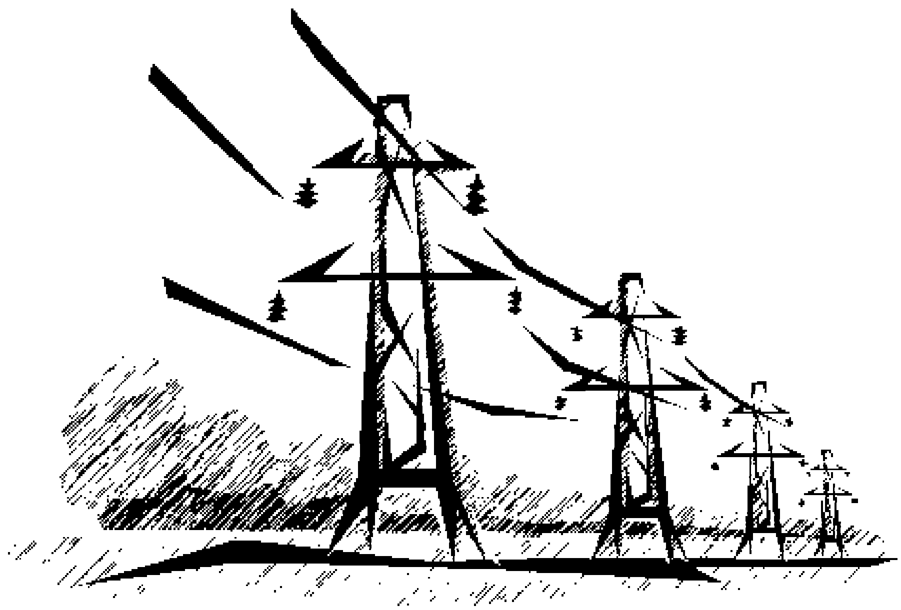
UNDERSTANDING ENERGY IN MONTANA



A Guide to Electricity, Natural Gas, Coal, and Petroleum Produced and Consumed in Montana

DEQ Report for the EQC

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Table of Contents

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Introduction

Energy issues have returned to the forefront this decade. The last four years have seen the California energy crisis, the sale of Montana Power Company and subsequent bankruptcy of NorthWestern Energy, the dramatic increase in the price of natural gas, serious talk of new markets and new transmission lines for Montana coal, and forty dollar a barrel oil. The EQC prepared this guide to provide the background information policymakers and citizens alike will need to make the best decisions they can in these turbulent times.

The guide focuses on historical and current patterns of supply and demand. These are the background facts needed to interpret past and future policies. The guide is divided into five sections. First is an overview of electricity supply and demand in Montana. The second section covers the electricity transmission system, especially how it works in Montana and the Pacific Northwest. This is the critical issue affecting access to existing markets and the potential for new generation in Montana. A third section addresses natural gas supply and demand, important in its own right and now much more intertwined with the electricity industry. The fourth section covers the Montana coal industry, which exists to fuel the generation of electricity and whose future will depend on what happens in that industry. The final section addresses petroleum and transportation, the sector most directly affected by international events.

The guide, with its focus on historical and current patterns, deals primarily with conventional resources. Nonetheless, Montana can expect to see renewables take a larger role in the future, especially in electricity supply. Energy efficiency (sometimes referred to as energy conservation) also is only given brief treatment, simply because so few data are available. Still, improving energy efficiency remains the cheapest way to meet energy demand. Public agencies, private business and individual citizens need to keep these possibilities in mind, even while they focus on the immediate problems with conventional resources.

Glossary

General

British Thermal Unit (Btu): A standard unit of energy equal to the quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit (F).

Class of Service: A group of customers with similar characteristics (e.g., residential, commercial, industrial, sales for resale, etc.) identified for the purpose of setting a utility rate structure.

Cogeneration: A process that sequentially produces useful energy (thermal or mechanical) and electricity from the same energy sources.

Consumer Price Index (CPI): This index is issued by the U.S. Department of Labor, Bureau of Labor Statistics as a measure of average changes in the retail prices of goods and services caused by inflation.

Demand-Side Management: Utility activities designed to reduce customer use of natural gas or electricity or change the time pattern of use in ways that will produce desired changes in the utility load.

End-Use Sectors: Energy use is assigned to the major end-use sectors according to the following guidelines as closely as possible:

Residential sector: Energy consumed by private household establishments primarily for space heating, water heating, air conditioning, cooking, and clothes drying.

Commercial sector: Energy consumed by non-manufacturing business establishments, including motels, restaurants, wholesale businesses, retail stores, laundries, and other service enterprises; by health, social, and educational institutions; and by federal, state, and local governments.

Industrial sector: Energy consumed by manufacturing, construction, mining, agriculture, fishing, and forestry establishments.

Transportation sector: Energy consumed to move people and commodities in both the public and private sectors, including military, railroad, vessel bunkering, and marine uses, as well as the pipeline transmission of natural gas.

Electric utility sector: Energy consumed by privately and publicly owned establishments that generate electricity primarily for resale.

Fossil Fuel: Any naturally occurring fuel of an organic nature, such as coal, crude oil, and natural gas.

Fuel: Any substance that, for the purpose of producing energy, can be burned, otherwise chemically combined, or split or fused in a nuclear reaction.

Implicit Price Deflator: A measure over time of price changes of goods and services. Unlike the Consumer Price Index, it is not based on surveys of the cost of a theoretical "market basket" of items, but rather is derived from data collected for the National Income Accounts. For this reason, it reflects price changes in actual current patterns of production and consumption.

Nominal Dollars: Dollars that measure prices that have not been adjusted for the effects of inflation. Nominal dollars reflect the prices paid for products or services at the time of the transaction.

Real Dollars: Dollars that measure prices that have been adjusted for the effects of inflation, using an index such as the Implicit Price Deflator (see Implicit Price Deflator).

Renewable Energy: Energy obtained from sources that are essentially sustainable (unlike, for example, the fossil fuels, of which there is a finite supply). Renewable sources of energy include wood, waste, solar radiation, falling water, wind, and geothermal heat.

Short Ton: A unit of weight equal to 2,000 pounds. All tonnages used in this publication are in short tons.

Coal

Average Mine Price: The total value of the coal produced at the mine divided by the total production tonnage (see FO.B. Mine Price).

Coal: A black or brownish-black solid combustible substance formed by the partial decomposition of vegetable matter without free access to air and under the influence of moisture and, often, increased pressure and temperature. The rank of coal (anthracite, bituminous, subbituminous, and lignite) is determined by its heating value.

Anthracite: Hard and jet black with a high luster, it is the highest rank of coal and is mined in northeastern Pennsylvania. Anthracite contains approximately 22 to 28 million Btu per ton as received.

Bituminous: The most common coal, it is soft, dense, and black with well-defined bands of bright and dull material. Bituminous is ranked between anthracite and subbituminous and is mined chiefly in Kentucky, Pennsylvania, and West Virginia. The heating value ranges from 19 to 30 million Btu per ton as received.

Lignite: A brownish-black coal of the lowest rank; it is mined in North Dakota, Montana, and Texas. The heat content of lignite ranges from 9-17 million Btu per ton as received.

Subbituminous: A dull black coal ranking between lignite and bituminous; it is mined chiefly in Montana and Wyoming. The heat content of subbituminous coal ranges from 16 to 24 million Btu per ton as received.

Coal Rank: A classification of coal based on fixed carbon, volatile matter, and heating value.

F.O.B. Mine Price: The "free on board" mine price. This is the price paid for coal measured in dollars per short ton at the mining operation site and, therefore, does not include freight/shipping and insurance costs.

Surface Mine: A mine producing coal that is usually within a few hundred feet of the earth's surface. Overburden (earth above or around the coal) is removed to expose the coal bed. The bed is then mined using surface excavation equipment such as draglines, power shovels, bulldozers, loaders, and augers.

Underground Mine: A mine tunneling into the earth to the coal bed. Underground mines are classified according to the type of opening used to reach the coal—i.e. drift (level tunnel), slope (inclined tunnel), or shaft (vertical tunnel).

Electricity Supply and Demand

Average Megawatt: A unit of energy output over a specified time period. For a year, it is equivalent to the total energy in megawatt-hours divided by 8,760 (the number of hours in a year).

Capacity: The amount of electric power which a generator, turbine, transformer, transmission circuit, station, or system is capable of producing or delivering.

Demand: The rate at which electric energy is delivered to a system, part of a system, or piece of equipment at a given instant or during a designated period of time (see <u>Load</u>).

Generation (Electric): The production of electric energy from other forms of energy; also, the amount of electric energy produced, expressed in kilowatt-hours (kWh).

Gross: The total amount of electric energy produced by the generating units in a generating station or stations, measured at the generator terminals.

Net: Gross generation less the electric energy consumed at the generating station for station use. (Energy required for pumping at pumped-storage plants is regarded as plant use and is subtracted from the gross generation and from hydroelectric generation.)

Gigawatt (GW): One billion watts.

Gigawatt-hour (GWh): One billion watt-hours.

Hydroelectric Power Plant: A plant in which the turbine generators are driven by falling water.

Kilowatt (kW): One thousand watts. The kW is the basic unit of measurement of electric power.

Kilowatt-hour (kWh): One thousand watt-hours. The kWh is the basic unit of measurement of electric energy, and is equivalent to 3,412 Btu.

Megawatt (MW): One million watts.

Megawatt-hour (MWh): One million watt-hours.

Nameplate Capacity: The full-load continuous rating of a generator, prime mover, or other electrical equipment under specified conditions as designated by the manufacturer. Installed station capacity does not include auxiliary or house units. Nameplate capacity is usually shown on the manufacturer's identification plate attached mechanically to the equipment. Because manufacturers have differing standards, there may be no fixed relationship between "nameplate capacity" and maximum sustainable capacity.

Load (Electric): The amount of electric power required by equipment in use at a given time at any specific point or points on a system.

PURPA: Public Utility Regulatory Policies Act of 1978. First federal legislation requiring utilities to buy power from qualifying independent power producers.

Qualifying Facilities: Small power producers or cogenerators that meet the Federal Energy Regulatory Commission's or the Montana Public Service Commission's size, fuel source, and operational criteria as authorized by PURPA.

Steam-Electric (Conventional) Plant: A plant in which the prime mover is a steam turbine. The steam used to drive the turbine is produced in a boiler by heat from burning fossil fuels (see Fossil Fuel and Fuel).

Watt: The electrical unit of power or rate of doing work. A watt is the rate of energy transfer equivalent to 1 ampere flowing under pressure of 1 volt at unity power factor (volt and ampere in phase). It is analogous to horsepower or foot-pound-per-minute of mechanical power. One horsepower is equivalent to approximately 746 watts.

Electricity Transmission

AC/DC/AC converter station: A back-to-back installation that takes Alternating Current power on one side, rectifies it to Direct Current, and then inverts the Direct Current back to Alternating Current in phase with a different system. These stations provide for power transfers between separate synchronous grids. They use the same equipment—AC/DC rectifiers and DC/AC inverters—that are required at each end of a long distance DC transmission line.

ATC: (Available Transmission Capacity) is calculated by subtracting committed uses and existing contracts from total rated transfer capacity.

Contract Path: A path across portions of the interconnected grid, owned by two or more different owners, for which a transaction has gained contractual permission from the owners or other rights holders with transferable rights.

Distribution: Relatively small, low voltage wires used for delivering power from the transmission system to local electric substation and to electric consumers. Compare with Transmission.

ERCOT: The Electric Reliability Council of Texas, a separate synchronous grid connected only by AC/DC/AC converter stations to the Western Interconnection and the Eastern Interconnection.

FERC: Federal Energy Regulatory Commission (formerly the Federal Power Commission). The federal agency that regulates interstate and wholesale power transactions including power sales and transmission services, as well as licensing of dams on rivers under federal jurisdiction.

High voltage: Voltage levels generally at above 69 kV. Some utilities also count 50 and 69 kV lines as transmission lines. Transmission lines in Montana are built at voltage levels of 100 kV, 115 kV, 161 kV, 230 kV and 500 kV. In other states lines have also been built at 345 kV and 765 kV. Canadian utilities build at still other voltage levels. Direct current transmission lines have been built at +/- 400 kV, which may sometimes be described as 800 kV.

Impedance: A measure of the composite force that must be used to push power through an Alternating Current transmission line. Impedance is composed of resistance, inductance and capacitance. Resistance is a property of the wire itself and is also present in DC circuits. Impedance is a function of expanding and collapsing magnetic fields in coils (such as transformers) in AC circuits. Capacitance is a function of expanding and collapsing electric fields in parallel wires in AC circuits. Neither impedance nor capacitance is relevant to DC transmission.

Inadvertent Flows: Portions of power transactions that flow over portions of the interconnected grid that are not on the contract path for the transaction.

IndeGO: "Independent Grid Operator" A failed effort, roughly 1998-1999, to form an organization that would have taken over operation of the Northwest transmission system. The effort was revived and superceded by the RTO West discussions.

Loop Flow: A characteristic of mass power flows across the Western Interconnection in which seasonal flows in the summer from the Northwest to California, nominally shipped south over the North-South California Intertie, flow in part around the eastern part of the interconnection through Montana, Utah and Arizona and then back into California in a clockwise direction. In the winter seasonal flows from California to the Northwest over the Intertie also flow in part counter-clockwise through the same sections of the grid. A similar phenomenon is associated with seasonal shipment of power from Arizona to California, where portions of the power flow counter-clockwise up to Montana and Idaho, into the Northwest and then south into California over the North-South Intertie.

Phase Shifter: A device for controlling the path of power flows in Alternating Current circuits.

Reliability: The characteristic of a transmission system (or other complex system) of being able to provide full, uninterrupted service despite the failure of one or more component parts.

Synchronous: Operating at the same frequency and on the same instantaneous power cycle. The Western Interconnection is a synchronous grid, which means all generators in the western grid are producing power in phase with each other (always at the same point on the same sine wave). Other synchronous grids in North America include ERCOT, Quebec, and the Eastern Interconnection (the entire continental U.S. except for ERCOT and the Western Interconnection).

Total Transfer Capacity: The rated ability of a transmission line, or group of related transmission lines, to carry power while meeting the regionally accepted reliability criteria.

Transmission: High voltage electric wires used for bulk movement of large volumes of power across relatively long distances. Compare with Distribution, which is composed of relatively smaller, lower voltage wires used for delivering power from the transmission system to local electric substation and to electric consumers.

Unscheduled Flows: See Inadvertent Flows.

Western Interconnection: The interconnected, synchronous transmission grid extending from British Columbia and Alberta in the north, to the U.S.-Mexican border in the south, and from the Pacific Coast to a line extending from the Alberta-Manitoba border through eastern Montana, eastern Wyoming, western Nebraska and the extreme west part of Texas.

West of Hatwai: A transmission path consisting of ten related transmission lines that are generally located in the area west and south of Spokane, WA. The West of Hatwai path is a bottleneck for power flowing from Montana to the West Coast and California and it is relatively heavily used.

Natural Gas

Bcf: One billion cubic feet.

Dekatherm (dkt): One million Btu of natural gas. One dekatherm of gas is roughly equivalent in volume to one mcf.

Gas Condensate Well: A gas well that produces from a gas reservoir containing considerable quantities of liquid hydrocarbons in the pentanes and heavier range generally described as "condensate."

Gas Well: A well that is completed for the production of gas from either nonassociated gas reservoirs or associated gas and oil reservoirs.

Gross Withdrawals: Full well stream volume excluding condensate separated at the lease.

Lease Condensate: A natural gas liquid recovered from gas well gas (associated and nonassociated) in lease separators or natural gas field facilities. Lease condensate consists primarily of pentanes and heavier hydrocarbons.

Liquefied Petroleum Gases (LPG): Propane, propylene, butanes, butylene, butane-propane mixtures, ethane-propane mixtures, and isobutane produced at refineries or natural gas processing plants, including plants that fractionate raw natural gas plant liquids.

Marketed Production: Gross withdrawals less gas used for repressuring, quantities vented and flared, and nonhydrocarbon gases removed in treating or processing operations.

Mcf: One thousand cubic feet. One mcf of natural gas is roughly equivalent in heat content to one dekatherm.

MMcf: One million cubic feet.

Natural Gas: A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in natural underground reservoirs at reservoir conditions. The principal hydrocarbons usually contained in the mixture are methane, ethane, propane, butane, and pentanes. Typical nonhydrocarbon gases that may be present in reservoir natural gas are carbon dioxide, helium, hydrogen sulfide, and nitrogen. Under reservoir conditions, natural gas and the liquefiable portions occur either in a single gaseous phase in the reservoir or in solution with crude oil, and are not distinguishable at the time as separate substances.

Natural Gas Liquids: Those hydrocarbons in natural gas that are separated from the gas through the processes of absorption, condensation, adsorption, or other methods in gas processing or cycling plants. Generally, such liquids consist of propane and heavier hydrocarbons and are commonly referred to as condensate, natural gasoline, or liquefied petroleum gases. Where hydrocarbon components lighter than propane are recovered as liquids, these components are included with natural gas liquids.

Petroleum

Asphalt: A dark-brown-to-black cement-like material containing bitumens as the predominant constituents obtained by petroleum processing. The definition includes crude asphalt as well as the following finished products: cements, fluxes, the asphalt content of emulsions (exclusive of water), and petroleum distillates blended with asphalt to make cutback asphalts.

Aviation Gasoline: All special grades of gasoline for use in aviation reciprocating engines, as given in ASTM Specification D910 and Military Specification MIL-G-5572. Aviation gasoline includes blending components.

Barrel: A volumetric unit of measure for crude oil and petroleum products equivalent to 42 U.S. gallons.

Crude Oil (Including Lease Condensate): A mixture of hydrocarbons that exists in liquid phase in underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Included are lease condensate and liquid hydrocarbons produced from tar sands and oil shale.

Diesel Fuel: Fuel used for internal combustion in diesel engines, usually that fraction of crude oil that distills after kerosene (See Distillate Fuel Oil).

Distillate Fuel Oil: A general classification for one of the petroleum fractions produced in conventional distillation operations. It is used primarily for space heating and on- and off-highway diesel engine fuel (including railroad engine fuel and fuel for agricultural machinery), and electric power generation. Included are products known as No. 1, No. 2 and No. 4 fuel oils; No. 1, No. 2, and No. 4 diesel fuel.

Ethanol: Ethyl alcohol or grain alcohol (CH_3CH_2OH). It is the alcohol contained in intoxicating beverages. Ethanol can be produced from biomass by the conversion process called fermentation (See Gasohol).

Gasohol: A blend of finished motor gasoline (leaded or unleaded) and alcohol (generally ethanol but sometimes methanol) in which 10 percent or more of the product is alcohol.

Jet Fuel: The term includes kerosene-type jet fuel and naphtha-type jet fuel. Kerosene-type jet fuel is a kerosene quality product used primarily for commercial turbojet and turboprop aircraft engines. Naphtha-jet fuel is a fuel in the heavy naphtha range used primarily for military turbojet and turboprop aircraft engines.

Kerosene: A petroleum distillate that boils at a temperature between 300-550 degrees F, that has a flash point higher than 100 degrees F, that has a gravity range from 40-46 degrees API, and that has a burning point in the range of 150-175 degrees F. Kerosene is used in space heaters, cook stoves, and water heaters, and is suitable for use as an illuminant when burned in wick lamps.

Liquefied Petroleum Gases (LPG): Propane, propylene, butanes, butylene, butane-propane mixtures, ethane-propane mixtures, and isobutane produced at refineries or natural gas processing plants, including plants that fractionate raw natural gas plant liquids.

Lubricants: Substances used to reduce friction between bearing surfaces or as process materials either incorporated into other materials used as processing aids in the manufacturing of other products or as carriers of other materials. Petroleum lubricants may be produced either from distillates or residues. Other substances may be added to impart or improve certain required properties.

Motor Gasoline: A complex mixture of relatively volatile hydrocarbons, with or without small quantities of additives, obtained by blending appropriate refinery streams to form a fuel suitable for use in spark-ignition engines. Motor gasoline includes both leaded and unleaded grades of finished motor gasoline, blending components, and gasohol.

Petroleum: A generic term applied to oil and oil products in all forms, such as crude oil, lease condensate, unfinished oil, refined petroleum products, natural gas plant liquids, and nonhydrocarbon compounds blended into finished petroleum products.

Petroleum Products: Petroleum products are obtained from the processing of crude oil (including lease condensate), natural gas, and other hydrocarbon compounds. Petroleum products include unfinished oils, naturalgasoline and isopentane, plant condensate, unfractionated stream, liquefied petroleum gases, aviation gasoline, motor, gasoline, naphtha-type jet fuel, kerosene-type jet fuel, kerosene, distillate fuel oil, residual fuel oil, naphtha less than 400° F end-point, other oils over 400° F end-point, special naphthas, lubricants, waxes, petroleum coke, asphalt, road oil, still gas, and miscellaneous products.

Residual Fuel Oil: The topped crude of refinery operation that includes No. 5 and No. 6 fuel oils, Navy special fuel oil, and Bunker C fuel oil. Residual fuel oil is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes.

Summary

Summary Points:

UNDERSTANDING ENERGY IN MONTANA

**A GUIDE TO ELECTRICITY,
NATURAL GAS, COAL AND PETROLEUM
PRODUCED AND CONSUMED IN MONTANA**

These lists of points summarize the guide prepared for the Environmental Quality Council. They cover the status of electricity, natural gas, coal, and petroleum supply and demand in Montana and the Montana electric transmission grid. The reader should consult the guide itself for detailed explanations of technical points and to see the data tables that underpin these summaries.

Summary

Electricity Supply and Demand in Montana

- Montana generates more electricity than it consumes. Montana generating plants have the capacity to produce 5,100 MW of electricity. An annual average of 3,000 aMW (1 aMW=8,760 MWh) was produced in the period 1999-2003. During that time, Montana consumption accounted for slightly more than half of production, with Montana sales and transmission losses averaging less than 1,600 aMW. (p. I-1)

- 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, two Canadian provinces and a bit of northern Mexico. Only about 7 percent of Montana's load is in the eastern interconnection, along with about 2 percent of the electricity generated in-state. (p. I-2)

- Montana is a small player in the western electricity market. The 2003 Montana load (sales plus transmission losses) was equivalent to less than 2 percent of the 90,772-aMW load in the entire western interconnection. Montana generation accounted for over 3 percent of total west-wide generation that year. (p. I-2)

- There are 44 electric generating facilities in Montana. The largest facility is the four privately owned coal-fired plants at Colstrip, which have a combined capability of 2,094 MW. The largest hydroelectric plant is the U.S. Corps of Engineers' Libby Dam with a capability of 598 MW. (p. I-2)

- Two plants have come on line this decade: Montana Dakota Utilities' Glendive #2 43.0 MW natural gas turbine (2003) and Tiber Montana LLC's 7.5 MW hydro plant at Tiber Dam (2004). The only electric generation plants of any size coming on line in the 1990's were two qualifying facilities (QFs): Montana One waste coal plant (41.5 MW) and BGI petroleum coke-fired plant (65 MW). These two combined now account for about 92 percent of the electricity output of QFs in Montana. (p. I-3)

- PPL Montana's facilities, previously owned by Montana Power Company, produced over 30 percent of the total generated in Montana in the period 1999-2003, making PPL the largest generating company in the state. Puget Power was the second largest producer with 18 percent. Federal agencies—the Bonneville Power Administration and Western Area Power Administration—collectively produced 18 percent of the electricity generated in Montana. (p. I-3)

- Montana generation is powered almost entirely by coal (63 percent) and hydro (35 percent) (1995-2003 average). Until 1986, hydro was the dominant source of electric generation in Montana. Over the last 15 years, about 25 percent of Montana coal production has gone to generate electricity in Montana. (p. I-3)
- Montanans are served by 32 distribution utilities: 2 investor-owned, 26 rural electric cooperatives, 3 federal agencies and 1 municipal. (Two additional investor-owned utilities and four additional co-ops based in other states serve a handful of Montanans.) (p. I-4)
- 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. (p. I-4)
- 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. (p. I-5)
- Sales tripled between 1960 and 2000, then dropped by over 15 percent as industrial loads tumbled following the electricity crisis of 2000-2001. (p. I-5)
- The cost of electricity changed dramatically following 2000. 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. (p. I-5)
- In 2003, Montana prices averaged 6.3 cents/kWh vs. 7.4 cents/kWh nationally. (p. I-5)
- Plants under construction include Thompson River Co-gen plant, a 16.5 MW coal or biomass-fired fluidized bed plant and Rocky Mountain Power, a 116 MW pulverized coal plant near Hardin. (p. I-6)
- There are no comprehensive estimates of the potential for efficiency improvements. However, it is reasonable to assume potential reductions are in a range around 10 percent. (p. I-7)
- During the electricity crisis of 2000-2001, the Pacific Northwest ultimately reduced its demand by around 20 percent. Most of that came from business suspensions, primarily in response to payments from their electricity providers. This reduction would not be advisable or cost-effective under normal conditions, but does indicate 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. (p. I-8)

Summary

The Montana Electric Transmission Grid: Operation, Congestion and Issues

- Montana's strongest electrical interconnections with other regions are: the Colstrip 500 kV line which connects as far as Spokane and then into the BPA northwest grid; the BPA 230 kV lines heading west from Hot Springs; PacifiCorp's interconnection from Yellowtail south to Wyoming; WAPA's DC tie to the east at Miles City; and the AMPS line running south from Anaconda parallel to the Grace line to Idaho. (p. II-1)
- The western United States is a single, interconnected, and synchronous electric system. It is not closely connected with the eastern part of the country. The interconnections are only weakly tied to each other with AC/DC/AC converter stations. One such station connecting the eastern and western grids is located at Miles City, with 200 MW capability in either direction. Also, a limited amount of additional power can be moved from one grid to the other by shifting units at Fort Peck Dam. (p. II-1)
- The transmission system is managed differently than the way it operates physically. (p. II-3)
- The physical reality of electricity (electrons) is that power sent from one point to another flows over all transmission lines in the interconnected system. Actual flows at any time are the net result of all transactions, and are the same for any given pattern of generation and load, regardless of transactions. (p. II-4)
- Management of the grid is different from where the electricity actually flows. Grid management requires a single "contract path" for each scheduled transaction. A "contract path" is permission to use a route across separately owned transmission systems from a point to origin to a point of delivery. It does not have to be the major route taken by the actual power flows that occur, which could happen over multiple routes. (p. II-4)
- Power flows are managed on a limited number of "rated paths." Each path consists of a number of more-or-less parallel transmission lines that together can be constrained under some patterns of generation and loads. (p. II-6)
- Path ratings are set to provide reliability by ensuring sufficient redundant capacity to allow for outages of some of the facilities comprising the path. Path ratings may be reduced if reliability standards are tightened. The West of Hatwai path currently has a

rating of 2800 MW east to west. The Montana-Northwest path has a rating of 2200 MW east to west and 1350 MW west to east. (p. II-6)

- Schedules are only accepted up to the limit of rated capacity. Netting of schedules is allowed only for a single scheduler. Netting against other's schedules is not allowed. (p. II-5)

- Scheduling rights across rated paths are generally owned by the transmission owners and holders of long-term contracts for power delivery. (p. II-7)

- In 1996, FERC ordered transmission owners to separate marketing and transmission operations and to maintain web sites ("OASIS" sites) on which "available capacity" is posted and offered for use by others. "Available capacity" is total transfer capacity less committed uses and existing contracts. Almost no available capacity ever is listed on paths from Montana to the West Coast. (p. II-7)

- Non-firm access is available on uncongested paths but only at the last minute. (p. II-7)

- A path may be fully scheduled, and therefore congested, even though the actual flow may be considerably less than the path capacity. For example the West of Hatwai path was deemed congested and some schedules had to be rejected 8 percent of the time during a period in 2001 during which the path was never actually loaded more than about 90 percent of capacity. (p. II-8)

- FERC is promoting independent organizations ("Regional Transmission Organizations" or RTOs) to operate and manage the transmission grid. RTO management would allow for regional management of path congestion and scheduling for better utilization and availability of the transfer capacity of the grid. (p. II-9)

- An organization—Grid West—has been proposed to conduct the RTO negotiations in the West. (p. II-10)

- Issues involved in the amount and availability of capacity include the need of utilities to withhold capacity because of uncertainty, the way reliability criteria are set, the limited number of hours that transmission paths are congested, and the challenges and costs of siting and building new transmission lines. (p. II-10)

- In 2004, the Governors of Utah and Wyoming convened the Rocky Mountain Transmission Study (RMATS) as a followup to transmission studies sponsored by the Western Governors' Association. RMATS was given the task of identifying transmission that would enable the development of coal and wind generation resources in the Rocky Mountain west and carry the power to markets on the West Coast, California, and the Denver area. (p. II-14)

Natural Gas in Montana: Current Trends, Forecasts and the Connection with Electric Generation

- Alberta provides the largest supply of natural gas for Montana customers and will likely continue to do so in the years to come. (p. III-1)
- Most gas produced in Montana comes from the north-central portion of the state. The bulk of what Montana produces is exported. In-state gas production has been increasing in recent years, standing at 86.1 billion cubic feet in 2003. (p. III-1)
- Recent Montana natural gas consumption has averaged 60-70 billion cubic feet per year. Future Montana natural gas consumption is expected to increase slowly at less than 1 percent annually. (p. III-4)
- Over the past two decades, a number of changes in energy markets, policies, and technologies have combined to spur an increase in the total usage of natural gas in the U.S. These include deregulation of the natural gas industry starting in 1978, air quality regulations that favor natural gas, deregulation of wholesale electricity markets, improvements in exploration and production technologies, and investment in major pipeline construction expansion projects. (p. III-5)
- Three distribution utilities and two transmission pipelines handle over 99 percent of the natural gas consumed in Montana. The distribution utilities are NorthWestern Energy, Montana-Dakota Utilities Co. (MDU), and Energy West of Great Falls, which uses NWE for gas transmission. NWE and the Williston Basin Interstate pipeline (affiliated with MDU) provide transmission service for in-state consumers and export Montana natural gas. (p. III-6)
- Northwestern Energy is the largest provider of natural gas in Montana, serving about 162,000 customers in the western two-thirds of the state. Montana-Dakota Utilities Co. is the second largest, serving the eastern third of the state. (pp. III-6, III-8)
- The delivered price of natural gas to homes and businesses includes the wellhead price of gas (price of the gas itself out of the ground), plus transmission and delivery fees, plus other miscellaneous charges. Wellhead prices are set in a continent-wide market. The natural gas transmission and delivery fees are set by utilities and/or pipelines, under regulation by state and federal agencies. (p. III-10)

- The wellhead price for natural gas in Montana is based on the AECOC index. This index, named after the AECO C storage hub in Alberta, is the equivalent in this area of the New York Mercantile Exchange. The wellhead price of Alberta natural gas is determined largely by the North American free market, with adjustments for transportation costs. (p. III-10)

- Natural gas customers in Montana and in the Pacific Northwest have historically paid relatively low gas rates compared to the rest of the U.S. In the past few years, however, gas prices across this region have risen to be more in line with the rest of the nation. In 2004, the prices are above $8.00/dkt. (p. III-11)

- The average U.S. wellhead price of gas as of May 2004 was about $6.00/dkt which is well above historical norms. These prices are expected to stay high until at least the end of 2004. (p. III-11)

- Although average gas prices are expected to increase slowly in the long run, Montanans may be subject to increasing gas price volatility from extreme or unexpected events. The increasing convergence of the electricity and natural gas markets means that extreme events like the California energy crisis are likely to affect both electricity and gas markets simultaneously. (p. III-13)

- Recent high natural gas prices in the past few years point out three lessons for Montana. First, our natural gas prices are affected by a number of factors beyond any one entity's or state's control. Second, the growing use of natural gas for electricity generation may lead to high and volatile gas prices not experienced before in Montana. Finally, to the extent that the western United States depends on natural gas for new electricity generation, the price of natural gas will be a key determinant of future electricity prices. (p. III-15)

Summary

Coal in Montana

- Montana is the sixth largest producer of coal in the United States, with over 37 million tons mined in 2002. Almost all the mining occurs in the Powder River Basin south and east of Billings. (p. IV-1)
- In 1958, after almost a century of mining, Montana production bottomed at 305,000 tons, an amount equivalent to less than 1 percent of current output. As Montana mines began supplying electric generating plants in Montana and the Midwest in the late 1960's, coal production jumped. Production in 1969 was 1 million tons; ten years later, it was 32.7 million tons. Since the end of the 1970's, production has increased gradually to around 40 million tons. (p. IV-1 and 2)
- Over the past decade Montana has produced a little less than 4 percent of the coal mined each year in the U.S., more or less maintaining its share of the national market. In comparison most eastern states lost market share during this decade, primarily to Wyoming. Western states other than Wyoming followed a path similar to Montana, more or less maintaining market share. (p. IV-2)
- The price of Montana coal averaged $9.27 per ton at the mine in 2002, including taxes and royalties. The price of coal has been on a downward trend since the early 1980's, when the average price of coal peaked at $14.22 per ton ($22.67 in 2002 dollars). By 2002 that price had fallen 60 percent in real terms. The decline in Montana prices mirrors the decline in prices nationally. (p. IV-2)
- In 2001 over 55 percent of Montana coal came from federal lands and under 15 percent from reservation lands. (p. IV-3)
- Montana had eight coal mines in operation in 2003. The largest was Westmoreland's Rosebud Mine at Colstrip, producing 10-11 million tons per year. No major new mines have opened since 1980, though the West Decker and Spring Creek mines have expanded significantly. (p. IV-3)
- Westmoreland is the largest producer in Montana, accounting for 47 percent of 2001 production. Kennecott is the second largest, accounting for 24 percent of coal production outright and holding a half-interest in mines producing an additional 22 percent of Montana coal. (p. IV-3)

- 2001 marked the end of over 40 years of utility ownership of operating coalfields in Montana. Utility-owned production had been substantial in past years. (p. IV-3)

- About 95 percent of the coal consumed in Montana is used to generate electricity. Montana coal consumption has been more or less stable since the late 1980's, after Colstrip 4 came on line. (p. IV-3 and 4)

- Almost all of Montana coal production is used to generate electricity. In recent years, about three-quarters of production has been shipped by rail to out-of-state utilities and the rest burned in-state to produce electricity, with over half that electricity going to out-of-state utilities. (p. IV-4)

- Over the last decade, Michigan, Minnesota, and Montana have each taken about a quarter of all the coal produced in Montana. The rest has gone to numerous other states. (p. IV-4)

- The Montana industry, like the coal industry nationwide, has become more productive, with the number of employees dropping even while the amount of coal mined increased. (p. IV-4)

- Taxes on coal, despite decreases from historical highs, remain a major source of revenue for Montana, with $30.1 million collected in state fiscal year 2003, about one-third in nominal terms the amount collected in 1984. Coal severance tax collections dropped due to changes in the tax laws that began with the 1987 Legislature and due to the declining price of coal. Production has risen modestly since the cut in taxes. (p. IV-4 and 5)

- Montana's output is dwarfed by Wyoming's, which produced 34.1 percent of the country's output in 2002. This is ten times as much coal as Montana produced. This is due to a combination of geologic, geographic and economic factors that tend to make Montana coal less attractive than coal from Wyoming. (p. IV-5)

Summary

Petroleum in Montana

- The first oil wells in Montana were drilled in 1889 near Red Lodge, but weren't very successful. Cat Creek, near Winnett, was the first commercially successful field discovered in Montana (1920). (p. V-1)
- Montana production peaked in 1968 at 48.5 million barrels. In 2003, production was 19.3 million barrels. (p. V-1)
- The average price of Montana crude peaked in 1981 at almost $35 per barrel. (p. V-2)
- Petroleum pipelines serving Montana consist of three separate systems. One bridges the Williston and Powder River basins in the east and the other two link the Sweetgrass Arch, Big Snowy and Big Horn producing areas in central Montana. All these systems also move crude oil from Canada to Montana and Wyoming. (A fourth—Express—primarily carries Canadian crude through Montana.) (p. V-2 and 3)
- In recent years, around 90 percent of crude oil production has been exported. (p. V-3)
- Montana has four refineries, with a combined capacity of 181,200 barrels/day: ConocoPhillips (60,000 bbl/day) and ExxonMobil (58,000 bbl/day) in Billings, Cenex (55,000 bbl/day) in Laurel, and Montana Refining (8,200 bbl/day) in Great Falls. (p. V-4)
- Montana refineries now use around 60 million barrels of crude a year. In the last decade on average, less than 5 percent of that came from Montana crude, with around 75 percent from Canada and around 20 percent from Wyoming. (p. V-4)
- The four refineries provided almost all of the petroleum products consumed in Montana. Beyond that, around 55 percent of the liquid fuel produced at the refineries is exported. (p. V-5)
- In 2003, 23 million barrels of product were shipped out of state, with nearly half heading south and the remainder split roughly between east and west. (p. V-5)
- Petroleum product consumption in Montana peaked at 33 million barrels in 1979. Present consumption is around 30 million barrels per year. (p. V-5)
- The transportation sector is the single largest user of petroleum. In 2001, 38 percent of petroleum consumption was in the form of motor gasoline and 28 percent was distillate, mostly diesel fuel. (p. V-5)

- Gasoline use peaked at over half a billion gallons in 1978, dropped and then has almost returned to that level in 2002. (p. V-6) Diesel use is at an all-time high of about 350 million gallons.

- Fuel use shows a cyclical rise and fall through the year, tending to rise during the summer months and taper off during the winter. The winter trough in fuel use is a third lower from the summer peak. (p. V-6)

- Gasoline prices (not adjusted for inflation) are at all-time highs in 2004. Average price in March was $1.687/gallon and has climbed about $0.30/gallon since then. (p. V-6)

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 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.

Key Electricity Facts for Montana

Generation capability	-	5,100 MW
Average generation	-	3,000 aMW
Average load	-	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.

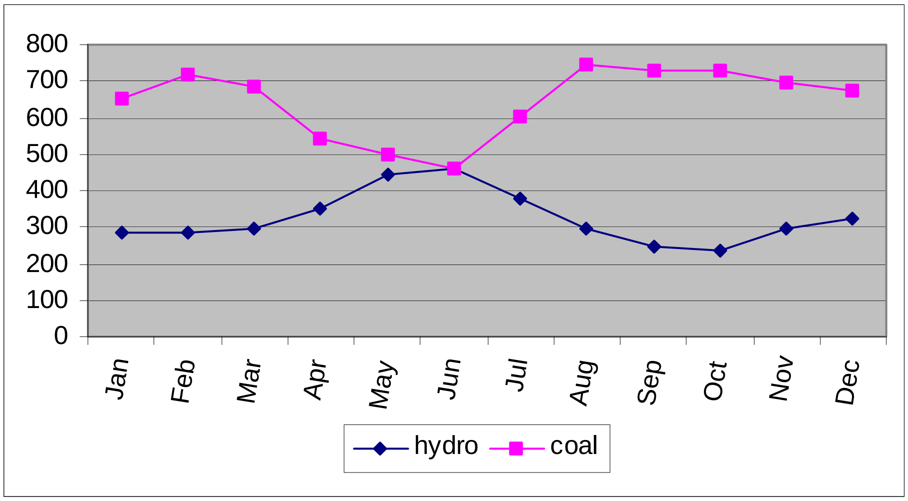
Two plants have come on line this decade: Montana Dakota Utilities' (MDU) Glendive #2 43.0 MW natural gas turbine and Tiber Montana LLC's 7.5 MW hydro plant at Tiber Dam. In the previous decade, the only sizeable additions were two plants built to take advantage of the federal Public Utility Regulatory 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)

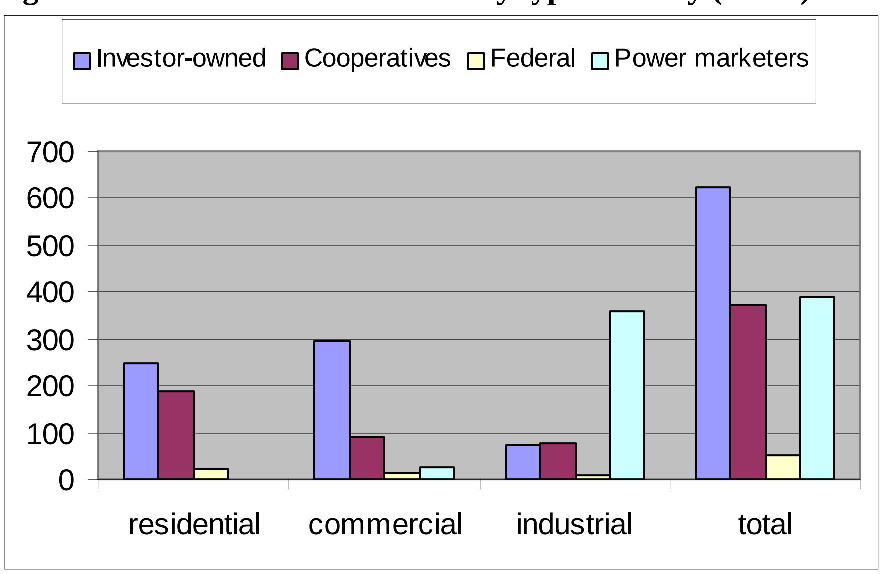


Note: Assumes PPL's monthly production from Colstrip 1- 4 was equal to its ownership share.
Source: U.S. DOE, Energy Information Administration, Form EIA906 databases
http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html.

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)

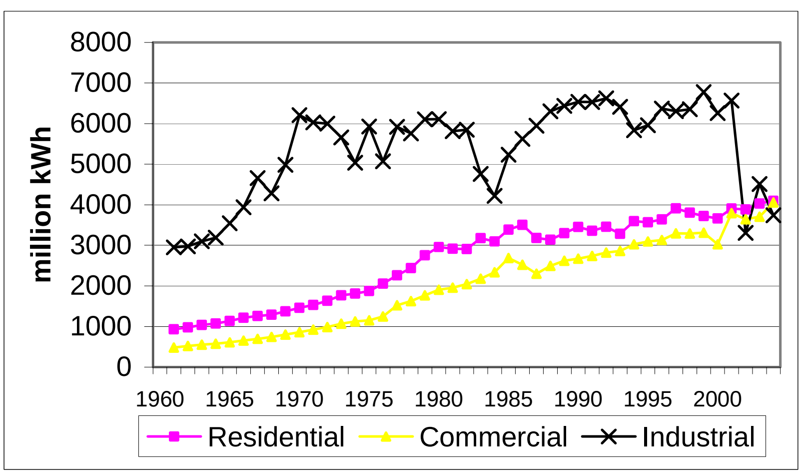


Source: Table E8.

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.

Table E1. Electric Power Generating Capacity by Company and Plant as of August 2004[1]

COMPANY	PLANT	COUNTY	ENERGY SOURCE	INITIAL OPERATION (First Unit)	GENERATOR NAMEPLATE	CAPACITY (MW) SUMMER CAPABILITY	WINTER CAPABILITY
Avista	Noxon Rapids	Sanders	Water	1959	466.2	527.0	527.0
Mission Valley Power Co.	Hell Roaring	Lake	Water	1916	0.4	0.4	0.4
Montana-Dakota Utilities	Glendive #1	Dawson	Natural Gas/#2 Fuel Oil	1979	40.7	34.1	42.3
Montana-Dakota Utilities	Glendive #2	Dawson	Natural Gas/#2 Fuel Oil	2003	43.0	38.7	30.0
Montana-Dakota Utilities	Lewis & Clark	Richland	Lignite Coal/Natural Gas	1958	50.0	52.3	47.6
Montana-Dakota Utilities	Miles City	Custer	Natural Gas/#2 Fuel Oil	1972	23.3	24.3	28.9
Clark Fork and Blackfoot LLC[2]	Milltown	Missoula	Water	1908	2.4	2.3	1.9
Northern Lights Cooperative	Lake Creek	Lincoln	Water	1917	4.5	4.7	4.5
NWE QF - Colstrip Energy Partnership	Montana One	Rosebud	Waste Coal	1990	41.5	39.0	39.0
NWE QF - Hydrodynamics	South Dry Creek	Carbon	Water	1985	2.0	2.0	-
NWE QF - Montana DNRC	Broadwater	Broadwater	Water	1989	9.6	6.0	8.0
NWE QF - wind	Various	Various	Wind	Various	0.3	-	-
NWE QF - other hydro	Various	Various	Water	Various	2.4	-	-
NWE QF - Yellowstone Partnership	BGI	Yellowstone	Petroleum Coke	1995	65.0	57.0	57.0
PacifiCorp	Bigfork	Flathead	Water	1910	4.1	4.2	4.2
PPL Montana	Black Eagle	Cascade	Water	1927	24.0	19.0	17.0
PPL Montana	Cochrane	Cascade	Water	1958	48.0	52.0	32.0
PPL Montana	Hauser Lake	Lewis & Clark	Water	1911	17.0	16.0	17.0
PPL Montana	Holter	Lewis & Clark	Water	1918	38.4	36.0	49.0
PPL Montana	J. E. Corette	Yellowstone	Subbituminous Coal	1968	163.0	160.0	160.0
PPL Montana	Kerr	Lake	Water	1938	211.5	180.0	165.0
PPL Montana	Madison	Madison	Water	1906	8.8	8.0	8.0
PPL Montana	Morony	Cascade	Water	1930	45.0	48.0	47.0
PPL Montana	Mystic Lake	Stillwater	Water	1925	12.4	11.0	11.0
PPL Montana	Rainbow	Cascade	Water	1910	35.6	40.0	40.0
PPL Montana	Ryan	Cascade	Water	1915	48.0	60.0	60.0
PPL Montana	Thompson Falls	Sanders	Water	1915	87.5	85.0	85.0
PPL Montana (50%) Puget Sound Power & Light (50%)	Colstrip 1	Rosebud	Subbituminous Coal	1975	358.0	307.0	307.0
PPL Montana (50%) Puget Sound Power & Light (50%)	Colstrip 2	Rosebud	Subbituminous Coal	1976	358.0	307.0	307.0
PPL Montana (30%) Avista (15%), PacifiCorp (10%) Portland General Electric (20%) Puget Sound Power & Light (25%)	Colstrip 3	Rosebud	Subbituminous Coal	1984	778.0	740.0	740.0
NorthWestern Energy (30%) Avista (15%), PacifiCorp (10%) Portland General Electric (20%) Puget Sound Power & Light (25%)	Colstrip 4	Rosebud	Subbituminous Coal	1986	778.0	740.0	740.0
Salish-Kootenai Tribe	Boulder Creek	Lake	Water	1984	0.4	0.4	0.4
Tiber Montana, LLC	Tiber Dam	Liberty	Water	2004	7.5	7.0	5.5
US Corps - North Pacific Division	Libby	Lincoln	Water	1975	525.0	598.0	573.0
US Corps - Missouri River Division	Fort Peck[3]	McCone	Water	1943	185.3	212.0	209.0
US BurRec - Great Plains Region	Canyon Ferry	Lewis & Clark	Water	1953	49.8	58.9	58.6
US BurRec - Great Plains Region	Yellowtail[4]	Big Horn	Water	1966	250.0	288.0	250.0
US BurRec - Pacific Northwest Region	Hungry Horse	Flathead	Water	1952	428.0	424.0	368.0
TOTAL MONTANA CAPACITY (MW)					5212.6	5130.9	4992.7

[1] Does not include a 10.8 MW waste-wood facility that supplies the Stone Container plant in Missoula and other, small self-generation units.

[2] An affiliate of NorthWestern Energy; previously owned by Montana Power Company. One unit is broken and may not be repaired, which would affect capability.

[3] Three of the five units in this dam, with a total capability of 118 MW, may be synchronized either to the west (WECC) or the midwest (MAPP).

[4] Units 1-4 are normally synchronized to the west (WECC); however, two units may be synchronized to the midwest (MAPP).

Source: On-line date and nameplate - U.S. DOE Energy Information Administration "Existing Electric Generating Units in the United States by State, Company and Plant, 2003 (Preliminar Data)" http://www.eia.doe.gov/cneaf/electricity/page/capacity/newunits2003.xls; Capability - Western Electricity Coordinating Council, *Existing Generation and Significant Additions and Changes to System Facilities 2003 - 2013*; Fort Peck and Canyon Ferry capability - Mid-Continent Area Power Pool Regional Reliability Council *Coordinated Bulk Power Supply Program* (Eia-411; 07/01/01; http://www.mapp.org/assets/pdf/2001_USA.PDF); MDU plant capability - MDU; Lake Creek capability - Northern Lights Cooperative; Milltown, South Dry Creek and wind/other hydro Qualifying Facilities capability - NorthWestern Energy; Hellroaring and Boulder Creek data - Mission Valley Power; Tiber Dam data - Tiber Montana, LLC.

Table E2. Average Generation by Company, 1995-1999 and 1999-2003

Company	aMW[1] 1995-1999	aMW[1] 1999-2003
Avista[2]	403.1	359.8
Bonneville Power Administration[3]	381.7	312.3
Colstrip Energy Partnership	29.9	31.7
Hydrodynamics	0.9	0.8
Mission Valley Power	0.2	0.2
Montana-Dakota Utilities	27.9	35.0
MT Dept of Natural Resources and Conservation	5.9	5.2
Northern Lights Cooperative	3.5	2.9
NorthWestern Energy[2,4]	169.0	180.6
NWE QF - other hydro[4]	0.9	0.6
NWE QF- wind[4]	0.1	0.1
PacificCorp[2]	113.5	121.6
Portland General Electric[2]	222.5	238.8
PPL Montana [2,5]	939.5	913.5
Puget Sound Power & Light[2]	509.0	546.3
Salish-Kootenai Tribes	0.2	0.1
Western Area Power Administration[3]	322.7	197.4
Yellowstone Energy Partnership	46.9	46.6
TOTAL	3,177.3	2,993.5

[1] aMW = average megawatt, or 8,760 megawatt hours in a year

[2] Output for Colstrip 1-4 is reported for the entire facility, not individual units. In this table, ouput was allocated among the partners on the basis of their ownership percentages. NorthWestern actually holds a lease on a portion of output from Colstrip 4.

[3] Distributes power generated at US Corps of Engineers and US Bureau of Reclamation

[4] NWE plants and contracts were owned by Montana Power Company until February 2002

[5] PPL Montana plants were owned by Montana Power Company until mid-December 1999

Source: U.S. Department of Energy, Energy Information Administration, Form 906 databases (http://www.eia.doe.gov/cneaf/electricity/page/data.html); NorthWestern Energy for QF data, 2000 hydro data and 2000-2003 Milltown data; Mission Valley Power; Northern Lights Cooperative.

Table E3. Net Electric Generation By Plant, 1999-2003[1] (MWh)

COMPANY / PLANT	1999	2000	2001	2002	2003	Average	aMW 1999-2003	aMW 1995-99
Avista								
Noxon	1,896,663	1,635,238	1,020,729	1,816,491	1,542,705	1,582,365	180.6	236.2
Bonneville Power Administration								
Hungry Horse	888,086	1,016,427	537,371	994,748	729,010	833,128	95.1	103.3
Libby	2,468,710	1,762,671	1,116,106	2,256,895	1,908,585	1,902,593	217.2	278.4
Clark Fork and Blackfoot LLC								
Milltown[2]	15,815	14,543	13,663	12,354	6,493	12,574	1.4	2.1
Colstrip Energy Partnership								
Montana One (NWE QF)[2,3]	308,100	295,828	309,584	173,750	302,419	277,936	31.7	29.9
Hydrodynamics								
South Dry Creek (NWE QF)[2]	7,323	6,965	7,876	7,180	45	5,878	0.7	0.7
Strawberry Creek (NWE QF)[2]	863	1,286	1,388	1,329	1,308	1,235	0.1	0.2
Mission Valley Power								
Hellroaring	1,687	1,827	1,671	1,351	1,703	1,648	0.2	0.2
Montana-Dakota Utilities								
Glendive	12,128	9,975	7,366	4,458	16,344	10,054	1.1	1.6
Lewis-Clark	224,643	323,757	311,849	286,512	323,158	293,984	33.6	25.4
Miles City	3,429	3,469	2,171	1,590	2,181	2,568	0.3	0.9
MT Dept of Nat. Res. and Con.								
Broadwater Dam (NWE QF)[2]	55,367	48,358	40,474	41,777	43,837	45,963	5.2	5.9
Northern Lights Cooperative								
Lake Creek[4]	35,300	26,198	13,505	28,643	25,430	25,815	2.9	3.5
PacifiCorp								
Big Fork	18,945	13,021	17,729	19,523	26,555	19,155	2.2	2.3
PPL Montana								
Black Eagle[5]	135,880	116,726	102,539	111,880	122,072	117,819	13.4	16.6
Cochrane[5]	327,364	228,394	189,721	207,567	234,704	237,550	27.1	39.7
Colstrip[6]	15,403,447	14,310,363	15,452,158	13,886,845	14,955,622	14,801,687	1,689.7	1,574.2
Hauser Lake[5]	133,870	121,266	101,890	99,306	120,040	115,274	13.2	15.7
Holter[5]	345,262	241,006	201,580	199,901	250,752	247,700	28.3	39.2
J E Corette	1,059,744	1,173,300	1,029,287	1,132,762	1,251,896	1,129,398	128.9	104.2
Kerr	1,161,144	1,124,722	676,582	1,095,991	886,695	989,027	112.9	133.5
Madison[5]	57,615	59,299	62,362	58,767	60,057	59,620	6.8	6.8
Morony[5]	337,742	242,008	200,158	216,100	244,474	248,096	28.3	40.4
Mystic Lake[5]	49,312	47,187	38,751	40,652	45,052	44,191	5.0	5.7
Rainbow[5]	274,047	220,991	195,445	205,499	215,588	222,314	25.4	29.1
Ryan[5]	463,726	392,161	334,015	350,490	347,549	377,588	43.1	54.2
Thompson Falls	546,245	506,722	368,182	498,775	452,393	474,463	54.2	56.6
Salish-Kootenai								
Boulder Creek	1,070	797	824	778	225	739	0.1	0.2
Various Qualifying Facilities								
Other NWE QF - hydro[2,7]	6,777	5,400	5,374	4,149	5,286	5,397	0.6	0.9
Other NWE QF - wind[2,8]	630	598	549	655	548	596	0.1	0.1
Western Area Power Administration								
Canyon Ferry	404,744	292,982	239,601	240,389	321,143	299,772	34.2	49.9
Fort Peck	1,019,613	924,319	672,931	747,042	819,292	836,639	95.5	139.7
Yellowtail	1,190,750	628,691	474,227	344,399	325,278	592,669	67.7	133.1
Yellowstone Energy Partnership								
Billings Generation Inc. (NWE QF)[2,9]	445,827	441,247	425,962	348,125	378,005	407,833	46.6	46.9
TOTALS							2,993.5	3,177.3

[1] Net generation equals gross generation minus plant use.
[2] NWE plants and contracts were owned by MPC until February 2002.
[3] 1995-1999 column is for 1999 only.
[4] 1995-1999 column is for 1997 - 1999.
[5] 2000 production provided by NorthWestern Energy.
[6] Operated by PPL; actual ownership shared by six utilities.
[7] 1995-1999 column includes one facility for 1997-1999.
[8] 1995-1999 column is for 1999 - 2000.
[9] 1995-1999 column is for 1996 - 1999.

Source: U.S. Department of Energy, Energy Information Administration, Form 860 and 906 databases (http://www.eia.doe.gov/cneaf/electricity/page/data.html); NorthWestern Energy for QF data, 2000 PPL hydro data and 2000-2003 Milltown data; Mission Valley Power; Northern Lights Cooperative.

Table E4. Annual Consumption of Fuels for Electric Generation, 1960-2002[1]

YEAR	COAL (thousand short tons)	PETROLEUM[2] (thousand barrels)	NATURAL GAS (million cubic feet)
1960	186.9	*	341.3
1961	262.5	*	356.2
1962	291.6	1.3	3,712.5
1963	285.5	0.7	3,303.3
1964	293.8	3.6	2,449.5
1965	295.8	0.7	1,992.3
1966	323.5	82.2	2,977.2
1967	325.4	6.1	502.5
1968	399.2	22.9	631.3
1969	576.6	104.9	1,520.5
1970	722.7	26.0	2,529.4
1971	672.0	0.2	1,079.8
1972	768.7	17.5	1,217.4
1973	892.6	152.2	2,167.4
1974	854.6	14.0	1,038.0
1975	1,061.3	62.6	1,073.3
1976	2,373.7	81.1	708.5
1977	3,196.7	195.3	953.3
1978	3,184.2	98.1	909.4
1979	3,461.4	146.5	2,320.4
1980	3,351.6	58.6	4,182.1
1981	3,337.9	38.5	2,069.4
1982	2,595.8	30.6	337.0
1983	2,356.0	31.0	335.0
1984	5,113.0	78.0	360.0
1985	5,480.0	38.0	468.0
1986	7,438.0	25.0	407.0
1987	7,530.0	44.0	478.0
1988	10,410.0	63.0	286.0
1989	10,208.0	60.0	336.0
1990	9,572.6	63.2	417.6
1991	10,460.3	44.7	267.7
1992	11,027.7	35.8	219.9
1993	9,121.2	49.5	270.0
1994	10,780.5	44.4	632.2
1995	9,640.8	472.7	388.4
1996	8,074.9	661.5	470.4
1997	9,464.7	662.9	419.9
1998	10,896.5	1,071.5	521.8
1999	10,902.9	1,142.7	290.9
2000	10,385.4	1,166.2	191.6
2001	10,838.1	1,080.9	159.7
2002	9,746.4	1,058.0	115.9

* less than 0.05

[1] Data includes fuel use at independent power producers, which first came on line in 1990. The data do not include self-generation at industrial facilities. Data exclude small amounts of waste gases used for generation.

[2] Includes petroleum coke starting in 1995. One ton of petroleum coke equals 6.07 barrels.

Sources: Federal Energy Regulatory Commission, Form 4 News Releases (1960-76); U.S. Department of Energy, Energy Information Administration, Electric Power Statistics, EIA-0034 (1977-78); U.S. Department of Energy, Energy Information Administration, Power Production, Fuel Consumption and Installed Capacity, EIA-0049 (1979); U.S. Department of Energy, Energy Information Administration, Electric Power Annual, EIA-0348 (1980-89); U.S. Department of Energy, Energy Information Administration, Electric Power Annual 2002 - Consumption Spreadsheet (Form EIA906 data-http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html)(1990-2002).

Table E5. Net Electric Generation by Type of Fuel Unit, 1960-2003[1]

YEAR	HYDROELECTRIC (million kWh)	%	COAL (million kWh)	%	PETROLEUM[2] (million kWh)	%	NATURAL GAS (million kWh)	%	TOTAL
1960	5,801	97	NA		NA		NA		5,992
1961	6,499	96	263	4	0	0	19	*	6,780
1962	6,410	91	291	4	1	*	349	5	7,051
1963	6,011	91	284	4	0	0	299	5	6,594
1964	6,821	93	286	4	2	*	220	3	7,329
1965	8,389	95	285	3	0	0	171	2	8,845
1966	7,940	93	317	4	43	*	273	3	8,573
1967	8,703	96	314	3	3	*	41	*	9,061
1968	8,925	95	434	5	10	*	52	*	9,421
1969	9,447	91	735	7	52	*	147	1	10,381
1970	8,745	88	966	10	14	*	228	2	9,953
1971	9,595	91	901	9	1	*	96	1	10,593
1972	9,444	89	1,079	10	7	*	108	1	10,639
1973	7,517	83	1,303	14	69	*	195	2	9,084
1974	9,726	88	1,210	11	6	*	98	1	11,040
1975	9,560	85	1,544	14	17	*	96	1	11,217
1976	12,402	77	3,558	22	27	*	67	*	16,054
1977	8,460	63	4,788	36	92	1	87	1	13,427
1978	11,708	70	4,871	29	35	*	84	*	16,698
1979	10,344	66	5,114	33	58	*	188	1	15,704
1980	9,966	64	5,140	33	22	*	351	2	15,479
1981	11,323	68	5,047	30	13	*	176	1	16,559
1982	10,920	74	3,853	26	10	*	33	*	14,816
1983	11,561	77	3,452	23	10	*	34	*	15,057
1984	11,113	59	7,650	41	36	*	40	*	18,839
1985	10,178	54	8,465	45	16	*	58	*	18,717
1986	10,863	49	11,469	51	9	*	52	*	22,393
1987	8,931	43	11,836	57	17	*	58	*	20,842
1988	8,246	33	16,462	66	30	*	37	*	24,775
1989	9,580	37	16,129	63	30	*	43	*	25,782
1990	10,717	41	15,120	58	27	*	41	*	25,980
1991	11,970	42	16,433	58	19	*	24	*	28,508
1992	8,271	32	17,454	68	16	*	23	*	25,843
1993	9,614	40	14,083	59	22	*	24	*	23,821
1994	8,150	32	16,809	67	19	*	61	*	25,081
1995	10,746	42	14,934	58	167	1	32	*	25,888
1996	13,795	52	12,463	47	444	2	38	*	26,767
1997	13,406	47	14,616	51	436	2	32	*	28,521
1998	11,118	39	16,785	59	426	2	41	*	28,401
1999[3]	11,844	40	16,993	58	487	2	20	*	29,344
2000	9,623	36	16,201	61	520	2	13	*	26,389
2001	6,613	27	17,036	71	498	2	11	*	24,158
2002	9,567	38	15,338	60	470	2	8	*	25,402

*Less than or equal to 0.5 percent.

[1] Gross generation less the electric energy consumed at the generating station for facilities owned by or selling to electric utilities and cooperatives. Starting in 1983, annual output of non-utility plants selling into the grid, except for a minor amount of small hydro, is included. The data do not include generation from wood-fired plants that do not provide power into the grid; historically, these collectively have produced less (and usually considerably less) than 75 million kWh per year. From 1990, Total includes minor amounts of generation from sources not listed in the table.

[2] Includes fuel oil and petroleum coke.

[3] U.S. DOE figures appear to have double-counted output from some of the dams MPC sold to PPL in December. Therefore, DEQ adjusted the hydroelectric generation and total generation, based on the data presented in Table E3.

Sources: Federal Power Commission (1960-76); U.S. Department of Energy, Energy Information Administration, *Power Production, Fuel Consumption and Installed Capacity Data* , EIA-0049 (1977-80); U.S. Department of Energy, Energy Information Administration, *Electric Power Annual* , EIA-0348 (1981-89); U.S. Department of Energy, Energy Information Administration, *1990 - 2002 Net Generation by State by Type of Producer by Energy Source* (spreadsheet derived from EIA-906 database - http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html).

Table E6. Annual Sales of Electricity, 1960-2003 (million kilowatt-hours)

	MONTANA					USA
Year	**Residential**	**Commercial**	**Industrial**	**Other[1]**	**Total**	**TOTAL**
1960	935	479	2,951	209	4,575	686,493
1961	982	518	2,975	222	4,697	720,120
1962	1,041	551	3,099	254	4,946	775,381
1963	1,077	574	3,191	259	5,101	830,079
1964	1,139	610	3,544	249	5,541	896,059
1965	1,216	654	3,939	270	6,080	959,493
1966	1,261	698	4,657	286	6,902	1,035,145
1967	1,291	746	4,282	293	6,612	1,099,137
1968	1,373	805	4,982	273	7,433	1,202,871
1969	1,462	863	6,208	247	8,781	1,312,406
1970	1,534	924	6,029	264	8,750	1,392,300
1971	1,633	990	5,999	268	8,890	1,469,306
1972	1,768	1,070	5,660	265	8,763	1,595,161
1973	1,812	1,125	5,034	246	8,217	1,713,380
1974	1,873	1,156	5,929	213	9,171	1,707,852
1975	2,058	1,250	5,069	197	8,575	1,736,267
1976	2,261	1,525	5,922	203	9,911	1,855,246
1977	2,440	1,625	5,759	189	10,013	1,948,361
1978	2,754	1,768	6,106	158	10,786	2,017,922
1979	2,957	1,907	6,111	154	11,129	2,071,099
1980	2,916	1,957	5,815	137	10,825	2,094,449
1981	2,906	2,045	5,848	157	10,956	2,147,103
1982	3,178	2,180	4,759	159	10,276	2,086,441
1983	3,097	2,334	4,217	166	9,813	2,150,955
1984	3,386	2,687	5,229	164	11,466	2,278,372
1985	3,505	2,521	5,623	173	11,822	2,309,543
1986	3,181	2,302	5,948	161	11,593	2,350,835
1987	3,139	2,495	6,304	484	12,423	2,457,272
1988	3,301	2,620	6,438	582	12,942	2,578,062
1989	3,456	2,670	6,535	400	13,061	2,646,809
1990	3,358	2,738	6,529	499	13,125	2,712,555
1991	3,459	2,819	6,622	507	13,407	2,762,003
1992	3,286	2,859	6,414	536	13,096	2,763,365
1993	3,598	3,026	5,837	469	12,929	2,861,462
1994	3,567	3,096	5,961	561	13,184	2,934,563
1995	3,640	3,133	6,368	278	13,419	3,013,287
1996	3,911	3,299	6,306	305	13,820	3,101,127
1997[2]	3,804	3,293	6,353	284	13,733	3,145,610
1998[3]	3,722	3,313	6,774	335	14,145	3,264,231
1999[3]	3,664	3,025	6,258	334	13,282	3,312,087
2000[3]	3,908	3,792	6,568	312	14,580	3,421,414
2001[3]	3,885	3,645	3,310	324	11,165	3,369,781
2002[3]	4,030	3,707	4,511	326	12,575	3,462,521
2003[3]	4,098	4,058	3,743	280	12,180	3,499,968

[1] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and inter-departmental sales.

[2] EIA data on industrial sales corrected by adding BPA sales, which EIA didn't include in this year.

[3] Some power marketers did not report sales data. This problem is believed to be most pronounced in 1999, the first full year of deregulation. In 2002, a year for which data are available, NWE reported delivery of 256,858 MWh more than power marketers reported sold. This unreported power went primarily to the commercial sector. Most of it may have been sold by Commercial Energy, which has not filed Form 861 reports with US DOE.

Sources: Federal Power Commission (1960-76); U.S. Department of Energy, Energy Information Administration, *Electric Power Statistics* , EIA-0034 (1977-78); U.S. Department of Energy, Energy Information Administration, *Financial Statistics of Electric Utilities and Interstate Natural Gas Pipeline Companies* , EIA-0147 (1979-80); U.S. Department of Energy, Energy Information Administration, *Electric Power Annual* , EIA-0348 (1981-99); U.S. Department of Energy, Energy Information Administration, Form 861 Database (1997-2003, http://www.eia.doe.gov/cneaf/electricity/page/at_a_glance/sales_tabs.html); updated information on sales from Bonneville Power Administration (1997).

Table E7. Average Annual Prices for Electricity Sold, 1960-2003 (cents per kilowatt-hour)

	MONTANA								U.S.
Year	Residential	Commercial	Industrial	Street & Highway Lighting	Other Public Authorities	Railroads & Railways	Interdepart-mental	All Sales	All Sales
1960	2.33	2.25	0.43	2.45	0.79	0.56	1.27	1.05	1.69
1961	2.32	2.18	0.45	2.70	0.74	0.55	1.70	1.06	1.69
1962	2.29	2.13	0.46	2.50	0.61	0.55	1.43	1.07	1.67
1963	2.25	2.06	0.45	2.78	0.78	0.57	1.67	1.07	1.64
1964	2.20	2.02	0.45	2.56	0.71	0.53	2.00	1.03	1.63
1965	2.12	1.93	0.44	2.75	0.70	0.59	1.67	0.98	1.59
1966	2.09	1.92	0.43	2.56	0.66	0.57	1.67	0.92	1.56
1967	2.04	1.89	0.42	2.79	0.63	0.49	1.08	0.95	1.55
1968	1.99	1.83	0.40	2.77	0.61	0.58	1.11	0.90	1.54
1969	2.10	1.93	0.41	2.75	0.57	0.53	1.05	0.88	1.54
1970	2.13	1.94	0.42	2.88	0.60	0.55	1.00	0.94	1.59
1971	2.12	1.94	0.43	3.02	0.62	0.50	0.95	0.95	1.68
1972	2.16	1.98	0.44	3.21	0.53	0.49	1.19	1.00	1.77
1973	2.21	2.04	0.53	3.27	0.60	0.58	1.67	1.16	1.86
1974	2.23	2.05	0.50	3.23	0.58	0.53	1.41	1.10	2.30
1975	2.19	2.08	0.62	2.99	0.58	--	1.51	1.25	2.70
1976	2.23	2.06	0.60	3.32	0.73	--	1.67	1.24	2.89
1977	2.38	1.90	0.67	3.53	0.80	--	1.79	1.38	3.21
1978	2.62	2.50	0.72	3.88	0.87	--	2.16	1.53	3.46
1979	2.67	2.52	0.80	3.86	0.87	--	1.99	1.62	3.82
1980	2.95	2.78	0.98	4.00	0.97	--	1.91	1.87	4.49
1981	3.38	3.19	1.30	4.50	1.42	--	2.34	2.24	5.16
1982	3.58	3.30	2.09	4.69	1.69	--	2.70	2.81	5.79
1983	4.19	3.88	2.37	5.28	1.83	--	3.01	3.31	6.00
1984	4.30	3.88	2.57	5.72	2.02	--	2.58	3.38	6.27
1985	4.70	4.20	2.55	7.35	2.08	--	2.15	3.56	6.47
1986	5.02	4.54	2.60	8.04	2.54	--	1.89	3.71	6.47
1987	5.23	4.68	2.72	8.79	2.65	--	3.49	3.83	6.39
1988	5.41	4.79	3.16	9.41	2.60	--	3.40	4.14	6.36
1989	5.38	4.68	3.09	10.57	2.83	--	3.32	4.09	6.47
1990	5.45	4.74	2.84	11.59	2.07	--	3.87	3.97	6.57
1991	5.77	5.08	2.87	9.27	2.92	--	4.96	4.18	6.76
1992	5.86	5.23	2.86	10.21	2.73	--	4.82	4.23	6.85
1993	5.77	5.10	3.10	7.07	2.44	--	4.65	4.36	6.94
1994	5.96	5.17	3.30	7.17	2.28	--	4.54	4.51	6.91
1995	6.09	5.31	3.44	10.35	3.33	--	4.43	4.65	6.90
1996	6.22	5.51	3.30	11.99	5.38	--	4.73	4.72	6.86
1997	6.40	5.80	3.66	13.51	5.28	--	NA	5.20	6.85
1998[1]	6.50	5.87	3.19	14.09	NA	--	NA	4.80	6.74
1999[1]	6.78	6.35	2.84	14.36	NA	--	NA	5.01	6.66
2000[1]	6.49	5.60	3.97	NA	NA	--	NA	5.00	6.81
2001[1]	6.88	6.11	6.54	NA	NA	--	NA	6.54	7.32
2002[1]	7.23	6.53	3.70	NA	NA	--	NA	5.75	7.21
2003[1]	7.60	6.46	4.50	NA	NA	--	NA	6.28	7.40

NA: Not available. These categories now are rolled into Commercial or Other Sales (not included as a separate column in this table).

Note: Average annual prices were calculated by dividing total revenue by total sales as reported by Edison Electric Institute (1960-1999) and by U.S. Department of Energy Energy Information Administration (2000-2003).

[1] Calculation of prices are based on data that include distribution utility receipts for delivering power for power marketers, but may not include revenue and sales for some power marketers. This problem is believed to be most pronounced in 1999, the first full year of deregulation. Errors in price, where they exist, are unlikely to be more than a tenth of a cent or two.

Source: Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry* , 1961-2000; U.S. Department of Energy, Energy Information Administration, Form 861 Database (2000-2003, http://www.eia.doe.gov/cneaf/electricity/page/at_a_glance/sales_tabs.html).

Table E8. Utility Revenue, Retail Sales, Consumers and Average Price per Kilowatt-hour, 2002 (with comparison to 2000 average price)

	RESIDENTIAL			Average price		COMMERCIAL			Average price		INDUSTRIAL			Average price		TOTAL			Average price	
	Revenue	Sales		(cents/kWh)[3]		Revenue	Sales		(cents/kWh)[3]		Revenue	Sales		(cents/kWh)[3]		Revenue	Sales		(cents/kWh)[3]	
UTILITY NAME	('000s)	(aMW)[1]	Consumers[2]	2002	2000	('000s)	(aMW)[1]	Consumers[2]	2002	2000	('000s)	(aMW)[1]	Consumers[2]	2002	2000	('000s)	(aMW)[1]	Consumers[2]	2002	2000
Cooperative	$127,744	189.6	140,349	7.7	6.6	$54,651	90.3	18,523	6.9	5.7	$36,136	75.0	488	5.5	3.2	$228,166	371.0	168,305	7.0	5.2
Beartooth Electric Coop Inc	$3,989	5.3	4,571	8.6	7.7	$437	0.7	226	7.0	6.8	--	--	--	--	5.3	$4,553	6.3	4,870	8.3	7.5
Big Flat Electric Coop Inc	$1,433	2.0	1,458	8.2	8.1	$651	0.9	182	8.7	7.4	$230	0.2	6	10.8	10.2	$2,508	3.3	1,712	8.6	8.4
Big Horn County Elec Coop Inc	$2,547	3.6	2,905	8.1	7.7	$1,807	2.7	467	7.7	7.4	--	--	--	--	--	$4,593	6.6	3,454	7.9	7.6
Big Horn Rural Electric Co	$26	0.0	26	7.5	7.6	$69	0.1	23	12.1	11.2	--	--	--	--	--	$95	0.1	49	10.4	10.0
Fall River Rural Elec Coop Inc	$1,223	1.6	1,250	8.7	7.1	$1,884	3.4	482	6.4	5.4	--	--	--	--	--	$3,107	5.0	1,732	7.2	5.9
Fergus Electric Coop Inc	$4,899	6.2	5,160	9.0	8.6	$614	1.0	239	7.3	6.9	--	--	--	--	--	$6,192	8.5	5,560	8.3	8.0
Flathead Electric Coop Inc[4]	$43,317	60.4	43,417	8.2	5.1	$26,938	42.8	8,058	7.2	4.7	$24,427	49.9	14	5.6	2.8	$95,742	154.4	54,077	7.1	3.6
Glacier Electric Coop Inc	$5,431	7.1	5,395	8.8	7.6	$4,099	7.3	1,421	6.4	5.3	$1,317	2.9	5	5.2	4.6	$11,133	17.7	6,945	7.2	6.1
Goldenwest Electric Coop Inc	$370	0.5	456	8.5	9.8	$93	0.1	9	10.1	10.9	--	--	--	--	--	$513	0.6	627	9.2	10.5
Grand Electric Coop Inc	$7	0.0	14	6.7	7.1	--	--	--	--	--	--	--	--	--	--	$7	0.0	14	6.7	7.1
Hill County Electric Coop Inc	$2,969	3.7	3,154	9.1	9.3	$1,224	2.1	132	6.5	6.7	$1,296	4.7	2	3.2	2.8	$5,565	10.7	3,337	6.0	6.1
Lincoln Electric Coop Inc	$2,829	6.1	3,571	5.3	5.1	$1,069	2.4	538	5.0	4.8	$1,654	3.9	9	4.8	4.6	$5,584	12.6	4,124	5.1	4.9
Lower Yellowstone R E A Inc	$1,804	2.8	1,652	7.4	7.5	$604	0.7	424	9.5	9.6	$1,725	2.1	245	9.4	9.8	$4,451	5.9	3,019	8.6	8.8
Marias River Electric Coop Inc	$1,538	3.6	2,524	4.9	4.9	$2,329	4.8	1,190	5.5	5.6	--	--	--	--	5.1	$4,006	8.7	3,731	5.3	5.3
McCone Electric Coop Inc	$3,653	4.5	4,269	9.3	9.3	$1,223	1.9	462	7.2	7.2	$92	0.1	62	8.7	8.8	$4,979	6.5	4,797	8.7	8.7
McKenzie Electric Coop Inc	$42	0.1	105	8.0	7.8	$3	0.0	2	7.0	9.1	--	--	--	--	--	$45	0.1	107	7.9	7.8
Mid-Yellowstone Elec Coop Inc	$1,313	1.9	1,571	7.9	7.4	$208	0.3	152	7.4	7.7	--	--	--	--	--	$1,868	2.9	1,855	7.5	7.2
Missoula Electric Coop Inc	$7,944	14.2	10,740	6.4	6.6	$1,676	3.6	1,051	5.4	5.6	$671	1.5	4	5.0	5.0	$10,537	19.9	12,084	6.0	6.2
Northern Electric Coop Inc	$1,249	1.8	948	7.9	7.9	$1,183	1.4	291	9.7	10.3	--	--	--	--	--	$2,438	3.2	1,242	8.7	8.8
Northern Lights Inc	$2,746	3.6	2,994	8.7	7.2	$543	0.8	227	7.7	5.5	$474	0.5	3	9.9	7.6	$3,763	5.0	3,224	8.7	6.9
Park Electric Coop Inc	$4,136	5.7	4,372	8.2	8.3	$319	0.6	70	6.4	6.5	$2,034	4.8	1	4.8	7.0	$6,860	11.8	4,657	6.7	7.7
Powder River Energy Corp	$47	0.1	89	7.7	8.9	$363	0.7	69	5.7	5.8	--	--	--	--	--	$410	0.8	158	5.9	6.1
Ravalli County Elec Coop Inc	$6,765	11.3	7,551	6.8	6.8	$510	0.9	243	6.2	6.2	$169	0.4	1	5.0	5.0	$7,754	13.4	8,339	6.6	6.6
Sheridan Electric Coop Inc	$1,938	3.2	2,433	6.9	6.6	$3,653	5.4	710	7.8	7.4	--	--	--	--	12.5	$5,873	8.8	3,737	7.6	7.2
Southeast Electric Coop Inc	$1,539	1.6	1,861	11.0	7.6	$39	0.1	15	8.5	9.3	$291	0.6	1	5.7	5.7	$1,875	2.2	1,878	9.5	7.2
Sun River Electric Coop Inc	$3,681	5.0	3,738	8.3	8.4	$484	1.0	47	5.6	5.7	--	--	--	--	--	$5,787	8.6	4,999	7.7	7.0
Tongue River Electric Coop Inc	$3,366	5.8	3,549	6.6	6.8	$561	1.0	480	6.3	6.4	$840	1.7	41	5.6	6.0	$5,306	9.3	4,713	6.5	6.8
Valley Electric Coop Inc	$1,472	1.9	1,560	8.9	8.8	$370	0.5	212	8.3	7.7	--	--	--	--	--	$1,941	2.5	1,840	8.9	8.5
Vigilante Electric Coop Inc	$4,857	8.8	6,457	6.3	6.0	$364	0.8	113	5.3	5.3	--	--	--	--	--	$7,423	14.0	7,606	6.1	5.6
Yellowstone Valley Elec Co-op	$10,614	17.2	12,559	7.1	7.0	$1,334	2.3	988	6.6	6.5	$916	1.6	94	6.7	--	$13,258	21.8	13,818	6.9	6.8
Federal	$9,319	20.8	12,706	5.1	5.2	$5,746	11.7	2,785	5.6	5.8	$2,184	7.5	2	3.3	2.0	$18,772	53.3	18,252	4.0	2.4
Bonneville Power Administration[5]	--	--	--	--	--	--	--	--	--	--	$1,383	5.3	1	3.0	2.0	$1,383	5.3	1	3.0	2.0
USBIA-Mission Valley Power	$9,319	20.8	12,706	5.1	5.2	$5,746	11.7	2,785	5.6	5.8	$801	2.2	1	4.1	4.0	$16,094	34.9	18,228	5.3	5.4
Western Area Power Administration	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	$1,295	13.1	23	1.1	0.4
Municipal																				
Troy City of	$512	1.1	759	5.3	5.3	$141	0.3	78	5.1	4.6	$5	0.0	6	7.2	5.3	$761	1.6	912	5.3	5.1
Investor-Owned	$153,764	248.5	259,359	7.1	6.5	$164,112	293.7	58,201	6.4	5.7	$28,062	72.5	165	4.4	4.0	$357,720	622.4	321,578	6.6	5.7
Avista	$7	0.0	11	4.9	4.6	$2	0.0	1	6.5	8.0	--	--	--	--	--	$15	0.0	19	5.6	5.3
Black Hills Power Inc	$5	0.0	11	6.7	7.3	$18	0.0	19	9.8	12.2	$573	1.5	2	4.5	4.6	$596	1.5	32	4.6	4.7
MDU Resources Group Inc	$10,871	16.9	18,635	7.3	7.4	$11,090	22.9	4,526	5.5	5.6	$8,854	23.1	135	4.4	4.3	$31,615	64.6	23,632	5.6	5.7
NorthWestern Energy	$142,881	231.6	240,702	7.0	6.5	$153,002	270.8	53,655	6.4	5.8	$18,635	47.9	28	4.4	3.9	$325,494	556.2	297,895	6.7	5.7
Power Marketers[6,7]	$5	0.0	9	3.1	NA	$7,495	27.1	888	3.2	NA	$96,274	360.0	19	3.1	NA	$103,774	387.1	916	3.1	NA
Conoco Inc	--	--	--	--	NA	--	--	--	--	NA	$13,096	44.2	4	3.4	NA	$13,096	44.2	4	3.4	NA
Energy West Resources Inc	$5	0.0	9	3.1	2.4	$7,495	27.1	888	3.2	2.4	--	--	--	--	2.9	$7,500	27.2	897	3.2	2.6
Granite Peak Energy	--	--	--	--	NA	--	--	--	--	NA	$1,953	7.2	1	3.1	NA	$1,953	7.2	1	3.1	NA
Hinson Power Company, L.L.C.	--	--	--	--	NA	--	--	--	--	NA	$30,157	130.1	1	2.6	NA	$30,157	130.1	1	2.6	NA
PPL EnergyPlus LLC	--	--	--	--	NA	--	--	--	--	NA	$51,068	178.5	13	3.3	NA	$51,068	178.5	13	3.3	NA
STATE TOTALS	$291,344	460.0	413,182	7.2	6.5	$232,145	423.2	80,475	6.3	5.7	$162,661	515.0	680	3.6	2.9	$709,193	1,435.4	509,963	5.6	4.9

NA - not applicable

[1] One average megawatt = 8,760 kilowatt-hours. [2] The number of ultimate consumers is an average of the number of consumers at the close of each month.

[3] Average price is the average revenue per kilowatt-hour of electricity sold, which is calculated by dividing revenue (in current dollars) by sales. It includes hook-up and demand charges.

[4] Between 2000 and 2002, Hinson Power took over provision of power to CFAC from Flathead Cooperative. This increased the average price of both Flathead and cooperatives in general.

[5] Market incentives paid CFAC to suspend operations were not subtracted from total revenue in 2000.

[6] Revenues don't cover transmission and distribution costs. For a rough estimate of price to the consumer, add 2.0 cents/kWh (or possibly more) to commercial and 1.0 cents/kWh (or possibly less) to industrial.

[7] NWE reported delivery of 29.3 aMW more than the listed power marketers reported sold. This unreported power went primarily to the commercial sector. Most of it may have been sold by Commercial Energy, which did not file Form 861 reports with US DOE.

Source: U.S. DOE, Energy Information Administration, Form 861 Database:http://www.eia.doe.gov/cneaf/electricity/page/eia861.html for 2000 and 2002.

Table E9. Percent Of Utility Sales In Montana And Other States, 2002

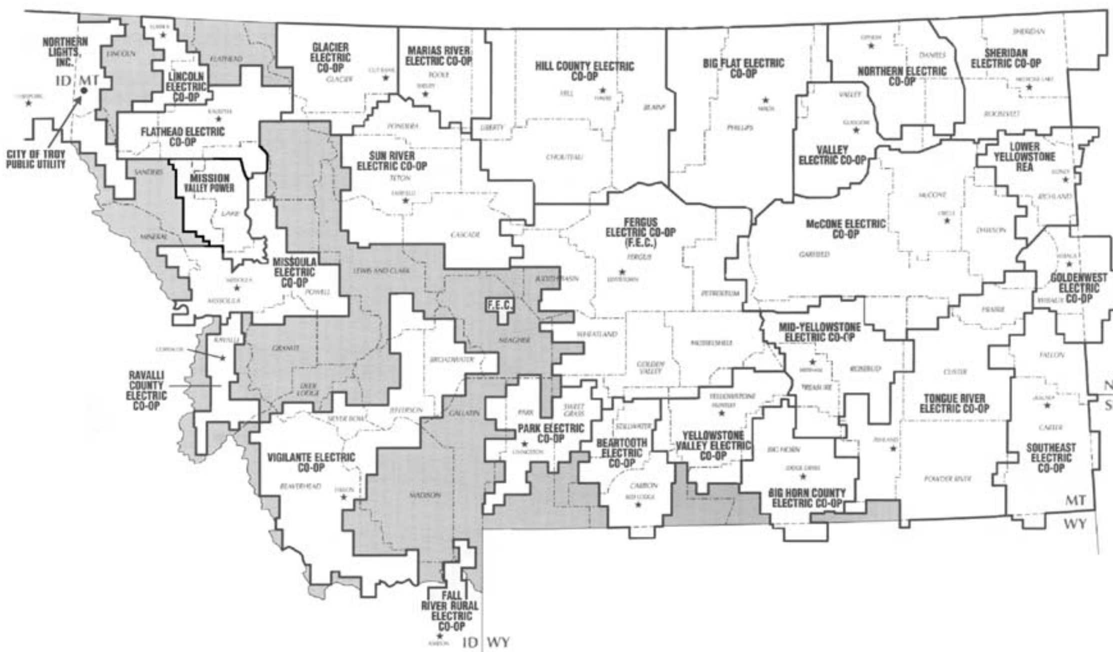
Utility	Percentage in Montana	Other States State	Percent	State	Percent	State	Percent
Avista Corp	*	WA	66	ID	34		
Beartooth Electric Coop	100						
Big Flat Electric Coop	100						
Big Horn County Elec Coop	94	WY	6				
Big Horn Rural Electric Co.	1	WY	99				
Black Hills Power	1	SD	90	WY	10		
Bonneville Power Admin	4	WA	94	OR	2		
Conoco	100						
Energy West Resources	100						
Fall River Rural Elec Coop	20	ID	76	WY	4		
Fergus Electric Coop	100						
Flathead Electric Coop	100						
Glacier Electric Coop	100						
Goldenwest Electric Coop	34	ND	66				
Grand Electric Coop	*	SD	100				
Granite Peak Energy	100						
Hill County Electric Coop	100						
Hinson Power Company, L.L.C.	100						
Lincoln Electric Coop	100						
Lower Yellowstone R E A	79	ND	21				
Marias River Electric Coop	100						
McCone Electric Co-op	100						
McKenzie Electric Coop	*	ND	100				
MDU Resources Group	25	ND	59	WY	11	SD	6
Mid-Yellowstone Elec Coop	100						
Mission Valley Power	100						
Missoula Electric Coop	99	ID	1				
Northern Electric Coop	100						
Northern Lights	19	ID	81	WA	*		
NorthWestern Energy LLC	99	WY	1				
Park Electric Cooperative	100						
Powder River Energy Corp	*	WY	100				
PPL EnergyPlus LLC	52	PA	46	NJ	1	Other	1
Ravalli County Elec Coop	100						
Sheridan Electric Coop	94	ND	6				
Southeast Electric Coop	97	SD	2	WY	*		
Sun River Electric Coop	100						
Tongue River Electric Coop	100						
Troy City of	100						
Valley Electric Coop	100						
Vigilante Electric Coop	100	ID	*				
Western Area Power Admin	2	CA	60	AZ	16	Other	21
Yellowstone Valley Elec Coop	100						

* Less than 0.5 percent.

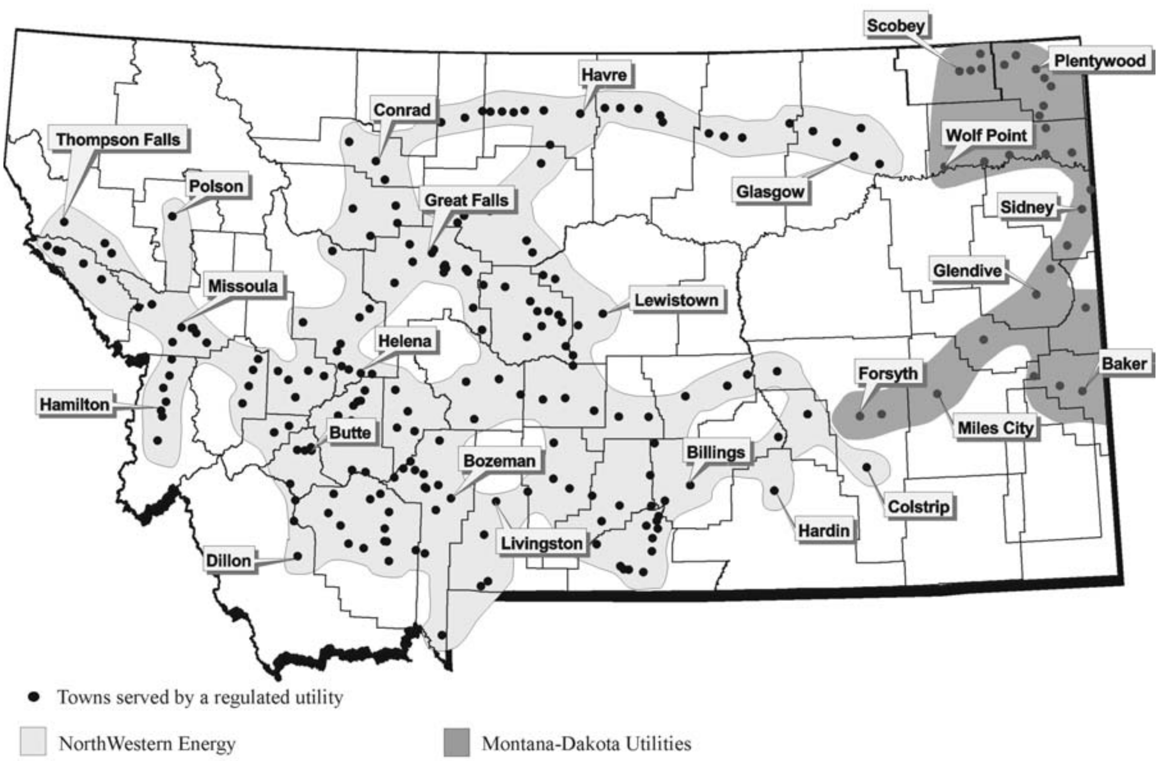
Source: U.S. Department of Energy, Energy Information Administration, Form EIA-861 database 2002, http://www.eia.doe.gov/cneaf/electricity/page/eia861.html.

SERVICE TERRITORY MAPS

ELECTRICITY DISTRIBUTION UTILITIES NOT REGULATED BY THE PUBLIC SERVICE COMMISSION



ELECTRICITY DISTRIBUTION UTILITIES REGULATED BY THE PUBLIC SERVICE COMMISSION



● Towns served by a regulated utility

NorthWestern Energy — Montana-Dakota Utilities

NOTE: These utilities provide electricity to towns and varying amounts of the surrounding areas. Their service areas are not necessarily continuous town to town. The depictions of service areas in this map are for illustrative purposes only and may include some areas served by rural electric cooperatives.

Montana Electric Transmission Grid: Operation, Congestion, and Issues

The transmission grid serves the vital function of moving power from many different generating plants to customers and their electric loads. Moreover, it provides service robustly and reliably even though individual elements of the transmission grid may be knocked out of service or taken down for maintenance. This paper describes how the transmission grid developed, how it works in terms of physics and how it is managed commercially, and how reliability is ensured. It discusses the ownership and rights to use the system, the extent of congestion and how it is managed, and how management would be changed under the proposed regional transmission organization. Finally, it discusses several issues involved in the construction of new transmission lines to expand the capacity of the grid.

1. Historical Development Of Transmission In Montana

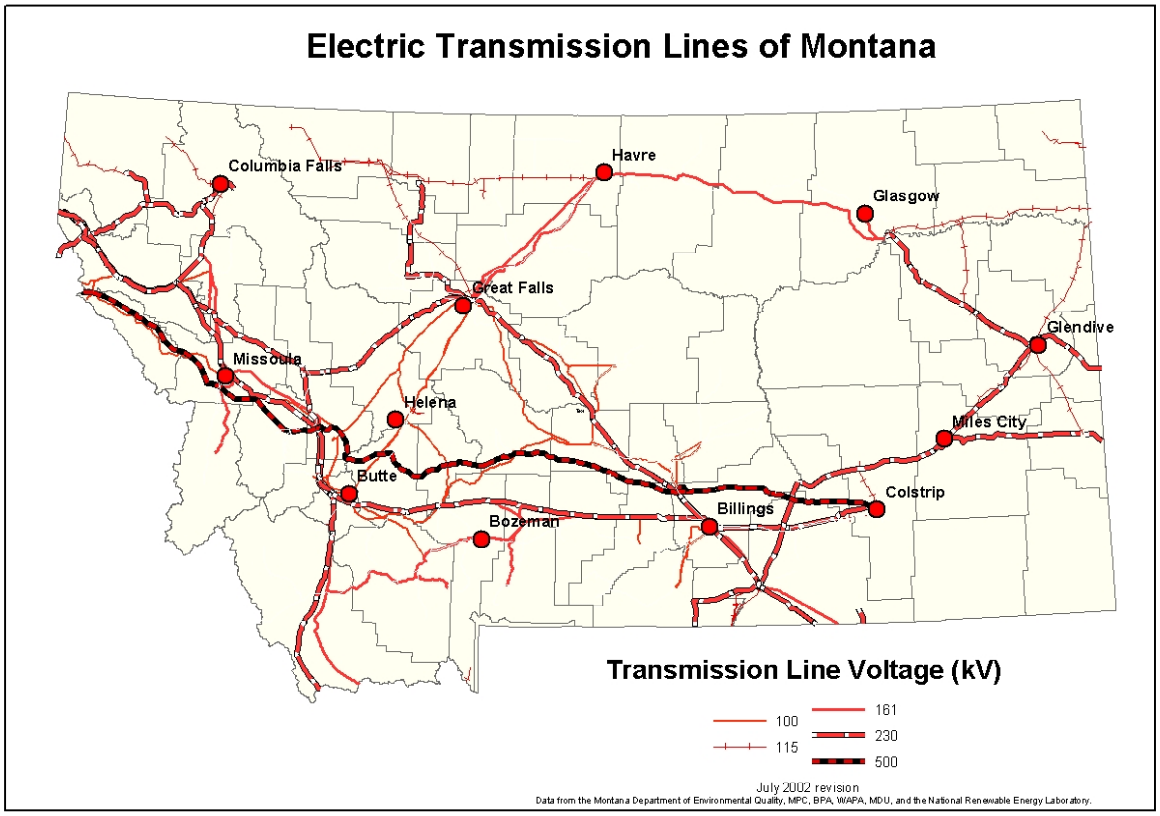
The transmission network in Montana, as in most places, developed over time as a result of local decisions in response to growing demand for power and decisions on where to build generation. The earliest power plants in Montana were small hydro generators and coal-fired steam plants, built at the end of the nineteenth century to serve local needs for lighting, power, and streetcars. The earliest long distance transmission lines were built from the Madison plant, near Ennis, to Butte and from Great Falls to Anaconda. The latter was, at the time of construction, the longest high voltage (100 kilovolt—kV) transmission line in the country.

As the Montana Power Company (MPC—now NorthWestern Energy) system, and rural electric cooperatives (co-op) loads dependent on its system for delivery grew, MPC expanded its network to include 161 kV and ultimately a 230 kV backbone. Long distance interconnections did not develop until World War II. During the war the 161 kV Grace line was built from Anaconda south to Idaho. Later, BPA extended its high voltage system into the Flathead Valley to interconnect with Hungry Horse Dam and to serve the aluminum plant at Columbia Falls.

Montana's strongest interconnections with other regions are now the 500 kV lines from Colstrip to Spokane, the BPA 230 kV lines heading west from Hot Springs, PacifiCorp's interconnection from Yellowtail Dam south to Wyoming, WAPA's DC tie to the east at Miles City, and the AMPS line running south from Anaconda parallel to the Grace line to Idaho.

As U.S. and Canadian utilities have grown and increasingly depend on each other for support and reliability, the North American transmission network has developed into two major interconnected grids, divided roughly along a line that runs through eastern Montana south to west Texas. The western United States is a single, interconnected and synchronous electric system (see next page). Most of the eastern United States is a single, interconnected and synchronous electric system. Texas and Quebec are exceptions; Texas is considered a separate interconnection with its own reliability council, ERCOT.

Figure 1. The Montana transmission network

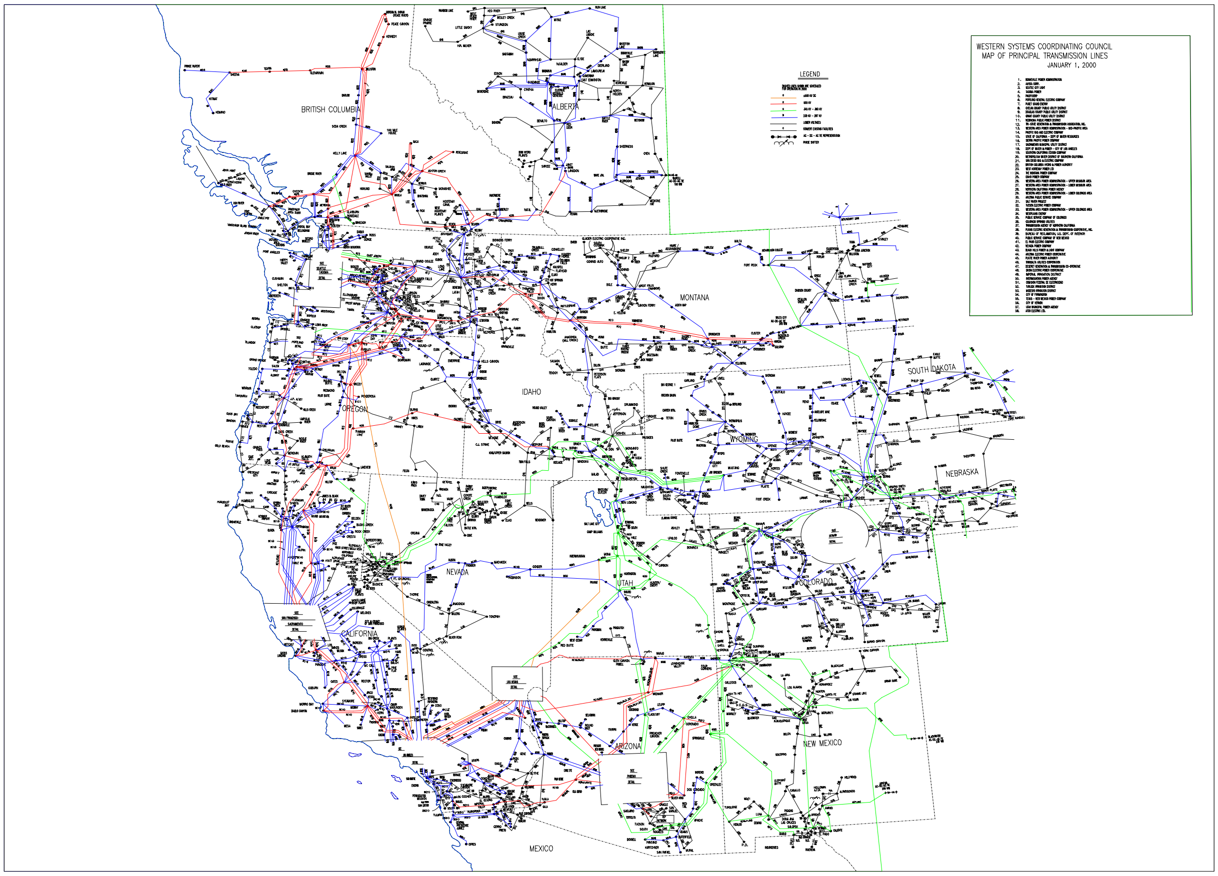


The interconnections are not synchronous with each other. Each interconnection is internally in synch at 60 cycles per second, but each system is out of synch with the other systems. They cannot be directly connected because there would be massive instantaneous flows across any such connection. Therefore they are only weakly tied to each other with AC/DC/AC converter stations. One such station is located at Miles City. It is capable of transferring up to 200 MW in either direction. Depending on transmission constraints, a limited amount of additional power can be moved from one grid to the other by shifting units at Fort Peck Dam. By contrast, this transfer capacity is about one tenth the peak load in Montana, which is one of the smaller loads in the West.

There are currently four DC converter stations between the western and eastern grids with a combined capacity of 710 MW. An additional station at Lamar, CO, with 210 MW capacity, will be operating by the end of 2004. There are also two converter stations with a combined capacity of 420 MW linking the Western Interconnection with ERCOT. The peak load of the Western Interconnection, by comparison, was around 136,000 MW in 2002.

Most of Montana is integrally tied into the Western electrical grid. However the easternmost part of the state, with around 7 percent of total Montana load, is part of the Eastern Interconnection and receives its power from generators in that grid.

Figure 2. The Western Interconnection transmission network



2. How The Transmission System Works

There are big differences between the way the transmission system operates and is managed physically, and the way it is operated commercially. The flows of power on the transmission network follow certain physical laws. Transactions to ship power across the grid follow a different and not fully compatible set of rules.

<u>Physical operation:</u> The transmission grid is sometimes described as an interstate highway system for electricity, but the flow of power on a grid differs in very significant ways from the flow of most physical commodities. First, when power is sent from one point to a distant location on the transmission grid, the power will flow over all connected paths on the network. It will distribute itself so that the greatest portions flow over the paths of lowest resistance ("impedance," in alternating current circuits), and it generally cannot be constrained to any particular physical or contract path. For example, power sent from Colstrip to Los Angeles will flow mostly west to Oregon and Washington and then south to

California. But portions will flow south via Garrison into Idaho, and even southeast from Colstrip into Wyoming and then south to Arizona before continuing to Los Angeles.

A second way in which power flows differently than other commodities is that flows in opposite directions net against each other. If traffic is congested in both directions on an interstate highway it will come to a halt in all lanes and not a single additional vehicle will be able to enter the flow. By contrast, if 100 MW were shipped westbound on a transmission line from point A to point B, and 25 MW were sent simultaneously eastbound from point B to point A, the actual measured flow on the line would be 75 MW in a westbound direction. If 100 MW were sent in each direction the net measured flow would be zero. If power were shipped simultaneously in opposite directions at the full capacity of a transmission line, the net flow would be zero, and additional power still could flow in either direction up to the full capacity of the line.

As a consequence of the above factors, the actual flows on the network are the net result of all generators and all loads on the network. In any real transmission network there are many generators located at hundreds of different points on the network, and many loads of varying sizes located at thousands of different locations. Because of netting, regardless of where power is sent or from where it is purchased, path loadings will depend only on the amounts and locations of electric generation and load.

<u>Management of the grid.</u> In contrast with the physical reality of the transmission network, management of transmission flows has historically been by use of a "contract path." A transaction shipping power between two points will be allowed if space has been purchased on any path connecting the two points, from the utilities owning the wires (or the rights to use those wires, if they are transferable) along that path. Transactions are deemed to flow on the contract path. Portions that flow on other paths are termed "inadvertent flows" or "unscheduled flows."

For example, power sent from Colstrip to the West Coast uses a contract path along the 500 kV lines through Garrison and Taft, then across the West of Hatwai path into western Washington and Oregon. However somewhere between 15 and 20 percent of the power actually flows south across two other paths, the Yellowtail-South path and the Montana-Idaho path south from Anaconda.

The topology of the western grid is such that major inadvertent flows occur around the entire interconnection. Power sent from the Northwest to California flows in part clockwise through Utah and Colorado into New Mexico and Arizona and then west to California. Conversely, a portion of power sent from Arizona to California flows counterclockwise through Utah, Montana and Idaho, then west to Washington and Oregon, and then south into California. These major inadvertent flows are called "loop flow." Expensive devices ("phase shifters") have been installed at several locations to control loop flow and to limit its effect on owners of affected portions of the grid.

Owners of rights or contracts on contract paths are allowed to schedule transactions as long as the total schedules do not exceed the path ratings. Scheduling against reverse flows is not allowed, despite their netting properties, because the capacity created by reverse schedules is not deemed to be firm. (If the flow scheduled in one direction was reduced at the last minute, capacity to carry power in the opposite direction would automatically go down by the same amount.)

Inadvertent flows may interfere with the ability of path owners to make full use of their rights. The Western Electricity Coordinating Council (WECC) Unscheduled Flow Reduction Procedure requires utilities whose wires are affected by inadvertent flows to first accept flows up to the greater of 50 MW or 5 percent of the path rating by curtailing their own schedules. If further reductions are necessary the path owners can request the operation of phase shifters (to block loop flows) or curtailments of schedules across other paths that affect their ability to use their own path. Phase shifters are limited to operation no more than 2000 hours per year, because they have limited lifetimes and are degraded by use.

The shift to management of the grid by a Regional Transmission Organization (RTO—discussed below) will do away with the use of the contract path, and with it, the necessity for special management of inadvertent flows.

If the scheduled flows do not exhaust the path rating, the unused capacity may be released as non-firm transmission capacity. This capacity cannot be purchased in advance; it can be scheduled only at the last hour. Owners of capacity who do not plan to use it could release it earlier, but often are reluctant to do so because of their own needs for flexibility or a desire to withhold access by competitors to their markets.

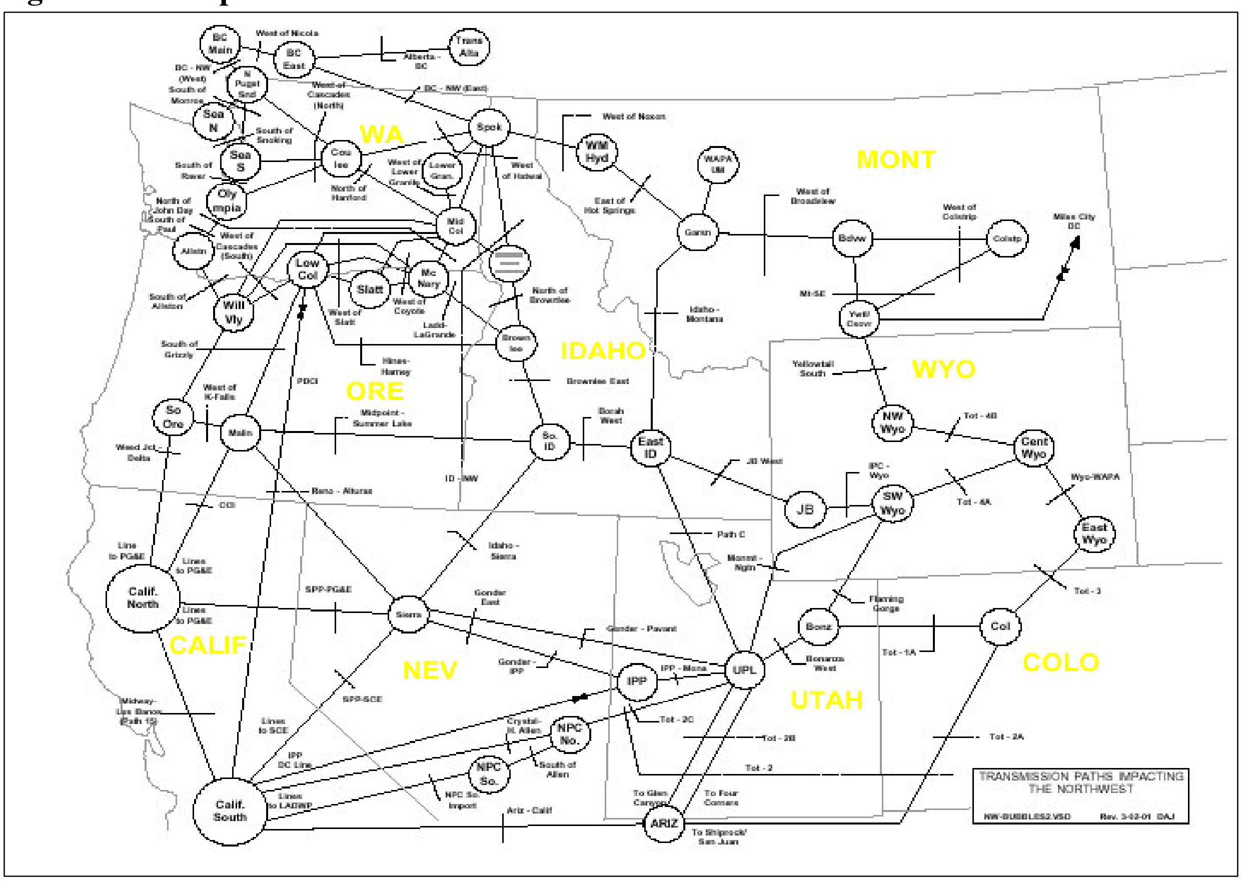
3. Grid Capacity and Reliability

The amount of power a transmission line can carry is limited by several factors. A major factor is its thermal limit. When flows get high enough the wire heats up and stretches, eventually sagging too close to the ground and arcing. Other factors relate to inductive and capacitative characteristics of AC networks. (Inductive characteristics are associated with magnetic fields that are constantly expanding and contracting in AC circuits wherever there are coils of wire such as transformers. Capacitative characteristics are associated with electric flows induced in wires that are parallel to each other, such as long transmission lines.) But the most important factor, indeed the limiting factor, is reliability. The transmission network is composed of thousands of elements that are subject to random failure, caused by such things as lightning strikes, ice burdens, pole collapse, trees falling on conductors and vandalism. Since customers value reliability and can be greatly harmed by loss of power, reliability of the grid is assured by building redundancy into it. The grid is designed to withstand the loss of key elements and still provide uninterrupted service to customers. Service is provided by the network, not by individual transmission lines. Reliability concerns limit the amount of power that can be carried to the amount of load that can be served with key elements out of service.

Two examples will show how this applies. Within NorthWestern Energy's (NWE) service area the reliability of the transmission system is evaluated by computer simulation of the network at future load and generation levels, taking individual elements out of service and determining whether all loads can be served with voltage levels and frequencies within acceptable ranges. If acceptable limits are violated, the network must be expanded and strengthened. Typically this means adding transmission lines or rebuilding existing ones to higher capacities. Identical procedures are used by other utilities and by regional transmission and reliability organizations.

The second example relates to major transmission paths used to serve distant load or to make wholesale transactions. Paths are groups of more or less parallel transmission lines that carry power between the same general areas. Most major paths are rated in terms of the amount of power they can carry, based on their strongest element being unavailable. (In some cases the reliability criteria require the ability to withstand two or more elements out of service.) For example, the Colstrip 500 kV lines are a double circuit line, but they cannot reliably carry power up to their thermal limit because one circuit may be out of service.

Figure 3. Rated paths on the transmission network



The paths through Montana toward the west have been rated and are limited generally to 2200 MW east to west and 1350 MW west to east. The West of Hatwai path, which is comprised of a number of related lines west of the Spokane area, is rated at 2800 MW.

West of Hatwai is currently being expanded by approximately 1500 MW. A large but unknown share of that amount is committed to new generation in the Spokane area. Regional transmission studies (Rocky Mountain Area Transmission Study – RMATS – and Northwest Transmission Assessment Committee - NTAC) have identified relatively low-cost improvements that would expand capacity on the Montana-NW path by about 500 MW, but use of this to access West Coast markets could require additional improvements on West of Hatwai.

4. Ownership And Rights To Use The Transmission System

Rights to use the transmission system are generally held by the owners or by holders of long-term contract rights. Rights to use rated paths have been allocated among the owners of the transmission lines that comprise the paths. In addition the owners have committed to a variety of contractual arrangements to ship power for other parties. Scheduled power flows are not allowed to exceed the path ratings.

FERC Order 888, issued in April 1996, required that transmission owners functionally separate their transmission operations to make them independent of their power marketing operations. They must allow other parties to use their systems under the same terms and conditions as their own marketing arms. They must maintain a web site ("Open Access Same-Time Information System" or OASIS) on which available capacity is posted.

Available transmission capacity (ATC) is calculated by subtracting committed uses and existing contracts from total rated transfer capacity. Little or no ATC is available on most major rated paths, including those leading west from Montana to the West Coast. The rights to use the capacity are fully allocated and closely held. None is available for purchase by new market entrants.

These existing rights – and ATC, if any were available – are rights to transfer power on a firm basis every hour of the year. The owners of the rights on rated paths may or may not actually schedule power in every hour, and when they don't, the space they are not using may be available on a non-firm basis. In fact, the paths are fully scheduled for only a small portion of the year, and non-firm space is almost always available. For example, according to NWE, in the 12 months through September 2001, the West of Hatwai path was fully scheduled or over- scheduled about 8 percent of the time. The remainder of the time, 92 percent of the year, non-firm access was available.

However, non-firm access cannot be scheduled in advance or guaranteed. It is a workable way to market excess power for existing generators. It may be a reasonable way to make firm power transactions if backup arrangements can be made to cover the contracts in the event the non-firm space turns out to be unavailable. However it may be difficult to finance new generation if it cannot be shown with certainty that the power can be moved to market.

5. Congestion

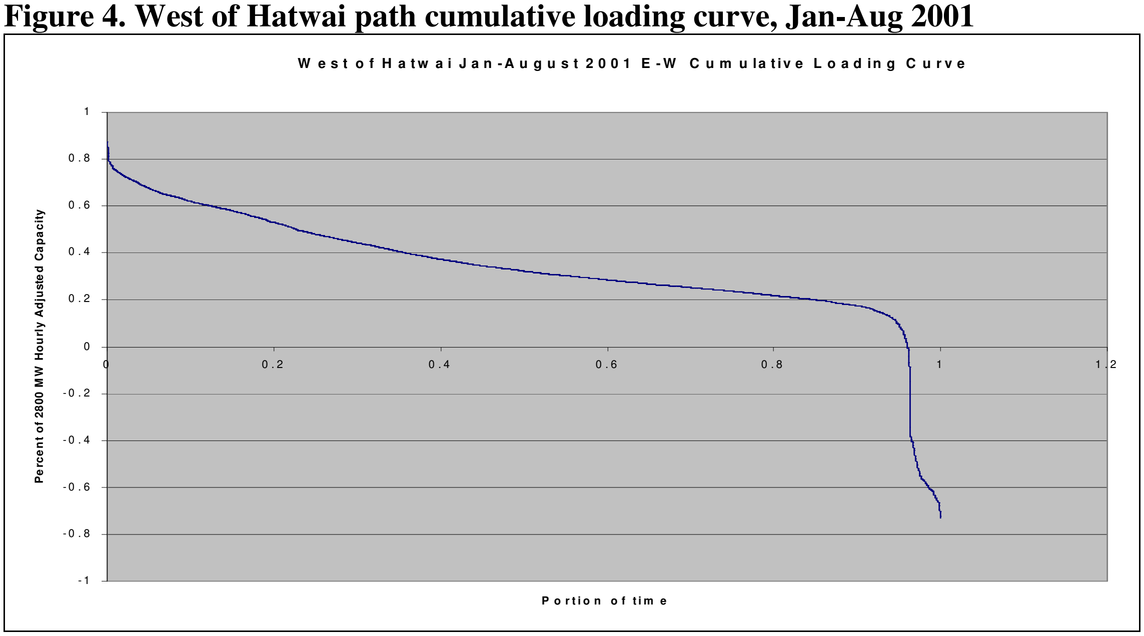
A transmission path may be described as congested if no rights to use it are for sale. Alternately, congestion could mean that it is fully scheduled and no firm space is available. Or it could mean that the path is fully loaded. These are three different concepts.

By the first definition, the paths west of Montana are congested – no rights are available and no ATC is offered for sale on the OASIS.

By the second definition, the paths are congested a few hours of the year - the rights holders fully use their scheduling rights a fraction of the time, and the rest of the time they use only portions of their rights. From October 2000 through September 2001, the West of Hatwai path was congested under this definition around 8 percent of the time.

The third definition is based on actual loadings. Actual loadings are different than scheduled flows because of the difference between the physics and the management of the grid – schedules are contract-path-based, and actual loadings are net-flow-based. Actual flows on the paths west of Montana are almost always below scheduled flows, because of the net impacts of inadvertent flows and loop flows. Actual hourly loadings on the West of Hatwai path are posted on BPA's OASIS site. Figure 4, below, shows that the first eight months of 2001, highest actual loadings were around 90 percent of the path capacity for only a few hours. For most hours the path was not heavily loaded. By the third definition, the lines currently are never congested – even when the lines are fully scheduled, the net flows are below path ratings.

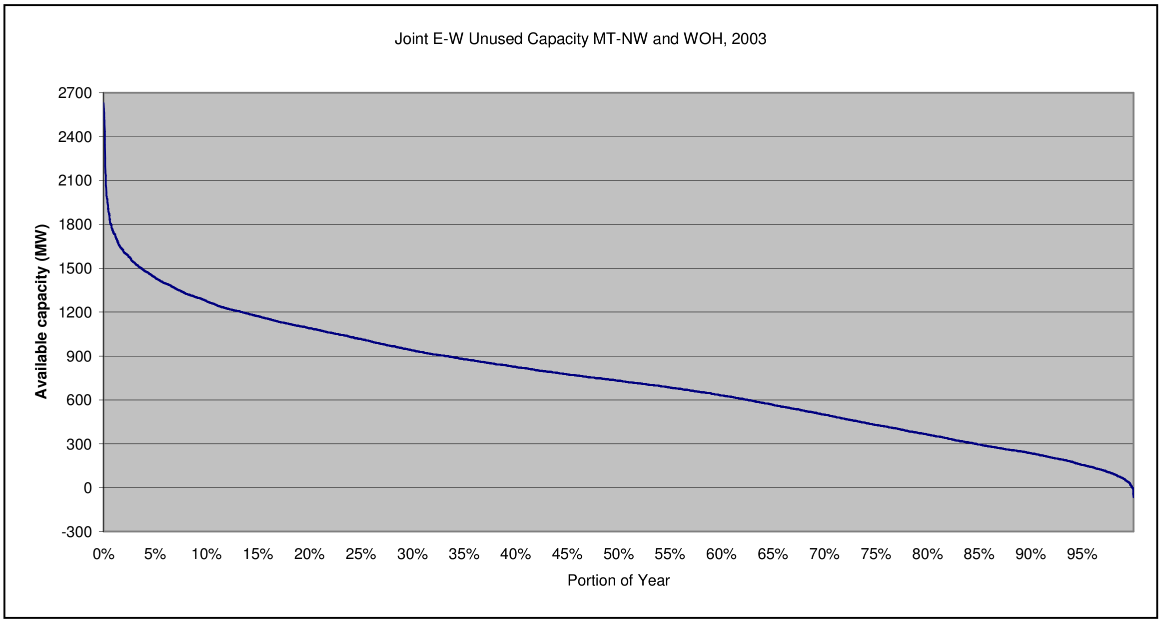
Figure 4. West of Hatwai path cumulative loading curve, Jan-Aug 2001



(Negative flows mean power was flowing from west to east)

The Montana-NW path shows a similar cumulative loading pattern – rarely if ever fully loaded and considerable unused capacity most of the time. However, the two paths do not load at the same times, and capacity from Montana to the Pacific Northwest is limited by the amount of space that is simultaneously available on both paths. Figure 5 shows the cumulative unused capacity that is simultaneously available on Montana-NW and West of Hatwai.

Figure 5. Simultaneous unused capacity, West of Hatwai and Montana-NW Paths, 2003



6. Grid Management By Grid West

Discussions to have an independent body take over operation and control of access for the transmission system have been underway since the mid-1990's among the transmission owners and other stakeholders in the Northwest. These started partly out of a recognition by the transmission owners that proof of independence, as required by FERC Order 888, would become an increasingly difficult burden, and partly out of anticipation that FERC would ultimately move to order such a transfer. Initial discussion revolved around IndeGO, a proposed independent system operator that would lease and operate the wires. The IndeGO discussions ultimately foundered on cost-shifting concerns, but after FERC issued Order 2000 the discussions revived, focusing now on a Regional Transmission Organization (RTO) that would operate the system under a contractual Transmission Operating Agreement (TOA) with the participating transmission owning utilities. These discussions have proved to be contentious and prolonged.

Assumption of responsibility for grid management by an independent entity is important because for the first time it would provide for a market-driven means of managing congestion. The current fixed assignment of rights to use the grid prevents non-incumbents from making use of unused capacity, and even hinders their ability to bid for it. The RTO would allow all parties to signal their willingness to pay for access and to make efficient use of the grid. In addition the RTO management would result in congestion price signals that would allow economic decisions on location of new generation and on expansion of capacity on congested transmission paths.

Initial efforts to gain regional consensus on a fully formed RTO resulted in a proposal and a filing with FERC in 2002. Subsequently, issuance by FERC of a draft Standard Market Design proposal created much confusion and much opposition in the region to continued pursuit of the RTO West 2002 proposal. In May, 2003 a "regional representatives group" (RRG) was convened to seek consensus on what the problems were with the current management of the grid, and on some evolutionary means of solving them. This effort has resulted in a proposal, now called Grid West, to form an initial, developmental, independent entity that would try to craft Transmission Operating Agreements and other operating protocols. The proposal includes a governance structure with a stakeholders committee that would elect board members and that would have to approve the evolutionary steps in the conversion of the developmental body into an operating entity. The operating entity would have limited functions, and would generally have to gain approval for each significant step into its evolution into a full RTO. Proposal details are at: http://128.242.83.219/Doc/RRGA_ProcessNarrativeandDiagram_Feb242004.pdf.

7. Major Issues of Transmission

There are a number of issues affecting the transmission system and the need for and ability to complete new transmission projects. These include the downgrading of capacity for reliability reasons, the way reliability criteria are set, the limited number of hours the system is congested, the problems involved in siting high voltage transmission lines, the cost of new capacity, making the commitment for new capacity, the alternatives for financing new transmission discussed in the Western Governors' Association Transmission Study, the follow-on work to the governors' study, and the proposed National Energy Bill.

Availability of Existing Capacity. A considerable amount of existing capacity is not available for use because it is held off the table for reliability reasons when paths are rated. (See discussion of reliability issues, below.) Transmission owners may withhold capacity because of uncertainty, the need for flexibility and in some cases, a desire to protect their markets.

Uncertainty affects the transmission needs of utilities because they don't know in advance what hourly loads will be or which generating units may be unavailable.

The need for flexibility affects transmission needs because utilities want the right to purchase power to serve their loads from the cheapest source at any given time. When RTO West tried to convert existing contract rights into flow based rights the claims greatly exceeded available capacity. This was largely due to utilities that had a right, for example, to move 100 MW on any of several paths, claiming a simultaneous right of 100 MW on all of them.

Withholding of capacity for market protection is a violation of Order 888. Withholding has been a problem since the order was issued, with a number of utilities around the country being cited and fined by FERC for violations. The failure of Order 888 to result in open and comparable access was a major reason for FERC Order 2000, which requires utilities to form RTOs.

Reliability Criteria. Reliability is an issue because the criteria governing the setting of path capacity and the operation and expansion of the transmission system relate only vaguely to economics. They do not reflect very well the probability or the consequences of the events being protected against. Since the system is quite reliable as currently built and operated, reliability concerns generally focus on very low probability events that may, depending on when they occur, have high costs. The criteria apply everywhere on the transmission grid despite the fact that in some areas and on some paths the consequences may be minimal while in other areas and other paths the same type of event may have large consequences. For example, Path 15 in central California or the Jim Bridger West path in Idaho, where a line outage can result in cascading failure and impact many millions of people, should probably be operated more stringently than parts of the transmission grid where an outage might cause a generating unit to trip off, but not affect any load.

Reliability criteria for the Western Interconnection are set by the Western Electricity Coordinating Council (WECC), which is part of the National Electric Reliability Council (NERC). The Western Electricity Coordinating Council was formed in 2002 from a merger of the Western Systems Coordinating Council (WSCC) with several other transmission organizations. WECC has much broader representation on its board than the WSCC did, and has stakeholder advisory committees.

Limited Hours of Congestion. As discussed above, the congested portions of the transmission grid tend to be fully or heavily scheduled and loaded only a few hours to a few hundred hours of the year. The rest of the time excess capacity is available, although it is a challenge to make use of it on a firm basis. Expanding capacity is expensive and difficult. Yet it has been the preferred method of gaining access for additional transactions and additional flows. If the costs of new construction could be assigned to the congested hours only it is very likely cheaper alternatives to that construction would be found. For example, some current users with relatively low valued transactions or with ready alternatives might be willing, at some price, to sell their rights to new users.

Siting. High voltage transmission lines can be difficult and contentious to site, especially in forested, mountainous or populous areas. For example, the Colstrip double circuit 500 kV lines were relatively easy to site in eastern Montana where they traversed rolling agricultural and grazing land. Siting in western Montana was a different story, particularly in the areas of Boulder, Rock Creek and Missoula. The resulting route had to stay away from the Interstate highway corridor, instead opening new corridors through forested areas with issues such as impacts to elk security areas and increased access. Lengthy detours around

Boulder and Missoula added considerably to the cost of the line. Rural growth and residential construction in western Montana since the Colstrip lines were sited in the early 1980s, combined with the already limited siting opportunities due to wilderness areas and Glacier National Park, can be expected to make siting challenges likely for additional construction.

<u>Cost.</u> High voltage transmission lines are expensive to build. A typical single-circuit 500 kV line may run to $1 million per mile. A double-circuit 500 kV line may cost around $1.5 million or more per mile. 500 kV substations cost around $50 million each, depending on the complexity caused by their location on the network. If series compensation is required, 500 kV substations may cost up to $100 million. 230 kV lines are somewhat cheaper – about half the cost per mile of 500 kV lines, and substation costs run around $25-30 million each. DC lines are cheaper still but the equipment required to convert alternating current to direct current and back is extremely expensive, so this technology is generally used only for very long distance transmission with no intermediate interconnections. At present there are only two DC lines in the Western Interconnection – the Pacific DC Intertie, from Celilo in southern Oregon to Sylmar near Los Angeles, and the IPP line from the Intermountain Power Project generating station in Utah to the Adelanto substation, also near Los Angeles. Neither line has any intermediate connections.

<u>Transmission Capacity to Accommodate New Generation in Montana.</u> There is considerable interest in Montana in building in-state energy facilities as an economic development tool. Rising natural gas prices have improved the climate for marketing coal and wind energy from Montana. The lack of available transmission capacity to reach West Coast markets may be a significant barrier. As discussed above, there is some amount of unused capacity on the existing transmission network for a large part of the time, but it is not available on a firm basis. Changes in the way the transmission system is managed could make this space available, and could support some modest increase in new generation in the state. Significant additional generation would require new transmission capacity.

There is a “chicken and egg” problem in developing new transmission to facilitate economic development. If no capacity is available to reach markets, generation developers may have a difficult time financing their projects. Yet without financing, they probably can’t make the firm commitments for transmission services that would encourage utilities to invest on their own in transmission capacity for new projects. The alternative approaches, where the generation developers build needed new capacity or where new merchant transmission capacity is built in the hopes new generation will appear, still need to convince the financial markets that the transmission project is viable. In any event, the regulatory structure requires a showing of need for new transmission projects that may be difficult to make without firm commitments from generators. Of course, the regulatory requirements can be changed to accommodate economic development as a basis of need. Eminent domain is another matter. Eminent domain seizures could be at risk of court challenges if a landowner were to convince the court the public purposes of the line were speculative.

The issues confronting merchant plants are different than those faced under traditional utility procedures, where generation and transmission were planned, financed and built together. Generation developers either must absorb the risk of building new transmission capacity or convince some other party to absorb the risk for them.

Western Governors' Association Transmission Study. In the spring of 2001 the WGA asked the utility industry and the Committee for Regional Electric Power Cooperation (CREPC—an organization of western states' public service commissions and energy offices) to study the need for new transmission in the western United States. A working group of experts modeled the transmission grid and the likely growth of demand and new generation, and concluded that little new transmission (somewhere less than $2 billion over a 10 year period) would be needed beyond that already planned or under construction. This was a result of mostly natural-gas-fired new generation planned for locations close to loads or well served by existing transmission capacity. At the request of the Governors the group also studied a "fuel diversity" scenario in which half of new capacity was coal-fired generation or wind generation. This scenario resulted in a need for approximately $12 billion in new transmission capacity, including construction in Montana of a new 500 kV line to the West Coast and a new 500 kV line to Alberta.

The Western Governors' Association then requested a study of how to finance new transmission lines, and the resulting report discussed two alternative proposals. The first was an "interstate highway" model in which all electric customers in the west would share in the costs of all transmission in the west, regardless of use. This model envisioned transmission expansion to eliminate most or all congestion. The second is a model in which the beneficiary pays: regional financing of reliability improvements, utility financing of load service improvements, and generation and customer financing of capacity expansions to eliminate congestion.

Each approach has advantages and disadvantages. The interstate highway model would avoid the need to determine the relative merits of different possible lines and simply eliminate all congestion. It would make a great deal more capacity available and could encourage the development of resources in places previously difficult to build. For Montana, it would make it easier to develop coal and wind resources. On the other hand, it would require agreement by all states and all utilities to spread the costs to all ratepayers. There is no existing agency with the authority to require such spreading and there is unlikely to be universal agreement to spread these costs without such an agency. The interstate highway approach could also result in overbuilding the transmission system, for example to alleviate congestion that may be minimal or that could be more cheaply addressed in other ways.

The "beneficiary pays" model is currently implementable and reflects the way transmission is currently financed for certain types of lines, such as lines needed for reliability and lines needed to serve growing utility loads. It results in a closer correspondence of benefits and costs than the interstate highway approach, and could make siting easier by reducing controversies over need. On the other hand, if future benefits are uncertain it could make financing difficult, and it would not provide the benefits to Montana coal and wind developers unless they were willing to pay the costs of needed transmission. Further, proponents of the interstate highway model are skeptical that the beneficiary pays model will result in the timely construction of new transmission capacity.

Rocky Mountain Area Transmission Study. In 2004 the Governors of Utah and Wyoming convened RMATS as a followup to the WGA transmission study. RMATS was given the task of identifying transmission that would enable the development of coal and wind generation resources in the Rocky Mountain west and carry the power to markets on the West Coast, California, and the Denver area. RMATS was also tasked with figuring out how to finance the desired transmission and how to allocate the costs.

Montana has participated actively in this study. RMATS defined two levels of projects. "Recommendation 1" projects include a moderate upgrade of the existing Montana-Northwest transmission system that would involve installation of capacitors at various points and construction of a new substation at Ringling, but no new transmission lines. It would expand capacity by approximately 500 MW. Recommendation 1 also includes a transmission line from Wyoming to Colorado, from Wyoming to Utah, and expansions on the Bridger transmission line.

The second level of expansion contained in "Recommendation 2" is more ambitious. It would include a new 500 kV transmission line from Montana to eastern Washington, and another from the Ringling Substation proposed in the first recommendation, south through the Dillon area and Monida Pass to markets in California and to the West Coast via the Bridger transmission lines.

National Energy Bill The omnibus National Energy Bill introduced in the 2003 session included a provision to enable DOE to designate transmission lines of national interest to overcome significant congestion. This provision would also allow FERC to authorize construction and the use of federal eminent domain authority for such lines. No federal funding is provided. As of the summer of 2004 the Bill had not made significant progress toward passage, but DOE had initiated discussions and public hearings on the procedures for designating national interest transmission lines. The transfer of transmission siting authority to the Federal Government raises mixed concerns for the state. Economic development interests see it as a way to speed construction of the infrastructure that would allow the state to develop its energy resources. Environmental interests see it as a loss of the state's ability to permit needed transmission lines and to site them to minimize environmental damage. Other parties question the need for a transfer of authority when there has been no history of difficulties in the west in permitting and siting transmission lines. Instead, they see it as a solution in search of a problem.

Natural Gas in Montana: Current Trends, Forecasts and the Connection with Electric Generation

Natural gas is a major source of energy for Montana's homes, businesses, and industries. This chapter discusses current natural gas trends in Montana, and what to expect in the coming years. Montana is part of the North American gas market, with gas prices and availability set more by events outside than inside Montana. As electricity generation around the country comes to rely more on natural gas and as production from North American gas wells levels out or declines, the price and availability of gas are already moving in ways Montanans have not experienced in previous decades.

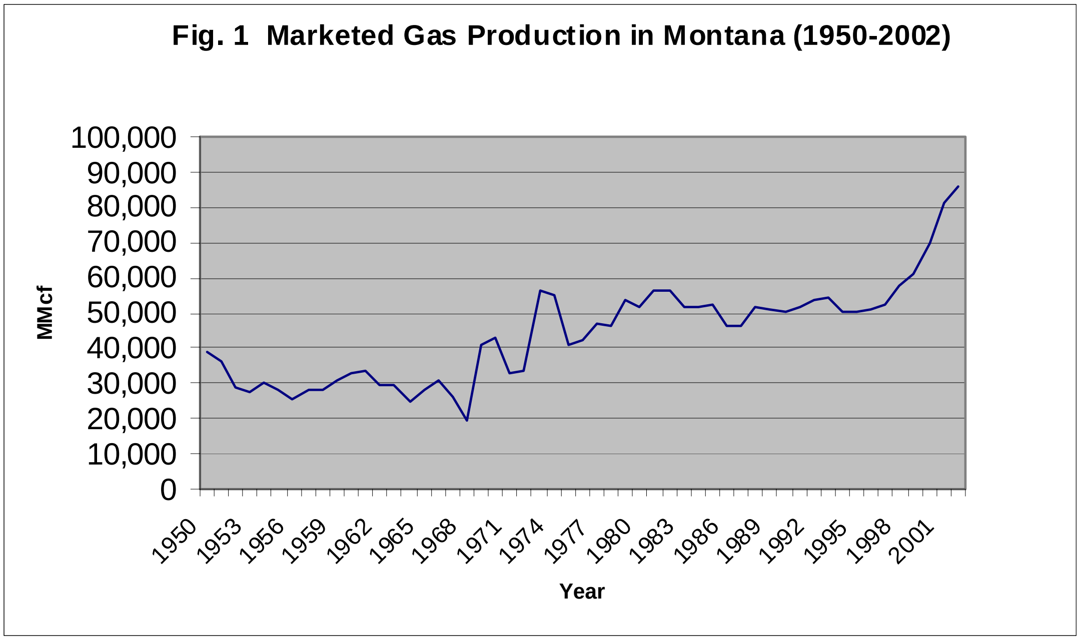
1. Natural Gas Supplies for Montana

Alberta provides the largest supply of natural gas for Montana customers and will likely continue to do so in the years to come. The reason for this is our proximity to Alberta's large gas reserves. The next largest supply for Montana is from in-state wells mostly located in the north-central portion of the state. Supplies from the other Rocky Mountain states represent a small portion of total in-state usage and continue to decline from historic levels. Future changes in supplies from in-state development and from other Rocky Mountain states are uncertain at this point. Coal bed methane may eventually increase the portion of gas used in Montana that comes from Rocky Mountain states, but the peak of that production is still a few years off.

Montana currently produces more gas than it consumes. In 2002, Montana produced 86.1 billion cubic feet (bcf) and consumed 69.6 bcf (Tables NG1 and NG2). The bulk of what Montana produces is exported, and the bulk of what Montana consumes is imported. In 1999, for example, Montana produced 61.2 bcf of gas and exported 51.8 bcf total to North Dakota, South Dakota and the Midwest. The reasons for this are the way in which natural gas utilities structure their gas purchasing contracts and the configuration of gas pipelines in Montana.

Most gas produced in Montana comes from the north-central portion of the state. In 2002, the north-central portion accounted for 71% of total production and the northeastern portion of the state accounted for 15% (MBOGC 2003). In-state gas production has been increasing in recent years (Figure 1, below). The south-central and northeastern portions have greatly increased their production level since 1998, resulting in most of the recent statewide increase (MBOGC 2003). Because most gas is exported, increases or decreases in natural gas production in Montana likely have little impact on Montana natural gas consumers.

Coal bed methane development in Montana has not yet become significant, due in part to difficult environmental issues. Some residents in Montana have forcefully opposed methane development, especially in or near the Powder River Basin. However, with the Montana Environmental Impact Statement completed and released to the public in the fall of 2003, in-state development is expected to increase in the near future. The total amount of methane development that will occur in Montana is yet to be determined. The future extraction of other known gas reserves along Montana's Rocky Mountain Front likewise is uncertain at this point.



Source: U.S. EIA, Natural Gas Annual Reports, 1950-2002 (Table NG1).

2. Natural Gas Supplies for the United States

U.S. natural gas supplies are largely domestic, supplemented by substantial imports from Canada. About half of current U.S. reserves are located in Texas, Louisiana and offshore in the Gulf of Mexico. As of 2001, about a quarter of U.S. reserves were located in the Rocky Mountain states of New Mexico, Wyoming, and Colorado (U.S. EIA 2001). As of 2002, Texas, New Mexico, Oklahoma, Wyoming, and Louisiana (including Federal offshore production) accounted for about 80% of domestic marketed production (U.S. EIA 2004a). The Rocky Mountain states are the most important source of domestic natural gas supply to the Pacific Northwest region in which Montana is located. Alaska's North Slope is potentially the largest source of new natural gas resources for the nation as a whole (U.S. EIA 2001).

After declining during the 1990s, natural gas drilling in the U.S. picked up dramatically in early 2000 and 2001 in response to high gas prices, only to fall off again in 2002 as prices returned to their historic average levels. Drilling increased again after 2002 (U.S. EIA 2004a and U.S. EIA, 2004a). Today in 2004, more than 1,000 rigs are drilling for natural gas in the U.S., which is close to the 2001 high. If natural gas prices remain at their current high levels, domestic drilling will continue to grow, perhaps at higher rates than recently experienced.

According to the U.S. Energy Information Administration (U.S. EIA), domestic natural gas production, with its large and accessible resource base, is expected to increase from 19.9 trillion cubic feet (tcf) in 2002 to a projected 24.4 tcf in 2020 to meet growing domestic demand. Increased production would come primarily from lower-48 onshore conventional sources, although onshore *un*conventional production is expected to increase at a faster rate than other sources during that time (U.S. EIA 2004b).

Today, 15-16% of the total natural gas consumed in the U.S. is imported from other countries with most of that coming from Canada (US EIA 2004a). In 2002, the United States imported 3.79 tcf of natural gas from Canada. Imports from Canada have been increasing over time with 2002 being the sixteenth consecutive year of increased imports from our neighbors to the north (U.S. EIA 2004a). Net natural gas imports into the U.S. are expected to increase from 3.6 tcf in 2002 to a projected 7.2 tcf in 2025, with imports making up an increasingly larger share of the total percentage consumed in the U.S. (U.S. EIA 2004b).

It is hard to predict how much natural gas is left in North American reserves that could go toward U.S. consumption. Reserves are constantly being consumed and replaced. The relative rates of consumption and replacement vary with economic conditions and natural gas prices. The Northwest Power and Conservation Council estimates between 2,100 and 2,650 tcf remaining of North American gas *resources* and about 290 tcf remaining in gas *reserves* (excluding Mexico).[1] Mexico used to send gas supplies to the U.S., but not longer does. Using these numbers and assuming that U.S. and Canadian consumption grows at 2.3 percent per year from current levels, estimated remaining North American resources would satisfy North American consumption for about 40 or 50 more years (not including imports and exports and unforeseen events). The entire world is estimated to contain 13,000 tcf in natural gas reserves with much of that located in the Middle East (Northwest Power and Conservation Council 2003; Morlan 2001). Proved reserves for the U.S. as of 2003 are 183 tcf (U.S. EIA 2003)

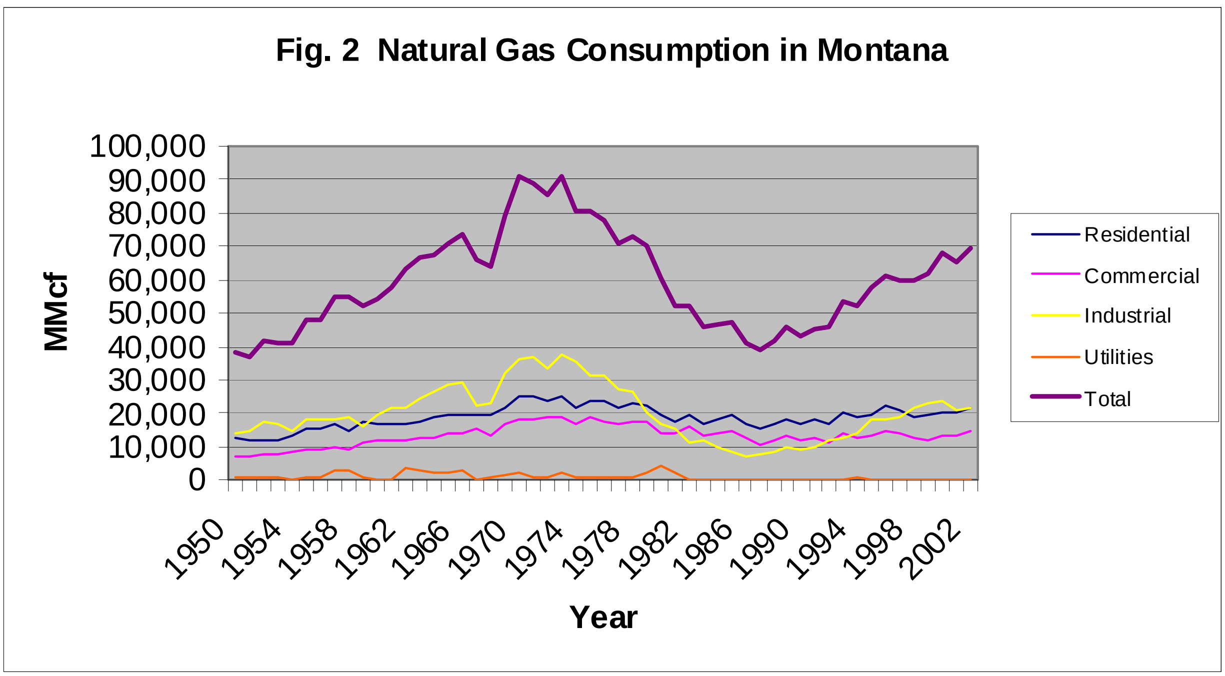
In the last year, some important trends in gas production have occurred with respect to North American supply. The government of Canada recently announced that they did not expect Alberta natural gas production to grow in the coming years as it has in the past, but instead to level off (Morlan 2004). Also, new wells being drilled in the U.S. by Devon Energy, the largest U.S. independent producer of gas, are finding fewer reserves than predicted with greater decline rates in their wells. Furthermore, the cost of finding natural gas in North America is rising. From 2001 through 2003, the three-year average finding cost for natural gas was $1.53/dkt, which was up 29% from the three-year average the year

[1] "Reserves" refers to natural gas that has been discovered and proved producible given current technology and markets. Natural gas "resources" are more speculative estimates of natural gas that might be developable with known technology and at feasible costs. By definition, resource estimates are more uncertain than reserve estimates.

before. In 2003 alone, the average finding cost was $1.73/dkt[2] (Wall Street Journal 2004). It is therefore possible that the gas production in North America in future years may not grow as quickly as the above projections say nor as quickly as historical trends.

3. Natural Gas Consumption in Montana

Recent Montana natural gas consumption has averaged 60-70 billion cubic feet (bcf) per year. Future Montana natural gas consumption, excluding that for new electric generation built in-state, is expected to increase slowly at less than 1 percent annually according to projections by Montana's largest gas utilities, Northwestern Energy and Montana-Dakota Utilities Co. Both residential and commercial gas consumption are growing very slowly, and usage by industry is expected to stay fairly level over time (see figure 2). In the 1970's, Montana's industrial sector used much more natural gas than it does now. The closure of smelters in Anaconda, in particular, contributed to the drop in industrial usage that occurred in the 1980's.



Source: U.S. EIA, *Natural Gas Annual Report*, 1950-2002 (Table NG2).

If new gas-fired electric generation plants get built in Montana, total gas consumption in Montana could significantly increase over current levels. The unfinished Montana First Megawatts gas-fired electric generation plant just north of Great Falls was expected to create a significant increase in total Montana annual natural gas consumption, but the project is on hold indefinitely and may be scrapped. Average new gas usage by this plant

[2] One dekatherm (dkt) is equal to a million British Thermal Units (BTUs). Often, natural gas prices will be reported either in dekatherms or in units of 'a thousand cubic feet' (Mcf's). Assuming an average BTU content for U.S. natural gas at standard conditions, 1.0 Mcf = 1.03 dkt according to the U.S. EIA (U.S. EIA, Natural Gas Annual, Table B2, 2002).

was expected to be around 13 bcf per year for first 160 MW of electric generation capacity built. This would have been equivalent to about 20 percent of the current total gas consumption in Montana. The proposed 500 MW Silver-Bow electrical generation plant near Butte is also on hold indefinitely with no action currently taking place. If it ever comes on line, the plant would consume about 30 bcf per year of gas—equivalent to almost 50 percent of current total gas consumption in Montana. The Silver-Bow project would have demanded a major upgrade in NorthWestern Energy's (NWE) gas pipeline system. Recent high natural gas prices and recent changes in the electric generation market are significant reasons why these plants have not been built. The Basin Creek plant near Butte at 51 MW generating capacity is negotiating with NWE, but may be up and running by late 2005. Natural gas usage at the Basin Creek plant would only constitute a small percentage of Montana's total usage right now, and would not require extensive upgrades to the NWE's pipeline system (Waterman 2004).

4. Natural Gas Consumption in the U.S.

Over the past two decades, a number of changes in energy markets, policies, and technologies have combined to spur an increase in the total usage of natural gas in the U.S. (U.S. EIA 2001). These include:

- Deregulation of wellhead prices begun under the Natural Gas Policy Act of 1978 and accelerated under the Natural Gas Wellhead Decontrol Act of 1989;
- Deregulation of transmission pipelines by Federal Energy Regulatory Commission (FERC) Orders 436 (1985), 636 (1992), and 637 (2000). The FERC orders separated natural gas commodity purchases from transmission services so that pipelines transport gas on an equal basis. These orders were intended to ensure that all natural gas suppliers compete for gas purchasers on an equal footing, to enhance competition in the natural gas industry, to ensure that adequate and reliable service is maintained, to improve efficiency in the gas transportation marketplace, and to protect customers from the exercise of market power. Also, Order 636 allows gas customers to purchase natural gas from a supplier other than the utility that delivers their natural gas;
- Passage of the Clean Air Act Amendments of 1990 and subsequent regulations affecting air quality standards for industries and electricity generators in non-attainment areas, which favor natural gas since it burns relatively clean compared to coal;
- Deregulation of the wholesale electricity market. High-efficiency combined cycle combustion turbine technology, coupled with low gas prices, has made gas the fuel of choice for conventional electric generation nationwide. Though coal is expected to continue to be the leading fuel for electricity generation, the natural gas share of total electric generation is expected to increase from 16 to 36 percent between 1999 and 2020. Today, over 95 percent of new electric generation coming on-line in the western U.S. is gas fired;
- Improvements in exploration and production technologies and a reduction in their associated costs, improving the return for exploration and production efforts;
- Investment in major pipeline construction expansion projects from 1991 through 2000 adding about 50 billion cubic feet per day of capacity; and
- Increased imports from Canada.

These factors created new markets and lowered the price of natural gas for existing markets. However, it is important to note that some of these trends are on the decline in 2004. For example, Canadian exports to the U.S. are beginning to level off, production in major producing areas like Alberta is leveling off, and gas prices are currently very high relative to historical norms. This reversal in trends may or may not be temporary.

In 2002, the U.S. consumed over 23.0 trillion cubic feet (tcf) of natural gas, the highest level ever recorded. In 2003, it tapered off slightly to 21.9 tcf. In the U.S., natural gas consumption is increasing at a healthy pace and the Pacific Northwest region is no exception. Three reasons for increased use in the Pacific Northwest are a historically ample and attractively priced gas supply (although prices are currently high), strong regional economic growth, and increased gas-fired electrical generation. At present, the use of gas for electricity generation is the second-largest consuming sector in the U.S. Industrial use is the largest consuming sector (36% of the total in 2002), but has been declining as a share of the total market. Residential usage is the third largest (US EIA 2004a). The U.S. EIA forecasts that U.S. total natural gas consumption will increase from the current level of about 23.0 trillion cubic feet per year to nearly 29.0 trillion cubic feet per year in 2020, which would indicate an annual growth rate in usage of about 1.4% (U.S. EIA 2004b). The 1.4% number is lower than the 2.3% increase in U.S. consumption per year predicted up through 2020 by the Northwest Power and Conservation Council in 2003 (US EIA 2004a).

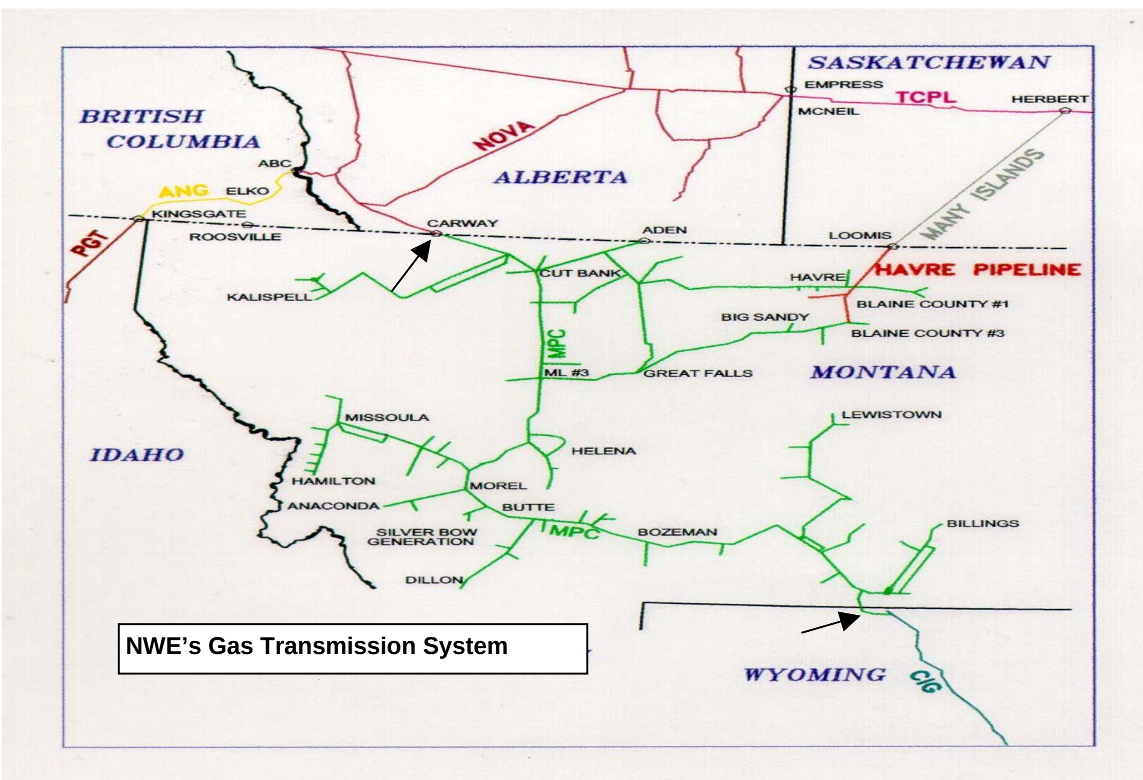
5. Montana's Natural Gas Pipeline System

Three distribution utilities and two transmission pipelines handle over 99 percent of the natural gas consumed in Montana (Table NG5). The distribution utilities are NorthWestern Energy (NWE; previously the Montana Power Company), Montana-Dakota Utilities Co. (MDU) and Energy West of Great Falls, which uses NWE for gas transmission. NWE and the Williston Basin Interstate pipeline (affiliated with MDU) provide transmission service for in-state consumers and, with a handful of other pipelines, export Montana natural gas.

Northwestern Energy (NWE) is the largest provider of natural gas in Montana, accounting for about 60 percent of all regulated sales in the state according to annual reports from Montana utilities (Table NG5). NWE provides natural gas transmission and distribution services to about 162,000 natural gas customers in the western two-thirds of Montana (including the Conoco and Cenex oil refineries in Billings). These customers include residences, commercial businesses, municipalities, state and local governments and industry. NWE's gas transportation system, both long-distance pipeline transmission and local distribution, lies entirely within Montana. NWE's transmission system is regulated by the Montana Public Service Commission. The NWE system consists of over 2,100 miles of transmission pipelines, 3,300 miles of distribution pipelines and three in-state storage facilities. NWE's system has pipeline interconnections with Alberta's NOVA Pipeline, the Havre Pipeline Company, the Williston Basin Interstate Pipeline Company and the Colorado

Interstate Gas Company. The Havre pipeline also is regulated by the Montana Public Service Commission.

Alberta sends natural gas to Montana primarily through NWE's pipeline at Carway and at Aden where it ties in with Alberta's NOVA Pipeline. Referring to the diagram below, NWE's pipeline system runs in a north-south direction from Carway (top arrow) and Aden at the Canadian border down through Cut Bank and south towards Helena approximately paralleling the Rocky Mountain Front. Near Helena, the main pipeline turns west and runs close to Highway 12 and then turns south and runs close to I-90 passing near Anaconda. It then turns east towards Butte, still following I-90. From Butte, it runs approximately east passing near Bozeman. At Big Timber it turns southeast and runs towards the Grizzly Interconnect near the Wyoming Border where it connects (bottom arrow) with the Colorado Interstate Gas line (CIG) and the Williston Basin Interstate/Warren line (WBI). The NWE gas system branches out from the main pipeline at various locations and runs to Missoula, Great Falls, the Flathead Valley, Dillon, Livingston and Billings. NWE's natural gas delivery system includes two main storage areas. The Cobb Storage is located north of Cut Bank near the Canadian border. The Dry Creek storage is located northwest of the Grizzly Interconnect, near the Wyoming border. Natural gas storage provides a critical supply component during the heating season, helps satisfy sudden shifts in demand and supply, and smoothes gas production throughout the year (U.S. EIA 2003).



NWE's Gas Transmission System

A majority of NWE's natural gas purchases come from Alberta. The NWE pipeline system has a <u>daily</u> peak capacity of 300 million cubic feet of gas (MMcf). The system delivers about

40 bcf of total gas per year to its customers on average compared with total annual Montana consumption of about 60-70 bcf. About one half of the total gas throughput on NWE's system is used by “core” customers, who include residential and commercial business users. NWE has the obligation to meet all the supply needs of core customers. The other half of gas throughput is used by non-core customers including industry, local and state governments and by Energy West, which supplies Great Falls. NWE only provides delivery service for these non-core customers; they contract on their own for their gas supply. Peak gas usage occurs on cold weather days when daily demand is often close to peak pipeline capacity. Significantly smaller amounts are used when the weather is warm (Waterman 2001).

As of 2004, there is no unused firm capacity on the NWE pipeline transmission system. This means that no additional gas user of significant size, such as a large industrial company, can obtain guaranteed, uninterrupted gas delivery on the current system. At times of peak consumer usage, the pipeline is full and cannot deliver any more gas. As of mid-2004, customer peak daily demand on the system is an estimated 300 million cubic feet (MMcf), and thus the system’s maximum daily capacity is currently matched by peak daily demand. The projected growth rate of maximum daily load and thus of required “daily pipeline delivery capacity” (excluding future electric generation plants) is 1.7 percent annually which translates to 5 MMcf/day annually. This growth is expected to come almost solely from core customers (Waterman 2001). Meeting the demands of the Montana First Megawatts gas-fired plant (240 MW if completed) would require pipeline upgrades beyond those already needed. The same is true for the proposed Silver-Bow plant near Butte. Both, however, are on hold indefinitely, and may not get built.

In 2004, the NWE's main gas transmission system is adding two loops to meet its projected increasing peak load in the coming years. The first loop to be built in 2004 is the Lewis and Clark loop, which will provide additional capacity to customers in the Flathead Valley. The existing Kalispell line (to which this loop would be added) runs west from NWE's mainline near the Canadian border, over Marias Pass (along Route 2), along the lower boundary of Glacier National Park, and over to the Flathead Valley. If all goes as planned, this loop should be in service in time for the 2004 winter heating season. The second loop to be built is the Rock Creek Loop that will increase capacity off of the main NWE pipeline (near Deer Lodge) to Missoula and the Bitterroot Valley. This project should begin in the fall of 2004 (Waterman 2004). The Bitterroot Valley (fed by the Missoula line) and the Flathead Valley (fed by the Kalispell line) are two of the fastest growing areas in Montana.

Montana-Dakota Utilities Co. (MDU) is the second largest natural gas utility in Montana and accounts for about 25-30 percent of all regulated natural gas sales in Montana (Table NG5). It distributes natural gas to most of the eastern third of the state, including Billings. MDU primarily uses the Williston Basin Interstate/Warren (WBI) pipeline for the transmission of its purchased gas. The WBI gas pipeline provides service for other utilities and is regulated at the federal level by FERC. MDU buys its gas from over 20 different suppliers. Most of its purchased gas is domestic with about 50 percent coming from Wyoming, various percentages coming from North Dakota and Montana, and about 10 percent coming from Canada. Periodically, MDU buys a certain amount of pipeline capacity on the WBI pipeline to match what it feels will be needed for the busiest usage day, based on the number of homes in its area. MDU expects less than 1 percent growth per year in its gas sales for the near future (Ball 2004).

Energy West (formerly Great Falls Gas Co.) is the third largest gas provider in Montana, accounting for about 11-13 percent of all regulated gas sales in Montana (Table NG5). It provides gas to the Great Falls area, and uses NWE's pipeline system for gas transmission. The other Montana utilities account for about 1 percent of all gas sales and include the Cut Bank Gas Company and Shelby Gas Association. All of these rely on NWE to provide transmission service.

Alberta, which contains a significant share of the Canadian natural gas supply, sends gas to the West Coast of the U.S. primarily through the GTN pipeline, which enters the U.S. in Idaho. Alberta sends gas to the U.S. Midwest and East Coast through the Alliance and Northern Border pipelines. Finally, Alberta sends gas to Montana through several smaller pipelines connected to its main pipeline system. Northern Border, which passes through the northeast part of Montana, is the largest pipeline in the state, though it has no injection points in Montana. The large Alliance pipeline (1.3 bcf transport capacity per day) runs from the Edmonton, Alberta area to the Chicago, Illinois area and allows other parts of the U.S. to compete with Montana and the Pacific Northwest for Alberta's large gas supply (Smith 2001). All of these Alberta lines also tie in with the large Trans-Canadian Pipeline that runs east to west across Canada.

6. Measuring Natural Gas Commodity Prices in Montana and the U.S.

Natural gas prices are measured in different ways at different points in the gas supply system. The "wellhead" price is the price of the gas itself right out of the ground. The wellhead price for natural gas (which varies a bit from region to region) is set in the national wholesale market, which was deregulated by the federal government in 1978. No state, including Montana, can regulate this wholesale market. The gas prices on the major indices such as the Henry Hub and AECOC Hub reflect the wellhead price of gas plus a relatively small fee to transport the gas to the particular hub. The difference between the Henry Hub price of natural gas and the US wellhead price from 1989 to late 2001 was about $0.12/dkt (Northwest Power and Conservation Council 2003). Thus, the major U.S. gas indices are a good approximation of wellhead prices. The "citygate" price typically reflects the wellhead price *plus* pipeline transmission fees (to get the gas to a particular locale or distribution system). The "delivered" gas price we pay in our homes and businesses is the citygate price *plus* local distribution fees and other miscellaneous charges from the utility. Transmission and distribution fees are set by utilities and/or pipelines and are regulated by state and federal agencies.

Natural gas prices on the major indices (or the "commodity market") are measured in several ways. There are "spot market" prices for immediate sales, and "futures market" prices for long-term contracts. Spot prices are volatile and represent a small portion of market sales. One pays the current market price on the spot market for natural gas, just as one would pay the current price for a stock in a financial market. A futures price is the cost of natural gas obtained by contract for delivery at some future point at a set price. Futures contracts are more commonly used by larger buyers than spot prices and cover purchases over some length of time. NorthWestern Energy, as an example, buys much of its natural gas for core customers using long-term contracts (up to 1 year) to lock in an acceptable price and to avoid large price swings on the spot market (Smith 2001).

Because Montana continues to rely on Alberta for much of its natural gas, what happens with Alberta gas directly affects Montana. Alberta sets the wellhead price for natural gas in Montana and in other parts of the U.S. that directly obtain their supply from there. The wellhead price of Alberta natural gas is, in turn, determined largely by the North American free market, subject to the contract conditions agreed to by each buyer and seller.

Prices in Alberta's main trading forums are determined by the AECOC index. This index, named after the AECO C storage hub in Alberta, is the equivalent in our area of the New York Mercantile Exchange (NYMEX) for gas and is very liquid for trading. Gas can be bought in spot or futures markets (Morris 2001). The AECOC index generally tracks the Henry Hub Index with some price differential. The Henry Hub Index is measured at the Henry Hub in southern Louisiana, a major pipeline interconnection and transshipment point. It is America's largest natural gas index and sets the nationwide price. Due to its geographic location, AECOC's price is often 20 to 30 cents cheaper per Mcf than the Henry Hub price.

Increases in demand for Alberta gas tend to cause contracted gas prices to rise in Montana, all else being equal. Conversely, as Alberta's supply increases, prices in Montana tend to go down, all else being equal. It is the interplay between the supply and demand of Alberta's gas that has the greatest effect on the gas prices paid in Montana. Today, this interplay occurs both on a national level and regionally for both supply and demand. Thus, the price of gas in Montana is determined by forces well beyond our state borders.

Historically, the delivered price for natural gas to Montana customers was at least twice the average wellhead price. Thus, typically less than 50 percent of what residences paid in their final gas bill was for the actual gas itself. Today, with wellhead prices so high, that situation is no longer true. As of January 2004, NWE residential customers paid an average delivered gas price of about $8.00/dkt. About $4.60 of that was for the commodity itself, whereas $3.33 of that was for transmission and distribution charges (Burchett 2004). Had the wellhead price of gas purchased in 2004 by NWE been around $2.00 as in previous years, then most of the final cost of gas to residential consumers would have been in transmission and distribution fees.

7. Natural Gas Prices in Montana

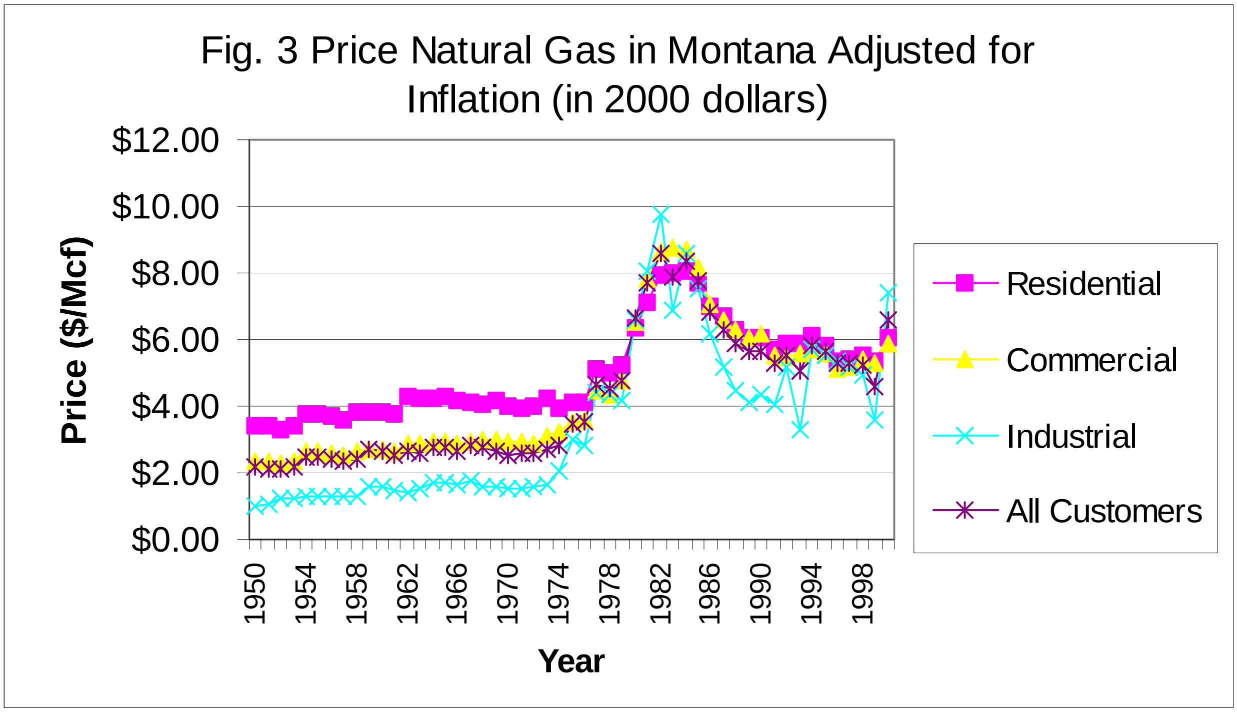
Natural gas customers in Montana and in the Pacific Northwest have historically paid relatively low gas rates compared to the rest of the U.S. In the past few years, however, gas prices across this region have risen to be more in line with the rest of the nation. In fact, the region's relatively low rates may be a thing of the past. More pipelines connect gas supplies in western Canada and the western U.S. to buyers in the eastern U.S. This means that more customers are competing for the same gas that supplies Montana. If demand for a commodity goes up, all else equal, prices also go up. Another reason for potentially higher long-term prices is that the pipeline infrastructure of the Northwestern U.S. is less and less able over time to meet today's gas demand. This means that the regional gas market could more easily be upset by extreme events such as very cold weather.

The historical delivered gas prices (the price seen on one's gas bill) in Montana for all

real dollars (below $4/Mcf) until the 1980's (see Table NG3). Delivered prices then rose in the mid-80's and mostly settled in the $5-6/Mcf range using today's dollars. Recently, they have shot up to $8.00/dkt range in 2004 and are nearing $9.00/dkt in the Fall of 2004. This increase in delivered gas price is due almost solely to the recent increases in the U.S. wellhead price of gas.

Figure 3 shows *delivered* natural gas prices in Montana adjusted for inflation and reported in 2000 dollars. Recent high prices from 2003 and 2004 are not available, because the data for thoe years is not yet available on an annual basis. The delivered prices graphed below are the rices that residents and businesses see in their final energy bill reflecting all charges (wellhead gas price, plus transmission and delivery fees, plus additional fees).

The average U.S. wellhead price of gas as of May 2004 was about $6.00/dkt which is well above historical norms and well above the long-term U.S. EIA forecast for wellhead price in 2020 of $4.40/dkt in today's dollars. The U.S. EIA, in its current short-term energy outlook from May of 2004, predicts that natural gas spot prices (composites for major gas producing hubs) are likely to average about $6.00/dkt ($5.80/Mcf) for 2004. Spot prices averaged about $5.65/dkt ($5.50/Mcf) in the first quarter of 2004 and were near $6.20/dkt ($6.00/Mcf) as of May 2004. These prices are very high with respect to historical norms. According to the U.S. EIA, the likelihood appears small that spot prices will fall significantly below $6.00/dkt ($5.80/Mcf) for the rest of 2004 (U.S. EIA, 2004a). Within the next several years, gas prices are likely to fall back closer to historical norms. The stark change between the EIA 2004 short-term price outlook (about $6.00/dkt) and their long-term price outlook (about $4.40/dkt in 2020) demonstrates how quickly the gas market can change and how volatile gas prices are today.



Source: U.S. EIA, *Natural Gas Annual Report*, 1950-2002 (Table NG3).

Utilities are prohibited from earning any profit on the cost of gas they purchase. Rather, they simply pass higher gas costs to consumers. They earn their profit through a return on their capital investment, such as the gas transmission and distribution systems, but don't earn a profit on their expenses, such as gas purchases. The average price of gas purchased by NWE, MDU and Energy West reflects current gas market conditions and that price is constantly changing. Any price change requested by NWE must be approved by the Public Service Commission in what is called a 'tracker' hearing. A tracker hearing covers only the cost of purchased gas, and not any of the other costs of the utility. Trackers usually are routine procedures, but can sometimes be contentious. NWE currently computes a new tracker each month to more accurately reflect the gas costs it incurs.

NWE raised gas bills for its core customers, who are mostly residential and commercial users, by 35% in December 2002. This increase was due to the expiration of a five-year contract NWE held with Pan-Canadian. Finishing this contract caused a 55% increase in the price of the natural gas commodity, from $2.17/dkt in a mid-2002 tracker to $3.37/dkt as of December 15, 2002. The increase in wholesale gas costs, and minor reductions in other billing categories, meant that a household consuming 10 dkt of gas per month on average saw an increase in their monthly gas bill at that time from $46 to about $62. Retail delivered prices for core customers started December 2002 at $4.60/dkt and finished the month at about $6.20/dkt. Delivered gas prices to residential and commercial consumers have steadily increased since the end of 2002 to $7.80/dkt as of June 2004. The delivered gas price may rise up to $9.00 later this year (Smith 2004), a 45% increase in gas bills over the

December, 2002 number, or almost a doubling of price from the fall of 2002 when gas was only $4.60/dkt.

MDU and Energy West customers essentially are in the same boat in terms of rising prices. Customers of both utilities must pay what the wholesale market price is for gas in the utility contract. Delivered prices for customers of both utilities are comparable to what is being paid by NWE customers, with comparable increases over the last two years.

Due to natural gas deregulation, most large industrial customers in Montana contract for gas directly with NWE, MDU and Energy West or with other independent suppliers. Industry still uses the local utilities for distribution and transportation services. Despite typically paying lower gas rates than residents and commercial businesses (i.e. core customers), industry has also faced an increase in gas bills as wholesale gas prices climb. The increase for each industrial customer depends upon each specific contract, who the gas supplier is, and the ability of the given industry to switch from natural gas to some other fuel if prices get too high.

Today, four of the largest natural gas users in Montana are the three oil refineries in and near Billings and Stone Container in Missoula. Montana State University, ASiMi in Butte and Barretts (talc processing) in Dillon are also large users in Montana. The refineries in Billings have some flexibility in switching fuels to run their operations, so they might not be hit as hard by higher gas prices as other customers. Those customers, such as Stone Container and Montana State University, probably have less flexibility to switch fuels, and are likely are feeling more of the cost of recent gas price increases. Large gas users who buy on the spot market, such as Montana State University-Billings, could be hurt more by these high prices, whereas those with longer-term contracts at lower prices are at least partially insulated until their contracts run out.

8. Future Price Increases and Price Volatility

The wellhead price Montana utilities and their customers pay for gas is likely to remain fairly close (within a $0.30-$0.70 cent differential) to average U.S. prices on the national market. The AECO C price in Alberta is forecast to run about $0.45 below the Henry Hub price in the coming years (Northwest Power and Conservation Council 2003), though in 2004, the difference has been closer to $1.00/Mcf (Terry Morlan 2004). It is likely that any price differential between what Montana pays and what the U.S. pays will partially depend upon how much Canadian supply is available and how much pipeline capacity there is to get that gas to its demand base. Because natural gas prices are determined on a national level, any single large gas-fired project built in Montana should have no significant effect on the Alberta gas price and thus no long-term effect on Montana's price (Smith 2001).

Although gas prices are expected to increase slowly in the long run on average, Montanans may be subject to increasing gas price volatility from extreme or unexpected events such as the California energy crisis of 2000-2001. One reason for potentially greater price volatility is the increased pipeline capacity from Alberta out to the U.S. Midwest and East Coast. Increased transmission capacity means that the wellhead price paid in Montana today is closely tied to wellhead prices paid nationwide. National prices are sometimes affected by unexpected events worldwide like cold snaps and political turmoil. The Pacific Northwest, for example, now feels the effects of cold snaps in the Northeastern U.S. that drain storage fields (WA OTED 2001). Events outside of Montana will affect our prices more than ever before in coming years.

Another factor in future gas prices paid by Montanans is the fact that domestic and Canadian supplies have leveled off at the present time (in part due to more mature gas fields), while U.S. demand continues to climb with economic recovery and more natural gas fired electric generation on the horizon. This could raise the price of natural gas faster than some of the long-term forecasts included in this document might indicate.

Wholesale electric and natural gas prices are becoming intimately linked. The Northwest Power and Conservation Council states that, "Fuel prices affect electricity planning in two primary ways. They influence electricity demand because they are substitute sources of energy for space and water heating and some other end-uses as well. They also influence electricity supply and price because they are potential fuels for electricity generation. Natural gas, in particular, has become the most cost-effective generation fuel when used to fire efficient combined-cycle combustion turbines." (Page 4, Northwest Power and Conservation Council 2003). The increasing convergence of the electricity and natural gas markets means that extreme events like the California energy crisis are likely to affect both electricity and gas markets simultaneously. Gas prices rose in 2000 nationwide because supplies of natural gas were temporarily tight, due in part to low storage and pipeline constraints. Utilities paid more for natural gas than they did before, but high electricity prices encouraged them to produce electricity anyway, further straining gas supply (Morlan 2001).

The effects of new gas-fired power plants around the nation upon Montana's gas supply and price will depend on the number and timing of both the new plants coming on line and available gas supplies (WA OTED 2001). While the demand from new gas-fired power plants in California and other western states will place pressure on the Northwest's natural gas infrastructure, Montana's infrastructure which runs directly from Alberta and Wyoming will likely not be as strained. Thus, Montana may experience more moderate price fluctuations than in other areas of the U.S.

Utilities and industry can reduce price risks by buying gas at fixed prices and using long-term and futures contracts. They can also store gas to prevent having to buy on the spot market. Residential and commercial customers can use budget billing to smooth out their gas bills over a given billing year, although this does not protect one from yearly fluctuations. There are also programs to help low-income users pay their energy bills. At this point, electricity efficiency improvements may be the 'biggest bang for the buck' for a way to reduce natural gas demand. Residential and commercial air conditioning is a big driver in the U.S. for marginal electricity demand and thus natural gas demand. Gas often powers peak electricity demands--up to 60% of margin in some areas. This might be an area to target for efficiency in the nation as a whole.

This convergence of the electricity and gas markets bears a number of implications for regional electricity and natural gas utility systems and for industrial customers purchasing their supplies directly. Electric utilities that were caught short in the 2000 energy crisis will likely pursue strategies that provide better insurance against future gas price volatility. New electric generating facilities that do not use natural gas will be more attractive options. For example, most of the major utilities in the Pacific Northwest have acquired, or plan to acquire, wind generation, in part because of the hedge that fixed-priced wind power could provide against volatile natural gas prices for electric generation. Finally, energy efficiency investments are also more attractive than they have been in recent years.

Recent high natural gas prices in the past few years point out three lessons for Montana. First, our natural gas prices are affected by a number of factors beyond any one entity's or state's control. Second, the growing use of natural gas for electricity generation has the potential to upset the traditional seasonal patterns of natural gas storage and withdrawals in Montana. This could lead to high or volatile prices not experienced before. Finally, to the extent that the western United States depends on natural gas for new electricity generation, the price of natural gas will be a key determinant of future electricity prices. Economic theory suggests that in the long run, electricity prices will closely follow the cost of new sources of gas.

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Coal in Montana

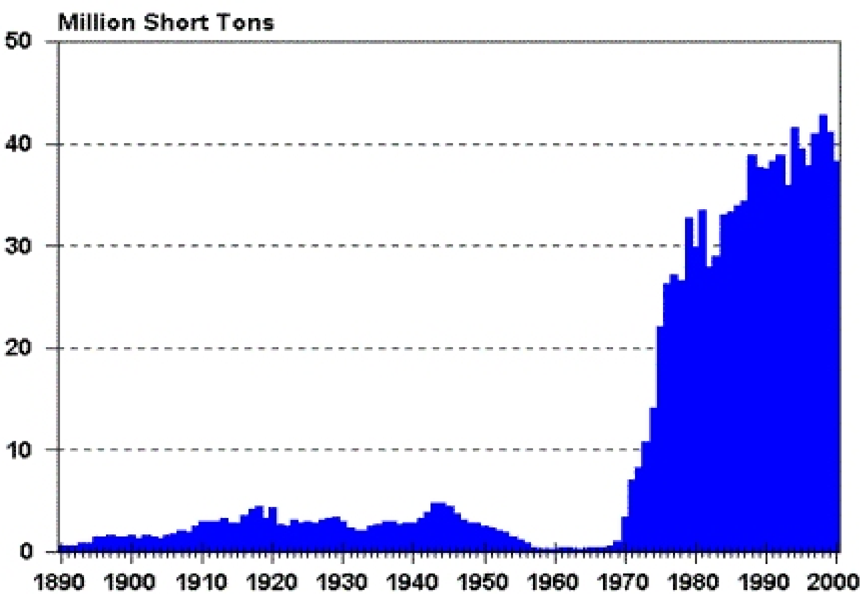
The Montana coal industry exists to support the generation of electricity. All but a tiny fraction of the coal mined in Montana eventually is converted to electricity. In recent years, over half the electricity generated in Montana has come from coal-fired plants. Almost three-quarters of the coal mined in the state are exported, primarily to Midwestern utilities. Even though new generating stations built around the country in recent years have relied on natural gas or wind, coal continues to provide half of the nation's electricity.

1. Production

Montana is the sixth largest producer of coal in the United States, with over 37 million tons mined in 2002 (Table C1). Almost all the mining occurs in the Powder River Basin south and east of Billings. With the exception of the small lignite mine at Sidney, Montana production is entirely low-sulfur subbituminous coal, with 17-18 million Btu per ton. Like most Western coal, Montana coal is cleaner but lower in heat content than coal mined in the East.

Coal has been mined in Montana since territorial days, first as a heating fuel and later primarily for the railroads. Production initially peaked in the 1940s at around 5 million tons (see Figure 1). As steam locomotives were phased out, production declined, bottoming in 1958 (Table C2).

Figure 1. Historical coal production

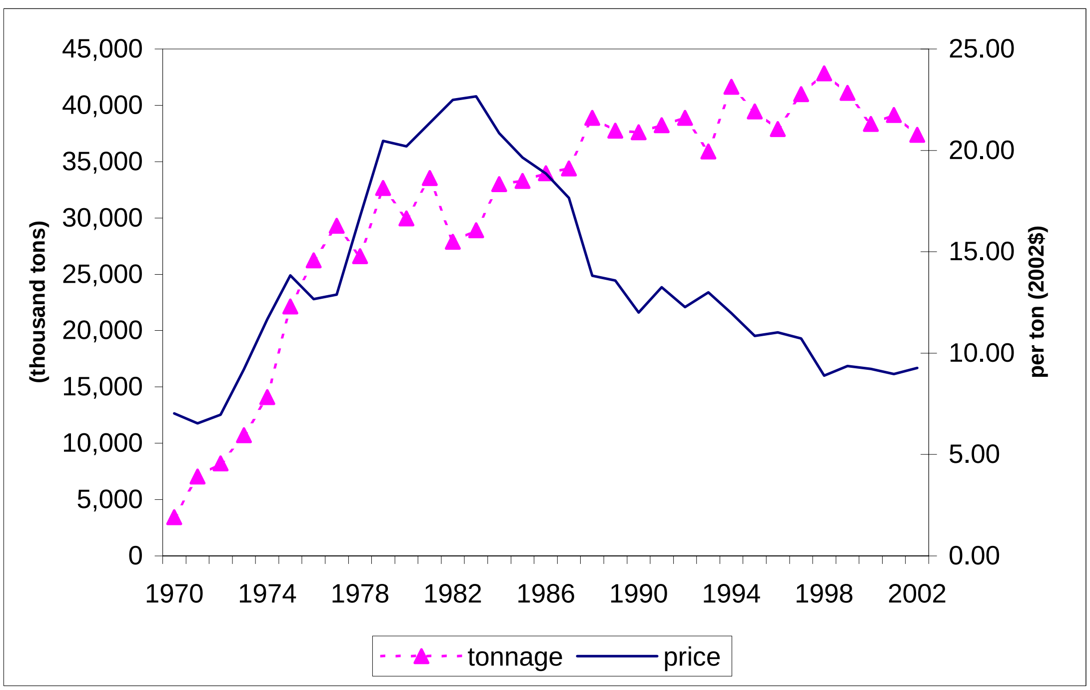


Source: U.S. Department of Energy, Energy Information Administration (http://www.eia.doe.gov/cneaf/coal/statepro/imagemap/mt.htm)

That year, only 305,000 tons were mined, an amount equivalent to less than 1 percent of current output. Output remained stagnant for a decade, maintained by production for a small generating plant opened in Sidney in 1958 by Montana-Dakota Utilities. Production began to grow again in 1968, when Western Energy Company began shipping coal from Colstrip to a generating plant in Billings owned by its parent, Montana Power Company.

As Montana mines began supplying electric generating plants in Montana and the Midwest, coal production jumped. Production in 1969 was 1 million tons; ten years later, it was 32.7 million tons. Since the end of the 1970's, production increased gradually to almost 43 million tons in 1998 and then dropped off slightly to its current level (Table C2; see Figure 2). Over the last decade, Montana has more or less maintained its share of the U.S. market. In comparison most eastern states lost market share during this decade, primarily to Wyoming. Western states other than Wyoming followed a path similar to Montana, more or less maintaining market share. Over the past decade Montana has produced less than 4 percent of the coal mined each year in the U.S..

Figure 2. Montana production and average price (2002 $)

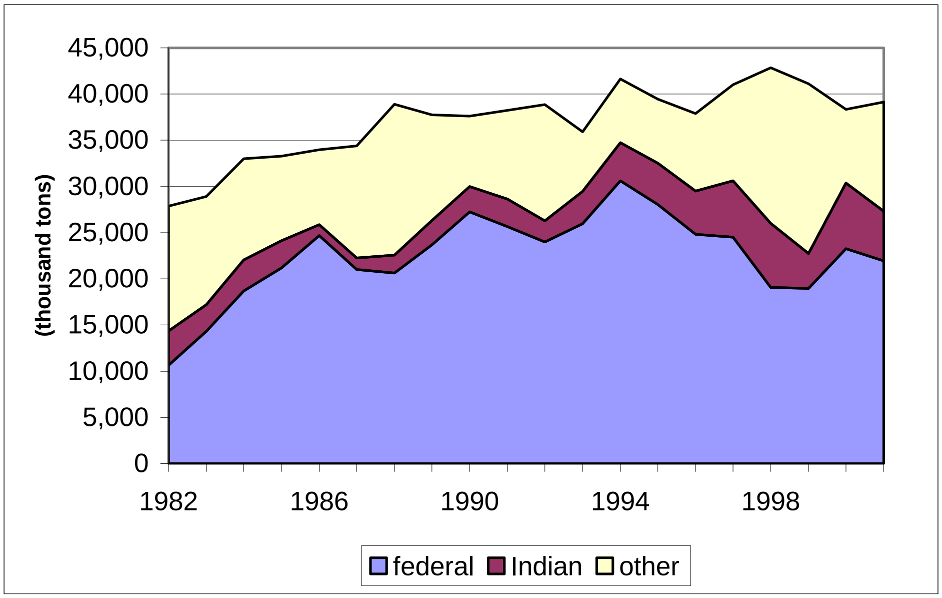


Source: Table C2.

The price of Montana coal averaged $9.27 per ton at the mine in 2002 (Table C2); this includes taxes and royalties. The price of coal has been on a downward trend since the early 1980's, when the average price of coal peaked at $14.22 per ton ($22.67 in 2002 dollars). By 2002 that price had fallen 60 percent in real terms. The decline in Montana prices mirrors the decline in prices nationally.

Most coal in Montana is mined on federal lands (Table C3; see Figure 3). A significant portion also comes from Indian reservations. In 2001, the most recent year for which data are available, over 55 percent of Montana coal came from federal lands and under 15 percent from reservation lands.

Figure 3. Production by land ownership type



Source: Table C3

Montana had eight coal mines in operation in 2003 (Table C4). The largest mine is Westmoreland's Rosebud Mine at Colstrip, producing 10-11 million tons per year. During the 1990's, the last Montana mine producing less than 100,000 tons annually closed, but a new mine at that site, near Roundup, opened in 2003. No major new mines have opened since 1980, though the West Decker and Spring Creek mines have expanded significantly.

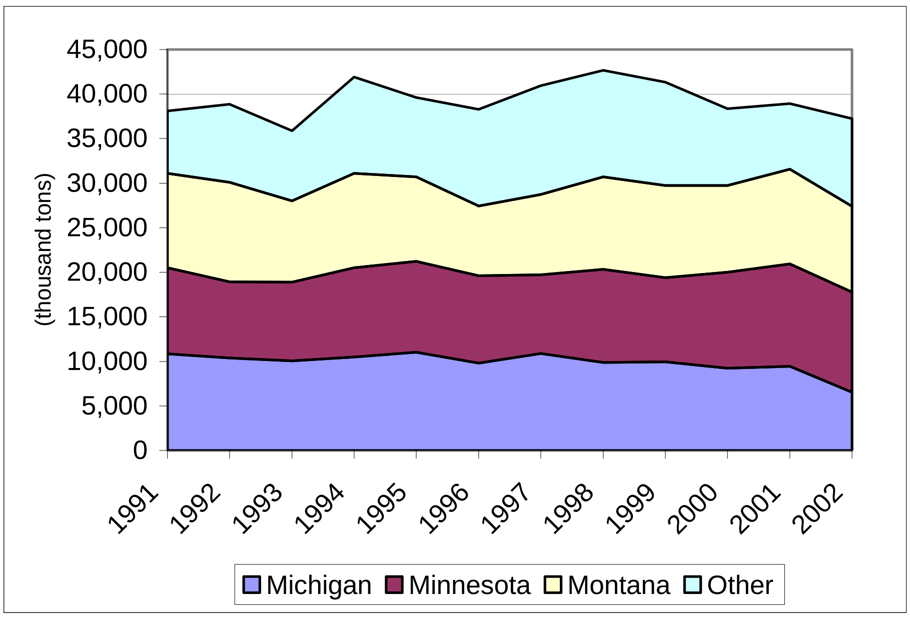
Westmoreland is the largest producer in Montana, accounting for 47 percent of 2003 production. Kennecott is the second largest, accounting for 24 percent of coal production outright and holding a half-interest in mines producing an additional 22 percent of Montana coal. The year 2001 marked the passing of an era in Montana coalfields. With Westmoreland buying Montana Power Company's Western Energy and MDU Resources Group's (Knife River Coal) Savage Strip Mine in 2001, over 40 years of utility ownership of operating coalfields in Montana came to an end. Utility production had been substantial. MPC, through Western Energy, was the 11th largest coal producer in the country in 1998.

2. Consumption

Over 95 percent of the coal consumed in Montana in recent years has been used to generate electricity. Minor amounts of residential and commercial heating and some industrial use account for the remainder. Montana coal consumption has been more or less stable since the late 1980's, after the Colstrip 4 generating unit came on line (Table C5).

Similarly, almost all of Montana coal production is used to generate electricity (Table C6). In recent years, about three-quarters of production has been shipped by rail to out-of-state utilities. Most of the remaining quarter is burned in-state to produce electricity, primarily at Colstrip. Prior to deregulation, about 40 percent of the electricity generated in Montana with coal went to Montana customers, and 60 percent was shipped by wire to out-of-state utilities. No public data are available now, but it's likely that the majority of coal burned in Montana still produces electricity for export. Over the last decade, Michigan, Minnesota and Montana have taken about three quarters or more of all the coal produced in Montana (Table C7; see Figure 4). The remaining quarter now goes to 9 other states and Canada.

Figure 4. Destination for Montana coal



Source: Table C7.

3. Coal Economics

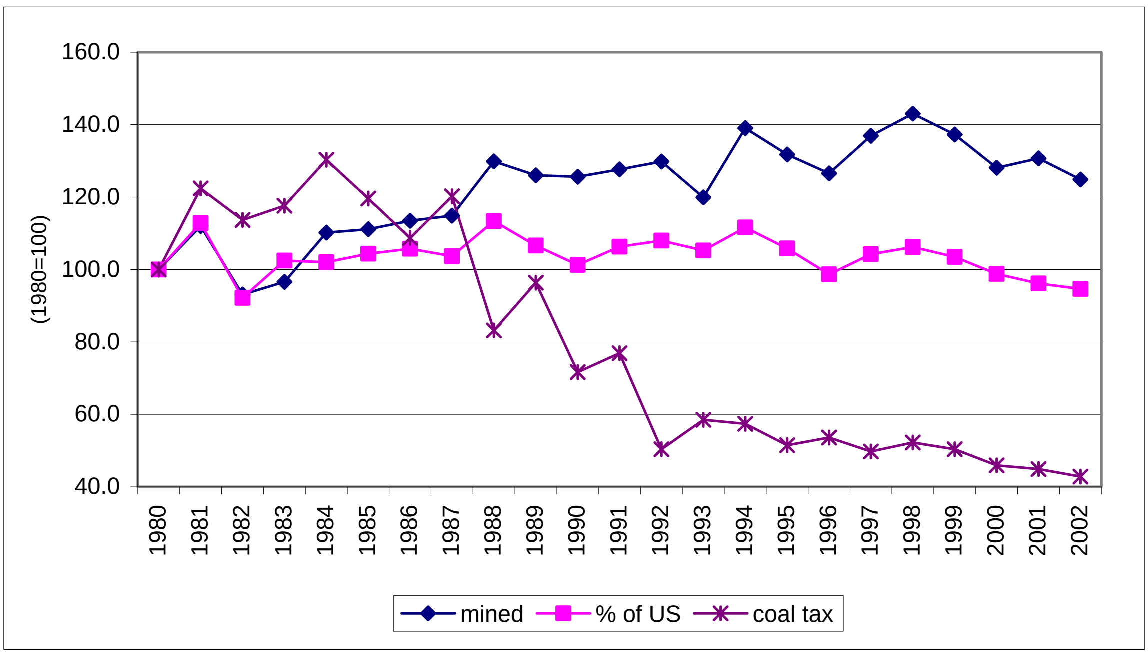
The Montana industry, like the coal industry nationwide, has become more productive, with the number of employees dropping even while the amount of coal mined increased (Table C8; see Figure 5). Taxes on coal, despite decreases from historical highs, remain a major source of revenue for Montana, with $30.1 million collected in coal severance tax in state fiscal year 2003 (July 2002-June 2003).[1] That is one-third in nominal terms the amount collected in fiscal year 1984. Coal severance tax collections dropped due to changes in the tax laws that began with the 1987 Legislature and due to the declining price of coal. While the tax rates vary based on a number of factors, the rate on most coal in Montana has dropped from 30 percent to 15 percent of price. This drop in rates has had a bigger impact

[1] Also, a gross proceeds tax of 5% goes to the county where the coal was mined. Another 0.4% goes for the Resource Indemnity and Groundwater Assessment Tax that, among other things, pays for reclamation of old unreclaimed mined areas.

on tax collections than the drop in the price of coal. The impact on levels of coal production is less clear. Production has risen modestly since the cut in taxes and Montana has been able to retain most of its share of the national market.

While significant, Montana's output is dwarfed by Wyoming, which produced 34.1 percent of the country's output in 2002. This is ten times as much coal as Montana produced. This due in part to a combination of physical factors that make Montana coal less attractive than coal from Wyoming. Montana coal generally is more costly to mine because the coal seams tend to be thinner—though still thick in comparison to eastern coal—and buried under more overburden than seams in Wyoming. Moreover, Wyoming coal tends to have slightly lower average ash and sulfur content than Montana coal. Coal from the Decker area does have the highest Btu in the entire Powder River Basin and about the same sulfur as Wyoming coal, but it has the disadvantage of having a high sodium content, which can cause problems in combustion.

Figure 5. Changes in Montana production, share of U.S. market and severance tax collections



Source: Table C8.

The cost of transportation to distant markets may also affect the competitiveness of Montana coal. Nearly all coal exported from Montana leaves on Burlington Northern Santa Fe lines. Some is later transshipped by barge. Transportation costs can double to more than triple the delivered cost of Montana coal bought by out-of-state generating plants. Though transportation costs have fallen over the last fifteen years, the minemouth cost of coal has fallen faster, making transportation a larger component of final cost. Coal shipped from the Powder River Basin (Wyoming and Montana) in 2000 had the highest ratio of transportation cost to delivered price, on a per ton basis, for U.S. coalfields. (U.S. Department of Energy, Energy Information Administration *Energy Policy Act Transportation Rate Study: Final Report* *on Coal Transportation,* 2000). The cost of Montana coal may be further affected by the rail transportation network being better developed in the southern end of the Powder River Basin than in the northern end.

Table C1. Coal Production by State and Coal Rank, 2002 (Thousand Short Tons)

Rank	State	Bituminous Production	Subbituminous Production	Lignite Production	Anthracite Production	Total Production	Percentage of U.S. TOTAL 2002	Percentage of U.S. TOTAL 1991[1]
1	Wyoming	715	372,447	-	-	373,161	34.1%	19.5%
2	West Virginia	149,943	-	-	-	149,943	13.7%	16.8%
3	Kentucky	123,883	-	-	-	123,883	11.3%	15.9%
4	Pennsylvania	66,921	-	-	1,189	68,110	6.2%	6.5%
5	Texas	22	-	45,225	-	45,247	4.1%	5.4%
6	**Montana**	**-**	**37,058**	**328**	**-**	**37,386**	**3.4%**	**3.8%**
7	Indiana	35,321	-	-	-	35,321	3.2%	3.2%
8	Colorado	27,715	7,388	-	-	35,103	3.2%	1.8%
9	Illinois	33,307	-	-	-	33,307	3.0%	6.1%
10	North Dakota	-	-	30,799	-	30,799	2.8%	3.0%
11	Virginia	29,909	-	-	-	29,909	2.7%	4.2%
12	New Mexico	14,428	14,488	-	-	28,916	2.6%	2.2%
13	Utah	25,300	-	-	-	25,300	2.3%	2.2%
14	Ohio	21,109	-	-	-	21,109	1.9%	3.1%
15	Alabama	18,920	-	-	-	18,920	1.7%	2.7%
16	Arizona	12,804	-	-	-	12,804	1.2%	1.3%
17	Washington	-	5,827	-	-	5,827	0.5%	0.5%
18	Maryland	5,122	-	-	-	5,122	0.5%	0.4%
19	Louisiana	-	-	3,803	-	3,803	0.3%	0.3%
20	Tennessee	3,151	-	-	-	3,151	0.3%	0.4%
21	Mississippi	-	-	2,305	-	2,305	0.2%	none
22	Oklahoma	1,403	-	-	-	1,403	0.1%	0.2%
23	Alaska	-	1,146	-	-	1,146	0.1%	0.1%
24	Missouri	248	-	-	-	248	0.0%	0.2%
25	Kansas	205	-	-	-	205	0.0%	0.0%
26	Arkansas	12	-	-	-	12	0.0%	0.0%
	Iowa					0	none	0.0%
	California					0	none	0.0%
	East of Miss. River	**487,586**	-	**2,305**	**1,189**	**491,081**	44.9%	59.3%
	West of Miss. River	**82,852**	**438,353**	**80,154**	-	**601,359**	55.0%	40.7%
	U.S. Total	**570,438**	**438,353**	**82,459**	**1,189**	**1,092,440**	99.8%	100%
	Unknown[2]		-	-	-	890	0.1%	
	Refuse Recovery[3]	896	-	-	58	953	0.1%	
	U.S. Total	571334	**438,353**	**82,459**	**1,247**	**1,094,283**	100.0%	100.0%

[1] Total U.S. production in 1991 was 993,486,000 tons.
[2] Includes all mines and refuse recovery operations producing less than 10,000 short
[3] Excludes refuse recovery operations producing less than 10,000 short tons.

Note: Coal production excludes silt, culm, refuse bank, slurry dam, and dredge operations except for Pennsylvania anthracite. Totals may not equal sum of components due to independent rounding.

Note: Total U.S. coal production increased 10.1% between 1991 and 2002.

Sources: U.S. Department of Energy, Energy Information Administration Form EIA-7A, "Coal Production Report," and U.S. Department of Labor, Mine Safety and Health Administration, Form 7000-2, "Quarterly Mine Employment and Coal Production Report," as reported in U.S. Department of Energy, Energy Information Administration *Annual Coal Report 2002* (http://www.eia.doe.gov/cneaf/coal/page/acr/table6.html).

Table C2. Montana Coal Production and Average Mine Price by Rank of Coal, 1950-2002

Year	PRODUCTION (thousand short tons) Subbituminous	Lignite	TOTAL	AVERAGE MINE PRICE (dollars per short ton) Subbituminous	Lignite	AVERAGE
1950	2,468	52	**2,520**	$2.30	$3.37	**$2.33**
1951	2,310	35	**2,345**	2.61	3.51	**2.63**
1952	2,039	31	**2,070**	2.80	3.70	**2.81**
1953	1,848	25	**1,873**	2.64	3.77	**2.66**
1954	1,491	NA	**1,491 E**	2.79	NA	**NA**
1955	1,217	30	**1,247**	3.01	3.82	**3.03**
1956	820	26	**846**	4.11	3.70	**4.10**
1957	387	26	**413**	5.33	3.80	**5.23**
1958	211	94	**305**	5.94	2.34	**4.84**
1959	152	193	**345**	7.06	2.08	**4.28**
1960	113	200	**313**	6.87	2.06	**3.79**
1961	97	274	**371**	6.76	2.01	**3.26**
1962	78	304	**382**	6.90	1.99	**2.98**
1963	53	290	**343**	7.51	1.95	**2.82**
1964	46	300	**346**	7.40	1.95	**2.68**
1965	63	301	**364**	7.24	1.96	**2.88**
1966	91	328	**419**	7.10	1.96	**3.08**
1967	65	300	**365**	NA	NA	**NA**
1968	189	330	**519**	3.12	1.89	**2.33**
1969	722	308	**1,030**	2.18	2.03	**2.13**
1970	3,124	323	**3,447**	1.83	2.13	**1.86**
1971	6,737	327	**7,064**	1.79	2.27	**1.82**
1972	7,899	322	**8,221**	2.01	2.45	**2.02**
1973	10,411	314	**10,725**	2.83	2.60	**2.82**
1974	13,775	331	**14,106**	3.91	3.00	**3.90**
1975	21,620	520	**22,140**	5.06	5.04	**5.06**
1976	25,919	312	**26,231**	NA	NA	**4.90**
1977	29,020	300	**29,320**	NA	NA	**5.30**
1978	26,290	310	**26,600**	NA	NA	**7.37**
1979	32,343	333	**32,676**	w	w	**9.76**
1980	29,578	369	**29,948**	w	w	**10.50**
1981	33,341	204	**33,545**	w	w	**12.14**
1982	27,708	174	**27,882**	w	w	**13.57**
1983	28,713	211	**28,924**	w	w	**14.22**
1984	32,771	229	**33,000**	w	w	**13.57**
1985	33,075	212	**33,286**	w	w	**13.18**
1986	33,741	237	**33,978**	w	w	**12.93**
1987	34,123	277	**34,399**	w	w	**12.43**
1988	38,656	225	**38,881**	w	w	**10.06**
1989	37,454	288	**37,742**	w	w	**10.27**
1990[1]	37,266	230	**37,616**	w	w	**9.42**
1991	37,944	283	**38,227**	w	w	**10.76**
1992	38,632	248	**38,879**	w	w	**10.20**
1993	35,626	291	**35,917**	w	w	**11.05**
1994	41,316	323	**41,640**	w	w	**10.39**
1995	39,153	297	**39,451**	w	w	**9.62**
1996	37,635	256	**37,891**	w	w	**9.96**
1997	40,763	242	**41,005**	w	w	**9.84**
1998	42,511	329	**42,840**	w	w	**8.25**
1999	40,827	275	**41,102**	w	w	**8.82**
2000	37,980	372	**38,352**	w	w	**8.87**
2001	38,802	340	**39,143**	w	w	**8.83**
2002	37,058	328	**37,386**	w	w	**9.27**

NA - Not Available E - Estimated value. w - Withheld to avoid disclosure of individual company data.

[1] The 1990 total includes 120,000 tons of bituminous coal.

NOTES: For 1997 and before, average mine price is calculated by dividing total free on board (f.o.b.) mine value of coal produced by total production. Since 1998, an average open market sales price is calculated by dividing the total free on board (f.o.b) rail/barge value of the open market coal sold by the total open market coal sold. (Open market includes all coal sold on the open market to other coal companies or consumers.) Excludes mines producing less than 10,000 short tons, which are not required to provide data. Excludes silt, culm, refuse bank, slurry dam, and dredge operations. Totals may not equal sum of components because of independent rounding.

SOURCES: U.S. Bureau of Mines (1950-76); U.S. Department of Energy, Energy Information Administration, (1977-78); U.S. Department of Energy, Energy Information Administration, *Coal Production,* annual reports for 1979-92 (EIA-0118);U.S. Department of Energy, Energy Information Administration, *Coal Industry Annual* , 1993-2000 (EIA-0584); U.S. Department of Energy, Energy Information Administration, *Annual Coal Report* 2001-2002 (http://www.eia.gov/cneaf/coal/page/acr/acr_sum.html).

Table C3. Coal Mining Acreage, Production and Royalties from Federal and American Indian Leases in Montana, 1982-2001

Year	Federal Leases			American Indian Leases		
	Acres Leased	Production (thousand short tons)	Royalties (thousand dollars)	Acres Leased	Production (thousand short tons)	Royalties (thousand dollars)
1982	23,455	10,652	9,517	14,746	3,704	2,603
1983	23,535	14,335	7,947	14,746	2,844	2,031
1984	29,469	18,696	9,709	14,746	3,350	1,557
1985	27,943	21,181	15,174	14,746	2,949	2,016
1986	25,463	24,682	22,447	14,746	1,169	812
1987	30,848	21,012	39,111	14,746	1,232	709
1988	30,031	20,626	35,592	14,746	1,927	1,127
1989	31,931	23,695	26,544	14,746	2,615	1,489
1990	31,821	27,246	29,155	14,746	2,731	1,500
1991	31,821	25,648	35,585	14,746	2,979	1,367
1992	31,821	23,993	34,096	14,746	2,300	1,175
1993	36,728	25,955	38,665	14,746	3,518	1,786
1994	39,141	30,615	41,959	14,746	4,134	1,979
1995	36,612	28,038	38,420	14,746	4,468	2,037
1996	31,540	24,816	32,935	14,746	4,681	2,139
1997	26,996	24,502	32,214	14,746	6,094	2,790
1998	26,562	19,061	25,807	14,746	6,956	3,135
1999	26,461	18,948	25,865	14,746	3,783	1,890
2000	29,408	23,264	25,667	14,746	7,102	3,403
2001	29,408	21,937	24,539	14,746	5,367	2,571

Notes: Output from Federal and American Indian Lands is reported as sales volume, the basis for royalties. It is approximately equivalent to production, which includes coal sold and coal added to stockpiles. Totals may not equal sum of components due to independent rounding. Data from 2002 forward are not yet available due to complications connected with pending lawsuits.

Source: United States Department of the Interior, Minerals Management Service, *Mineral Revenues* (1982-1992); United States Department of Energy, Energy Information Administration, *Coal Industry Annual* (1993-2000); United States Department of Energy, Energy Information Administration, *Annual Coal Report 2001*.

Table C4. Coal Production by Company, 1980-2003 (short tons)

	Beartooth Coal Co.[1]	Blaine Warburton (owner)	BMP Investments[2]	Coal Creek Mining Co.	Decker Coal[3]		Kennecott Energy (previously Spring Creek Coal)[4]	Peabody Coal Co.	Red Lodge Coal Co.	Storm King Coal Mining Co.[5]	Westmoreland (previously Knife River Coal)[6]	Westmoreland[7]	Westmoreland (previously Western Energy Co.)[8]	TOTAL
					East Decker Mine	West Decker Mine								
County	Carbon	Blaine	Musselshell	Powder River	Big Horn	Big Horn	Big Horn	Rosebud	Carbon	Musselshell	Richland	Big Horn	Rosebud	
1980	7,321		11,189	64,398	5,576,607	5,616,695	118,660	2,964,359		8,571	305,578	4,905,262	10,401,972	29,980,612
1981			7,404	64,142	5,350,113	5,331,626	4,368,885	3,193,570		8,165	204,492	4,450,296	10,352,966	33,331,659
1982			15,141	16,608	4,914,970	4,884,920	1,352,181	2,891,428		8,062	171,556	4,158,578	9,424,857	27,838,301
1983			11,655		5,040,018	5,308,799	2,102,606	2,571,861		5,896	206,543	3,868,844	9,544,062	28,660,284
1984			15,865		5,019,186	5,278,365	2,962,008	3,945,865		16,379	236,954	3,621,544	11,957,724	33,053,890
1985			21,400		5,191,701	6,149,987	2,837,037	3,336,907		3,251	212,654	3,112,595	12,275,351	33,140,883
1986		276	23,915		5,397,476	6,706,592	4,664,238	2,594,306			252,754	2,028,595	12,074,698	33,742,850
1987		305	14,495		4,042,597	6,355,523	6,557,228	3,234,538	900		290,264	1,858,315	12,022,894	34,377,059
1988		248	15,542		3,655,067	7,068,653	4,704,442	3,788,137			227,603	3,304,822	16,155,867	38,920,381
1989		96	15,760		3,582,885	6,495,027	5,979,405	3,715,325			295,089	4,011,156	13,677,234	37,771,977
1990			14,307		2,595,829	6,602,744	7,133,285	3,602,851			234,010	4,471,345	12,800,898	37,455,269
1991			12,202		2,408,968	7,576,380	6,740,401	3,104,829			282,641	4,101,847	13,802,840	38,030,108
1992			9,235		2,621,326	9,323,561	6,641,332	2,212,071			247,155	3,490,797	14,347,159	38,892,636
1993			11,182		2,864,005	7,940,085	7,175,434	2,518,117			290,928	3,224,143	11,909,423	35,933,317
1994			2,600		2,787,908	7,726,969	9,934,305	3,053,125			323,381	4,363,500	13,390,492	41,582,280
1995			4,128		1,802,249	8,475,335	8,512,520	4,708,970			297,290	4,425,759	11,260,339	39,486,590
1996			151,024		601,544	10,388,948	9,015,361	4,984,352			256,476	4,668,021	7,775,391	37,841,117
1997			24,023		1,911,702	9,961,746	8,306,306	4,334,750			249,593	7,051,062	8,927,138	40,766,320
1998					1,583,454	8,892,053	11,312,935	3,468,192			329,038	6,458,279	10,251,547	42,564,760
1999					1,973,954	8,904,115	10,994,827	2,867,223			274,695	5,466,678	10,362,062	41,103,261
2000					2,465,352	7,466,814	11,301,905	1,404,139			371,971	4,910,907	10,173,297	38,307,961
2001					1,207,580	8,254,718	9,664,969	2,569,541			346,355	5,904,724	11,051,692	39,231,408
2002					746,967	9,281,431	8,905,368	2,805,392			312,037	5,160,921	10,061,856	37,273,972
2003			13,446		611,984	7,480,364	8,894,014	2,596,262			368,867	6,016,678	11,002,723	36,984,338

[1] Underground mine.

[2] This site has been operated by different companies, most recently by P.M. Coal Co. and Mountain, Inc; RBM Mining Inc. did contract mining here from 1991 to 1994. Both underground and strip mining have been done at this site.

[3] Decker Coal Co. is a 50-50 joint venture between Peter Kiewit Sons' and Kennecott Energy Company. Kennecott purchased the share held by NERCO, a PacifiCorp subsidiary, in 1993.

[4] Kennecott Energy Co. purchased NERCO, a Pacific Power and Light subsidiary which owned Spring Creek Coal, in 1993.

[5] Prior to a change in ownership in 1983, this was called the Divide Coal Mining Company.

[6] Lignite mine. It was purchased from Knife River Coal Co., a subsidiary of MDU Resources Group, in 2001.

[7] The Absaloka Mine (also known as Sarpy Creek Mine) is operated by Washington Group International (formerly Morrison-Knudsen).

[8] Purchased from Montana Power Company in 2001. Since 1990, production volume includes in the low to mid-200,000 range of tons per year of waste coal sold to CELP generation plant.

Note: Total production is slightly different than in other coal tables. The data come from a state, rather than federal, source.
Source: Montana Department of Labor and Industry, Employment Relations Division (previously, Workers' Compensation Division) (1978-2003).

Table C5. Distribution of Coal for Use In Montana, 1974-2002

(thousand short tons)

Year	Electric Utilities	Residential and Commercial	Industrial	TOTAL
1974	843	9	55	**907**
1975	1,203	7	42	**1,252**
1976	2,452	5	108	**2,565**
1977	3,225	1	182	**3,408**
1978	3,334	4	183	**3,522**
1979	3,513	3	214	**3,731**
1980	3,462	14	182	**3,658**
1981	3,318	7	253	**3,578**
1982	2,619	9	197	**2,824**
1983	3,058	8	120	**3,186**
1984	4,979	6	153	**5,138**
1985	5,625	8	220	**5,852**
1986	8,094	22	317	**8,433**
1987	7,603	8	180	**7,791**
1988	10,556	9	230	**10,795**
1989	10,242	53	185	**10,480**
1990	9,574	57	252	**9,883**
1991	10,614	45	265	**10,924**
1992	10,963	21	261	**11,245**
1993	8,818	11	365	**9,194**
1994	10,179	4	548	**10,728**
1995	9,058	10	610	**9,678**
1996	7,869	4	486	**8,359**
1997	9,056	83	478	**9,617**
1998	10,594	4	227	**10,825**
1999	10,517	3	557	**11,077**
2000	9,876	3	576	**10,455**
2001	11,045	3	307	**11,355**
2002	10,305	3	114	**10,422**

Note: This data series consistently shows the amount of coal distributed to Electric Utilities to be slightly different than the amount received at Electric Utility Plants shown in Table C6. Differences in distribution and receipt data are due to the time lag between distribution and receipt of coal shipments, and due to the survey threshold differences. In recent years the Corette plant has burned several hundred thousand tons of Wyoming coal most years, which further increases the difference.

Sources: U.S. Department of Interior, Bureau of Mines, *Mineral Industry Surveys, Bituminous Coal and Lignite Distribution* annual reports for 1974-76; U.S. Department of Energy, Energy Information Administration, *Bituminous Coal and Lignite Distribution* , quarterly reports for 1977; U.S. Department of Energy, Energy Information Administration, *Bituminous Coal and Lignite Distribution* , annual report for 1978 (EIA-0125);. U.S. Department of Energy, Energy Information Administration, *Bituminous and Subbituminous and Lignite Distribution* , annual report for 1979 (EIA- 0125); U.S. Department of Energy, Energy Information Administration, *Coal Distribution* , annual reports for 1980-97 (EIA-0125); U.S. Department of Energy, Energy Information Administration, *Coal Industry Annual* (1998-2000)(EIA-0584); *Annual Coal Report 2002 (Table 26, http://www.eia.doe.gov/cneaf/coal/page/acr/table26.html)* .

Table C6. Receipts of Montana Coal at Electric Utility Plants[1] 1973-2002

(thousand short tons)

Year	Received at Montana Utilities			Received at Out-of-State Utilities	TOTAL
	Subbituminous	Lignite	Montana Total		
1973			882	9,741	**10,623**
1974			822	13,114	**13,936**
1975			1,197	20,180	**21,377**
1976			2,316	22,642	**24,958**
1977			3,223	22,730	**25,954**
1978	3,033	298	3,331	22,976	**26,307**
1979	3,207	304	3,511	24,613	**28,124**
1980	3,071	293	3,364	24,561	**27,925**
1981	3,129	210	3,339	26,634	**29,973**
1982	2,424	177	2,601	25,439	**28,040**
1983	1,804	206	2,010	25,756	**27,766**
1984	4,823	200	5,023	27,432	**32,455**
1985	5,292	168	5,460	25,975	**31,435**
1986	7,308	190	7,498	22,992	**30,490**
1987	7,376	220	7,596	24,607	**32,203**
1988	10,306	168	10,474	26,076	**36,550**
1989	9,989	235	10,224	25,858	**36,082**
1990	9,343	176	9,519	26,108	**35,627**
1991	10,173	225	10,398	26,091	**36,489**
1992	10,683	177	10,860	26,449	**37,309**
1993	8,619	230	8,849	25,052	**33,901**
1994	10,069	241	10,310	28,559	**38,869**
1995	9,089	224	9,313	26,377	**35,690**
1996	7,685	192	7,877	27,540	**35,417**
1997	9,005	155	9,160	29,172	**38,332**
1998[2]	9,915	277	10,192	30,243	**40,435**
1999[2]	9,646	215	9,861	29,803	**39,664**
2000[2]	8,899	317	9,216	27,579	**36,795**
2001[2]	10,074	307	10,381	26,637	**37,018**
2002[2]	9,285	283	9,568	25,929	**35,497**

[1] Plants of 25-megawatt capacity or larger (1973-82); plants of 50-megawatt capacity or larger (1983-1997); all plants supplied by companies distributing 50,000 tons of coal or more per year (1998-2002). The change in definition in 1998 increased the size of the universe being covered.

[2] Since January 1998, regulated utilities have been selling off their electric plants. Once divestiture was complete, data were no longer required to be filed on the FERC Form 423 survey. Therefore, Montana Total, Received at Out-of-State Utilities and TOTAL from 1998 forward actually are EIA Form 6 survey data (Distribution of Coal Originating in Montana) . Subbituminous data for 1998 forward are numbers calculated by DEQ by subtracting Form 423 data on Lignite from Montana Total.

Note: This data series consistently shows the amount of coal distributed to Electric Utilities to be slightly different than the amount received at Electric Utility Plants shown in Table C6. Differences in distribution and receipt data are due to the time lag between distribution and receipt of coal shipments, and due to the survey threshold differences. In recent years the Corette plant has burned several hundred thousand tons of Wyoming coal most years, which further increases the difference.

Sources: Federal Energy Regulatory Commission (formerly the Federal Power Commission), Form 423 (1973-77); U.S. Department of Energy, Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants,* annual reports for 1978-2002 (EIA-0191; based on FERC Form 423); U.S. Department of Energy, Energy Information Administration, *Coal Industry Annual* , 1998-2000 (EIA-0584; based on EIA Form 6); U.S. Department of Energy, Energy Information Administration, *Annual Coal Report* , 2001-2002 (http://www.eia.doe.gov/cneaf/coal/page/coaldistrib/coaldistrib.html; based on EIA Form 6).

Table C7. Distribution of Montana Coal by Destination, 1991-2002(thousand short tons)

Destination	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Arizona								94	69	198	275	81
Colorado	101	106	86	89	63	26						
Illinois	3,203	3,013	3,295	4,338	2,713	2,162	1,545	1,679	1,769	2,552	2,362	3,125
Indiana	725	451	433	749	720	869	1,259	126	1,308	1,011	1,608	1,441
Iowa			1		2		105	136				
Kansas							104	379	1,319	1,464		
Michigan	10,838	10,376	10,055	10,481	11,014	9,806	10,866	9,861	9,952	9,239	9,435	6,542
Minnesota	9,668	8,566	8,852	10,038	10,199	9,791	8,847	10,477	9,429	10,771	11,510	11,248
Mississippi	105	82	178	1,314	1,234	2,226	3,235	2,833	1,926	151		
Missouri					6							
Montana	10,578	11,159	9,115	10,581	9,477	7,844	9,019	10,360	10,346	9,723	10,610	9,625
Nebraska	150	142	136	71	205	113	47	81				
Nevada											1	1
New Hampshire											10	
New Mexico												
North Dakota	425	444	422	559	469	417	402	517	877	145	618	487
Ohio						26	42		168	153	*	
Oregon		1,835	355						1,507			675
South Dakota					457	1,301	1,867	1,698	1,496			
Tennessee		2										
Washington		715	753	1,097	583	113	333	1,503		1,685	1,452	847
Wisconsin	2,005	1,878	2,057	2,307	2,135	2,950	2,649	2,053	482	578	511	2,922
Wyoming	8	11	31	49	71	125	34	62		64	67	58
Domestic Total	37,812	38,804	35,795	41,672	39,362	37,770	40,363	41,860	40,649	37,735	38,459	37,050
Canada[1]	10		54	90	259	316	438	814	682	608	485	180
Overseas[1]	297	62	67	153		202	141					
TOTAL	38,119	38,866	35,916	41,915	39,621	38,288	40,942	42,674	41,331	38,343	38,944	37,230

* Less than 500 short tons

[1] All distribution was steam coal.

Source: U.S. Department of Energy, Energy Information Administration *Coal Industry Annual* 1993-2000 (EIA-0584); U.S. Department of Energy, Energy Information Administration *Annual Coal Report*, 2001-2002 (http://www.eia.doe.gov/cneaf/coal/page/coaldistrib/coaldistrib.html).

Table C8. Montana Coal Production, Employment and Severance Tax

YEAR	Coal Produced (thousand tons)[1]	Percentage of U.S. production	Number of miners[2]	Average cost per ton[1]	Coal Severance Tax[3]
1980	29,948	3.6%	1131	$10.50	$70,415,018
1981	33,545	4.1%	1227	$12.14	$86,186,886
1982	27,882	3.3%	1051	$13.57	$80,044,981
1983	28,924	3.7%	1024	$14.22	$82,823,410
1984	33,000	3.7%	1112	$13.57	$91,748,856
1985	33,286	3.8%	1173	$13.18	$84,217,213
1986	33,978	3.8%	932	$12.93	$76,546,593
1987	34,399	3.7%	847	$12.43	$84,638,312
1988	38,881	4.1%	872	$10.06	$58,565,583
1989	37,742	3.8%	682	$10.27	$67,870,544
1990	37,616	3.7%	821	$9.42	$50,457,839
1991	38,227	3.8%	794	$10.76	$54,114,111
1992	38,879	3.9%	715	$10.20	$35,481,334
1993	35,917	3.8%	660	$11.05	$41,187,973
1994	41,640	4.0%	705	$10.39	$40,416,167
1995	39,451	3.8%	722	$9.62	$36,260,949
1996	37,891	3.6%	705	$9.96	$37,740,212
1997	41,005	3.8%	708	$9.84	$35,045,243
1998	42,840	3.8%	925	$8.25	$36,767,488
1999	41,102	3.7%	927	$8.82	$35,469,791
2000	38,352	3.6%	867	$8.87	$32,337,172
2001	39,143	3.5%	843	$8.83	$31,614,049
2002	37,386	3.4%	806	$9.27	$30,149,398

[1] Coal production and average cost from Table C2. For 1997 and prior years, average mine price is calculated by dividing the total free on board (f.o.b.) mine value of the coal produced by the total production. For 1998 and forward, average mine price is calculated by dividing the total f.o.b. rail value of the coal sold by the total coal sold.

[2] Includes all employees engaged in production, preparation, processing, development, maintenance, repair, ship or yard work at mining operations, including office workers for 1998 forward. For 1997 and prior years, includes mining operations management and all technical and engineering personnel, excluding office workers.

[3] For state Fiscal Year starting July 1 of the calendar year listed; thus, FY2003 starts in the middle of calendar year 2002. Includes all interest, penalties and accruals, except for FY2003, which only includes receipts. Does not include temporary Coal Stabilization Tax in FY1993-94, which totaled $2,712,696. The amount of coal mined during a given fiscal year is not the same as during that calendar year.

Source: U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 2000* (EIA-0384); U.S. Department of Energy, Energy Information Administration, *Coal Production*, annual reports for 1980-92 (EIA-0118); U.S. Department of Energy, Energy Information Administration, *Coal Industry Annual*, 1993-2000 (EIA-0584); U.S. Department of Energy, Energy Information Administration, *Annual Coal Report*, 2001-2002; Montana Department of Revenue *Biennial Report* (1980-2002); Montana Department of Revenue files (2004).

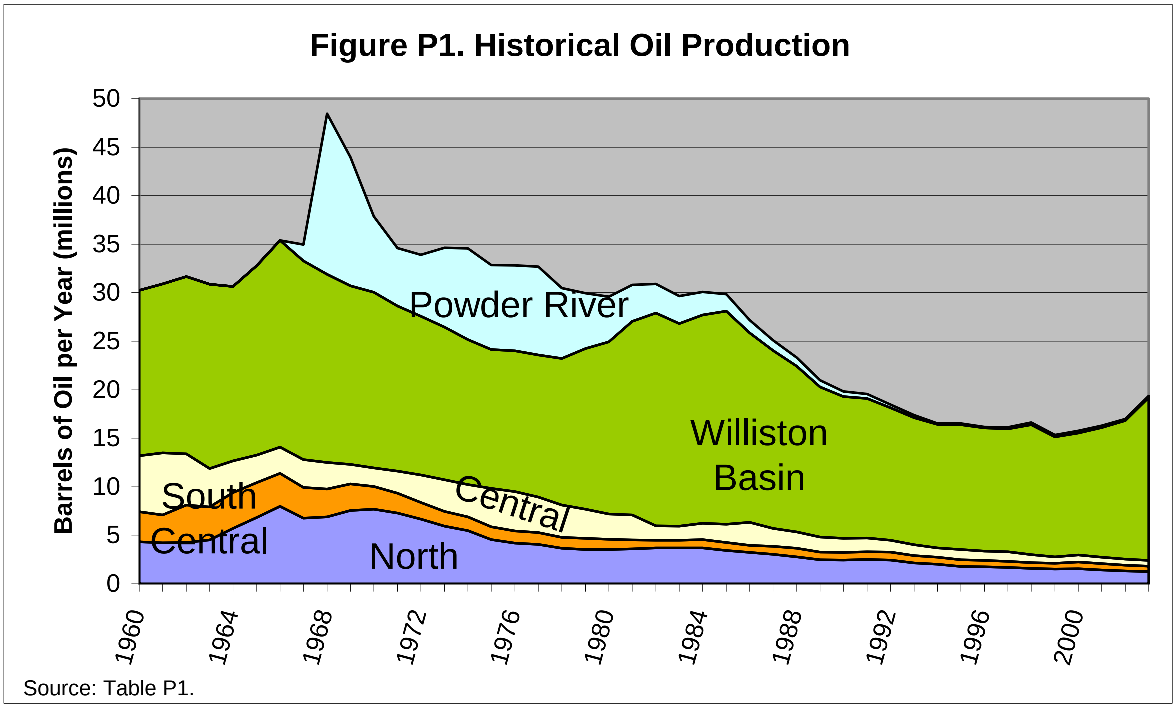
Petroleum and Petroleum Products in Montana

Montana Petroleum Quick Facts (in round numbers)
Recent production: 19 million barrels per year
Amount of crude production exported: 90 percent
Refineries in state: Billings (2), Laurel, Great Falls
Total refinery capacity: 180,000 barrels/day
Crude oil receipts at refineries: 60 million barrels per year
Source of crude oil refined in state in recent years: Montana – 4 percent Alberta – 75 percent Wyoming – 21 percent
Amount of liquid fuel refined products exported: 55 percent
States petroleum products are exported to: Washington North Dakota Wyoming (and points south)
Montana consumption of petroleum products: 30 million barrels (includes refinery usage)
Gasoline sold in-state: 500 million gallons
Diesel fuel sold in-state: 350 million gallons (includes railroad usage)

1. Production History

The first oil wells drilled in Montana were located in the Butcher Creek drainage between Roscoe and Red Lodge, beginning in 1889. These wells were not very successful. The first significant oil production in the state came from wells drilled in the northward extension of Wyoming's existing Elk Basin field in 1915, southeast of Belfry. Montana's first new oil field was Cat Creek, near Winnett, discovered in 1920. That soon was followed by the Kevin Sunburst field discovery in 1922. Over the next 40 years, more oil fields were developed in the Williston Basin (northeast Montana), the Sweetgrass Arch (northern Montana), the Big Snowy Uplift (central Montana), the northern extensions of Wyoming's Big Horn Basin (south central Montana) and the Powder River Basin (southeastern Montana).

Montana's petroleum production peaked in 1968 at 48.5 million barrels (1 barrel = 42 gallons), the result of cresting Williston Basin production combined with a surge of production from the newly discovered Bell Creek field in the Powder River Basin (Table P1 and Figure P1). Production then declined quickly until 1971, when a series of world oil supply shocks began to push prices upward, stimulating more drilling. Production remained relatively stable between 1971 and 1974 as Powder River Basin output increased to match a decline in Williston Basin output. After 1974 production began to decline, despite the continued escalation of oil prices (Table P2).

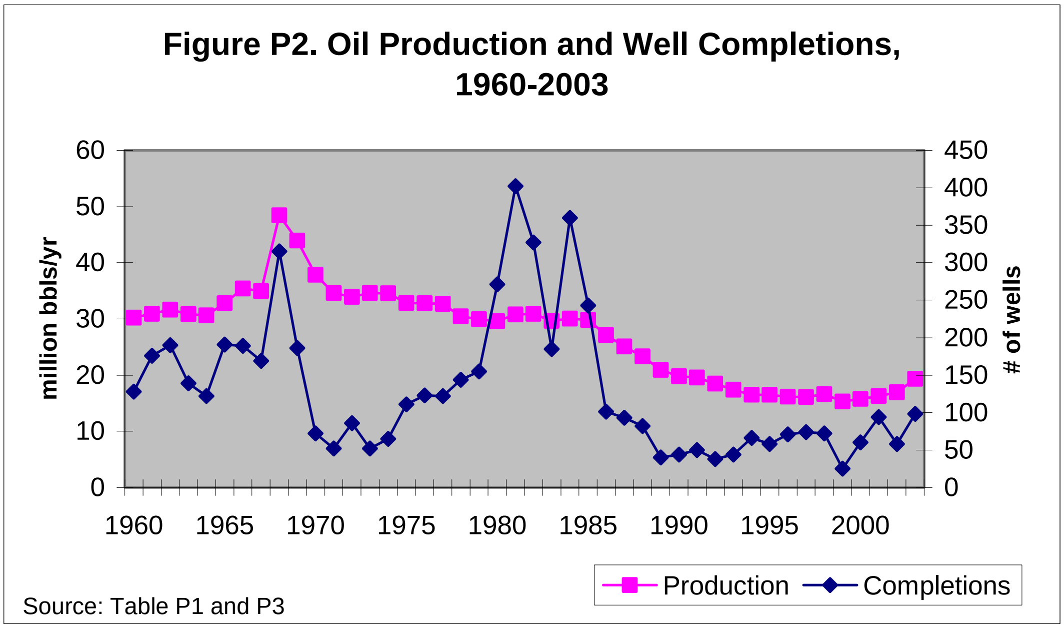


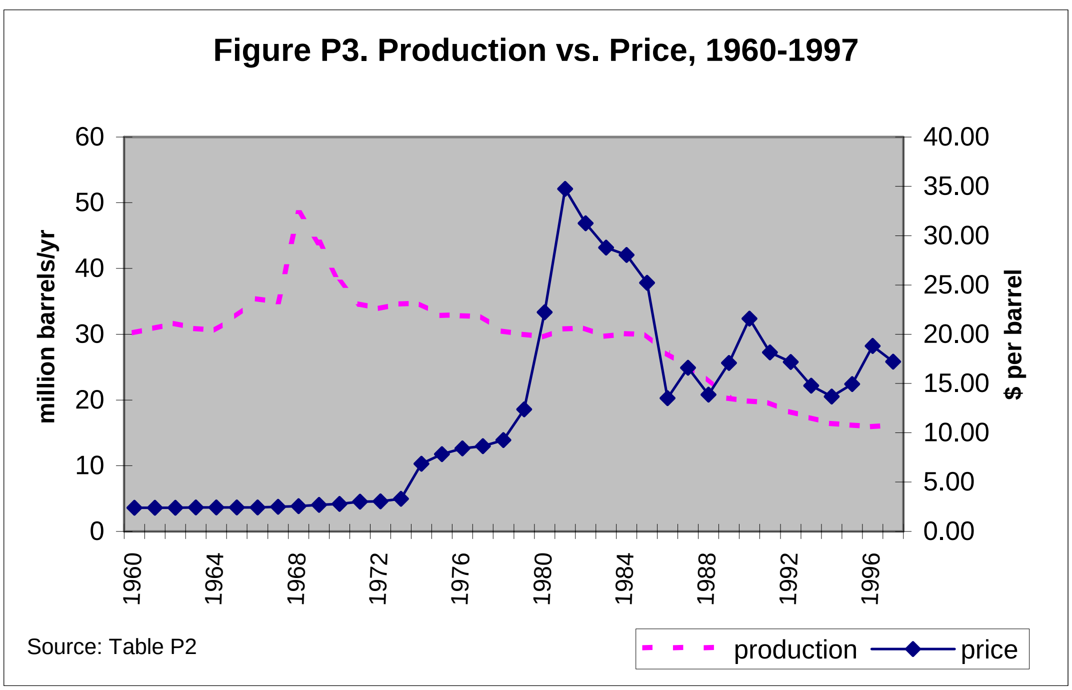
World oil price shocks following the Iran crisis in 1979 sparked a drilling boom, which peaked at 1,149 new wells of all types in 1981 (Table P3). That year, the average price of Montana crude climbed to almost $35 per barrel. While the increase in the price of oil encouraged more drilling, it did little to increase Montana production (Figure P2). The drilling produced a high percentage of dry holes and was unable to slow the decline in statewide production (Figure P3). Output increased in the Williston Basin during the early 1980s, but this was matched by a steep decline in output from other areas. Production declined significantly following the drop in world oil prices in 1985, stabilizing around 16 million barrels per year in the mid-1990's, before climbing back over 19 million barrels in 2003. Wells in Montana are not that prolific, averaging 15-18 barrels per day in recent years (Table P1).

2. Refineries and Pipelines

Petroleum pipelines serving Montana consist of three separate systems (see Map, below). One bridges the Williston and Powder River Basins in the east and the other two link the

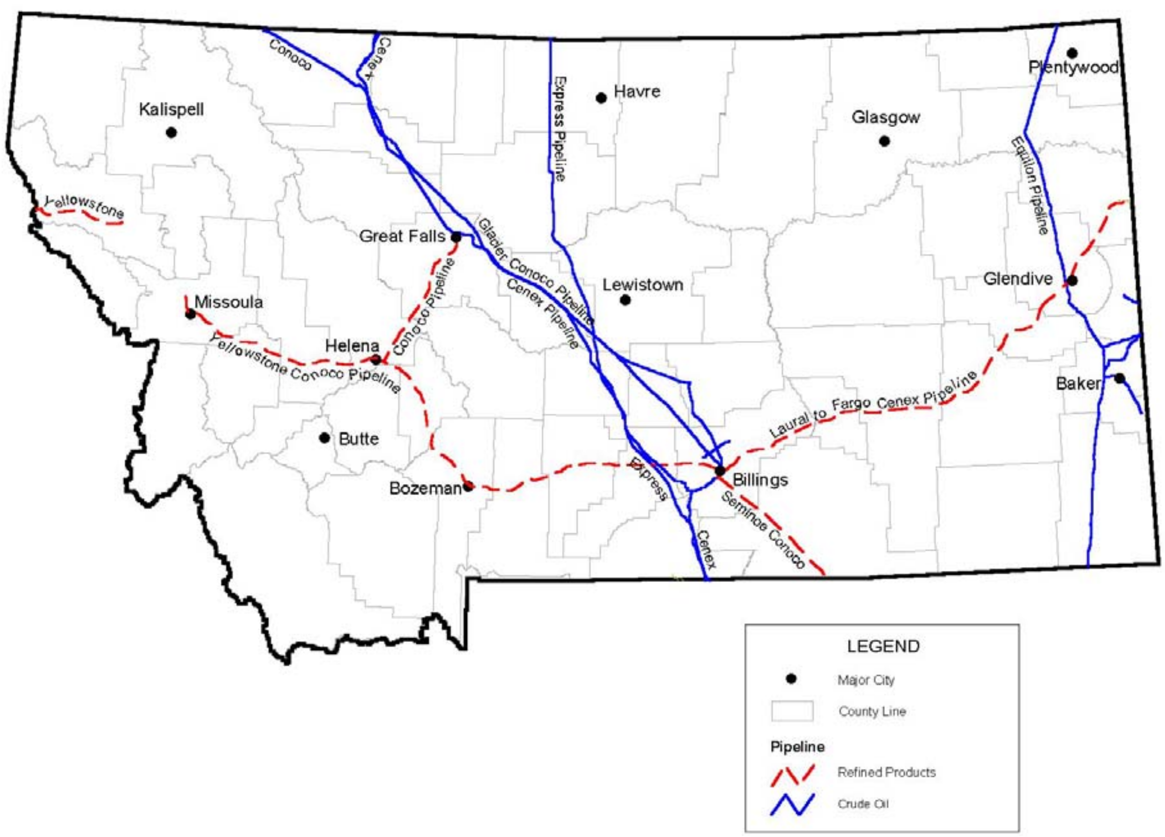
Sweetgrass Arch, Big Snowy and Big Horn producing areas in central Montana. All these systems also move crude oil from Canada to Montana and Wyoming. (A fourth—Express—primarily carries Canadian crude through Montana.) In recent years, around 90 percent of oil production has been exported from the state, mostly to Wyoming and beyond through the eastern pipeline system. This pipeline system is not connected to any of the Montana refineries, which limits the amount of Montana crude they can use.





Montana has four refineries, with a combined capacity of 181,200 barrels/day: ConocoPhillips (60,000 bbl/day) and ExxonMobil (58,000 bbl/day) in Billings, Cenex (55,000 bbl/day) in Laurel, and Montana Refining (8,200 bbl/day) in Great Falls. Montana refineries now use around 60 million barrels of crude a year (Table P4). In the last decade, less than 5 percent of that came from Montana crude. Oil fields in the Sweetgrass Arch, Big Snowy and Big Horn areas provided crude to the Montana refineries. Collectively, around 75 percent of the refinery crude inputs came from Alberta, Canada and around 20 percent came from Wyoming. The shipments from Canada have increased since the late 1960s, as Montana oil production and imports of Wyoming crude declined. (Figure P4, below)

MAP: Petroleum Pipelines in Montana

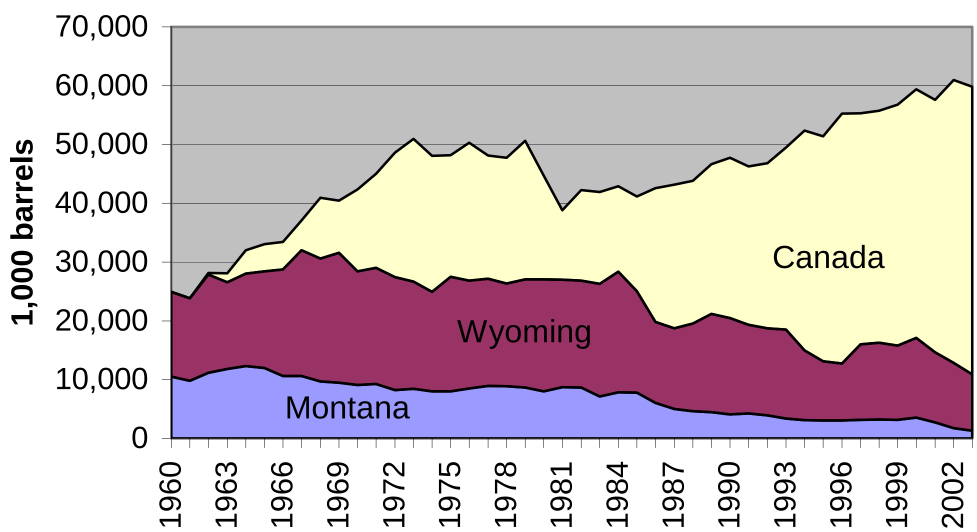


The refineries vary in their sources of crude inputs (Table P5). ConocoPhillips is the most dependent on Canadian crude, taking an average (1998-2003) of 94 percent of its total receipts from Canada. ExxonMobil is the least dependent on Canadian crude (43 percent of receipts) but by far the most dependent on Wyoming (54 percent of receipts).

Almost all of refinery output is moved by pipeline. The Billings area refineries ship their products to Montana cities and east to Fargo, North Dakota (Cenex pipeline), to Wyoming and further south (Conoco Seminoe pipeline) and west to Spokane and Moses Lake, Washington (Conoco Yellowstone pipeline). In 2003, 23 million barrels of product were shipped out of state, with nearly half heading south and the remainder split roughly between east and west.

The four refineries provided almost all of the petroleum products consumed in Montana. Beyond that, around 55 percent of the liquid fuel produced at the refineries is exported. Montana refineries provided about 10 percent of Washington's combined gasoline and distillate use in recent years. North Dakota received over one-third of its combined gasoline and distillate use from Montana refineries. For both states, Montana provided more gasoline than diesel.

Figure P4. Refinery Receipts by Source of Oil, 1960-2003



Source: Table P4

3. Petroleum Products Consumption

Petroleum product consumption in Montana peaked at 33 million barrels in 1979 (Table P6). It then drifted lower, settling in the mid-1980's around 24 million barrels per year. After that, consumption began a slow climb, to around 30 million barrels per year at present.

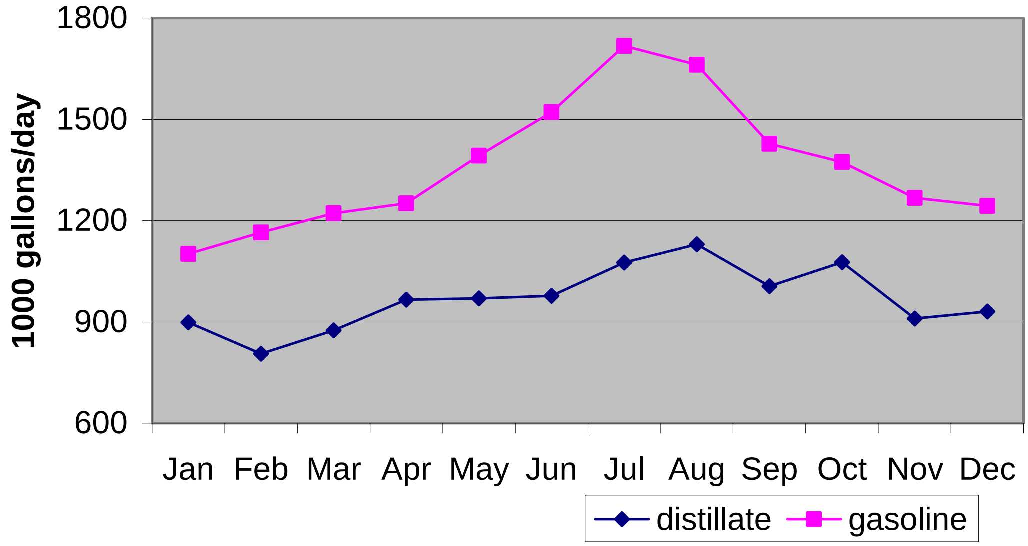
The transportation sector is the single largest user of petroleum and the second largest user of all forms of energy in Montana. In 2001, 38 percent of petroleum consumption was in the form of motor gasoline and 28 percent was distillate, mostly diesel fuel. Around 20 percent was consumed in petroleum industry operations (Table P6).

Gasoline use peaked in 1978, at half a billion gallons, dropped and slowly climbed back to near that level currently, with minor fluctuations since the mid-1990s (Tables P10 and P11). Diesel use generally has increased since the 1970's. In the last decade, highway diesel use grew at a far greater rate than did gasoline use (Table P11).

The fluctuations in demand for gasoline and diesel fuel since 1970 reflect changes in the state and national economy and the international price of oil. The embargo by the Organization of Petroleum Exporting Countries (OPEC) in 1973-1974 and the Iranian crisis of 1979-1980 drove prices up and demand down. The increase in prices prompted advances in vehicle efficiency and a fuel switch by heavy-duty trucks from gasoline to diesel. The crash in international prices in 1985, the economic growth of the 1980's and 1990's, along with the decline in vehicle fleet fuel efficiency in recent years pushed gasoline and diesel demand back up.

Fuel use shows a cyclical rise and fall through the year (Tables 12a and 12b; Figure P5). Use tends to rise during the summer months and taper off during the winter. The winter trough in fuel use is a third lower from the summer peak. This seasonal pattern is caused by variations in the use of Montana's one million vehicles, by the increase in tourist traffic during the summer, and by seasonal agricultural uses.

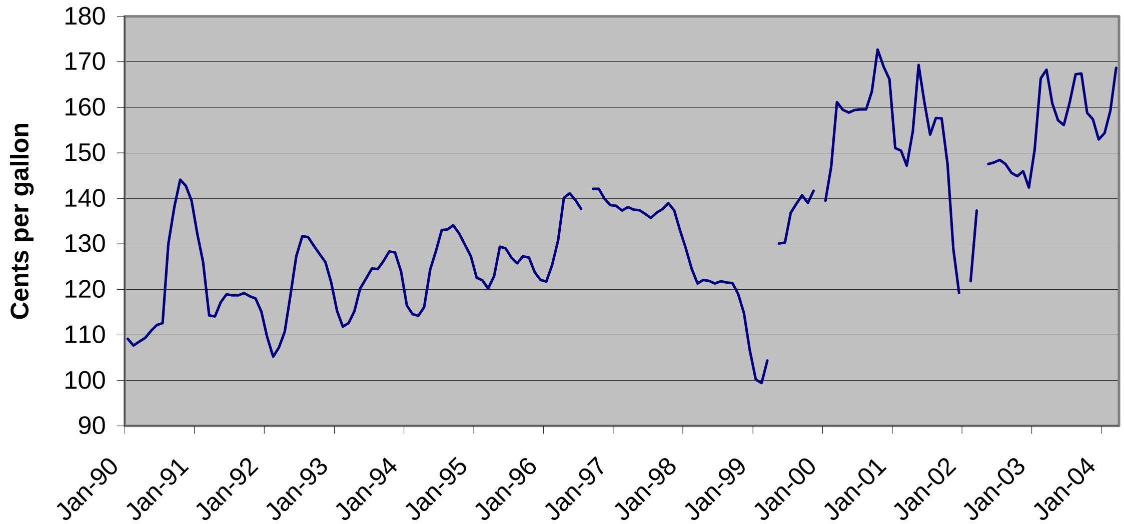
Figure P5. Average Daily Deliveries to Retail Outlets 1998-2003



Note: Deliveries are to retail outlets for sale.

The price of gasoline has been rising over the last decade, hitting all-time highs (not adjusted for inflation) in the past year (Table P13 and P14; Figure P6). The price of gasoline can vary significantly around the state, a fact that is masked by the data, which only are available as statewide averages. (Complete data on the Montana price of diesel were not available.) The price of gasoline has a cyclical rise and fall, just like demand for gasoline; however, price lags demand, with peak prices tending to appear after the peak driving season (Figure P7).

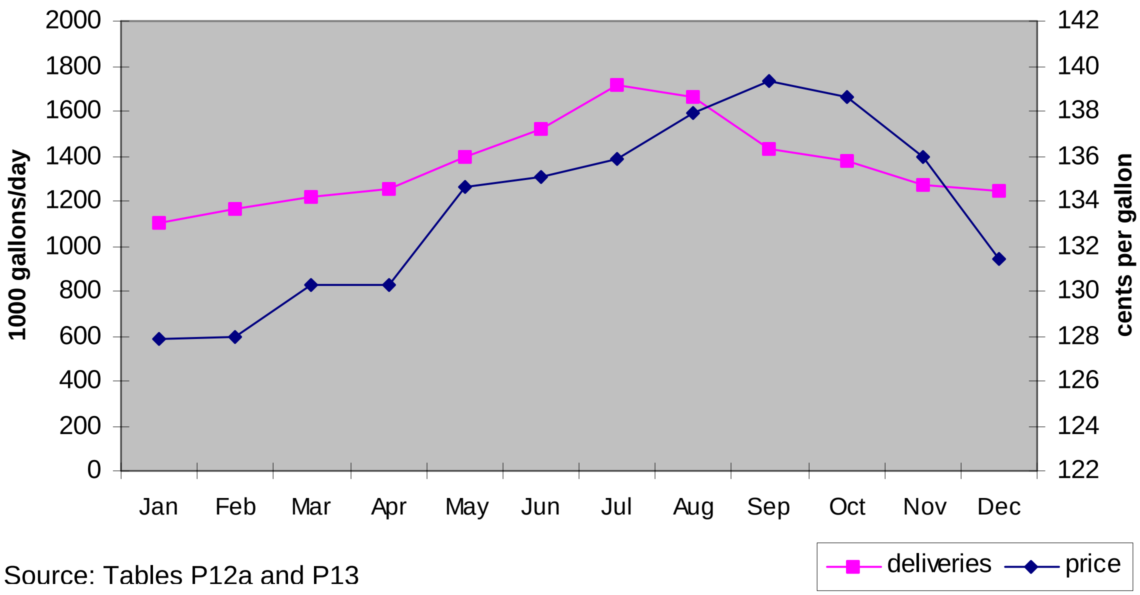
Figure P6. Retail Price of Gasoline, 1990-2004*



* Average of all grades of gasoline statewide, in nominal dollars (some data missing).

Source: EIA 782a database

Figure P7. Average Monthly Price of Gasoline vs Delivery for Sale (1998-2003)



Source: Tables P12a and P13

Comments on the data

Data for this report come from a variety of sources, which don't always agree exactly. In part this is due to slightly different data definitions and methods of data collection. The reader should always consider the source and context of specific data

Table P1. Average Daily Oil Production per Well and Annual Production by Region, 1960-2003

	Average Daily Production per Well (barrels)						Oil Production by Region (barrels)					
Year	North	South Central	Central	Williston Basin	Powder River Basin	STATE AVERAGE	North	South Central	Central	Williston Basin	Powder River Basin	TOTAL
1960	4.2	88.1	52.3	93.9		22.3	4,332,218	3,087,871	5,780,420	17,039,406		30,239,915
1961	4.7	97.9	53.8	89.3		25.0	4,211,017	2,895,587	6,367,524	17,431,916		30,906,044
1962	4.5	119.9	43.4	76.3		23.5	4,252,304	3,851,672	5,279,163	18,264,368		31,647,507
1963	4.9	113.4	34.8	74.4		23.2	4,530,510	3,383,587	3,950,490	19,005,066		30,869,653
1964	7.4	115.1	28.8	65.7		25.2	5,705,948	3,699,927	3,269,768	17,971,855		30,647,498
1965	7.1	97.6	25.5	70.9		23.6	6,826,261	3,597,647	2,849,923	19,504,287		32,778,118
1966	9.5	87.7	24.7	73.6		27.6	7,991,302	3,392,890	2,710,194	21,285,732		35,380,118
1967	8.8	90.7	27.5	69.9	70.6	28.2	6,758,280	3,181,132	2,872,604	20,475,733	1,671,277	34,959,026
1968	9.9	79.6	26.4	67.6	138.0	39.0	6,883,493	2,885,272	2,728,357	19,390,652	16,572,472	48,460,246
1969	11.3	69.5	22.6	66.4	91.4	36.1	7,557,966	2,739,346	2,011,445	18,396,618	13,248,737	43,954,112
1970	11.6	69.3	26.2	66.8	57.9	32.3	7,680,831	2,329,187	1,915,273	18,110,147	7,843,259	37,878,697
1971	11.3	57.9	29.4	62.4	50.9	30.1	7,292,476	2,028,304	2,274,124	17,042,703	5,961,116	34,598,723
1972	9.8	57.4	34.4	63.3	65.3	29.6	6,646,908	1,742,749	2,817,045	16,361,771	6,335,666	33,904,139
1973	9.5	50.0	36.2	60.8	90.4	31.7	5,948,826	1,515,088	3,238,967	15,735,703	8,181,598	34,620,182
1974	8.3	45.6	34.2	57.4	110.3	30.5	5,464,319	1,432,528	3,334,759	14,939,292	9,383,064	34,553,962
1975	6.0	36.1	35.8	53.4	103.2	26.2	4,551,324	1,318,779	3,954,024	14,312,685	8,706,862	32,843,674
1976	5.8	35.1	35.2	53.8	133.3	27.1	4,200,539	1,246,005	4,063,897	14,496,380	8,807,439	32,814,260
1977	5.6	30.4	29.4	50.8	140.2	26.2	4,060,957	1,210,064	3,677,361	14,621,635	9,110,037	32,680,054
1978	4.9	26.1	26.4	48.9	117.6	23.5	3,671,322	1,095,737	3,343,556	15,103,853	7,252,869	30,467,337
1979	4.6	27.7	24.4	51.2	94.9	22.9	3,536,296	1,131,798	3,029,397	16,546,576	5,713,032	29,957,099
1980	4.3	23.2	19.9	48.7	86.0	21.1	3,516,807	1,055,105	2,612,091	17,739,142	4,660,659	29,583,804
1981	4.3	18.9	20.0	50.6	59.2	21.0	3,605,207	910,595	2,583,690	19,954,159	3,759,760	30,813,411
1982	4.1	16.0	16.5	44.2	38.8	19.2	3,680,043	806,366	1,496,895	21,934,760	2,999,247	30,917,311
1983	3.7	14.4	14.0	39.6	35.1	16.9	3,682,130	790,150	1,467,855	20,877,527	2,847,618	29,665,280
1984	3.9	15.8	15.9	37.9	30.4	17.0	3,708,185	829,090	1,709,653	21,449,415	2,383,476	30,079,819
1985	3.3	16.3	12.3	39.1	22.1	16.0	3,419,300	838,817	1,868,780	21,979,087	1,744,433	29,850,417
1986	2.9	24.7	14.4	35.4	19.5	14.2	3,220,769	722,118	2,387,266	19,520,103	1,314,374	27,164,630
1987	2.9	17.4	13.9	35.1	26.2	14.1	3,040,941	827,229	1,847,551	18,319,149	1,069,179	25,104,049
1988	2.7	18.9	13.0	32.6	23.3	13.2	2,779,524	884,954	1,684,853	17,089,238	878,887	23,317,456
1989	2.6	16.2	12.8	30.8	16.8	12.5	2,488,169	773,372	1,544,989	15,476,534	686,228	20,969,292
1990	2.6	16.4	12.3	29.5	12.8	12.0	2,432,506	805,807	1,454,066	14,592,497	550,211	19,835,087
1991	2.7	17.9	12.3	29.4	16.9	12.2	2,510,130	804,003	1,393,046	14,380,288	485,881	19,573,348
1992	2.6	16.5	11.7	27.8	14.1	11.5	2,426,783	832,580	1,227,475	13,637,695	355,139	18,479,672
1993	2.4	17.4	10.1	27.9	13.3	11.4	2,143,943	772,668	1,095,551	13,110,882	272,517	17,395,561
1994	2.4	14.8	9.6	26.6	3.5	11.0	2,003,272	733,965	955,703	12,747,075	90,965	16,530,980
1995	2.3	14.5	11.4	26.9	12.4	11.9	1,783,331	698,537	1,040,127	12,877,305	126,524	16,525,824
1996	3.2	17.6	13.7	31.8	15.5	15.3	1,740,101	657,135	955,626	12,696,542	125,797	16,175,201
1997	3.2	15.9	13.5	31.4	12.0	15.2	1,691,825	603,422	991,714	12,667,200	180,142	16,134,303
1998	3.1	15.4	12.7	33.6	13.5	16.2	1,590,323	582,568	828,028	13,385,593	236,190	16,622,702
1999	3.1	17.7	11.5	31.6	11.7	15.5	1,511,263	606,812	638,239	12,373,436	208,707	15,338,457
2000	2.9	18.9	11.2	30.4	11.2	14.8	1,555,552	696,340	725,437	12,559,879	213,671	15,750,879
2001	2.7	16.3	10.4	31.0	10.0	15.1	1,429,196	656,160	650,982	13,371,388	173,567	16,281,293
2002	2.7	14.5	10.7	31.9	9.1	16.0	1,312,421	603,383	630,368	14,275,395	157,118	16,978,685
2003	2.6	14.3	9.8	36.7	8.4	18.2	1,254,814	572,145	590,237	16,787,840	141,033	19,346,069

SOURCE: Montana Department of Natural Resources and Conservation, Oil and Gas Division, *Annual Review, 1960-2001*; Montana Department of Natural Resources and Conservation, *Annual Review 2003*.

Table P2. Crude Oil Production and Average Wellhead Prices[1], 1960-2003

DNRC Statistics

Year	Crude Oil Production (Mbbls)	Average Wellhead Price ($/bbl)	Gross Value of Production (million $)
1960	30,240	2.41	72.9
1961	30,906	2.42	74.8
1962	31,648	2.42	76.6
1963	30,870	2.44	75.3
1964	30,647	2.43	74.5
1965	32,778	2.43	79.7
1966	35,380	2.44	86.3
1967	34,959	2.50	87.4
1968	48,460	2.57	124.5
1969	43,954	2.69	118.2
1970	37,879	2.78	105.3
1971	34,599	3.01	104.1
1972	33,904	3.06	103.7
1973	34,620	3.33	115.3
1974	34,554	6.85	236.7
1975	32,844	7.83	257.2
1976	32,814	8.42	276.3
1977	32,680	8.63	282.0
1978	30,467	9.25	281.8
1979	29,957	12.39	371.2
1980	29,584	22.24	657.9
1981	30,813	34.73	1070.1
1982	30,917	31.26	966.5
1983	29,665	28.79	854.1
1984	30,080	28.04	843.4
1985	29,934	25.23	755.2
1986	27,165	13.52	367.3
1987	25,104	16.62	417.2
1988	23,317	13.87	323.4
1989	20,269	17.08	358.2
1990	19,835	21.58	428.0
1991	19,573	18.18	355.9
1992[2]	18,237	17.20	313.7
1993[2]	17,327	14.78	256.1
1994[2]	16,425	13.68	224.7
1995[2]	16,170	14.96	241.9
1996[2]	15,957	18.81	300.2
1997[2]	16,233	17.22	279.6
1998			
1999			
2000			
2001			

DOR Statistics

Fiscal Year[3]	Crude Oil Production (Mbbls)	Average Wellhead Price ($/bbl)	Gross Value of Production (million $)
FY1995	16,448	14.60	240.1
FY1996	15,695	15.60	244.8
FY1997			
FY1998			
FY1999			
FY2000			
FY2001	15,736	27.40	431.2
FY2002	16,603	20.56	341.4
FY2003	17,742	27.27	483.8

1 Average wellhead prices were computed by dividing the gross value of production by the number of barrels extracted.

2 Due to a legal opinion on the confidentiality of tax records, the Montana Department of Revenue stopped providing data DNRC used to calculate the average price and valuation for individual fields. The DNRC data published for these years were summaries prepared by DoR. Some oil production is exempt from state taxation and is not included in DoR's production figures. Wells are classified for tax purposes as either oil or gas wells; only oil from wells classified as oil wells is included in DoR figures. After 1997, DNRC stopped publishing this data table.

3 State fiscal years start July 1. They are numbered according to the calendar year in which they end. Thus, FY2003 began July 1, 2002 and ended June 30, 2003. Information for intervening years cannot be retrieved from DoR's computer system.

SOURCE: Montana Department of Natural Resources and Conservation, Oil and Gas Conservation Division, *Annual Review*, 1960-2001; Montana Department of Revenue, Biennial Report 1994-1996 and DoR files for FY01-03.

Table P3. Number of Producing Oil Wells by Region and Number of Oil and Gas Wells Completed by Type, 1955-2003

	Number of Producing Oil Wells						Number of Wells Completed										
							Development					Exploratory					
Year	North	South Central	Central	Williston Basin	Powder River Basin	TOTAL	Oil	Gas	Dry Holes	Service Wells	Sub-Total	Oil	Gas	Dry Holes	T.A.[1]	Sub-Total	TOTAL
1955	2,950	94	176	194		3,414	158	21	69		248	11	4	145		160	408
1956	2,969	96	213	306		3,584	229	6	75		310	12	0	171		183	493
1957	3,130	103	214	376		3,823	182	17	57		256	12	2	162		176	432
1958	3,120	102	248	446		3,916	159	7	46		212	12	2	109		123	335
1959	3,067	100	266	455		3,888	156	12	71		239	7	6	101		114	353
1960	2,811	96	303	497		3,707	114	4	58		176	14	3	150		167	343
1961	2,447	81	324	535		3,387	169	6	60		235	7	2	173		182	417
1962	2,615	88	333	656		3,692	182	16	57		255	8	2	154		164	419
1963	2,550	82	310	700		3,642	131	6	60		197	8	5	152		165	362
1964	2,216	88	317	708		3,329	100	7	109		216	22	3	150		175	391
1965	2,649	101	306	754		3,810	177	9	107		293	14	1	199		214	507
1966	2,308	106	301	792		3,507	179	9	96		284	10	3	185		198	482
1967	2,097	96	286	802	109	3,390	162	14	104		280	7	5	191		203	483
1968	1,898	99	282	784	328	3,391	300	14	89		403	15	13	509		537	940
1969	1,827	108	244	759	397	3,335	171	44	105		320	15	5	466		486	806
1970	1,806	92	200	743	371	3,212	60	30	63		153	12	11	272		295	448
1971	1,768	96	212	748	321	3,145	49	36	34		119	3	22	323		348	467
1972	1,856	83	224	706	265	3,134	79	97	87		263	7	19	435		461	724
1973	1,708	83	245	709	248	2,993	46	165	100		311	6	36	366		408	719
1974	1,802	86	267	712	233	3,100	58	179	212		449	7	21	265		293	742
1975	2,067	100	303	734	231	3,435	105	261	222		588	6	15	236		257	845
1976	1,978	97	316	737	181	3,309	106	264	169		539	17	8	223		248	787
1977	1,999	109	343	789	178	3,418	98	220	188		506	24	19	129		172	678
1978	2,052	115	347	863	169	3,546	123	223	232		578	21	15	179		215	793
1979	2,089	112	340	886	165	3,592	120	235	182		537	35	20	211		266	803
1980	2,212	124	358	996	148	3,838	241	203	206		650	30	12	260		302	952
1981	2,280	132	354	1,080	174	4,020	276	133	188		597	126	85	341		552	1,149
1982	2,455	138	249	1,360	212	4,414	263	145	120	19	547	64	46	248		358	905
1983	2,693	150	287	1,446	222	4,798	160	55	88	10	313	25	16	156	23	220	533
1984	2,610	144	294	1,577	214	4,839	327	99	87	20	533	33	21	189	25	268	801
1985	2,803	141	417	1,540	216	5,117	227	84	90	18	419	16	2	192	11	221	640
1986	3,017	80	453	1,509	184	5,243	90	81	69	4	244	11	10	130	10	161	405
1987	2,850	130	363	1,430	112	4,885	86	75	39	21	221	7	9	100	11	127	348
1988	2,821	128	355	1,434	103	4,841	72	54	46	12	184	10	19	100	9	138	322
1989	2,644	131	331	1,377	112	4,595	32	115	29	8	184	8	12	38	0	58	242

Year	North	South Central	Central	Williston Basin	Powder River Basin	TOTAL	Oil	Gas	CBM[2]	Storage	EOR[3] Injection	Disposal	Dry	Other	Total
1990	2,579	135	323	1,356	118	4,514	44	192	0	2	4	1	92	0	335
1991	2,534	123	310	1,338	79	4,384	50	155	4	2	3	0	62	1	277
1992	2,568	138	287	1,338	69	4,400	38	154	0	3	0	2	66	4	267
1993	2,408	122	298	1,287	56	4,171	44	78	0	1	5	0	46	1	175
1994	2,324	136	272	1,311	71	4,114	66	102	0	7	2	2	77	4	260
1995	2,093	132	249	1,310	28	3,812	58	88	0	2	1	2	53	6	210
1996	2,020	120	242	1,271	49	3,702	71	66	0	2	7	2	50	0	198
1997	1,963	117	235	1,298	73	3,686	74	224	10	0	8	3	74	0	393
1998	1,912	118	236	1,292	82	3,640	72	144	21	0	10	1	65	3	316
1999	1,854	118	225	1,265	72	3,534	25	235	111	3	19	0	63	1	457
2000	1,891	125	229	1,305	77	3,627	60	287	77	6	3	0	57	0	490
2001	1,845	131	220	1,344	62	3,602	94	295	48	1	13	2	82	4	539
2002	1,756	130	215	1,393	57	3,551	58	312	8	6	6	0	71	1	462
2003	1,762	128	222	1,430	52	3,594	98	287	188	0	9	3	62	0	647

[1] T.A. - Temporarily abandoned. [2] CBM - Coalbed Methane [3] EOR - Enhanced Oil Recovery

NOTE: The Montana Board of Oil and Gas revised its record keeping procedures several years ago. The data for wells drilled since 1990 supercede those in the previous Annual Reviews. After 1990, the number of wells drilled no longer is broken out by "Development" and "Exploratory."

SOURCE: Montana Department of Natural Resources and Conservation, Oil and Gas Division, *Annual Review,* 1955-2001.
Permit Data 1990-2001: Board of Oil and Gas Live Data Access, November 15, 2002 and July 29, 2004, http://bogc.dnrc.mt.gov/OnlineData.htm

Table P4. Refinery Receipts by Source of Crude Oil, 1960-2003 (thousand barrels)

	MONTANA		WYOMING		CANADA		NORTH DAKOTA		
Year	Crude Oil	Percent of Total	Crude Oil	Percent of Total	Crude Oil	Percent of Total	Crude Oil	Percent of Total	TOTAL
1960	10,531	42.3	14,383	57.7	21	0.1			24,935
1961	9,797	41.0	14,038	58.8	33	0.1			23,869
1962	11,175	39.7	16,708	59.4	266	0.9			28,149
1963	11,798	42.0	14,745	52.5	1,553	5.5			28,097
1964	12,292	38.4	15,714	49.1	4,002	12.5			32,007
1965	11,971	36.2	16,416	49.7	4,654	14.1			33,041
1966	10,626	31.8	18,120	54.2	4,684	14.0			33,429
1967	10,632	28.7	21,393	57.7	5,052	13.6			37,078
1968	9,690	23.7	20,915	51.0	10,347	25.2			40,951
1969	9,465	23.4	22,130	54.7	8,843	21.9			40,438
1970	9,080	21.5	19,342	45.7	13,908	32.8			42,330
1971	9,262	20.6	19,732	43.8	16,003	35.6			42,997
1972	8,194	16.9	19,241	39.6	21,156	43.5			48,591
1973	8,437	16.6	18,235	35.8	24,295	47.7			50,967
1974	7,989	16.6	16,949	35.3	23,115	48.1			48,053
1975	8,002	16.6	19,465	40.4	20,690	43.0			48,157
1976	8,517	16.9	18,311	36.4	23,494	46.7			50,322
1977	8,928	18.5	18,248	37.8	20,921	43.3	200	0.4	48,297
1978	8,848	18.5	17,513	36.6	21,369	44.7	69	0.1	47,739
1979	8,668	17.1	18,368	36.3	23,578	46.6	6	0.0	50,620
1980	8,016	17.9	19,050	42.6	17,627	39.4	25	0.1	44,719
1981	8,691	22.4	18,298	47.2	11,797	30.4	14	0.0	38,801
1982	8,653	20.5	18,178	43.0	15,402	36.5		0.0	42,234
1983	7,120	16.9	19,183	45.7	15,584	37.2	45	0.1	41,932
1984	7,821	18.2	20,552	47.9	14,516	33.8	55	0.0	42,945
1985	7,804	19.0	17,258	41.9	16,075	39.1	10	0.0	41,149
1986	6,019	14.1	13,795	32.4	22,778	53.5			42,593
1987	4,993	11.6	13,758	31.9	24,396	56.5			43,147
1988	4,607	10.5	14,907	34.0	24,306	55.5			43,820
1989	4,475	9.6	16,675	35.8	25,480	54.6			46,630
1990	4,057	8.5	16,431	34.4	27,271	57.1			47,760
1991	4,272	9.2	15,031	32.5	26,991	58.3			46,294
1992	3,907	8.3	14,820	31.6	28,110	60.0			46,837
1993	3,395	6.9	15,116	30.5	30,977	62.6			49,489
1994	3,109	5.9	11,865	22.7	37,383	71.4			52,357
1995	3,042	5.9	10,074	19.6	38,266	74.5			51,381
1996	3,033	5.5	9,686	17.5	42,549	77.0			55,269
1997	3,178	5.7	12,840	23.2	39,296	71.0			55,314
1998	3,203	5.7	13,067	23.5	39,449	70.8			55,719
1999	3,162	5.6	12,623	22.2	40,986	72.2			56,772
2000	3,520	5.9	13,579	22.9	42,281	71.2			59,380
2001	2,702	4.7	11,947	20.7	42,950	74.6			57,599
2002	1,733	2.8	11,100	18.2	48,130	78.9			60,963
2003	1,332	2.2	9,550	16.0	48,957	81.8			59,838

NOTE: Data originally reported by the Montana Oil and Gas Conservation Division have been revised on the basis of further information received from individual refineries. The Oil and Gas Conservation Division data originally understated Canadian inputs and overstated Wyoming inputs to the Continental Oil refinery, at least for the years 1968-75. Canadian inputs to the Big West Oil and Westco refineries were apparently not reported to the Oil and Gas Conservation Division. Revised data are available only for the years 1972-75, but it is likely that Canadian inputs to these two refineries were significant before 1972.

SOURCE: Montana Department of Natural Resources and Conservation, Oil and Gas Conservation Division, *Annual Review*, 1960-2003.

Table P5. Refinery Receipts by Source of Oil, 1998-2003 (barrels)

Average (1998-2003)	Cenex		Conoco		Exxon		Montana Refining		TOTALS	
Montana	1,238,904	7%	254,943	1%	717,215	4%	397,652	17%	2,608,715	4%
Wyoming	869,008	5%	862,857	4%	10,245,757	54%	-	-	11,977,621	21%
Canada	15,457,960	88%	18,267,294	94%	8,138,996	43%	1,927,998	83%	43,792,248	75%
Total Received	17,565,871	100%	19,385,094	100%	19,101,968	100%	2,325,650	100%	58,378,584	100%
2003	**Cenex**		**Conoco**		**Exxon**		**Montana Refining**		**TOTALS**	
Montana	889,294	5%	302,072	2%	-	-	140,380	6%	1,331,746	2%
Wyoming	408,712	2%	674,758	4%	8,466,132	43%	-	-	9,549,602	16%
Canada	17,827,042	93%	17,715,443	95%	11,129,578	57%	2,284,724	94%	48,956,787	82%
Total Received	19,125,048	100%	18,692,273	100%	19,595,710	100%	2,425,104	100%	59,838,135	100%
2002	**Cenex**		**Conoco**		**Exxon**		**Montana Refining**		**TOTALS**	
Montana	1,026,972	5%	119,337	1%	333,345	2%	253,772	10%	1,733,426	3%
Wyoming	402,446	2%	1,024,976	5%	9,672,522	52%	-	-	11,099,944	18%
Canada	17,693,908	93%	19,691,191	95%	8,567,758	46%	2,177,015	90%	48,129,872	79%
Total Received	19,123,326	100%	20,835,504	100%	18,573,625	100%	2,430,787	100%	60,963,242	100%
2001	**Cenex**		**Conoco**		**Exxon**		**Montana Refining**		**TOTALS**	
Montana	1,299,462	7%	101,308	1%	924,568	5%	376,851	17%	2,702,189	5%
Wyoming	758,202	4%	642,068	3%	10,546,750	57%	-	-	11,947,020	21%
Canada	15,511,970	88%	18,409,816	96%	7,148,432	38%	1,879,859	83%	42,950,077	75%
Total Received	17,569,634	100%	19,153,192	100%	18,619,750	100%	2,256,710	100%	57,599,286	100%
2000	**Cenex**		**Conoco**		**Exxon**		**Montana Refining**		**TOTALS**	
Montana	1,324,090	8%	485,023	2%	1,261,768	6%	449,119	21%	3,520,000	6%
Wyoming	1,530,079	9%	578,760	3%	11,469,924	57%	-	-	13,578,763	23%
Canada	13,569,484	83%	19,660,159	95%	7,312,076	36%	1,739,580	79%	42,281,299	71%
Total Received	16,423,653	100%	20,723,942	100%	20,043,768	100%	2,188,699	100%	59,380,062	100%
1999	**Cenex**		**Conoco**		**Exxon**		**Montana Refining**		**TOTALS**	
Montana	1,368,726	8%	298,747	2%	972,330	5%	522,394	22%	3,162,197	6%
Wyoming	1,541,855	9%	670,904	4%	10,410,600	52%	-	-	12,623,359	22%
Canada	13,673,690	82%	16,906,241	95%	8,563,587	43%	1,842,652	78%	40,986,170	72%
Total Received	16,584,271	100%	17,875,892	100%	19,946,517	100%	2,365,046	100%	56,771,726	100%
1998	**Cenex**		**Conoco**		**Exxon**		**Montana Refining**		**TOTALS**	
Montana	1,524,879	9%	223,173	1%	811,281	5%	643,397	28%	3,202,730	6%
Wyoming	572,752	3%	1,585,674	8%	10,908,612	61%	-	-	13,067,038	23%
Canada	14,471,664	87%	17,220,914	90%	6,112,547	34%	1,644,159	72%	39,449,284	71%
Total Received	16,569,295	100%	19,029,761	100%	17,832,440	100%	2,287,556	100%	55,719,052	100%

Source: Montana Department of Natural Resources and Conservation Montana Oil and Gas Annual Review (1998-2003).

Table P6. Petroleum Product Consumption Estimates, 1960-2001 (thousand barrels)

Year	Asphalt & Road Oil	Aviation Gasoline	Distillate Fuel	Jet Fuel	Kerosene	LPG	Lubricants	Motor Gasoline	Residual Fuel	Other[1]	TOTAL
1960	865	1,006	4,898	265	477	737	161	6,922	2,063	1,725	19,118
1961	823	1,427	5,278	280	366	859	157	6,979	2,580	2,112	20,861
1962	786	473	5,549	311	265	819	171	7,553	3,052	2,320	21,298
1963	900	499	5,393	340	359	766	171	7,481	2,852	2,704	21,465
1964	1,328	340	5,702	360	679	925	179	7,374	2,300	2,654	21,842
1965	1,003	312	4,962	384	248	926	189	7,709	1,241	2,835	19,809
1966	974	198	5,695	441	118	1,167	196	7,953	1,459	2,977	21,177
1967	1,066	131	3,394	574	859	1,585	175	8,104	1,231	3,092	20,211
1968	1,221	65	4,113	697	815	1,689	192	8,585	1,509	3,540	22,427
1969	1,189	38	4,641	806	657	1,690	196	8,737	1,556	3,739	23,250
1970	1,347	43	4,827	649	376	1,326	200	9,262	1,268	3,372	22,670
1971	1,337	42	5,715	767	362	1,402	188	9,494	1,262	3,356	23,926
1972	1,489	94	6,206	762	383	1,705	201	10,137	1,469	3,864	26,308
1973	1,397	110	6,989	757	405	1,503	219	10,883	1,765	4,018	28,048
1974	1,222	105	7,840	780	174	1,466	210	10,550	2,262	3,708	28,316
1975	924	79	7,586	818	122	1,370	208	10,630	2,178	3,772	27,687
1976	1,283	94	8,411	753	79	1,421	231	11,605	2,525	3,440	29,843
1977	1,133	92	8,258	772	93	1,368	247	11,100	2,506	3,700	29,270
1978	942	87	8,232	699	95	1,662	266	12,809	2,502	3,705	30,999
1979	1,054	122	9,037	907	17	1,094	278	11,162	5,773	3,424	32,869
1980	1,020	159	7,509	920	0	1,806	247	10,416	4,025	3,159	29,262
1981	1,035	177	6,469	800	26	1,027	237	10,797	2,494	2,623	25,686
1982	884	92	5,828	625	0	1,446	216	10,429	1,608	2,398	23,525
1983	1,130	102	8,863	652	18	1,497	227	10,525	1,306	2,328	26,648
1984	1,215	77	8,161	642	19	1,032	242	10,451	798	2,639	25,277
1985	1,463	91	10,444	678	10	1,576	225	10,188	133	2,512	27,320
1986	1,989	105	6,621	867	22	1,505	220	10,158	47	2,507	24,041
1987	1,642	82	6,223	718	8	1,716	249	10,258	23	3,236	24,156
1988	1,473	107	6,078	809	4	1,515	240	10,441	221	3,624	24,513
1989	1,749	95	7,336	750	3	1,608	246	10,310	180	3,615	25,893
1990	1,487	111	7,280	708	8	1,740	253	10,328	218	3,659	25,792
1991	1,350	108	7,220	615	3	1,053	227	10,360	145	3,203	24,284
1992	1,309	75	6,836	864	1	1,018	231	10,727	88	4,007	25,156
1993	1,707	64	7,315	901	8	2,200	235	10,999	680	3,295	27,404
1994	1,964	75	7,381	855	7	1,055	246	11,097	369	3,655	26,703
1995	1,293	78	8,049	1,052	1	918	242	11,328	236	4,713	27,909
1996	1,702	99	8,070	999	1	1,618	235	11,753	181	5,200	29,857
1997	1,448	71	9,037	792	2	277	248	11,480	162	4,897	28,413
1998	1,594	102	7,863	797	3	271	259	11,596	106	5,545	28,137
1999	2,625	121	7,921	836	2	527	262	11,768	20	6,344	30,428
2000	2,151	134	8,069	747	1	1,324	258	11,559	1	5,375	29,617
2001	903	109	8,476	756	12	1,400	237	11,640	2	6,740	30,276

1 In Montana "Other Petroleum Products" are used primarily in petroleum industry operations and as refinery fuels.

NOTE: DOE models provide the best consumption estimates publicly available. However, the continuity of these data series estimates may be affected by changing data sources and estimation methodologies, which may account for some of the more dramatic year-to-year variation in consumption levels. See the "Additional Notes" under each type of energy in Technical Notes (http://www.eia.doe.gov/emeu/states/sep_fuel/notes/_fuelnotes_multistate.html#use_technotes). Additionally, this table revises DEQ's 2002 report in the Distillate Fuel category, for 1984-1999 and the Other category for all years except 1985-1988.

SOURCE: U.S. Department of Energy, Energy Information Administration, *State Energy Data Consumption* tables (formerly *State Energy Data Report*), 1960-2001 (see Revised Historical Data at http://www.eia.doe.gov/emeu/states/sep_fuel/notes/_fuelnotes_multistate.html#use_technotes as of June 2004).

Table P7. Residential Petroleum Product Consumption Estimates, 1960-2001 (thousand barrels)

Year	Distillate Fuel	LPG[1]
1960	262	506
1961	335	616
1962	335	560
1963	328	499
1964	312	655
1965	277	636
1966	286	758
1967	196	994
1968	250	1,068
1969	289	1,072
1970	249	887
1971	397	905
1972	436	1,094
1973	495	965
1974	542	1,026
1975	589	973
1976	646	993
1977	616	993
1978	657	1,276
1979	675	606
1980	421	829
1981	273	503
1982	352	736
1983	449	901
1984	380	428
1985	309	604
1986	325	641
1987	220	709
1988	213	715
1989	345	831
1990	291	813
1991	287	703
1992	180	598
1993	234	548
1994	159	541
1995	218	473
1996	325	519
1997	685	152
1998	404	86
1999	225	342
2000	170	922
2001	170	940

[1] DOE has numerous caveats on its allocation of LPG consumption to the various sectors.

NOTE: This table excludes a small amount of kerosene consumption, which could not be estimated accurately by DOE models.

NOTE: DOE models provide the best consumption estimates publicly available. However, the continuity of these data series estimates may be affected by changing data sources and estimation methodologies, which may account for some of the more dramatic year-to-year variation in consumption levels. See the "Additional Notes" under each type of energy in Technical Notes (http://www.eia.doe.gov/emeu/states/sep_fuel/notes/_fuelnotes_multistate.html#use_technotes). Additionally, this table revises DEQ's 2002 report in the Distillate Fuel category, for 1984-1999.

SOURCE: U.S. Department of Energy, Energy Information Administration, *State Energy Data Consumption* tables (formerly *State Energy Data Report*), 1960-2001 (see Revised Historical Data at http://www.eia.doe.gov/emeu/states/sep_fuel/notes/_fuelnotes_multistate.html#use_technotes as of June 2004).

Table P8. Commercial Petroleum Product Consumption Estimates, 1960-2001 (thousand barrels)

Year	Distillate Fuel	LPG[1]	Motor Gasoline[2]	Residual Fuel
1960	297	89	135	2
1961	380	109	146	3
1962	380	99	121	4
1963	372	88	141	4
1964	354	116	127	3
1965	315	112	144	1
1966	324	134	123	1
1967	223	175	135	1
1968	284	188	133	1
1969	329	189	107	1
1970	283	157	220	1
1971	451	160	127	1
1972	496	193	168	1
1973	562	170	136	1
1974	616	181	125	2
1975	668	172	174	2
1976	734	175	163	3
1977	699	175	157	3
1978	746	225	167	4
1979	766	107	179	11
1980	346	146	92	7
1981	380	89	110	0
1982	183	130	127	5
1983	1,104	159	76	172
1984	935	75	61	105
1985	772	107	72	126
1986	373	113	76	37
1987	272	125	80	13
1988	181	126	76	9
1989	192	147	77	13
1990	154	143	84	11
1991	164	124	63	3
1992	140	106	55	4
1993	170	97	12	5
1994	159	95	15	3
1995	102	83	13	3
1996	229	92	19	2
1997	162	27	12	1
1998	114	15	14	1
1999	142	60	14	2
2000	143	163	14	1
2001	197	166	14	0

[1] DOE has numerous caveats on its allocation of LPG consumption to the various sectors.
[2] Includes miscellaneous (including unclassified) and public nonhighway sales of motor gasoline.

NOTE: DOE models provide the best consumption estimates publicly available. However, the continuity of these data series estimates may be affected by changing data sources and estimation methodologies, which may account for some of the more dramatic year-to-year variation in consumption levels. See the "Additional Notes" under each type of energy in Technical Notes (http://www.eia.doe.gov/emeu/states/sep_fuel/notes/_fuelnotes_multistate.html#use_technotes). Additionally, this table revises DEQ's 2002 report in the Distillate Fuel category, for 1984-1999.

SOURCE: U.S. Department of Energy, Energy Information Administration, *State Energy Data Consumption* tables (formerly *State Energy Data Report*), 1960-2001 (see Revised Historical Data at http://www.eia.doe.gov/emeu/states/sep_fuel/notes/_fuelnotes_multistate.html#use_technotes as of June 2004).

Table P9. Industrial Petroleum Product Consumption Estimates, 1960-2001 (thousand barrels)

Year	Distillate Fuel[1]	LPG[2]	Lubricants	Motor Gasoline[3]	Residual Fuel[4]
1960	1,500	112	23	816	1,684
1961	1,841	104	23	923	1,960
1962	2,159	125	30	685	2,575
1963	2,174	145	30	796	2,438
1964	2,331	128	31	746	1,986
1965	1,693	164	41	887	914
1966	2,123	254	43	681	980
1967	1,033	356	40	791	882
1968	1,222	359	44	745	1,242
1969	1,373	361	45	476	1,212
1970	1,274	246	46	635	1,123
1971	1,750	282	43	570	1,174
1972	1,863	339	46	702	1,390
1973	2,073	302	60	568	1,577
1974	2,413	206	58	503	2,126
1975	2,494	174	46	774	1,963
1976	2,926	202	51	774	2,303
1977	2,890	162	51	703	2,176
1978	2,375	115	55	578	2,270
1979	2,787	364	57	663	5,609
1980	1,925	786	51	619	4,018
1981	1,943	382	49	663	2,494
1982	1,396	551	45	632	1,603
1983	3,173	383	47	509	1,132
1984	2,686	461	50	558	692
1985	5,192	814	46	677	7
1986	1,968	696	45	637	10
1987	1,607	844	51	574	10
1988	1,473	626	50	575	212
1989	2,623	578	51	631	168
1990	2,778	717	52	615	207
1991	2,868	178	47	611	142
1992	2,141	279	48	572	85
1993	2,404	1,513	49	567	675
1994	1,917	360	51	603	365
1995	2,283	333	50	646	233
1996	2,569	991	48	663	178
1997	2,422	90	51	686	161
1998	1,955	108	54	437	106
1999	1,982	112	54	420	18
2000	1,904	227	53	406	0
2001	1,907	275	49	546	2

[1] Includes deliveries for industrial use (including industrial space heating and farm use), oil company use, off-highway use, and "other" uses. Does not include use at electric utilities.

[2] DOE has numerous caveats on its allocation of LPG consumption to the various sectors.

[3] Includes sales for agricultural use, construction use, and industrial and commercial use.

[4] Includes industrial use, oil company use, and "other" uses.

NOTE: This table does not show the categories "asphalt and road oil" and "other petroleum products," which are consumed solely in the industrial sector and already are reported in Table P6. It also does not include kerosene, since the consumption has been minimal in recent years.

NOTE: DOE models provide the best consumption estimates publicly available. However, the continuity of these data series estimates may be affected by changing data sources and estimation methodologies, which may account for some of the more dramatic year-to-year variation in consumption levels. See the "Additional Notes" under each type of energy in Technical Notes (http://www.eia.doe.gov/emeu/states/sep_fuel/notes/_fuelnotes_multistate.html#use_technotes). Additionally, this table revises DEQ's 2002 report in the Distillate Fuel and Residual Fuel categories, for 1984-1999.

SOURCE: U.S. Department of Energy, Energy Information Administration, *State Energy Data Consumption* tables (formerly *State Energy Data Report*), 1960-2001 (see Revised Historical Data at http://www.eia.doe.gov/emeu/states/sep_fuel/notes/_fuelnotes_multistate.html#use_technotes as of June 2004).

Table P10. Transportation Petroleum Product Consumption Estimates, 1960-2001 (thousand barrels)

Year	Aviation Gasoline[1]	Distillate Fuel[2]	Jet Fuel[3]	LPG[4]	Lubricants	Motor Gasoline[1]	Residual Fuel[6]
1960	1,006	2,839	265	29	137	5,972	377
1961	1,427	2,721	280	31	134	5,910	617
1962	473	2,675	311	35	141	6,747	471
1963	499	2,520	340	34	141	6,544	410
1964	340	2,705	360	26	148	6,501	307
1965	312	2,676	384	13	148	6,678	325
1966	198	2,961	441	21	153	7,148	396
1967	131	1,941	574	60	135	7,178	342
1968	65	2,356	697	73	148	7,708	243
1969	38	2,649	806	68	151	8,155	238
1970	43	3,020	649	36	154	8,407	119
1971	42	3,116	767	56	145	8,797	87
1972	94	3,408	762	78	155	9,267	63
1973	110	3,834	757	65	159	10,179	44
1974	105	4,266	780	53	152	9,922	122
1975	79	3,835	818	50	162	9,682	160
1976	94	4,101	753	50	180	10,668	141
1977	92	4,049	772	37	196	10,240	136
1978	87	4,451	699	46	211	12,064	134
1979	122	4,791	907	18	220	10,320	24
1980	159	4,759	920	45	196	9,705	0
1981	177	3,834	800	52	188	10,024	0
1982	92	3,866	625	29	172	9,671	0
1983	102	4,106	652	54	180	9,940	3
1984	77	4,082	642	69	192	9,831	2
1985	91	4,132	678	51	179	9,439	*
1986	105	3,930	867	55	175	9,445	0
1987	82	4,080	718	39	197	9,604	0
1988	107	4,149	809	48	190	9,789	0
1989	95	4,115	750	53	195	9,602	0
1990	111	3,993	708	67	201	9,630	0
1991	108	3,856	615	48	180	9,687	0
1992	75	4,339	864	35	183	10,100	0
1993	64	4,457	901	43	187	10,421	0
1994	75	5,100	855	58	195	10,479	0
1995	78	5,390	1,052	28	192	10,669	0
1996	99	4,886	999	16	186	11,070	0
1997	71	5,718	792	8	197	10,782	0
1998	102	5,350	797	62	206	11,145	0
1999	121	5,536	836	12	208	11,334	0
2000	134	5,812	747	11	205	11,139	0
2001	109	6,200	756	20	188	11,079	0

* Less than 0.5.

[1] Includes military and non-military use.
[2] Includes deliveries for military use, railroad use and highway use.
[3] Non-military use only of kerosene-type jet fuel.
[4] DOE has numerous caveats on its allocation of LPG consumption to the various sectors.
[5] This table does not cover all uses of gasoline included in "Highway Use of Motor Fuel" in Table P11.
[6] Includes military use and railroad use.

NOTE: DOE models provide the best consumption estimates publicly available. However, the continuity of these data series estimates may be affected by changing data sources and estimation methodologies, which may account for some of the more dramatic year-to-year variation in consumption levels. See the "Additional Notes" under each type of energy in Technical Notes (http://www.eia.doe.gov/emeu/states/sep_fuel/notes/_fuelnotes_multistate.html#use_technotes). Additionally, this table revises DEQ's 2002 report in the Distillate Fuel category, for 1984-1999.

SOURCE: U.S. Department of Energy, Energy Information Administration, *State Energy Data Consumption* tables (formerly *State Energy Data Report*), 1960-2001 (see Revised Historical Data at http://www.eia.doe.gov/emeu/states/sep_fuel/notes/_fuelnotes_multistate.html#use_technotes as of June 2004).

Table P11. Motor Fuel Use, 1960-2002 (thousand gallons)

Year	Highway Use of Motor Fuel Gasoline	Diesel	Subtotal	Nonhighway Use of Motor Fuel (gasoline)	Losses Due to Evaporation, Handling, etc.	TOTAL Consumption of Motor Fuel
1960	242,430	27,216	269,646	69,974	3,150	342,770
1961	240,490	31,255	271,745	89,218	3,360	364,323
1962	274,043	30,311	304,354	41,413	3,654	349,421
1963	267,671	33,447	301,118	46,958	3,738	351,814
1964	273,144	35,294	308,438	42,657	3,612	354,707
1965	280,705	38,879	319,584	48,872	3,906	372,362
1966	269,659	43,253	312,912	40,736	3,780	357,428
1967	300,192	40,668	340,860	44,078	3,990	388,928
1968	321,429	45,756	367,185	40,607	4,032	411,824
1969	342,954	49,868	392,822	27,902	4,074	424,798
1970	352,654	58,136	410,790	39,654	4,242	454,686
1971	372,174	61,295	433,469	33,345	4,242	471,056
1972	394,482	69,145	463,627	42,185	4,368	510,180
1973	432,272	76,954	509,226	35,933	4,662	549,821
1974	412,004	72,955	484,959	31,842	4,452	521,253
1975	404,957	72,682	477,639	45,256	4,494	527,389
1976	449,092	87,051	536,143	46,148	4,998	587,289
1977	431,617	89,381	520,998	42,667	4,452	568,117
1978	511,119	100,375	611,494	38,123	5,208	654,825
1979	443,580	103,756	547,336	44,112	5,250	596,698
1980	416,511	98,615	515,126	40,788	4,662	560,576
1981	423,780	108,849	532,629	44,001	4,704	581,334
1982	406,462	110,864	517,326	40,371	4,410	562,107
1983	418,919	105,234	524,153	33,306	4,494	561,953
1984	416,324	117,012	533,336	34,828	-	568,164
1985	403,929	109,043	512,972	37,675	-	550,647
1986	404,386	107,192	511,578	36,006	-	547,584
1987	407,673	108,341	516,014	33,187	-	549,201
1988	412,126	117,389	529,515	33,710	-	563,225
1989	408,306	120,917	529,223	35,714	-	564,937
1990	410,718	125,346	536,064	36,646	-	572,710
1991	409,896	116,176	526,072	36,365	-	562,437
1992	432,413	133,926	566,339	32,650	-	598,989
1993	441,553	139,443	580,996	29,807	-	610,803
1994	444,618	156,703	601,321	32,358	-	633,679
1995	447,134	159,632	606,766	34,258	-	641,024
1996	466,331	146,177	612,508	36,169	-	648,677
1997	454,226	175,736	629,962	35,250	-	665,212
1998	469,369	172,711	642,080	26,862	-	668,942
1999	480,754	185,212	665,966	26,486	-	692,452
2000	469,683	190,450	660,133	26,394	-	686,527
2001	467,567	198,232	665,799	32,041	-	697,840
2002	476,027	202,477	678,504	33,151	-	711,655

NOTE: Motor fuel is defined by the US Department of Transportation as all gasoline covered by state motor fuel tax laws plus diesel fuel and LPG used in the propulsion of motor vehicles. (The Montana data do not include any LPG.) Gasohol is included with gasoline. Military use of motor fuel and aviation jet fuel use are excluded from DOT data. Figures for highway use of fuels may be understated because of refunds given on fuel for nonhighway use such as agriculture.

Starting in 1984, losses due to evaporation and handling are no longer calculated by FHWA. Total consumption of motor fuel from 1984-2002, therefore, does not include this figure. To compare the total for these years to the total for the previous years, the losses should be subtracted from the 1950-83 total consumption column.

SOURCE: U.S. Department of Transportation, Federal Highway Administration, *Highway Statistics* , annual reports, 1960-2002.

Table P12a. Monthly Deliveries of Gasoline 1998-2003 (1000 gallons/day)[1]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL (1,000 gal.)
1998	1,076	1,122	1,201	1,273	1,354	1,496	1,753	1,633	1,443	1,321	1,232	1,224	491,119
1999	1,071	1,148	1,317	1,235	1,343	1,533	1,735	1,654	1,473	1,326	1,330	1,326	502,166
2000	1,029	1,184	1,231	1,200	1,419	1,559	1,647	1,632	1,383	1,328	1,272	1,192	490,570
2001	1,115	1,162	1,212	1,293	1,385	1,452	1,665	1,693	1,372	1,363	1,293	1,230	494,358
2002	1,145	1,193	1,239	1,254	1,416	1,516	1,752	1,690	1,475	1,405	1,300	1,242	506,322
2003	1,171	1,183	1,130	1,251	1,436	1,570	1,754	1,666	1,418	1,500	1,179	1,246	502,674
avg.	1,101	1,165	1,222	1,251	1,392	1,521	1,718	1,662	1,427	1,374	1,268	1,243	497,868

[1]These data are from motor fuel tax collections and are supposed to cover all gasoline delivered for any purpose in Montana. On-road use of diesel accounts for over half these totals. The volumes come from distributors' bills of lading and therefore do not directly correlate with consumption; this may explain some more extreme month to month variation.

Source: Montana Department of Transportation motor fuel tax data base, July 2004.

Table 12b. Monthly Deliveries of Diesel 1998-2003 (1000 gallons/day)[1,2]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL (1,000 gal.)
1998	756	715	773	937	902	985	1,050	1,104	1,024	1,066	860	787	333,809
1999	911	885	1,052	1,103	1,038	1,052	1,115	1,158	1,052	1,028	986	1,506	392,680
2000	751	823	980	952	1,021	887	996	1,135	991	1,065	960	819	347,282
2001	967	902	878	1,049	1,083	1,056	1,147	1,193	994	1,135	906	855	370,436
2002	1,082	708	740	777	761	892	1,028	1,016	951	970	803	720	318,340
2003	924	803	823	978	1,010	990	1,119	1,171	1,023	1,198	943	897	361,915
avg.	899	806	874	966	969	977	1076	1130	1006	1077	910	931	354,077

[1]These data are from motor fuel tax collections and are supposed to cover all diesel, dyed and undyed, delivered for any purpose in Montana. The volumes come from distributors' bills of lading and therefore do not directly correlate with consumption; this may explain some more extreme month to month variation.

Source: Montana Department of Transportation motor fuel tax data base, July 2004.

Table P13. Average Retail Price of Gasoline, 1990-2004 (cents/gallon)[1]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1990	109.2	107.7	108.5	109.4	110.9	112.2	112.6	130.0	138.2	144.1	142.8	139.5
1991	132.2	126.0	114.3	114.1	117.2	118.9	118.7	118.7	119.2	118.5	118.0	115.1
1992	109.6	105.2	107.3	110.7	118.8	127.3	131.7	131.5	129.6	127.8	126.0	121.6
1993	115.3	111.8	112.6	115.2	120.2	122.4	124.6	124.5	126.2	128.3	128.1	123.9
1994	116.5	114.6	114.2	116.1	124.4	128.5	133.0	133.2	134.1	132.3	129.7	127.3
1995	122.6	122.0	120.2	122.9	129.4	129.0	127.0	125.7	127.3	127.0	123.8	122.1
1996	121.7	125.3	130.8	140.1	141.1	139.6	137.7		142.1	142.1	139.9	138.5
1997	138.4	137.3	138.1	137.5	137.4	136.6	135.7	136.9	137.7	138.9	137.4	133.0
1998	129.1	124.5	121.3	122.1	121.9	121.3	121.8	121.5	121.4	119.0	114.8	106.7
1999	100.2	99.4	104.4		130.1	130.3	136.8	138.8	140.7	139.0	141.7	
2000	139.5	147.0	161.2	159.5	158.9	159.4	159.6	159.6	163.5	172.7	168.9	166.2
2001	151.1	150.5	147.2	154.8	169.3	161.2	154.0	157.7	157.6	147.5	128.9	119.2
2002		121.8	137.3		147.6	147.9	148.5	147.6	145.6	144.9	146.0	142.4
2003	150.7	166.4	168.3	160.9	157.2	156.1	161.0	167.3	167.4	158.8	157.4	153.0
2004	154.4	159.3	168.7									
Average	127.9	127.9	130.3	130.3	134.6	135.1	135.9	137.9	139.3	138.6	136.0	131.4
Median	125.9	124.5	121.3	122.5	129.8	129.7	134.4	133.2	138.0	139.0	133.6	127.3

[1]State-wide average price of sales to end users through retail outlets, in nominal dollars.

Source: U.S. Department of Energy, Energy Information Agency, Form EIA-782A and Form EIA-782B data bases; also appears in *Petroleum Monthly*, Table 31, as of June, 2004.

Table P14. Estimated Price of Motor Fuel and Motor Fuel Taxes, 1970-2003

YEAR	Motor Gasoline ($/gallon)	State Tax (¢/gallon)	Date Changed	Federal Tax (¢/gallon)	Date Changed	Diesel ($/gallon)	State Tax (¢/gallon)	Date Changed	Federal Tax (¢/gallon)	Date Changed	Gasohol State Tax (¢/gallon)	Date Changed	Gasohol Fed. Tax (¢/gallon)	Date Changed
1970	0.36	7		4		0.21	9		4					
1971	0.37	7		4		0.22	9		4					
1972	0.35	7		4		0.22	9		4					
1973	0.40	7		4		0.25	9		4					
1974	0.54	7		4		0.40	9		4					
1975	0.60	7.75	June 1	4		0.41	9.75	June 1	4					
1976	0.61	7.75		4		0.43	9.75		4					
1977	0.66	8	July 1	4		0.48	10	July 1	4					
1978	0.69	8		4		0.50	10		4					
1979	0.88	9	July 1	4		0.71	11	July 1	4		2	April 1	0[1]	Jan. 1
1980	1.07	9		4		1.03	11		4		2		0	
1981	1.31	9		4		1.20	11		4		2		0	
1982	1.30	9		4		1.17	11		4		2		0	
1983	1.15	15	July 1	9	April 1	0.99	17	July 1	9	April 1	15	July 1	4	Apr. 1
1984	1.16	15		9		1.00	17		15	Aug. 1	15		4	
1985	1.16	15		9		0.94	17		15		15		3	Jan. 1
1986	0.90	17	Aug. 1	9		0.95	17		15		17	Aug. 1	3	
1987	0.98	20	July 1	9.1	Jan. 1	0.98	20	July 1	15.1	Jan. 1	20	July 1	3.1	Jan. 1
1988	0.99	20		9.1		1.01	20		15.1		20		3.1	
1989	1.10	20		9.1		1.13	20		15.1		20		3.1	
1990	1.22	20		14.1	Dec. 1	1.27	20		20.1	Dec. 1	20		8.7[2]	Dec. 1
1991	1.19	20		14.1		1.24	20		20.1		20		8.7[2]	
1992	1.22	21	July 1	14.1		1.23	21	July 1	20.1		21	July 1	8.7[2]	
1993	1.22	24	July 1	18.4	Oct. 1	1.24	24	July 1	24.4	Oct. 1	24	July 1	13[2]	Oct. 1
1994	1.27	27	July 1	18.4		1.24	27.75	July 1	24.4		27	July 1	13[2]	
1995	1.25	27		18.4		1.25	27.75		24.4		27		13[2]	
1996	1.37	27		18.3	Jan. 1	1.40	27.75		24.3	Jan. 1	27		12.9[2]	Jan. 1
1997	1.37	27		18.4	Oct. 1	1.20	27.75		24.4	Oct. 1	27		13[2]	Oct. 1
1998	1.20	27		18.4		1.31	27.75		24.4		27		13[2]	
1999	1.31	27		18.4		1.30	27.75		24.4		27		13[2]	
2000	1.60	27		18.4		1.63	27.75		24.4		27		13[2]	
2001	1.51	27		18.4		1.49	27.75		24.4		27		13.1[2]	Jan. 1
2002	1.40	27		18.4		NA	27.75		24.4		27		13.1[2]	
2003	1.61	27		18.4		NA	27.75		24.4		27		13.2[2]	Jan. 1

[1] Gasohol was not defined in federal tax law until 1979. Products later defined as gasohol (10 percent ethanol by volume) were taxable as gasoline until 1979. From 1979 to 1983, gasohol was exempt from gasoline tax.

[2] Blends using methanol, and amounts of ethanol between 5.7 and 10 percent, were taxed at lower rates.

NOTES: Price is average of all grades, in nominal dollars, including state and federal per gallon fuel taxes. All prices except 1984-2003 gasoline prices are derived from the *State Energy Price and Expenditure Report*, which reports prices in $/million Btu. The source database for gasoline prices 1984-2003 omits all fuel taxes; therefore, DEQ added those taxes into the figures presented here. The source document omits federal diesel fuel tax from 1970-82; therefore, the federal tax has been added and is included in the 1970-82 diesel prices listed above. See the source document for information on changes over time in the data sources and in the estimation methods used. In particular, note that diesel prices from 1984 forward are estimated as the ratio of the PAD IV diesel fuel price to the PAD IV motor gasoline price times the State motor gasoline price, plus federal and state per gallon taxes. PAD IV includes Colorado, Idaho, Montana, Utah and Wyoming.

SOURCES: Gasoline prices for 1984-2003 are from U.S. Department of Energy, Energy Information Administration, *Petroleum Marketing Annual,* Refiner/Reseller Motor Gasoline Prices by Grade, Sales to End Users Through Company Outlets, annual reports, 1985-2003 (EIA-0487). All other fuel prices are from U.S. Department of Energy, Energy Information Administration, *State Energy Data 2002 Price and Expenditure Data* (formerly, *State Energy Price and Expenditure Report*, annual reports 1970-2002 (EIA-0376). Pre-1986 diesel fuel prices may include non-highway diesel costs. Tax rates are from U.S. Department of Transportation, Federal Highway Administration, *Highway Statistics*, annual reports 1970-2002.