APPENDIX D: FUTURE RESOURCE OPTIONS

This Appendix provides an overview of the supply side resource technologies that were incorporated into the planning analysis as described in Section V of Minnesota Power's (or the "Company's") 2025 Integrated Resource Plan ("2025 Plan"). This appendix is organized in the following sections:

- Part A: Overview
- Part B: Resource Option Listing
- Part C: Short-Term Bilateral and Market Purchases for Market Capacity
- Part D: New Generation
- Part E: Policy Considerations

A. Overview

The resource technologies discussed in this appendix were considered for the capacity expansion plan analysis using the EnCompass production cost model, along with demand side alternatives discussed in Appendix B. The information in Appendix D is essential in defining the attributes of each supply side resource alternative.

B. Resource Option Listing

Through the planning process, Minnesota Power identified potential resources to meet future energy and capacity needs. The options below were considered at the beginning of the planning process:

Short-Term Bilateral and Market Purchases

- Market capacity purchase of 100 MW available post-2030

New Generation

- Coal: Super Critical Pulverized Coal ("PC")
- Natural Gas: Combustion Turbine ("CT"), Combined Cycle ("CC"), and Reciprocating Engine ("RICE")
- Carbon Dioxide ("CO_2") Capture and Sequestration ("CCS"): PC and CC
- Renewable Energy: Biomass, Enhanced Geothermal, Wind, and Solar Photovoltaic ("PV")
- Nuclear: Small Modular Nuclear
- Energy Storage: Lithium-Ion Battery, non-Lithium Battery, and Pumped Hydroelectric

C. Short-Term Bilateral and Market Purchases for Market Capacity

Market Capacity Purchase

The capability to purchase up to 100 MW of market capacity has been developed as a short-term capacity resource that can be selected by EnCompass post 2030 through the study period seasonally.

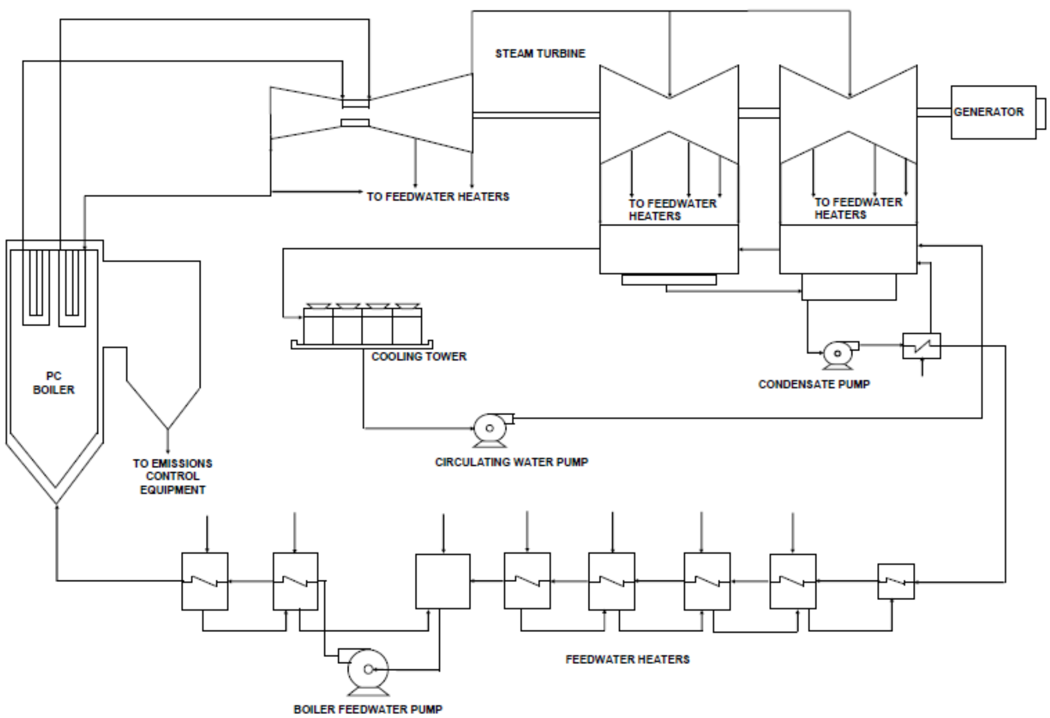
D. New Generation

Coal Technologies

Super Critical Pulverized Coal Generation

PC technology is a reliable energy generation resource throughout the world. PC units can be retrofitted to burn gas, biomass, and other fuels based on availability and British Thermal Units ("BTU") characteristics. PC technology can be divided into two distinct designs, subcritical or supercritical, which are distinguished by the maximum operating pressure of the cycle. The subcritical or supercritical terms refer to the state of the water used in the steam generation process. The critical point of water, which distinguishes subcritical and supercritical states, is 3,208.2 psia[1] at 705.47 degrees Fahrenheit ("°F"). Subcritical power plants use pressures below this point and supercritical power plants use pressures above it. Supercritical steam generators are generally more efficient than subcritical units of the same size resulting in fuel savings and decreased emissions, but at a higher installation and maintenance cost. To minimize the carbon footprint of the plant, for purposes of this assessment, a supercritical design has been evaluated. The main components of the PC unit are shown in Figure 1.

Figure 1. PC Unit Diagram



Coal from bunkers is fed into pulverizers, which crush it into fine particles. The primary air system transfers the fine coal particles to the steam generator burners for combustion. In the boiler, high-pressure steam is generated for the steam turbine. The expansion of the steam through the turbine provides the energy required by the generator to produce electricity. The

[1] PSIA is the acronym for pounds per square inch, absolute.

steam turbine exhausts into a condenser. The heat load of the condenser is typically transferred to a wet cooling tower system (assumed for purposes of this study). The condensed steam is then returned to the steam generator through the condensate pumps, low-pressure feedwater heaters, deaerating heater, boiler feed pumps, and high-pressure feedwater heaters. CCS, which Minnesota Power included when modeling new coal generation in the IRP, is discussed in greater detail below.

Natural Gas Technologies

Natural gas-fired generators provide the most electricity generating capacity in the United States, having surpassed coal-fired generators in 2018. They are a versatile energy source for supporting the intermittency of renewable energy. Current advanced class gas turbines are capable of burning a mixture of up to 30 percent hydrogen fuel by volume. Manufacturers are also working on retrofits that will enable gas turbines to burn 100 percent hydrogen in dry low emissions combustors.

Combustion Turbine Generation

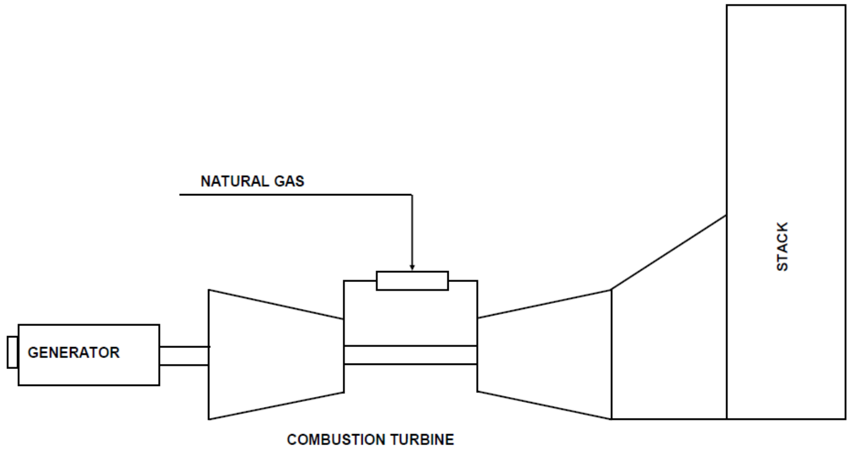
The thermodynamic cycle utilized by gas turbines is one of the most efficient ways to convert natural gas or fuel oil to mechanical power or electricity. A simple cycle gas turbine consists of a compressor section, combustor, and turbine section. Ambient air is compressed in the compressor. Fuel is mixed with the compressed air and ignited in the combustor section. The combustion products exit the combustor and expand through the turbine section. Typically, more than 50 percent of the turbine shaft work produced is consumed by the compressor section. The remaining shaft work is used to drive a generator. The exhaust gas exits the turbine section at approximately 800-1,200°F and flows through the exhaust stack. A simple cycle gas turbine also offers the advantage of being readily converted to a larger CC generation unit, providing additional capacity and energy to meet more substantial load demands.

Gas turbines are separated into two main categories, aero derivatives and frames. An aero derivative engine is based on jet engine design for airplanes. They offer robust design, fast start capabilities, low maintenance, and very high efficiency. The aero derivative uses high quality alloy materials, which give them the ability to endure much higher cycling with lower maintenance costs. Aero derivative maintenance is not affected by startups and is only based on hours of operation. Based on these characteristics, the aero derivative is typically used as a peaking unit or for load following that requires high cycling. Aero derivatives are more expensive on a $/kW basis compared to a frame turbine and the largest aero derivative turbines generate approximately 100 MW. Also, due to their high efficiency and subsequent low exhaust temperatures (800-1,000°F), the aero derivatives are less economical to convert to CC.

Frame gas turbines are much larger and heavier than aero derivatives. They traditionally have longer start times, are less efficient than the aero derivatives, and have higher, start-based maintenance costs. However, frame gas turbines are much larger and less expensive on a $/kW basis. The largest frame gas turbines exceed 400 MW per engine. The frame gas turbine is also very conducive to CC conversion since they have much higher mass flow and exhaust temperatures (1,000-1,200°F) compared to aero derivatives. Recently, gas turbine manufacturers have been developing designs for faster start times, higher efficiencies, and larger engines that have the ability to burn alternate fuels including hydrogen and renewable natural gas. Frame gas turbines have become much more flexible in recent years but are still not achieving the attributes of aero derivatives.

The main components of a simple cycle gas turbine unit are shown in Figure 2.

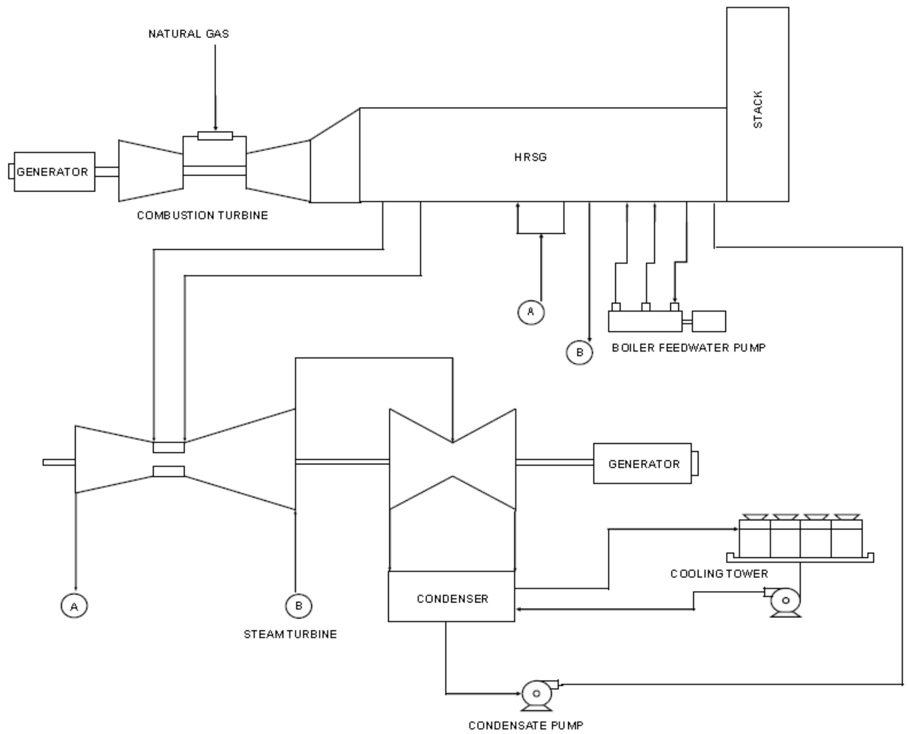
Figure 2. Simple Cycle Unit Diagram



Combined Cycle Generation

The use of both the gas turbine cycle (also known as the Brayton Cycle) and the steam turbine cycle (Rankine Cycle) in a single plant is referred to as a gas turbine CC. The basic principle of the CC is to fire natural gas (or fuel oil) in a gas turbine, which produces power directly via a coupled generator. The exhaust from the turbine is used to create steam in a heat recovery steam generator ("HRSG") that can drive a steam turbine generator. The main components of a CC unit are shown in Figure 3.

Figure 3. Combined Cycle Unit Diagram



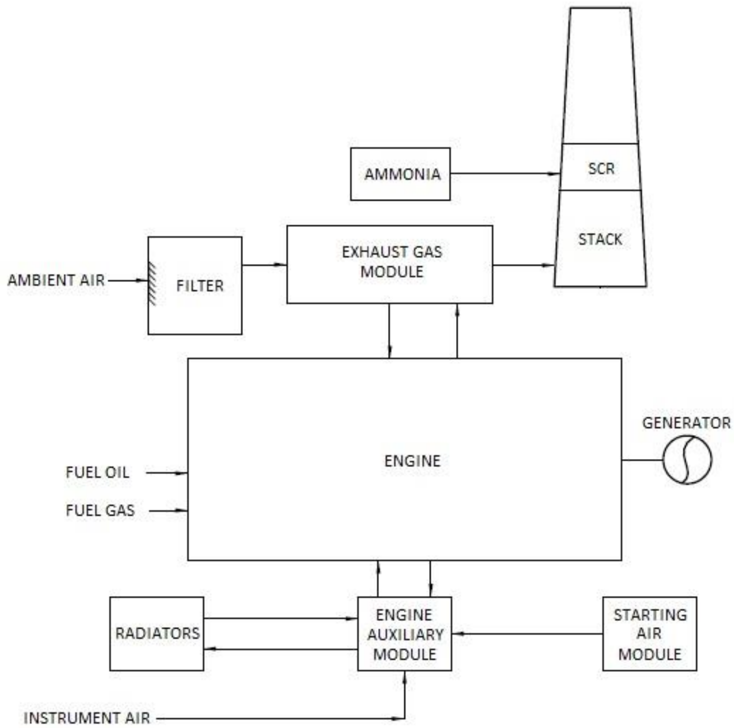
A CC facility results in high energy conversion efficiencies and low emissions (with selective catalytic reduction ("SCR") and CO catalyst). The gas turbine cycle, as noted above, is one of the most efficient for converting fuel (natural gas or fuel oil) to mechanical power or electricity. Adding a steam turbine to utilize steam produced in the HRSG increases the efficiencies to a range of 52 to over 60 percent in current advanced class turbines, compared to the efficiency range of 30 to 40 percent for a frame CT. To increase peaking power output, additional natural gas firing (duct firing) can be performed in the HRSG, and steam can be injected into the gas turbine for power augmentation.

Gas turbine CCs can be arranged in multiple configurations. The diagram above shows a 1x1 configuration (one gas turbine/HRSG and one steam turbine). A 2x1 configuration would include two gas turbines/HRSG's feeding one common steam turbine. Assuming the same gas turbines, a 2x1 plant will generate approximately twice as much power as a 1x1 plant. A 2x1 plant will also have a slightly higher efficiency.

Reciprocating Engine Generation

A RICE utilizes the Carnot cycle to mechanically convert fuel to energy. The RICE burns fuel in a combustion chamber which pushes a piston connected to a crankshaft which turns the generator. Most large RICE for power generation have 18 or 20 cylinders and the largest engines generate approximately 18-20 MW. Multiple banks of engines are typically installed to meet generation needs and result in a highly dispatchable facility. The main components of a RICE are shown in Figure 4.

Figure 4. Reciprocating Engine ("RICE") Diagram



A RICE's efficiency is approximately 45 percent for current technology. It is as efficient as the most efficient simple cycle gas turbines. A RICE for power generation comes standard with a SCR and CO catalyst to control oxides of nitrogen and carbon monoxide ("CO"). With these controls, the RICE have low emission rates but not as low as CC gas turbines.

Carbon Dioxide Capture and Sequestration

For PC and CC natural gas technologies, the capture of the CO_2 from the combustion byproducts is done on a post-combustion basis. Carbon capture technologies for pulverized coal and natural gas-based generation continue to develop as more demonstration projects move forward. The coal and CC units in this assessment include CCS using the advanced amine process. The advanced amine process is an enhancement of the monoethylamine ("MEA") process that was developed over 60 years ago and has been adapted to treat flue gas streams for CO_2 capture. Other organic chemicals belonging to the family of compounds known as "amines" are now being used to reduce cost and power consumption as compared to the traditional MEA solvent. Numerous companies are developing their own proprietary amine solvents including Fluor Corporation, Hitachi, Ltd., Mitsubishi Heavy Industries Ltd. ("MHI"), Shell, and other companies.

The amine technology is the most developed of the large-scale power generation facility CCS technologies on the market. In the advanced amine process, a continuous scrubbing system is used to separate CO_2 from the flue gas stream. The system consists of two main elements: an absorber where CO_2 is removed from the flue gas and absorbed into an amine solvent, and a regenerator (or stripper), where CO_2 is released (in concentrated form) from the solvent and the original amine solvent is then recovered and recycled. Cooled flue gases flow vertically upwards through the absorber, countercurrent to the absorbent (amine in a water solution, with some additives). The amine reacts chemically with the CO_2 in the flue gas to form a weakly bonded compound, called carbamate. The scrubbed gas is then washed and vented to the atmosphere. The CO_2-rich solution leaves the absorber and passes through a heat recovery exchanger and is further heated in a reboiler from low-pressure steam. The carbamate formed during absorption is broken down by the application of heat, regenerating the sorbent and producing a concentrated CO_2 gas stream. The hot CO_2-lean sorbent is then returned to the opposite side of the heat exchanger where it is cooled and sent back to the absorber. Fresh reagent is added to make up for losses incurred during the process.

In North America, multiple CCS projects have gone through various stages of development, including the following examples. SaskPower, the Saskatchewan provincial utility, completed its 115 MW Boundary Dam CCS project near Estevan, Saskatchewan in October 2014, making it the first power station in the world to successfully use CCS technology.[2] The facility utilizes the Shell Cansolv amine-based, post combustion capture system. Second, NRG Energy, Inc.'s Petra Nova facility near Houston, Texas was designed to capture carbon from a 240 MW slipstream of flue gas from one of the W.A. Parish coal boilers. The facility became operational in December of 2016, utilizing Fluor's amine-based, post combustion capture system.[3] However, the facility was placed in reserve shutdown in May 2020 due to economic conditions. Finally, Minnkota Power Cooperative's Project Tundra is proposed to be the world's largest CO_2 capture facility, which would capture CO_2 from the Milton R. Young Station in North Dakota.[4] Project Tundra is in the project development phase and will be based on MHI's capture system technology. Several other projects are in various stages of Front-End Engineering Design ("FEED") studies looking to implement CCS technology.

Carbon Dioxide Sequestration

Other than the mid-continent rift, no potential geological sequestration sites exist in Minnesota. It is important to note that the mid-continent rift requires extensive evaluation that will require years of research at a high cost before it can be determined if it is a viable sequestration site. Two different forms of sequestration are currently viable, and each form has varying tax credit implications. The first form, permanent underground sequestration, pumps captured carbon from a carbon capture facility into a cavity in the ground without using the product as a tertiary injectant. Currently, Minnesota Power is modeling carbon capture assets with permanent underground sequestration.

The second form, enhanced oil recovery ("EOR"), extracts value from the captured CO_2 as a tertiary injectant through increased oil production. The long-term "value" of CO_2 will be impacted by the amount of CO_2 that is available in the region, which will be subject to the number and size of carbon capture projects that are installed.

The 45Q Tax Credit currently offers $17 in tax credits per metric ton of CO_2 that is captured and geologically sequestered. An entity may also receive $12 per metric ton of CO_2 that is used as a tertiary injectant in a qualified enhanced oil or natural gas recovery project. The entity may then receive a five times multiplier for these credits for meeting prevailing wage and apprenticeship requirements, bringing these totals to $85 and $60 per metric ton of CO_2. It should

[2] Boundary Dam Carbon Capture Project, SaskPower, available at https://www.saskpower.com/our-power-future/infrastructure-projects/carbon-capture-and-storage/boundary-dam-carbon-capture-project.
[3] Petra Nova – W.A. Parish Project, U.S. Department of Energy, available at https://www.energy.gov/fecm/petra-nova-wa-parish-project.
[4] Project Tundra, available at https://www.projecttundrand.com/.

be noted that these credit amounts are available for non-direct air capture ("DAC") facilities. DAC facilities are eligible for alternate credit amounts under Section 45Q. The credit is available for 12 years beginning on the date the equipment is originally placed in service.

Location

The location of a new coal or CC generating resource with carbon capture for Minnesota Power would be dependent on the ability to site and permit the facility as well as the fuel, transmission, and carbon implications at the proposed location.

For coal technology with carbon capture, a North Dakota location was used as the starting point in the assessment for the 2025 IRP.[5] It is unlikely that a new coal generation facility would be selected in the IRP analysis due to its higher cost compared to other technologies. Utilizing the high-level coal resource location screening assessment shown in Table 1, Minnesota Power chose to include one coal generation alternative and selected the North Dakota location.

For CC technology with carbon capture, Minnesota Power's 2025 IRP assumes the site would be located in Minnesota. Natural gas supply would be sourced from regional pipelines and a natural gas lateral to the site would be constructed to supply the facility.

Table 1. New Coal Resource Location Considerations

	Minnesota Powder River Basin Coal	North Dakota Lignite Coal	Explanation
Fuel Cost	Higher	Lower	North Dakota mine to mouth plant eliminates the cost of rail.
Capital Costs	Lower	Higher	Lignite fuel characteristics require a larger boiler.
Transmission	Lower	Higher	Minnesota location will be closer to the load centers.
Sequestration Costs	Higher	Lower	North Dakota mines are adjacent to sequestration options, reducing the amount of capital for CO_2 piping and the operating costs of the compressor booster stations.
Impact on the limited northeast Minnesota Air Shed Increment	High	Low	The limited northeast Minnesota Air Shed increment is important to Minnesota Power's natural resource-based customers who cannot relocate their operations.

Renewable Technologies

Biomass Generation

The term biomass refers any organic matter that is available on a renewable or recurring basis, including agricultural crops and trees, wood and wood waste and residues, plants including

[5] Minnesota law prohibits constructing a new large energy facility that would contribute to statewide power sector carbon dioxide emissions (Minn. Stat. § 216H.03, subd. 3).

aquatic plants, grasses, residues, fibers, animal waste, and the organic portion of solid wastes.[6] For the purposes of this assessment, untreated wood products such as mill and forest residue are assumed to be the biomass fuel source. Wood-fired boilers are typically a derivative of either older stoker type designs, or the newer bubbling fluidized bed design, and range in size from 10 to 50 MW. Though not evaluated in this IRP, other potential alternative biomass fuels are agricultural residues such as straw from cereal production, torrefied biomass (i.e. industrial wood pellets), residues from crop processing, energy crops grown specifically for use as a fuel, and animal waste.

The steam cycle and main components of a biomass unit are similar to those of a PC unit shown in Figure 1, with the exception of the reheat cycle. For units of this size, the capital cost and complexity added by addition of a reheat cycle are not often economically justified.

Enhanced Geothermal

Traditional geothermal energy utilizes naturally occurring hydrothermal reservoirs, where hot water or steam is extracted from beneath the Earth’s surface. Reservoirs for geothermal energy generation are typically found in regions with significant tectonic activity, such as volcanic areas or along major tectonic plate boundaries. In traditional geothermal power plants, wells are drilled into these reservoirs, allowing hot water or steam to be extracted, which is then used to drive a turbine generator. Traditional geothermal systems typically operate at temperatures between 300 and 700 ºF.

Enhanced Geothermal Systems (“EGS”), in contrast, expand geothermal energy production to areas where natural hydrothermal reservoirs are not available. EGS use hot dry rock formations as the heat source, which are typically located several miles below the Earth’s surface. Since these rocks do not naturally contain sufficient fluid or permeability to extract heat, EGS technology involves injecting water into the rock to fracture it, creating artificial reservoirs where the water can absorb heat and then be pumped back to the surface. The EGS process is shown in Figure 5.[7]

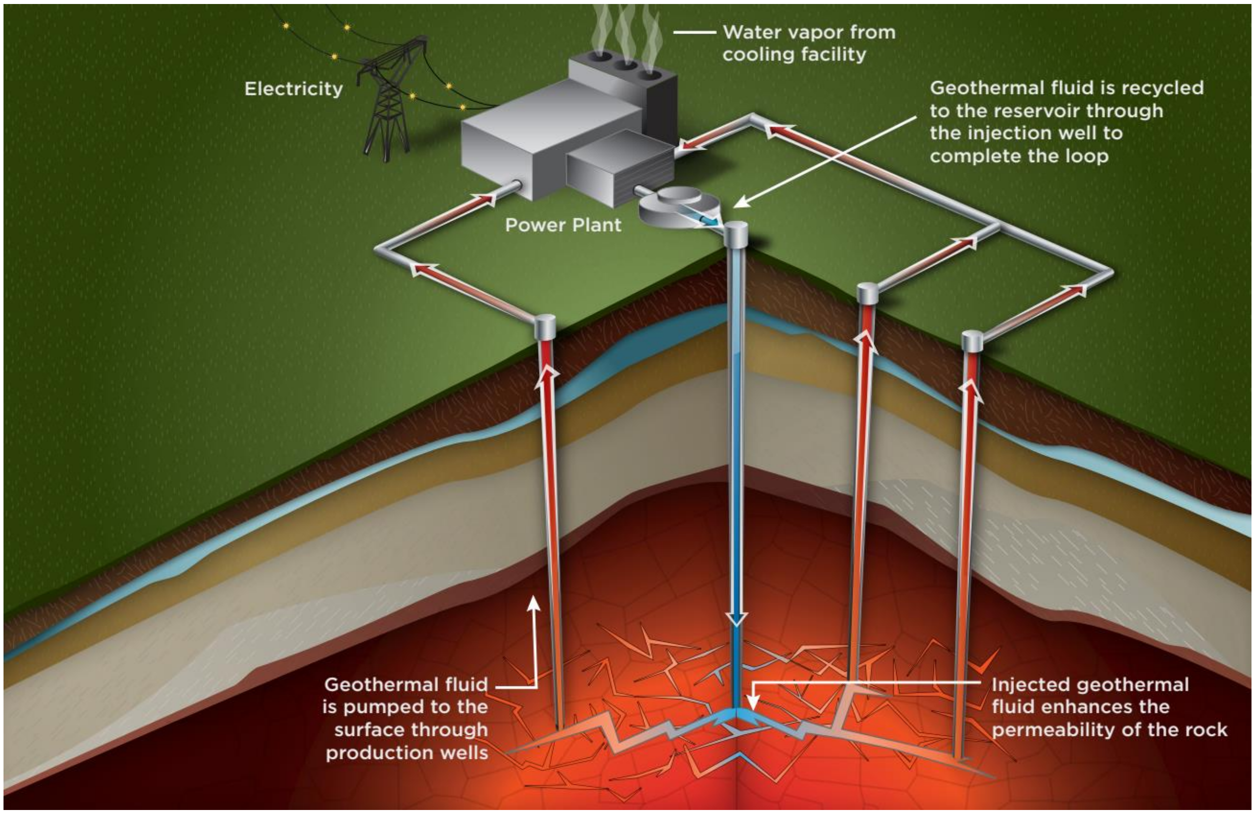
Geothermal energy has the potential to provide abundant, carbon-free, grid scale electricity in the United State. However, according to the United States Department of Energy’s Pathways to Commercial Liftoff: Next-Generation Geothermal Power, Minnesota is one of just a few states in the country to be geologically assessed at 0 potential gigawatts of next-generation geothermal energy.[8] Such energy would have to be secured via next generation technologies in the Dakotas or further afield and transported to Minnesota via new transmission lines. Grid scale geothermal is years to decades away.

[6] Minn. Stat. § 41A.15, subd. 2e. Minn. Stat. § 216B.1691, subd.1(c)(5) defines biomass as an “eligible energy technology” that generates electricity from renewable energy sources. *See also* Biomass – renewable energy from plants and animals, U.S. Energy Information Administration (“EIA”), available at https://www.eia.gov/energyexplained/biomass/#:~:text=Biomass%20is%20renewable%20organic%20material%20that%20comes%20from,especially%20for%20cooking%20and%20heating%20in%20developing%20countries (defining biomass as any fuel that can be grown, harvested, and regrown or animal manure and human sewage).

[7] Geothermal Energy: A Glance Back and a Leap Forward, U.S. Department of Energy, available at https://www.energy.gov/eere/articles/geothermal-energy-glance-back-and-leap-forward.

[8] Blankenship, Doug, et. al. Pathways to Commercial Liftoff: Next-Generation Geothermal Power at 11, U.S. Department of Energy, available at, https://liftoff.energy.gov/wp-content/uploads/2024/03/LIFTOFF_Next-Generation-Geothermal-Power_Updated-2.5.25.pdf (March 2024).

Figure 5. Enhanced Geothermal Power Generation Process



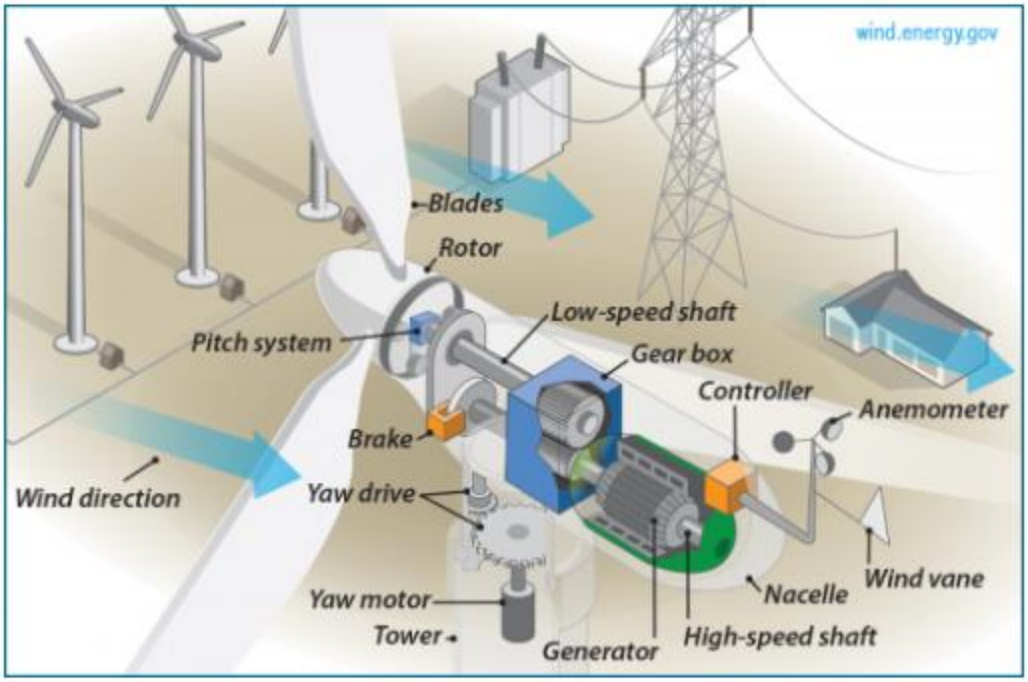
Wind Generation

Modern wind turbine technology combined with the federal tax credits has resulted in wind turbine generators becoming a standard resource option on a utility scale. Key to that evolution has been increases in the size of wind turbine units and efficiency improvements of those units, providing the economy of scale required to be competitive. Although the larger size and more efficient units have been a key part of the puzzle, it is also critical that the turbines are located in an area with good wind characteristics to yield an effective renewable energy resource, as well as ensuring access to the bulk transmission system.

Wind projects are currently eligible for federal tax credits, which were modified within the Inflation Reduction Act of 2022 ("IRA") and extended through at least 2033. Additions, such as the prevailing wage requirements, which adjust over time, a 10 percent adder for wind projects with domestic content threshold, and a 10 percent adder for projects located in energy communities, were added in the IRA. The IRA also includes the ability for the direct transfer of tax credits, allowing utilities to more efficiently capture tax credit benefits. The IRA gives wind projects the option to opt for either the Investment Tax Credit ("ITC") or the Production Tax Credit ("PTC").

The basics of wind are the conversion of the kinetic energy in wind to turn a shaft that turns a generator. The main components of a wind generator are shown in Figure 6 below.

Figure 6. Wind Generator Diagram



Locations that have a high average wind velocity over a large area of land are key to making a viable energy resource. Within Minnesota Power's service territory, the best wind resource is located along the Laurentian Divide near active iron mining areas. However, the quality of wind resource characteristics in the Company's service territory is lower than in other parts of the upper Midwest. Within the upper Midwest region, the best location for wind resources is in southwestern Minnesota, North Dakota, and South Dakota. These areas have a lower busbar cost but may have transmission constraints that need to be factored into siting.

Wind generation is a variable resource, and as such, cannot sustain the needs of a reliable electric system alone. To ensure reliability when the wind resource is not available, other dispatchable resources or energy storage is needed.

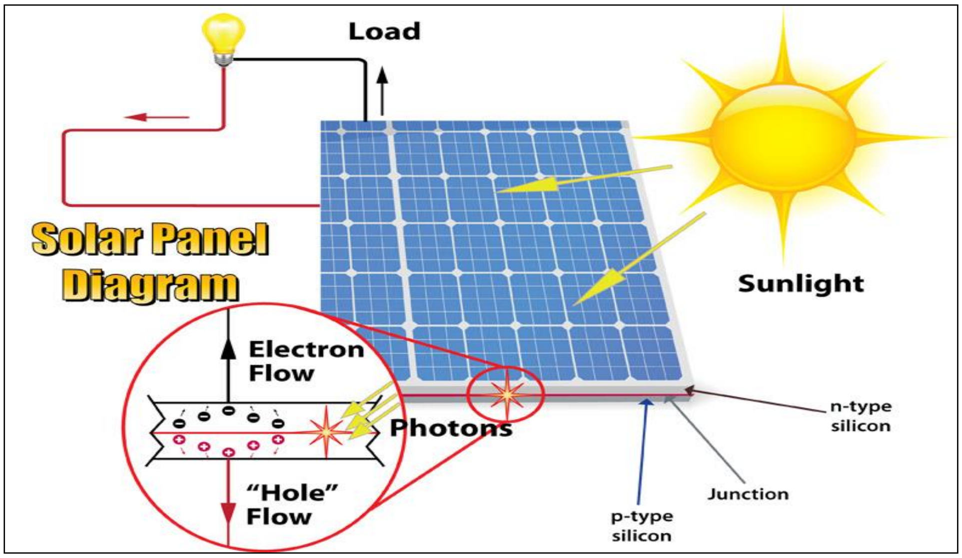
Solar Generation

Solar PV generation directly converts the energy in sunlight into electricity when the semiconductors absorb the photons in the sunlight. Inverters are used to convert the direct current from PV modules into alternating current. There are two primary types of PV cells: crystalline silicon and thin film. Crystalline silicon cells offer higher efficiency but are typically higher initial costs. Thin film cells are typically more affordable and less prone to damage.

Solar installations are typically either fixed-tilt or single-axis-tracking. Single axis tracking solar sites have trackers that move the modules to track the sun, while fixed-tilt sites remain stationary. Additionally, some more recent solar panel models are bifacial, meaning that the backside of the panel also intakes sunlight, albeit with less efficiency. Bifaciality is becoming a more common feature in solar panels to maximize land usage. Most modules utilize single cell technology; however, some module manufacturers produce half-cell modules, which are less susceptible to shading loss effects. Solar panel efficiency in newer panel models generally ranges from 23 percent to 25 percent.

Figure 7 demonstrates this technology. Like wind, solar is also a variable resource.

Figure 7. Solar PV Diagram



Solar generation projects are currently eligible for similar federal tax incentives as wind within the IRA, including election of either the PTC or ITC, prevailing wage requirements, adders for domestic content and projects located in energy communities, and the ability to transfer of tax credits.

A suitable project site is key to making a solar project a viable energy resource. The amount of solar energy available to capture varies based on location. Other locational factors impacting viability of solar include site topography and soil conditions.

Nuclear Technology

Small Modular Reactor

Manufacturers including NuScale Power, Holtec, and GE/Hitachi have begun designing small modular reactors ("SMR") with the intent to create a smaller scale, completely modular nuclear reactor. According to these manufacturers, the benefit of these SMRs is two-fold: 1) the smaller unit size of less than 300 MW will allow more resource generation flexibility; and 2) the modular design will reduce overall project costs. The conceptual technologies are similar to Advanced Pressurized-Water Reactors, but the entire process and steam generation is contained in one modular vessel. The steam generated in this vessel is then routed to a steam turbine generator. Due to the design's modularity, most of the fabrication is planned to be done in the manufacturing facility before the vessel is shipped to the site. The goal is to reduce field labor and the construction schedule.

Several manufacturers have begun conceptual design of these modular units to target lower output and overall costs of nuclear facilities. In the United States, leading developers of SMR designs include GE/Hitachi, X-energy, TerraPower, NuScale, Westinghouse, and Holtec. Only NuScale has received design approval from the Nuclear Regulatory Commission ("NRC") to date, and all other manufacturers are in varying stages of design. Therefore, there is currently little industry experience with developing this technology outside of the conceptual phase and the information provided in this assessment for the SMR option is based on feedback and initial indications from SMR manufacturers. Figure 8 demonstrates SMR technology.

Active project developments in the United States include the TerraPower Nuclear Plant, the Tennessee Valley Authority ("TVA") Clinch River Nuclear Site, and Duke Energy's Belews Creek coal-to-nuclear site. A summary of the current project statuses is outlined below:

a) The TerraPower Nuclear Plant project is located in Kemmerer, Wyoming, at the site of the existing coal-fired Naughton Power Plant. The project is a result of a partnership between Terrapower and PacifiCorp, who owns and operates the coal facility (through its Rocky Mountain Power subsidiary). The TerraPower Nuclear Plant project is currently the only development with a commercial advanced reactor permit application submitted to the NRC. While the design is not yet approved by the NRC, the project aims to deploy TerraPower's Natrium SMR technology and demonstrate its feasibility for commercial applications. TerraPower broke ground on the site in June 2024 with anticipated completion in 2030. Currently, the biggest challenge for the TerraPower site is the ongoing domestic development of the High-Assay Low-Enriched Uranium ("HALEU") nuclear fuel on which the facility is designed to operate.

b) TVA's Clinch River has been in early development since 2016. TVA submitted an Early Site Permit ("ESP") to the NRC for approval in 2016 before being approved in 2019. TVA has not committed to construction of an SMR facility at the Clinch River site to date, although the company did approve an additional $150 million in advanced nuclear funding in August 2024 to support continued design work at the site. A technology has not yet been selected, although a plant parameters envelope ("PPE") has been developed which outlines the site characteristics which a reactor technology must accommodate.

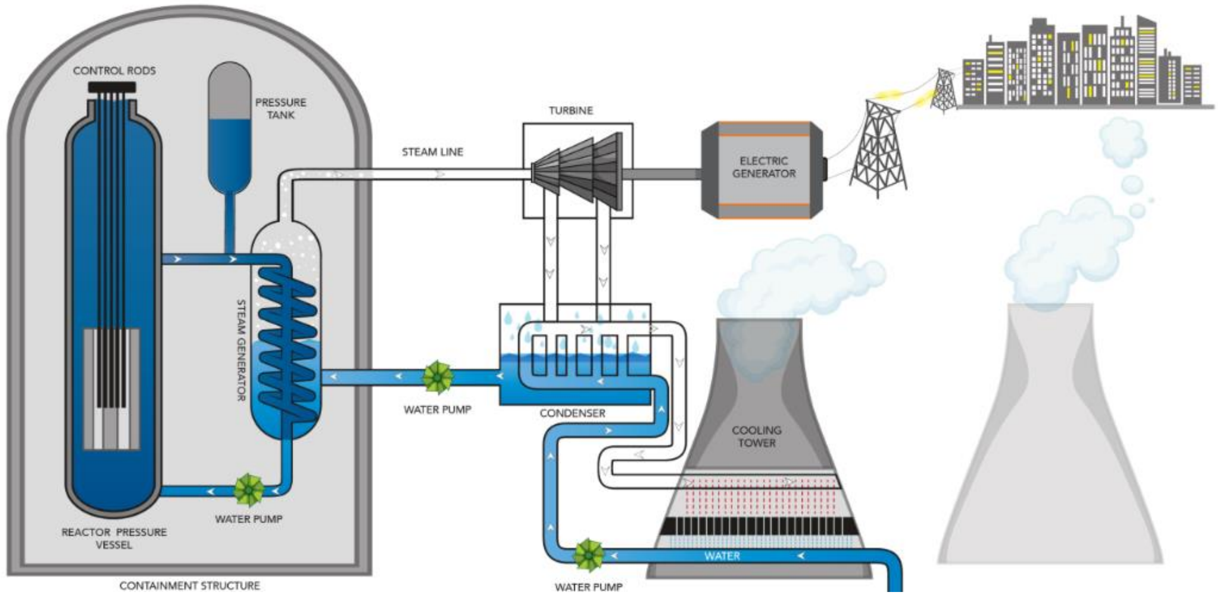
c) Duke Energy has engaged the NRC in pre-application activities for nuclear development on the site of the coal-fired Belews Creek Power Station in Stokes County, North Carolina. Duke has indicated to the NRC that it plans to submit an ESP for Belews Creek in which the site would accommodate up to three reactors. A reactor technology has not yet been selected.

In addition to these active projects, Utah Associated Municipal Power Systems ("UAMPS") had worked with NuScale on the Carbon Free Power Project ("CFPP"). The CFPP was intended to utilize NuScale SMR modules to provide low carbon power to UAMPS's service territory. The project was cancelled in 2023 due to rising capital cost projections.

In Canada, Ontario Power Generation ("OPG") announced in November 2020 the resumption of planning activities for future nuclear power generation that would utilize SMRs at its Darlington Nuclear Station.[9] OPG claims construction of its first SMR at Darlington is anticipated to be completed as early as 2028, with a total of four SMRs to be completed between 2034 and 2036. GE/Hitachi's BWRX-300 SMR technology has been selected for development at the site.

[9] OPG resumes planning activities for Darlington New Nuclear, Ontario Power Generation, available at https://www.opg.com/releases/opg-resumes-planning-activities-for-darlington-new-nuclear/ (Nov. 13, 2020).

Figure 8. SMR Nuclear Generation Diagram (Generic Pressurized Water Reactor)[10]



Energy Storage Technologies

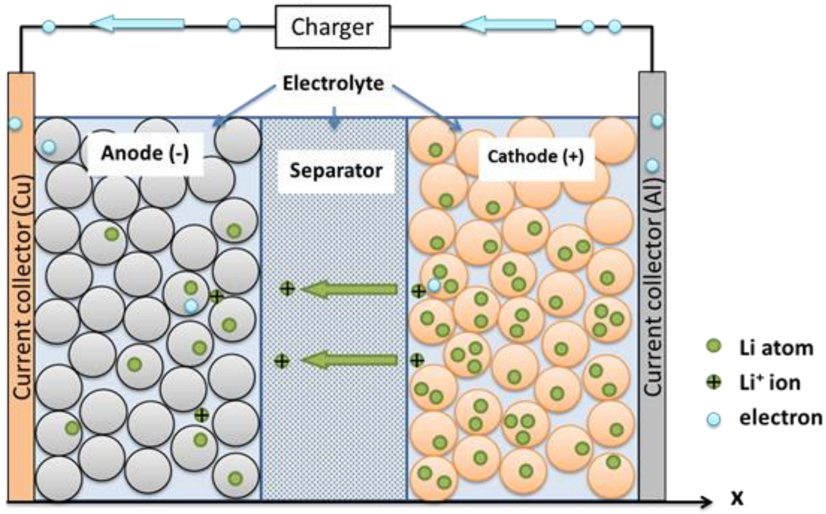
Energy storage technologies take advantage of excess energy during lower demand or high renewable generation periods by storing it for use during periods of higher demand. In addition to enhancing reliability and reducing curtailments of intermittent renewable generation, energy stored off-peak and delivered on-peak can help reduce on-peak prices and is therefore beneficial to consumers. Energy storage technology continues to be developed at a rapid pace with different technologies providing different benefits. While lithium-ion battery storage technology is currently capturing the vast majority of new energy storage project market-share, research, development, and product commercialization spending on alternative battery technologies specifically targeted at stationary energy storage has been increasing dramatically in the last decade. The following sections review lithium-ion battery storage, alternative battery energy storage technologies that have recently gained traction in the market, and other non-battery energy storage technologies.

Lithium-Ion Battery Storage

A conventional battery contains a cathodic and an anodic electrode and an electrolyte sealed within a cell container than can be connected in series to increase overall facility storage and output. During charging, the electrolyte is ionized such that when discharged, a reduction-oxidation reaction occurs, which forces electrons to migrate from the anode to the cathode, thereby generating electric current. Batteries are designated by the electrochemicals utilized within the cell, and the lithium-ion type is one of the most common designs. A lithium-ion battery schematic is shown in Figure 9.

[10] Nuclear 101: How Does a Nuclear Reactor Work, U.S. Department of Energy, available at https://www.energy.gov/ne/articles/nuclear-101-how-does-nuclear-reactor-work (Aug. 2, 2023).

Figure 9. Lithium-Ion Battery Diagram



Lithium-ion batteries contain graphite electrodes, metal-oxide electrodes, and lithium ions dissolved within an organic electrolyte. The movement of lithium ions during cell charge and discharge generates current. Lithium-ion technology has seen an advance in development interest due to its high energy density, low self-discharge, high cycling tolerance, efficiency, and fast response times. The life-cycle is dependent on cycling (charging and discharging) and depth of charge (charged load depletion). Total system cycles across a project life can range from 2,000 to 3,000 cycles at higher discharge rates, up to 7,000 cycles at lower discharge rates.

Lithium-ion batteries have gained traction in several markets, including the utility and automotive industries. Most of the utility-scale battery systems used for energy storage on the U.S. electric grid use lithium-ion batteries.[11]

Non-Lithium Battery Energy Storage

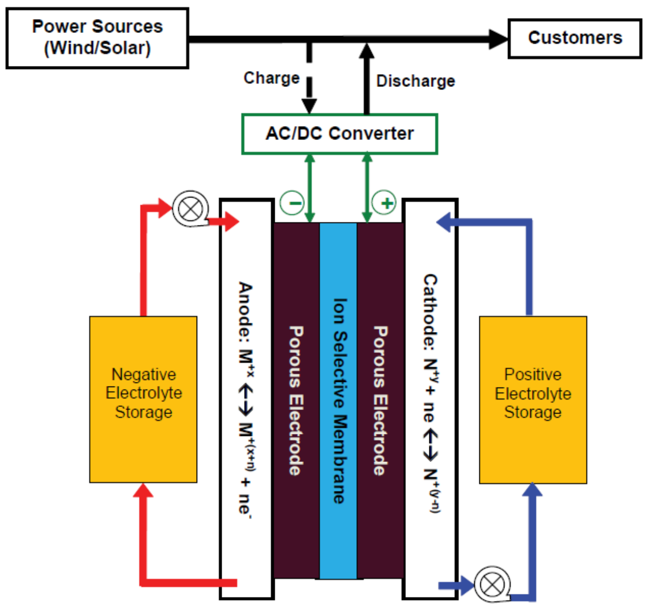
The non-lithium battery energy storage market is comprised of technologies of varying technological and commercial maturity that seek to compete and/or differentiate from the technical and commercial capabilities of lithium-ion battery energy storage. Non-lithium systems have gained market share in the energy storage industry in recent years for a variety of reasons. One reason for this trend involves the growing need for longer duration storage. Lithium-ion systems being installed today are typically sized for use cases that call for 1-4 hours of rated duration, but there are several examples of lithium-ion technologies being used for longer (i.e. 8-hour) duration use cases.[12] Common non-lithium battery energy storage technologies include iron flow batteries, vanadium redox flow batteries, zinc bromine flow batteries, aqueous zinc batteries, high temperature batteries such as sodium-sulfur and calcium-antimony technologies, and iron-air batteries.

Flow batteries are a type of energy storage system where electrolyte is pumped through one or more electrochemical cells to create an electrochemical reaction. There are many different

[11] Most utility-scale batteries in the United States are made of lithium-ion, U.S. Energy Information Administration, available at https://www.eia.gov/todayinenergy/detail.php?id=41813 (Oct. 30, 2019).
[12] Battery Storage in the United States: An Update on Market Trends, U.S. Energy Information Administration, available at https://www.eia.gov/analysis/studies/electricity/batterystorage/ (July 24, 2023).

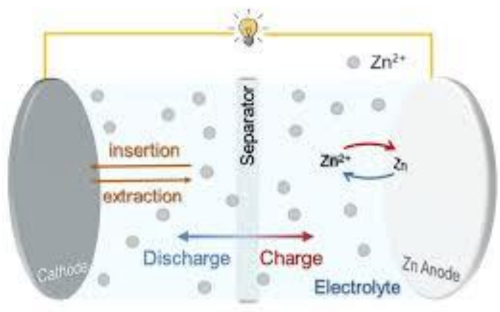
chemistries of flow batteries, many of which can be classified by the following categories: full redox versus hybrid, inorganic versus organic, and vanadium-based versus zinc-bromine-based versus iron-based. For all combinations of flow battery types, the electrodes do not contain any active elements that participate in electrochemical reactions. Therefore, electrodes are not subject to the same irreversible chemical deterioration that depletes electrical performance from lithium-ion batteries, resulting in theoretically higher cycle lives for flow batteries. In many cases, however, stack components are prone to mechanical deterioration that may cause some performance degradation over time. Various control and pumped circulation systems complete the flow battery system, as shown in Figure 10. Note that the cells can be stacked in series to achieve the desired voltage difference.

Figure 10. Flow Battery Diagram



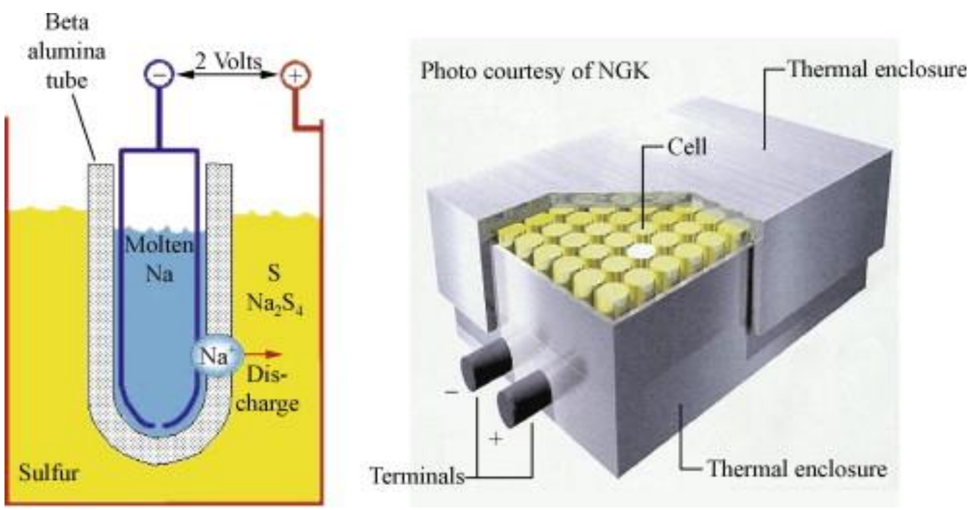
Aqueous-zinc batteries were first explored in the 1980s, but research activity has recently surged due to technological developments and the quest for safer and less expensive raw material alternatives to lithium-ion batteries. Aqueous-zinc batteries take on a similar chemistry to a zinc-bromine flow battery, but all the necessary electrolyte is contained within a battery cell instead of being stored in tanks and pumped into and out of the battery stack.

Figure 11. Aqueous-zinc Battery Diagram



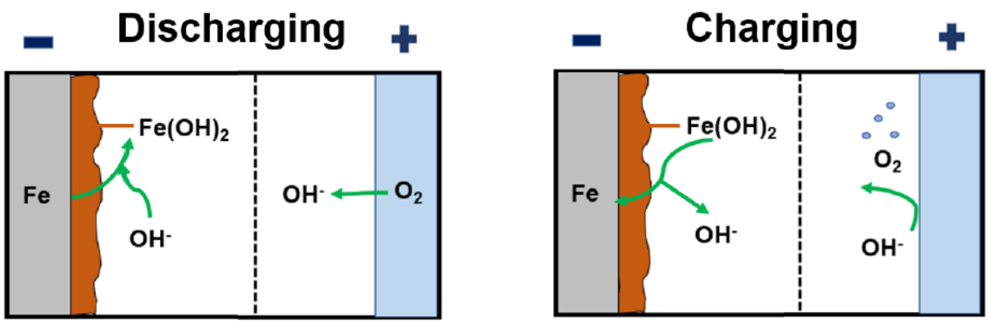
High temperature batteries are battery cells that require high temperatures to keep a metal in its molten state for operation. In their charged state, high temperature batteries have the pure form of a metal anode and the pure form of another element as its cathode. The battery chemistry leverages the natural electrochemical potential difference of the two elements. The operation of these technologies is typically considered reversible alloying. Two leading chemistries of high temperature batteries are sodium-sulfur and calcium-antimony. High temperature batteries have the most similar performance attributes to lithium-ion systems and are seen in the market as a competitive non-lithium technology based on cost.

Figure 12. High Temperature Battery Diagram (Sodium-Sulfur Example)



Iron-air batteries were first explored by the National Aeronautics and Space Administration (‘NASA”) in the 1960s but have recently regained interest in the eyes of the storage world after recent development and commercialization investment into the iron-air technology, which was ultimately motivated by a perception of utility-scale multi-day energy storage potential. Iron-air batteries use a process known as reversible rusting in which a pure iron anode is oxidized via oxygen (O_2) to form iron oxide in a reversible reaction that releases electrons. The rust is reduced back to pure iron during a battery charge. The active materials and reactions of the iron-air batteries are considered to be inherently safer than in lithium-ion batteries and present no risk of thermal runaway. Iron-air batteries cannot charge or discharge very quickly, therefore iron-air batteries are better suited for long duration, low c-rate applications.

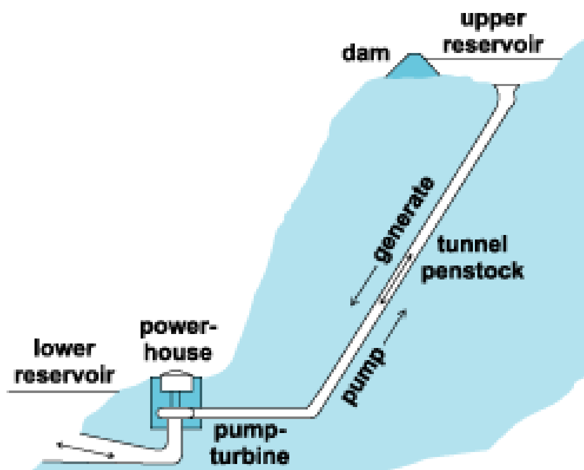
Figure 13. Iron-air Battery Diagram



Pumped Hydro Energy Storage

A pumped hydroelectric plant (pumped hydro) is a peaking energy storage power generating facility. The plant includes a lower reservoir (usually existing), a powerhouse, an upper reservoir (usually constructed with the pumped hydro project), and a means for conveying water between the upper and lower reservoirs. The powerhouse includes reversible generator/motors and pump/turbines. This is illustrated in Figure 14.

Figure 14. Pumped Hydro Diagram



During off-peak hours or periods of high renewable generation, when a surplus of lower cost energy exists, the plant is operated in the pump mode to pump water from the lower reservoir to the upper reservoir. During peak periods, the water is released from the upper reservoir through the pump/turbines to generate electrical energy to meet the system peak demand.

E. Policy Considerations

Some of the technologies discussed in this appendix could have challenges due to policy at the state and national level that must be considered when assessing their feasibility as future resource option for Minnesota. The following are a few examples, but this is not an exhaustive list of all policy issues that could arise when constructing new generation.

Biomass and CCS are both currently being assessed in a Commission proceeding along with other complex fuels. While biomass is included in Minnesota Statute as an Eligible Energy Technology for meeting the Renewable Energy Standard, whether it will be considered fully or partially eligible under the Carbon-Free Standard ("CFS") will be determined pending a life-cycle analysis methodology to be determined by the Commission in 2025.[13] This proceeding will also determine the eligibility and calculation metrics for CCS technology on fossil fuel generation. The regulatory outcome for these technologies will have a large impact on their viability for individual utilities.

Minnesota has had a moratorium on the construction of new nuclear power stations since 1994. Without a legislative change in policy toward nuclear power at the state level, no SMRs can be built. Even if the state moratorium was lifted, the large expense of constructing such generation, the timeline for receiving U.S. Nuclear Regulatory Commission licenses to operate and construct it and identifying how to safely and securely dispose of nuclear waste are substantial barriers in their own right.

Lastly, permitting new emerging technologies can be more challenging than existing generation where the impacts on the environment and community are known from prior projects. This can introduce challenges on the timeline certainty for bringing emerging technologies online. This also has implications for meeting regulations or Minnesota renewable and CFS requirements, if emerging technologies are identified as needed to meet the CFS but have implementation challenges due to permitting issues at the local, state, or federal level.

[13] *In the Matter of a Commission Investigation into a Fuel Life-Cycle Analysis Framework for Utility Compliance with Minnesota's Carbon-Free Standard*, Docket No. E-999/CI-24-352, Notice of Comment Period (Jan. 22, 2024).