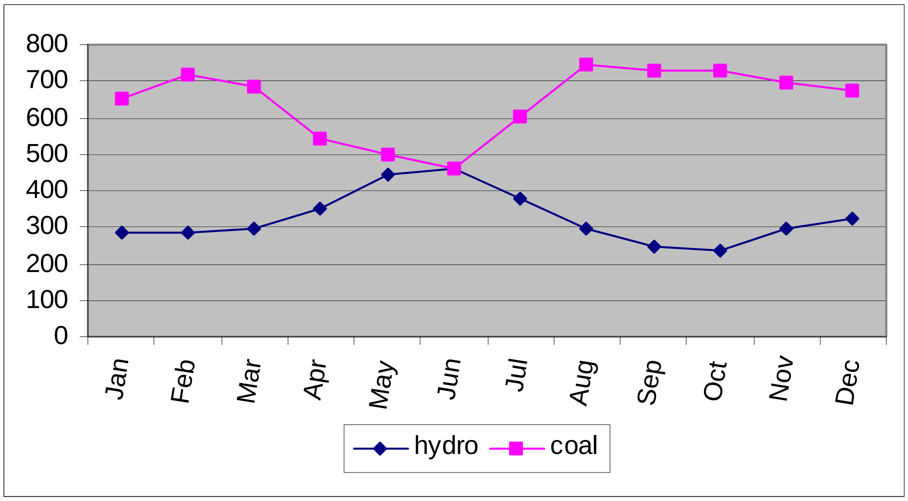
Two plants have come on line this decade: Montana Dakota Utilities' (MDU) Glendive #2 43.0 MW natural gas turbine and Tiber Montana LLC's 7.5 MW hydro plant at Tiber Dam. In the previous decade, the only sizeable additions were two plants built to take advantage of the federal Public Utility Regulatory Policies Act of 1978. PURPA established criteria under which, prior to deregulation of the wholesale electricity markets, non-utility generators (or qualifying facilities—QFs) could sell power to utilities. The Montana One waste-coal plant (41.5 MW) was built near Colstrip in 1990 and the BGI petroleum coke-fired plant (65 MW) was built in Billings in 1995. These two account for about 92 percent of the average production of all QFs in Montana.

PPL Montana plants (previously owned by MPC) produce the largest amount of electricity in Montana (see previous page; Table E2). PPL Montana's facilities accounted for over 30 percent of the total generation in Montana in the period 1999-2003. Federal agencies—the Bonneville Power Administration and Western Area Power Administration—collectively produced 18 percent of the electricity generated in Montana. The MPC plants not bought by PPL—Milltown Dam and a lease for a share of Colstrip Unit 4—now belong to NorthWestern Energy and produce 6 percent of the electricity.

Montana generation is powered almost entirely by coal (63 percent average for 1999-2002) and hydro (35 percent). Over the last 15 years, about a quarter of Montana coal production has gone to generate electricity in Montana. Until 1986, hydro was the dominant source of net electric generation in Montana (Table E5). Most of the small amount of petroleum used actually is petroleum coke from the refineries in Billings. Very small amounts of natural gas and wind round out the picture.

During spring runoff, utilities operate their systems to take advantage of cheap hydropower, both on their systems and on the non-firm market around the region. Routine maintenance on thermal plants is scheduled during this period. Thermal plants generally must be run more in the fall when hydro is low. This pattern is apparent in the graph of operations on PPL Montana's plants during 2001 through 2003 (see Figure 1).

Figure 1. Average output of PPL Montana power plants, 2001-2003 (aMW)

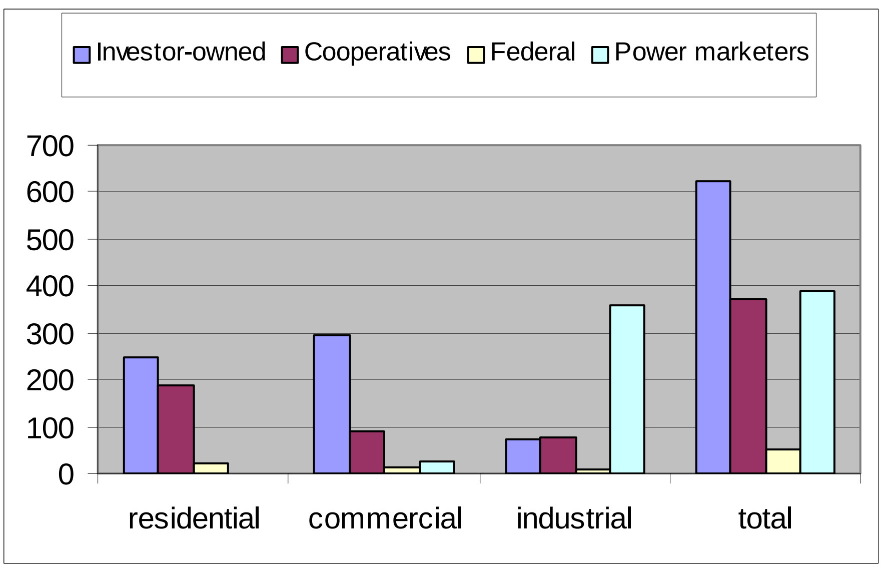


Note: Assumes PPL's monthly production from Colstrip 1- 4 was equal to its ownership share.
Source: U.S. DOE, Energy Information Administration, Form EIA906 databases
http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html.

4. Consumption

Montanans are served by 32 distribution utilities: 2 investor-owned, 26 rural electric cooperatives, 3 federal agencies and 1 municipal (Table E9; Maps). Two additional investor-owned utilities and four additional co-ops, based in other states, serve a handful of Montanans. In 2002, NWE and BPA also distributed power from six power marketers, primarily to industrial customers (Table E8). In 2002, investor-owned utilities made 43 percent of the electricity sales in Montana, co-ops 26 percent, federal agencies 4 percent and power marketers 27 percent (Table E8; Figure 2). Three-quarters of these entities operate mostly or exclusively in Montana.

Figure 2. Distribution of 2002 sales by type of utility (aMW)

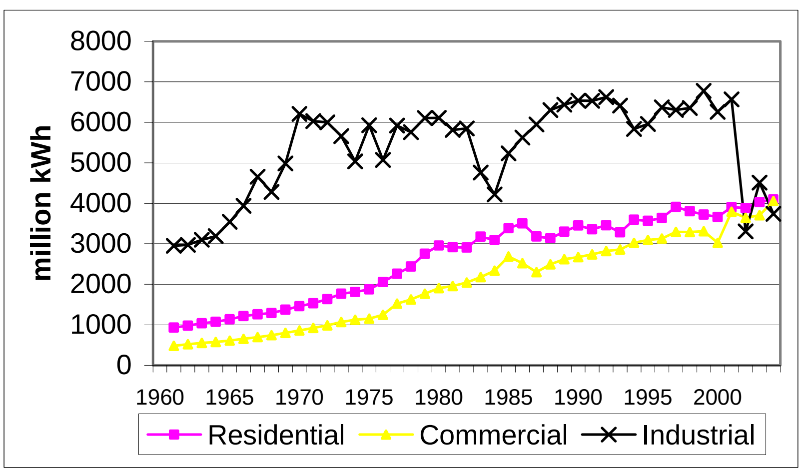


Source: Table E8.

Reported sales in 2003 were 12.2 billion kWh. (Unreported power marketer sales may have been around 0.3 billion kWh.) The residential, commercial and industrial sectors each accounted for about one-third of sales. Sales tripled between 1960 and 2000, then dropped by over 15 percent as industrial loads tumbled following the electricity crisis of 2000-2001 (Table E6; Figure 3). Growth was faster in the first half of those four decades than in the latter. Since 1990, sales to the commercial sector have grown the most, followed by the residential sector. Industrial sales bounced around, then dropped significantly. Consumption patterns in this decade will be noticeably different than those of previous decades.

The cost of electricity changed dramatically following 2000 (Table E7). The average price per kWh for residential customers was 7.6 cents in 2003, up from 6.5 cents in 2000. The average price per kWh for commercial customers was 6.5 cents in 2003, up from 5.6 cents in 2000; for industrial, the comparable figures are 4.5 cents and 4.0 cents. The residential and commercial sectors saw about the same increase in price between 2000 and 2003 as they did during the entire previous decade. As in the other sectors, industrial electricity prices increased between 2000 and 2003 at a faster rate than they did during the 1990's, but the total increase was not as great as in the residential and commercial sectors. On average, the rates of cooperatives and private utilities were within about 6 percent of each other in 2003; however, that average masks considerable variation. As in previous decades, electricity in Montana costs less than the national average. In 2003, Montana averaged 6.3 cents/kWh vs. 7.4 cents/kWh nationally.

Figure 3. Annual sales in Montana, 1960-2003



Percentage of sales, 2003

Residential	-	34 %
Commercial	-	33
Industrial	-	31
Other	-	2
Total	-	100 %

Source: Table E6.

Montana residential consumption averaged 810 kWh/month in 2003, or about 1.1 akW annually, basically unchanged since 2000 (Table E8). This average covers a wide range of usage patterns. Households without electric heat can run 200 kWh to 1,000 kWh per month (0.3-1.4 akW annually), depending on size of housing unit and amount of appliances. Electrically heated houses easily could range between 1,800 kWh to 3,000 kWh per month (2.5 and 4.1 akW annually). Extreme cases could run higher or lower than these ranges.

Commercial accounts averaged 3,840 kWh/month or 5.2 akW per year. Because so many different types of buildings and operations are included in the commercial sector, it's difficult to describe a typical use pattern.

Variability in the load and pattern of use are even greater in the industrial sector. Some of the largest industrial customers are shown in the following table. These figures date from before the price spikes in 2000 and 2001 forced some companies to cut consumption, but are the only data available. Data on coal mines, which are major consumers, were not available.

Large Industrial Electricity Use (aMW)

ASiMI	~75	Holcim	5.0
Ash Grove Cement	4.6	Roseburg Forest Products*	7.0
Cenex	18	Montana Refining	3.4
Conoco Pipeline	20.0	Montana Tunnels	9.5
Conoco Refinery	27.0	Plum Creek	33
ExxonMobil	27.0	Smurfit-Stone	52.0
Golden Sunlight	10.0	Stillwater Mining	20.0

Data initially provided from best available sources by Don Quander, Large Customer Group; compiled by EQC and DEQ.

*At the time, Louisiana Pacific Corporation.

5. Future Supply and Demand

New generating plants are starting to appear in Montana. Glendive #2, a 43 MW gas turbine, came on-line in 2003, followed in 2004 by Tiber Dam, a 7.5 MW hydro facility. Other plants are under construction or have obtained all the necessary permits. Thompson River Co-gen plant, a 16.5 MW coal or biomass-fired fluidized bed plant is nearing completion, though there may be some question about its permits. Rocky Mountain Power, near Hardin, is a 116 MW pulverized coal plant expected on-line toward the end of 2005. A 51 MW natural gas combustion plant near Butte and wind plants near Great Falls (9 MW) and Judith Gap (180 MW at build-out) are very near construction. Numerous other coal and wind plants around the state are in various earlier stages of preparation.

Electricity sales show an overall decline. The overwhelming majority of Montana customers, including many of those served by co-ops, have seen significant increases in the cost of electricity since 2000, the start of the electricity crisis. In spite of that, residential consumption rose at an average annual rate of 1.6 percent (2000 to 2003) and commercial consumption at 2.3 percent. Residential growth tends to track population growth, while commercial growth tends to track economic activity, but growth in both sectors will slow if prices continue to rise. Industrial consumption, on the other hand, has fallen dramatically, due to plant closures and operations cutbacks following the surge in electricity prices.

There are no statewide forecasts for future electricity consumption. The rising prices of electricity combined with an economy that has slowed since the early 1990's suggest the growth in electricity consumption will be slower this decade than the last. The drop in the industrial sector has led to Montana loads declining by over 250 aMW since 2000. Improved efficiency, especially in response to higher prices also could reduce loads significantly (see Section 6). Finally, if the trend over the last few decades towards warmer winters continues, Montana's electricity use could decline further.

To be economically viable, any addition to generation resources in Montana will need contracts in out-of-state markets or to displace existing resources for in-state consumption. Therefore, any new generation would need 1) to offer the price and have the transmission access to compete in out-of-state markets; 2) to offer a better package of prices and conditions than those resources currently supplying Montana loads; or 3) to be conceded a Montana market by existing resources choosing to take higher profits by selling out of state. Transmission access is a critical issue; it is discussed in a separate chapter.

6. Potential for Efficiency Improvements

Cost-effective energy efficiency improvements plausibly could meet much or all of the net increase in statewide load over the next decade. There are no comprehensive estimates of the potential for efficiency improvements. However, analyses that have been done and the load reductions seen during the electricity crisis in 2000 and 2001 suggest that significant potential exists.

Efficiency improvements reduce both cost and risk. First, they can reduce the total cost of energy services. For customers, they reduce the monthly bill. For providers, they postpone or eliminate the need to acquire more expensive resources. Second, efficiency improvements reduce exposure to electricity price volatility. By reducing the need for electricity, especially peak-hour electricity, such improvements provide a hedge against the impacts of expensive upswings in price.

The amount of energy efficiency improvements worth pursuing depends on the future price of electricity. The lower or the less volatile expected future prices, the less attractive energy efficiency investments are. The higher or more volatile expected future prices, the more attractive such investments are. Just like any other energy resource, there is a range of energy efficiency rather a fixed amount waiting to be developed.

There are no statewide estimates of the potential energy efficiency improvements, either in total or by sector. While some of the easiest and least difficult to obtain are in large commercial and industrial operations, potential efficiency improvements can be found in all sectors. Based on studies around the country, as well as some in-state estimates, it has been reasonable to assume potential reductions are in a range around 10 percent. Given how perceptions of the electricity industry have changed over the last two years, that range may be low.

NorthWestern Energy currently is developing a program to add energy efficiency to its resource portfolio. As this program gets underway, better estimates of the efficiency potential in Montana should be developed. (NWE still is the largest provider of electricity in Montana, accounting for about 40 percent of total sales.)

The reductions can't be compared to the extensive load reductions in 2001 around the western United States. These were short-term responses to a crisis situation. However, the crisis did give an indication of the amount of flex in electricity use and suggests the magnitude of changes in use that are possible. Those changes are far larger than had been expected previously.

The Readiness Steering Committee of the Pacific Northwest region studied the impact of various actions to reduce energy use in the region during the electricity crisis of 2000-2001. (The committee was an ad hoc group of utility industry, large customer and public agency representatives that advised the Northwest Power Pool and the region on electricity shortages.) The committee, in an October 2001 special report, estimated that the total impact of all electricity demand actions was a reduction by summer of 2001 of about 4,000 megawatts, almost 20 percent of what Northwest loads would have been under normal conditions. These actions included utility initiated programs, general appeals to the public and the response of consumers to price increases.

The largest portion of the response came from curtailing industrial production. By July 2001 the electricity use of aluminum smelters had almost completely disappeared, a reduction of more than 2,500 megawatts; operators found it more profitable to resell their contracted supplies than to produce aluminum. Irrigation customers also reduced their use by an average of 300 megawatts over the May-September irrigation season, in exchange for payment from their suppliers. About 500 megawatts of reduction came from industrial customers who faced high market prices. Not all of this reduced use was due to cutbacks in operations; a portion came from customers beginning to generate some of their own electricity. Another 160 megawatts came from customers in other sectors who accepted payment from their electricity suppliers to reduce their consumption by cutting back operations. Demand response to higher electricity rates charged by some utilities was estimated at about 150 megawatts by July. Finally, while customers of most utilities were insulated from the high prices in the wholesale market, expanded conservation education programs, along with the media coverage of the California shortages, were believed to have caused some reduction in regional loads, though this couldn't be quantified.

The load reductions seen by the summer of 2001 would not be cost-effective or advisable under normal conditions. What they do show is the ability of consumers to change their usage in the face of higher prices, either in terms of what they pay or what they're offered to forego using electricity. As prices for electricity climb, some improvement in the economy's energy efficiency can be expected in any event, though not to the extent that could come from a more formal program of resource acquisition. Difficulties in obtaining information and financing always will deter some individual consumers from otherwise cost-effective investments.