UNDERSTANDING ENERGY IN MONTANA

2023

ACKNOWLEDGEMENTS

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Montana's energy industry continues on a dynamic course of change, garnering significant public interest in the state. In recent years, consumers and the energy sector workforce have witnessed growth in wind and solar energy resources, a changing coal and petroleum industry, mainstream emergence of electric vehicles and new home heating and cooling options. Meanwhile, utilities are navigating the growing risks of extreme weather events, the retirement of traditional energy resources, and new opportunities in energy storage and regional electricity markets.

This edition of Understanding Energy in Montana builds on two decades of analysis and updates by the Montana Energy Office, housed in the Department of Environmental Quality (DEQ), in partnership with the Montana Legislature. The Legislature's Energy and Telecommunications Interim Committee in 2021 agreed to again revise this guide to provide updated information to Montana policymakers, energy sector stakeholders and the Montana public.

The 2023 edition includes a restructured electricity section to better reflect the current nature of electricity generation in the state. The guide focuses on recent and historical trends in energy supply and demand and is divided in to five sections. The first is an overview of electricity supply and demand in Montana. The section is further divided into chapters concerning major generating resource types in the state. The second section details the electric transmission grid, how it works and constraints on transmission capacity in the state. The third section addresses natural gas supply and demand. The fourth section covers the coal industry in Montana, detailing the mining history of the state and the present state of coal extraction in Montana. The final section of the guide addresses the state's petroleum production and refining.

Understanding Energy in Montana provides readers both historical and current perspectives on the large and complex energy sector in Montana. Emerging resources like distributed generation and energy efficiency programs are discussed along with traditional generation resources in an effort to best understand this changing industry.

Special thanks should be extended to the DEQ and Legislative staff listed at the front of this guide. Their work in preparing information and compiling statistics was integral to the publication of this document.

COMMENTS ON THE DATA

Data for this guide comes from several sources, which do not always align. This is due to slightly different data definitions and methods of data collection between the sources referenced. The reader should always consider the source and context of specific data.

A significant amount of data used in this publication comes from utilities that operate in Montana. This includes NorthWestern Energy and Montana-Dakota Utilities. The petroleum industry has also been very cooperative in this effort. Another significant source of data, especially for the maps and charts, is the U.S. Department of Energy's Energy Information Administration. The authors would like to thank these entities for their help.

Please send data corrections to mtenergy@mt.gov

1. ELECTRICITY SUPPLY AND DEMAND IN MONTANA

1A. OVERVIEW OF ELECTRICITY GENERATION AND DEMAND

As Montana's electricity sector continues to evolve with the rest of the nation, supply and demand are increasingly influenced by complex national trends. The decarbonization goals and policies of other states are impacting Montana's electric generation mix, which is steadily shifting to include a higher percentage of variable renewable sources. Two of the Colstrip Power Plant's four generating units were shuttered by their owners in 2020 and utilities serving west coast customers are readying to exit the plant by 2025, leaving an uncertain future for the remaining Units 3 and 4. Development of new in-state generation is being led by wind resources, natural gas, solar assets, and increasingly, large-scale batteries. Evolving regional real-time energy markets and resource sharing pools are modernizing management of energy resources and loads while giving Montana utilities and energy producers access to new markets (see chapter 2 for a detailed discussion of regional transmission integration and electricity market development).

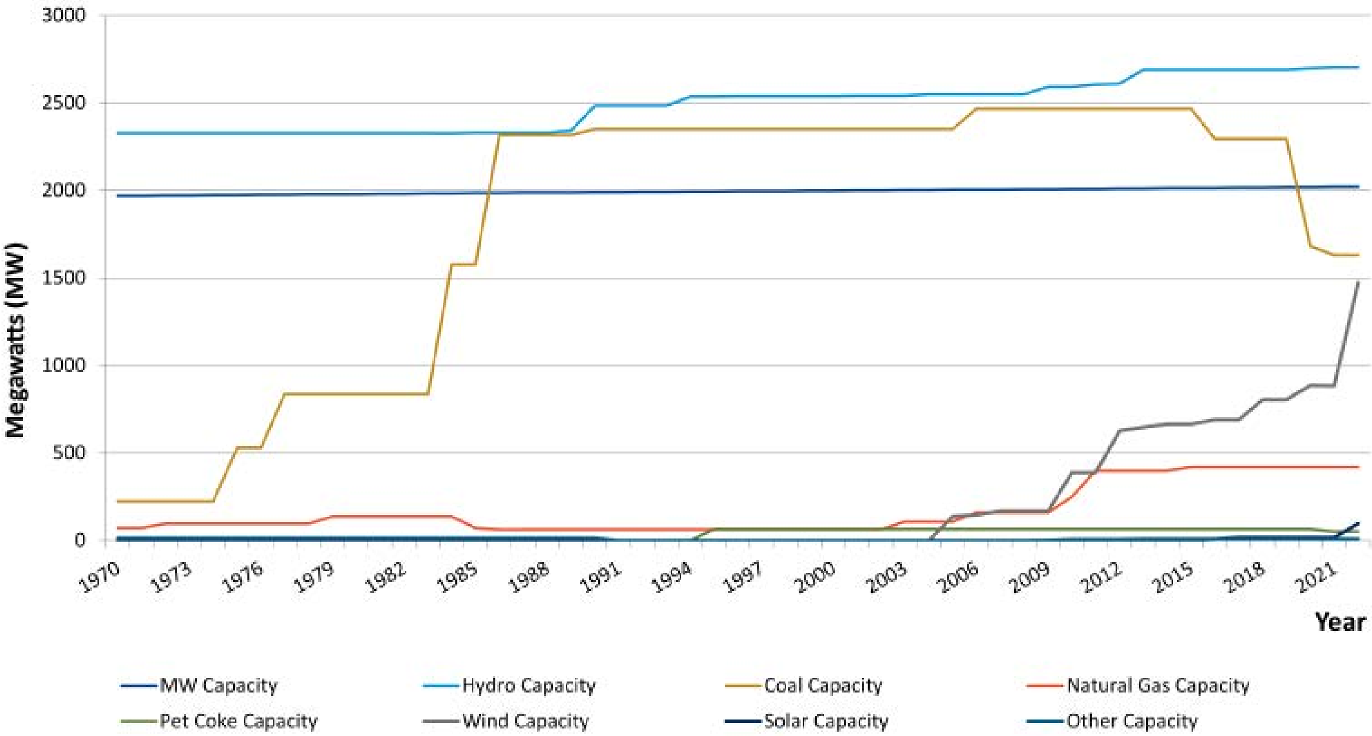
In-state electricity demand has remained flat in recent decades due to a higher penetration of energy efficiency and flat industrial demand. However, electricity demand could increase as transportation and other economic sectors electrify, and as Montana's population steadily increases.

Montana electricity consumers are served by a mix of 33 utilities. NorthWestern Energy, Montana's largest electric utility, emerged from bankruptcy in late 2004 and has gradually established a portfolio of utility-owned generating assets across the state that includes hydro electric dams, a portion of the Colstrip generating station, wind farms, and natural gas generation.

Electricity Facts for Montana 2021
Generation Capability: 5,950 Megawatts (MW)
Average Generation: (2016-2020)—3,075 aMW
Average Load (demand): 1,700 aMW

Montana exports approximately 40 percent of the energy generated in the state, and yet is a relatively small player in the larger western U.S. electricity market. As of 2022, Montana generating plants have the capacity to produce about 5,950 Megawatts (MW) of electricity. This number changes year-to-year with plant closures and construction of new generation resources. Plants do not run constantly, nor do they produce exactly the same amount of electricity every year. For example, the output from hydroelectric generators depends on the rise and fall of river flows, and any type of plant requires downtime for refurbishing and repairs.

Figure 1.1 Montana Electric Power Generating Capacity by Fuel Type, 1970-2022 (Total MW Capacity)[1]



Montana generators in total produced 3,278 aMW (average Megawatts) from 2006 to 2010, 3,325 aMW from 2011 to 2015, and 3,075 aMW from 2016 to 2020. Montana usage accounts for just over half of total in-state production, or about 1,700 aMW.[2] Transmission line losses account for less than 10 percent of total electricity produced. The rest of Montana electricity production is contractually exported west to Idaho, Washington and Oregon via the Colstrip transmission lines, or north to Alberta and south into Wyoming via other high voltage lines. The Colstrip coal generation plant, the Glacier and Rimrock Wind Farms, and a few of the larger dams in northwestern Montana account for the vast majority of contracted Montana electricity exports. Notably, for the first time in decades, hydropower emerged as the largest form of energy generation in 2020.

1B. DEREGULATION AND REGULATION OF MONTANA UTILITIES

In January 1997, the Montana Power Company and a number of Montana's large energy customers brought forward a legislative proposal (Senate Bill 390) to deregulate retail electricity supply in Montana. Montana's electricity laws and policies have received significant public attention and scrutiny since that time, when

1 *Current generation capacity is initially taken from U.S. DOE Energy Information Administration, EIA-923 and EIA-860 Reports, except where noted: Flathead Landfill Gas to Energy-John Gorosky, Flathead coop; MDU facilities-Darcy Neigum, MDU; YELP-Kelli Schermerhorn NWE and Dan Carter at Exxon; Noxon Dam-Steve Esch, Avista; NorthWestern Energy facilities-Benjamin Fitch-Fleischmann, NWE--large hydro updated by Carrie Harris, NWE; Boulder Creek, Steve Clairmont; NWE QFs including YELP, CELP, Two Dot Wind Farm, Broadwater Dam, South Dry Creek, Gordon Butte, Fairview, QF other hydro and QF other wind-Kelli Schermerhorn, NWE; Culbertson Waste Heat/Ormat Technologies--Basin Electric; Lake Creek-Clint Brewington, Northern Lights Cooperative; additional Fort Peck Dam information from Dale Pugh, USACE. Generation capacity over time from Montana Energy Office institutional knowledge.*

2 *U.S. EIA, 2017.*

Montana decided to deregulate electricity supply and opted to allow some Montana consumers to choose, given a competitive market, their own electricity supplier. At the time, it was a fundamental policy shift for the state from regulating the price of electricity supply to allowing competitive markets to set the price of electricity supply. It was also a shift that would dominate the energy policy discussion in Montana for the next 20 years.

The fundamental premise of Montana's restructuring law was that competition would provide greater benefits to consumers than they would otherwise have received under a historically regulated environment. One of the driving forces behind restructuring was a 1996 decision by the Federal Energy Regulatory Commission to deregulate electricity supply markets at the wholesale level. Wholesale transactions involve the sale of electricity from large suppliers (i.e., power producers) to large electricity buyers and sellers (utilities, power marketers, etc.).

In January 1997, the Montana Power Company and a number of Montana's large customers brought forward a legislative proposal to deregulate retail electricity supply. The reasons stated in the testimony before the Montana Legislature to pass Senate Bill 390 were:

Competitive markets would provide Montana electricity consumers with cheaper prices over the long term.

- Congress was seriously contemplating national deregulation legislation, and Montana should take a leadership position so that the federal government would grandfather in our policy choices.
- Montana's large industrial customers were looking at an electricity supply market that was cheaper than the traditional regulated utility supply. If they could get better prices, it would enhance plant profitability and promote economic development in Montana.
- The Montana Power Company needed to be proactive in a competitive environment that was emerging, as opposed to reactive.
- Competition is here, wholesale power supply markets are competitive, and large customers are demanding retail access.

The legislation passed 36-14 in the Senate and 78-21 in the House of Representatives. Montana joined several other states that had already enacted legislation or adopted policies to implement customer choice. In passing Senate Bill 390 (Chapter 505, Laws of 1997), the 1997 Legislature noted that competitive markets exist, that Montana customers should have the freedom to choose their electricity supplier, that Montana consumers should be protected, and that the financial integrity of Montana utilities should be maintained.[3]

Restructuring and customer choice applied primarily to the Montana Power Company service territory, but it also applied to PacifiCorp's territory in Northwest Montana. PacifiCorp, which served about 36,000 Montana customers primarily in Flathead and Lincoln counties, put its Montana distribution facilities up for sale and announced that Flathead Electric was the successful bidder. At the time, the Public Service Commission (PSC) processed transition plans for both Montana Power Company and PacifiCorp. Rural electric cooperatives were

3 *For text of testimony in support and in opposition, see the committee minutes of Senate Bill 390 during the 1997 legislative session.*

allowed to determine whether their customers would be offered a choice of electricity supplier. Because North Dakota is the primary service territory of Montana-Dakota Utilities, that utility originally was allowed to defer customer choice until July 1, 2006.

Deregulation was a highly controversial decision, and one the Legislature did not take lightly.

"In the legislative debate over Senate Bill 390, one thing that proponents and opponents managed to agree upon was the importance of the issue.I don't know that I'll ever carry legislation that is more significant," reflected Senator Fred Thomas (R-Stevensville), the lead sponsor.

And the lead opponent, Rep. David Ewer (D-Helena), commented quite plainly, "This bill is the most economically significant bill of the session and one of the most economically significant of our history."[4]

By the end of 1999, the Montana Power Company ultimately sold most of its generating units to Pennsylvania Power and Light Montana (PPL Montana/Talen Energy/Riverstone Holdings). The company sold its generation assets to PPL for $757 million. The sales price was a little over $150 million higher than the estimated book value of the generation assets. As a result, Montana Power Company proposed a 4 percent rate reduction in energy supply through the remainder of the then-transition period through June 2002. The remainder of Montana Power Company's contracts and leases, including qualifying facility (QF) contracts and the entire transmission and distribution utility, was sold to NorthWestern in February 2002. NorthWestern paid $1.1 billion to buy the electric transmission and distribution assets and natural gas properties in Montana. That acquisition was largely financed with debt and helped drive NorthWestern into bankruptcy – addressed later in this chapter. By June 2003, Touch America, the telecommunications company spun off of Montana Power, also filed for bankruptcy.

Under the provisions of Senate Bill 390, the governance of restructuring was shared by the PSC and a multifaceted Transition Advisory Committee (TAC) that combined legislators, executive branch appointees, representatives from industry, labor, and consumer groups, and was funded entirely by contributions from the private sector. The TAC's job was to monitor the transition to competition as set forth in state law, and the PSC's job was to craft and enforce implementing rules.

In 2001, the California energy crisis began to unfold, with wholesale energy prices in California increasing by 270 percent from the previous year.[5] Suspicion that Enron and other power marketers and suppliers were gaming the California system to maintain high electricity prices also began to surface. The power crisis spilled over into other states as California scrambled to secure out-of-state power. Wholesale energy prices in the Pacific Northwest rose to unprecedented levels.[6] "Although the new legislation had little immediate effect on small customers, large industrial customers were able in 1998 to obtain electrical energy from cheaper suppliers than the Montana Power Company (MPC). Otherwise, regulators, MPC, public interest groups, the TAC, and others muddled through the arcana of transition plans, stranded costs, rules for the licensure of 'can't wait to market in Montana' power suppliers, and the inevitable litigation. Except for noticing that our electricity bills detailed the separate costs of energy generation, transmission, and distribution, most of us were blithely unaware of the awesome choice awaiting us," according to an early TAC report.

However, some industrial customers were hit hard by the increased market prices attributed to the California energy crisis. In addition, when cost-based rates expired at the end of the transition period, Montana Power Company, later NorthWestern Energy, utility customers did see significant rate increases associated with the transition to market-based rates. Between May 2001 and July 2003, the

4 *Montana's power trip: Electric deregulation consumers and the environment, Patrick Judge, University of Montana, Graduate School Thesis, 2000, page 13.*

5 *The Congress of the United States, Congressional Budget Office, Causes and Lessons of the California Electricity Crisis, (Washington, DC, September 2001), p. viii.*

6 *The Electrical Utility Industry Restructuring Transition Advisory Committee," a report to the Governor and 58th Legislature, Jeff Martin and Todd Everts, December 2002.*

average residential bill increased by 20 percent.

The 2001 Legislature was faced with the energy crisis and questions about Montana's decision to deregulate in 1997. In response, the Legislature enacted House Bill 474. It extended the transition period to competition to July 1, 2007. The bill also designated the default supplier as the customers' distribution supplier and required that the distribution services provider have an ongoing regulated default supply obligation beyond the end of the transition period. Customers who chose an alternative electrical energy supplier (primarily large industrial customers) were also given an opportunity to receive electrical energy from the default supplier.

House Bill 474 also authorized a Montana Power Authority to purchase, construct, and operate electrical generation facilities or electrical energy transmission or distribution systems and to enter into joint ventures for these purposes. The Board of Examiners was authorized to issue revenue bonds (not to exceed $500 million) for the Montana Power Authority to acquire electrical generation facilities and build electrical energy transmission or distribution systems.[7]

The 2001 Legislature also passed House Bill 645 creating a power pool designed to free up energy being supplied to Montana Power Company by PPL at cost based rates. The change allowed power to be used to bail out industrial customers that were shutting down and laying off workers due to high market prices. In March 2001, Montana Power Company also was evaluating bids from wholesale suppliers to provide energy once its buy-back contract with PPL expired on July 1, 2002. At the time those bids were in the range of $80-$100 per Megawatts per hour (MWh). The tumultuous times were just beginning.

Shortly after passage of House Bill 474, the PSC determined that the legislation not only protected ratepayers but also attempted to foster the financial integrity of the Montana Power Company as a public utility and as a distribution services provider – a serious conflict. PPL Montana and the Montana Power Company filed complaints against the PSC in federal district court and state district court, respectively, challenging the PSC's assertion of authority.[8]

About the same time, Representatives Michelle Lee of Livingston and Christopher Harris of Bozeman initiated a petition to refer House Bill 474 to the voters at a November 5, 2002 general election. They argued that the legislative process that led to the enactment of the legislation was flawed and was closed to public scrutiny. In addition, Montana taxpayers would be on the hook for a default on any energy loans provided by the Montana Board of Investments.[9] After a few legal stops, the referendum qualified for the ballot as Initiative Referendum 117. On November 5, 2002, the voters rejected House Bill 474 by a 60 percent to 40 percent margin. The decision, however, did not overturn deregulation. Another bill, for example, Senate Bill 19, also had passed in 2001 – extending customer transition to June 30, 2007. Senate Bill 269 had also passed in 2001, indefinitely delaying transition to competition for Montana Dakota Utilities.[10]

The November 2002 voters also were presented with Initiative 145 to "buy back" the dams in Montana. The initiative created an elected public power commission to determine whether purchasing hydroelectric dams in Montana was in the public interest and repealed the Montana Power Authority created by the 2001 legislature.[11] It was defeated 68 percent to 32 percent.

The 2003 Legislature continued to address the evolution of deregulation in Montana. The 2003 Legislature passed House Bill 509 addressing default supply planning, establishing an Energy and Telecommunications Interim Committee of the

7 *http://leg.mt.gov/content/publications/committees/interim/2001_2002/trans_adv_com/1158jfea.pdf*

8 *For an analysis of the Public Service Commission's assertion of regulatory authority over the default supplier's electricity supply obligation under House Bill No. 474 and contrary view of the apparent conflict in legislative intent under House Bill No. 474, see Greg Petesch, letter to Senator Fred Thomas, June 7, 2001, in Transition Advisory Committee, Minutes, June 19, 2001.*

9 *"The Electrical Utility Industry Restructuring Transition Advisory Committee," a report to the Governor and 58th Legislature, Jeff Martin and Todd Everts, December 2002.*

10 *http://leg.mt.gov/content/publications/committees/interim/2001_2002/trans_adv_com/1158jfea.pdf*

11 *http://sos.mt.gov/Portals/142/Elections/archives/2000s/2002/2002_VIP.pdf*

Legislature, and requiring a cost recovery mechanism. In addition, Senate Bill 247 was passed in the 2003 session allowing for preapproval of default supply resources. The Legislature also further extended the date for full customer choice until July 1, 2027. The PSC also continued to exert its regulatory authority. By August 2003, Montana customers, however, were paying some of the highest electricity rates in the region.[12]

In August 2003, the Montana Consumer Counsel petitioned the PSC to open a financial investigation into NorthWestern. In September 2003, NorthWestern filed for chapter 11 bankruptcy. In a written statement, then-Gov. Judy Martz called the bankruptcy filing another "unfortunate chapter" in the state's business history. NorthWestern said the financial decision would not lead to interruption of services to its 300,000 gas and electric customers.

While there was much finger-pointing about what role Montana regulators and legislators could have played to prevent the financial troubles, about a year later, NorthWestern announced it had officially emerged from bankruptcy and started trading its newly issued stock. In connection with the bankruptcy stipulations, the PSC approved a consent order in July 2004 between NorthWestern, the PSC, and the Consumer Counsel. The agreement remains in place today and stipulates aspects for rate review, certain regulatory controls, and some financial requirements.[13]

Montana's energy supply journey, however, continued, and in June 2006, NorthWestern and Babcock and Brown Infrastructure (BBI) filed a joint application with the PSC seeking the commission's approval of BBI's acquisition of NorthWestern. In 2007, the PSC unanimously denied the application, finding that the proposed $2.2 billion merger would present a risk to NorthWestern's financial integrity and to Montana customers of NorthWestern. [14]

Ultimately, competitive choice did not develop for small residential and commercial customers in the state, and with the approval of the "Electric Utility Industry Generation Reintegration Act" by the 2007 Legislature, the transition to customer choice ended for NorthWestern customers. The act also put NorthWestern on track to transition into a vertically integrated utility, owning both generation assets and transmission and distribution assets.

The 2007 Electric Utility Industry Restructuring and Customer Choice Act, or the "reregulation" bill as it was often called, allowed NorthWestern to own electric power plants again and to dedicate the power it produces to Montana customers. It significantly tailored customer choice, limiting the ability of retail customers with a monthly demand of less than 5,000 kilowatts (kW) to migrate to other electricity suppliers if those customers were receiving electricity from a public utility prior to October 2007.

Prior to the 2007 law, as previously discussed, a NorthWestern customer could choose an electricity supplier. If a customer was a member of a cooperative that did not open up to competition or a customer of Montana-Dakota, the price of retail electricity supply remained set by either the cooperative board or the PSC, respectively. For the most part, competitive markets did develop to serve large industrial electricity customers, and most of those customers selected alternative electricity suppliers.

The TAC, in its November 2000 annual report, described some positive results of the transition to competition. It found that most large industrial customers in Montana obtained electricity from suppliers other than Montana Power Company at cost savings of 5 percent to 10 percent. Both Glacier Electric Cooperative and Flathead Electric also opened their systems to competition. Flathead Electric purchased the distribution system of PacifiCorp and began serving PacifiCorp's former customers.[15] But the positive aspects also came with some caveats. As mentioned previously, some industrial customers were hard hit. The PSC also ended up filing an injunction in state district court to prevent PacifiCorp

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12 2002 Voter Information Pamphlet, Montana Secretary of State. http://sos.mt.gov/Portals/142/Elections/archives/2000s/2002/2002_VIP.pdf

13 PSC Docket D2003.8.019, Order No. 6505e.

14 PSC Docket D2006.6.82, Final Order 6754e.

15 http://leg.mt.gov/content/publications/committees/interim/1999_2000/tac/final1999report.pdf from selling the utility and fleeing the state to avoid what the PSC determined to be stranded benefits due to PacifiCorp's customers as a result of the transition to competition.

Market volatility and the lack of significant small-customer retail competition, however, forced the 2007 Legislature to effectively put an end to full customer choice. In January 2007, the Energy and Telecommunications Interim Committee requested that a bill be brought forward (House Bill 25) to move toward reregulation of Montana's retail electricity supply. The bill was amended several times and was the subject of much debate. The reasons stated in the testimony before the Legislature to pass House Bill 25 were:

- Competitive markets had not developed for small customers in Montana and electricity consumers were being exposed to higher market prices.
- NorthWestern, with no generation assets of its own, lacked power at the bargaining table when securing the supply it needed to meet customer demand.
- Continuing to have small customer choice in law while a competitive market didn't actually exist created electric load uncertainty that impeded NorthWestern's ability to plan for and procure electricity supply at optimal terms and prices.
- NorthWestern needed the ability to build new plants and dedicate that power to Montana customers at regulated, stable rates.[16]

In signing House Bill 25 (Chapter 491, Laws of 2007) in May 2007, former Governor Brian Schweitzer noted: "Potential benefits from HB 25 will only accrue down the road."

After passage of House Bill 25, if someone in Montana is a small customer of NorthWestern who did not choose an alternative electricity supplier prior to October 2007, that person is now part of the electricity supply load that is regulated by the PSC. Small NorthWestern customers still have the opportunity to purchase a separately marketed product composed of the environmental attributes or renewable energy credits from renewable resources – subject to a tariff and other limitations.

With changes made by the 2007 Legislature, NorthWestern also began pursuing its own generation assets, using the guidelines put into place in House Bill 25 and directing the PSC on the steps to be followed in reviewing and potentially approving NorthWestern's electricity supply resources. To ease concerns about financing new power plants, Montana law allows utilities to obtain pre-approval for certain, significant generating projects they hope to build or acquire. While preapproval was intended to provide some level of cost recovery assurance prior to constructing or acquiring generation assets, a Montana district court ruling on NorthWestern's application for pre-approval of generation and battery storage assets in 2022 found that the law is unconstitutional.

By 2015, owned generation resources supplied about 75 percent of NorthWestern's retail load requirements. NorthWestern owns about 854 megawatts, including 222 megawatts or a 30 percent share in Colstrip Unit 4, 150 megawatts of generation from the Dave Gates Generation Station, which is used as a regulating reserve plant, 40 megawatts from Spion Kop Wind, and 442 megawatts from the 2014 purchase of hydroelectric

16 *For the text of testimony in support and in opposition, see the committee minutes of House Bill No. 25 during the 2007 legislative session.*

generating facilities in Montana.[17]

In 2014 NorthWestern acquired the 11 hydroelectric facilities previously owned by Talen Energy Corp. (PPL Montana) representing 633 megawatts of capacity and one storage reservoir. The $900 million purchase of the hydroelectric generating facilities includes Thompson Falls Dam on the Clark Fork River; Kerr Dam on the Flathead River; Madison Dam on the Madison River; Mystic Lake Dam on West Rosebud Creek; and Hauser, Holter, Black Eagle, Rainbow, Cochrane, Ryan and Morony dams along the Missouri River. In 2015, Kerr Dam was transferred to Energy Keepers, Inc., a wholly owned corporation of the Confederated Salish and Kootenai Tribes.

The sale signaled the return of the dams to utility ownership -- about 15 years after they were sold by Montana Power Company during Montana's experiment with deregulation. To pay for the acquisition, NorthWestern customers are paying a rate increase amounting to about 5 percent or $4.20 per month for a typical residential customer.[18]

"The dams that are so much a part of Montana's environment and heritage are now dedicated to serve our Montana customers, at prices based on the cost of providing service, not on the western power market. Fifty years from now, as these assets are paid down, our children and grandchildren will appreciate the farsighted leadership of Montana PSC Chairman Gallagher and his colleagues, who made this possible," said Bob Rowe, NorthWestern's CEO.

The 2009 Legislature also continued to take steps to allow for utility integration. In approving House Bill 294 (Chapter 127, Laws of 2009), the Legislature allowed a natural gas utility that had restructured to acquire natural gas production and include it in the rate base. The revisions to the law also establish procedures for a utility to apply to the PSC for approval to include them in the rate base prior to the acquisition.

During the 2017 Legislature, questions were raised about NorthWestern's treatment in the current law, and whether all aspects of House Bill 25 should remain in place or whether NorthWestern has successfully transitioned into a vertically integrated utility.

The 2017 Legislature passed and approved House Bill 193, revising how NorthWestern's electricity cost recovery is conducted. It standardized the treatment of all public utilities, including NorthWestern, for the approval of cost-tracking adjustments. It eliminated an exemption allowing the utility to recover the full cost of power it purchases from other sources. The Montana Consumer Counsel supported the legislation and asked that a "relic of deregulation" be removed. NorthWestern opposed the bill and argued that it eliminated prudency in regulatory decisions.

"NorthWestern has struggled mightily to put humpty-dumpty together again," John Alke, representing NorthWestern, told the 2017 House Energy, Technology and Federal Relations Committee.

The company argued that the company still operates under a bankruptcy agreement and consent order entered into by the PSC, Montana Consumer Counsel, and company in July 2004 and therefore standardized treatment was inappropriate.[19]

With passage of the bill, the PSC in May 2017 initiated a process to develop a replacement electricity tracker for NorthWestern. The action became intertwined with other 2017 PSC decisions regarding qualifying facilities and contract lengths. The issue continues to simmer, with the PSC finding, "the commission remains interested in potential adjustment base rates."[20]

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17 https://www.northwesternenergy.com/docs/default-source/documents/ataglance/ataglancemt

18 http://billingsgazette.com/business/features/northwestern-purchase-of-montana-dams-complete/article_86bfb948-d78d-5098-98df-b579743b8436.html

19 For the text of testimony in support and in opposition, see the committee minutes of House Bill No. 193 during the 2017 legislative.

20 PSC Docket D2017.5.39, Order 7563.

1C. GENERATION

There are more than 50 major generating facilities in Montana. Montana's 10 largest electric generation plants are listed below by generating capacity and annual energy output **(Table 1.1 and Table 1.2)**. The oldest operating generating facility in Montana is Madison Dam near Ennis, built in 1906. The newest, is at the time of this publication, the Pryor Mountain Wind Farm in Carbon County, which was energized by owner PacifiCorp in 2021. Montana's largest generating facility is made up of the two privately owned coal-fired generating units at Colstrip. The combined capacity of the units totals 1,480 MW or about 26 percent of Montana's total current generation capacity. The largest hydroelectric plant in Montana is Avista's Noxon Rapids Dam, recently upgraded to 562 MW in capacity. The largest wind facilities are the 240 MW Pryor Mountain facility, and the 189 MW Rimrock and 210 MW Glacier Wind projects which are now owned by Berkshire Hathaway Energy and went on-line in 2012 and 2008 respectively.

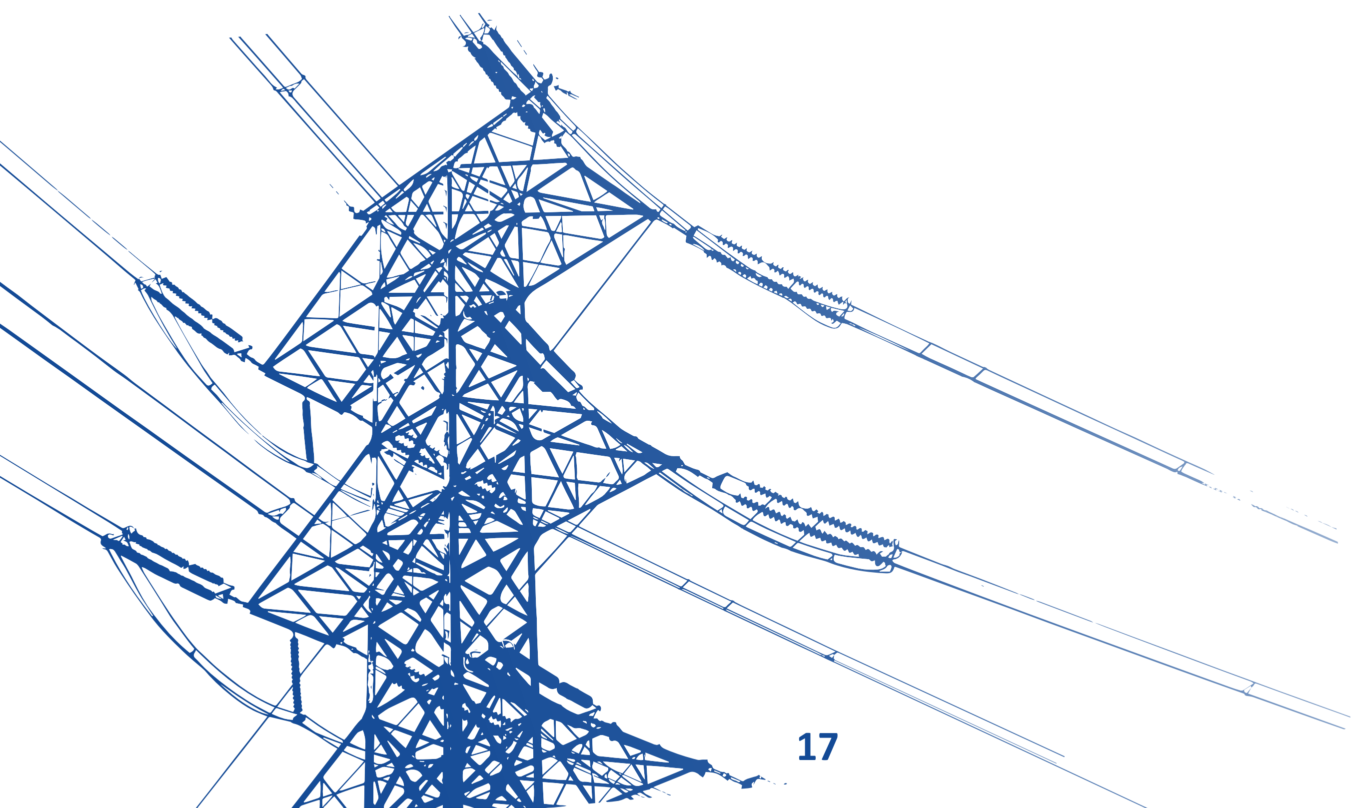


Table 1.1 Ten Largest Plants by Generation Output, 2020[21]

Plant	Primary Energy Source or Technology	Operating Company	2020 Output (MWh)
1. Colstrip	Coal	Talen Energy	7,935,170
2. Libby Dam	Hydroelectric	U.S. Army Corps of Engineers - North Pacific Division	2,310,881
3. Noxon Rapids Dam	Hydroelectric	Avista Corp	1,596,460
4. Fort Peck Dam	Hydroelectric	U.S. Army Corps of Engineers - Missouri River District	1,105,657
5. Sėliš Ksanka Ql͏́ispė Dam	Hydroelectric	Confederated Salish-and Kootenai Tribes	962,819
6. Hungry Horse Dam	Hydroelectric	U.S. Bureau of Reclamation	925,709
7. Yellowtail Dam	Hydroelectric	U.S. Bureau of Reclamation	780,391
8. Rim Rock Wind Farm	Wind	Morgan Stanley	705,585
9. Judith Gap Wind Farm	Wind	Invenergy Services LLC	517,396
10. Billings Generation Inc.	Petroleum Coke	Yellowstone Energy Partnership Ltd.	459,339

Table Summary: This table lists the largest generators in Montana by 2022 electrical output. Colstrip had the largest output by far. The next six largest generators were large hydro dams. Two wind farms and a petroleum coke plant rounded out the top ten.

21 *U.S. EIA data.*

Table 1.2 Ten Largest Plants by Generation Capacity, 2022[22]

Plant	Primary Energy Source or Technology	Operating Company	Net Summer Capacity (MW)
1. Colstrip*	Coal	Talen Energy	1,480
2. Noxon Rapids Dam	Hydroelectric	Avista Corp	562
3. Libby Dam	Hydroelectric	U.S. Army Corps of Engineers-North Pacific Division	525
4. Hungry Horse Dam	Hydroelectric	U.S. Bureau of Reclamation	428
5. Yellowtail Dam	Hydroelectric	U.S. Bureau of Reclamation	287
6. Pryor Mountain Wind Farm	Wind	PacifiCorp	240
7. Glacier	Wind	Morgan Stanley	210
8. Sėliš Ksanka Qĺispė Dam	Hydroelectric	Confederated Salish and Kootenai Tribes	206
9. Rimrock Wind Farm	Wind	Morgan Stanley	189
10. Fort Peck Dam	Hydroelectric	U.S. Army Corps of Engineers—Missouri River District	180

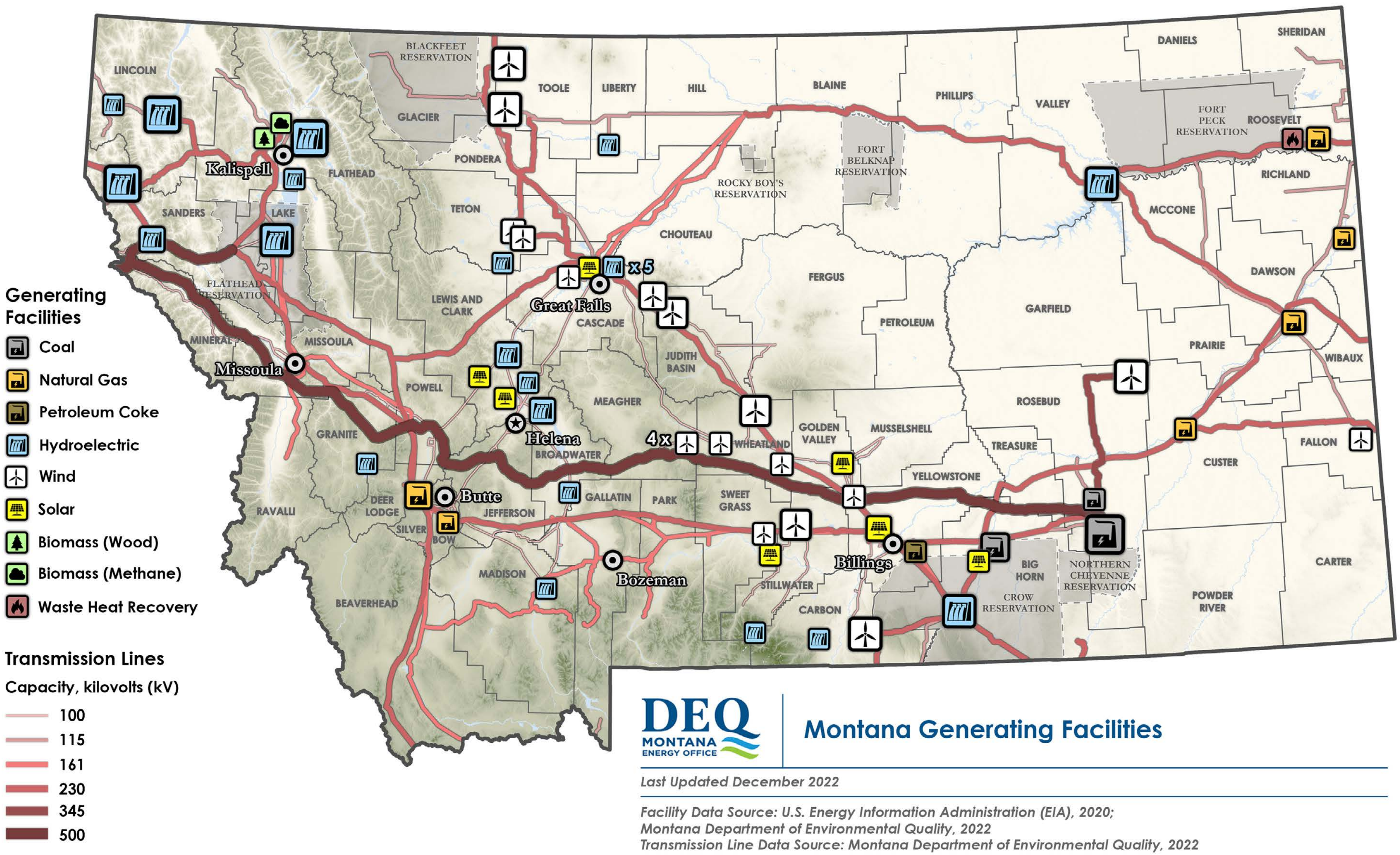
**Colstrip Units 3 and 4 are operated by Talen Energy; actual ownership is shared by six utilities. Units 1 and 2 closed in early 2020, bringing its nameplate capacity down to just under 1,500 MW.*

Table Summary: This table lists the largest generators in Montana by 2022 electric generation capacity. Colstrip is the largest plant by far. Large wind plants and hydroelectric dams round out the top ten.

NorthWestern, Avista, Talen, Puget Sound Energy and Federal Agency-owned facilities produce the largest percentage of electricity generated in Montana. These entities account for approximately 50 percent of all owned generation in the state. NorthWestern's generation is derived mostly from the company's hydroelectric dams, and a 30 percent share in Colstrip Unit 4. Talen and Puget Sound Energy's generation comes from the companies' shares in the Colstrip generating facility. Avista's ownership comes from its share in Colstrip and the Noxon Dam. The federal agencies own the large hydro dams in Montana not owned by NorthWestern or the Confederated Salish and Kootenai Tribes.

22 U.S. EIA data.

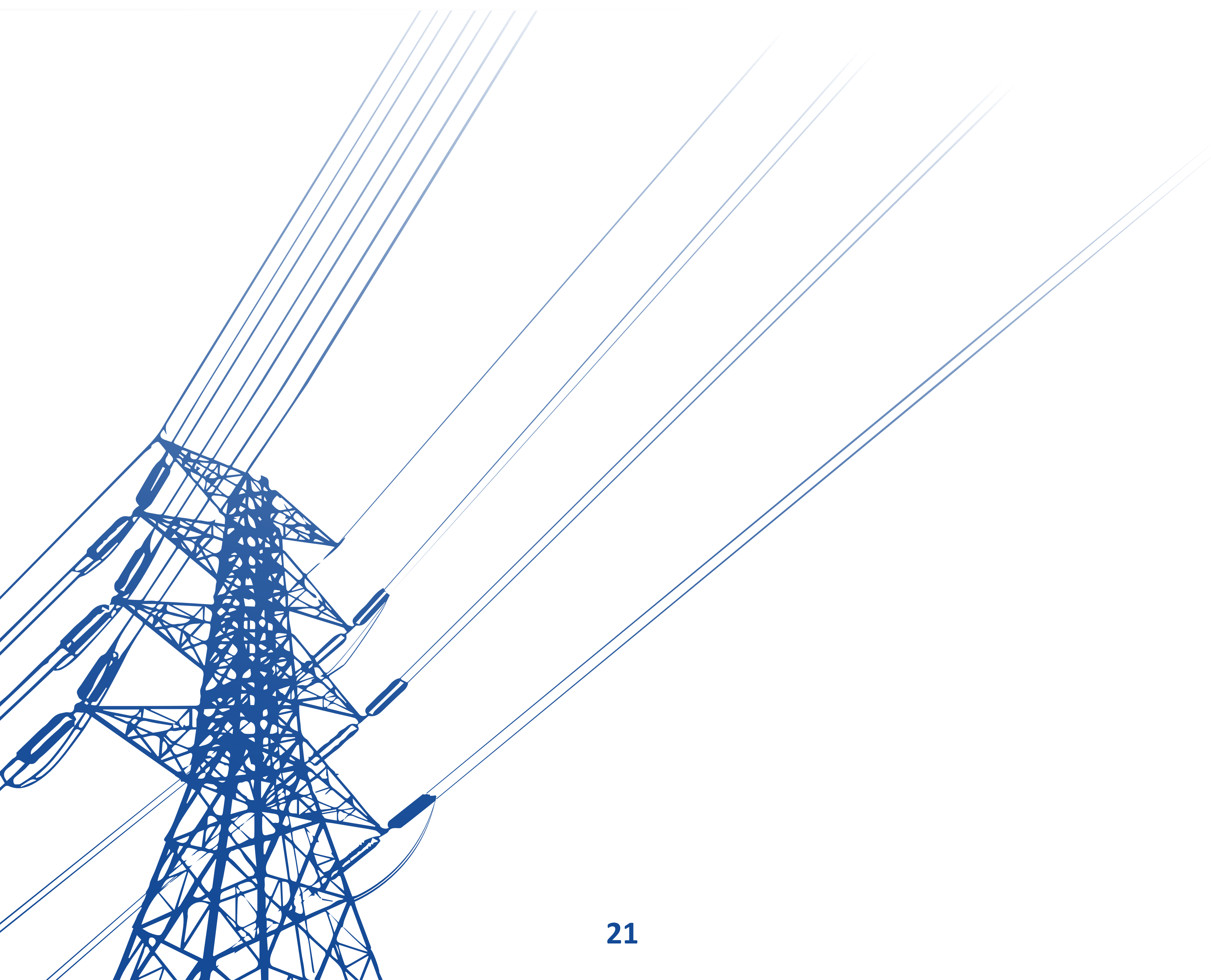
Map 1.1 Montana Generating Facilities



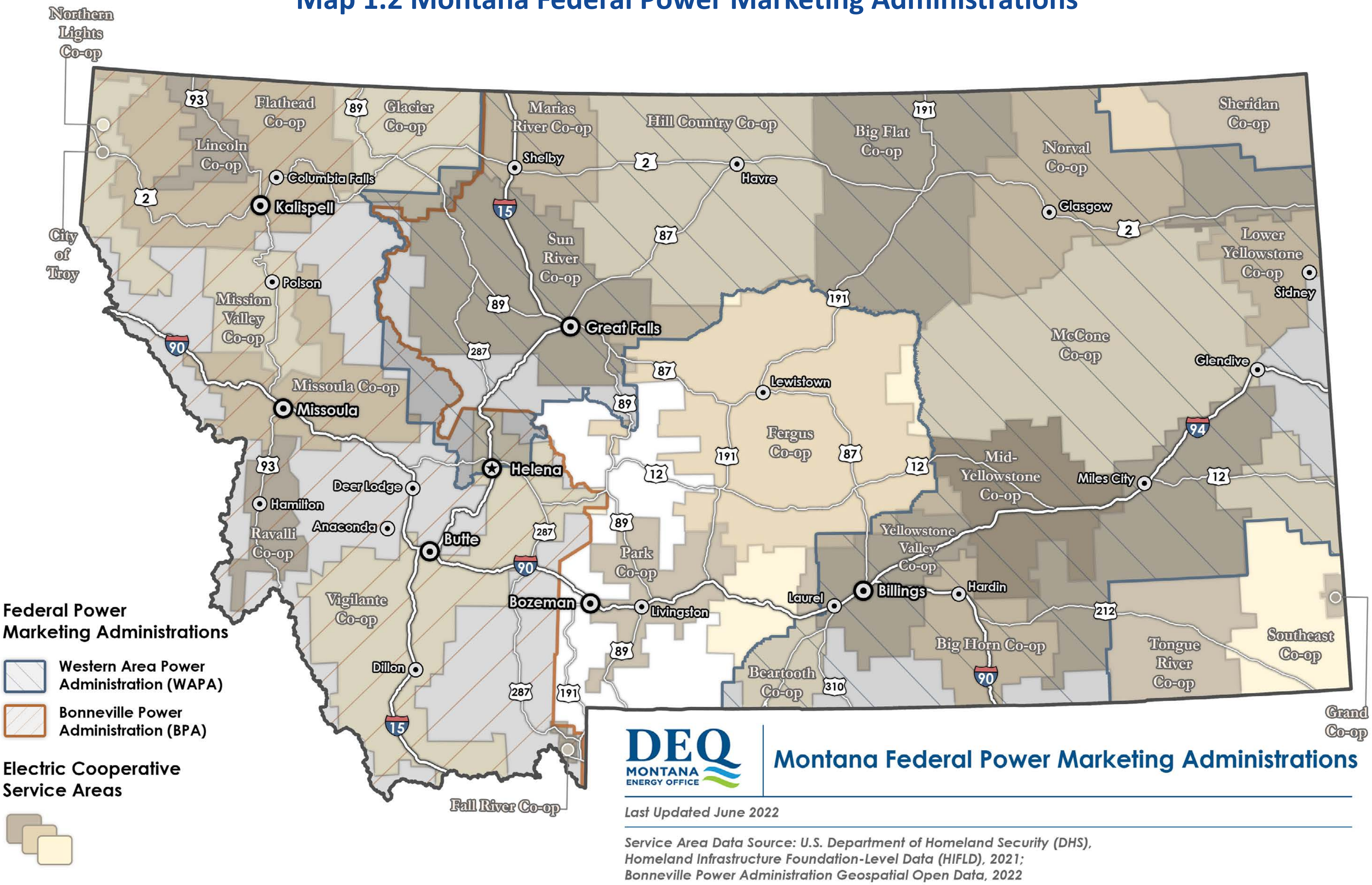
Bonneville Power Administration (BPA) and the Western Area Power Administration (WAPA) are federal power marketing agencies, administered under the U.S. Department of Energy. They are responsible for marketing hydropower primarily from multiple-purpose water projects operated by the Bureau of Reclamation, and the U.S. Army Corps of Engineers. Both BPA and WAPA also operate extensive transmission systems.

Two of Montana's largest energy generation facilities, Libby Dam on the Kootenai River (U.S. Army Corp of Engineers) and Hungry Horse Dam on the South Fork of the Flathead (U.S. Bureau of Reclamation), provide power for BPA. Headquartered in Portland, Oregon, BPA transmits and sells wholesale electricity in Washington, Oregon, Idaho, and western Montana. BPA is the marketing agent for power from all of the federally owned hydroelectric projects in the Pacific Northwest and is one of four federal power marketing agencies. BPA is a large player in northwestern Montana for both electric supply and transmission line operations.

WAPA markets power for federal hydroelectric facilities in the region east of the Continental Divide in Montana. WAPA markets power and energy from three hydroelectric facilities in Montana: Yellowtail Dam on the Bighorn River (U.S. Bureau of Reclamation), Canyon Ferry Dam near Helena (U.S. Bureau of Reclamation), and Fort Peck Dam (U.S. Army Corp of Engineers) on the Missouri River. The Fort Peck Dam is configured to deliver electricity to both the Western and Eastern Interconnections within Montana.



Map 1.2 Montana Federal Power Marketing Administrations

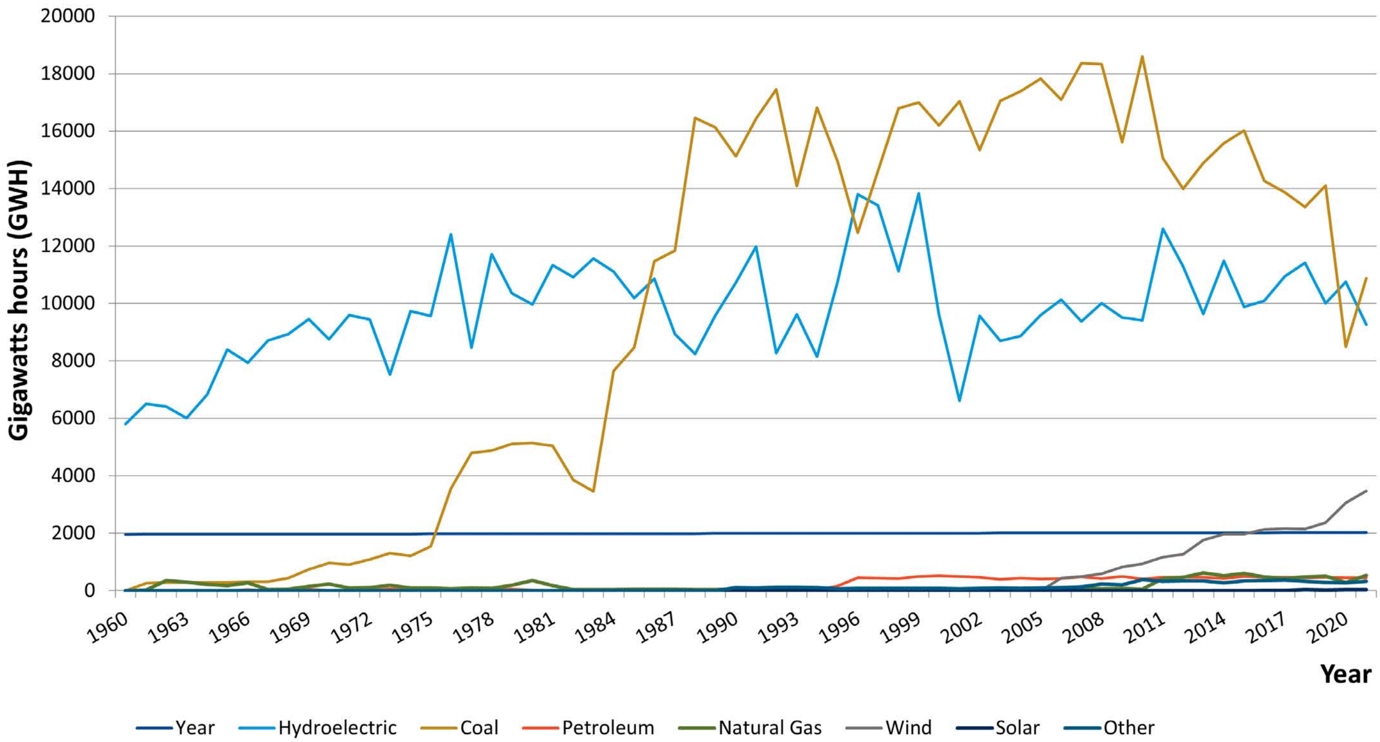


NorthWestern is the largest utility in Montana on the basis of customers and sales, and is regulated by the PSC. Its Montana operations are headquartered in Butte. The company's corporate headquarters are located in Sioux Falls, South Dakota. NorthWestern provides generation and transmission to a majority of customers in the western two-thirds of Montana, although a number of large industrial companies and some co-ops purchase their electricity supply elsewhere.

NorthWestern owned very little generation in Montana in 2002, but began acquiring generation facilities following the 2007 passage of the Electric Utility Industry Generation Reintegration Act. NorthWestern now owns a 30 percent interest in Colstrip Unit 4 (about 4 percent of the state's total generation capacity) and purchases electricity from a number of qualifying power production facilities (QFs) that include waste coal, petroleum coke, small hydroelectric, solar, and increasingly wind generation. In 2011, NorthWestern commissioned the Dave Gates Generating Station, a simple cycle combustion turbine generating facility near Anaconda (150 MW) to provide regulation services for NorthWestern's balancing area (the footprint served by transmission lines that are operated by NorthWestern). In 2014, the PSC approved NorthWestern's purchase of 11 hydroelectric facilities from PPL. NorthWestern also has power purchase contracts for the output from the Basin Creek natural gas plant, Judith Gap Wind Farm, and Tiber Dam.

From 1986 to 2019, the majority of Montana generation was powered by coal averaging around 60 percent in the 2000s and around 50 percent in the 2010s. Hydropower was the next dominant fuel at typically 35 to 40 percent those same two decades. Until 1986, when Colstrip 4 was completed, hydropower was the dominant source of net electric generation in Montana. In 2020, hydropower once again became the dominant source with the closure of Colstrip units 1 and 2. Most of the small amount of petroleum used for electric generation (2 percent of total generation in 2015) is actually petroleum coke from a refinery in Billings. A small amount of natural gas (1 percent of total generation in 2020) and increasing amounts of wind (13 percent of total generation in 2020) round out the in-state generation picture.

Figure 1.2 Montana Historical Electricity Production Chart by Fuel Type, 1990-2021[23]



During spring runoff, hydroelectric utilities operate their systems to take advantage of cheap hydroelectric power, both on their own systems and on the wholesale market around the region. Routine maintenance on thermal plants is scheduled during this period. Thermal plants generally must run more in the fall and winter when hydroelectric power availability is low.

COAL-FIRED GENERATION

Between 1986 and 2020, coal-fired generation provided the majority of the electricity produced in the state. This coal-dominated era started when Colstrip Unit 4 was completed in 1986. But now the future of coal generation in Montana is changing. Montana-Dakota shuttered the 44 MW coal-fired Lewis and Clark Generating Station in 2021 after the utility's economic analysis found the Sidney plant could no longer compete with other resources. That closure was preceded by shut down of Colstrip Units 1 and 2 in 2020 after owners Talen and Puget Sound Energy determined that operation of both 307 MW plants was no longer economical. Portland General Electric, Puget Sound Energy, Avista, and PacifiCorp, all of which own shares of the remaining Colstrip Units 3 and 4, have all announced that they will be financially ready to exit the plant by 2025. Talen Montana, which owns a 30 percent stake in Unit 3, and NorthWestern, which owns a 30 percent share of Unit 4, have not announced plans for an early exit from the plant. In 2023 NorthWestern announced plans to acquire Avista's 222 MW share of Units 3 and 4 effective January 1, 2026. NorthWestern's depreciation schedule for its share of the plant currently runs through 2042.

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23 *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, 1990-2021, Form EIA-923 detailed data with previous form data (EIA-906/920), 'Net Generation by State by Type of Producer by Energy Source, fille named 'Annual_generation_state', https://www.eia.gov/electricity/data/state/. Up to 2019, Solar data came from NWE generating capacity additions as reported by Montana Renewable Energy Association based on data from NWE. As of 2020, solar data is from the same source as the other fuels.*

Only two other small coal plants are actively running with any regularity in the state. One is the Colstrip Energy Limited Project (CELP) plant, which is fueled with waste coal from the Colstrip power plant, and which has a QF contract for sale of its output to NorthWestern that will expire in 2024. The other is Beowolf's 116 MW Hardin Generating Station. The Hardin plant has been powering a cryptocurrency mining operation in recent years but that contract is set to expire by the end of 2022, leaving the future of the plant in question. With the closure of Colstrip Units 1 and 2 in early 2020, hydropower became the largest source of electricity for Montana with coal falling to second place.

As of June 2022, there was a total of 1,630 MW of coal-fired generating capacity in Montana, representing 29 percent of the state's nameplate generating capacity. In comparison in 2020, coal generated a total of 8,490 GWh, representing 36 percent of all in-state electricity generation. In 2015, coal generation was even higher totaling 16,013 GWh, representing 55 percent of all in-state electric generation.[24]

Table 1.3 Montana Coal-Fired Generation Facilities[25]

Facility Name	Company Name	County	Initial Operation Date	Generator Nameplate (MW)
Colstrip Unit 3	Talen Energy (30%), Puget Sound Energy (25%), Portland General Electric (20%), Avista (15%), PacifiCorp (10%)	Rosebud	1984	740
Colstrip Unit 4	NorthWestern Energy (30%), Puget Sound Energy (25%), Portland General Electric (20%), Avista (15%), PacifiCorp (10%)	Rosebud	1986	740
Rosebud Power Plant	Colstrip Energy Limited Partnership (CELP)	Rosebud	1990	35
Hardin Generating Station	Beowolf/Big Horn Datapower Holdings LLC	Big Horn	2006	107

Table Summary: This table lists the largest coal generation plants in Montana. There are four remaining coal plants in Montana.

The two-unit facility in Colstrip leads all coal-fired electric generation in terms of capacity. It also contributes the most electric production of any facility in the state averaging more than 14,000 GWh annually over the past decade, although output is under 10,000 GWh as of 2020. The two units at Colstrip are jointly owned by a total of six entities (see Table 1.4.).

24 *U.S. Department of Energy, Energy Information Administration, Form EIA-923.*

25 *Montana Energy Office.*

Table 1.4 Colstrip Ownership Breakdown[26]

	Unit 1 (retired 2020—no longer operational)	Unit 2 (retired 2020—no longer operational)	Unit 3	Unit 4	Total (% of Units 3 and 4)	Total (MW of Units 3 and 4)
Puget Sound Energy	50%	50%	25%	25%	25%	370
Talen Energy	50%	50%	30%	--	15%	222
Portland General Electric	--	--	20%	20%	20%	296
NorthWestern Energy	--	--	--	30%	15%	222
Avista Corp.	--	--	15%	15%	15%	222
PacifiCorp	--	--	10%	10%	10%	148

Table Summary: This table lists the percentage ownership in Colstrip Units 3 and 4. Six companies own shares in Colstrip.

NATURAL GAS GENERATION

Montana is home to six natural-gas fired generation plants. Two are in the Butte area, and the other four are in the eastern part of the state on the Eastern U.S. grid. Three of the four plants in the eastern part of the state are owned by Montana-Dakota and run infrequently. The other two are owned by or under contract with NorthWestern. In 2011, NorthWestern commissioned the Dave Gates Generation Station, which is comprised of three natural gas-fueled, 50 MW simple cycle combustion turbines (SCCT) totaling 150 MW of generation capacity. The plant, located near Anaconda, provides regulation services for NorthWestern's balancing area (the transmission footprint managed by NorthWestern). The 53 MW Basin Creek electric generation plant near Butte began operations in late 2005. Natural gas usage at the Basin Creek plant constitutes a small percentage of Montana's total usage. Basin Creek is a peaking plant under contract with NorthWestern. NorthWestern dispatches the plant as needed to meet demand spikes and when market prices exceed variable costs to operate the plant. The Culbertson Generation Station, a nearly 90 MW facility, began operations in 2010 on the U.S. Eastern Electric Grid. The Culbertson Generation Station operates with a low capacity factor. The natural gas generation plants at Miles City, Glendive and Sidney are all peaker plants that run infrequently, as required to meet system demand.

NorthWestern is currently pursuing development of a new 175 MW natural gas plant near Laurel. The planned Yellowstone County Generating Station would include 18 flexible reciprocating internal combustion engines (RICE) and is intended to add a dispatchable capacity resource to NorthWestern's electricity supply portfolio.

26 *Montana Energy Office.*

Table 1.5 Montana Natural Gas Generation Facilities[27]

Facility Name	Company Name	County	Initial Operation Date	Generator Nameplate (MW)
Dave Gates	NorthWestern Energy	Deer Lodge	2011	150
Culbertson	Basin Electric Power Cooperative	Richland	2010	91
Glendive*	Montana-Dakota Utilities	Dawson	1979/2003	84
Basin Creek	Basin Creek Equity Partners, LLC (contracted with NorthWestern Energy)	Silver Bow	2006	52
Miles City	Montana-Dakota Utilities	Custer	1972	23
Lewis and Clark	Montana-Dakota Utilities	Richland	2015	19

**This facility can also run on fuel oil when natural gas supplies are constrained.*

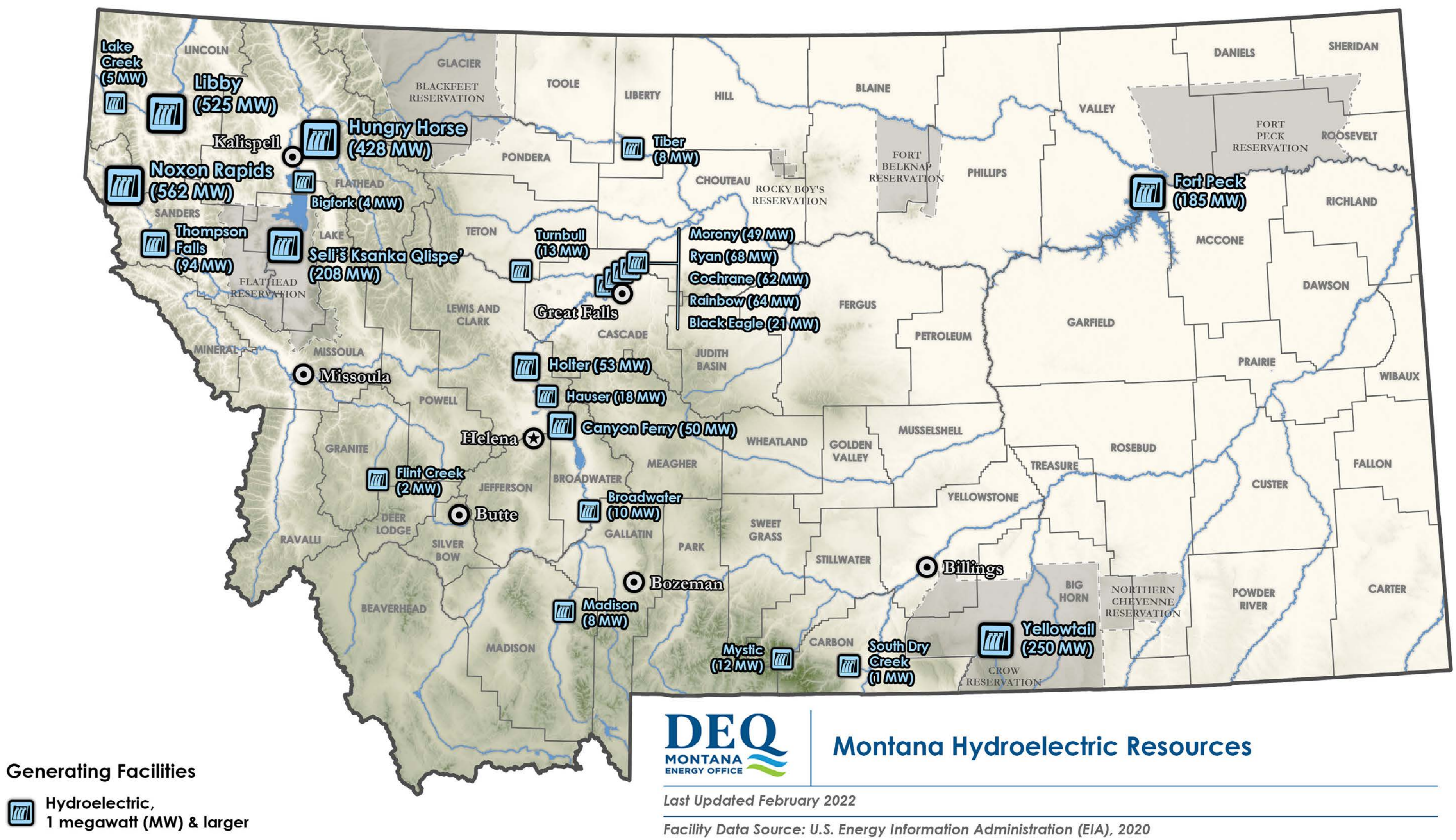
Table Summary: This table lists the natural gas fueled electric generators in Montana.

HYDROPOWER

Hydroelectric dams are an important resource in Montana's energy generation mix and produced half of the state's net electric generation in 2021. There are currently 32 operating hydroelectric facilities in Montana and six of the state's ten-largest generating plants are water powered. At more than 562 MW of nameplate capacity, Noxon Rapids is the largest hydroelectric facility in Montana and is located on the Clark Fork River in Sanders County. Nearly all of its power is exported out of state. In 2021, Montana ranked sixth among all states for power generated by hydroelectric dams. Ownership of hydropower dams in Montana includes utilities and federal agencies. One of the largest facilities, the Seli'š Ksanka Qlispe' Dam (207 MW; formerly the Kerr Dam) was purchased by the Confederated Salish and Kootenai Tribes in 2015. This is the first Tribally-owned hydro-electric dam in the United States.

27 *Montana Energy Office.*

Map 1.3 Montana Hydroelectric Resources



Many of Montana's hydroelectric dams are run-of-the-river dams located along the Missouri River and generate power to serve customers in Montana. These dams were built between the late 1800s and the 1950s to meet the electricity demand of the state's increasing population and high-energy consuming industries such as copper mining and production. Other large hydroelectric dams in Montana are part of the Federal Columbia River Power System which includes a series of hydropower projects on the Columbia River and its tributaries in Idaho, Oregon, Washington, Montana and Wyoming. Hungry Horse and Libby dams are storage dams that generate electricity but also help serve other purposes for the Federal Columbia River Power System such as flood control and irrigation. BPA, a federal power marketing agency, markets power from these two dams and sells it to rural electric cooperatives in Montana and other utilities across the Northwest.

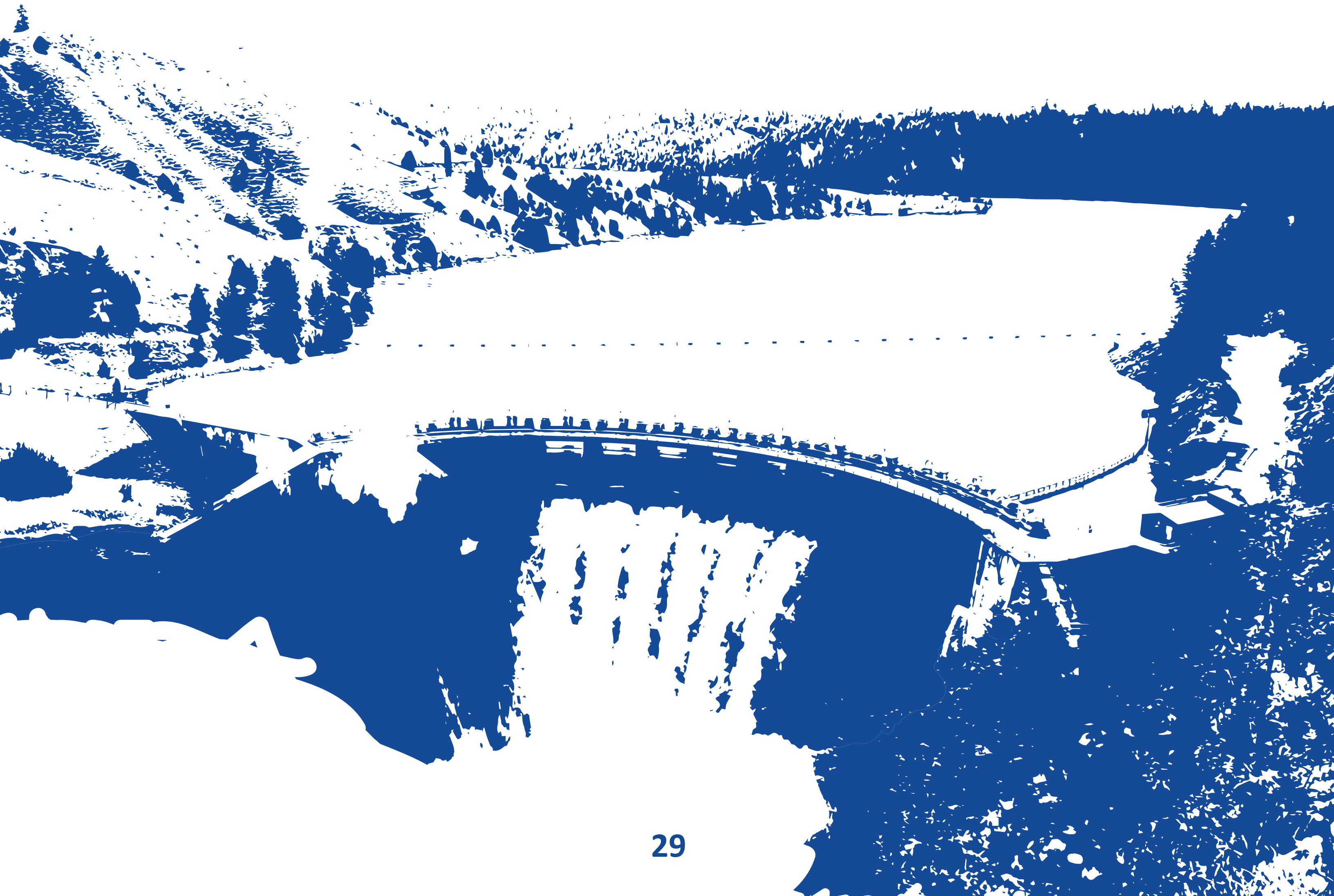


Table 1.6 Montana Hydroelectric Facilities Larger Than 1 Megawatt (MW)[28]

Facility Name	Company Name	County	River	Included in Federal Columbia River Power System	Initial Operation Date	Generator Nameplate (MW)
Noxon Rapids	Avista	Sanders	Clark Fork River	--	1959	562.4
Libby Dam	U.S. Corps of Engineers	Lincoln	Kootenai River	Yes	1975	525.0
Hungry Horse Dam	U.S. Bureau of Reclamation	Flathead	South Fork Flathead River	Yes	1952	428.0
Yellowtail Dam	U.S. Bureau of Reclamation	Big Horn	Bighorn River	--	1966	250.0
Seli'š Ksanka Qlispe' Dam	Confederated Salish and Kootenai Tribes (CSKT)	Lake	Flathead River	--	1938	207.6
Fort Peck Dam	U.S. Corps of Engineers	McCone	Missouri River	--	1943	180
Thompson Falls	NorthWestern Energy	Sanders	Clark Fork River	--	1915	87.1
Cochrane Dam	NorthWestern Energy	Cascade	Missouri River	--	1958	60.4
Rainbow Dam	NorthWestern Energy	Cascade	Missouri River	--	1910	60.0
Canyon Ferry Dam	U.S. Bureau of Reclamation	Lewis and Clark	Missouri River	--	1953	49.8
Ryan Dam	NorthWestern Energy	Cascade	Missouri River	--	1915	48.0
Morony Dam	NorthWestern Energy	Cascade	Missouri River	--	1930	45.0
Holter Dam	NorthWestern Energy	Lewis and Clark	Missouri River	--	1918	38.4
Hauser Dam	NorthWestern Energy	Lewis and Clark	Missouri River	--	1911	17.0
Black Eagle Dam	NorthWestern Energy	Cascade	Missouri River		1927	16.8
Turnbull Hydro	Turnbull Hydro, LLC	Teton	Irrigation Canal	--	2011	13.0
Mystic Dam	NorthWestern Energy	Stillwater	West Rosebud Creek	--	1925	10.0
Broadwater Dam	Montana DNRC	Broadwater	Missouri River		1989	9.6
Madison Dam	NorthWestern Energy	Madison	Madison River	--	1906	8.8
Tiber Dam	Tiber Dam, LLC	Liberty	Marias River	--	2004	7.5
Lake Creek	CSKT	Lincoln	Lake Creek	--	1917	4.5
Bigfork	Pacificorp	Flathead	Swan River	--	1910	4.2
Flint Creek Dam	Granite County	Granite	Flint Creek	--	1901	2.0
South Dry Creek Dam	Hydrodynamic	Carbon	South Dry Creek	--	1985	2.0

Table Summary: This table lists all the hydroelectric dams in Montana.

28 *Montana Energy Office.*

The history of the dams currently owned by NorthWestern reflects Montana's history with electricity deregulation and the re-regulation that followed. The 11 hydroelectric facilities currently owned by NorthWestern were built over several decades between the early 1900s and the late 1950s. The Montana Power Company (NorthWestern's predecessor) was formed in 1912 and acquired the existing dams and built additional large dams over several decades to serve their customers.

WIND POWER

Montana's large geographic area and high plains regions make it one of the highest ranked states for utility wind generation potential in the United States. The National Renewable Energy Laboratory estimates Montana's wind potential at 80 meters above ground to be 679,000 MW, ranking Montana second in total wind energy production potential. As depicted in the map below, most of the state's best wind energy resource lies in the central and eastern areas of the state. Despite this potential, Montana's distance from large population centers (energy loads) and its transmission constraints have resulted in the state only developing a small fraction of its utility scale wind potential. As of 2022, Montana had 1,124 MW of installed wind energy capacity. This puts Montana at 22nd out of 50 states for installed wind capacity in the United States.

Wind accounted for about 13 percent of Montana's net electricity generation in 2020.

Map 1.4 Montana Wind Resources

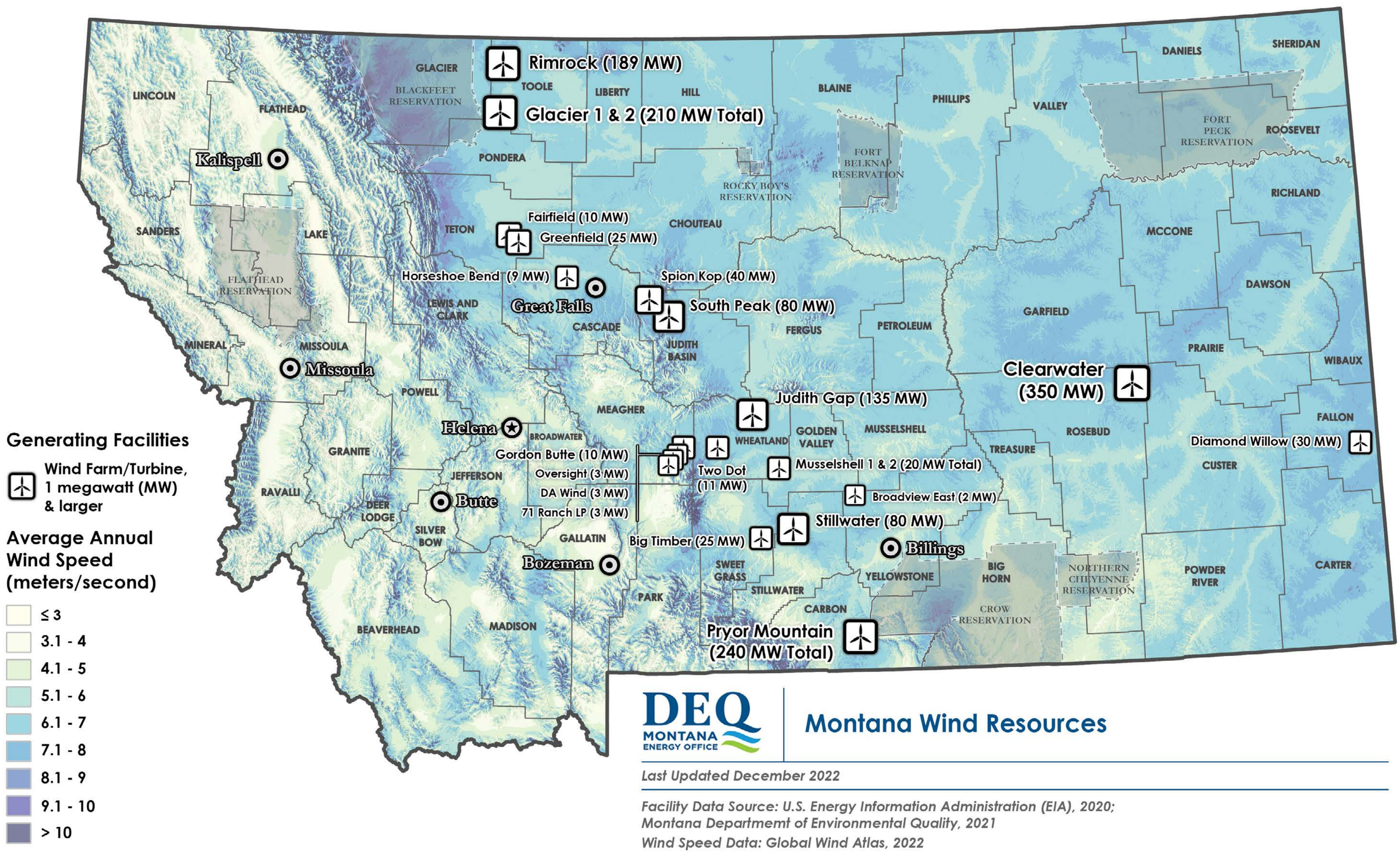
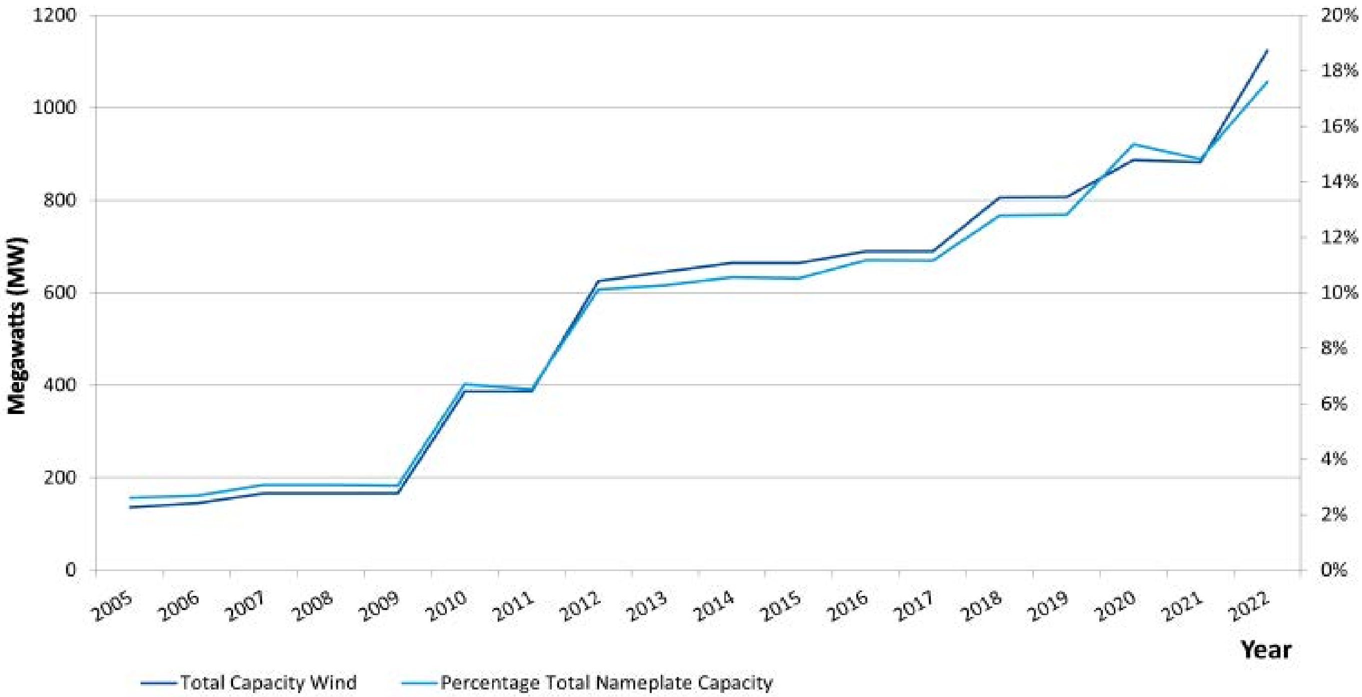


Figure 1.3 Montana Wind Generation Total Nameplate Capacity and Percentage Total Capacity 2005-2022[29]



CURRENT PROJECTS

Montana's first utility-scale wind project, the 135 MW Judith Gap wind facility near Harlowton, started operating in 2005. Judith Gap is owned by Invenergy and supplies energy under a power purchase agreement to NorthWestern. Montana saw several additional wind energy projects come online between 2005 and 2012. In 2007, the Diamond Willow Wind Farm near Baker began operating. This 30 MW facility is owned by Montana-Dakota. In 2009, both phases of the 210 MW Glacier Wind Farm were completed. This is currently the second largest wind energy facility in the state and is located near the town of Shelby in northcentral Montana. The 189 MW Rim Rock Wind Farm located north of Cut Bank and the 40 MW Spion Kop Wind Farm northwest of Geyser were completed in 2012. In addition to the larger wind energy developments, a number of smaller wind energy developments have successfully obtained power purchase contracts to sell renewable electricity to NorthWestern. These developments included the 10 MW Gordon Butte Wind Farm completed in 2012 outside of Martinsdale, and the 20 MW Musselshell I&II Wind Farms completed in 2012 south of Shawmut. Montana's newest wind facilities came online between 2018 and 2022. The Stillwater facility is owned by Pattern Energy and began operating in 2018. The 80 MW South Peak Wind Farm south of Geyser has been operated by Allete Clean Energy since 2020 and sells power through a power purchase agreement to NorthWestern. The 240 MW Pryor Mountain wind facility near Bridger began operation in 2021 and is the largest wind facility in Montana as of mid 2022. By early 2023, the Clearwater Wind Farm will be the largest in Montana. It is owned and operated by PacifiCorp, a large investor-owned utility that serves customers in Wyoming, Utah, Washington, and Oregon. Several smaller wind projects under 1 MW also have contracts to sell their power to NorthWestern.

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29 Sources: The initial operation date, name and location for facilities is from DEQ Energy Office institutional knowledge and inquiries with utilities over time. 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, 1990-2021, Form EIA-923 detailed data with previous form data (EIA-906/920), 'Net Generation by State by Type of Producer by Energy Source, fille named 'Annual_generation_state', https://www.eia.gov/electricity/data/state/.

Table 1.7 Montana Wind Facilities Larger than 9 Megawatts (MW)[30]

Facility Name	Owner	County	Operation Date	Generator Name-plate (MW)
Pryor Mountain	PacifiCorp	Carbon	2021	240
Glacier Wind 1&2	NaturEner	Toole	2008, 2009	210
Rimrock Wind	NaturEner	Toole	2012	189
Judith Gap Wind	Invenergy	Wheatland	2005	135
Spion Kop Wind	NorthWestern Energy	Judith Basin	2012	40
Diamond Willow 1&2	Montana-Dakota Utilities	Fallon	2007, 2010	30
Greenfield Wind	Greenbacker Renewable Energy	Teton	2016	25
Fairfield Wind	Greenbacker Renewable Energy	Teton	2014	20
Musselshell 1 &2	Goldwind USA	Wheatland	2012	20
Two Dot Wind	NJR Clean Energy Ventures	Wheatland	2014	9.7
Gordon Butte Wind	Gordon Butte Wind, LLC	Meagher	2012	9.6
Horseshoe Bend Wind	United Materials of Great Falls, Inc.	Cascade	2006	9
South Peak Wind	Allete Clean Energy	Judith Basin	2020	80
Stillwater Wind	Pattern Energy	Stillwater	2018	80

Table Summary: This table lists the large wind farms in Montana.

30 *Montana Energy Office.*

SOLAR POWER

Utility-scale solar photovoltaic (PV) generating systems are an emerging energy supply in Montana, but still represent a small slice of Montana's generating mix. Distributed utility customer-sited PV systems have been gradually installed in Montana over the past decade. Utility-scale solar farms developed to sell power directly into the grid have only come online in the last five years. The combined output from solar PV systems in Montana represents about 0.04 percent of statewide electricity sales. That puts Montana ahead of neighboring Wyoming, North Dakota and South Dakota on the basis of energy supplied from solar, but behind Idaho. By comparison, states with the highest levels of solar energy development in the country are currently supplying 3 to 13 percent of their electricity from solar PV installations (Table 1.8).

Table 1.8 Solar Market Penetration Summary.[31]

	Montana	Idaho	Wyoming	North Dakota	South Dakota	California	North Carolina	Arizona	Hawaii
Number of Customers (2015)	605,057	835,429	336,471	450,869	461,994	14,832,166	5,012,181	3,011,728	489,694
2016 Peak Demand (MW)	4,348	3,935	1,256	8,032	3,558	66,775	42,637	19,560	1,659
Solar Capacity (MW)	28	359.3	3	0.3	0.4	18,920	3,288	3,151	748
Solar Capacity as % of Peak Demand	0.64%	9.13%	0.24%	0.00%	0.01%	28.33%	7.71%	16.11%	45.12%
2015 Retail Electric Sales (MWh)	11,485,015	23,058,814	16,924,762	18,128,948	12,101,979	181,586,115	133,847,523	77,295,498	9,503,226
% Electricity from Solar	0.04%	0.61%	0.01%	0.00%	0.00%	13.39%	3.25%	5.11%	7.01%

Table Summary: This table lists the penetration of solar power in Montana and in neighboring states.

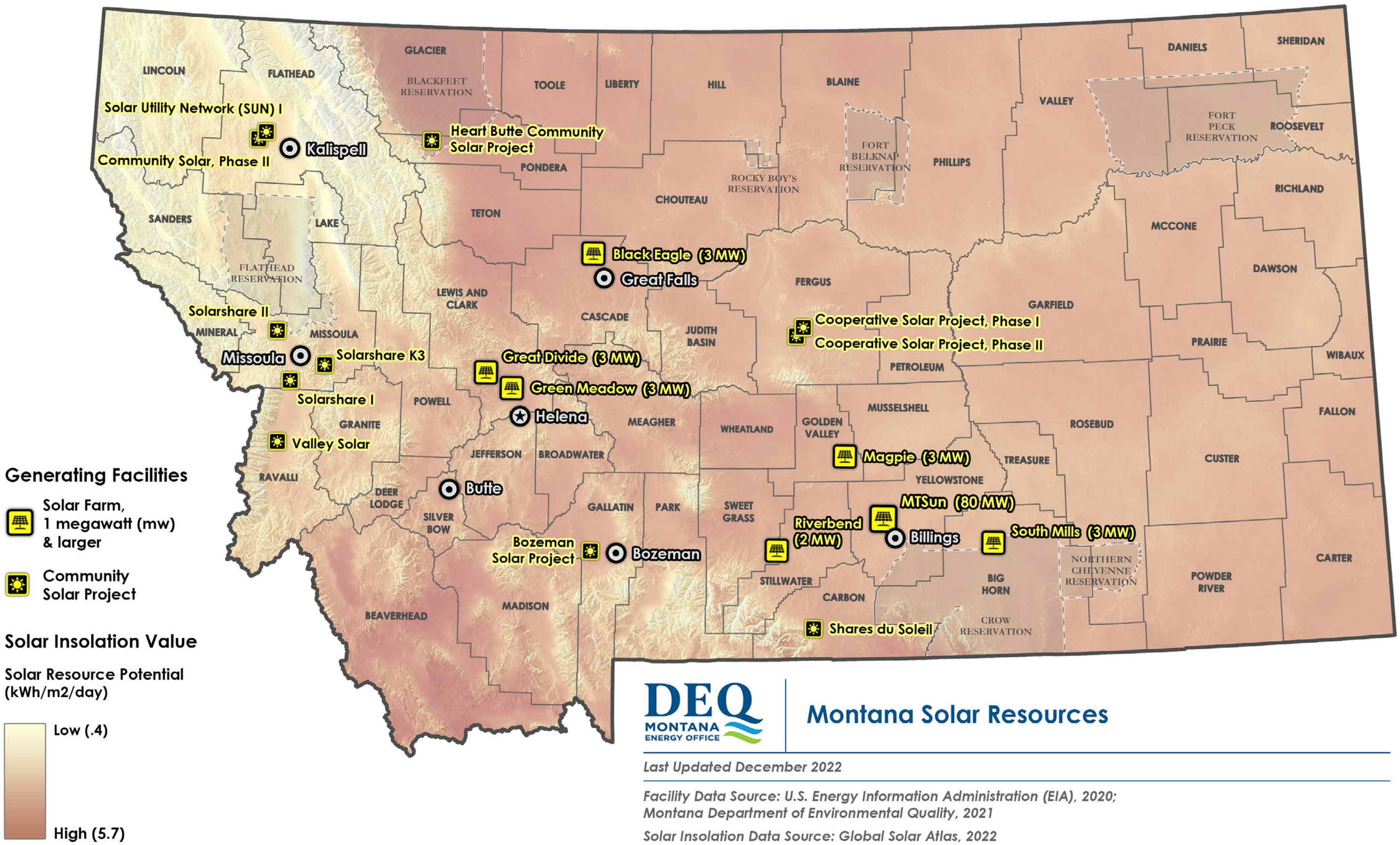
31 *Montana Department of Environmental Quality. (2017). Montana Solar Market Assessment. Retrieved from: http://deq.mt.gov/Portals/112/Energy/Documents/Montana%20Solar%20Market%20Assessment%20-%20Final.pdf?ver=2017-09-15-114156-387, pg. 11.*

MONTANA'S SOLAR RESOURCE

Being a northern state, Montana does not have the solar energy resources found in the desert Southwest states of California, Nevada, Arizona, and New Mexico, which have seen sustained increases in solar energy in recent years, including the installation of large, utility-scale solar energy facilities. Nevertheless, Montana has respectable solar energy potential as compared to other U.S. cities.

The combination of a high number of sunny or partly sunny days with a more temperate summer climate, which reduces efficiency losses that occur with PV systems as temperatures increase, help to make up for the northern latitude of the state. The strongest solar potential within Montana can be found in areas across the southern tier of the state, with the weakest in the northwest Map 1.5.

Map 1.5 Montana Solar Resources



Source: U.S. Department of Energy, National Renewable Energy Laboratory. (2007). Global Solar Radiation at Latitude Tilt-Annual, Montana.

OPERATIONAL UTILITY-SCALE SOLAR PROJECTS

There are six operational, utility-scale solar projects in Montana (See Solar Resources Map and Table 2), each with a generating capacity of 2 to 3 MW.[32] All of the projects have been built on private land and are approximately 30 to 40 acres in size. The projects consist of many rows of solar modules (panels) mounted on single-axis trackers (mechanical equipment that rotates the modules from east to west over the course of the day to follow the sun).

Table 1.9 Utility-Scale Solar PV Facilities[33]

Facility Name	Company Name	County	Initial Operation Date	Generator Nameplate (MW-AC)
Green Meadow Solar, LLC	Adapture Renewables	Lewis & Clark	2017	3
River Bend Solar, LLC	Adapture Renewables	Sweet Grass	2017	2
South Mills Solar, LLC	Adapture Renewables	Big Horn	2017	3
Great Divide Solar, LLC	Adapture reneewables	Lewis & Clark	2017	3
Magpie Solar, LLC	Adapture Renewables	Golden Valley	2017	3
Black Eagle Solar, LLC	Adapture Renewables	Cascade	2017	3
			TOTAL	17

Table Summary: This table lists the solar power farms in Montana.

32 *The generating capacity of PV systems in this section is reported in megawatts of alternating current (AC) however the capacity from PV systems may be measured in either AC or direct current (DC). PV modules produce DC voltage which is converted by inverters to AC voltage in order for the output to be compatible with the transmission and distribution grid. Due to inefficiencies in the conversion from DC to AC, the DC rating of a PV system is always higher than then AC rating. For example, a 3 MW-AC array would have a DC rating of approximately 4.8 MW-DC. Residential and small-commercial PV systems are typically described by their DC rating, however utility scale generators and power plants (wind, gas, coal, etc.) are rated by their AC output.*

33 *Cypress Creek Renewables.*

The six solar farms operating state-wide were developed by Cypress Creek Renewables, FLS Energy, and Adapture Renewables to sell energy to NorthWestern under the requirements of the federal Public Utility Regulatory Policies Act (PURPA). The projects were developed as PURPA qualifying facilities (QFs) and were granted 25-year standard rate power purchase agreements by NorthWestern, at a rate of approximately $66/MWh. While QFs up to 80 MW may negotiate a rate with NorthWestern or appeal to the PSC to set an appropriate rate, standard rates are limited to facilities with a generating capacity of 3 MW or less and are based on the utility's avoided cost (the marginal cost the utility would pay to procure power from another source). The standard rate under which each of the six original Enerparc, and now Adapture projects were developed was suspended by the PSC in June of 2016. The commission approved revised standard offer terms in April 2021 with contract lengths up to 20 years. The rate during low demand hours for a 20-year contract is $34.55/MWh. Rates during high demand hours are based on the type of generator as follows, for 20-year contracts: $74.83/MWh for solar, $61.11/MWh for wind, and $106.45/MWh for Hydro or other qualifying generators.[34]

1D. DEMAND

ELECTRICITY CONSUMPTION OVERVIEW

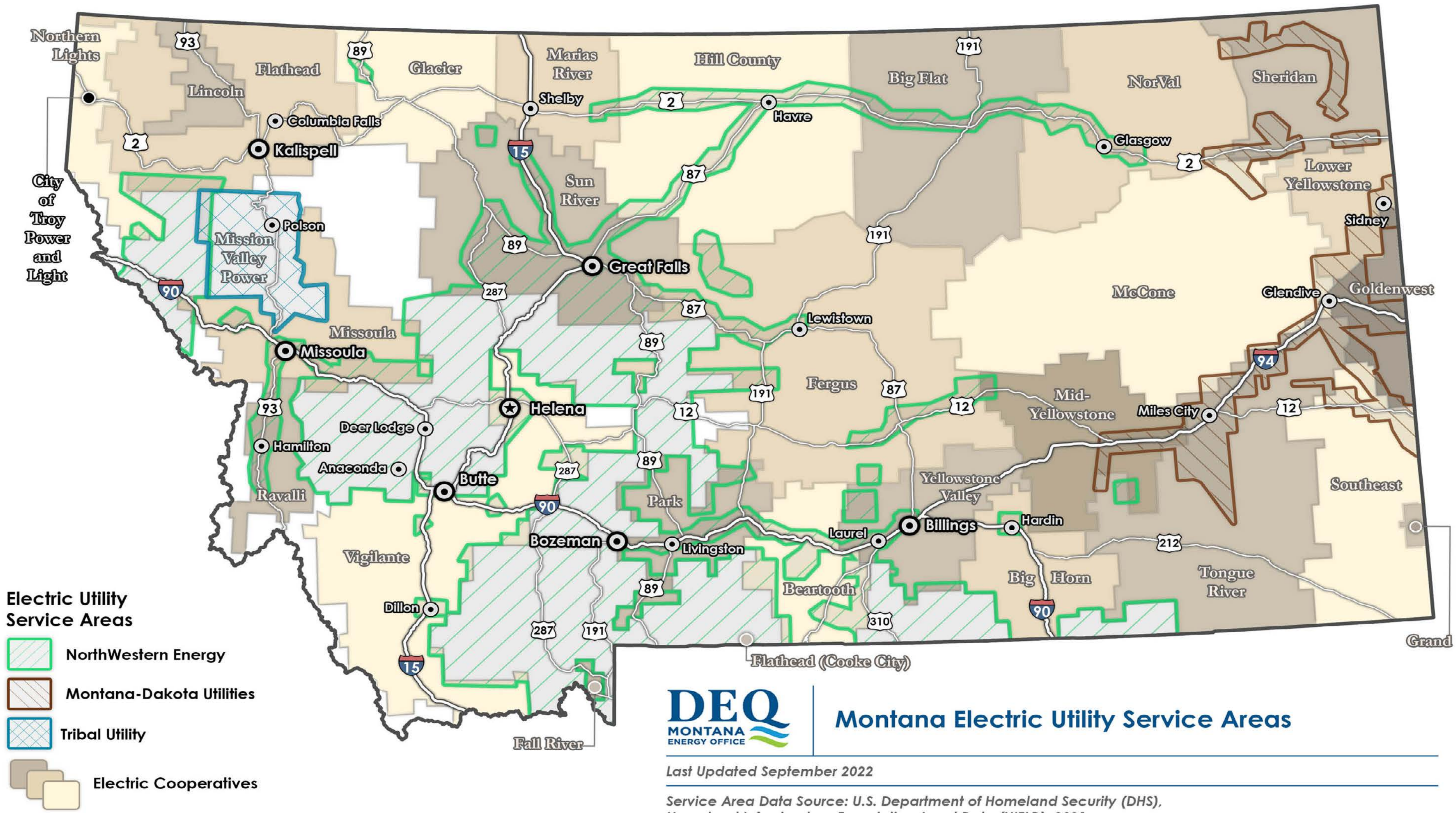
Montana electric consumers are served by 31 distribution utilities: two investor-owned utilities, 25 rural electric cooperatives, two federal agencies (Map 1.2), and one municipal utility. Two additional investor-owned utilities and four cooperatives based in other states serve a small number of Montana consumers.[35] In 2020, investor-owned utilities were responsible for 47 percent of the electricity sales in Montana, cooperatives 35 percent, federal agencies 3 percent, and power marketers 15 percent.[36]

34 Will Rosquist, Montana Public Service Commission, 2022.

35 Two electric co-ops, one based in Ashton, Idaho and the other in Sagle, Idaho, have service areas in Montana. The West Yellowstone area, including the town of West Yellowstone, is served by the Ashton co-op, Fall River Electric Co-op. The Trout Creek area, and other areas west of Thompson Falls, are served by the Sagle co-op, Northern Lights, Inc. There are one or two co-ops in North Dakota that have very small service areas in Montana. Gary Wiens, Montana Electric Coop Association, Oct, 2021.

36 U.S. Department of Energy, Energy Information Administration, Form EIA-861 and EIA-861S, U.S. EIA website.

Map 1.6 Montana Electric Utility Service Areas



Utility service area boundaries shown on this map are approximate

DEQ MONTANA ENERGY OFFICE

Montana Electric Utility Service Areas

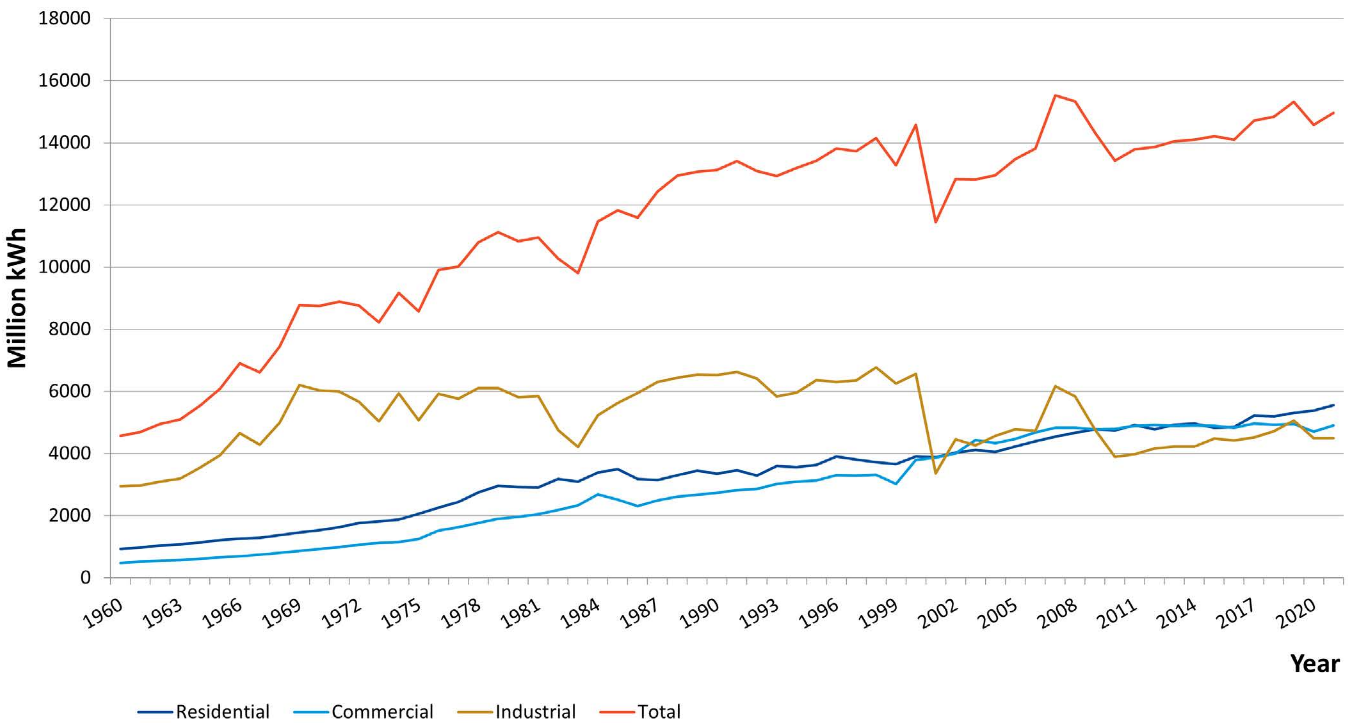
Last Updated September 2022

Service Area Data Source: U.S. Department of Homeland Security (DHS), Homeland Infrastructure Foundation-Level Data (HIFLD), 2021; Montana-Dakota Utilities Company, 2022

Reported sales of electricity in Montana in 2020 were about 14.6 billion kWh (14,600 GWh), down slightly from 15.5 billion kWh in 2007.[37] Part of this decline may be attributed to the partial shutdown of the economy at the start of the COVID-19 pandemic. Since 1990, sales to the commercial sector have grown the most, followed by sales to the residential sector. In the same time period, industrial sales were inconsistent. Residential growth tends to track population growth, while commercial growth tends to track economic activity. Sales dipped sharply in 2001 after the 2000-2001 electricity crisis in the U.S. West due to reduced industrial consumption. Growth in electricity sales may slow if electricity prices rise or energy efficiency technology continues to permeate the market. On the other hand, electrification of the transportation sector and other parts of the economy may spur growth in the coming decades.

Consumption patterns continually shift as existing electricity-consuming equipment and appliances become more efficient, while conversely, new electric-powered appliances, heating systems and technology gain market share in U.S. homes and jobs.

Figure 1.4 Annual Montana Sales Of Electricity By Sector,1960-2021(Million Kilowatt-Hours)[38]



Electricity in Montana costs less than the national average. In 2020, the Montana delivered electricity price averaged 9.13 cents/kWh compared to 10.59 cents/kWh nationally.[39] In 1997 before electricity deregulation, Montana's average price of 5.2 cents/kWh was 1.7 cents below the national average of 6.85 cents/ kWh. For both Montana and the U.S., electricity prices rose about in line with inflation since 1997.[40] Current threats to the

37 *U.S. Energy Information Administration, 2022.*

38 *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 (2000-2021), Annual-by sector by state; https://www.eia.gov/electricity/data/state/.*

39 *U.S. EIA, 2021.*

40 *Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry, 1961-2000; U.S. Department of Energy, Energy Information Administration, 2001-2021 (Data from forms EIA-861- schedules 4A-D, EIA-861S and EIA-861U).*

stability of electricity prices across the west include Russia's invasion of Ukraine, which spiked natural gas prices globally, increasingly extreme weather events, transmission constraints, and a mismatch of new electric loads and increasingly variable, non-dispatchable energy supply portfolios.

Montana's largest electricity consumers are large industrial customers, including metal mines, four in-state oil refineries, large petroleum pipelines, forestry products companies, a silicon manufacturer, and cement plants. These customers generally use NorthWestern, Montana-Dakota, or WAPA as their electricity transmission provider, but most buy their power from non-utility suppliers, such as power marketers. These are generally privately negotiated contracts.

CURRENT TOPICS

ELECTRIFICATION

Electrification of end-uses in residential and commercial buildings, industrial processes, and transportation could significantly alter the current energy system and increase electricity demand across all sectors. Increased adoption of electric heat pumps for space and water heating in buildings and electric vehicles for transportation is helping drive increased electricity demand across the United States. Growth in electricity demand will continue as electric options for appliances and vehicles improve, costs decline, and concerns about emissions from traditional fuel sources increase.

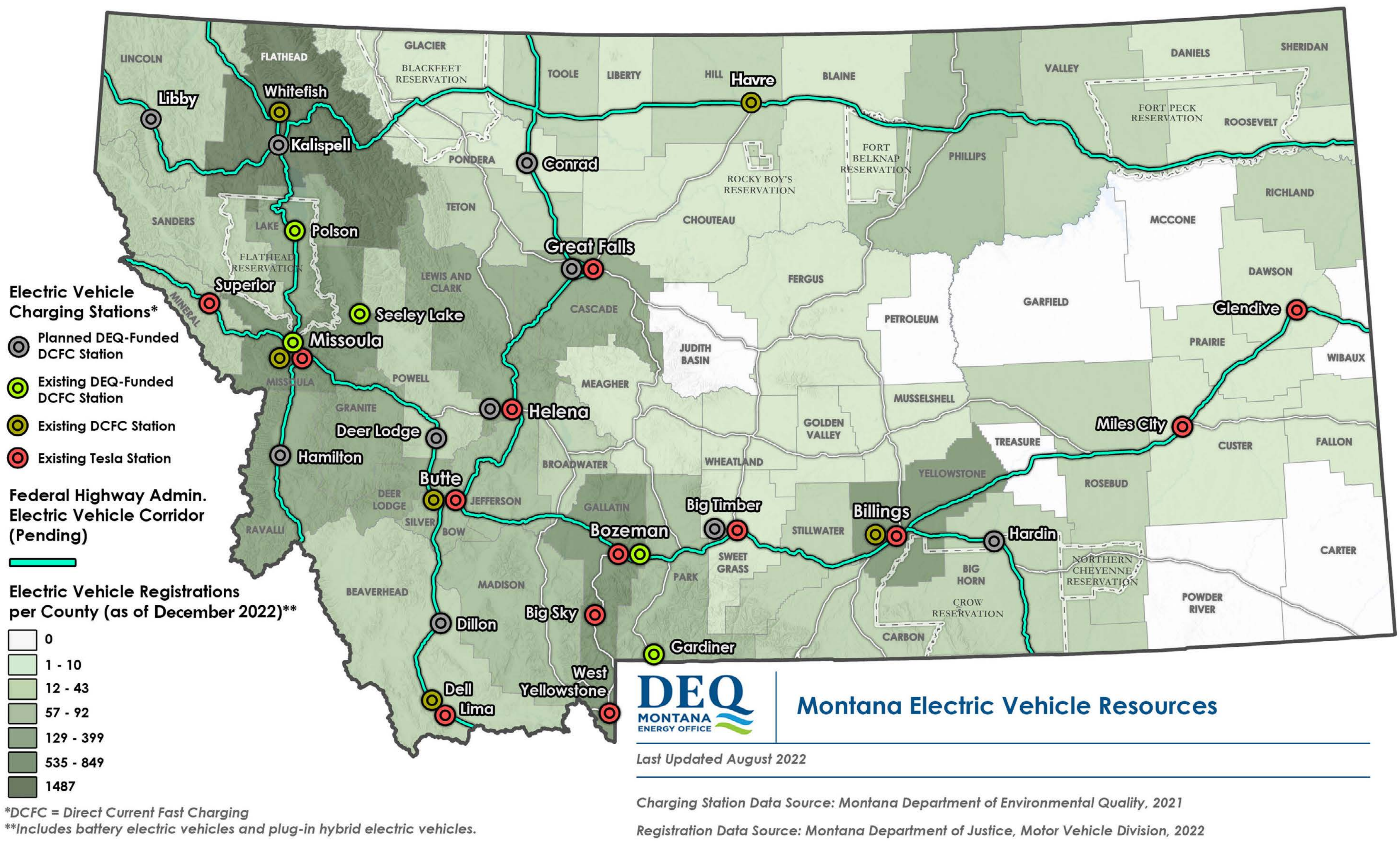
ELECTRIC VEHICLES

Electric vehicles (EVs) use batteries, either fully or in part, to supply electric fuel to the vehicle. In a battery-electric vehicle (BEV), batteries power one or more electric motors, which propels the vehicle. Plug-in hybrid electric vehicles (PHEVs) use a battery to power the vehicle for a limited distance and can switch to a gasoline (or other fuel) engine to propel the vehicle. PHEVs and BEVs, unlike standard hybrid vehicles require an external power source to charge the vehicle. Electric vehicle chargers, or electric vehicle charging stations (EVCS) are used to fuel EVs. There are three levels of EV chargers, differentiated by the amount of electricity that they can deliver to a vehicle. Level 1 charging is typically used for home charging and is powered by a standard 110V outlet. Level 2 charging is faster and requires a 220V power source. Level 2 chargers are common for home charging and "destination" charging at parking lots, hotels, and other commercial locations. Level 3 stations, or DC-fast charging stations (DCFC), can charge a vehicle much faster than Level 1 and Level 2 stations and are typically located near interstates, highways, and other important travel routes.

In Montana, there is increasing interest in electric transportation as more vehicle models become available and purchase costs decline. Electric vehicle adoption in Montana is relatively low compared to more populated states, but electric vehicle registrations in the state have increased steadily since 2016. At the end of 2016, the Montana Department of Justice estimated that there were 400 electric vehicles registered in Montana. At the time, the registration data system did not differentiate between plug-in hybrid electric vehicles and battery-electric vehicles. As of January 2022, vehicle registration data indicated there were 1,893 BEVs and 1,001 PHEVs registered.[41] Between 2020 and 2021 BEV's and PHEV's accounted for 0.18 percent of all light-duty vehicle registrations in Montana.

41 *Atlas EV Hub, https://www.atlasevhub.com/materials/state-ev-registration-data.*

Map 1.7 Montana Electric Vehicle Resources



Electric vehicle charging station availability is an important aspect of EV technology adoption because charging station availability can help reduce drivers' concerns about travelling long distances in an electric vehicle and running out of fuel. To date, the publicly available charging stations in Montana have been concentrated in more populated communities and western side of the state. The map above shows the publicly available charging stations in Montana. According to the U.S. Department of Energy's Alternative Fuels Data Center (AFDC), there are 99 publicly available charging ports available at 56 locations in Montana.[42]

COVID IMPACTS ON DEMAND

The COVID-19 pandemic impacted electricity demand in Montana, particularly during 2020. In 2020, residential electricity demand on NorthWestern's system increased by 2.3 percent compared to 2019 loads. This is approximately a 71 percent increase over the 1.4 percent increase expected under normal conditions for NorthWestern's system. This increase was due to people working from home due to COVID-19 closures. Alternatively, electric loads in the commercial sector decreased. During 2020, commercial customer loads on NorthWestern's system decreased by about 2.8 percent compared to 2019 loads Montana's industrial load decreased from 2019 to 2020.

Similar electricity demand trends were observed across the country. In 2020, overall electricity use in the United States declined by 3 percent.[43] This was due to decrease in demand in the commercial and industrial sectors, and actions by states and businesses to limit the spread of COVID-19.

ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT

Energy demand in the residential, commercial and industrial sectors is increasing across the United States and in Montana. As this demand increases, it is important to not only understand how much energy is generated, but also how much energy is consumed and how consumption is reduced through energy efficiency and conservation. Energy efficiency and conservation are often used interchangeably, but they describe two different ways to reduce energy consumption. Energy efficiency means using less energy to perform the same task or achieve the same result. Energy conservation is often behavioral and means using less energy overall. As an example, installing an LED light bulb instead of an incandescent light bulb would be considered an energy efficiency measure. Turning that light off when it is not in use is energy conservation. Energy efficiency is often measured in terms of "average megawatts" (aMW) savings that utilities can achieve through customer energy savings.

Energy efficiency can help utilities meet growing customer demand by yielding energy savings that can reduce the need to build new generation resources. Energy efficiency can also reduce or defer the need to build new powerlines and upgrade or replace transmission and distribution system equipment. Because of its low-cost and flexible attributes, many utilities categorize energy efficiency as a resource, on par with any other generating resources. In the Northwest states of Oregon, Washington, Idaho and Montana, energy efficiency was the second largest electricity resource after hydropower in 2014.

Demand-side management (DSM) encompasses programs designed to encourage consumers to modify their level and pattern of energy usage. DSM programs are often utility-administered and include financial incentives for customers to reduce or defer their energy use. These programs are designed to save consumers money while simultaneously allowing utilities to avoid spending ratepayer dollars to procure energy on the market, or build new resources and upgrade existing infrastructure. Some DSM programs can be targeted at reducing

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42 U.S. Department of Energy Alternative Fuels Data Center, https://afdc.energy.gov/.

43 U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report.", Form EIA-861S, "Annual Electric Power Industry Report (Short Form)" and Form EIA-923, "Power Plant Operations Report".

energy use during the highest use (peak) periods. Utilities often make infrastructure investment decisions based on the consumer demand during peak periods.

ENERGY EFFICIENCY SAVINGS

In 2021, utilities across the United States invested approximately $6.1 billion in electric energy efficiency programs and saved approximately 26.6 million megawatt-hours (MWh), or 2,899 aMW of electricity.[44] Most energy savings can be attributed to federal, state and local policies and utility-initiated programs that encourage energy efficiency in the industrial, commercial and residential sectors. The American Council for an Energy-Efficient Economy (ACEEE) is a non-profit organization that publishes an annual energy efficiency scorecard for states in terms of performance and programs and policies that support energy efficiency. In 2021, Montana ranked 29th in the country on ACEEE's scorecard. [45] The scorecard estimates that Montana's net incremental electricity savings of approximately 63,721 MWh of electricity, or 0.44 percent of 2020 retail sales. Other state's energy efficiency savings range from 0.01 percent of sales in West Virginia to 2.3 percent of electricity sales for Massachusetts, the highest ranked state for energy efficiency programs and policies. Most of Montana's current energy efficiency savings are driven by utility programs, state-led initiatives, and energy efficiency incentives. Montana's largest utility, NorthWestern Energy, set a goal in their last biennial resource plan of achieving 3.77 average MW of energy savings per year for the next 15 years. By 2036, this would result in a total of 69.6 aMW of energy efficiency and other DSM savings.[46]

The electric cooperatives in western Montana receive their electricity supply from the BPA and participate in BPA energy efficiency programs to varying degrees. Overall, the BPA energy efficiency programs in Montana have averaged about 2.3 aMW for the last several years. In total, Montana utilities average about 11.5 aMW per year in energy efficiency savings.

ENERGY EFFICIENCY PROGRAMS AND POLICIES

Certain policies can help encourage utilities to increase investment and customers participation in energy efficiency programs. Some utilities in Montana offer rebates and other incentives for their customers to purchase energy-efficient appliances and light bulbs and to receive energy audits and participate in other energy conservation and efficiency programs. Most of the funding for electric and gas utility efficiency programs in Montana comes from the Universal Systems Benefits (USB) fund passed by the Legislature in 1997. USB programs were established to ensure continued utility funding after deregulation to support three public purposes: 1) low-income energy assistance, 2) energy conservation, and 3) renewable resource projects. Investor-owned and electric cooperatives are required to establish and fund USB programs that meet these three public purposes. There is a USB surcharge on each electric and gas utility customer's bill that funds the utility USB programs. On average, this charge adds about one dollar to customers' natural gas and electric bills each month. Since 2007, over $60 million of funding has been contributed by utilities toward USB programs across the state.

Other policies such as energy codes reduce energy consumption in the building sector. Energy codes that require certain energy efficiency measures or energy use for new construction are also adopted by states and local governments to reduce energy consumption. Buildings consume 74 percent of the electricity and 41 percent of the total energy used in the United States. Montana's residential energy code requires state standards for measures such as insulation levels, thermal ratings for windows, and heating appliance performance. Montana's current statewide energy code for new residential buildings is based on the 2021

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44 *American Council for an Energy-Efficient Economy. The 2017 State Energy Efficiency Scorecard. September 2017.*

45 *Berg, W.S. Vaidyanathan, B. Jennings, E. Cooper, C.Perry, M. DiMasico, and J. Singletary. The 2020 State Energy Efficiency Scorecard, Washington, DC.*

46 *NorthWestern Energy, 2019 Electricity Supply Resource Procurement Plan, Volume 1. Page 3-1.*

International Energy Conservation Code (IECC). Every three years, the Montana Department of Labor & Industry must review the energy code and consider whether to adopt all or parts of the latest versions of national and international building standards for energy efficiency.

ENERGY EFFICIENCY SAVINGS POTENTIAL

The Northwest Power Planning and Conservation Council (the Council) develops a regional power plan every five years for four states in the Columbia River Basin. These states are Washington, Oregon, Idaho and Montana. The Northwest Power Act of 1980 established the Council and also the purposes of the regional power plan. One of the primary purposes is to encourage conservation and efficiency in the use of electric power within the Pacific Northwest. Since 1980, over half of the northwest region's growth in demand for electricity has been met with energy efficiency and the region has exceeded annual efficiency targets set by the Council every year since 2005. In 2021, the Council adopted its new Power Plan that estimates that across the four states there is between 750 to 1,000 average megawatts of electricity sector conservation needed by 2027 to help maintain system adequacy.

DEMAND RESPONSE

Demand response is a specific type of demand side management that represents a voluntary and temporary change in consumer electricity use when the power system is stressed. Demand response programs often create price signals for consumers to reduce electricity use at the times of the day and during certain periods of the month when electricity use is the highest (peak load). Reducing electricity use during peak periods can help significantly reduce costs associated with transmission and other electricity system upgrades because systems are typically built, upgraded and expanded to accommodate peak electricity use. The Council's 2021 regional power plan recommends that utilities consider demand response options including residential time of use (TOU) programs that reduce electricity load during peak times, and demand voltage reduction, which maintains distribution feeder voltage at a lower range to reduce system demand.[47] The 2021 Plan estimates that 200 MW of time of use savings and 520 MW of demand voltage reduction are available across the region by 2027.

In Montana, Montana-Dakota offers an Interruptible Demand Response rate and Commercial Demand Response Resources Program that at the end of 2020 combine to provide approximately 40 MW of demand response for Montana-Dakota's system. Montana-Dakota plans to grow the commercial demand response program to 60 MW over the next 5 years.[48] Flathead Electric has a residential customer demand response offering, called the Peak Time Rebate Program. This program allows customers the option to have the utility install a device on their hot water heater and the ability to turn it off during short periods of peak demand. Customers receive a monthly bill credit for participating in the program.

DISTRIBUTED GENERATION IN MONTANA

"Distributed generation" refers to geographically dispersed, utility customer-owned renewable energy systems, usually interconnected on the customer side of a utility meter. In 1999, with the passage of Montana net metering legislation (SB 409; Chapter 323, Laws of 1999) by the Montana Legislature, NorthWestern customers were given the opportunity to interconnect a grid-compatible solar, wind, or hydropower generator with a generating capacity of 50 kW[49] or less on their property. A net metering system provides energy to

47 2021 Northwest Power Plan. March 10, 2022, Page 47.

48 Montana Dakota Utilities, 2021 Integrated Resource Plan, Volume 1. Page 2.3

49 For reference, a 50 kilowatt (kW) solar PV array in Helena would generate approximately 69,000 kilowatt hours annually, more than 7 times the amount of energy consumed by an average NorthWestern Energy residential customer.

the customer generator's premises; any excess energy is exported back to the utility and credited on the customer's bill. That credit may be carried forward over a twelve-month billing cycle. The utility does not pay customer generators for excess energy provided to the utility.

The Montana PSC approved a net metering tariff for Montana-Dakota in 2008, modeled closely after the state's statute. Many of the state's electric cooperatives have established their own net metering policies with varying terms and requirements.

Nine Montana utilities currently provide net metering data to the U.S. Energy Information Administration (EIA). EIA data indicates nearly 4,000 utility customers of these nine utilities with net metering systems in October 2020 (Table 1). Of the net metered generating capacity reported by EIA, solar PV systems account for 91 percent of capacity. Wind generation represents the second largest type of generator. Among the Flathead Electric Co-op members with net metering systems are two cities with hydro generating facilities (Whitefish--200 kW, and Libby--12 kW).

Table 1.10 Net Metering Facilities Interconnected To Selected Montana Utilities[50]

	Number Of Net Metering Customers	Generating Capacity Of Net Metering Systems (kW-DC)
Flathead Electric Co-op[4]	435	854
Fall River Electric Co-op	5	31
Lower Yellowstone REA	2	20
Missoula Electric Co-op	218	640
NorthWestern Energy	3,217	22,238
Montana-Dakota Utilities	12	60
Mission Valley Power	48	269
Yellowstone Valley Electric Co-op	51	433
Fergus Electric Co-op	34	383
TOTAL	3,971	24,360

Table Summary: This table shows the number and total generating capacity of Net metering facilities interconnected to selected Montana utilities.

Technology and production advances in the solar PV industry have helped drive down the cost of distributed solar PV installations relative to other distributed generation technology. Historical NorthWestern net metering data show a trend in which installations of distributed wind energy systems have largely decreased since 2011, while installations of solar PV systems have accelerated in recent years.

The adoption rate of distributed generation hinges on multiple factors, including the installed cost of the equipment, eligibility of the owner for federal credits and other incentives, and the kilowatt-hour rate at which excess generation is credited to the owner. National data reported for the last quarter of 2021 showed installed cost for residential PV (2.5-10 kW) hovering around $3.90/watt, with the installed cost for small commercial systems (10-100 kW) closer to $3.38/watt[51] That cost is down from $4.00/watt and $3.90/watt for residential

50 *Energy Information Administration, U.S. Department of Energy. (2017). Form EIA-861M, Net metering, through August 2017. Retrieved from: https://www.eia.gov/electricity/data/eia861m/.*

51 *National Renewable Energy Laboratory, U.S. Department of Energy. (2017). Q4 2016/Q1 2017 Solar Industry Update. Retrieved from: https://www.nrel.gov/docs/fy17osti/68425.pdf.*

and small commercial systems respectively in 2017. Data from Montana's Alternative Energy Revolving Loan Program (AERLP) suggest installed costs for distributed solar PV installations are lower than national averages. The average pre-incentive installed cost per watt for grid-tied systems funded by the AERLP in July 2020 through June 2021 was $2.40/watt.[52] The average is based on cost data from forty systems ranging in size from 2 to 50 kW-DC.

After accounting for local costs, available tax incentives, and Montana-specific utility rates, the payback for a residential solar PV array installed in Montana ranges from approximately 13 years for a NorthWestern customer to approximately 23 years for a member of Flathead Electric Co-op, which has significantly lower retail electricity rates and higher fixed monthly charges than NorthWestern.[53] The useful life of a solar PV array is typically considered to be 25 years or longer.

COMMUNITY SOLAR

Montana's first community solar installations were built in 2016 and 2017. There are now five "virtually net metered" or "shared solar" projects operated by rural electric co-ops in which co-op members have purchased one or more panels of a solar PV array sited on co-op property, or in one case on a public school. The participating members are given a credit on their monthly electric bill equal to the output of their proportional ownership in the array. The projects were built using a variety of different funding sources including, in some cases, grants from the U.S. Department of Agriculture Rural Energy for America Program and the Bonneville Environmental Foundation. NorthWestern, which is currently restricted in state law from operating a similar virtual net metering project, has built a 385 kW solar PV array on land owned by the City of Bozeman. The project is being used to evaluate the output of the solar array compared to a variety of Bozeman-area residential and commercial utility customers. Montana State University is also a partner in the pilot project.

52 *Montana Department of Environmental Quality.*

53 *Norris, Benjamin, P. Gruenhagen, M. Chang, and S. Fields. (2017). Montana Solar Market Assessment. Clean Power Research and Synapse Energy Economics. Prepared for Montana Department of Environmental Quality. Retrieved from: https://deq.mt.gov/files/Energy/EnergizeMT/Renewables/Documents/Solar/Montana_Solar_Market_Assessment_Final_Update.pdf, pg. 21.*

Table 1.11 Community Solar Installations In Montana[54]

	Year Installed	Total Installed Community Solar Capacity (kW-DC)	Number Of Panels	Cost Per Panel	Outside	Approximate Payback Per Panel (Inclusive Of Federal Investment Tax Credit)
Ravalli Electric Co-op	2016	50	176	$750	Yes	20 years
Missoula Electric Co-op	2016	100 (two 50 kW phases)	358	$700	Yes for phase one, no for phase two	23 years
Flathead Electric Co-op	2016	101	356	$900	Yes	21 years
Fergus Electric Co-op	2017	100	324	$595	No	9.4 years
NorthWestern Energy	2016	385	1,152	N/A—Panels or shares in pilot project were not sold	No	N/A—Pilot project not structured with subscription model
Heart Butte School	2021	160		N/A- Panels or shares were not sold. Selected households and community college receive credit on their utility bills.	Yes	N/A – not structured with subscription model.

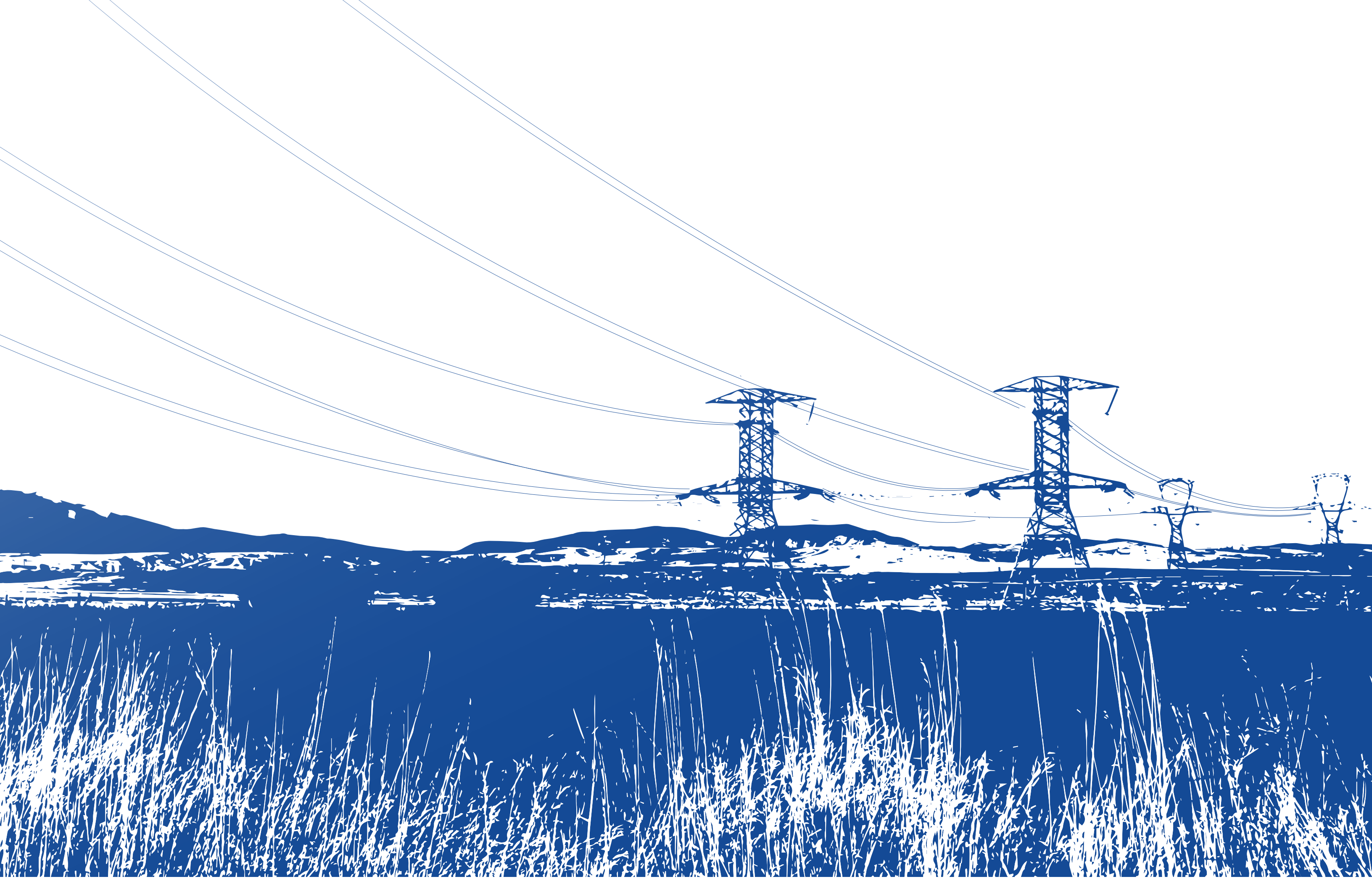
Table Summary: This table summarizes community solar installations in Montana.

54 Ibid.

2. MONTANA'S ELECTRIC TRANSMISSION GRID

2A. INTRODUCTION TO THE GRID

The electric transmission and distribution grid serves the vital function of moving power from generating plants to customers and their electric loads (demand). Montana's transmission grid reliably provides this service even though from tim-to-time individual grid elements may suffer outages or be taken down for maintenance. The ownership of and rights to use the transmission system are complex matters, and these issues are further complicated by line congestion on in-state and interstate lines. The way in which electric transmission systems are regulated and operated is also changing, with more regulation at the national level, market formation at the regional level, and increasing amounts of variable generation on the system. The construction of new in-state and interstate transmission lines to expand the capacity of the current grid is a challenging topic, raising questions about property rights, economic development, and the need for new lines. Due in no small part to the complexities mentioned, only one new major transmission has been built in the past two decades in Montana.



- Transmission lines are generally high voltage lines, usually 50 or 69 kilovolts (kV) and higher, that deliver electricity over long distances from generation sources and major substations to population centers or industrial sites. Power lines that deliver power directly to end-use customers, including homes and businesses, are typically considered "distribution lines." Distribution lines are generally radial in structure, i.e., power flows to end-use loads through distribution lines and does not loop back to other areas of the grid. The support structures for transmission and distribution lines can include single wooden poles, metal structures, and engineered laminated wood structures.

- NorthWestern operates the largest transmission balancing area in Montana. Bonneville Power Administration (BPA) operates a very large system in the Pacific Northwest that extends into the northwest part of Montana. WAPA runs part of its system in the northeast and eastern parts of the state. Montana-Dakota mostly uses WAPA lines in the Eastern portion of the state. Most distribution lines in Montana are owned by NorthWestern, one of 25 distribution cooperatives, or Montana-Dakota.

- Montana spans parts of both the Eastern and Western Interconnections in the U.S. Most of Montana, around 90 percent of its load, is in the Western Interconnection.

- Grid operations in the United States are changing alongside the development of real-time energy markets. In the West, existing market offerings include the California Independent System Operator's Energy Imbalance Market and Southwest Power Pool's Western Energy Services. Additional market offerings being discussed include an Enhanced Day-Ahead Market, Markets+ and the possibility of one or more Regional Transmission Organization (RTO).

- Most of Montana is not part of an Independent System Operator (ISO) or RTO, but rather operates within the vertically integrated model of utility regulation. A small portion of Montana in the U.S. eastern grid is part of the Midcontinent ISO (MISO).

2B. HISTORICAL DEVELOPMENT OF TRANSMISSION IN MONTANA

The transmission network in Montana initially developed as a result of local decisions in response to a growing demand for power. The earliest power plants in Montana were small hydroelectric generators and coal-fired steam plants built at the end of the nineteenth century to serve local needs for lighting, power, and streetcars.[55] The earliest long-distance transmission lines were built from the Madison Dam, near Ennis, to Butte and from Great Falls to Anaconda. The latter was, at the time of construction, the longest high-voltage (100 kV) transmission line in the country and is still operational today. These first lines were built in order to power the mining and smelting operations in the Butte-Anaconda area.

The Montana Power Company (MPC) presided over Montana's first integrated transmission system. As the transmission system grew, the MPC expanded its network to include 161 kV lines and ultimately a 230 kV backbone of lines. The federally-owned WAPA electric transmission system in Montana began to transport

55 *Montana-Dakota Utilities is not an SPP member or transmission owner, we take transmission service from both SPP and MISO to service our load west of Beulah, ND and everything in SD.*

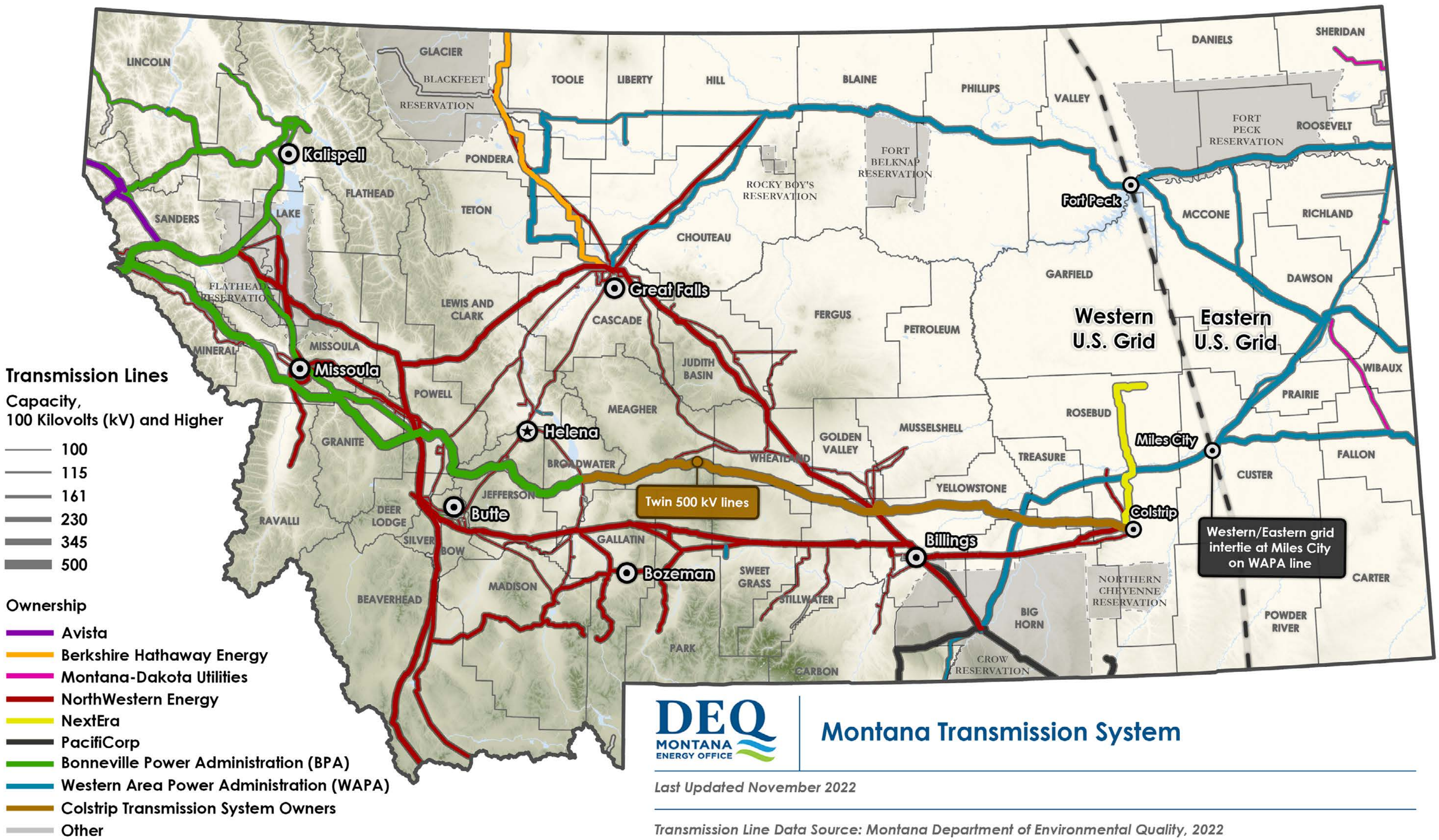
electricity to Fort Peck in the 1930s during construction of the dam there and then to move power to markets following construction of the generators at the dam. WAPA's system continued to grow in northern and eastern Montana as its needs to serve rural electric cooperatives expanded.

Long-distance interconnections between Montana and other states did not develop until around 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 now-defunct aluminum plant at Columbia Falls. In the mid-1980s, a double-circuit 500 kV line was built from the Colstrip generating plant in eastern Montana to the Idaho state line near Thompson Falls where it connects into two separate 500 kVs lines that head towards Washington State. The double circuit 500 kV lines are Montana's largest. Importantly, these Colstrip 500 kV lines, built to send power west out of state, are increasingly needed to import power east into NorthWestern's system to meet customer needs. By 2002, the MPC sold off all its generation and transmission holdings, becoming Touch America. Its transmission assets were purchased by NorthWestern and most of its generation was sold to Pennsylvania Power and Light (PPL). NorthWestern later purchased the hydro generation assets from PPL.

2C. CURRENT TRANSMISSION SYSTEM CONFIGURATION

Most in-state electric transmission in Montana is currently owned by NorthWestern Energy and WAPA. BPA has major interstate lines in northwest Montana and PacifiCorp owns a few smaller interstate lines as does Avista. Berkshire Hathaway Energy owns Montana Alberta Tie Ltd (MATL). WAPA lines in eastern Montana cross into North Dakota and serve local Montana loads in the eastern portion of the state. In most cases, Montana-Dakota's distribution service uses WAPA transmission lines and in a few cases co-owns the line. The electric distribution cooperatives in Montana are served by NorthWestern, Montana-Dakota, BPA, and WAPA transmission lines.

Map 2.1 Electric Transmission System



On an annual basis, Montana is an electricity exporting state. Until recently, the state's net electricity exports were almost equal to the amount of electricity consumed in the state each year. For example, in 2015 Montana generated 29,104 GWh and consumed just 14,207 GWh.[56] With the closure of Colstrip units 1 and 2, that changed in 2020. In that year, only 38 percent of Montana generated electricity was exported.

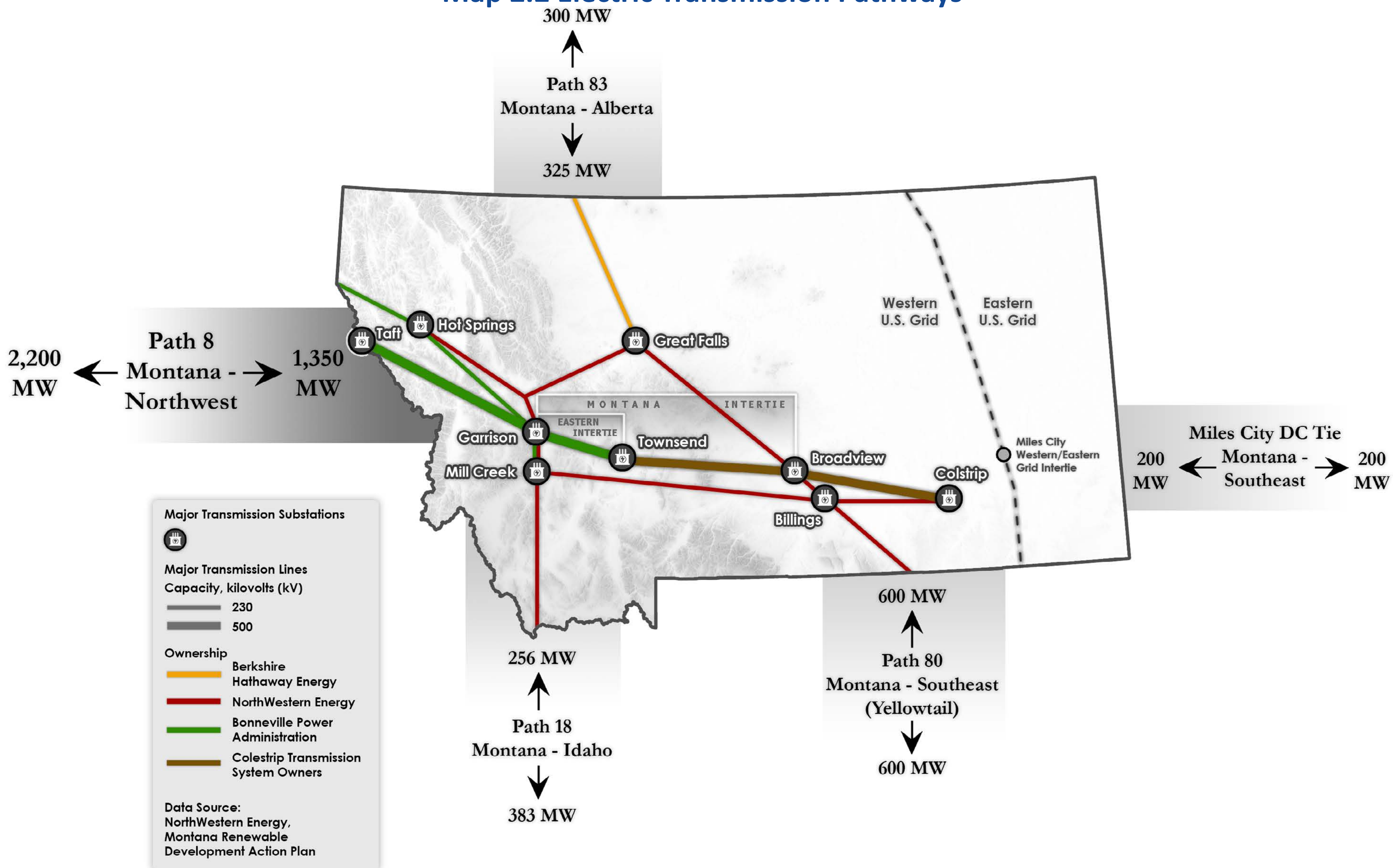
Transmission "paths" are generally groups of transmission lines that carry power within the same general areas along a given direction such as east-west or north-south. A given transmission path can consist of one or more transmission lines that transport electricity from one major electricity "node" to another. Nodes may consist of large generators, large loads, or a major substation. For example, the two transmission lines that run from the Dillon area into Idaho, the Grace line and the AMPS line, form what is called "Path 18".

There are four primary electric transmission paths that connect Montana to the rest of the Western Interconnect and larger markets in the West. These paths are:

- Montana to Northwest – Path 8
- Montana to Idaho – Path 18
- Montana Southeast – Path 80
- Montana to Alberta – Path 83

56 *U.S. Department of Energy, Energy Information Administration, 1990-2021, Form EIA-923 detailed data with previous form data (EIA-906/920).*

Map 2.2 Electric Transmission Pathways



Typically, power flows from east to west over Path 8, north to south over Paths 18 and 80, and varies on Path 83. Directionally, energy on these transmission lines typically flows from Montana to out-of-state loads, although increasingly electricity flows into Montana on these same lines. There is no official “path” leaving the most eastern portion of the state. It is important to note that Path 8 is very large, rated at 2,200 MW east-to-west whereas Path 18 is small rated at 383 MW north-to-south. The MATL path (Path 83) is rated at approximately 300 MW in both directions at this time and the transfer between Western and Eastern grids at Miles City (Path 80) is 200 MW and infrequently used. It is also important to note that these path rating amounts can change over time.

2D. HOW THE TRANSMISSION SYSTEM WORKS

There are big differences between the physical properties and economics of a typical alternating current (AC) electrical transmission system, as well as between its commercial operation and management. The flow of power on a transmission network (the charge of electrons) obeys the laws of physics. The commercial transactions that ship power across the grid follow a different, and not fully compatible, set of rules from the actual flow of power.

The transmission grid is sometimes described as an interstate highway system for electricity, but the flow of power on an AC grid differs in very significant ways from the flow of most physical commodities. When power is sent from one point to another on the transmission grid, the power will flow over all connected paths on the entire network (e.g. the Western Grid), rather than a single path (the scheduled path) or even the shortest distance path. A power transmission from one point to another will distribute itself so that the greatest portions of that power flow over the paths (transmission lines) of lowest electrical resistance. The resistance or impedance of a given transmission line depends on its voltage and current. Power flows generally cannot be constrained to any particular physical or contract path, but instead follow the laws of physics. It should be noted, however, that there are tools available to redirect some flows of power under certain economic or extreme circumstances.

Electric power 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 is shipped westbound on a given transmission line from point A to point B and 25 MW is sent simultaneously eastbound on that same line from point B to point A, the actual measured flow on the line is 75 MW in a westbound direction. If 100 MW is sent in each direction on the same line at the same time, the net measured flow is zero. In this simplified scenario, additional power could still physically flow in either direction up to the full capacity of the line in that particular direction. This is why transmission line operators usually offer a product called non-firm transmission when room is available on otherwise fully scheduled lines.

Electric power travels near the speed of light and is generally consumed at approximately the same moment it is generated. Almost all generated power distributed over the grid must be consumed instantaneously off of the grid. As a result, transmission operators constantly balance electricity supply (generation) and demand (consumption) in every moment. As time progresses, electricity is being stored as inventory in increasingly large quantities in batteries or pumped storage facilities. As battery technology quickly progress, higher levels of electricity storage are becoming a reality, but still remain a small fraction of total power being delivered.

Managing the grid is a complicated process that involves significant skilled personnel and automated technology.[57] Historically power was almost exclusively supplied from relatively consistent and/or dispatchable generation sources (e.g., hydro, coal, nuclear, gas) that were built to meet customer loads. The integration of variable resources like wind and solar generation at significant scale on the transmission system, adds complexity to the challenge of balancing transmission systems. The addition of variable resources to the grid has precipitated the deployment of highly flexible resources, including batteries, demand response, gas-fueled generation with quick ramping capabilities, and systems to curtail over-production of wind and solar generation. It is, in part, because of the constant need to balance supply and demand that the electric transmission system has been called the most complicated machine on the planet.

The actual physical flows on a grid are the net result of all generators and all loads (electricity demands) on the network at a given instant in time. 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 flows, actual transmission line path loadings at any given moment depend on the amounts and locations of electric generation and load as opposed to the contracted schedules in place at a given time. Actual path capacities are also impacted by congestion of certain lines or paths on the grid and outages on the grid. For example, Path 8 has a 2,200 MW path rating east to west under ideal conditions, but often has a lower rating under real-time conditions.

In contrast with the physical reality of the transmission network, management of transmission flows has historically been by "contract path". A transaction involving the shipment of power between two points, referred to as the contract path, is allowed to occur if space has been purchased on any path connecting the two points. Purchasers include the utilities or companies owning the lines or the entities holding rights to use those wires along that path at any given hour of the year (firm rights). Purchasers may also include entities that do not own firm rights but want to use the grid on a short-term basis when there is room available (non-firm transmission).

If scheduled flows do not exhaust a path rating (fill up the line), the unused capacity may be released as "non-firm" transmission capacity. Non-firm capacity is available during only some hours of the year, not during all hours as with firm capacity. Non-firm capacity is generally not purchased very far in advance. Owners of transmission capacity who do not plan to use extra room on their lines can in some instances release it early. Owners, however, are often reluctant to do so because of needs for flexibility or a desire to withhold access to markets from competitors.

In a perfect world, such transactions flow on the contract path agreed to by the interested parties. Due to the laws of physics that ultimately govern the grid and grid conditions at any given time, however, portions of any contracted transaction flow along other transmission paths aside from the contracted path. These are "unscheduled flows". An unscheduled flow is a result of the difference between the physics of the transmission system and the scheduling paradigm (contract rights). These flows can result in a variety of issues, including but not limited to unplanned loss of generators or load, data errors, and scheduling errors.[58]

Unscheduled flows may interfere with the ability of transmission path owners to make full use of their contractual rights. The Western Electricity Coordinating Council (WECC) addresses unscheduled flows with an unscheduled flow mitigation plan. Utilities (or other transmission owners) whose wires are affected accommodate a certain amount of this unscheduled flow by reducing their available transmission capacity. If further reductions are necessary, the path owners can request an adjustment of flows throughout the interconnection. Path owners can also call for curtailment of schedules across other paths that affect their ability to use their own path.[59]

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57 *There are several high-tech and human mechanisms for balancing supplies and demand on the entire Western Grid and within individual operating areas, like NorthWestern's balancing authority in Montana.*

58 *Byron Woertz, WECC, Manager, System Adequacy Planning.*

59 *Ibid.*

Transmission costs add monthly charges to electricity bills and can result in significantly different electricity costs across regions. Electricity prices are impacted by the cost of transmission service to move power from one area to another. For example, a generator in Montana who wishes to sell to the Mid-Columbia (Mid-C) market, the major electricity trading hub closest to Montana and located in Washington, pays transmission charges on the NorthWestern system and then on either the BPA or Avista system. These charges are necessary to transmit, or "wheel", the power from the NorthWestern system area to Mid-C.[60] These additional costs mean that the wholesale-priced power from generation in NorthWestern's territory for local Montana consumption is generally sold in Montana at a discount relative to the Mid-C market price for electricity because of the avoided transmission charges of sending that power into the Mid-C hub. In this manner, transmission pricing is integrally linked to electricity pricing throughout the region and the country. If transmission in a certain area tends to be congested, this can lead to higher electricity prices in areas that import that electricity. Southern California is a good example of a congested area with generally higher prices. This type of transmission fee structure would be very different if Montana utilities were a part of a RTO (see below).

Jurisdiction over transmission rates resides both with state utility regulators and with the Federal Energy Regulatory Commission (FERC), depending on circumstances. In the case of NorthWestern, transmission rates for bundled retail customers are determined by the Montana PSC. Wholesale transactions that use NorthWestern's transmission facilities pay the FERC-regulated transmission price. A standard feature of FERC-regulated transmission service is the Open Access Transmission Tariff (OATT). Each FERC-regulated transmission provider, including NorthWestern and BPA, posts the terms and conditions of its transmission service in its FERC-approved OATT. The OATT identifies various transmission product offerings, including network integration service, point to point (PTP) transmission service, and ancillary services.

PTP transmission service allows a transmission customer to wheel power to and from distinct locations. Ancillary services are services needed to support transmission service and maintain reliable operation of the transmission system. Each transmission provider's OATT includes terms and pricing for ancillary services that are required to support transmission service and maintain system balance. In general, FERC's treatment of these services is standardized across the country.

2E. MAJOR GRID INTERCONNECTIONS

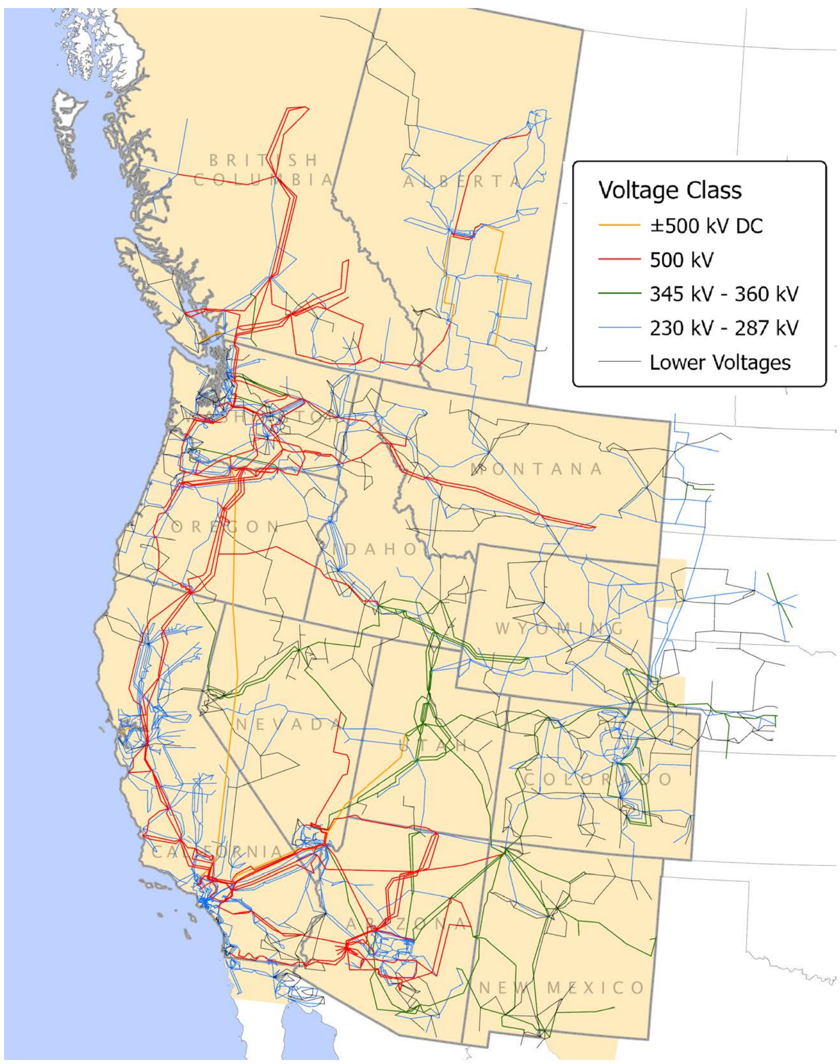
The United States transmission network has developed over time into three major interconnected grids or "interconnections", divided roughly along a line that runs through eastern Montana south to Texas. Most of Texas is on its own interconnection. The western United States is a single, interconnected, and synchronous electric system that will be referred to in this chapter as the U.S. Western Grid (Figure 5). Parts of Alberta and British Columbia are also part of the Western Grid. Most of the eastern and midwestern United States is a single, interconnected, and synchronous electric system as well (U.S. Eastern Grid). Texas is a separate interconnection with its own reliability council and is referred to as the Electric Reliability Council of Texas or ERCOT.

60 *In electric power transmission, wheeling is the transportation of electric energy (megawatt-hours) from within an electrical grid to an electrical load outside the grid boundaries. Two types of wheeling are 1) a wheel-through, where the electrical power generation and the load are both outside the boundaries of the transmission system and 2) a wheel-out, where the generation resource is inside the boundaries of the transmission system but the load is outside. Wheeling often refers to the scheduling of the energy transfer from one Balancing Authority to another.* https://en.wikipedia.org/wiki/Wheeling_(electric_power_transmission).

The Eastern and Western grids are not synchronous with each other. Each interconnection is internally in sync at 60 cycles per second, but each system is out of sync with the other systems. They cannot be directly connected because there would be massive instantaneous flows across any such connection. Therefore, the two grids are only minimally tied to each other with seven converter stations that convert AC electricity to Direct Current (DC) then back to AC.[61] One of these stations is located at Miles City. Operated by WAPA, the Miles City Converter Station is capable of transferring up to 200 MW of electricity in either direction from one grid to another.[62] Fort Peck Dam is the only other facility in Montana that bridges the Western and Eastern Interconnections. Hydroelectric generation units at the dam can be directed to either the Western or Eastern Interconnection depending on demand in either interconnect. However, unlike the Miles City Converter Station, Fort Peck Dam does not provide transfer capacity from one grid to the other.

Most of Montana is integrally tied into the U.S. Western Grid. The easternmost part of the state, with less than 10 percent of total Montana load, is part of the U.S. Eastern Grid and receives its power from generators located in that grid, including generators as far away as the east coast.

Map 2.3 U.S. Western Electric High-Voltage Grid[63]



61 National Renewable Energy Laboratory, 2021, "Where the east meets the west: Interconnections seam study shows value in joining U.S. transmission grids", https://www.nrel.gov/news/program/2021/where-the-east-meets-the-west-interconnections-seam-study.html.

62 Western Area Power Administration, https://www.wapa.gov/newsroom/Publications/Pages/converter-brochure.aspx.

63 Western Electricity Coordination Council.

Siting, construction and permitting of certain transmission lines in Montana are regulated under the Montana Major Facility Siting Act (MFSA) administered by the DEQ. The purposes of MFSA are to ensure the protection of the state's environmental resources, ensure the consideration of socioeconomic impacts from regulated facilities, provide citizens with an opportunity to participate in facility siting decisions, and establish a coordinated and efficient method for the processing of all authorizations required for regulated facilities. In general, electrical transmission lines greater than 69 kV and longer than ten miles in length are covered under MFSA if they meet certain criteria. Historically, the Montana PSC has jurisdiction over cost recovery for new transmission projects that serve Montana retail customers but not over siting decisions.

2F. TRANSMISSION SYSTEM RIGHTS

Rights to use the transmission system are held by the transmission line 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 compose the paths. In addition, the line owners have committed to a variety of contractual arrangements to ship power for other parties. Scheduled power flows by rights holders are not allowed to exceed the path ratings.

The FERC issued Order 888 in April 1996, which requires that transmission owners functionally separate their transmission operations and their power marketing operations. This means that all generators have the right to access utilities' transmission systems. If the transmission system in place does not have sufficient capacity to accommodate a bona fide request for transmission service, the utility must begin the process to build the needed upgrades, provided that the transmission customer pays for the incremental cost of the upgrades.

Power marketing occurs when transmission owners that own generation market it off-system to make money or to reduce costs for their native loads. These transmission line owners must allow other parties to use their systems under the same terms and conditions as their own marketing arms. Each transmission owner must maintain a public website called Open Access Same-Time Information System (OASIS) on which available capacity is posted.

Available transmission capacity (ATC) is the available room on existing transmission lines to move power during every hour of the year. ATC is calculated, at any given time, by subtracting committed uses and existing contracts from total rated transfer capacity on existing transmission lines. ATC may change on an hourly basis depending on grid conditions. These existing rights and ATC are rights to transfer power on a firm basis every hour of the year. The owners of transmission rights on rated paths may or may not actually schedule power during every hour. When they don't, the unused space may be available on a non-firm basis (as explained above). As of 2022, a small amount of ATC is available on most major rated paths on the U.S. Western Grid, including those paths leading west from Montana to the West Coast. The rights to use the existing capacity on these lines are for the most part fully allocated and tightly held.

In terms of ATC, incremental export capacity out of Montana is extremely limited. There is little incremental firm export capacity out of Montana to the Southwest (Path 18) and to the Northwest (Path 8). Half of the combined 614 MW generating capacity of Colstrip Units 1 and 2 was owned by Puget Sound Energy and served Washington customers; with the retirement of those units in 2020 the allocation of ATC on the Colstrip Transmission System undoubtedly changed but the details of those transmission contracts are not public information. ATC is also constrained in-state on NorthWestern's system--especially in the area south of Great Falls. Where ATC is available in-state, it is typically to move power within Montana or wheel power through Montana to interstate lines.

Despite little ATC availability, most transmission paths on the Western Grid are fully scheduled for only a small portion of the year, and non-firm space is often available. However, non-firm access cannot be scheduled far in advance, and its access cannot be guaranteed. Non-firm access is a workable way to market excess power for existing generators. Non-firm availability also may be a reasonable way to develop new firm power transactions if backup arrangements can be made to cover the contracts in the event that the non-firm space becomes unavailable.

2G. GRID CAPACITY AND RELIABILITY

The amount of power that a transmission line can carry is limited by several factors, including its thermal limit. When electricity flows get high enough on a particular line, the wire heats up and stretches, eventually sagging too close to the ground or other objects. Arcing -- electricity traveling to the ground -- may result. When that happens, the transmission line can fail, instantly stopping electricity flow and affecting connected transmission and distribution system assets. Inductive characteristics on a line are associated with magnetic fields that constantly expand and contract in AC circuits wherever there are coils of wire, including transformers. This is not an issue for DC transmission lines.

The most important reason for determining the total amount of power that a line can carry is reliability. Reliability is the ability of the transmission system to provide full, uninterrupted electricity service to its customers despite the failure of one or more component parts of that system. The transmission network is composed of thousands of elements that are subject to failure. Causes of failure include lightning, ice, pole collapse, animals shorting out transmission lines, falling trees, vandalism, and increasingly terrorism (including cyber-attacks). Reliability of the grid is ensured by building redundancy into it. The grid is designed to withstand the loss of key elements and still provide uninterrupted service to customers.

Reliability concerns limit the amount of power that can be carried over a line or path to the amount of load that can be served with key transmission elements out of service on the grid. Within NorthWestern's service area in Montana the reliability of the transmission system is evaluated by computer simulation through long-term transmission planning. The network is simulated at future load and generation levels while taking key individual elements out of service. The simulation determines whether all loads can be served with voltage levels and frequencies within acceptable ranges. If acceptable limits are violated, the transmission network must be expanded and/or strengthened. Typically, this entails adding transmission lines to the system, replacing components of the system, or rebuilding existing lines to higher capacities.

Another example of reliability limits relates to major transmission paths used to serve distant loads or to make wholesale transactions. Most major paths are rated in terms of the amount of power they can carry based on their strongest transmission element being unavailable (usually a single large line). In some cases, the reliability criteria require the ability to withstand having two or more elements out of service. The Colstrip 500 kV lines west of Townsend are a double-circuit line, but they cannot reliably carry power up to their thermal limit because one circuit may be out of service and because both circuits are on the same towers (increasing the chance of a wildfire or other catastrophic event taking out both paths). As a result, they carry significantly less power than their thermal limit in either direction.

The actual rating on a path can change hourly and depends on several factors, including ambient air temperature, other lines being out of service, and various load and supply conditions on the larger grid. The Montana transmission lines heading west toward the Idaho panhandle and Washington are called the Montana-Northwest path (Path 8). The Montana-Northwest path is generally limited to 2,200 MW east to west and 1,350 MW west to east. These are the maximum ratings under ideal conditions, and the ratings on these paths are often lower. The Montana-Northwest path leads to the West of Hatwai path, which is larger and is composed of a number of related lines west of the Spokane area. The closing of Colstrip over time could change these limit ratings.

2H. CONGESTION

Transmission constraints are often referred to as transmission 'congestion'. Transmission congestion raises the price of delivered power. It often prevents low-cost power from reaching the areas where it is needed. Low-cost power has little value if it cannot be transmitted to a location where energy is needed. For example, because most existing Montana transmission is fully contracted, future generators in Montana may be prevented from selling their power into external markets except by using non-firm rights or paying for new transmission lines to be built. When transmission congestion exists, generators may be forced to sell into other locations where buyers pay less for power or to even curtail their power.

In general terms, additional transmission capacity allows more generators to access the grid, promoting competition and lowering prices. Conversely, limited capacity necessitates either energy transaction curtailment or re-dispatch from a generator that bypasses the bottleneck in the system. Transmission congestion can have several different meanings. A transmission path may be described as congested if no rights to use it are for sale. Congestion also may mean that a path is fully scheduled, and no firm space is available, or it could mean that the path is fully loaded in the physical sense.

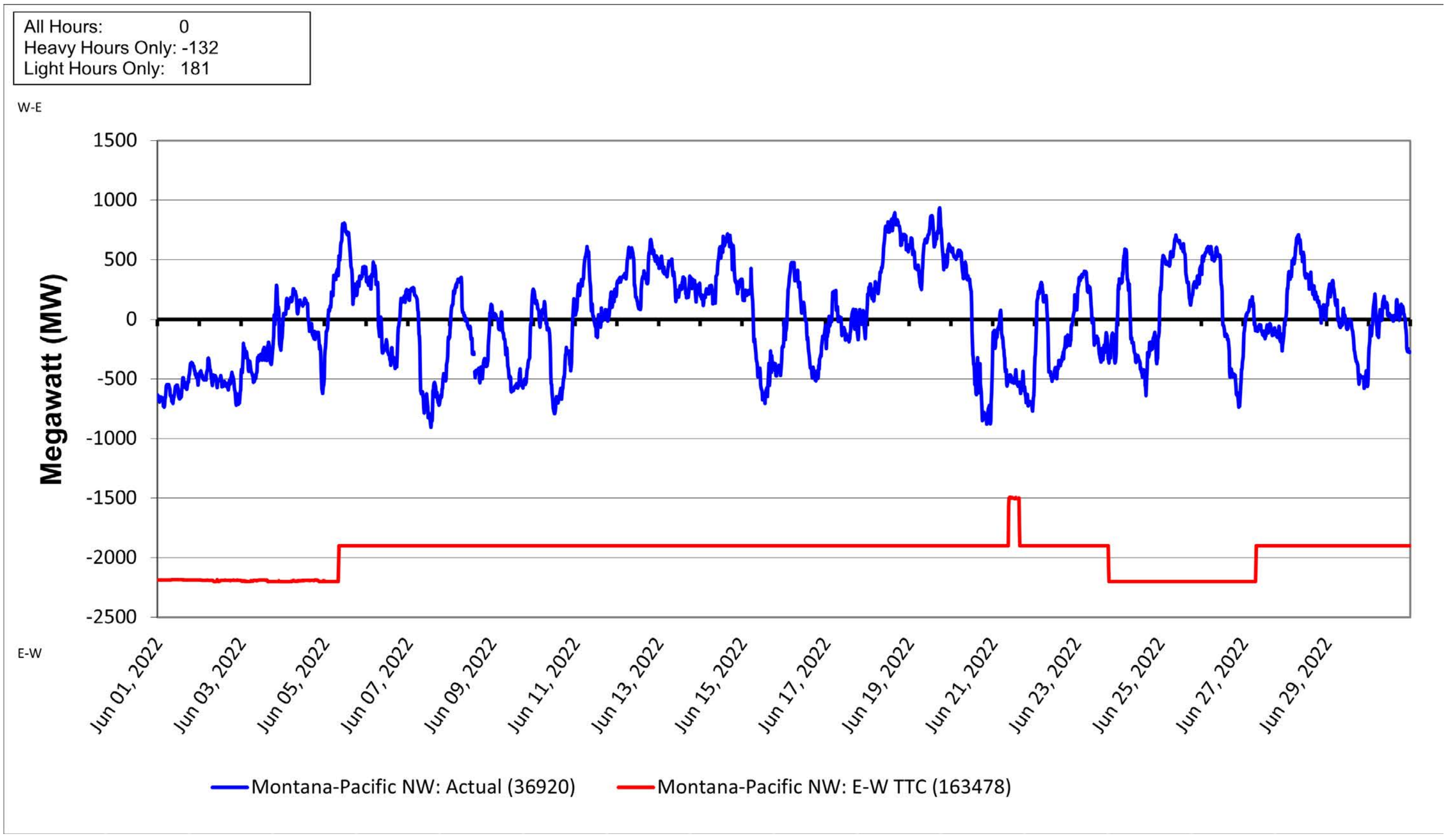
By the first definition, the paths through which generators in Montana send their power west, and that includes West of Hatwai, are mostly congested – and few firm rights are currently available for those paths. By the second definition, the paths west of Montana are congested during a few hours of the year – contract holders fully use their scheduling rights only a small fraction of the time; the rest of the time they use only portions of their rights.

By the third definition, the lines are almost never physically congested. Even when the lines are fully scheduled, the net flows are almost always below path ratings. The third definition is based on actual loadings. Actual loadings are different from scheduled flows because of the difference between the physics and the management of the grid. It should be noted, that although most transmission lines are not physically congested at a given moment in time, the instances where they are congested seem to be increasing because of electricity moving differently around the grid today and weather disruption of lines become more frequent (e.g., high winds, wildfires).

Actual flows on the paths west of Montana are almost always below scheduled flows because of the inadvertent flows and loop flows in that part of the grid. For most hours, flows on paths out of Montana are not heavily loaded. Even a well-used path such as Path 8, usually has physical space available for more electrons.

The most recent month of data from Path 8, the Northwest-Montana cutplane, in June 2022, shows actual flows (in blue) well below Total Transmission Capacity (red line). This figure should be read upside-down in the sense that the red line is the capacity level and anything above it is electricity loading below capacity.

Figure 2.1 Montana-Pacific NW: 15-Min Averages Actual Loadings: 06/01/2022 - 07/01/2022 (30 Days)[64]



A considerable amount of existing capacity on transmission lines is not available for use because it is held off the table for reliability reasons when paths are rated. 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.

2I. RECENT TRANSMISSION LINE DEVELOPMENTS IN MONTANA

In recent years, there has been a strong interest in developing additional transmission to export Montana's generation potential to other markets. The Western Grid will need substantial new transmission resources in order to replace retiring generation and to meet environmental goals established in many states. Renewable resource mandates in many western states also suggest that a significant portion of newly built resources will be renewable. Most of the plants scheduled for retirement in the U.S. Western Grid are coal and nuclear generation plants.

The Montana Alberta Tie Ltd (MATL) came online in September 2013. It is the first direct interconnection between the Alberta and Montana balancing areas and is capable of carrying 300 MW in either direction.

64 *15-minute average of 2-second SCADA MW readings via PI BPA, https://transmission.bpa.gov/Business/Operations/Paths/. Note: BPA monitors system conditions and provides mitigation as needed per appropriate reliability issues and NERC standards.*

In the last decade, a few rebuilds of existing lines have taken place in Montana, including a WAPA 115 kV line between Great Falls and Havre built to 230 kV specifications and the rebuild of BPA's 115 kV line from Libby to Troy. NorthWestern replaced a 50 kV line between Three Forks and the Four Corners area with a new 161 kV line. NorthWestern also completed the upgrade to a 161 kV line between Four Corners and Big Sky. At this time, Montana-Dakota has indicated it has no major plans for electric transmission upgrades in Montana.

The Montana to Washington project (M2W) is a long-proposed upgrade to BPA's portion of the dual-circuit 500 kV line and could be used by new generators to access West Coast markets. Similar upgrades on the Colstrip lines have been discussed for central Montana. It would not require a new right of way and would utilize existing poles. Additional developers looking at projects in Montana have expressed interest in utilizing the potential upgraded BPA capacity that would be created by the project. Additional transmission constraints exist to the west of this segment in Washington State that would need to be dealt with separately to move power to the specific load centers that the Montana developers are interested in reaching.[65]

New lines connecting Montana to the rest of the Western Grid could potentially increase competition among Montana energy suppliers. This would especially be the case in conjunction with a RTO. Increasing supplier competition in Montana's market could lower or stabilize electricity prices to Montana ratepayers in the near and distant future, although the extent and significance of such savings are unknown. New lines could also allow substantial new generation to be built in Montana.

On the flip side, new high-voltage transmission lines can be difficult and contentious to site. Siting the Colstrip double-circuit 500 kV lines in western Montana, particularly in the areas of Boulder, Rock Creek, and Missoula, required much work with a variety of entities.[66] As a result, the resulting route was sited away from the interstate highway corridor, opening new corridors through forested areas. Recent experience with the MATL and the proposed Montana States Transmission Intertie (MSTI) transmission lines shows that Montana citizens and landowners are concerned about new line interference with farming practices, visual impacts, reductions in property values, potential human health effects, and the use of private land rather than public land for electric transmission purposes.

Rural growth and residential construction in western Montana since the Colstrip lines were sited in the early 1980s may compound siting challenges for additional new lines sited through the western portion of the state. Siting opportunities are limited by actual and contemplated wilderness areas and Glacier National Park in the western region. Siting and routing a new line out of the state in a westerly direction would likely prove extremely challenging due to geographical, wilderness, and political issues.

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65 *Mark Rellar, BPA.*

66 *The original centerline proposed by the Colstrip partners crossing of the Confederated Salish and Kootenai Tribes would not be granted an easement by the tribe to get to the Hot Springs substation. The Colstrip partners got BPA to take over responsibility to build the line from Townsend west. BPA had originally planned to build the line on a right-of-way BPA already owned through the reservation. But during the NEPA process, it was determined that going to the Taft substation was preferable to the one at Hot Springs.*

2J. REGIONAL TRANSMISSION INTEGRATION AND MARKET DEVELOPMENT

REGIONAL TRANSMISSION ORGANIZATIONS

A large portion of the electric load in the U.S. is procured through market transactions overseen by various Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs).[67] These organizations are independent entities that emerged because of guidelines prescribed in FERC Orders 888 and 889 with which FERC sought to introduce competition and efficiency into electricity markets. RTOs/ISOs are charged under these orders with promoting nondiscriminatory access to the grid.[68]

The California ISO (CAISO) is the only ISO or RTO in the western United States. Much of Alberta and British Columbia, which are part of the U.S. Western Grid, are served by their own ISOs. While most of Montana's service area is not part of an RTO, the MISO, which covers much of the Midwest, covers parts of eastern Montana that lie in the U.S. Eastern Grid. Most of the U.S. Western Interconnection is not part of an RTO. From here on, we will use RTO to refer to an ISO or RTO as they are virtually the same thing

RTOs are independent and each one has its own complex rules. RTOs provide open access to the transmission system, and optimize the dispatch of generation across broad areas, rather than have each utility do so. Typically, a fully functional ISO has a single balancing authority and conducts the reliability coordination functions for all member utilities. A utility that does not participate in an RTO, sets their own stacking order and costs, typically with bilateral contracts. An RTO does this for all of its utilities and dispatches generation accordingly. An RTO, in theory, allows all parties to signal their willingness to pay for transmission access and makes more efficient use of the grid. In addition, RTO management results in congestion price signals that encourage economic decisions on the location of new generation and on the expansion of capacity on congested transmission paths. RTOs also over time save utilities and their ratepayers money by allowing better access to cheaper generation and by saving balancing areas the need to build additional generation.

RTO transmission pricing generally avoids pancaked transmission rates (paying a single rate for each balancing authority crossed) and signals the actual amount of congestion on the system. Two types of transmission tariffs under RTOs are postage stamp and license plate rates. With postage stamp rates, transmission costs are recovered uniformly from all loads in a defined market area. With a license plate rate, each utility recovers the costs of its own transmission investments that reflects the costs and usage in the transmission zone within which they are located. RTO's also generally plan transmission expansion for their whole footprint over a larger area, versus each utility doing their own planning.

Discussions about allowing an independent body to take over operation and control of access for the transmission system began in the mid-1990s among transmission owners and other stakeholders in the Pacific Northwest. Effects of an RTO on Montana will need to be examined as the possibility of market formation grows. Talks continue among various entities in the West on expanding energy cost savings. Talks are also occurring on taking an incremental approach and developing certain aspects of RTOs such as Energy Imbalance Markets (discussed below) rather than implementing an RTO all at once. PacifiCorp, which operates as a retail electric utility in pockets across the Western Interconnect, including parts of Wyoming that neighbor Montana, has been working with CAISO to evaluate the steps that would be needed to integrate CAISO and the balancing authorities operated by PacifiCorp. The Mountain West Transmission Group, a group of electricity service

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67 For our purposes here, we will regard RTOs and ISOs as the same thing.

68 Markets for Power in the United States, Paul L. Joskow, The Energy Journal, Vol. 27, No. 1, 2006, page 17.

providers that cover Colorado and parts of four other western states, is exploring joining with the Southwest Power Pool's regional transmission organization, which currently resides on the U.S. Eastern grid, but which could expand to the western grid.

ELECTRICITY MARKET DEVELOPMENT

Over the past several decades, the U.S electric sector has trended toward organized markets to promote efficiency, reliability, cost savings and to lower emissions and assist states and utilities in meeting environmental goals.

The Western Energy Imbalance Market (EIM) is a real time wholesale energy trading market that enables participants anywhere in the West to buy and sell energy when needed. It is governed by the CAISO. To date, the EIM has generated over a billion dollars in gross profits.[69] The EIM allows participants to buy and sell power close to the time electricity is consumed, and gives system operators real-time visibility across neighboring grids. The result improves balancing supply and demand at a lower cost.[70] An EIM aggregates the variability of generation and load over balancing authorities and reduces the total amount of required reserves for a balancing area.

The enhanced day-ahead market is related to the Western EIM. As stated on CAISO's website[71]:

> *"This initiative will develop an approach to extend participation in the day-ahead market to the Western Energy Imbalance Market (EIM) entities in a framework similar to the existing EIM approach for the real-time market, rather than requiring full integration into the California ISO balancing area. The extended day-ahead market (EDAM) will improve market efficiency by integrating renewable resources using day-ahead unit commitment and scheduling across a larger area."*

Another RTO, the Southwest Power Pool, is looking to serve utilities across the west with its own grid services program, called Markets +, which would also offer an EIM and day-ahead market.

RESOURCE ADEQUACY PLANNING

Electric system reliability is expensive and currently in short supply across Montana and the Pacific Northwest. NorthWestern is one of the most capacity deficient utilities in the region, meaning it is short on flexible, dispatchable resources that can meet peak electricity demands, according to the utility. A combination of the shifting portfolio of generation assets across the Pacific Northwest and Montana, including coal plant retirements and significant new variable renewable energy assets, the increasing frequency of severe weather events, and increasing demand for electricity are creating new challenges for utilities and grid operators.

With a goal of improving reliability and flexibility for utilities across the west, the Western Power Pool, an organization of utilities and independent power producers, is developing the Western Resource Adequacy Program (WRAP). Absent an RTO in the immediate region this program is designed to help utilities share

69 https://www.caiso.com/Documents/western-energy-imbalance-market-fact-sheet.pdf

70 https://www.westerneim.com/Pages/About/HowItWorks.aspx

71 https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market resources in an organized way when needed (such as when one utility comes up short unexpectedly), and lower the chances that individual utilities will need to curtail load due to inadequate generation resources. The Montana Energy Office served on an advisory committee during the design and start-up phases of the WRAP. The WRAP will likely affect Montana customers of NorthWestern, which is participating in the first non-binding stage of this program, as well as electric cooperatives served by BPA, an additional participant in the WRAP.

Within this program, entities can pool the risk and the associated reserves and benefit from the so-called "diversity benefit" of the region, with overall reliability cost reductions being one of the targeted outcomes. Load and resource diversity drive the regional savings. In a large portion of the Western Power Pool footprint, utilities manage resource adequacy individually and with different methods. A regional resource adequacy program promises to facilitate coordinated resource forecasting and planning.

STATE-LED ANALYSIS OF MARKET BENEFITS AND COSTS

The last several years have featured numerous discussions and initiatives related to the formation of coordinated wholesale trading markets in the West. The Utah Governor's Office of Energy Development, in partnership with State Energy Offices of Idaho, Colorado, and Montana, applied for and received a grant from the U.S. Department of Energy to facilitate a state-led assessment of organized market options. The project was called Exploring Western Organized Market Configurations: A Western States' Study of Coordinated Market Options to Advance State Energy Policies or "State-Led Market Study".[72]

The project provided Western States with a neutral forum, and neutral analysis, to independently and jointly evaluate the options and impacts associated with new or more centralized wholesale energy markets and potential footprints. The regional economic case for new/expanded markets is supported by the technical findings of the study. Capacity benefits for the U.S. West were estimated at around 1,100 MW for an EIM and about 11,300 MW for an RTO (this is the estimated amount of electricity generation that would not have to be built for reliability under an organized market). The RTO market constructs achieved the greatest level of capacity savings of all constructs. At the state-level, all states achieve positive capacity savings in all market configurations. In addition, all states have estimated savings greater than $10 million per year under the One Market RTO construct. RTOs resulted in the most carbon emissions reductions and the least renewable curtailments compared to EIMs and a day-ahead market, according to the study. A west-wide RTO could result in up to $2 billion in benefits per year for the entire region.

The report also concluded that informed state engagement throughout the process of proposed market expansion is a best practice that can enhance states' ongoing influence and potentially improve outcomes associated with market formation. States can play a crucial role in shaping discussions around the development of market expansion proposals and in crafting an ongoing role for states through an influential regional state committee. To the extent that market proposals culminate in utilities seeking state public utility commission approval to join a market, utility commissions have an opportunity to carefully evaluate the proposal and set forth conditions of approval for market participation, reaffirming the important role of states in potential market expansion. In Montana, that body is the PSC. States can carefully consider any proposals that may come before them to unbundle retail electric rates in a manner that may reduce state jurisdiction over these costs.

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72 *https://static1.squarespace.com/static/59b97b188fd4d2645224448b/t/6148a03ea5c43d63b2873506/1632149569046/Final+Roadmap+-+Market+and+Regulatory+Review+Report+210730.pdf*

2K. CURRENT TRANSMISSION ISSUES

TRANSMISSION CAPACITY TO ACCOMMODATE NEW GENERATION IN MONTANA

There is a “chicken and egg” problem in developing new transmission projects to facilitate economic development. If no transmission capacity is available to reach markets, generation developers may have a difficult time financing transmission projects. Yet without financing, potential generators probably can’t make firm commitments to purchasing rights on lines in order for utilities to invest in new transmission capacity projects. Alternative approaches involve generation developers building for anticipated new load or construction of new merchant transmission capacity built in the hopes that generation will appear. These strategies still require financial markets to be convinced that the projects are viable.

New generation plants usually need firm power purchase agreements (PPA) in place with an off-taker in order to obtain project financing. Occasionally, generation plants are built to market their energy to sell into wholesale markets, but this is more common in deregulated electricity markets. With low spot prices across the West and tightened lending requirements (by financial institutions), the majority of projects expected to be built in the western U.S. in the next decade will probably need firm power purchase agreements before ground is broken. Few transmission projects were built at all in the U.S. West in the 2010s. The challenge that Montana projects—like all projects—face is contracting to produce power for customers at a price that is both profitable to the project developer/owner and competitive with other energy sources, including sources potentially closer to the end-consumer. Transmission charges could be high enough between Montana resources and West Coast load centers to challenge the competitiveness of Montana-based projects. Low/volatile electricity prices and ISOs/RTOs have thrown even more uncertainty into the process.

The regulatory structure in Montana requires a showing of need for new transmission projects that are 230 kV or larger and ten miles or longer that fall under MFSA (75-20-104(8)(a)(i), MCA). Transmission builders without PPA contract commitments from potential new generators looking to contract for transmission service may face an uphill battle in demonstrating the need for new transmission. Further complicating this issue is that many attributes of power, such as flexibility, ramping capability, etc. are not currently valued in energy markets. Thus, a generator that provides grid and/or power flexibility (such as a natural gas plant) may not be valued enough in the market to build the project at a time when such flexibility is needed on the grid.

SMART GRID

A smart grid is a modernized electrical grid that uses information and communications technology to gather and act on information in an automated fashion to improve the efficiency, reliability, economics, and sustainability of the production and distribution of electricity. “Smart grid” generally refers to a class of technology people are using to bring utility electricity delivery systems into the 21st century, using computer-based remote control and automation. These systems are made possible by two-way communication technology and computer processing that has been used for decades in other industries. Smart grid technology is beginning to be used on electricity networks, from the power plants and wind farms all the way to the consumers of electricity in homes and businesses. A smart grid can alert customers to real time prices in order to promote conservation and allow for tiered electricity pricing. This technology can also help the grid be managed from many places and sensors rather than one central location, and potentially lead to lower restorations times after a blackout. Concerns about the smart grid include cost, cybersecurity concerns, and personal privacy.

CYBERSECURITY

An adversary with the capability to exploit vulnerabilities within the U.S. power grid might be motivated to carry out a cyber-attack under a variety of circumstances. An attack on the power grid could be part of a coordinated military action, intended as a signaling mechanism during a crisis, or as a punitive measure in response to U.S. actions in some other arena. In each case, the United States should consider not only the potential damage and disruption caused by a cyberattack but also its broader effects on U.S. actions at the time it occurs. With respect to the former, a cyberattack could cause power losses in large portions of the United States that could last days in most places and up to several weeks in others. The economic costs would be substantial. As for the latter concern, the U.S. response or non-response could harm U.S. interests.

Attacks on power grids are no longer a theoretical concern. In 2015, an attacker took down parts of a power grid in Ukraine. Although attribution was not definitive, geopolitical circumstances and forensic evidence suggest Russian involvement. A year later, Russian hackers targeted a transmission level substation, blacking out part of Kiev. In 2014, Admiral Michael Rogers, director of the National Security Agency, testified before the U.S. Congress that China and a few other countries likely had the capability to shut down the U.S. power grid. Attacks could easily inflict much greater damage than intended, in good part because the many health and safety systems that depend on electricity could fail as well, resulting in widespread injuries and fatalities. Given the fragility of many industrial control systems, even reconnaissance activity risks accidentally causing harm.[73]

Today, the electric power industry is forging ahead with a series of initiatives to safeguard the electric grid from threats and is partnering with federal agencies to improve sector-wide resilience to cyber and physical threats. The Cybersecurity and Infrastructure Security Agency (CISA) leads the way with information on protecting energy companies from cyber intrusions and the 2021 Infrastructure Investment and Jobs Act bill provides funding. The industry also collaborates with the National Institute of Standards and Technology, the North American Electric Reliability Corporation, and federal intelligence and law enforcement agencies to strengthen its capabilities.[74]

WILDFIRES

Wildfires are an increasing concern for transmission operators. Fires can disrupt or damage transmission lines causing service disruptions and voltage fluctuations. Also, transmission lines have recently been a cause of wildfires, especially across the U.S. West. Operators of transmission lines are developing new strategies to deal with this issue including shutting lines off, employing video cameras in strategic locations to spot fires, and using advanced weather forecasting. California transmission line operators are especially using new technologies to address this issue. Montana has less forest-transmission line interface overall than some states, although there is plenty in the western part of the state. NorthWestern, BPA and Montana-Dakota plan tree maintenance every year along transmission line right-of ways as a part of its transmission planning.

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73 Text taken from Council on Foreign Relations, "A Cyberattack on the U.S. Power Grid", https://www.cfr.org/report/cyberattack-us-power-grid.

74 https://www.eei.org/issues-and-policy/security

3. NATURAL GAS IN MONTANA

Natural gas is a major energy source for residential, commercial, and industrial customers in Montana. Several electric generation plants in the state also use natural gas. Nationally, natural gas exports to other nations are increasing. Since the early 2010s, hydraulic fracturing of natural gas wells (commonly called "fracking") increased domestic supply, pushing down prices and increasing demand.[75] However, Russia's invasion of Ukraine in early 2022 destabilized natural gas prices as Europe and other markets look for options to wean their reliance on Russian gas supplies.

Montana is part of the North American natural gas market, with prices and availability set more often by events occurring outside Montana. Electricity and natural gas markets are intricately linked and affect gas prices on short notice. As natural gas markets become increasingly complex and fracking dominates the natural gas industry, the price and availability of natural gas in Montana may behave in ways unseen in previous decades.

3A. CURRENT ISSUES

Natural gas prices were low in 2020 and the first half of 2021 due in part to slightly lower natural gas demand from COVID-19-related restrictions including business closures. In the fall of 2021, the increased demand for energy increased natural gas exports, and higher futures prices pushed the price of natural gas to multi-year highs. The 2020 average Henry Hub spot price was $2.03 per Million British thermal units(MMBtu), the October 2021 price was $5.51 and in April 2022 was $6.60.[76] The U.S. EIA stated in November of 2021:

> *"U.S. natural gas production and consumption decreased in 2020 because of mild winter weather and the COVID-19 pandemic's effect on demand, according to our recently released Natural Gas Annual. Less natural gas was consumed in the United States, which pushed prices down; the annual Henry Hub spot price for 2020 averaged $2.03 per million British thermal units (MMBtu), the lowest annual price since 1997. The low prices contributed to record-high levels of natural gas exports and consumption in the electric power sector in 2020."*[77]

Electrical generation, both in-state and nationwide, relies on natural gas for a fuel source. Natural gas was the primary fuel choice for new electricity generation in the U.S. West for decades until that balance shifted toward wind and solar generation in the 2010s. Across the west the shift is a result of market and policy trends, including state-level carbon emissions goals and the proliferation of zero-fuel-cost renewable generation. Recently, natural gas generation has resurged as a preferred fuel source due to a need for dispatchable and flexible electricity sources. The trend is occurring as utilities across the west retire coal units and look to natural gas as one tool to integrate low-cost, variable renewable resources.

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75 *Since around 2010, shale gas produced by fracking has produced the majority of natural gas in the U.S. This trend is only expected to increase through 2050, U.S. Energy Information Administration, Annual Energy Outlook 2022 (AEO2022) https://www.eia.gov/outlooks/aeo/pdf/AEO2022_ChartLibrary_Naturalgas.pdf.*

76 *U.S. EIA, January, 2022, https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.*

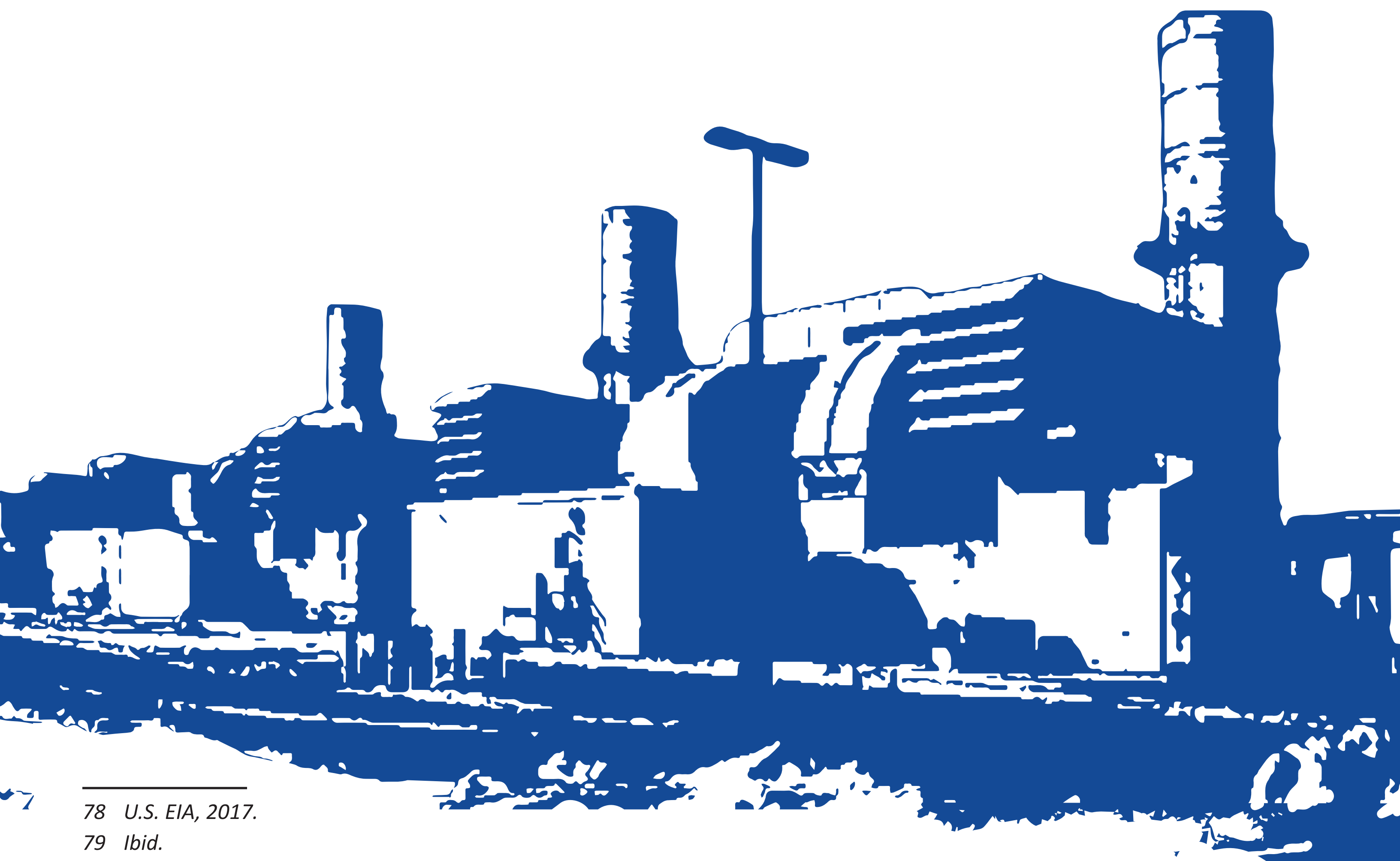
77 *U.S. EIA, Today in Energy, 2021, https://www.eia.gov/todayinenergy/detail.php?id=50196.*

A new 175 MW natural gas-fueled generating station is currently under construction in Laurel. The NorthWestern Energy project will be the first natural gas power plant to come online in Montana since Montana-Dakota Utilities completed the installation of the 19 MW Lewis and Clark plant in 2015. NorthWestern's Yellowstone County Generating Station, with a targeted on-line date of 2023, is slated to include 18 highly flexible, reciprocating internal combustion engine (RICE) units.

3B. IN-STATE NATURAL GAS PRODUCTION AND SUPPLY

Montana currently consumes more natural gas than it produces. In 2019, Montana produced 48.4 billion cubic feet (Bcf) and consumed a total of 81.1 Bcf.[78] A significant portion of in-state production is exported, and at least half of Montana's consumption is imported from Canada and other states. These market patterns of import and export are driven by the trading structure of natural gas contracts, as well as the configuration of pipelines and wells in Montana.

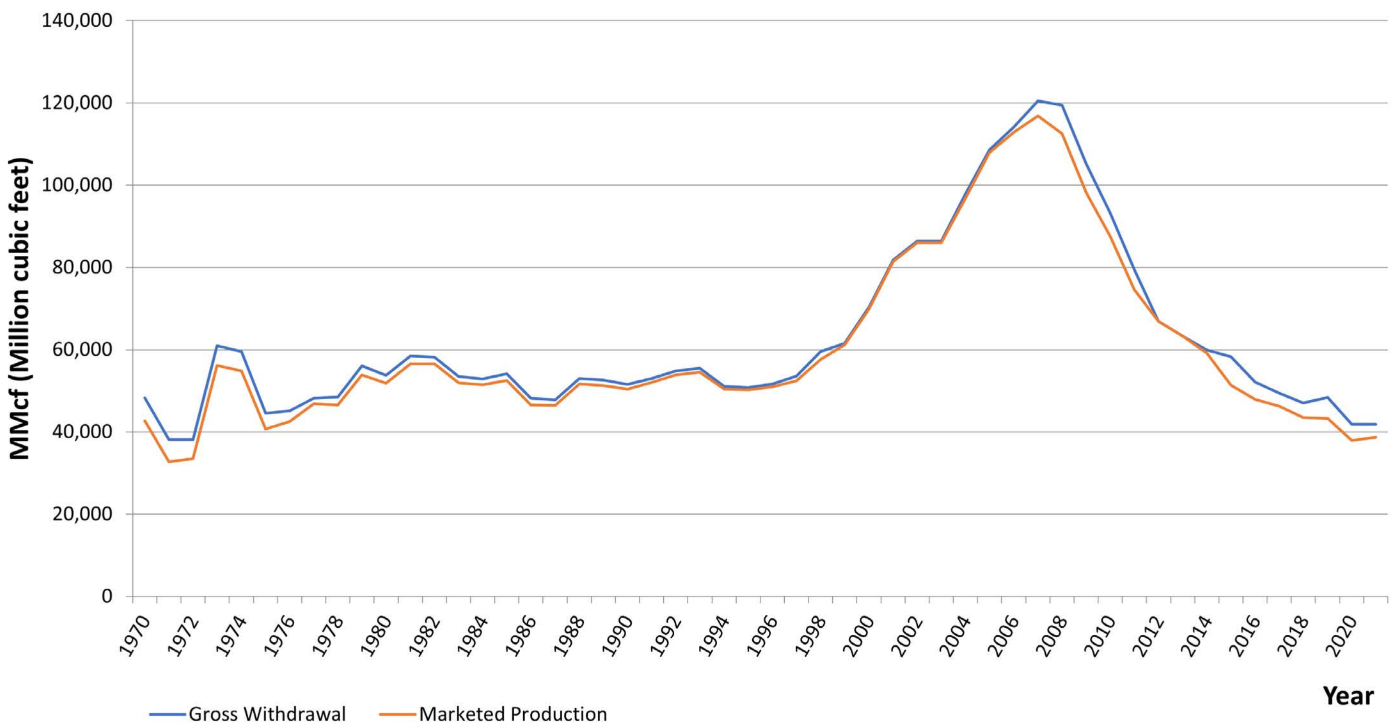
From 2015 to 2019, Montana produced an annual average of about 46 Bcf of gas, which is down from the early 2000s when the average was around 100 Bcf per year and annual production totals reached as high as 117 Bcf in 2007. Reasons for the recent decline in Montana gas production include less associated natural gas production from the Bakken oil field, the economic collapse of coal-bed methane, limited fracking in Montana, declining production from conventional shallow wells, and nearly no new conventional wells being drilled. This is shown in Figure 3.1. From 2015 to 2019, Montana consumed an annual average of 79.7 billion cubic feet (Bcf) of gas, rising slightly since 2000.[79]



78 U.S. EIA, 2017.

79 Ibid.

Figure 3.1 Natural Gas Production in Montana (1970-2020)[80]



Gas wells in Alberta and Montana provide most of the natural gas supply for Montana customers, a market condition unlikely to change in the future. Reasons include Montana's proximity to Alberta's large gas reserves and the configuration of pipelines within and outside of the state. Supplies from other states including Wyoming and North Dakota also represent a small portion of total in-state usage, mostly on Montana-Dakota's WBI Energy natural gas system. With NorthWestern's purchases of natural gas fields in north-central Montana in 2010 and 2013, a larger percentage of gas consumed in Montana is produced in-state than in past years. Before 2010, most of the gas in the north-central fields was collected by the Havre Pipeline. Before NorthWestern bought the Havre Pipeline, the gas on that line flowed north into Canada. NorthWestern also had a contract with Havre Pipeline that had some gas flowing south onto Northwestern's system during peaking events. Currently, by contrast, most gas on the Havre Pipeline ends up on NorthWestern's system for use by Montana customers.[81]

In-state gas wells are located primarily in the north-central portion of the state. In 2019, the northern portion of Montana accounted for 74 percent of total in-state production, the northeastern portion 24 percent, and the south-central portion 3 percent, as defined by Montana Board of Oil and Gas Conservation.[82] In-state gas production increased from relatively constant historical levels from 1995 to 2007 and then saw sharp declines in the years since. Blaine, Fallon, Hill, and Phillips counties produce the greatest amounts of natural gas in Montana. Powder River County and Richland County have both increased their percentage of the total amount, most of it as "associated gas," with oil production from the Bakken oil field. "Associated gas" is natural gas that is a byproduct from oil wells.

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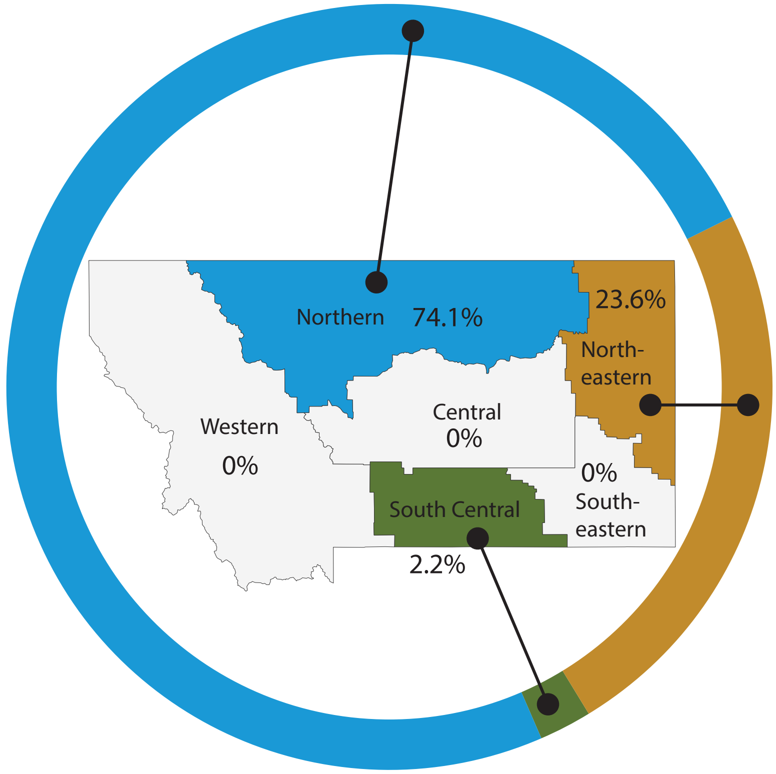
80 *U.S. Department of Interior, Bureau of Mines, Mineral Industry, Natural Gas Production and Consumption Annual Report, 1960-75; U.S. Department of Energy, Energy Information Administration, Natural Gas Production and Consumption Annual Report, 1976-79 (EIA-0131); U.S. Department of Energy, Energy Information Administration, Natural Gas Annual, 1980-2021; Most current numbers, U.S. EIA website.*

81 *Thomas Vivian, NorthWestern Energy, personal communication, 2022.*

82 *Montana, DNRC, Oil and Gas Conservation Division, Board of Oil and Gas Conservation, ANNUAL REVIEW 2015 Volume 59, https://bogfiles.dnrc.mt.gov//AnnualReviews/2011-2020/AR_2019.pdf.*

Figure 3.2 2019 Natural Gas Production In Montana By Region[83]



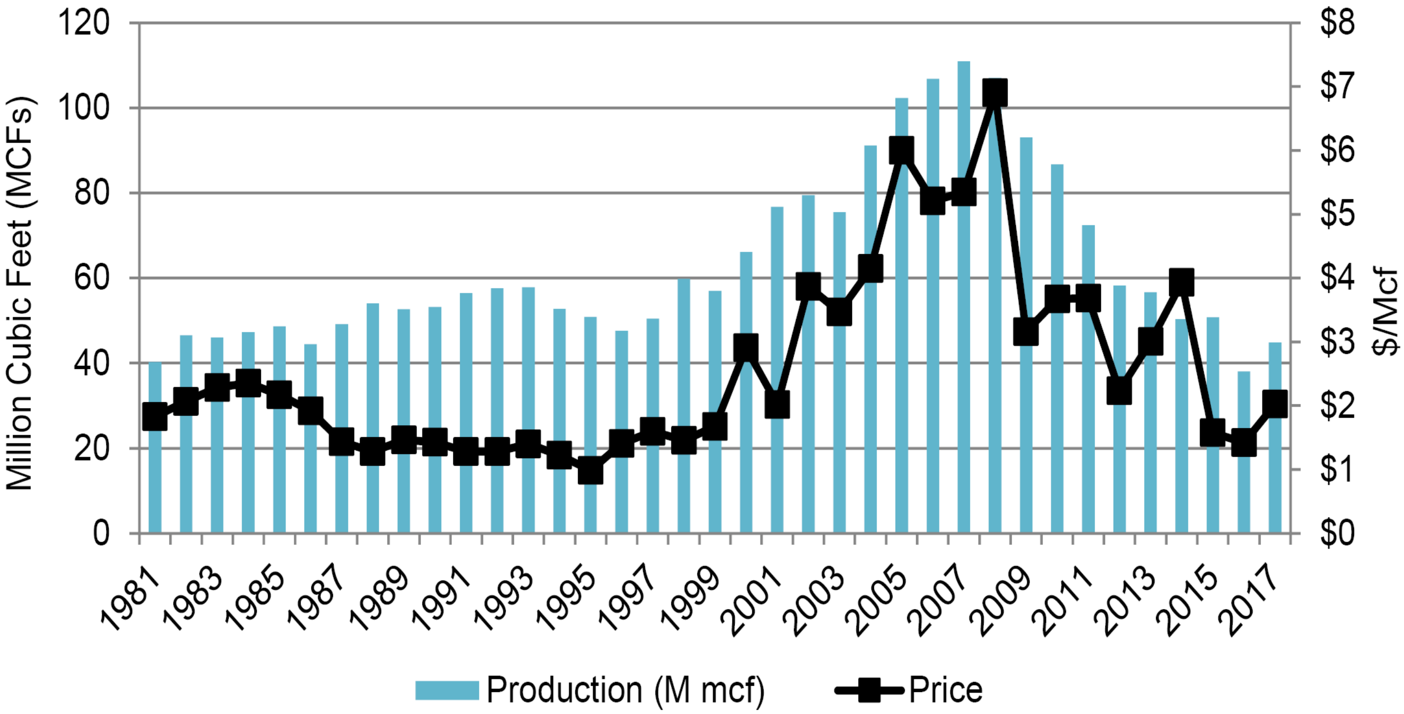
A portion of the gas produced in Hill and Blaine Counties in northern Montana flows directly into NorthWestern's gas transmission system and a portion into the Havre Pipeline gas transmission system that delivers to NorthWestern. Havre Pipeline and NorthWestern produce 5.5 Bcf annually from those wells to be consumed by customers in Montana connected to NorthWestern's system.[84] Gas produced in Fallon, Richland, and Phillips Counties mostly flows into Montana-Dakota's system, and depending on the seasonal demand, will flow west to central Montana or east to North Dakota.[85] Higher natural gas prices have generally been matched by higher production as shown in Figure 3.3.

83 Montana, DNRC, Oil and Gas Conservation Division, 2019 Annual Review, page 15.

84 Dean Vasco, NorthWestern Energy, August 2021.

85 Kevin Connell, Montana-Dakota Utilities, 2021.

Figure 3.3 Natural Gas Production & Price by Calendar Year[86]



3C. U.S. NATURAL GAS SUPPLIES

U.S. natural gas supplies are largely domestic, supplemented by imports mainly from Alberta, Canada. A small amount of gas imports arrive from other countries, a portion of which is liquefied natural gas (LNG). Domestic gas production and imported gas are usually more than enough to satisfy customer needs during the summer, allowing a portion of supplies to be placed in storage facilities for withdrawal in the winter. In winter, the additional requirements for space heating cause total demand to exceed production and import capabilities, requiring the use of stored supply.

Natural gas is injected into pipelines every day and transported to millions of consumers nationally. Much of it travels long distances from production areas to population centers through interstate pipelines owned and operated by pipeline companies. Once the gas arrives at a population center, it is delivered to residential customers and other end-use consumers through the complex network of pipes owned and operated by local distribution companies (LDCs). Since 2009, the U.S. has exported more than one trillion cubic feet (Tcf) annually, with 2020 exports totaling more than 5 Tcf compared to total U.S. consumption of about 30 Tcf.[87]

86 https://leg.mt.gov/content/Publications/fiscal/leg_reference/Brochures/2018-Oil-and-Gas-production.pdf

87 https://www.eia.gov/dnav/ng/hist/n9130us2a.htm

The 2020 Biennial Energy Report from the Oregon Department of Energy describes natural gas processing in detail:

> *"Once brought to the surface, natural gas must be processed to meet pipeline standards. Unrefined natural gas contains many contaminants that would damage natural gas pipelines that deliver processed gas. Some low-grade processing may be done at or near the production site, known as the wellhead. Unprocessed gas is transported from the wellhead to a central collection point using gathering pipelines. These pipelines generally operate at low pressures and flows and are smaller in diameter than transmission lines. The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration estimates that there are 240,000 miles of gathering pipelines in the nation. A complex gathering system can consist of thousands of miles of pipes, interconnecting the processing plant with upwards of 100 wells in the area. Before natural gas can be injected into transmission and distribution lines it must meet quality and purity standards. Therefore, most natural gas is processed in the region where it was sourced.*
>
> *This processing consists of separating all the various hydrocarbons and fluids from the methane to produce what is called pipeline-quality, dry natural gas. Associated hydrocarbons, known as natural gas liquids, including ethane, propane, butane, isobutane, and natural gasoline, are also separated and refined at these raw gas processing facilities. Processing natural gas to pipeline quality can be very complex and will vary depending on the contents of the gas. It usually involves four main processes to remove and separate its contents: • Oil and Condensate Removal • Water Removal • Separation of Natural Gas Liquids • Sulfur and Carbon Dioxide Removal. In addition to the four processes above, heaters and scrubbers are installed, usually at or near the wellhead. The scrubbers serve primarily to remove sand and other large-particle impurities. The heaters ensure that the temperature of the gas does not drop too low.*
>
> *As mentioned above, propane or liquid propane gas is a by-product of natural gas processing. In the United States about half the propane consumed is from natural gas processing, the other half is from crude oil refining. After processing, the pipeline-quality natural gas is injected into gas transmission pipelines and transported to the end users, often hundreds of miles away from the wellheads and processing facilities. These pipelines are wide-diameter, high pressure interstate pipelines. Compressor stations (or pumping stations) keep the gas flowing through the system. These stations are typically powered by the natural gas in the pipeline itself. The Northwest has far fewer transmission pipelines than other regions of the country."*[88]

88 https://energyinfo.oregon.gov/ber

Total U.S. marketed production of natural gas rose sharply in recent years. In 2006, production totaled 19.41 trillion cubic feet (Tcf), in 2012 production totaled 25.28 Tcf, and in 2020 production increased to 36.2 Tcf.[89] The increase is mostly due to fracking technology. The U.S. Department of Energy describes hydraulic fracturing (commonly called "fracking") as follows:

> *"Hydraulic fracturing is a technique in which large volumes of water and sand, and small volumes of chemical additives are injected into low-permeability subsurface formations to increase oil or natural gas flow. The injection pressure of the pumped fluid creates fractures that enhance gas and fluid flow, and the sand or other coarse material holds the fractures open. Most of the injected fluid flows back to the wellbore and is pumped to the surface."*[90]

According to the U.S. EIA, the top five states producing natural gas (measured as "marketed production") in 2019 were Texas (9.3 Tcf), Pennsylvania (6.9 Tcf), Oklahoma (3.2 Tcf) Louisiana (3.2 Tcf) and Ohio (2.6 Tcf). These five states accounted for about 65 percent of marketed natural gas production in the United States in 2015.[91] Marketed production from federal offshore wells in the Gulf of Mexico was about 1.1 Tcf in 2019, or about 3 percent of total domestic production. These amounts are sharply down from 20 years ago when the average annual off-shore natural gas production from the Gulf was around 4.0 Tcf. On-shore production is generally cheaper than off-shore production. The Rocky Mountain states are the primary domestic source of natural gas supply to the Pacific Northwest region, which includes Montana.

In 2019, less than 10 percent or 2.7 Tcf of the total natural gas consumed in the U.S. was imported from other countries. Some of that gas comes from Canada. LNG is the other significant source of natural gas imports, although it makes up a small portion of imports. LNG imports into the U.S. have fallen sharply since 2006 to about 3 percent of overall natural gas net imports.[92] U.S. exports increased from 0.8 Tcf in 2007 to 4.66 Tcf in 2019. Most of the export increase is realized in pipeline shipments to Canada and Mexico and other modes of shipping to various nations. Storage capacity remains steady in the U.S. with 412 natural gas storage sites operational in 2019 and a combined total capacity of 9.2 Tcf.[93]

It is difficult to predict precisely how much natural gas is left in North American reserves. Proved reserves are estimated volumes of hydrocarbon resources that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions. Unproved reserves are the balance of the rest of technically recoverable resources.

According to the U.S. EIA, U.S. Crude Oil and Natural Gas Proved Reserves, as of December 31, 2019 the U.S. total natural gas proved reserves—estimated as wet gas which includes hydrocarbon gas liquids (HGL)—totaled about 494.9 trillion cubic feet (Tcf), approximately 16 years of current U.S. consumption.[94] EIA estimates in the Annual Energy Outlook 2021 that as of January 1, 2019, the United States had about 2,867 trillion cubic feet (Tcf) of dry natural gas unproven reserves.[95]

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89 *U.S. EIA, 2017, 202.1*

90 *U.S. Department of Energy, 2022, "Hydraulic fracturing technology," Office of Fossil Energy and Carbon Management. Accessed May 11, 2022 at https://www.energy.gov/fecm/hydraulic-fracturing-technology.*

91 *U.S. EIA, 2021.*

92 *Ibid.*

93 *Ibid.*

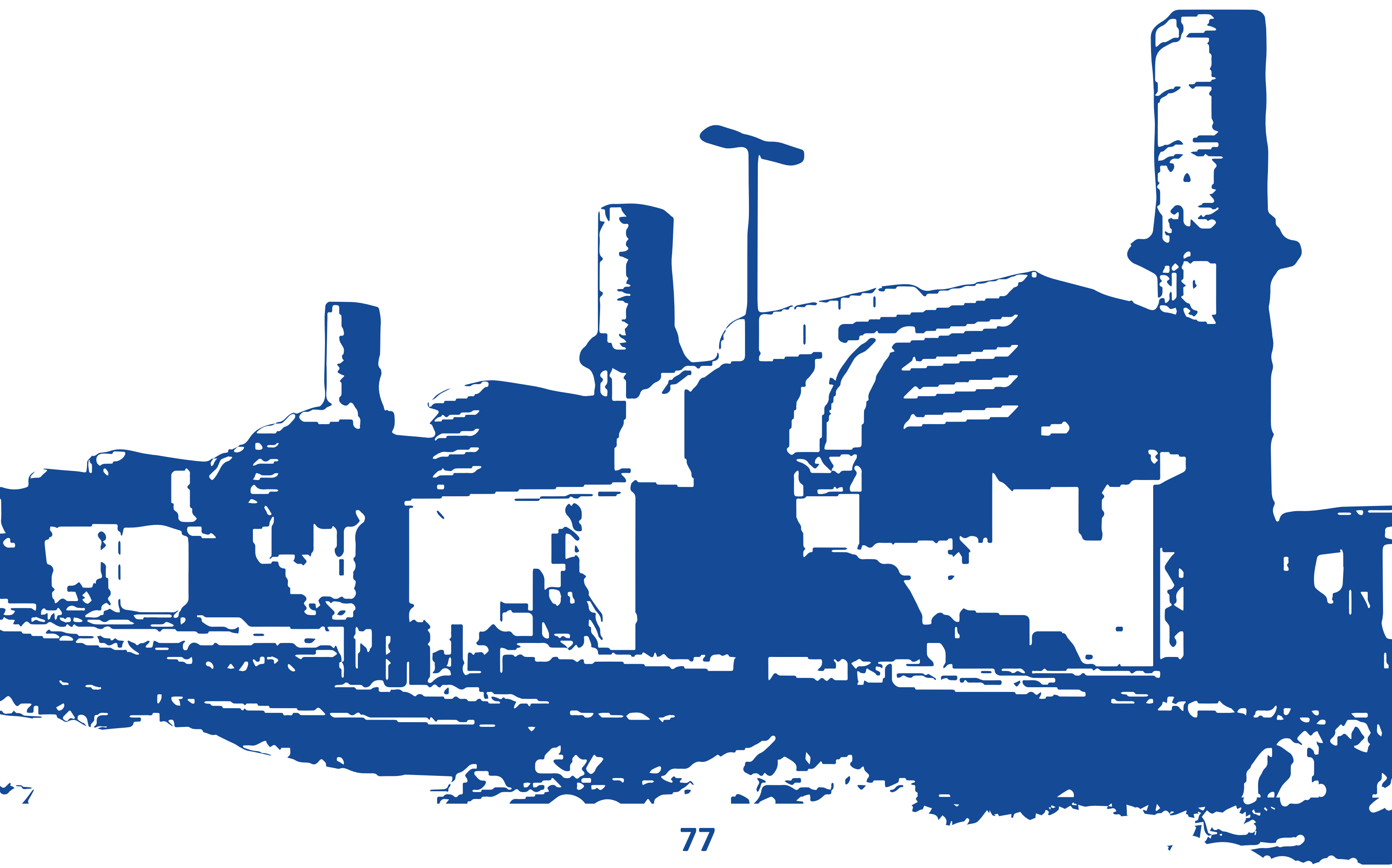
94 *U.S EIA, 2019.*

95 *https://www.eia.gov/energyexplained/natural-gas/how-much-gas-is-left.php#:~:text=According%20to%20U.S.%20Crude%20Oil,trillion%20cubic%20feet%20(Tcf)*

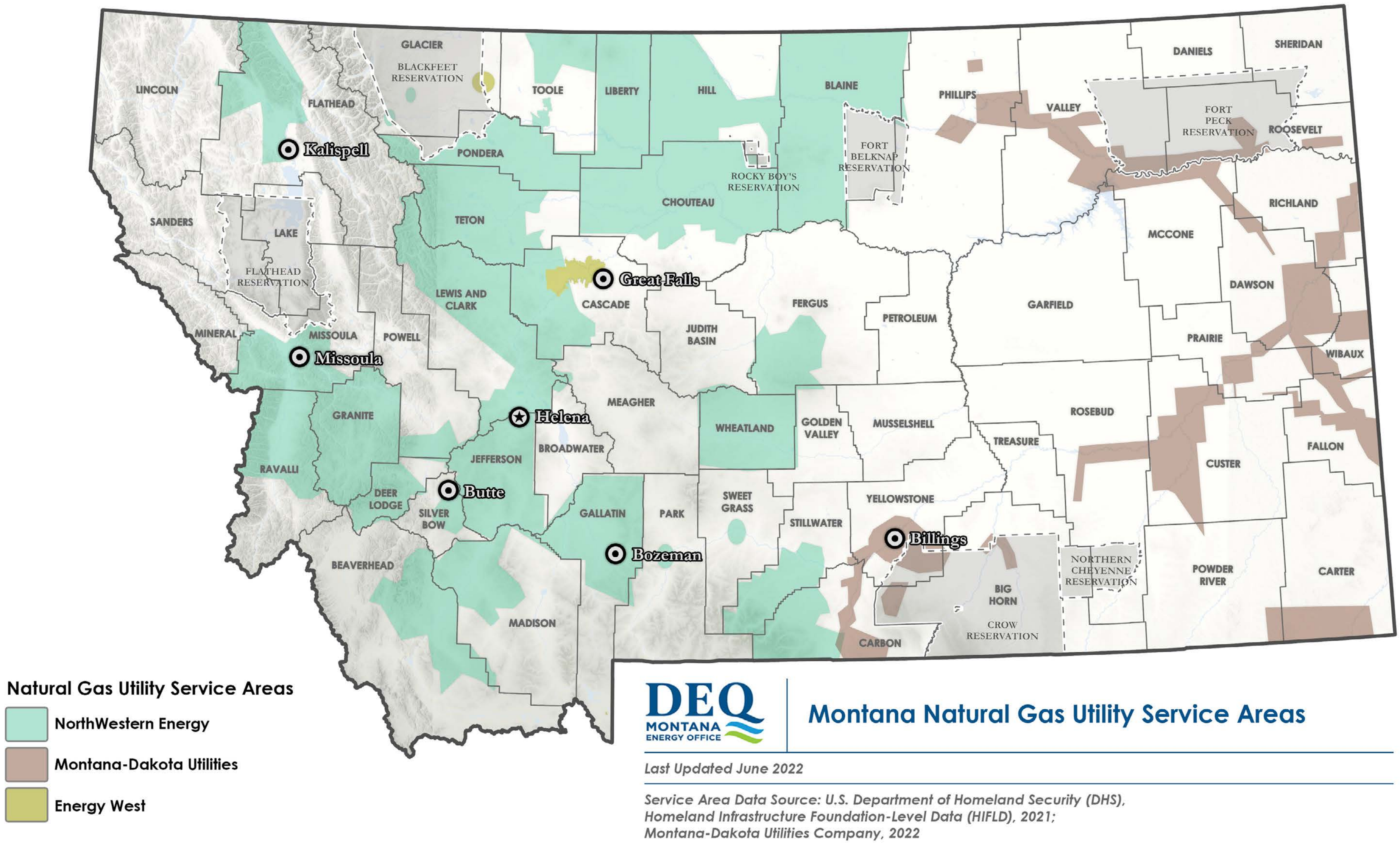
3D. NATURAL GAS CONSUMPTION

MONTANA NATURAL GAS CONSUMPTION TRENDS

Recent Montana natural gas consumption averages 75 to 80 Bcf per year (Figure 3.4). Both residential and commercial gas consumption are currently growing slowly, and remain roughly level with 1970s consumption figures. Industry usage is expected to stay fairly level in the near term unless a large new gas consuming company enters or leaves the state. Also, a new natural gas generating plant could significantly raise in-state consumption. Traditionally, industrial usage varies more than other sectors. Natural gas consumers in the state are served by one of three natural gas distribution utilities: NorthWestern, Montana-Dakota and Energy West (Map 3.1).



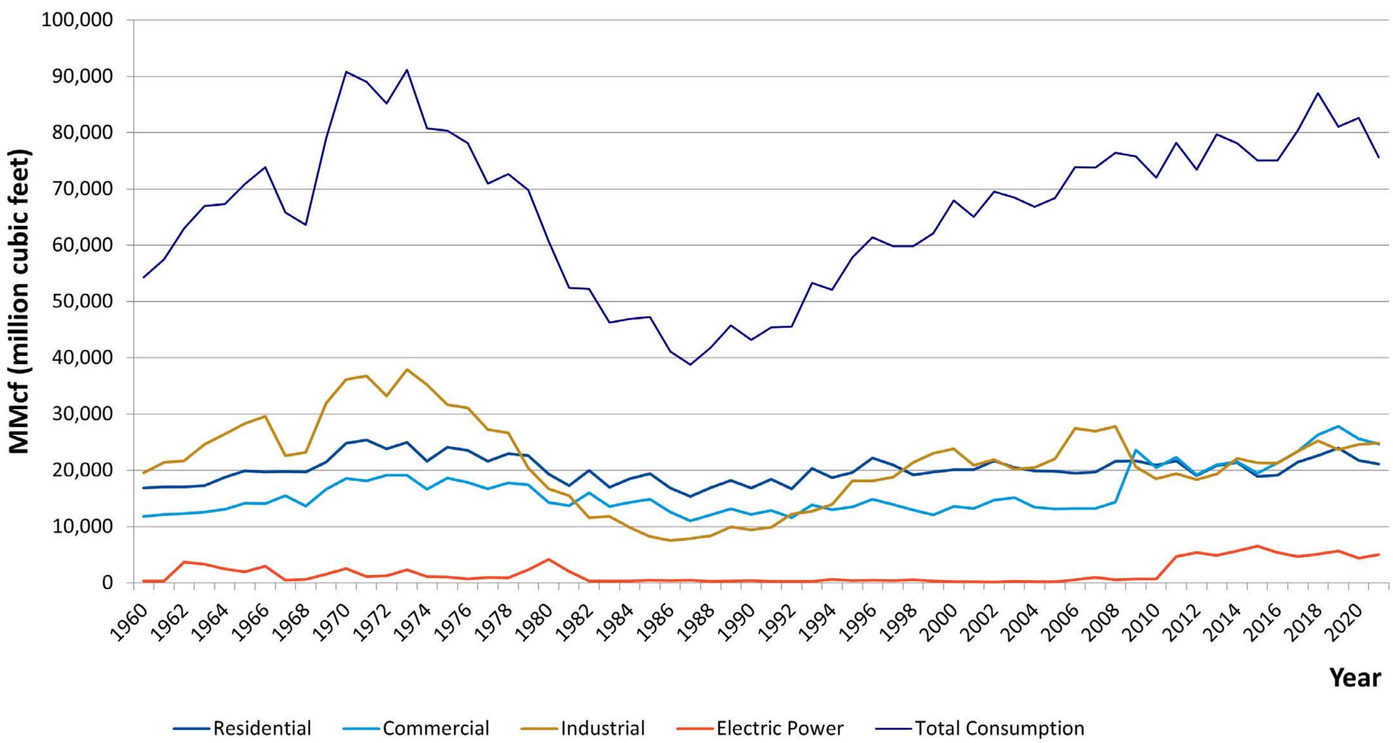
Map 3.1 Montana Natural Gas Utility Areas



In the 1970s, Montana's industrial sector used much more natural gas than it does today. The closure of smelters in Anaconda contributed to a drop in industrial usage in the 1980s. Other business closures, like those of Columbia Falls Aluminum Company and Smurfit-Stone in the past 15 years, contributed as well. Total in-state consumption is slowly creeping toward 1970s levels, due mainly to increases in the state's population, a growing commercial base, and natural gas-fired electrical generation.

Six in-state electrical generation facilities are fueled with natural gas (See Electricity Supply and Demand, Section 1C for details). Natural gas electric generation in Montana consumed 5.6 Bcf of gas in 2019, about 7 percent of the state total. A large, 500 MW natural gas plant running at high capacity could use nearly half as much natural gas as Montana currently consumes in a year, but no such plant exists in the state.

Figure 3.4 Natural Gas Consumption in Montana (1960-2021)[96]



U.S. NATURAL GAS CONSUMPTION TRENDS

In the last 40 years, changes in energy markets, policies, and technologies combined to spur an increase in the total usage of natural gas in the U.S. These changes included:

96 *U.S. Department of Interior, Bureau of Mines, Mineral Industry Surveys, Natural Gas Production and Consumption, Annual Reports for 1960-75; U.S. Department of Energy, Energy Information Administration, Natural Gas Production and Consumption, Annual Reports for 1976-79 (EIA-0131); U.S. Department of Energy, Energy Information Administration, Natural Gas Annual, Annual Reports for 1980-2021, Most current numbers, U.S. EIA website.*

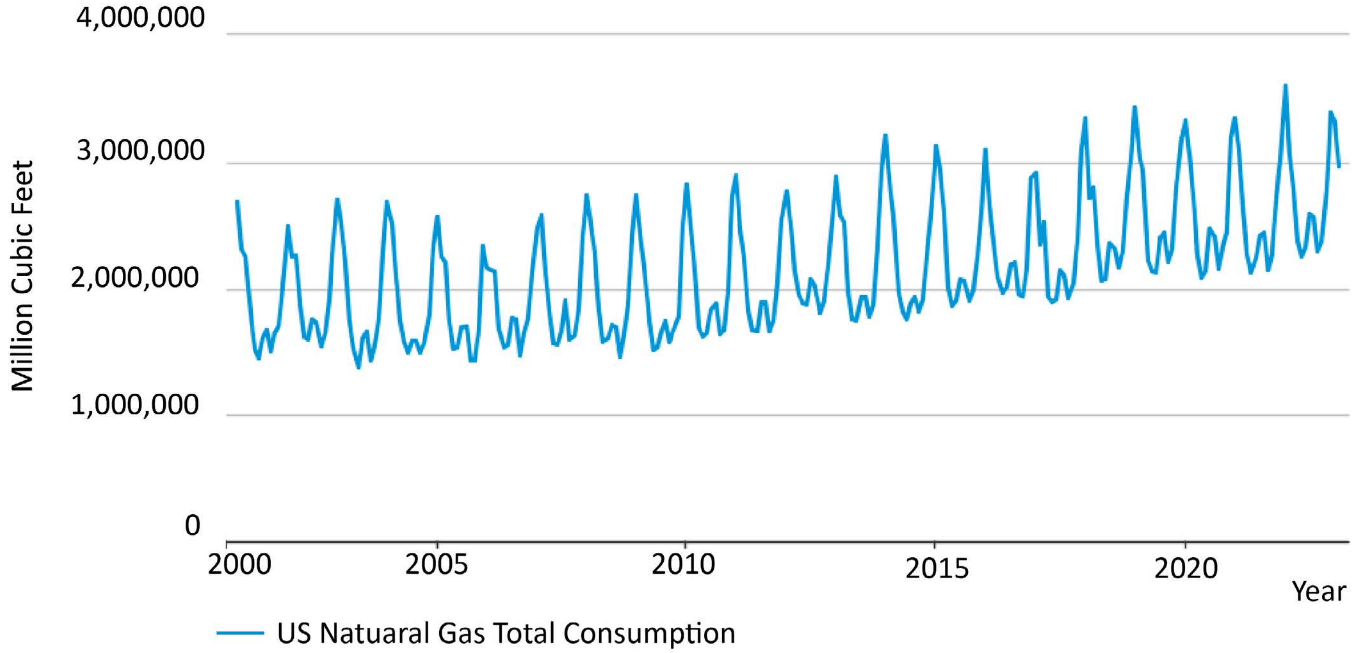
- Deregulation of wellhead prices under the Natural Gas Policy Act of 1978 and acceleration under the Natural Gas Wellhead Decontrol Act of 1989;
- Deregulation of transmission pipelines by FERC Orders 436 (1985), 636 (1992), and 637 (2000). The FERC orders separated natural gas commodity purchases from transmission services, requiring pipelines to transport gas on an equal basis. Order 636 allowed 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 nonattainment areas, which favor natural gas over other fossil fuels such as coal;
- Potential federal regulation that could constrain carbon emissions;
- Improvements in the efficiency and flexibility of natural gas generation and improvements in exploration and production technologies (e.g. fracking)
- Investment in major pipeline construction expansion;
- Low natural gas prices due to fracking technology implemented in the 2000's.

Nationally, gas consumption was 30.48 Tcf in 2020. Historically, U.S. natural gas consumption increased at a steady pace. In 2020, electric generation was the largest natural gas consuming sector in the U.S. at 38 percent (11.6 Tcf), up from 28.6 percent in 2006. That percentage is holding steady. Industrial usage of natural gas, the second largest category in the U.S., continues to decline as a share of the total market, although it increased recently due to low gas prices. Chemical and fertilizer industries, for example, benefit from lower natural gas prices. Residential usage is the third largest category.[97] U.S. consumption varies seasonally with higher natural gas consumption occurring in winter for heating as seen in the figure below.[98]

97 *U.S. EIA website.*

98 *Chart is found at [https://www.eia.gov/dnav/ng/hist/n3010mt3m.htm.](https://www.eia.gov/dnav/ng/hist/n3010mt3m.htm)*

Figure 3.5 U.S. Natural Gas Total Consumption[99]

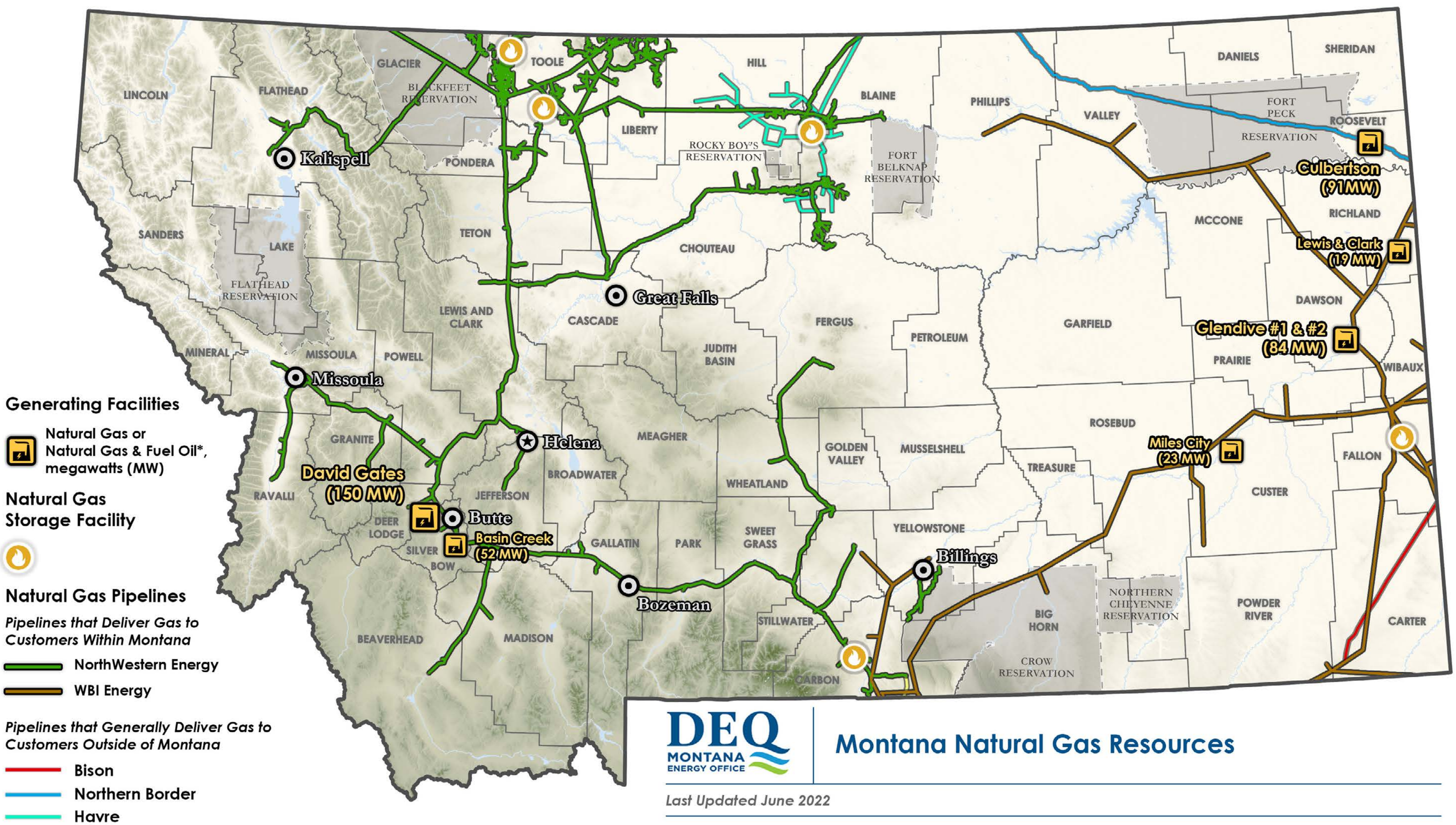


3E. MONTANA'S NATURAL GAS PIPELINE AND DISTRIBUTION SYSTEM

Three distribution utilities and two transmission pipeline systems handle more than 99 percent of the natural gas consumed in Montana. The distribution utilities are NorthWestern, Montana-Dakota, and Energy West, which uses NorthWestern for gas transmission. NorthWestern and WBI Energy (with a subsidiary of MDU Resources Group) provide transmission service for in-state consumers and, with a handful of other pipelines, export Montana natural gas. Map 3.2 provides an overview of natural gas transmission pipelines in Montana. Distribution lines are typically smaller and serve local customers, whereas transmission lines are larger lines that carry gas from production areas to large consumers and the distribution networks of populated areas.

99 U.S. EIA.

Map 3.2 Montana Natural Gas Resources



*Culbertson, Glendive 1 & 2, and Miles City are rated to operate with either natural gas or #2 fuel, but have been predominantly fueld by natural gas in recent years.

Facility Data Source: U.S. Energy Information Administration (EIA), 2020

Pipeline Data Source: U.S. Energy Information Administration (EIA), 2020

NorthWestern is the largest provider of natural gas in Montana, accounting for nearly 60 percent of all regulated sales in the state according to annual reports from Montana utilities.[100] NorthWestern provides natural gas transmission and distribution services to about 204,500 natural gas customers in 105 communities in the western two-thirds of Montana (including the Phillips 66 and Cenex oil refineries in Billings), and provides gas storage and transmission to other parties. These customers include residences, commercial businesses, municipalities, state and local governments, and industry. NorthWestern's gas transportation system, both long-distance pipeline transmission and local distribution, lies entirely within Montana.[101]

NorthWestern's gas transmission system is regulated by the Montana Public Service Commission. The NorthWestern system consists of 2,150 miles of transmission pipelines, about 4,900 miles of distribution pipelines, and three major in-state storage facilities. NorthWestern's system has pipeline interconnections with Alberta's NOVA Pipeline, the Havre Pipeline Company, WBI Energy, and the Colorado Interstate Gas Company. The Havre pipeline in the North-Central part of the state is partially owned by NorthWestern and is also regulated by the PSC.[102] It delivers some natural gas to NorthWestern's system.

NorthWestern serves its customers through a combination of company owned supply and contracts purchased on the market, with various durations of one year or less. The NorthWestern pipeline system receives gas from both Alberta and Wyoming. The price paid for gas in Montana on the northern end of NorthWestern's system is generally tied to prices in Alberta. The price paid for gas coming in on the southern end of Montana's system is generally tied to prices associated with Colorado Interstate Gas. Alberta sends natural gas to Montana primarily through NorthWestern's pipeline at Carway, which ties into TC Energy, and at Aden where it ties in with an independent producer.[103]

NorthWestern's natural gas transmission system delivers an average of about 42 Bcf of natural gas per year to its customers on average, compared with total annual Montana consumption of nearly 80 Bcf.[104]

In 2020, NorthWestern imported 16.8 Bcf or 75 percent of its 22.4 Bcf of regulated sales. NorthWestern's acquisition of the Bear Paw natural gas field located south of Havre changed the company's procurement mix slightly. While NorthWestern still obtains a larger percentage of its gas from Alberta, a significant portion of customer supply comes from owned production, as all of NorthWestern's Montana production is consumed in the state.[105]

The NorthWestern pipeline system has a daily peak capacity of 335 MMcf of gas. About one-half of the total gas on NorthWestern's system is used by "core" customers, who include residential and commercial business users. NorthWestern has the obligation to meet its core customers supply needs. The other half of the system's capacity is used by non-core customers, including industry, local and state governments, and by Energy West, which supplies Great Falls. NorthWestern provides only delivery service for these non-core customers that contract their own 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 during warm weather.[106]

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100 It is important to note that regulated sales do not include most of industrial consumption, because since 1991, industrial consumption has not been reported due to different reporting requirements and processes used by utilities since deregulation. Regulated sales also do not include gas used for pipeline transportation, and gas sales sold to other utilities for resale in Montana, lease and plant fuel, pipeline fuel, or fuel used by utilities.

101 Dean Vesco, NorthWestern Energy, September 2021.

102 Dean Vesco, NorthWestern Energy, September 2021.

103 Luke Hansen, NorthWestern Energy, 2021.

104 Tom Vivian, NorthWestern Energy, 201.

105 Luke Hansen, NorthWestern Energy, 2021.

106 Tom Vivian, 2021.

There is little unused firm capacity on the NorthWestern pipeline transmission system. No additional gas user of significant size, such as a large industrial company or a large natural gas generation plant, could obtain guaranteed, uninterrupted gas delivery on the current system. At times of peak consumer usage, the pipeline is full and could not deliver more gas. In other words, the system's maximum daily capacity is roughly matched by peak daily demand. The projected growth rate of natural gas use on the system is expected to come from core customers. Over the past decade, NorthWestern has expanded its gas transmission capacity by building loops on its current system, which is a second pipe running parallel along a main line. Meeting the demands of new gas-fired electrical generation or a large new industrial facility would likely require significant additional upgrades to the pipeline system.

Montana-Dakota Utilities is the second largest natural gas utility in Montana and accounts for about 25 to 30 percent of all regulated natural gas sales in Montana. Its annual sales in Montana are 9-12 Bcf. It distributes natural gas to most of the eastern third of the state, including parts of Billings. Montana-Dakota uses the WBI Energy line and NorthWestern pipelines for the transmission of its purchased natural gas in the state. The WBI Energy and NorthWestern systems provide service for other utilities and are regulated at the federal level by FERC. Montana-Dakota buys its gas from approximately 20 different suppliers throughout the upper Midwest. Of its current gas, Montana-Dakota is purchasing 10 to 15 percent from producing fields in Montana and about 40 to 50 percent of its supply from the North Dakota Bakken area. These percentages can change depending on seasonal demand. Montana-Dakota expects future growth to be about 1 percent per year for the near future.[107]

Energy West is the third largest natural gas provider in Montana, accounting for about 10 percent of all regulated gas sales in Montana. Its annual sales are about 4 Bcf. It provides gas to the Great Falls area and a small amount to West Yellowstone.

Other operating Montana utilities account for about 1 percent of all gas sales and currently include the Cut Bank Gas Company and Havre Pipeline Company. The Northern Border pipeline (2.2 Bcf/day capacity), which passes through the northeastern part of Montana, is the largest pipeline in the state, but includes few injection points in Montana. The Northern Border pipeline feeds the Culbertson Natural Gas Electric Generation Station. Also, pump stations on the Northern Border pipeline generate heat that is converted to electricity at the Ormat Waste Heat station near Culbertson. The Ormat station has not produced power since 2018 because nearby pump stations have not operated in the past few years. The terminus of the Northern Border pipeline is the U.S. Midwest market.

3F. NATURAL GAS COMMODITY PRICING

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 before it is transported from the well. 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 or control the wholesale market. The wholesale gas prices on the major gas indices, such as the Henry Hub and the AECO Hub in Alberta, reflect the wellhead price of gas plus a fee to transport the gas to the hub. The Henry Hub Index is measured at the Henry Hub in southern Louisiana, a major pipeline interconnection and transshipment point. It is one of America's largest natural gas indices and provides a nationwide price reference point.

107 Bob Morman, Montana-Dakota Utilities, August 2017.

While the Henry Hub price appears to be a good approximation of average U.S. wellhead prices, other hubs located in relatively remote areas, like Wyoming and Alberta, can have significantly higher or lower prices than the Henry Hub due to their location, local pipeline constraints, and local markets. Montana's wholesale natural gas spot price was 60-90 percent the price of the Henry hub from 2010 to 2020.[108]

The city gate gas price reflects the wellhead price plus pipeline transmission fees to get the gas to a particular location or distribution system. The delivered gas price paid by customers is the city gate price plus local distribution fees and other miscellaneous charges from the utility. Transmission and distribution fees are set by utilities, pipeline operators, or both and are regulated by state and federal agencies.

Natural gas wholesale prices on the major gas indices (or the commodity market) are measured in several ways. There are spot market prices for immediate sales and market prices for long-term contracts. Spot prices can be volatile and typically represent a small portion of market sales. 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 generally used by larger buyers rather than spot prices. NorthWestern, for example, buys much of its natural gas for its core customers using contracts to lock in an acceptable price and to minimize price risk that can be associated with the spot market. This helps keep the price paid by customers relatively stable in a market that can otherwise experience large price swings. All contracts for NorthWestern are tied to the AECO or CIG index prices, and those contracts are tied to the natural gas prices in those markets.[109]

The prices and market conditions for related fuels also affect natural gas. Historically in the U.S., most dispatchable electric generation is delivered from coal, nuclear, and hydroelectric generation. Because natural gas tends to be a higher-cost fuel, natural gas-fired power stations are traditionally used to cover mostly incremental power requirements during times of peak demand or sudden outages of baseload capacity. That dynamic is changing as increasing amounts of new dispatchable electricity is fueled by natural gas nationwide. The shift is due to lower gas prices, lower emissions from gas plants compared to coal, low initial capital cost for gas plants compared to new coal and nuclear plants, a fast online time, and the increased need for versatility on the system.

NATURAL GAS PRICES IN MONTANA

Until the late 1970s, delivered gas prices in Montana were relatively low, about $6/mcf in today's dollars (actual dollars adjusted for inflation). Delivered prices rose considerably through the mid-80s and mostly settled in the $8-$12/mcf range using today's dollars (Figure 12). In the 1990s, the delivered prices hovered around $8/mcf. From 2000 to 2004, delivered gas prices started increasing and showing more variation, rising to an average of more than $10/mcf for certain years in Montana. Since late 2005, prices have generally declined to historical lows. As of May 2021, NorthWestern residential customers pay an average delivered gas price of $6.97/mcf.[110] Figure 3.6 shows delivered natural gas prices in Montana adjusted for inflation through 2019 and reported in constant 2019 dollars. The delivered prices are the prices residents and businesses see in their final energy bill reflecting all charges. The U.S. delivered price of natural gas averaged just over $9.81/mcf in December 2020.[111]

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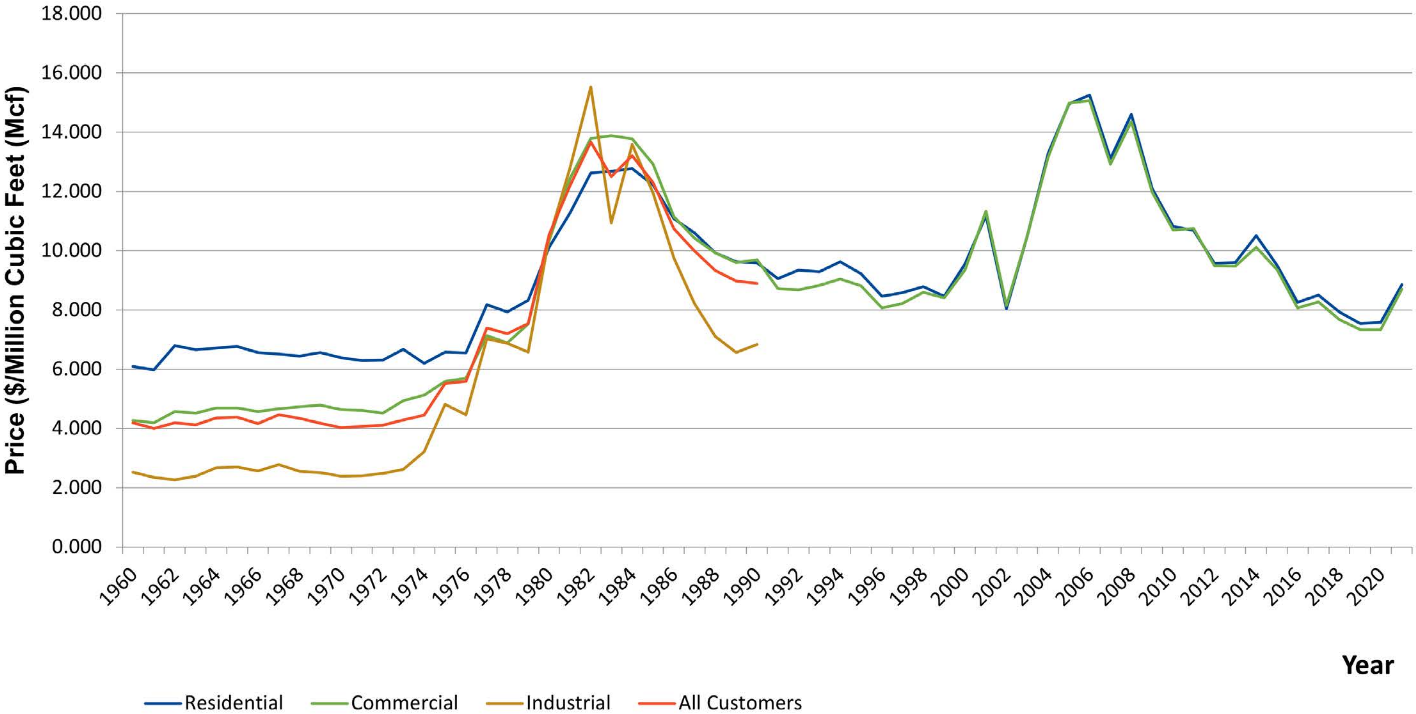
108 Natural Resource Taxes, Montana Legislative Fiscal Division, https://leg.mt.gov/content/Publications/fiscal/FR-2023/Volume-2/Natural-Resource-Taxes.pdf, June 2021

109 Luke Hansen, NorthWestern Energy, 2021.

110 NorthWestern Energy natural gas rates, [https://northwesternenergy.com/billing-payment/rates-tariffs/rates-tariffs-montana/natural-gas-rates-tariffs.](https://northwesternenergy.com/billing-payment/rates-tariffs/rates-tariffs-montana/natural-gas-rates-tariffs)

111 U.S. Energy Information Administration, [https://www.eia.gov/dnav/ng/hist/n3010us3m.htm.](https://www.eia.gov/dnav/ng/hist/n3010us3m.htm)

Figure 3.6 Delivered Price of Natural Gas in Montana Adjusted for Inflation, 1960-2021 (in 2021 dollars)[112]



The average price of gas purchased by NorthWestern, Montana-Dakota, and Energy West reflects current gas market conditions, and that price is constantly changing. It is important to note that the purchased cost of gas includes transportation costs to the utility's delivery system and, for NorthWestern, variable operating costs associated with owned production properties.

Due to natural gas deregulation, most large industrial customers in Montana contract for gas directly with Montana-Dakota and Energy West or with other independent suppliers. Industry still uses the local utilities for distribution and transportation services. The gas price for each industrial customer depends on each specific contract, the gas supplier, and the ability of the industry to switch from natural gas to some other fuel if prices get too high. Four of the largest natural gas users in Montana are the four oil refineries in and near Billings and Great Falls. Plum Creek Manufacturing, REC Silicon near Butte, and Basin Creek Power Services are also large users in Montana. Montana's major natural gas transmission pipelines also use large amounts of natural gas to fuel compressor stations that pump the product over long distances at appropriate pressures.

112 *U.S. Department of the Interior, Bureau of Mines, Mineral Industry Surveys, Natural Gas Production and Consumption, annual reports for 1960-75; U.S. Department of Energy, Energy Information Administration, Natural Gas Production and Consumption, annual reports for 1976-79 (EIA-0131); U.S. Department of Energy, Energy Information Administration, Natural Gas Annual, annual reports for 1980-2013; U.S. EIA website, 2014-2021. Inflation adjusted numbers from U.S. Dept of Labor, Bureau of Labor Statistics, Historical Consumer Price Index for All Urban Consumers (CPI-U): U. S. city average, all items: https://www.bls.gov/regions/mid-atlantic/data/consumerpriceindexhistorical_us_table.htm.*

4. COAL IN MONTANA

Montana's modern coal industry was built primarily to fuel power generation for markets in Montana and across the West. Consequently, Montana coal mines have seen significant production declines in the past decade as coal-fired power plants are shuttered throughout the U.S. Coal-fired power plants accounted for a majority of Montana's electric generation portfolio until early 2020 when Units 1 and 2 of the Colstrip Generating Station shut down. Coal fueled nearly two-thirds of the state's total electric generation in the 2000s and fueled between 50 percent and 55 percent of generation from 2010 to 2020. Coal production in Montana has decreased dramatically since 2015, with two of Montana's seven large mines closing in the past five years. Nearly three-quarters of the coal mined in Montana is exported, primarily to Midwestern utilities and to coal brokers. The coal that remains in Montana fuels electric generating plants, with most used at the Colstrip generating facility.

4A. HISTORY OF MONTANA COAL DEVELOPMENT

Coal in present-day Montana was documented by the earliest white explorers of the region. Captain William Clark, on the return trip through what is now Montana, led half of the Lewis and Clark Expedition down the Yellowstone River, passing within perhaps 50 miles of the coal beds of what is now known as the Rosebud field, part of the larger Fort Union Formation in the Powder River Basin.

> *The following excerpt is from Clark's Yellowstone River journal from the summer of 1806:*
>
> *In the evening I pass Starters of Coal in the banks on either side … bluffs about 30 feet above the water and in two vanes [veins] from 4 to 8 feet thick, in a horizontal position. This coal or carbonated wood is like that of the Missouri [River] of an inferior quality.*[113]

The annual federal Statistics of Mines and Mining compiled for the western states and territories for 1873 and 1875 indicated limited seasonal coal extraction in the Big Hole Valley, at Mullan Pass west of Helena, at Fort Benton, and at Belt along the Missouri River. During this time the coal was probably used principally to forge iron for blacksmithing in nearby towns.

Railroad planners became interested in local coal to build steam for locomotive power, and early surveys in Montana Territory often included geologists on the lookout for available deposits. In 1882, the geologists of the Northern Transcontinental Survey visited the region in the course of a general reconnaissance of the Northwest, a chief object of the exploration being to secure information concerning coal resources. The existence of valuable coal deposits in the Great Falls region was clearly recognized by the survey, as were lesser-quality deposits near present-day Lewistown and in the Bull Mountains.[114]

The narrow-gauge Utah & Northern (later Union Pacific) railroads reached Montana from the South in 1880, connecting to Butte the following year.[115] Northern Pacific and to a lesser extent Union Pacific formed coal

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113 Journals of the Lewis & Clark Expedition, R. Gold Thwaites, editor, 1905.

114 Geology of the Lewistown Coal Field, Montana, U.S.G.S., 1909, Calvert, W.R.

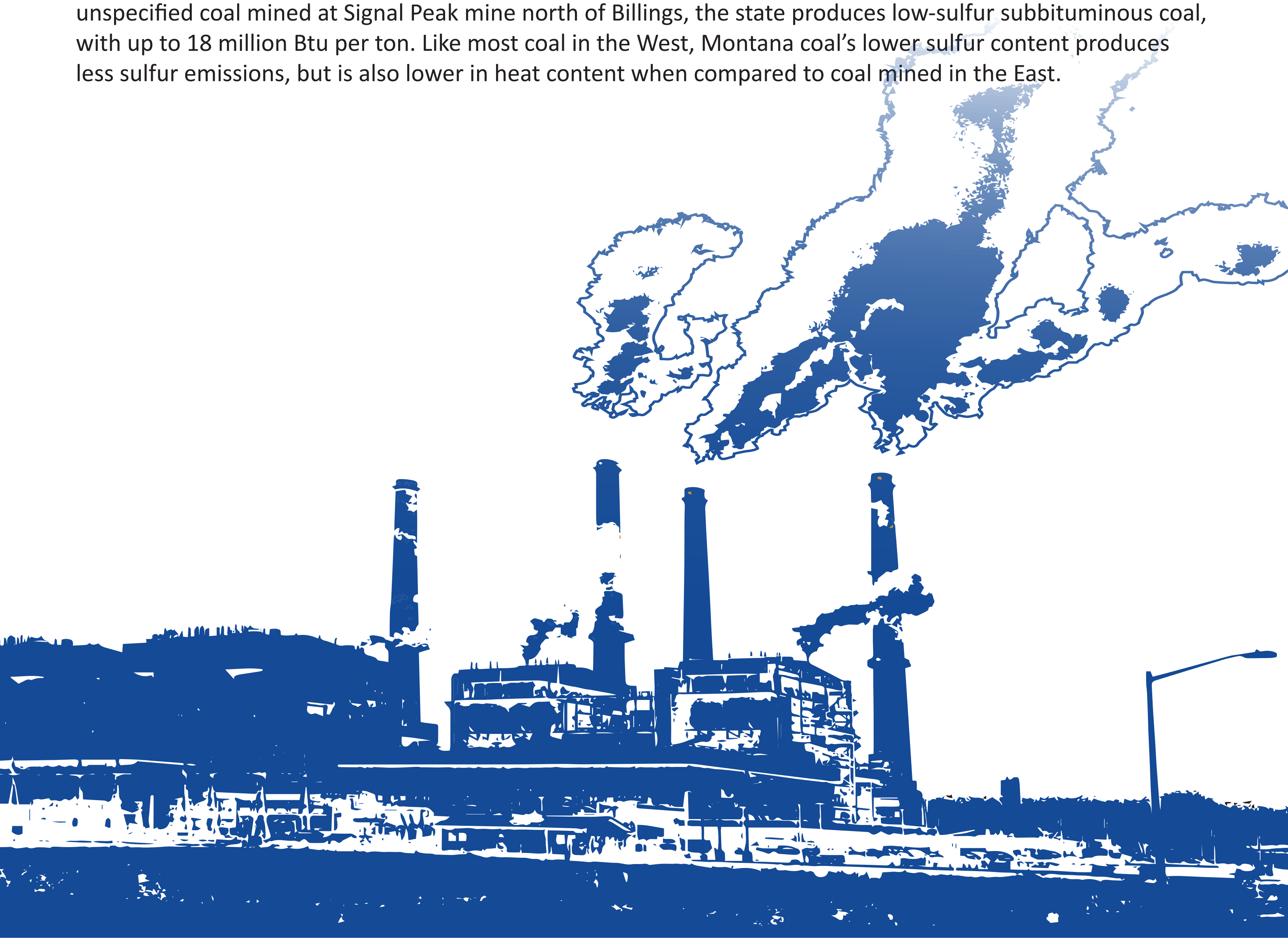
115 Montana: A History of Two Centuries, Malone, M., et al, 1976.

mining companies to exploit the deposits at Timberline near Bozeman Pass, and by 1885 more than 83,000 tons per year was mined there, mostly for rail transportation.[116] Great Northern launched a coal subsidiary in 1888 at Sand Coulee outside of Great Falls to provide for its Montana operations.[117]

By 1880, use of coal in Montana was growing to include more industrial uses–principally ore processing–in addition to commercial and domestic home heating. Non-transportation industrial use would grow significantly over the next quarter century with the rise of copper smelting and refining in the Butte-Anaconda district and at Great Falls. The use of coal for mineral reduction declined early in the twentieth century, at least partially as hydroelectric dams came online along the Missouri River.

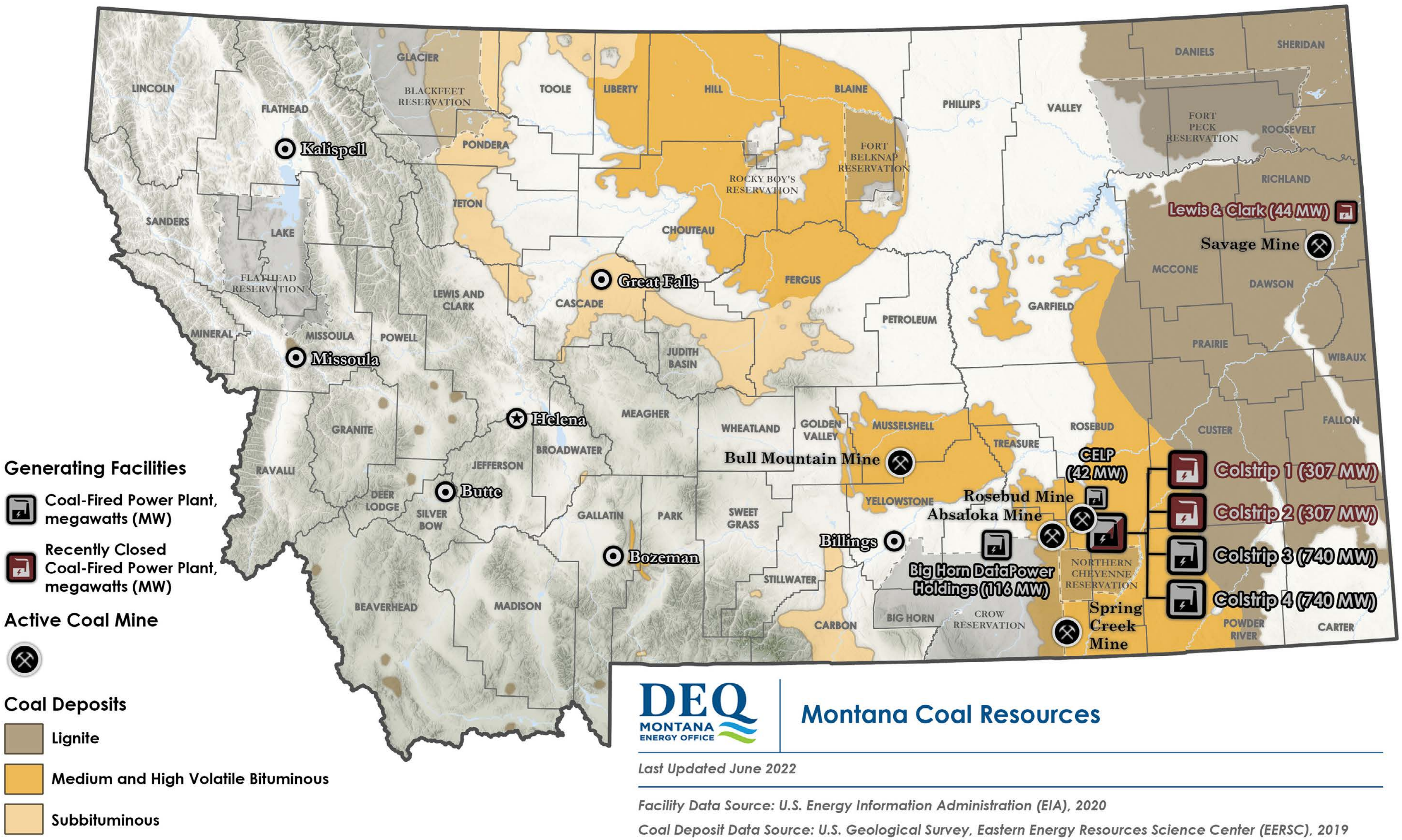
4B. MONTANA COAL PRODUCTION

Montana was the sixth largest coal producer in the U.S. in 2020, with 26.4 million tons mined. The majority of in-state mining occurs in the Powder River Basin southeast of Billings, although the two Decker mines located there recently closed. With the exception of the small lignite mine at Savage and some bituminous or unspecified coal mined at Signal Peak mine north of Billings, the state produces low-sulfur subbituminous coal, with up to 18 million Btu per ton. Like most coal in the West, Montana coal's lower sulfur content produces less sulfur emissions, but is also lower in heat content when compared to coal mined in the East.



116 McDonald, R. and Burlingame, M. Montana's First Commercial Coal Mine, Pacific Northwest Quarterly, January, 1956.
117 The Cascade County Album: Our History in Images, Cascade County Historical Society, 1999.

Map 4.1 Montana Coal Resources



Coal mining has occurred in Montana since territorial days. Early production filled the need for smelting, industrial steam power and locomotive power. Production initially peaked in the 1940s at around 5 million tons per year. As diesel replaced steam locomotives, production declined, reaching its lowest point in 1958. That year, only 305,000 tons were mined, an amount equivalent to about 1 percent of current output. Output remained stagnant for a decade, maintained by production for a small electric generating plant near Sidney. Production began to increase in 1968, when Western Energy Company began shipping coal mined from the Colstrip area to an electricity generating plant in Billings owned by its parent company, the Montana Power Company.

As Montana mines began supplying electric generating plants in Montana and the Midwest, coal production jumped. Production in 1969 totaled 1 million tons; 10 years later, production increased to 32.7 million tons as Colstrip Units 1 and 2 become operational and export markets continued to develop. Production increased gradually to almost 43 million tons in 1998. In the past two decades, production remained near 40 million tons, reaching 42 million tons in 2015. Nearly 25 percent of that amount fuels the Colstrip electric generation plant. With the closure of Colstrip Units 1 and 2 in 2020, that number declined to 27 million tons with further changes in these numbers expected when more Montana coal plants close or mines reach the end of commercial viability. In the past decade, Montana has accounted for 4 to 5 percent of the coal mined each year in the U.S., maintaining its share of the U.S. market. Wyoming's market share grew over that time in the rich and productive fields located in the Powder River Basin.

While significant, Montana's coal output is dwarfed by that of Wyoming, which produced 41 percent of the nation's coal in 2020. The gap between the two states is 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. Coal seams tend to be thinner, though still thick in comparison to eastern coal, and buried under more overburden than seams in Wyoming. Wyoming coal tends to have slightly lower average ash and sulfur content than Montana coal. The difference in production between the two states is further affected by the superior development of the rail transportation network in the southern end of the Powder River Basin in Wyoming.

The price of Montana coal averaged $21.66 per ton at the mine in 2019, up from the previous 20 years when it was closer to $10.00 per ton.[118] The average price of coal peaked at $14.22 per ton in the early 1980s and began a downward trend that lasted to the turn of the century. By 2002 the price fell nearly 60 percent. The price of Montana and Wyoming coal was far below the 2019 U.S. average of $36.07. The two main reasons for the difference are higher transportation costs and the lower heat content of the coal.

There are currently five major coal mines in Montana operating in Big Horn, Musselshell, Richland, and Rosebud Counties. Westmoreland Mining, LLC, controls three of these mines, accounting for almost 12 million tons of coal in 2019. In 2007, Westmoreland gained 100 percent ownership of the Absaloka Mine in Big Horn County. During the 1990s, the last Montana mine producing less than 100,000 tons annually closed. A new mine at that site, the Signal Peak Mine, near Roundup, opened in 2003.

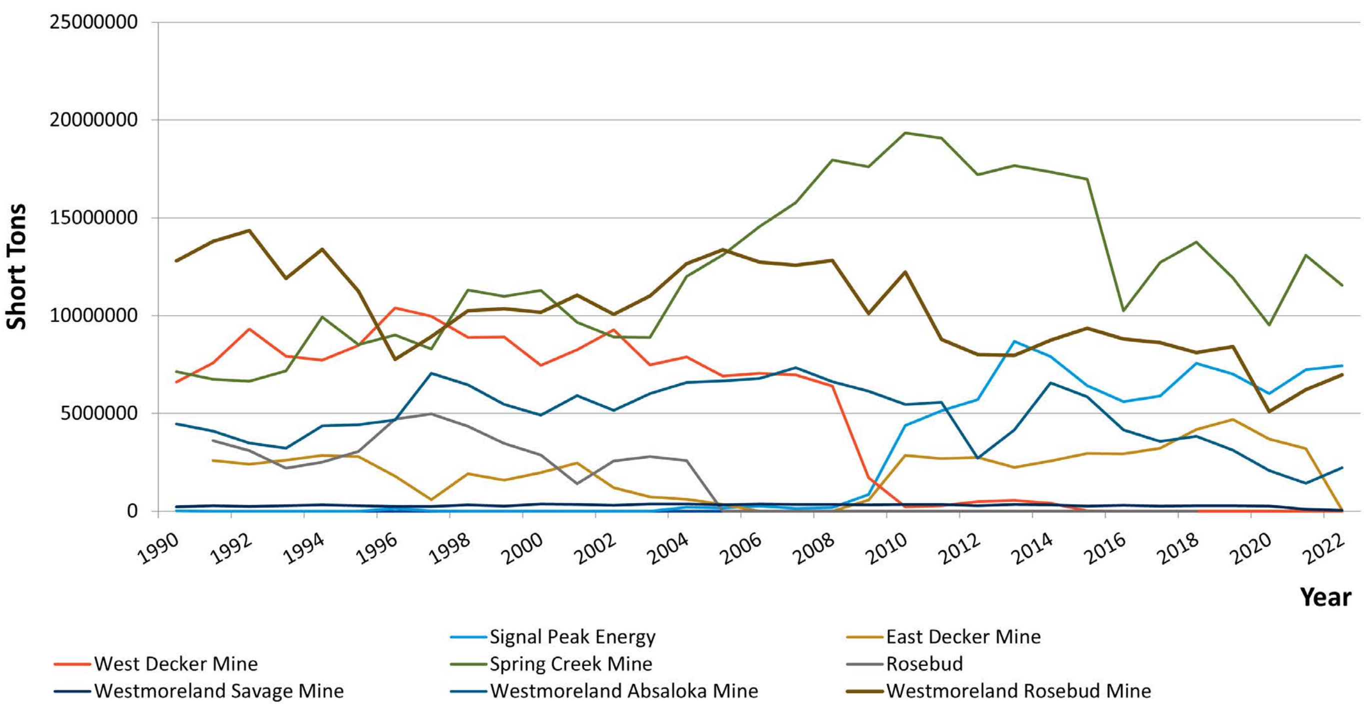
Expansions at the Signal Peak mine were expected to bring a significant increase in Montana's total current coal output. A 35-mile rail spur was added to the BNSF line near Broadview to deliver coal from Signal Peak to various markets. With the expansion, the mine was expected to ramp up production to about 15 million tons per year. However, production has leveled out at around 6-7 million tons in the past few years.

The West Decker Mine expanded significantly until 2008, before production from the mine sharply decreased in volume and it closed in 2015. The East Decker mine picked up a portion of that production in 2009 until it shut down in early 2021 amid bankruptcy proceedings. The Spring Creek mine, acquired by the Navajo Transitional Energy Company in 2019, was the largest producing mine in Montana in 2021, accounting for nearly 50 percent of production, or about 13 million tons. This is sharply down from

118 U.S. EIA, 2022.

previous years in which the total production was consistently more than 15 million tons. Western Energy Company (a subsidiary of Westmoreland) operates the Rosebud Mine and is the second largest in-state producer at 11.9 million tons, accounting for 34 percent of Montana coal production in 2019.

Figure 4.1 Montana Coal Production Chart[119]



Production has recently decreased in Montana, from about 45 million tons in 2008 to 26 million tons in 2020.[120] The trend mirrors national statistics, with production decreasing from about 1.2 billion tons mined in 2008 to just over 0.5 billion tons in 2019. Most of this decline can be credited to weak economic markets for coal both domestically and internationally. Coal generation for domestic electric generation plants is declining as older coal plants close and existing plants run less of the time. Low natural gas prices over the last decade and cheaper renewables have meant that natural gas, wind and solar are fueling more electricity production. Foreign demand also appears to have declined. Air quality regulations and state-level policy have accelerated the recent trend of coal plant closures. Natural gas is also substituted for coal in other industrial applications. The future of Montana coal economics depends in large part on greenhouse gas regulations for electric generation, the amount of U.S. coal-fired generation in operation (based in part on state policies), natural gas prices, and coal export markets.

4C. COAL CONSUMPTION

Almost all coal produced in Montana generates electricity. In recent years, about three-quarters of production has been shipped by rail to out-of-state utilities and, increasingly, foreign nations. The remaining quarter is

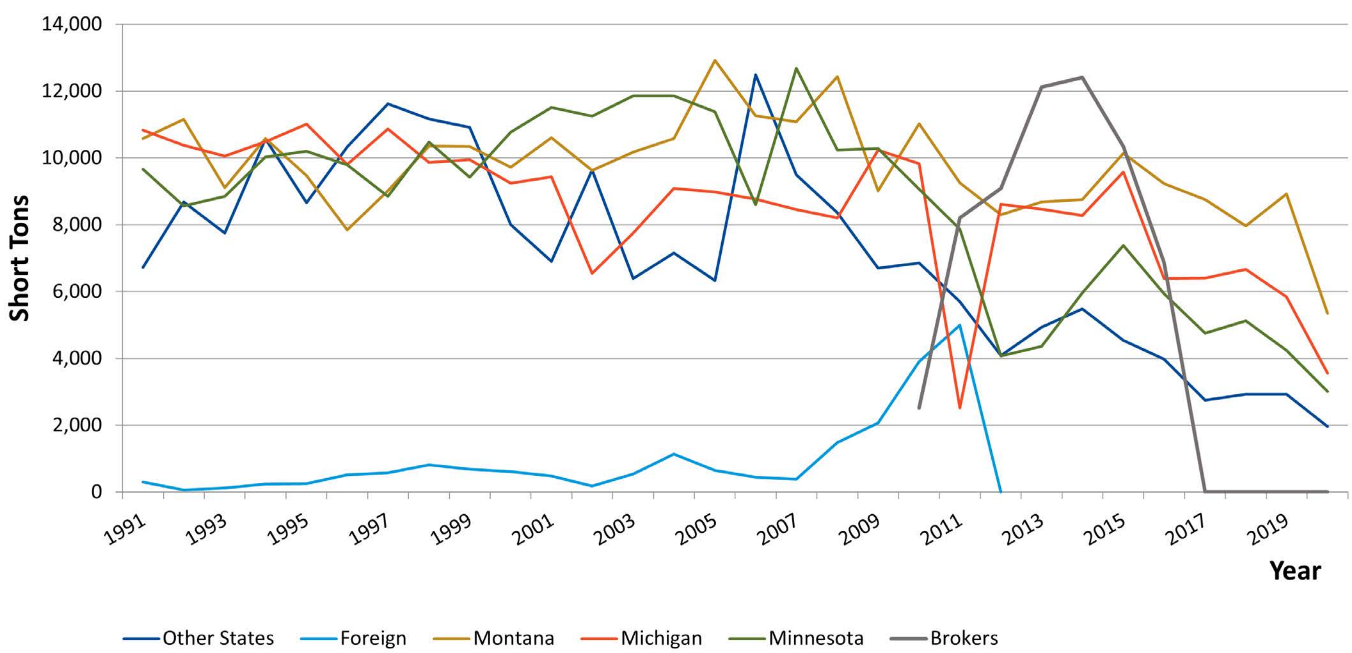
119 Lana Cooper, Montana Department of Labor and Industry, Employment Relations Division, Safety and Health Bureau, Mining Section (1990-2020).

120 U.S. EIA, 2022.

consumed in Montana. About 90 percent of what is consumed in Montana is burned to produce electricity, primarily at Colstrip. Minor amounts of residential and commercial heating and some industrial use account for the remainder.

Over the last decade Michigan, Minnesota, and Montana used about three-quarters or more of all the coal produced in Montana (Figure 14). Since 2010, the trend has remained similar, with nearly 75 percent of coal production still powering Montana, Michigan, and Minnesota, with the other 25 percent sold to brokers. After 2002, data on shipments to other countries was not available however, historically Montana has shipped coal to Canada. Most exports from Montana mines are currently sold to brokers, who don't consistently report the final destination for exports.

Figure 4.2 Montana Coal Destination Chart, 1991-2020 (thousand short tons)[121]



4D. COAL ECONOMICS IN MONTANA

Since 2002 the average price of coal has increased. The amount of coal mined and the number of in-state mining employees increased steadily from 2000 to 2015, and then dropped off after that through the present time (Figure X). Taxes on coal, despite decreases from historical highs, remain a major source of revenue

121 *For 2008-2020, EIA-923 (Schedule 2) data is used (see 'Sources' for Table C4 for methodology on calculating this data). 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 Distribution Report. Brokers numbers are from U.S. Energy Information Administration Form EIA-923, "Power Plant Operations Report," Form EIA-3, "Quarterly Survey of Non-Electric Sector Coal Data," Form EIA-7A, "Annual Survey of Coal Production and Preparation," Form EIA-8A, "Annual Survey of Coal Stocks and Coal Exports," and Bureau of the Census, U.S.Department of Commerce, "Monthly Report EM 545.*

for Montana, with almost $42 million collected in coal severance tax in state fiscal year 2020.[122] That is significantly less than the amount collected in fiscal year 1984, when collections peaked at around $92 million. Collections dropped in the 1980s and 1990s as tax laws changed, beginning with tax changes made by the 1987 Legislature. While the tax rates vary, the rate on most coal in Montana has dropped from 30 percent to 15 percent of price. This drop in rates has had a larger impact on tax collections than the change in coal prices.

The tax structure's impact on coal production is less clear. Production rose modestly since the 1980s cut in coal taxes, with substantial decline starting in 2015. Regardless, Montana has been able to retain most of its share of the national market. The cost of transportation to distant markets may also affect the competitiveness of Montana coal. Nearly all coal exported from Montana leaves on BNSF rail lines.

In addition to severance taxes, gross proceeds taxes are also paid to support the counties where mines are located.[123] The 2009 Legislature altered a series of tax laws applicable to coal producers. Severance tax rates for strip mines that recover coal using auger techniques were reduced. County commissioners have been granted authority to provide up to a 50 percent local abatement of coal gross proceeds taxes for up to 10 years at new or expanding underground mines. Montana coal producers also pay a Resource Indemnity Trust tax, federal taxes, and royalties. Federal leasing laws require 49 percent of the royalties collected from development of federal leases be returned to the state. That requirement was lowered from 50 percent in Oct. 2007.[124] A royalty is also paid on coal-producing land leased from the state.

Coal was the least expensive fossil fuel used to generate electricity for many years. In recent years, natural gas has closed the price margin when compared to coal. When natural gas was near $2/dkt in early 2013, it was briefly cheaper than coal on a fuel per Megawatts per hour (MWh) basis. Today, their cost competitiveness varies with market conditions. Wind power is often less costly than both fuels and is often used on a "must-take" basis by electricity dispatchers

4E. CURRENT ISSUES IN COAL

GREENHOUSE GAS REGULATION AND CARBON CAPTURE

The potential for federal regulation of greenhouse gas emissions remains uncertain. However, state-level policies (primarily in Washington and Oregon) regulating electric utilities with ownership stakes in the Colstrip Generating Station and other coal plants across the Pacific Northwest are driving the retirement of coal-fired generation with a corresponding reduction in coal mine production.

In late-2015, EPA finalized carbon dioxide (CO2) emission performance rates for new fossil fuel-fired power plants. For existing power plants, EPA established the emission rates based on analysis of the best system of emission reduction that had been demonstrated for the particular pollutant and particular group of sources. States had the flexibility to develop plans that met their specific needs, so long as they achieved the prescribed emission performance rates. On February 9, 2016, the Supreme Court stayed the implementation of the emission performance rates for existing power plants pending judicial review, halting the process. In late 2017, the Trump administration blocked implementation of the Clean Power Plan under EPA Administrator

122 A gross proceeds tax of 5 percent goes to both the county and state based on 1990 mills. Another 0.4 percent goes for the Resource Indemnity and Ground Water Assessment Tax that, among other things, pays for reclamation of old, unreclaimed mined areas. https://mtrevenue.gov/wp-content/uploads/2017/07/2016-Biennial-Report-Complete.pdf.

123 Montana Department of Revenue, Tax Policy and Research, Rosemary Bender.

124 Ibid.

Scott Pruitt. In June 2022 the Supreme Court ruled that the now defunct Clean Power Plan was indeed unconstitutional and that the EPA's approach to regulating carbon dioxide in a manner that would create a broad, energy sector-wide transition away from coal was beyond the authority granted to the EPA by Congress.

Capture and sequestration of carbon dioxide emissions from coal-fired power plants has long been considered a potential lifeline for power plants facing closure due to environmental policies or economic pressure to reduce greenhouse gas emissions, and thus a measure to continue supporting coal production in Montana. Montana is one of only a few states that have taken steps to implement carbon sequestration legislation (Chapter 474, Laws of 2009), including property tax incentives for carbon dioxide pipelines. While state law does not mandate the sequestration of carbon dioxide generated from sources, the law provides regulatory certainty to those interested in pursuing such technology. Montana has stated its intent to have jurisdiction over a sequestration program, while recognizing that its regulatory program will need to be in line with federal guidelines. Despite the incentives and regulatory structure in Montana, the application of carbon capture and sequestration has been limited to injections of carbon dioxide for enhanced oil recovery, using carbon dioxide delivered by pipeline from a natural gas processing plant in Wyoming. Carbon capture technology has not yet been applied to any existing coal generation plants in Montana.

COAL EXPORT TERMINALS

Beginning in 2010 various business interests proposed the construction of seven new Pacific Northwest coal export terminals that would ship coal transported to the terminals by rail from the Powder River Basin area in southeastern Montana and Wyoming to Asian markets. The U.S. coal industry sees exports as an opportunity to make up for declining domestic demand. However, federal and state permitting agencies have so far rejected plans to build new export terminals, and Asian markets have turned to other energy sources, limiting the viability of significant new exports of Montana coal.

5. PETROLEUM IN MONTANA

Montana's petroleum sector produces crude oil, mostly in the northeastern part of the state, and is a net exporter of refined products - including gasoline and diesel - from four refineries located in the state. During the 2020 fiscal year, Montana produced 21.2 million barrels of crude oil, worth $880 million in gross value.[125] This oil production accounted for a portion of the $85 million in oil and gas production tax revenue collected in fiscal year 2020 by Montana.[126] Approximately 95 percent of Montana's crude oil production is exported to other states, primarily North Dakota and Wyoming, while 92 percent of the crude oil refined in Montana is imported from Canada with another 6 percent from Wyoming.

Montana is home to four refineries, three in the Billings area and another in Great Falls. In total, Montana's refineries have the capacity to refine about 215,000 barrels/day (bbl/day) of crude oil. In 2020, Montana's four petroleum refineries exported about 53 percent of their refined liquid products to Washington, North Dakota, Wyoming, and additional points east and south. Nearly 60 percent of refined gasoline was exported, while less than 50 percent of refined diesel was exported.[127] Crude oil receipts at Montana's four refineries totaled 71 million barrels in 2020.

The four Montana refineries produced about 1.5 billion gallons of gasoline and just over 1 billion gallons of diesel in 2021. Montana's three refined pipelines delivered 70-80 percent of that production in-state and out-of-state, with the rest delivered by rail and truck.[128] About 0.55 billion gallons of gasoline were sold in Montana in 2020, and around 0.45 billion in diesel.[129]

Montana refinery production was virtually unchanged from 2019 to 2020, despite a drop in production related to the COVID-19 pandemic. Montana pipeline deliveries in 2019 and 2020 were similar. Consumption of gasoline and diesel in Montana decreased significantly in March, April and May of 2020 due pandemic-related economic contraction. Otherwise, in-state monthly consumption numbers remained similar to corresponding years.[130]

5A. PETROLEUM PRODUCTION

Oil production began in Montana somewhat later than neighboring states. The first oil wells drilled in Montana were likely in the Butcher Creek drainage between Roscoe and Red Lodge, beginning in 1889. Non-producing wells were drilled within today's boundaries of Glacier National Park in the early 1890s. The state's first oil boom was a discovery in what geologists refer to as the Middle Mosby Dome at Cat Creek, a tributary of the Musselshell River east of Lewistown. Oil was drilled and collected there in early 1920. By 1921, the Cat Creek area accounted for 1.3 million barrels (1 barrel = 42 gallons) of production. That was soon followed by the Kevin Sunburst field discovery in 1922. That field would lead production from about 1925 to 1935. A bit west, the Cut Bank oil fields were developed in the mid-1930s. Oil was discovered in the Williston Basin around 1955. Oil fields were developed in the Sweetgrass Arch in northern Montana, the Big Snowy Uplift in central

125 Montana Department of Natural Resources and Conservation, Oil and Gas Conservation Division, Annual Review; Montana Department of Revenue, Biennial Report, 2019-20.

126 Montana Department of Revenue, Biennial Report, 2019-2020, p. 155.

127 Montana Energy Office, DEQ 2021.

128 Montana Energy Office, DEQ, 2022.

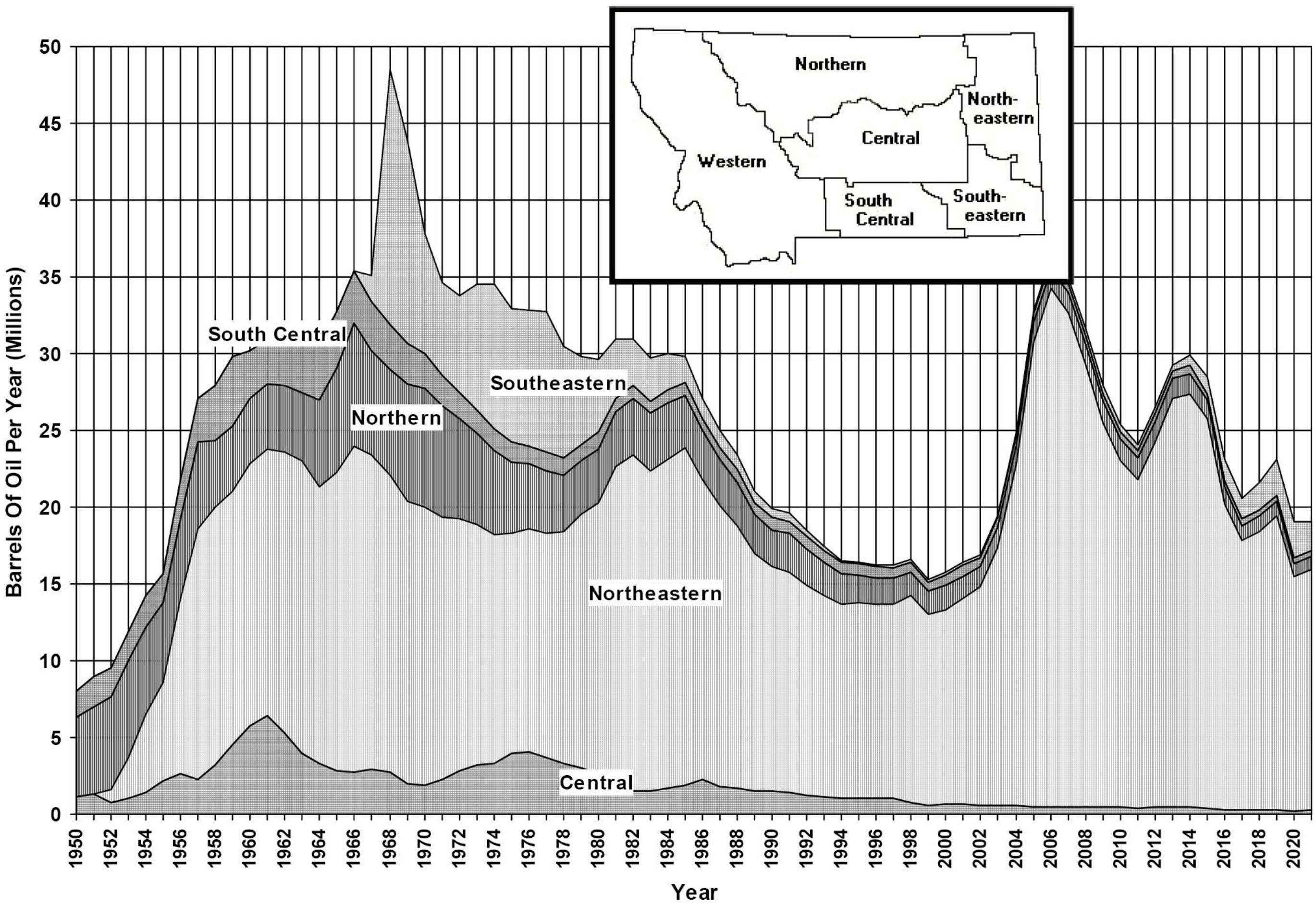
129 Montana Department of Transportation, Motor Fuel Section, 2022.

130 Montana Department of Transportation Motor Fuel Section, January, 2022.

Montana, the northern extensions of Wyoming's Big Horn Basin in southcentral Montana, and the Powder River Basin in southeastern Montana.

Montana's petroleum production peaked in 1968 at 48.5 million barrels, the result of cresting Williston Basin production combined with a surge of production from the newly discovered Belle Creek field in the Powder River Basin (Figure 5.1). Production then declined quickly until 1971, when a series of world oil supply shocks began to push crude oil prices upward, stimulating more drilling that would partially offset production declines through the remainder of the 1970s.

Figure 5.1 Crude Oil Production[131]



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 Montana in 1981. 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. The drilling boom of the early 1980s produced a high percentage of dry holes and was able only to delay the slow decline of statewide production.

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 at about 16 million bbl/year in the mid-1990s. After 1999, oil production increased sharply as horizontal drilling and hydraulic fracturing techniques began to be implemented more widely in the Williston Basin (Figure 5.2).

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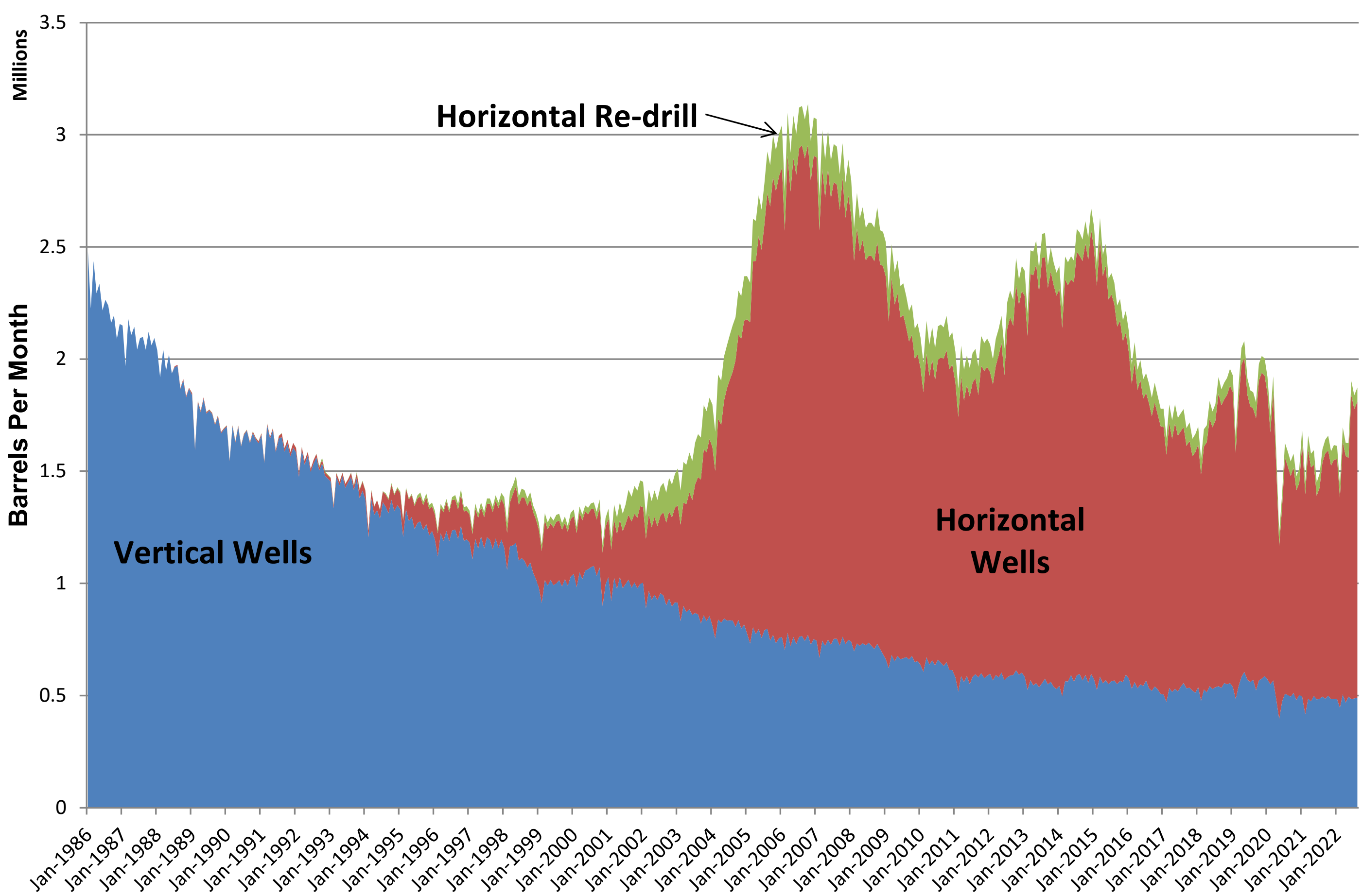
131 Montana Board of Oil and Gas, Annual Review, 2020.

Montana's most recent oil production boom peaked in 2006 when production exceeded 36 million barrels. This was up from a recent historical low of 15 million barrels of oil produced in 1999. More than 50 percent of 2006 Montana oil production was from the Elm Coulee field in Richland County, part of the larger Bakken formation. The number of wells drilled dropped sharply in 2015 with a drop in the price of oil, from 226 in 2014 down to 78 in 2019. The number of currently producing oil wells has stayed consistently above 4,000 since 2006.[132] Despite that, annual in-state production has fallen by almost half from 2006 to 19 million barrels in 2020.[133] While reserves in the Elm Coulee area were well known, horizontal drilling techniques were critical in making the field economical to develop. Horizontal drilling is a method that includes drilling a vertical well and then "kicking out" horizontally through the oil-bearing rock formation. The horizontal well innovations used in the Elm Coulee field would go on to be used to great effect in North Dakota to develop the larger Bakken oil field.

Figure 5.2 Montana Monthly Oil Production - Vertical vs. Horizontal Wells, 1986-2022[134]



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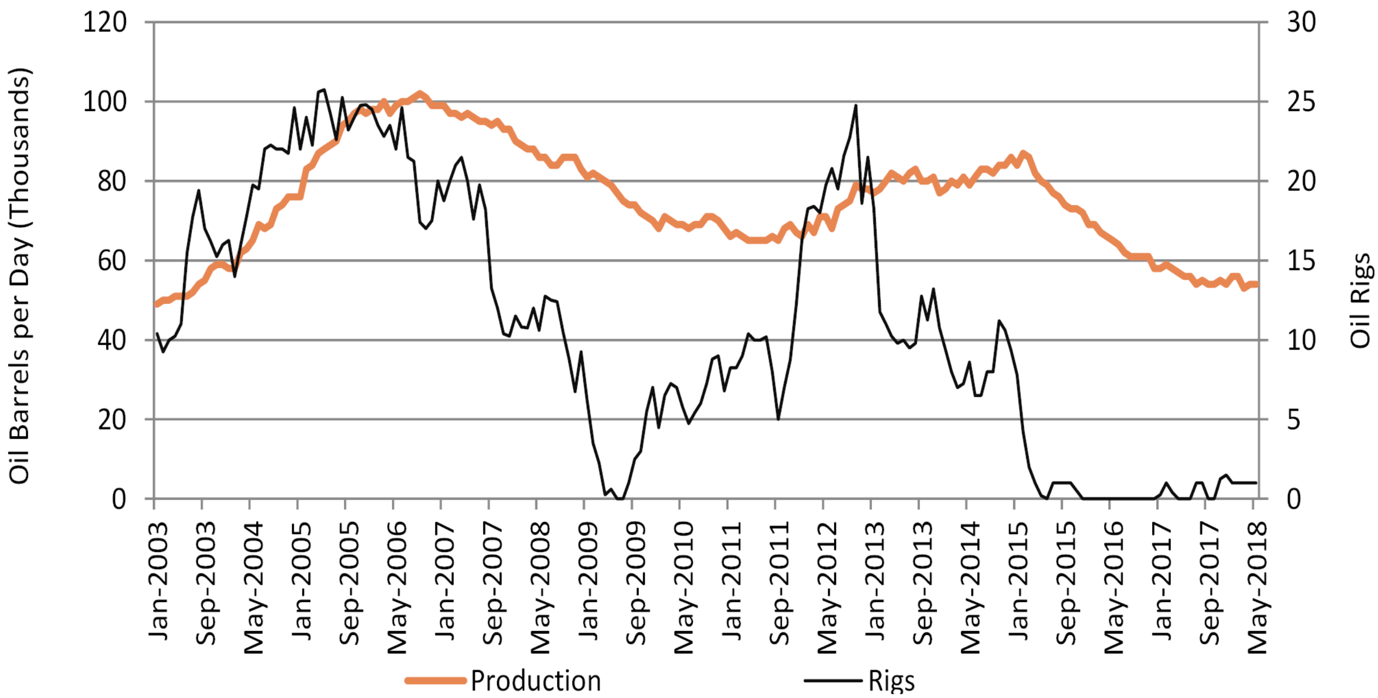
132 Montana Department of Natural Resources and Conservation, Oil and Gas Division, Annual Reviews, https://bogfiles.dnrc.mt.gov/Reference/Statistics/Production/221223_HorizontalvsVerticalOil.pdf.

133 Ibid.

134 Ibid.

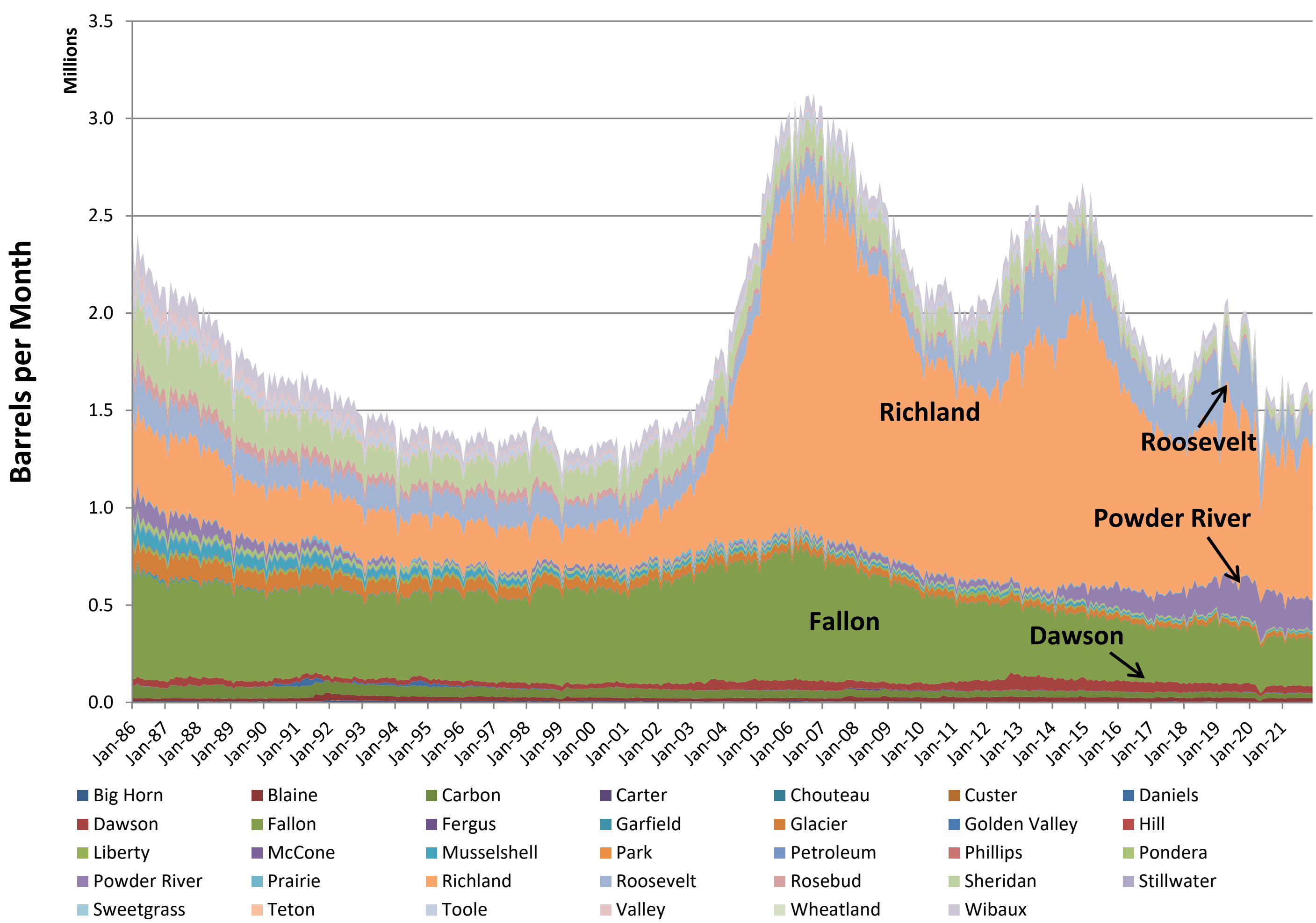
Figure 5.3 Montana Oil Production and Rigs[135]



Most Montana crude production over the past four decades has occurred in the Northeastern portion of the state at the edge of the Bakken field in the Williston Basin. The Williston Basin, which covers parts of eastern Montana, North Dakota, South Dakota, and Saskatchewan and includes the Bakken and Three Forks formations, is one of the newest large oil-producing regions in the country to produce hundreds of millions of barrels of oil annually. The Williston Basin's production peaked at more than 1.2 million barrels of crude oil production per day in 2014 before production receded with the crash in crude oil prices in the fall of 2014. However, Montana's oil production represents only a small portion of the recent oil production from the larger Williston Basin. Once Montana's Elm Coulee Field's production peaked in 2006, most of the drilling and production attention shifted to the middle of the Bakken formation in North Dakota ahead of the region's overall production peak in 2014. Drilling activity increased on the Montana side of the border from 2011 to early 2014 as high oil prices and infrastructure limitations in North Dakota led to drilling activity spreading away from the center of the Bakken field. With the collapse of crude oil prices in 2014, drilling throughout the Bakken region receded quickly and only began to return in late 2016.

135 Montana's Oil and Gas Production Tax, Montana Legislative Fiscal Division, 2018. https://leg.mt.gov/content/Publications/fiscal/leg_reference/Brochures/2018-Oil-and-Gas-production.pdf.

Figure 5.4 Monthly Oil Production by County[136]



After Montana's recent crude oil production peak of 36.3 million barrels in 2006, annual oil production slid by a third through 2011 before going through a second, smaller boom beginning in 2012, reaching 29.9 million barrels in 2014. Over the past decade, Montana's drilling rig activity has been largely focused in the western Bakken formation, but exploratory wells have been drilled in central and northern Montana as additional geologic formations that might lend themselves to horizontal drilling and hydraulic fracturing techniques are explored. In addition, the application of enhanced oil recovery techniques in the Belle Creek field in the Powder River Basin region of Montana has resulted in a production increase for the region. Until crude oil prices stay at high levels for a prolonged period of time, it is unlikely that Montana will see significant oil exploration or new drilling.

5B. MONTANA PETROLEUM PIPELINE SYSTEM

Several crude oil pipeline networks serve Montana's petroleum production regions. One network owned by True Companies bridges the Williston and Powder River Basins in the eastern part of the state but does not serve Montana refineries. The Front Range and Glacier Pipelines in Central Montana primarily move crude oil from Canada to Montana refineries in Billings and further south to points in Wyoming. Enbridge's Express

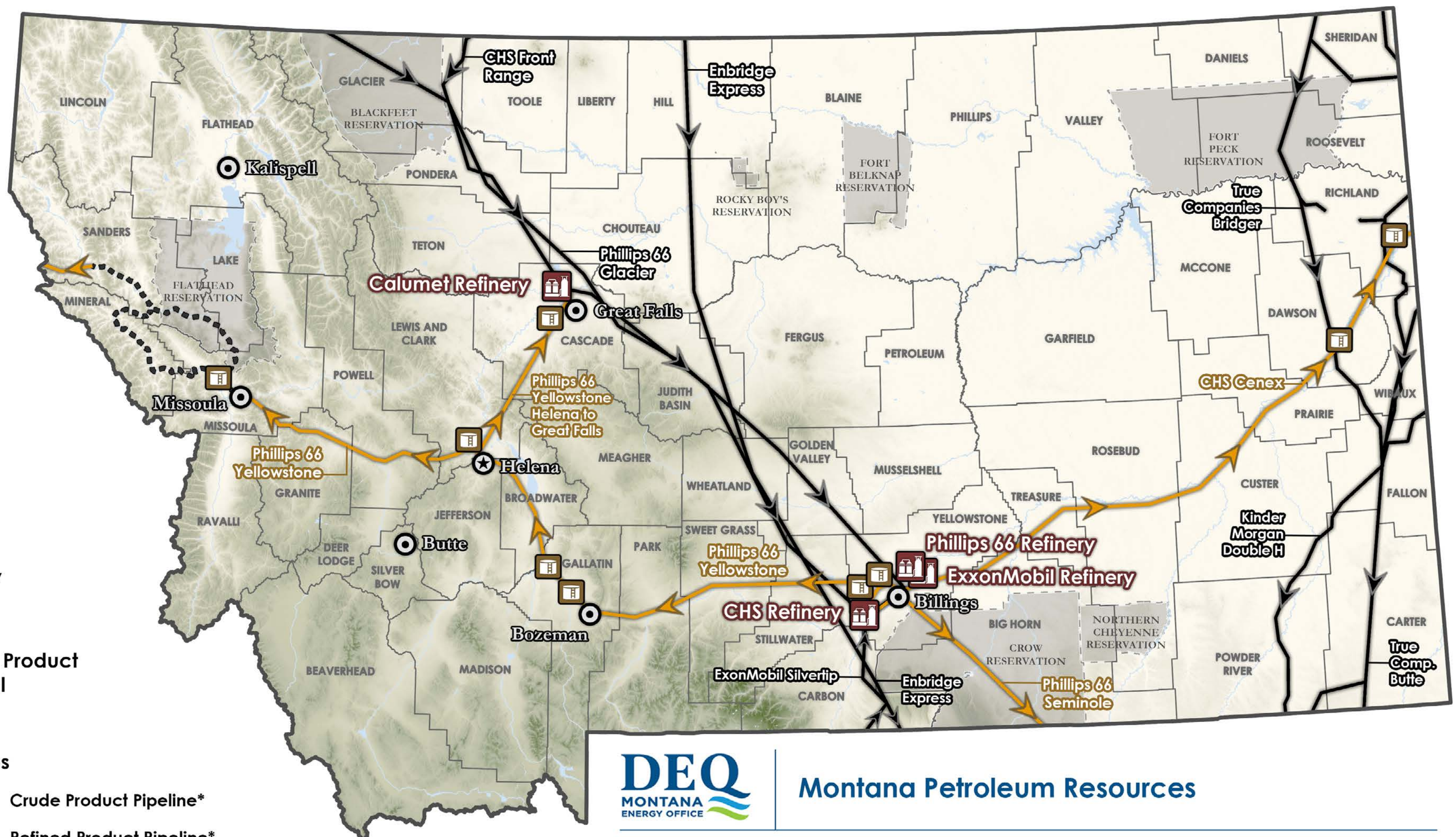
136 Montana Department of Natural Resources and Conservation, Oil and Gas Division, Annual Reviews, [https://bogwebfiles.dnrc.mt.gov/AnnualReviews/.](https://bogwebfiles.dnrc.mt.gov/AnnualReviews/)

pipeline in the same general area transports western Canadian crude through central Montana to Casper, Wyoming with some of that crude offloaded in-state. The Silvertip Pipeline delivers crude to the Exxon Refinery northward from Wyoming. In addition to the state's crude oil pipelines, three major refined petroleum product pipelines operate in the state, delivering refined petroleum products to many of Montana's larger cities as well as exporting products for use in neighboring states.

The majority of crude oil production in Montana occurs in the Williston Basin of eastern Montana, which is not connected by crude pipelines to Montana's four refineries. As a result, in 2016, more than 90 percent of Montana oil production was exported from the state, mostly to Wyoming and the Dakotas, through the eastern Montana pipeline system or through unit train shipments. Construction of the proposed Keystone XL pipeline that would have carried crude from Alberta, south through Montana to the central U.S., was terminated in 2021.

The majority of refined output from Montana's four refineries is moved by pipeline, with the rest moved by rail and truck. The Billings area refineries ship their products to Montana cities, east to North Dakota (Cenex Pipeline), south to Wyoming (Seminoe Pipeline), and west to Spokane and Moses Lake, Washington (Yellowstone Pipeline). The development of Billings as a refining center saw the rise of refined pipelines to export product out of Montana. The Yellowstone Pipeline from the Billings refineries (owned by Phillips 66) west to the Spokane area was completed in 1954. The 425-mile Oil Basin Pipeline (now Cenex) from Laurel to Minot, North Dakota was also built around this time. Phillips 66 also owns the Seminoe Pipeline that runs south from Billings into Wyoming. Each of these refined product pipelines is shared by the three large refineries in Billings under operating agreements. Montana's three refined pipelines deliver mostly gasoline and diesel to in-state and out-of-state terminals. The Calumet refinery does not ship refined product by pipeline.

Map 5.1 Montana Petroleum Resources



Refinery

Refined Product Terminal

Pipelines

Crude Product Pipeline*

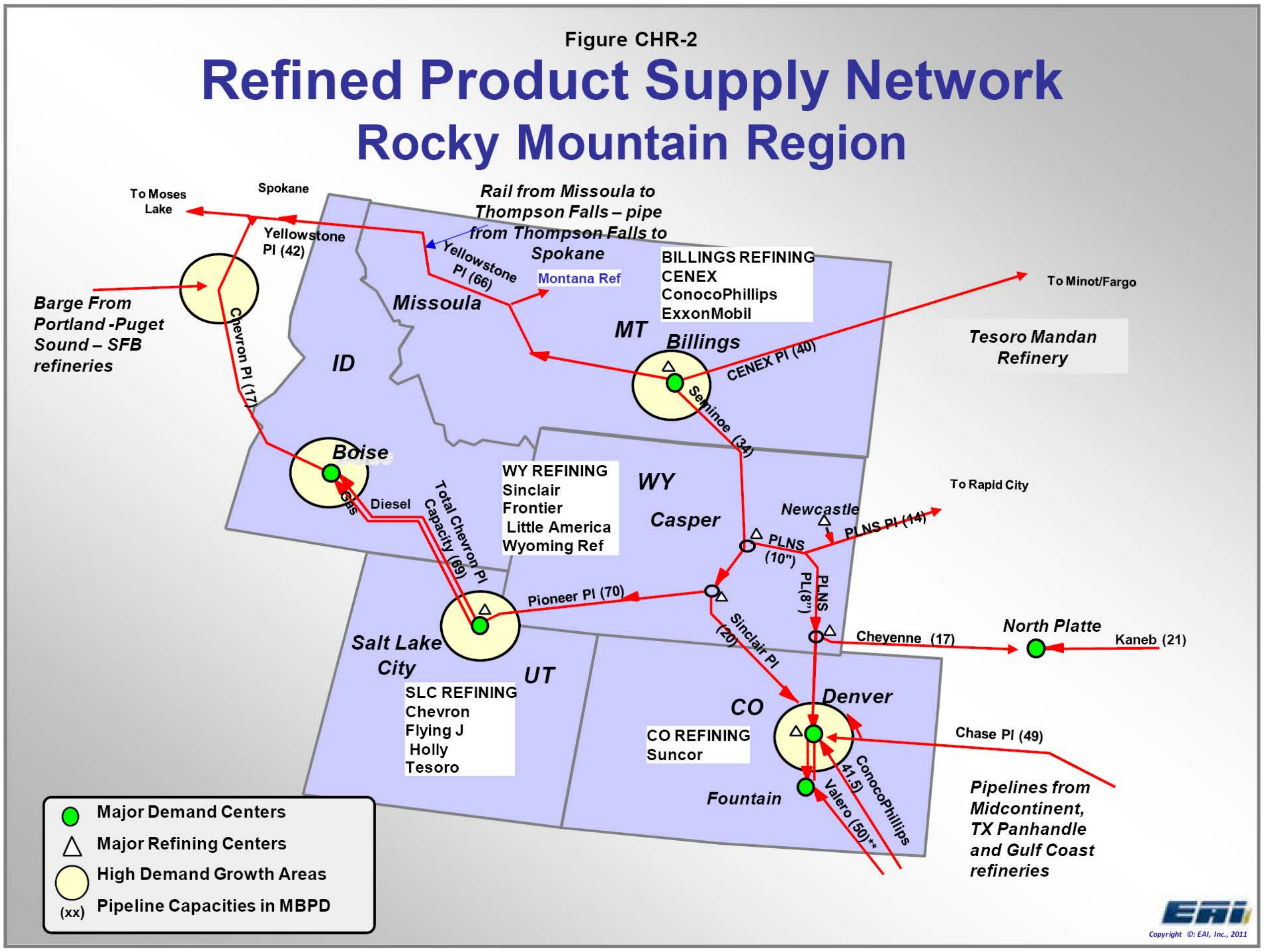
Refined Product Pipeline*

Railroad Link

Direction of arrow indicates directional flow of product

Pipeline Data Source: U.S. Energy Information Administration (EIA), 2020

Figure 5.5 Regional Refined Petroleum Product Supply Network[137]



5C. OIL REFINING OPERATIONS

HISTORY OF OIL REFINING IN MONTANA

Montana's earliest oil refining followed initial crude oil production. The first oil refinery was a small facility built in the Cat Creek area out of parts scavenged from large steam-powered tractors. Two formal refineries were soon constructed at Winnett near the Cat Creek strike. One operated intermittently into the early 1930s. An astounding number of oil refineries were built in Montana during the early decades of oil development and largely followed development of oil fields, beginning with Cat Creek and the larger Mosby Dome in the 1920s. These "tea kettle" refineries were installed close to the oil strikes. Even by the standards of the day, they were inefficient, skimming gasoline off the light oils that sometimes achieved a yield rate of only 50 percent. The remaining kerosene-type fuel oil was sold to the railroad with some residual tars marketed locally.[138]

Lewistown had two refineries by the early 1920s, both operated until the early 1940s. Two Kevin-Sunburst refineries and two near Cut Bank were built in the 1930s. Construction of refineries along transportation corridors outside of oil fields included ones in Great Falls, Butte, Missoula, and Kalispell. Yale Oil started a

137 EAI, Inc. (Energy Analysts International), 2011.

138 A History of Petroleum County, 1989.

refinery in Billings and the Laurel Oil and Refining Company built another down the road in Laurel, both dating from about 1930. These refineries processed oil from fields in northern Wyoming.

The war years further consolidated refining. According to the U.S. Bureau of Mines, 28 refineries operated in Montana at the outset of World War II in 1941; by 1947 there were only 11. In 1961, nine refineries operated at least seasonally in the state. Additional refineries continued to close through the 1960s and 1970s as the state's refining industry consolidated in Billings.

MONTANA OIL REFINING CAPACITY

Four petroleum refineries currently operate in Montana with a combined refining capacity of 211,100 bbl/day: ExxonMobil (61,500 bbl/day) and Phillips 66 (60,000 bbl/day) in Billings, CHS (59,600 bbl/day) in Laurel, and Calumet Montana Refining (30,000 bbl/day) in Great Falls. Montana refineries typically refine 63-70 million barrels of crude oil a year.[139] The majority of refined petroleum products (i.e. gasoline, diesel, propane, etc.) consumed in Montana are refined in Montana. There are a small amount of refined product imports (mostly trucked in) from Washington, Idaho, Canada and North Dakota.

A decade after the merger of Conoco Inc. and Phillips Petroleum Co. in 2002, ConocoPhillips spun off its downstream assets (refining and distribution) in 2012 by creating the Phillips 66 holding company. Phillips 66 now operates the Billings refinery previously operated by ConocoPhillips, as well as the Seminoe and Yellowstone refined product pipelines that deliver refined petroleum products south and west from Billings. Phillips 66 also owns the Glacier crude line that runs south from Canada to fuel its refinery. ExxonMobil also uses the Yellowstone Pipeline.

CHS owns one of the three large refineries in the Billings area and the Cenex Pipeline LLC refined product pipeline that runs east from Billings to North Dakota. CHS also owns the Front Range crude line that runs south from Canada. Exxon owns the third large refinery in the Billings area and the Silvertip crude pipeline that delivers crude oil from Wyoming. Exxon also receives crude from the Glacier and Front Range lines.

In 2012, Calumet Specialty Products Partners purchased the Montana Refining Company in Great Falls from Connacher Oil and Gas Limited of Canada. Calumet completed a $400 million expansion and upgrade of the Great Falls refinery, increasing its operating capacity to 24,000 bbl/day, after which it was expanded again to 30,000 bbl/day. Calumet began to produce renewable diesel in 2021.

The four Montana refineries produced about 1.5 billion gallons of gasoline and just over 1 billion gallons of diesel in 2021. About 0.55 billion gallons of gasoline were sold in Montana in 2020, and around 0.45 billion gallons in diesel.[140]

Today, Montana's refineries are primarily refining Canadian crude oil. In other words, most of the crude used to serve Montana refineries is imported from Canada. Shipments from Canada have steadily increased since the late 1960s. As Montana's refining capacity has increased, imports of Wyoming crude have declined, and Montana's oil production has shifted away from areas neighboring the refineries (Figure 21). Between 2015 and 2019, 1.8 percent of the crude oil processed at Montana refineries was Montana crude from oil fields in the Sweetgrass Arch, Big Snowy, and Big Horn regions of the state. Collectively, in 2020, 94 percent of the refinery crude inputs came from Alberta, Canada, and 4 percent from Wyoming.

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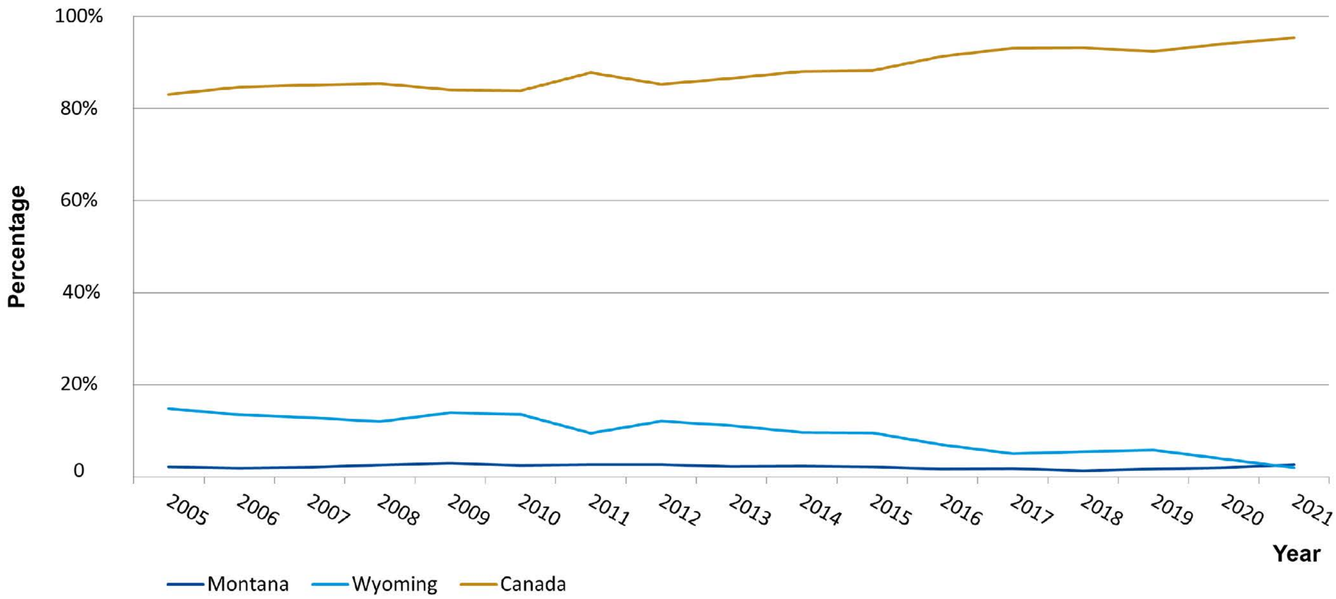
139 Montana Energy Office, 2022.

140 Montana Energy Office, Montana Department of Environmental Quality and Montana Department of Transportation, Motor Fuel Section, 2022. These totals include off-highway consumption as well.

Figure 5.6 Montana Refinery Oil Source[141]



5D. PETROLEUM PRODUCTS CONSUMPTION

The transportation sector is the single largest user of petroleum and the second largest user of all forms of energy in Montana. In 2019, about 70 percent of Montana petroleum consumption was in the form of motor gasoline, diesel and jet fuel.[142]

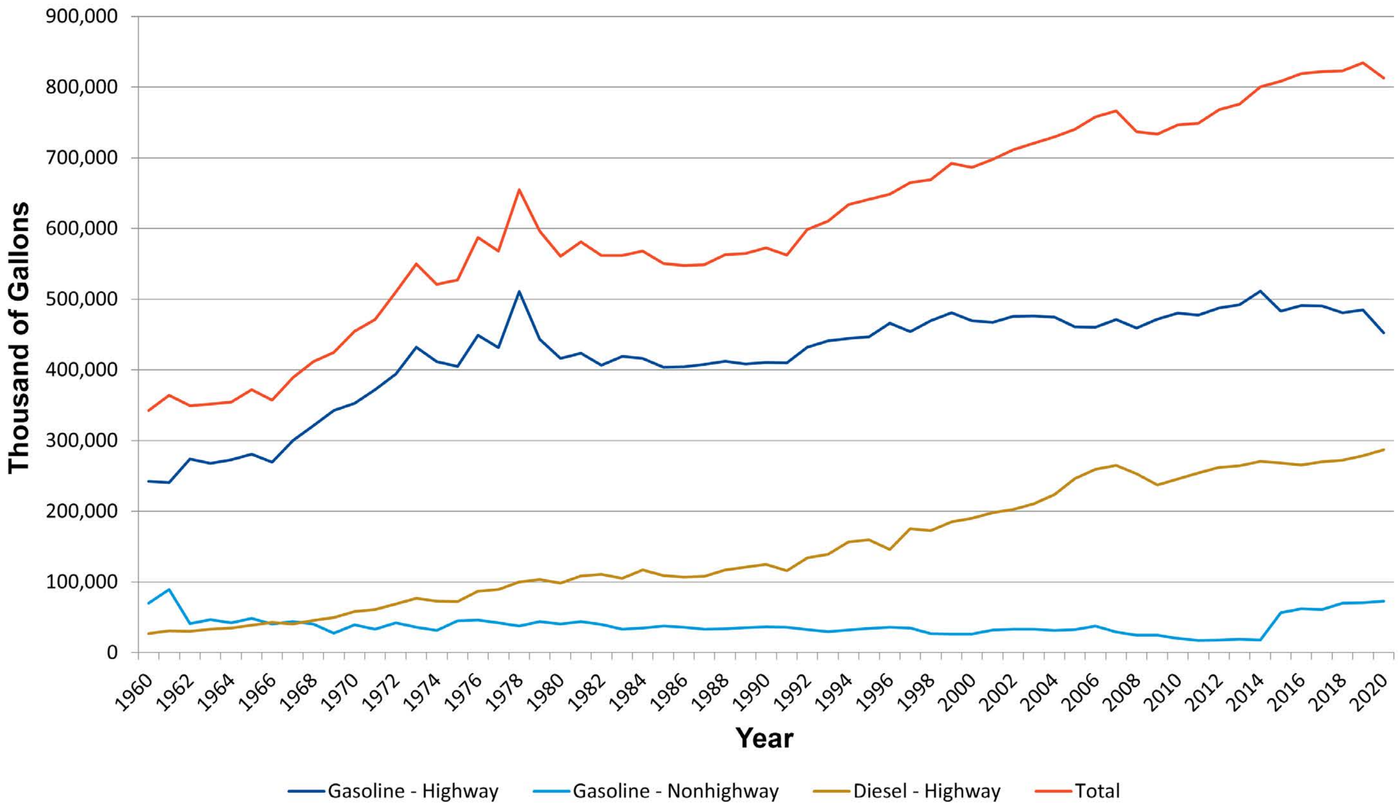
While Montana gasoline consumption peaked in 1978 at more than half a billion gallons before declining in response to the 1979 oil crisis, recent growth in Montana gasoline consumption has peaked again in 2021 at 557 million gallons. Flat through most of the 1980s, Montana gasoline consumption began to consistently rise in the 1990s, which continued unabated until the 2007 economic recession. Beginning in 2012, the upward trend in Montana gasoline consumption resumed. Today, gasoline consumption (including non-highway use) in Montana tops half a billion gallons annually whereas diesel consumption (including non-highway use) is just below half a billion gallons. More than 90 percent of Montana motor gasoline consumption is for highway vehicle use, while most of the remaining 10 percent is consumed by non-highway vehicles. Similarly, the last two years of data for diesel consumption in Montana have been the two highest on record, exceeding the previous peak recorded in 2007.[143]

141 Montana Energy Office. For 2008-2020, EIA-923 (Schedule 2) data is used.

142 U.S. EIA, SEDS, Table C2. Energy Consumption Estimates for Selected Energy Sources in Physical Units, 2019.

143 U.S. EIA, 2022.

Figure 5.7 Montana Motor Fuel Use Chart, 1960-2020[144]

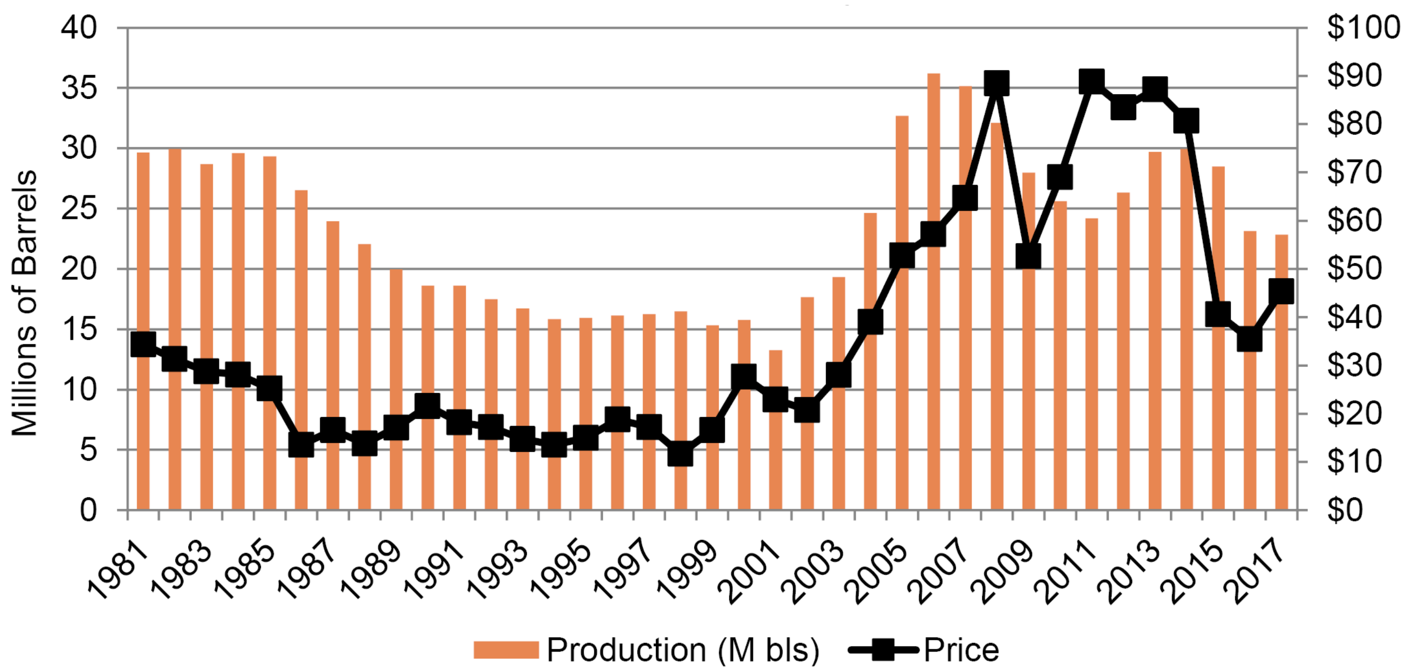


Between 1999 and 2010, national crude oil prices remained highly volatile, rising from an annual average of $15.56 per barrel in 1999 to a pre-recession annual average peak of $94.04 per barrel in 2008.[145] At its peak in July 2008, crude oil was trading at $145 per barrel before the economic recession caused global crude oil prices to plummet below $35 per barrel in February 2009. Crude prices again surpassed $100 per barrel in April 2011 and largely hovered between $85 and $100 per barrel until late 2014 when prices crashed once more. Crude prices hit a new floor in February 2016 and slowly rose until the COVID-19 pandemic that shut down travel. The average U.S. price of crude in 2020 was below $50 per barrel and was even negative at one point. As fossil fuel demand recovers, and supply attempts to catch up, the present oil price is high at around $100 per barrel in 2022. As can be seen in Figure 5.8, all of these market fluctuations have had a significant impact on the prices being paid at Montana gas pumps. Oil production in Montana has also varied significantly by oil price.

144 U.S. Department of Transportation, Federal Highway Administration, Highway Statistics, Annual Reports, Table MF-21, 1960-2020.

145 http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=f000000__3&f=m

Figure 5.8 Oil Production and Price chart[146]

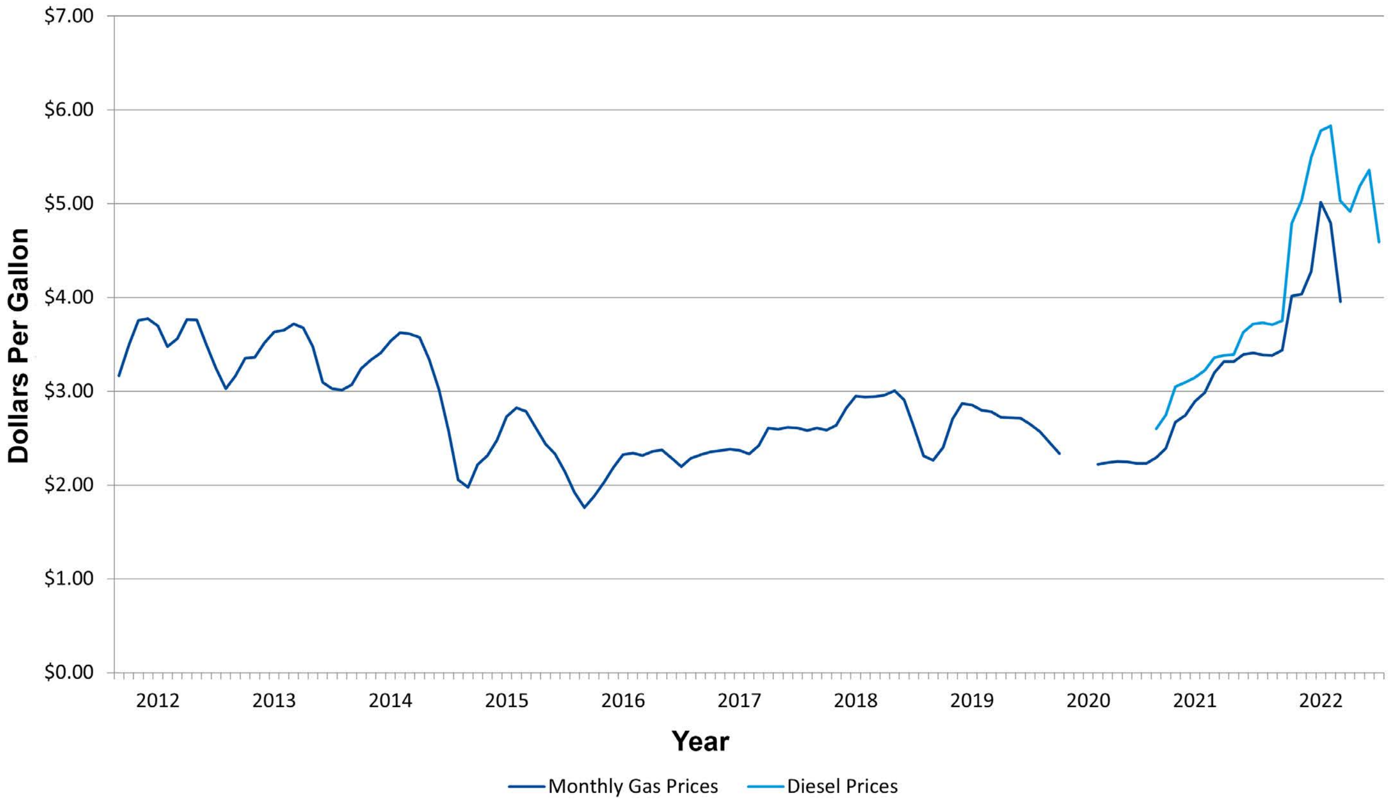


Fuel use shows a cyclical rise and fall through the year. Use tends to rise during the summer months and taper off during the winter. The winter trough in fuel use is a third lower than the summer peak. This seasonal pattern is caused by variations in the use of Montana's 1 million vehicles, by the increase in tourist traffic during the summer, and by seasonal agricultural uses.

The price of gasoline can vary significantly around the state, a fact that is masked by the data, which is available only as statewide averages. The price of gasoline has a cyclical rise and fall, just like demand for gasoline; however, price lags behind demand, with peak prices tending to appear after the peak driving season.

146 *Montana's Oil and Gas Production Tax, Montana Legislative Fiscal Division, 2018.* *https://leg.mt.gov/content/Publications/fiscal/leg_reference/Brochures/2018-Oil-and-Gas-production.pdf.*

Figure 5.9 Montana Average Gasoline and Diesel Prices, by Month-2012 to 2022[147]



5E. PETROLEUM PRODUCTION TAXES AND STATE REVENUE

There are various tax rates for oil and gas production in Montana based on the type of well, type of production, working or non-working interest, date when production began, and the price for which the crude oil is sold. This last point is important because crude oil from the Northern Rockies and Upper Midwest, including the Bakken region, frequently trades at a discount ($5-$15 per barrel) to West Texas Intermediate (WTI) prices. Montana's crude oil price ranged from 82 percent to 96 percent of the WTI price from 2010-2020.[148] Limited pipeline capacity before the Dakota Access pipeline began operation in 2017 and higher rail costs to transport the oil production to key trading hubs contributed to the higher prices. Despite the discounted price for Montana oil production, overall increases in oil production and crude oil prices between 2004 and 2014 provided the state with substantial tax revenues (Figure 5.10). With the fall of oil prices and resulting slide in Montana oil production, Montana tax revenue from the oil and gas industries has fallen significantly since fiscal years 2015 and 2016.

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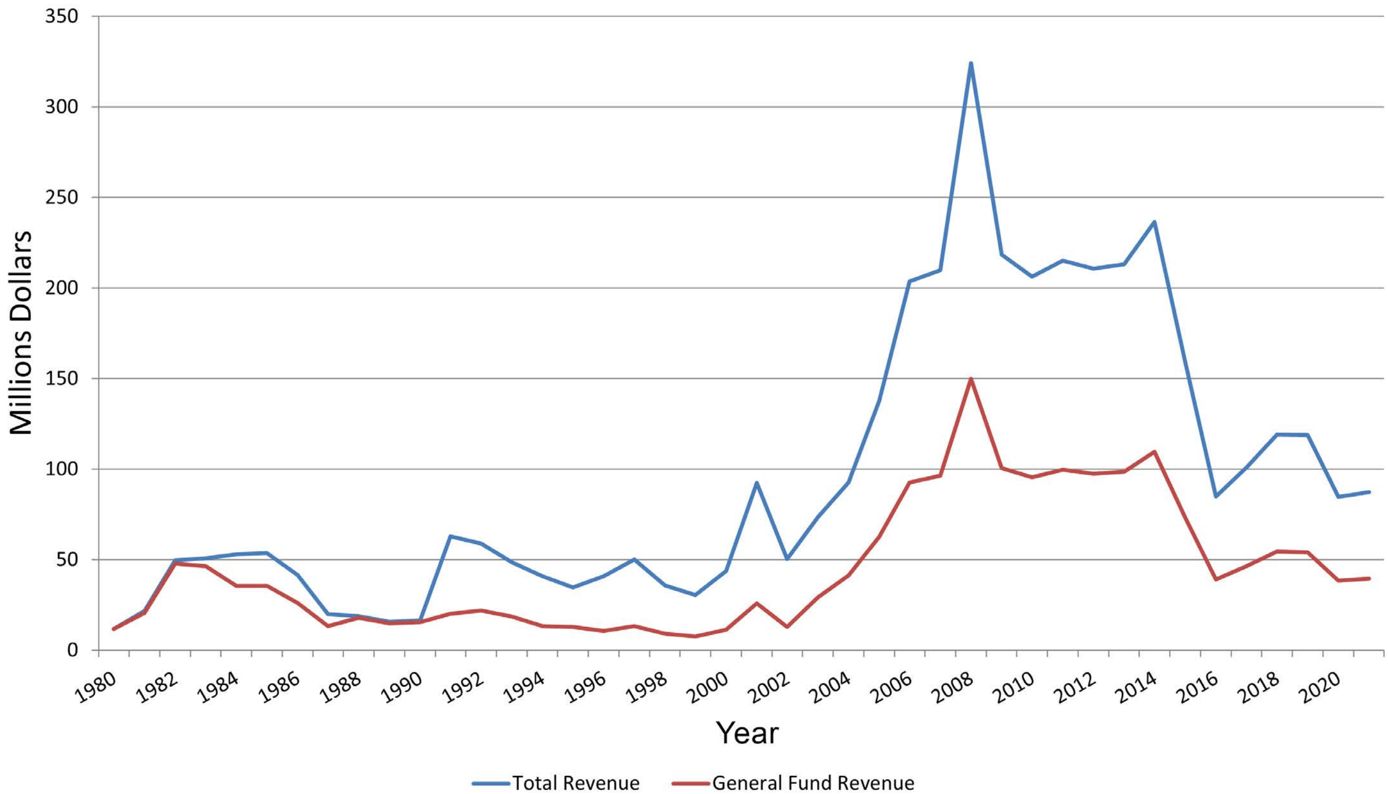
147 *U.S. Department of Energy, Energy Information Agency, Energy Information Administration, Forms EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report" and EIA-782B, "Resellers'/Retailers' Monthly Petroleum Product Sales Report." Regular gasoline only, through retail outlets. Data for 2012-2019 was collected by MT DEQ from regular sampling of state average retail gas prices posted to AAA's Daily Fuel Gauge Report website, https://gasprices.aaa.com/. Figures for May-August 2019 are taken from Michael Blasky at AAA (michael.blasky@norcal.aaa.com). Starting in July 2020, one sample is taken per month around the 15th of each month from http://fuelgaugereport.aaa.com/. An employee turnover change caused a gap in reporting from Sept 2019-June 2020.*

148 *Natural Resource Taxes, Montana Legislative Fiscal Division, https://leg.mt.gov/content/Publications/fiscal/FR-2023/Volume-2/Natural-Resource-Taxes.pdf, June 2021.*

Figure 5.10 Oil and Natural Gas Production Tax chart, 1980-2021[149]



According to the Montana Legislative Fiscal Division:

> *"The oil and natural gas production tax is imposed on the production of oil and natural gas in the state. Gross taxable value of oil and natural gas production is based on the type of well and type of production. A portion of the revenue from the tax may be returned to Indian Tribes per agreements between DOR and the Tribes."*[150]

Since January 1, 2006, approximately 50 percent of the revenue generated from oil and natural gas production taxes has been returned to the local county governments where the revenue was generated. Most of the remaining revenue is directed to the state's general fund. Small percentages of oil and gas production revenue are directed to specific state accounts to help fund particular interests.[151]

Unless there is an oil drilling resurgence in the state, future tax revenue from the oil and natural gas sectors will be dictated by the price at which each commodity is sold.

149 Montana's Oil and Gas Production Tax, 2021, Jared Isom, Montana Dept of Revenue; 2018, Montana Legislative Fiscal Division, https://leg.mt.gov/content/Publications/fiscal/leg_reference/Brochures/2018-Oil-and-Gas-production.pdf; 2019, 2020, Montana Department of Revenue, Biennial Report, 2019-20, 2002 to 2004, 2008-2010.

150 Natural Resource Taxes, Montana Legislative Fiscal Division, https://leg.mt.gov/content/Publications/fiscal/FR-2023/Volume-2/Natural-Resource-Taxes.pdf, June 2021.

151 Montana Department of Revenue, Biennial Report, 2014-16.

5F. CURRENT TOPICS IN PETROLEUM

RENEWABLE DIESEL PRODUCTION

U.S. West Coast and Canadian demand for transportation fuels derived from renewable feed stocks is driving a new business venture at Calumet's Great Falls refinery. In 2021 Calumet announced the creation of Montana Renewables LLC, a Calumet subsidiary that is ramping up to produce 12,000 bbl/d of renewable diesel, initially using Midwest soybean oil feedstock, but with plans to eventually incorporate Montana-sourced oil seed crops. Future production could be expanded to 25,000 bbl/d based on the capacity of the hydrocracker Calumet will employ.

Unlike its close cousin, "biodiesel", renewable diesel can be used as a 100 percent drop-in replacement for conventional petroleum-based diesel fuel. Renewable diesel is produced using hydrotreating and other refining processes, whereas biodiesel is produced via transesterification, a process in which the oil feedstock chemically reacts with methanol and a catalyst to create glycerin and biodiesel fuel. Calumet is also bringing online renewable hydrogen production. The hydrogen produced at the facility will be used in production of the renewable diesel fuel.

Calumet's entry into the nearly 1-billion-gallon domestic renewable diesel market, which has primarily been driven by California's Low Carbon Fuel standard, will constrain the Great Falls refinery's production capacity for conventional petroleum products to 12,000 bbl/day, down from 30,000 bbl/day.

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DEQ
Montana Department
of Environmental Quality