2020 Generation Technology Review
revised edition

Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland

Introduction

In an effort to continually improve the mix of resources used to deliver power to our customers, Platte River evaluates the acquisition and development of a variety of generation options as well as technologies that may be able to reduce or defer the need for generation.

The generation technology review (GTR) is a comprehensive study of resources that Platte River may evaluate in more detail during our 2020 integrated resource planning (IRP) process. The GTR helps to identify the most viable resource options to help meet the energy goals of our customers and their communities.

The GTR has two parts:

1. Provides an overview of each of Platte River's current resources.
2. Profiles the capabilities and viability of potential future energy resources that Platte River could add to its resource portfolio mix in the coming years.

Platte River's IRP documents, as well as high-level summaries for existing resources, can be found on Platte River's website at prpa.org.

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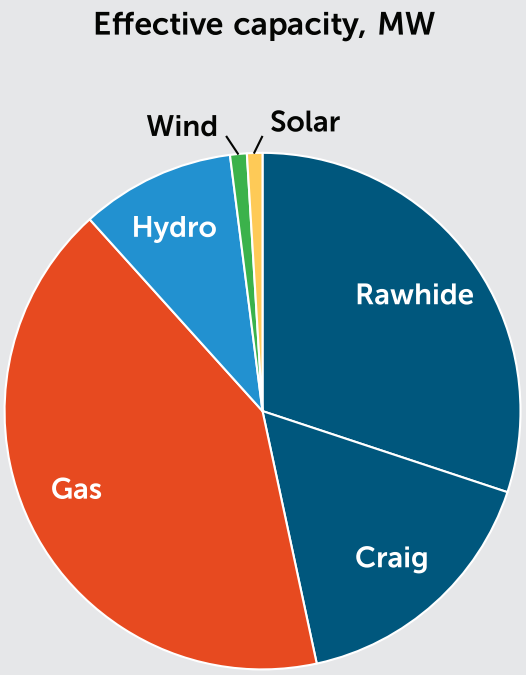
Platte River's existing resources

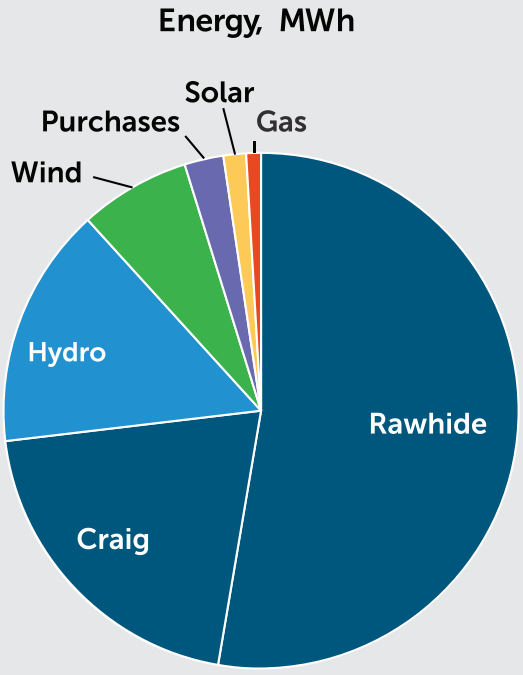
Screened resources

Platte River's existing resources

Platte River delivers energy to our owner communities through a diversified mix of generation resources, which are either owned by Platte River or contracted through third parties.

Platte River's resource mix (as of December 2018)





Rawhide Energy Station

Most of Platte River's generating resources are located at the Rawhide Energy Station in northern Larimer County.

Rawhide Energy Station includes:

- Rawhide Unit 1 coal facility
- Five natural gas simple-cycle turbines
- Rawhide Flats solar facility

By the early 2020s, a new generator outlet will connect the new Roundhouse wind project to Rawhide Energy Station for delivery to Platte River's customers. Additional solar generation will be added at the facility, further diversifying the resource mix at Rawhide Energy Station. These resources are discussed in more detail in the following sections.

The table below summarizes key information for Platte River's existing resources (as of December 2018). Additional history and details follow throughout.

Unit	Nameplate capacity (MW)	Effective summer capacity (MW)	Commercial operation	Normal retirement / contract expiration	Location	Platte River ownership or offtake
Coal						
Rawhide Unit 1	280	280	1984	2046	Wellington, CO	100%
Craig Unit 1	77	77	1980	2025	Craig, CO	18%
Craig Unit 2	74	74	1979	2042	Craig, CO	18%
Subtotal	**431**	**431**				
Natural gas (simple-clycle CT)						
Rawhide Unit A	65	65	2002	Indefinite	Wellington, CO	100%
Rawhide Unit B	65	65	2002	Indefinite	Wellington, CO	100%
Rawhide Unit C	65	65	2002	Indefinite	Wellington, CO	100%
Rawhide Unit D	65	65	2004	Indefinite	Wellington, CO	100%
Rawhide Unit F	128	128	2008	Indefinite	Wellington, CO	100%
Subtotal	**388**	**388**				
Fossil resources						
Subtotal	**819**	**819**				
Wind						
Medicine Bow	6	1	1998	2033	Medicine Bow, WY	100%
Silver Sage*	12	2	2009	2029	Laramie County, WY	29%
Spring Canyon II	32	4	2014	2039	Logan County, CO	100%
Spring Canyon III	28	4	2014	2039	Logan County, CO	100%
Subtotal	**78**	**10**				
Hydropower						
Loveland Area Project	30	30	1973	2054	CO, WY	
Colorado River Storage Project	60	60	1973	2057	AZ, UT, CO, WY, NM	
Subtotal	**90**	**90**				

Unit	Estimated solar capacity (MWac)	Effective summer capacity (MW)	Commercial operation	Normal retirement / contract expiration	Technology	Location	Platte River ownership or offtake
Solar							
Commercial solar power purchase program	3	0.9	Approved 2013	Varies	Fixed-tilt PV	Fort Collins, CO	100%
Fort Collins community solar	0.5	0.2	2015	2040	Fixed-tilt PV	Fort Collins, CO	100%
Foothills Solar (Platte River share)	0.5	0.2	2016	Indefinite	Single-axis PV	Loveland, CO	17%
Rawhide Flats	30	9	2016	2040	Single-axis PV	Wellington, CO	100%
Subtotal	**34**	**10**					
Non-carbon generation Subtotal	**202**	**110**					
Total generation resources	**1,021**	**929**					

*As of October 2018, Silver Sage RECs and associated energy have been sold and cannot be claimed as a renewable resource by Platte River or its owner communities.

Coal generation

Rawhide Unit 1

Rawhide Energy Station

Platte River's largest generating resource is Rawhide Unit 1. Rawhide Unit 1 is wholly owned and operated by Platte River, and began commercial operation on March 31, 1984. The 280-MW (net capacity) pulverized coal combustion facility consists of a boiler that feeds subcritical steam to a turbine generator, which in turn produces electricity.

Unit 1's boiler was manufactured by Combustion Engineering and incorporates a steam drum and natural water circulation and is designed with balanced drafting to enhance combustion within the boiler. It is also equipped with an economizer and a regenerative air heater to optimize water and air temperatures.

Unit 1's turbine-generator was manufactured by Westinghouse. It is a tandem-compound system that uses a two-flow process, where steam is injected at the center of the turbine shaft and exits at both ends, helping balance the shaft's rotation. A single reheat process increases electrical efficiency by recycling waste heat.

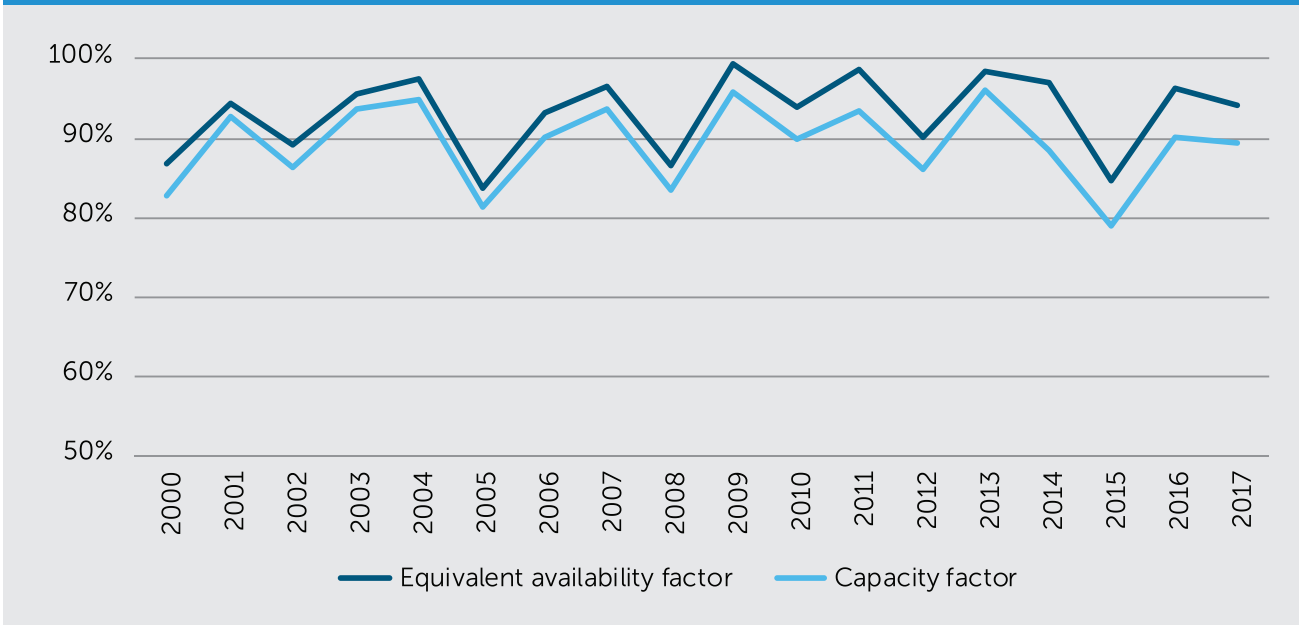
Rawhide Unit 1 uses a recirculating cooling system supported by the 16,000 acre-feet Hamilton reservoir. The reservoir covers 500 surface acres and its depth averages approximately 30 feet, with a maximum depth of 60 feet. Water is predominantly supplied through a 24-inch pipeline, directly from the Drake Water Reclamation Facility in the City of Fort Collins.

Rawhide's coal is supplied from the Antelope Mine in Wyoming's Powder River Basin. Approximately 1.2 million tons of coal are transported annually to the Rawhide Energy Station, where coal cars are unloaded and stored in above-ground silos or in an adjacent stockpile. Rawhide typically maintains about 75 days of coal supply for power production and reliability needs.

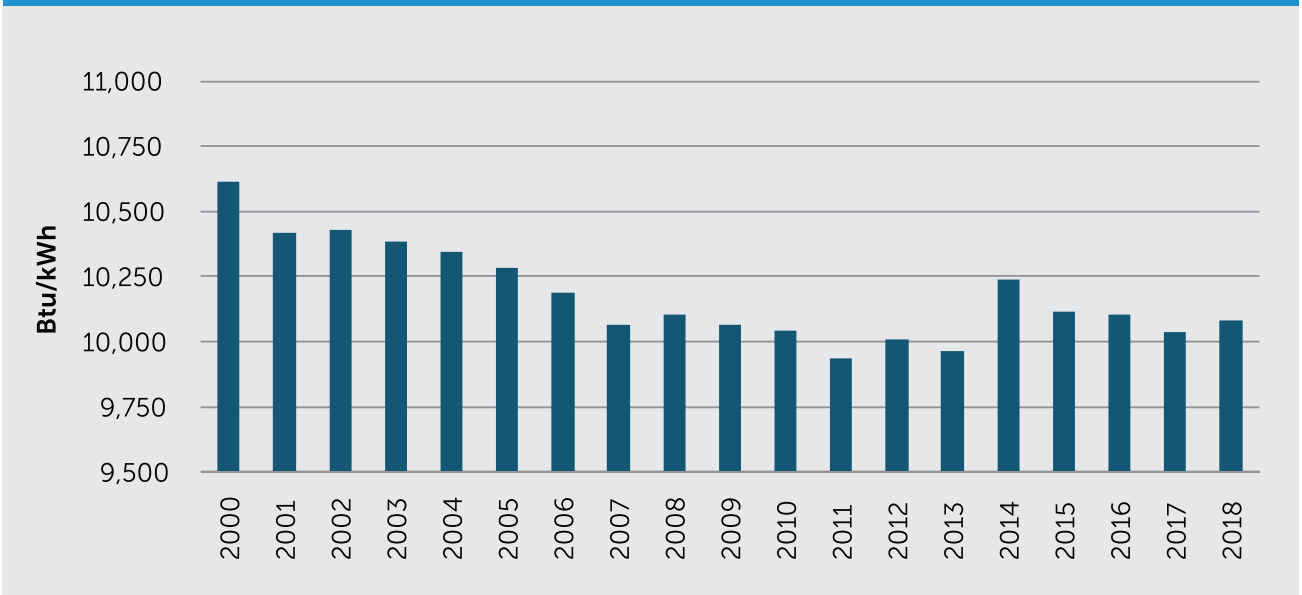
Power is delivered from the Rawhide Substation over two double-circuit 230-kV lines. The line traveling west connects to the LaPorte Substation, and primarily serves Platte River loads. The line traveling east connects to the Ault Substation and provides grid support, in addition to serving Platte River loads.

Rawhide Unit 1 is equipped with several systems to curb the plant's emissions: a low-NOx combustion control system provides primary control and optimization of nitrogen oxide emissions; sophisticated neural-network programming controls carbon monoxide emissions; mercury emissions are limited by a powder-activated carbon injection system; sulfur dioxide is controlled with a spray-dry absorber system; and two baghouses contain the release of particulate matter.

Rawhide Unit 1 equivalent availability and capacity factors



Rawhide Unit 1 heat rate history



Coal generation

Craig units 1 & 2

Craig Generating Station

Craig units 1 and 2 are part of the three-unit Craig Generating Station operated by Tri-State Generation and Transmission Association (TSGT). The facility is located in Craig, Colo., in the northwestern part of the state. Platte River is a joint owner of units 1 and 2 with partners TSGT, Pacificorp, Salt River Project and Public Service Company of Colorado. Overall, Craig 1 is rated at 427 MW while Craig 2 is rated at 410 MW (net capacities). Platte River owns an 18 percent share of Units 1 and 2, or approximately 77 MW for Unit 1 and 74 MW for Unit 2, for a total of 151 MW.

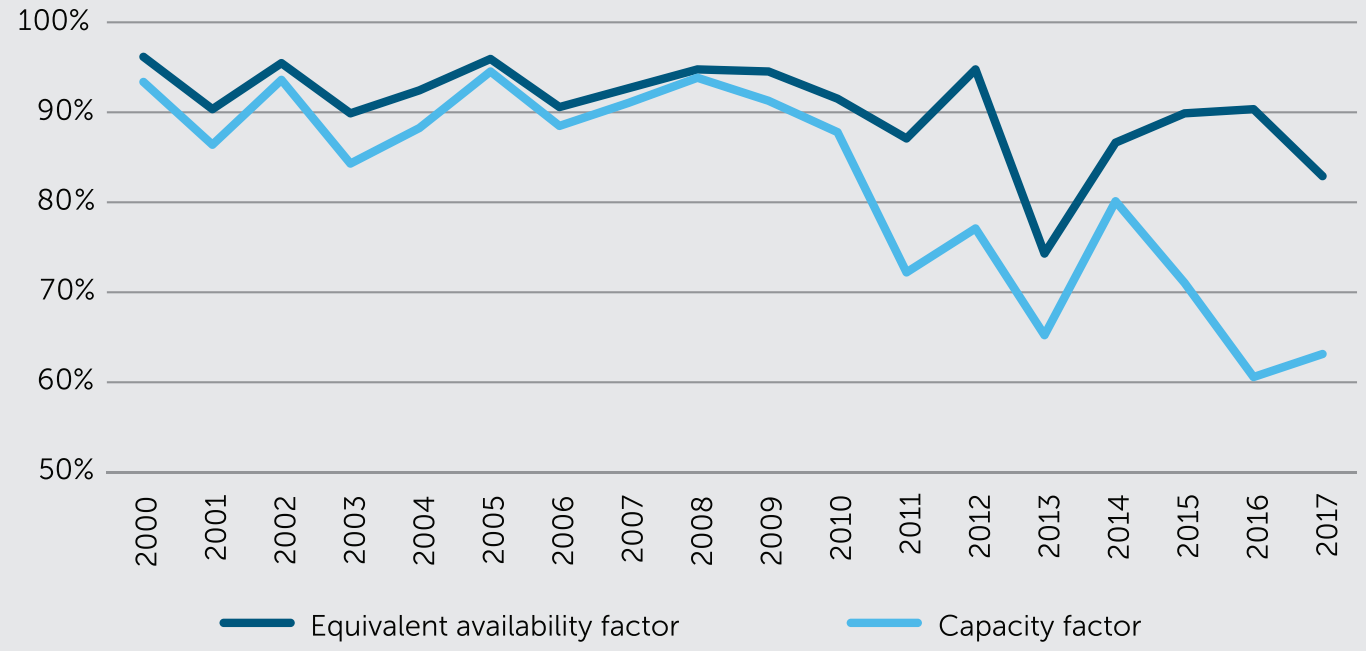
Construction on units 1 and 2 began in 1974. Unit 2 was completed in 1979, while Unit 1 became operational in 1980. The Craig Generating Station is a "mine-mouth" facility and is situated adjacent to the Trapper Mine. Between 400 and 500 thousand tons of coal are produced and used annually for Platte River's share of the Craig units.

The power production site includes the generation facilities, coal handling facility, small water storage reservoir and related transmission facilities. Units 1 and 2 are equipped with electrostatic precipitators to control fly ash and wet limestone scrubbers to remove SO_2.

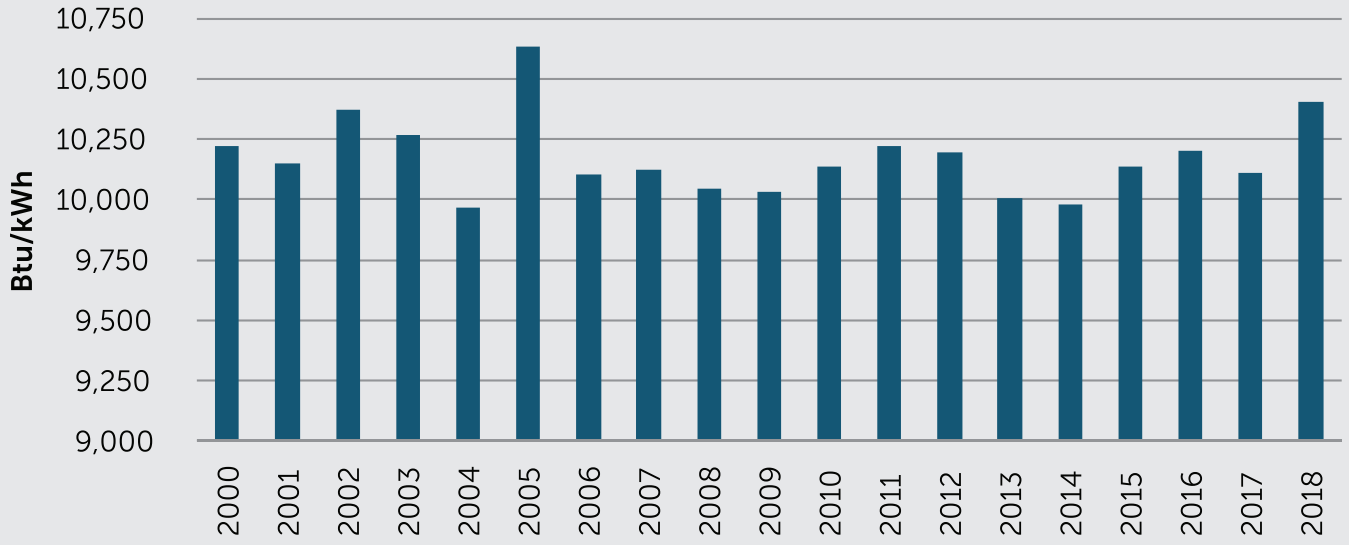
Platte River also owns approximately 190 MW of transmission capacity in the path from western to eastern Colorado, which delivers Platte River's share of the Craig Units. Platte River leases any unused transmission capacity on this path to another regional utility.

Craig Unit 1 will be retired by Dec. 31, 2025. Platte River's decision to join the co-owners in the retirement of Unit 1 is an important step in our plan toward portfolio diversification and greenhouse gas reductions.

Craig equivalent availability and capacity factors



Craig units 1 & 2 heat rate history



Natural gas peaking generation

Rawhide units A, B, C, D and F

Rawhide Energy Station

Platte River operates five natural gas-fired combustion turbines at the Rawhide Energy Station (Rawhide units A, B, C, D, and F). Units A-D are simple cycle "Frame E" units manufactured by General Electric, and Unit F is a simple cycle "Frame F" unit also manufactured by General Electric. Three of the units were commercially available for generation in 2002. The fourth came online in the spring of 2004, and the last unit came online in 2008.

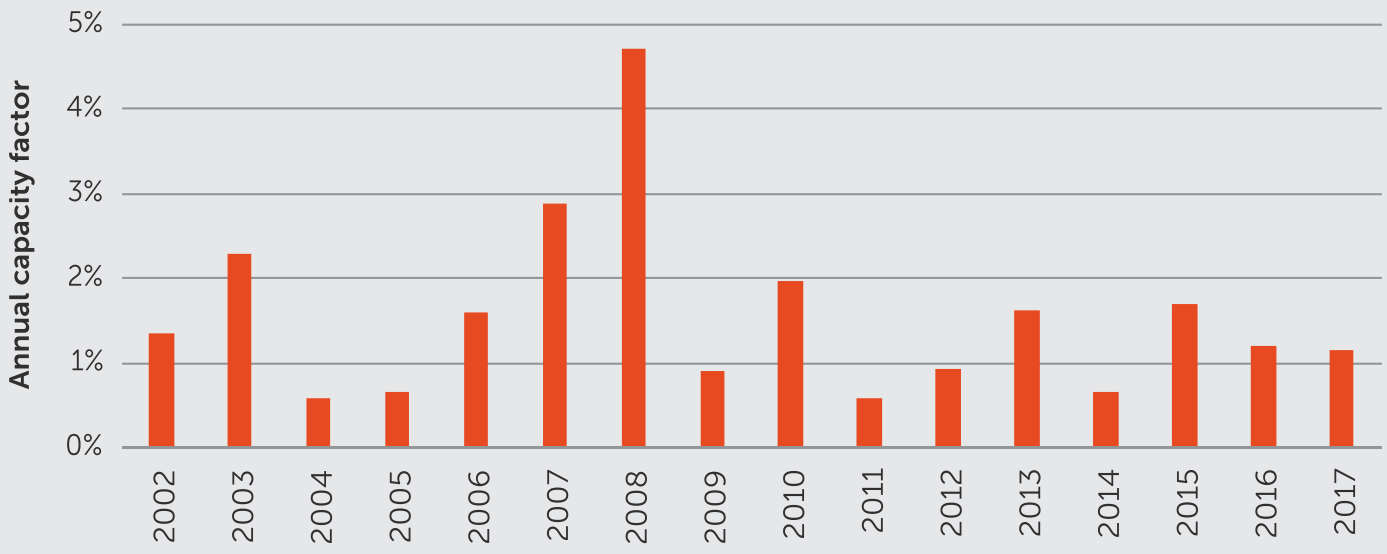
Of the five simple cycle units, Unit F has the highest operating efficiency with a heat rate of approximately 11,500 Btu/kWh, and is the most frequently dispatched. Units A-D have average heat rates of approximately 13,000 Btu/kWh and are dispatched for approximately half as many hours as Unit F.

These units provide peaking capacity as well as reserve capacity in the event of an outage at one of Platte River's other generating resources. Typically, the Rawhide gas units operate very infrequently—often to support Platte River's system as a backup resource, and occasionally to serve the region when market economics are favorable.

On average, Units A-F can be expected to operate 1 percent of the time (or less) and CO_2 output averages about 40,000 tons per year (about 1 percent of Platte River's total). However, the units provide a significant amount of insurance (388 MW in total) if outages or other system contingencies occur on Platte River's system. Units A-D each generate summer-rated capacities of 65 MW, while Unit F is rated to generate 128 MW.

A 15-mile natural gas pipeline currently supplies fuel to the natural gas-fired units A-F and has been designed with excess capacity.

Rawhide units A-F historical capacity factor



Solar generation

Rawhide Flats Solar

Rawhide Energy Station

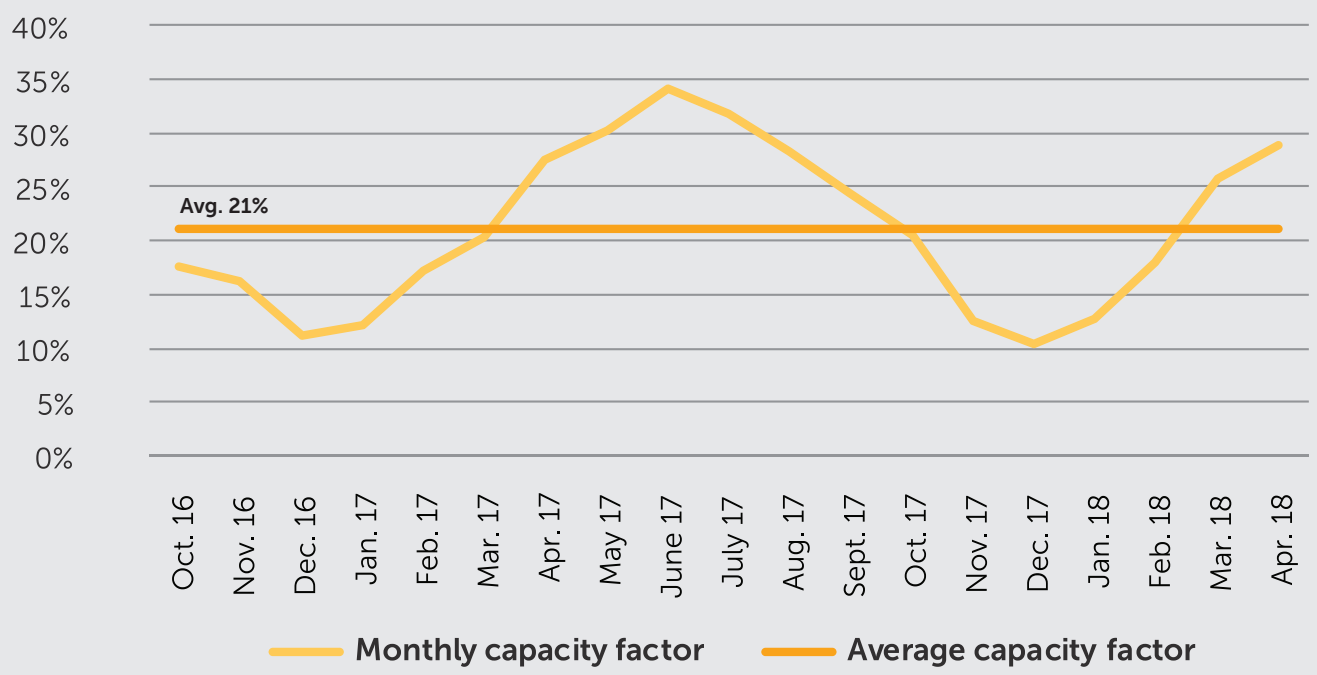
Commercial operation of the Rawhide Flats Solar began in the fall of 2016. Rawhide Flats Solar is a 30-MW_{AC} utility-scale solar installation located at the Rawhide Energy Station near Wellington, Colo. The installation covers approximately 189 acres with a total of 117,120 solar photovoltaic panels mounted on a single-axis tracking system. The single-axis tracking system orients the panels toward the east to collect solar energy during morning hours and toward the west to collect solar energy during the late afternoon hours. Output from the panel arrays is routed through a series of twelve central inverters to manage power quality supplied to the Rawhide Substation.

Construction on the facility commenced in spring 2016 and was completed in October 2016. The plant's generation is acquired through a purchased power agreement and Platte River receives the full energy output of the project. The term of the agreement extends through 2040.

New solar project in development

In 2018, Platte River released a request for proposals for the procurement of an additional 20 MW of solar energy which will include a 1-2 MWh lithium-ion battery. A power purchase agreement (PPA) for the new facility has been signed and construction is scheduled to begin in 2019 on land adjacent to the existing Rawhide Flats solar facility. Output from the new solar installation will be acquired under the PPA to serve Platte River's owner communities.

Rawhide Flats Solar capacity factor



Hydropower

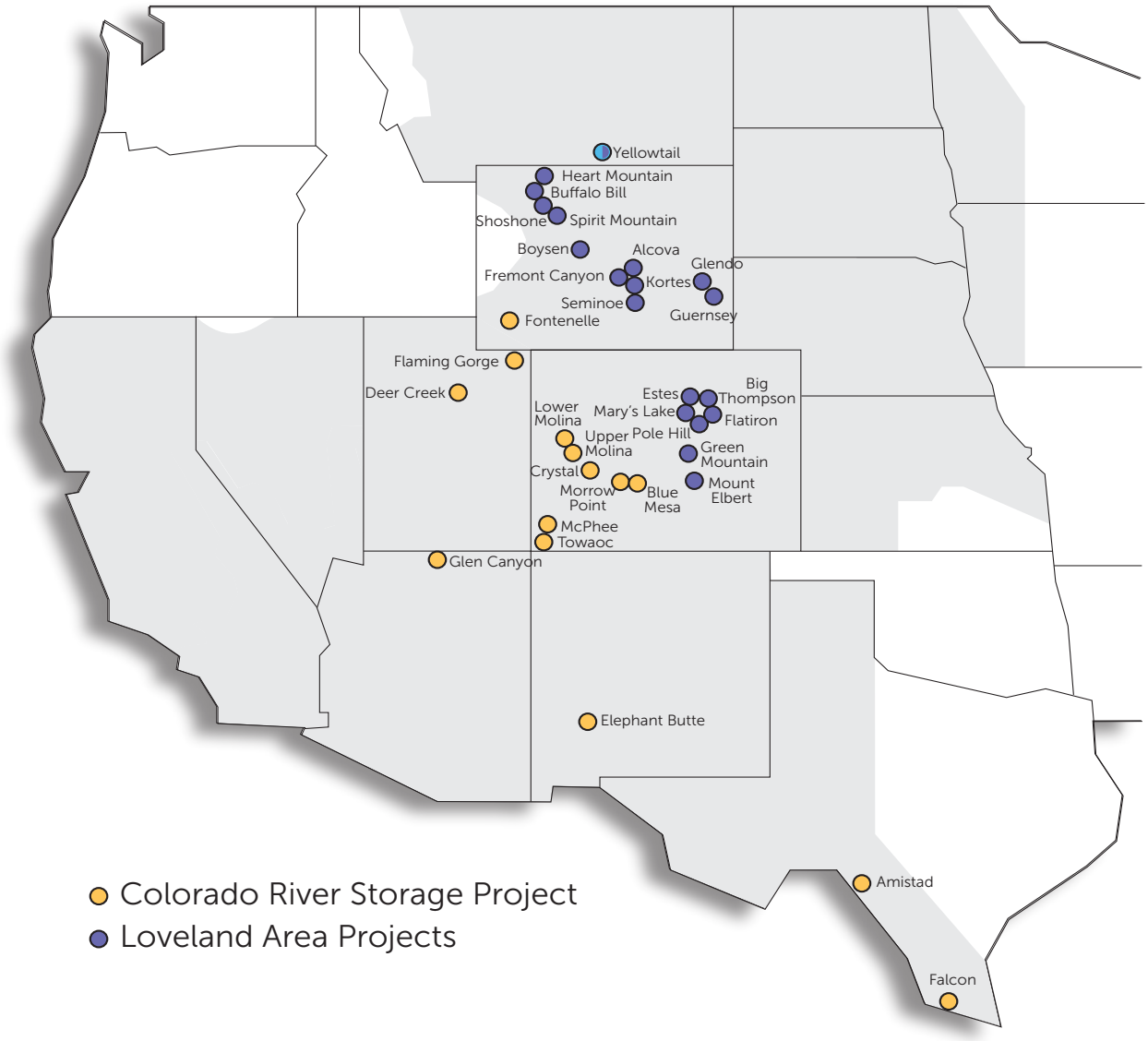
Loveland Area Project and Colorado River Storage Project

Platte River receives allocations of federal hydropower under contracts from the Western Area Power Administration's (WAPA) Loveland Area Project (LAP) and the Colorado River Storage Project (CRSP). These allocations vary by season.

The LAP contract runs through September 2054, and Platte River receives monthly quantities of approximately 30 MW to 32 MW of LAP capacity throughout the year.

The CRSP contract runs through September 2057. For long-range resource planning, Platte River uses WAPA's Sustainable Hydropower (SHP) component as the firm capacity expected to be available from the CRSP contract. SHP is approximately 50 to 60 MW during the summer season and 72 to 85 MW during the winter season.

The final component of the CRSP supply is based on the capacity difference between the contract-rate-of-delivery and SHP quantities. This difference is referred to as Western Replacement Power (WRP) or Customer Displacement Power (CDP). WRP represents capacity (and associated energy) that Platte River may be able to schedule from WAPA, depending on availability. CDP represents WAPA transmission which may be utilized by Platte River, depending on availability, but its associated energy is Platte River's responsibility to either generate or purchase.


Yellowtail
Heart Mountain
Buffalo Bill
Shoshone
Spirit Mountain
Boysen
Alcova
Glendo
Fremont Canyon
Kortes
Seminoe
Guernsey
Fontenelle
Flaming Gorge
Deer Creek
Estes
Big Thompson
Lower Molina
Mary's Lake
Flatiron
Upper Molina
Pole Hill
Green Mountain
Crystal
Morrow Point
Blue Mesa
Mount Elbert
McPhee
Towaoc
Glen Canyon
Elephant Butte
Amistad
Falcon
Colorado River Storage Project
Loveland Area Projects

Wind generation

Wind

Wyoming and Colorado

The growth in Platte River's wind resources over the past twenty years has been significant. Platte River currently receives 78 MW of wind power through purchase power agreements. The total energy supplied by wind is expected to be about 9 percent (excluding Roundhouse) of Platte River's total deliveries to its municipal owners at current production levels. Wind energy has proven to be a good source of non-carbon energy, reducing the need to burn fossil fuels. However, it cannot be counted on for full firm capacity at the time of Platte River's system peak.

Medicine Bow

In 1998, Platte River completed the development and commercial startup of two 600-kW wind turbines at its Medicine Bow Wind Project site in southeastern Wyoming. Together, the city of Fort Collins and Platte River were the first utilities in Colorado to provide wind energy to their customers. By 1999, all owner municipalities offered non-carbon energy to their customers. In 2013, Platte River sold the project to Medicine Bow Wind, LLC, which performed retrofits to prolong the turbines' rated useful lives from 20 years to 30 or more years. Platte River entered a power purchase agreement with Medicine Bow Wind, LLC that extends through 2033. Today, Platte River receives 6 MW of wind generation from the site, with an average capacity factor of about 33 percent.

Silver Sage

In October 2009, Platte River began receiving 12 MW of energy from the new 42-MW Silver Sage Wind Project site west of Cheyenne, Wyo. Deliveries from this facility are made under a 20-year power purchase agreement through 2029 with the owner, Duke Energy Carolinas, LLC. The Silver Sage facility consists of 20 wind turbines manufactured by Suzlon, each capable of generating 2.1 MW. The contractual output has subsequently been sold to a third party in order to allow Platte River to take greater advantage of wind output that will be delivered directly to the Rawhide Energy Station from the Roundhouse wind project.

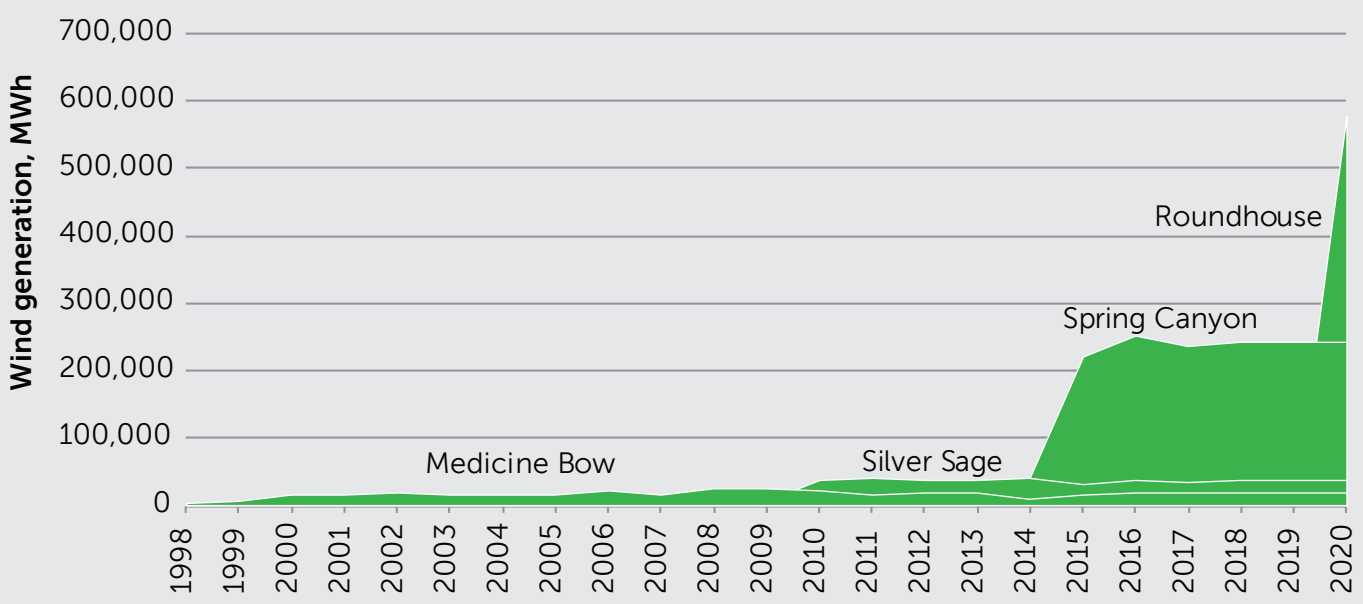
Spring Canyon

In 2013 and 2014, Platte River made separate 25-year commitments to purchase a total of 60 MW from Invenergy's Spring Canyon Energy Center in Logan County, Colo. Both contracts are active through 2039. The 60-MW wind farm has thirty-five 1.7-MW GE wind turbines with the capacity to generate nearly 240,000 MWh. The full 60 MW commitment was made in two phases—in 2013, Platte River agreed to buy 32 MW from Phase II of the project, and the following year Platte River purchased an additional 28 MW from Phase III when enough transmission became available to deliver the extra power from the site. In 2014, the facility became commercially operational.

Roundhouse

In January 2018, Platte River signed a power purchase agreement with Enyo Renewable Energy for 150 MW of wind capacity with deliveries expected in 2020. The new wind farm will be located on the Duck Creek Grazing Association property in southeastern Wyoming and will connect directly to Platte River's Rawhide Substation. In August 2018, Enyo transferred the Roundhouse agreement to NextEra Energy Resources, LLC. NextEra will construct the Roundhouse project with up to 75 wind turbines across 14,000 acres of land, including the additional transmission capacity needed for delivery to Platte River's loads.

Platte River wind generation growth (MWh/year)



Distributed energy resources

Distributed energy resource (DER) technology includes distributed solar generation, distributed energy storage, electric vehicles and demand response systems. In contrast to the energy efficiency resources in the next section, DER technologies tend to be more interactive by either providing additional generation on the grid in the case of distributed solar, or by providing flexibility in the scheduling of generation in the case of distributed energy storage, electric vehicles and demand response.

Distributed solar generation in Platte River's service area totaled about 14 MW_{AC} at the end of 2017 and includes projects installed as part of the Fort Collins Commercial Solar Power Purchase program as well as the Fort Collins Community Solar project, the Loveland Foothills Solar project and over 1,200 net-metered solar projects installed by the owner communities' retail customers.

- The Fort Collins Commercial Solar Power Purchase program is a feed-in-tariff program launched in 2013 and has grown to over 3.1 MW_{AC} of installed solar capacity. Solar projects are installed by third parties on commercial customer facilities. Energy is sold under agreements involving the developers, the customers, Fort Collins and Platte River. Platte River purchases and resells the energy from these facilities to Fort Collins, crediting them for the real time value of solar power.
- Fort Collins' Community Solar program consists of the 0.5-MW_{AC} Riverside Community Solar Array located at the intersection of Mulberry and Riverside in Fort Collins. Energy is sold under agreements involving the project developer, participating customers, Fort Collins and Platte River. Platte River purchases and resells the energy from these facilities to Fort Collins, crediting them for the real time value of solar power.
- Loveland's Foothills solar installation located west of Wilson Avenue in Loveland is a 3-MW_{AC} single-axis tracking solar facility. This project became operational in 2016 and was supported by Federal Emergency Management Agency funding to replace the Idylwilde hydroelectric facility, which sustained damage during the 2013 floods. Loveland owns this project and under agreements with Platte River uses 2.55 MW_{AC} of its output to meet municipal loads directly and sells the output of 0.45 MW_{AC} to Platte River for resale to Loveland, crediting them for the real time value of solar power.
- Platte River's owner communities continue to see growth in net-metered solar projects installed by residential and commercial customers. By the end of 2017, over 1,200 projects had been installed, with an estimated capacity of 7 MW_{AC}.

Distributed energy storage consists of small-scale residential and commercial battery installations. There are approximately 12 distributed energy storage installations within the city of Fort Collins.

There are approximately 2,500 electric vehicles (EV) within the four owner communities that Platte River serves. To support the EVs, there are approximately eight public DC fast chargers, over 100 level-2 chargers and nearly 20 Tesla superchargers.

Demand response (DR) includes the direct load control residential Peak Partners program in Fort Collins and the voltage reduction system in Longmont. In 2015, Platte River initiated a pilot to explore the wholesale benefits of dispatching these resources. DR resources included in the pilot consist of approximately 1,500 thermostats and 2,000 electric water heaters under the residential Peak Partners program, and voltage reduction controls installed on ten of Longmont's distribution transformers. The combined capacity of these resources is approximately 2.4 MW during the summer months and 1.3 MW during the non-summer months. Platte River is continuing to test DR resources to determine how they can best provide capacity to reduce peak demand or better integrate renewable energy.

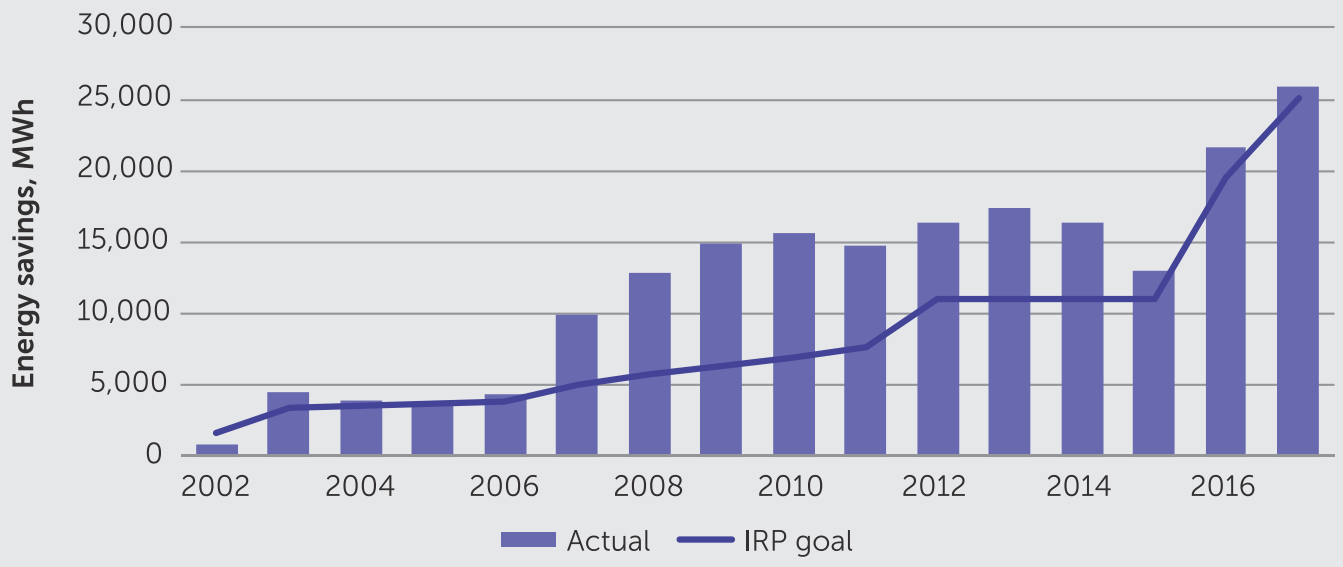
Energy efficiency programs

Platte River currently invests most of its demand side management (DSM) resources in energy efficiency (EE) programs, due in large part to the cost-effectiveness of EE programs. Additionally, EE programs have helped slow load growth that would otherwise have been met with existing fossil generation and would have potentially driven the need for additional generation capacity. Platte River and the owner communities collaborate to design, fund, implement and promote these programs to the owner communities' customers. Platte River and the owner communities created the Efficiency Works™ brand for their combined EE programs, with the goal of strengthening the owner communities' marketing efforts and providing one place for their retail customers to go for information on EE programs. In some cases, the owner communities offer additional programs beyond those offered by Platte River.

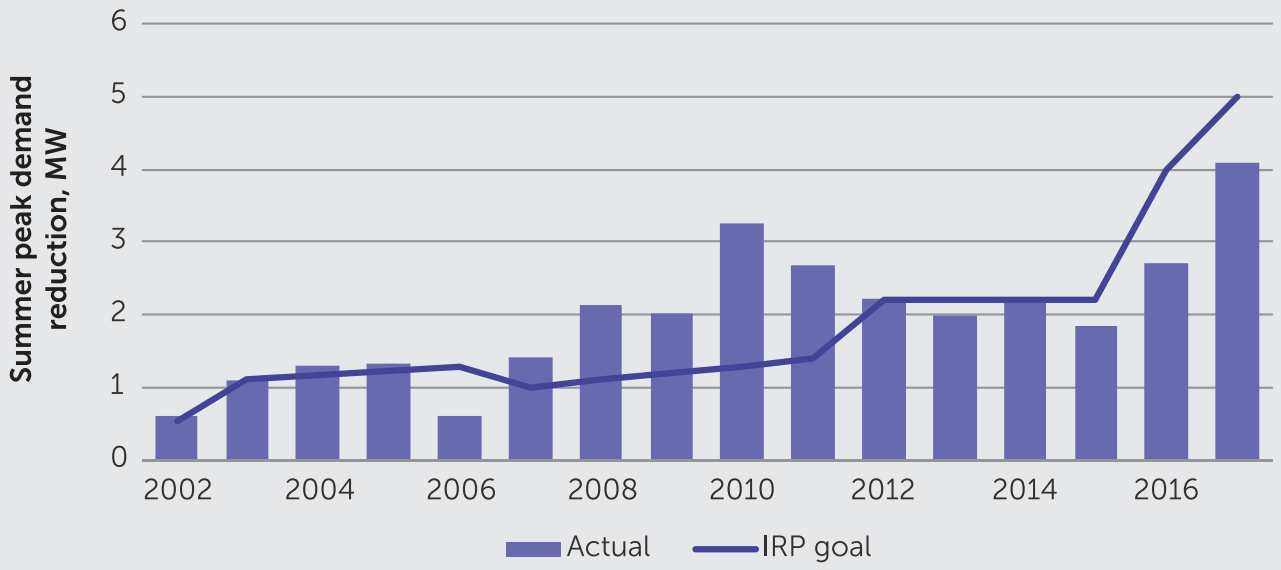
Efficiency Works programs include services and rebates that help customers identify and implement measures to improve energy efficiency. Platte River also works closely with trade allies—regional providers of energy efficient products and services, to ensure that the regional marketplace is prepared to respond to utility and customer efforts to adopt more efficient technologies.

Platte River has a Demand Side Management—Energy Efficiency Funding Policy that guides investments in energy efficiency. As described in the policy, Platte River seeks to balance EE program costs with the long-term benefits of avoiding additional generation capacity. In 2018, the goal for EE programs is to save 1 percent of annual energy consumption. A recent study indicated that the cost-effective level will be in the range of one to 1.5 percent annual savings. This will continue to be evaluated in light of new EE technologies, EE program performance and customer and market acceptance of programs.

Incremental energy savings from common EE programs



Incremental summer peak demand reduction from common EE programs



Screened **resources**

Prepared in conjunction with Pace Global

A wide variety of power generation methods could satisfy Platte River's strategic initiatives and future load growth. Over the past decade, several shifts in the energy industry have arisen that could influence the mix of future resources used by electric utilities to produce power. A few key measures that could affect how Platte River generates and delivers power to its customers in coming years include:

- The long-term energy choices and goals of Platte River's owner communities
- Potential federal and/or state regulations of greenhouse gases
- Decreases in the prices of solar generation and wind resources
- Sustained low gas prices driven by rapid growth in hydraulic fracturing
- Advancement in battery energy storage capability and competitive pricing
- Growth of distributed technologies
- Transportation electrification
- Increasing competition from third parties seeking to provide distributed technologies to end users

This section of the document develops a qualitative assessment of potential generation technologies, with the amount of detail based on the specific technology and its applicability to current and future markets. Investigation topics for each individual technology vary, such as:

- Technical operations of various power generation resources
- Installation costs and availability
- Existing and potential commercial viability
- Geographic constraints and advantages
- Environmental impacts and benefits

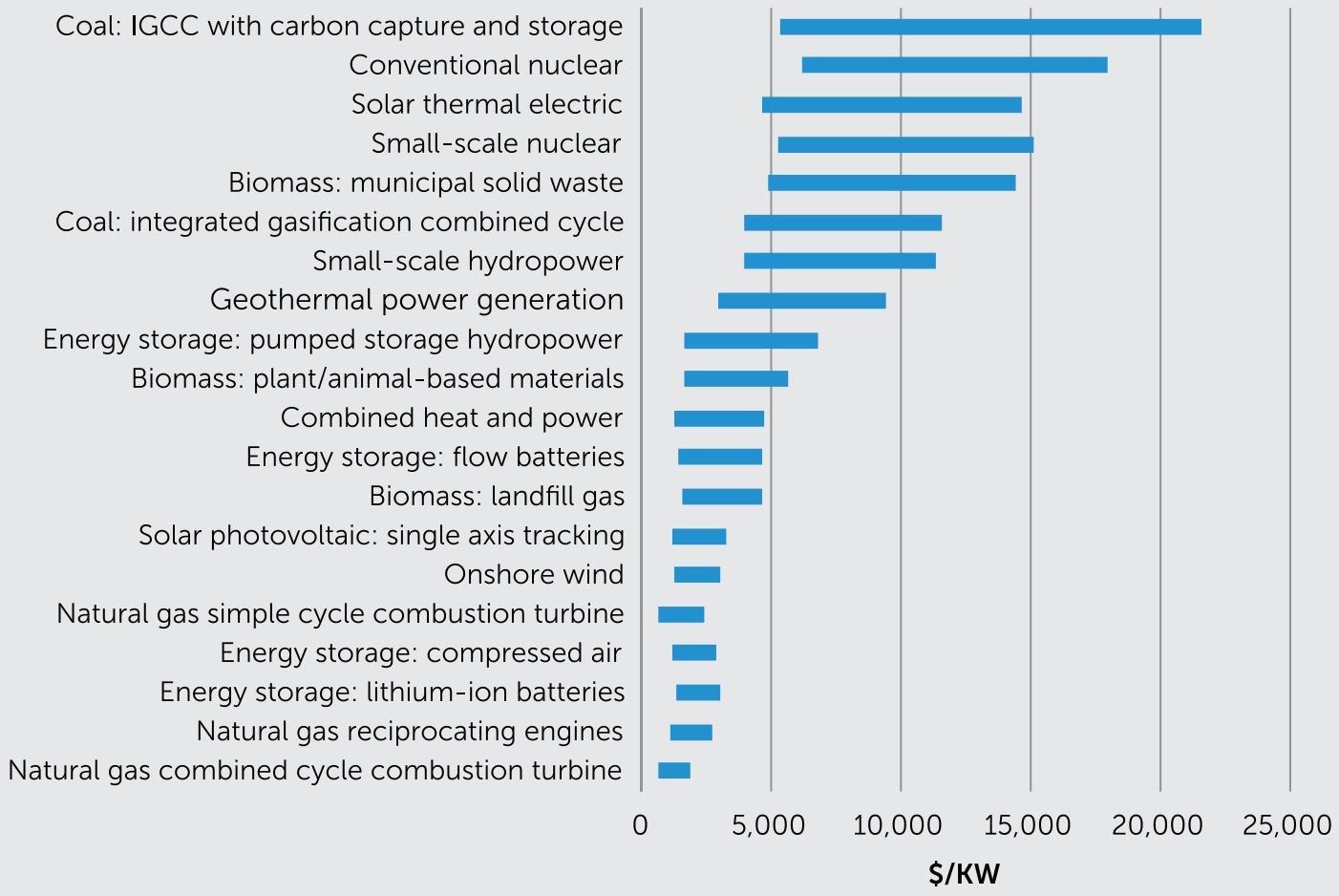
The resources reviewed are categorized as follows:

- **Non-carbon generation:** Power supply options that include wind, solar, geothermal, biomass and hydroelectric power.
- **Transformational technologies:** Emerging technologies that can help enhance decarbonization of the power grid and/or provide customers with more choice and flexibility in their power supply.

- **Transitional technologies:** Power resources that can move the power supply toward a non-carbon future by facilitating the integration of non-carbon resources or behind-the-meter technologies.
- **Conventional and other technologies:** Technologies that have traditionally made up much of the US generation mix, including coal and nuclear generation.

The following table and chart provide an overview of generation technologies that Platte River considered as options for its 2020 IRP, along with their associated installed costs. Each method will be described in more detail within this document.

Range of capital costs for various production technologies
$/kW, shown in $2017



Non-carbon generation

Onshore wind

Wind turbines provide a renewable source of power by converting the kinetic energy of wind into electric energy. Due to significant growth over the past decade, wind generation has become the second-largest source of non-carbon electric generation in the U.S., accounting for 6.3 percent of power produced in 2017. Wind generation has become well-established in the U.S., and capital and operating costs have dropped significantly over time. Currently, capital costs for wind projects range from $1,288 to $1,806 per kW.

The cost of energy procured through power purchase agreements (PPA) has dropped significantly over the past few years. The lower PPA prices have been enabled by improved technologies, declining costs, low interest rates and federal subsidies. Wind power prices vary by region of the country depending on wind capability, rates of adoption and government mandates.

The federal production tax credit (PTC) has made a significant impact on recent prices for wind power. However, the PTC is scheduled to phase out by 2020 which could affect near-term affordability for new wind resources. The PTC currently provides the following incentives (relative to an original PTC of $24/MWh)[1]:

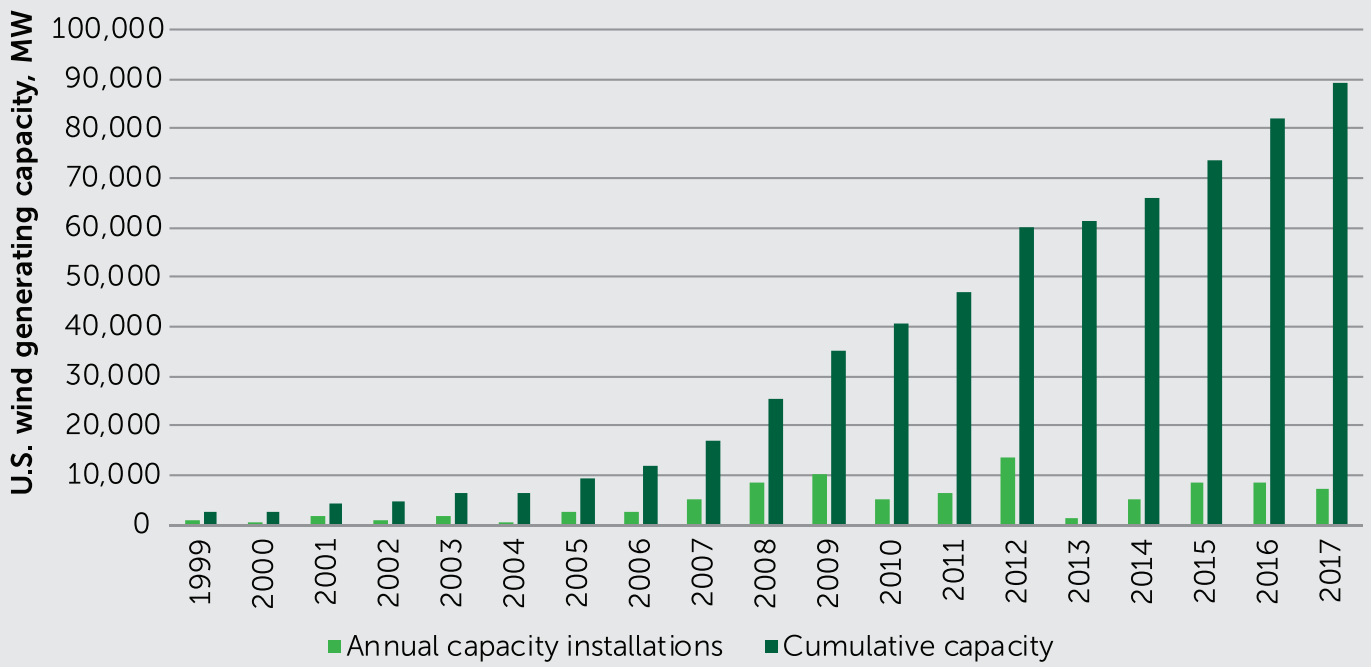
	Completion date	Tax credit percent	Tax credit ($/MWh)
Projects starting in 2017	Dec. 2021	80 percent of PTC	$19.2
Projects starting in 2018	Dec. 2022	60 percent of PTC	$14.4
Projects starting in 2019	Dec. 2023	40 percent of PTC	$9.6

Over time, wind turbine design innovations have resulted in improved performance and energy output. Newer turbines are taller and have a larger rotor-swept area, allowing them to produce more energy across a wider range of wind speeds, which drives up average capacity factors. U.S. wind projects commissioned in 2016 had an average capacity factor of 43 percent in their first year of operation.

Colorado has an established presence in wind power generation and equipment manufacturing. Over 17 percent of total electricity production in Colorado comes from wind, and the state is ranked ninth in the country with over three GW of installed wind capacity. Colorado is also home to 17 wind industry manufacturing facilities employing 5,000 to 6,000 workers, and creates $5 to $10 million in annual land lease payments to Colorado property owners.[2]

Wind power has become a fundamental source of non-carbon generation across the country, but also has operational limitations due to the intermittent nature of wind. Platte River will incorporate wind options into its 2020 IRP scenarios, and will also study the effects that higher amounts of intermittent resources have on the power production portfolio.

U.S. annual and cumulative utility-scale wind power



Wind facts

- Well-established non-carbon technology with over 89 GW installed in the U.S.
- Despite declining federal incentives, costs and efficiencies continue to support growth
- Over 80 percent of installed wind capacity is in rural low-income counties
- The U.S. wind industry supports over 100,000 full-time-equivalent jobs

Non-carbon generation

Solar photovoltaic

Solar photovoltaic (PV) systems directly convert the energy in solar radiation to electrical energy. Solar PV generation has been rapidly expanding as a desirable form of non-carbon generation in recent years, with total U.S. installed capacity reaching 55.9 GW in early 2018.[3] Worldwide annual capacity additions are expected to exceed 100 GW each year through 2022.[4]

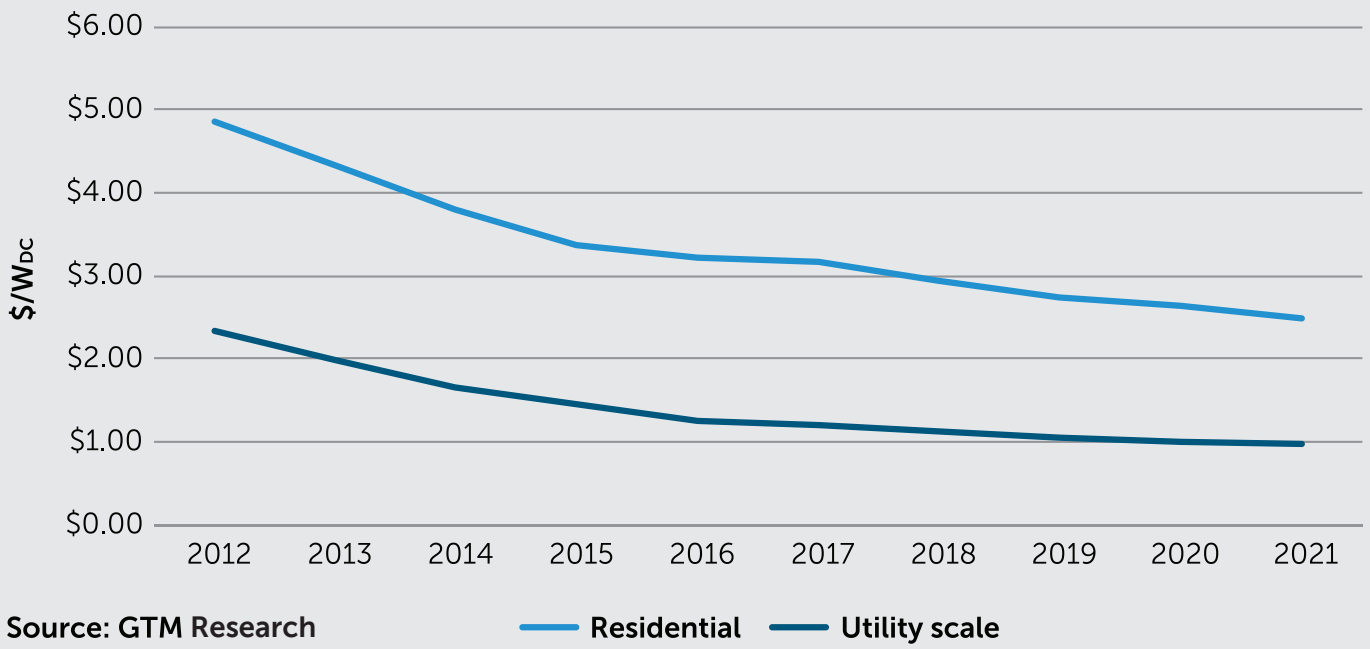
Renewable energy incentives have played a critical role in supporting the development of solar PV, either in the form of renewable portfolio standards (RPS), feed-in tariffs or tax credits. Falling costs have been another key driver of solar PV market penetration. In 2017, capital costs range from $1,181 to $2,105 per kWDC for single-axis tracking utility-scale projects.

Single-axis tracking PV systems require less land commitments than fixed-tilt systems for the same energy output and can increase energy production by 20 percent or more over an equivalently sized fixed array. Tracking-type solar installations now account for more than 50 percent of utility-scale solar PV in the U.S. and are most common in the southwest. Commercially-available solar module types include polycrystalline silicon, monocrystalline silicon, thin-film, and bi-facial panels. Polycrystalline modules are the most common, with efficiencies in the range of 15 to 17.5 percent in 2018.[5] Further reductions in module pricing, along with research and development improvements, are expected to bring down utility-scale solar PV system prices in the future.

Owners of solar projects can also benefit from the federal Investment Tax Credit (ITC) and, for businesses that own solar, Modified Accelerated Depreciation Cost-Recovery System (MACRS) tax benefits. The ITC allows taxable businesses and individuals to deduct 30 percent of their investment in a solar project from their tax liability. This deduction is scheduled to phase out, for projects starting construction in 2020 and beyond, with the credit dropping to 26 percent in 2020 and 22 percent in 2021. In 2022 and beyond, this credit drops to zero for individuals and remains at 10 percent for businesses. MACRS allows for businesses to claim tax benefits associated with depreciation of solar assets over the first five years of the project's life, providing an increased rate of return on solar projects. MACRS is included in federal tax code and is anticipated to be available for the foreseeable future.[6]

Like wind, solar power is becoming an increasingly important source of non-carbon generation across the country. Platte River will incorporate solar options into its 2020 IRP scenarios and will also study the effects of higher amounts of intermittent resources on the power production portfolio.

Solar photovoltaic solar prices, $/W$_{DC}$



Source: GTM Research

Solar facts

- Solar PV system prices have fallen by 44 percent from 2012 to 2017
- 100 GW of solar added annually worldwide
- Implemented under both utility-scale and distributed energy configurations, solar PV will continue to drive the need for more storage

Non-carbon generation

Solar thermal electric

Solar thermal electric (STE) generation concentrates solar energy from reflectors to receivers to produce temperatures high enough to drive a steam turbine that generates electrical power. There are three main STE technologies:

- Linear systems use long, linear runs of mirrors (typically parabolic trough shape) to focus the sun's energy on a narrow tube containing a fluid (usually oil), which is then used to generate steam.
- Dish technologies use a mirrored dish to focus light on a single central point, heating a working fluid (for example, hydrogen) that drives a Stirling engine.
- Power towers use fields of sun-tracking mirrors (heliostats), that constantly reflect the sun's light toward a tower-mounted receiver. The receiver concentrates the light onto a heat-transfer fluid (typically a molten nitrate salt) which is then used to run a steam turbine. Designed to include thermal energy-storage, the system can produce electricity during cloudy weather or at night.

Nearly 1,760 MW of STE-power generation is installed in the U.S., with most of the capacity installed in California.[7] Concentrating solar power projects in the U.S. account for 1,252 MW of this total. Costs for STE systems have been falling but remain relatively high with a wide range that depends on the addition of complementary storage. Estimated capital costs for STE projects range from $4,651 to $10,000 per kW.

While there are currently no dispatchable STE systems in operation in the U.S., technology advancements may allow for enough thermal storage to facilitate dispatchability in the future. The DOE recently provided $72 million in funding with the goal of making large-scale dispatchable solar energy systems cost-competitive without subsidies by 2020.[8]

Costs for STE are expected to decline due to anticipated cost reductions for components, engineering and installation. However, STE's current high capital costs and limited commercial penetration prevent it from being considered as a viable option for Platte River's 2020 IRP.

Solar thermal facts

- Requires strong direct sunlight (most U.S. projects are in the southwest)
- High capital costs have prevented widespread adoption
- Certain designs include up to 10 hours of storage using molten salts

Geothermal power

Geothermal power is produced by extracting heat from the earth. It generally involves injecting water into deep wells, where the earth's heat produces steam to spin turbines for power generation. Geothermal generation provides dispatchable baseload generating capacity with minimal CO_2 emissions. In 2017, geothermal plants had an average capacity factor of 69 percent, comparable to that of other baseload-generation types such as coal or nuclear, and substantially higher capacity factors than for wind and solar.

Geothermal power facts

- The resource is location-specific as high temperature rock or steam is required
- High capital costs and geographic limitations have prevented extensive development

The U.S. will have an estimated 3.1 GW of geothermal capacity installed by the end of 2018, with 875 MW of planned capacity additions through 2022. Although geothermal resources are used for heat pumps, greenhouses and district heating, Colorado does not currently derive any electric generation from geothermal resources;[9] however, the state has 1,105 to 8,900 MW of capacity potentially available for geothermal electric generation, located primarily on the western side of the state.[10]

The production costs and efficiencies of geothermal generation vary significantly depending on the geologic properties of the well. Capital costs can be affected by high exploration, development and transmission costs. Once a geothermal resource is developed, operating costs are relatively low, except when additional wells need to be drilled. Capital cost estimates for new geothermal plants range from $3,021 to $6,400 per kW.

Because of its limited geographic availability and high development costs, geothermal resources will not be included in the 2020 IRP as a power production alternative but will continue to be monitored by staff for future potential.

Non-carbon generation

Biomass

Plant and animal-based materials

Biomass fuels include products such as switch grass, waste wood, crop-based wood, manure, peat or other types of fuels that can be produced in a cycle that yields fuel for power generation. Biomass generation technology is similar to coal plant technology—fuel is combusted in a boiler to generate high pressure steam, which drives a steam turbine that produces power. Capacity of biomass generating stations ranges from less than 1 MW to well over 100 MW.

The technology and plant size for biomass generation facilities vary widely based on the underlying fuel type, and economic feasibility is restricted to specific applications due to the sustainability of biofuel feedstock. Estimated capital costs for a biomass unit range from $1,700 to $4,000 per kW, significantly higher than other thermal resource alternatives. Although the potential for utility-scale projects is limited, many opportunities exist for specific applications of biomass conversion. Over 14 GW of capacity from biomass fuel exists in the U.S. with 176 MW of projects under construction.

Municipal solid waste

Municipal solid waste (MSW) can be used to produce energy—either through combustion or gasification. Like other combustion processes, MSW is incinerated to produce steam that generates electricity. A waste-to-energy (WtE) combustion plant can be located at a landfill or a dedicated site. The thermal and chemical reactions produced through gasification convert waste materials to the byproduct synthesis gas (syngas) and small amounts of waste char. Syngas is then used as a combustion fuel to generate electricity with a turbine or engine, although syngas has a lower heat content than natural gas.

Although MSW WtE generation results in CO_2 emissions, it may be considered carbon neutral in some cases. This is because much of MSW ultimately decomposes into methane, a potent greenhouse gas itself. MSW can also be used as a fuel source for a combined heat and power (CHP) plant but requires a meaningful use for the heat created by the CHP plant.

Estimated capital costs for MSW WtE plants range from $4,876 to $9,572 per kW, with even higher costs for gasification plants. Concerns about potential pollutants entering the atmosphere can make MSW WtE plants difficult to develop; however, scrubber and filtration techniques can mitigate emissions to safe levels. Tipping fees, or the cost for sanitation services to dispose

of trash, need to be considered when evaluating the financial feasibility of MSW generation processes. Landfill tipping fees are low in northern Colorado, making it difficult for a WtE plant to compete with the cost of other forms of power generation.

MSW WtE plants are more common in Europe where space for landfills is limited. The largest landfill in Platte River's region, the Larimer County Landfill, could supply approximately 75 tons per day of useable, biogenic trash as feedstock to support a 2-MW plant. Because of the limited production potential and relatively high cost of MSW WtE plants, Platte River will not include this technology in its 2020 IRP planning efforts.

Landfill gas

Landfill gas (LFG) is produced through aerobic and anaerobic decomposition of organic waste and can be used to fire turbines and engines that produce power. LFG is composed of nearly equal amounts of methane and CO_2, with trace amounts of other compounds, and is extracted from deep wells at landfill sites. Newer regulations require landfills with a minimum amount of solid waste to capture and flare the methane to prevent the release of large quantities into the atmosphere.

The viability of LFG power generation depends on the physical characteristics of the landfill and its expected life, which could be impacted by waste reduction and recycling programs. LFG collection is practical for landfills that are at least 40 feet deep and have at least 1 million tons of waste.

Two main LFG power plants currently operating in Colorado are:

- **Denver Arapahoe Disposal Site (DADS):** This is the largest landfill in Colorado, with an estimated 41 million tons of waste-in-place. It produces enough methane to support 2.8 MW of power generation, and its power output is sold to Xcel Energy.[11]
- **Erie Landfill Gas to Energy Project:** The Denver Regional North Landfill, Denver Regional South Landfill and Front Range Landfill total approximately 15 million tons of waste-in-place. They provide gas for this project, with a power production capacity of approximately 3.0 MW.[12]

Locally, the Larimer County Landfill has approximately 5.0 million tons of waste-in-place and may be able to support an LFG facility with a generation capacity of approximately 0.1 MW. Capital costs for an LFG power plant arrange from $1,572 to $3,144 per kW. Due to limited potential for power production, an LFG option has been excluded from Platte River's 2020 IRP efforts. However, power generation from landfill gas has the potential to be a distributed energy strategy within Platte River's communities where available and cost competitive with other non-carbon resources.

Non-carbon generation

Small-scale hydropower

Small-scale hydropower systems capture the energy in flowing water and convert it to usable electricity. "Small-scale" generally means units up to 10 MW, but in the U.S., it can mean up to 30 MW.[13] Small scale hydropower systems can be further subdivided into mini-hydro (less than 500 kW) and micro-hydro (less than 100 kW).

Small-scale hydropower facts

- Small-scale hydro is a proven, non-carbon power production option
- May be more feasible than conventional hydropower but has limited potential and creates unique environmental challenges in Colorado, such as species recovery

One method of small-scale hydropower involves diverting segments of waterways through channels or penstocks. The flow turns a waterwheel, which rotates a shaft connected to an alternator or generator. Another method includes installing hydroelectric plants at existing dams, utilizing falling water to turn a turbine connected to a generator. Potential projects for installing generation at existing dams have the advantage of relatively lower initial costs. The U.S. has an estimated 5,600 MW of undeveloped small-scale hydropower potential, compared to the 8,100 MW of developed, installed capacity.[14]

Small-scale hydropower is considered a non-carbon form of electricity generation. Water resources with adequate flow and elevation drop are required to produce hydropower and these capabilities exist in the mountain states region. Hydropower capital costs vary depending on the system type and civil work requirements, but typically range from $3,963 to $7,425 per kW.

Small-scale hydro is not included as a modeled resource in Platte River's 2020 IRP planning efforts due to limited potential at existing waterways but may be incorporated in distributed technology cases where available and cost-competitive with other non-carbon resources.

Pumped storage hydropower

Pumped storage hydropower (PSH) is the most established, utility-scale energy storage technology with over 22 GW of installed capacity in the U.S. This represents roughly 96 percent of the energy storage market. PSH uses two water sources at different elevations. Using PSH, water is pumped from a lower water source to an upper reservoir, and when energy is needed later (usually during on-peak hours), water is released from the upper reservoir, spinning a turbine and generating power.

Project sizes in the U.S. range from 30 to 3,000 MW of capacity with cycle efficiencies between 75 to 85 percent, and storage durations of six to 20 hours. Most of the large pumped storage facilities in the U.S. were constructed prior to the 1980s.

There are three existing pumped storage facilities in Colorado—the 320-MW Cabin Creek project near Georgetown, the 200-MW Mt. Elbert site near Leadville, and the 8.5-MW Flatiron site near Loveland. There are no new PSH facilities in development in Colorado. Like many western states, Colorado's topology can provide the necessary elevation drop to produce power. A 2007 University of Colorado study indicates that an additional 2,500 MW of pumped hydro generating capacity is possible within the state. However, capital costs for pumped storage hydro facilities vary significantly due to civil work requirements (use of existing reservoirs vs. new construction) and are estimated to range from $1,671 to $5,188 per kW. In addition, PSH projects can take two to five years to design and construct, plus several additional years for permitting and approvals.

Although limitations exist for developing PSH, the importance that storage will play in low-carbon portfolios leads Platte River to include this resource type in its 2020 IRP planning scenarios.

Pumped storage hydropower facts

- Has a proven track record with over 22 GW of capacity installed in the U.S
- Most systems rely on at least one existing reservoir to keep costs low
- Economically viable projects tend to be 500 MW and larger in the U.S

Transformational technologies

Batteries

In recent years, battery energy storage has become more important as a utility-scale option to integrate non-dispatchable resources onto the energy grid. Over 600 MW of utility-scale battery storage (front-of-meter) has been installed in the U.S. through 2017.[15] Although interest and deployment of battery technology is on the rise, the amount of functioning capacity is still minor when compared to the total U.S. generating capacity of 1,088 GW in 2017.[16]

Lithium-ion (Li-ion) batteries are the most common type of battery storage used at the utility-scale and can target applications unsuitable to PSH or CAES. Li-ion batteries have accounted for 94 percent of all new energy storage capacity in the U.S. since 2012, growing at an average rate of 55 percent per year. Most of the installed Li-ion capacity provides frequency regulation, but recent projects in the U.S. have focused on alternative applications including peaking capacity, non-carbon resource integration and peak shaving.

Battery storage facts

- Lithium-ion batteries have emerged as the current leader in battery technology
- Batteries help integrate non-carbon generation
- Battery cell costs have continued to fall as demand has increased

Li-ion battery costs are rapidly declining as suppliers increase their production, making them a popular choice for current energy storage needs. Global manufacturing capacity was 103 GWh in Q1 of 2017, and 24 new battery factories with a total capacity of 332 GWh are expected to be constructed by 2021, mainly in China and South Korea.[17] Manufacturing capacity should continue to grow to meet strong energy storage demand from mobile devices, medical devices, and electric vehicles.

With improving economics, the incidence of significantly-sized battery system installations continues to increase. Tesla completed the largest deployment of utility-scale Li-ion batteries through 2017—a 100-MW system at Neoen's 315-MW Hornsdale wind farm in Australia—and has many other proven installations of Li-ion batteries in utility-scale applications.[18]

As an alternative to Li-ion batteries, flow batteries can provide storage for durations greater than four hours (the typical duration for Li-ion batteries). Flow batteries operate in a similar fashion to Li-ion batteries, except one or both reactive materials are in a fluid solution. While Li-ion battery suppliers manufacture the battery modules as a single system, flow batteries are built from many parts. Flow batteries have an advantage over Li-ion because they retain their rated capacity for more charge cycles. They also have the potential to more effectively scale up discharge times by using larger tanks. As of mid-2017, flow batteries only account for 9 MW of installed capacity in the U.S. due to the significant cost advantage held by Li-ion batteries. Still, there are pilot projects that suggest flow batteries could become a leading energy storage

technology for long duration applications. Currently, China's Rongke Power is building a 200-MW flow battery system that is expected to come online by 2020.

Current capital cost estimates for Li-ion batteries range between $1,338 and $1,700 per kW. Costs for flow batteries are relatively higher, ranging from $1,440 to $3,276 per kW.

Platte River will include battery storage options as an important component in the evaluation of low-carbon portfolios in its 2020 IRP effort.

Transformational technologies

Compressed air storage

Compressed air energy storage (CAES) is a form of energy storage that involves injecting compressed air into an underground cavern and then heating and expanding it to drive a generator.

This technology is commercially viable for smaller-scale use, such as the propulsion of mine locomotives, and is under development for utility-scale applications. Existing CAES technology lacks proven methods to recover waste heat and typical efficiencies are relatively low (about 42 percent).[19] The need for a suitable underground cavern restricts the geographic viability of CAES. Additionally, it is unknown if caverns can effectively contain compressed air without leakage. For utility-scale CAES, salt caverns are the most proven option for commercial CAES development—their viability has been demonstrated for decades from natural gas storage. With technology improvements over time, CAES could help manage grid reliability as more non-dispatchable, non-carbon resources are introduced into the grid.

Compressed air storage facts

- Cost-effective CAES projects usually require underground caverns as air storage reservoirs
- Geological requirements have limited the number of commercially operating units

There are two CAES plants in operation worldwide—a 290-MW plant in Huntorf, Germany (1978) that has an 8-hour charging to 2-hour discharging ratio and PowerSouth's 110-MW plant in Alabama (1991) that can deliver full power output for up to 26 hours with 54 percent round trip efficiency.

Recent interest in energy storage has renewed CAES development projects including a $500 million, 317-MW project in Texas set to start in 2020—a venture between Dresser-Rand and Apex Compressed Air Energy Storage.[20] PG&E has received funding from the California Energy Commission for the study phase of a 300-MW, 10-hour project.[21] In New York, NYPA is in early research stages of a 9-MW, 4.5-hour CAES project that will include an above ground air storage system. If effective, this pilot could lead the way for the development of other CAES projects by eliminating the need for underground storage. Although there are siting limitations, estimated costs for CAES projects are competitive with other storage options, ranging from $1,188 to $1,709 per kW.

Due to geological limitations and the relatively limited commercial penetration of the technology, Platte River will not model CAES options in its 2020 IRP analysis.

Distributed generation

Distributed generation (DG) is defined as generation units that are smaller than traditional utility-scale power plants and are normally located at sub-transmission levels near the owner's point of use. DG programs typically focus on non-carbon generation, such as solar photovoltaics (PV), or on combined heat and power (CHP) resources. Generally, costs are higher for distributed generation applications than for large, central plants due to lost economies of scale and more complex and costly integration needs. DG units can be an important part of a microgrid that allows an end-user to disconnect from the utility grid during certain periods of time and may provide economic opportunities in the coming years through transactive markets.

Common residential distributed generation systems include[22]:

- Solar photovoltaic panels
- Small wind turbines
- Natural gas-fired fuel cells
- Emergency backup generators, usually fueled by gasoline or diesel fuel

Notably, the penetration of residential rooftop solar PV systems has been rapidly rising across the country due to federal, state and local subsidies as well as falling equipment costs and a rise in customer interest. Since 2005, rooftop solar has grown five-fold across the U.S.

Common commercial and industrial DG systems include[23]:

- Combined heat and power systems
- Solar photovoltaic panels
- Wind
- Hydropower
- Biomass combustion or cofiring
- Municipal solid waste incineration
- Fuel cells which convert natural gas, methane or hydrogen
- Reciprocating combustion engines, including backup generators

The most prominent form of generation used by commercial and industrial facilities is backup generation, but it is typically used for emergency backup capacity (rather than energy production) due to higher fuel costs and emissions permitting for non-emergency operation. The fastest growing form of generation among commercial and industrial customers has been solar. However,

the growth rate has been lower among this group of customers than among residential customers.

Generation technologies used for DG applications vary in commercial maturity and will continue to be evaluated by Platte River. The 2020 IRP will include specific assumptions for distributed generation estimated through a third-party analysis.

Distributed generation facts

- Solar PV is the most common form of distributed generation, with 100 GW of capacity added annually worldwide
- Backup generation is the most common form of distributed generation for commercial applications
- Distributed solar PV will continue to drive the need for more distributed storage

Distributed energy storage

Like the recent rapid expansions in the wind and solar industries, energy storage applications are expected to accelerate in the coming years due in large part to continued improvements in battery technology. Batteries located near generation and transmission will likely be a necessary resource in the long run to help manage the intermittency and unpredictability of non-carbon generation at the utility-scale level. At the distribution level, batteries will enable the development of smart grids and microgrids and will enhance the ability for customers to manage their own loads and capitalize on the value of their distributed energy resources.

Distributed energy storage facts

- Behind-the-meter batteries account for nearly two-thirds of recent storage additions in the U.S
- The storage market is expected to reach $4.5 billion by 2023, with distributed systems representing most of installed applications
- Two states—California and Hawaii—accounted for nearly three-fourths of 2018 residential storage installations

Distributed energy storage may be able to provide many benefits along the energy supply chain, including mitigation of grid congestion, provision of ancillary services, integration of non-carbon generation, deferral of capital investments for utility structures and power quality and reliability improvements. These benefits will depend on the utility's ability to directly control battery operation, or to indirectly influence it by effective rate signals to customers who own and operate their own batteries ("behind-the-meter"). In addition, the benefits and costs of batteries may depend upon where along the system batteries are located.

Many factors are driving the growth in distributed energy storage, including state incentives and changes in net metering tariffs. Combined with FERC Order 841, these industry shifts have helped to double the U.S. pipeline of projects to 33 gigawatts.[24]

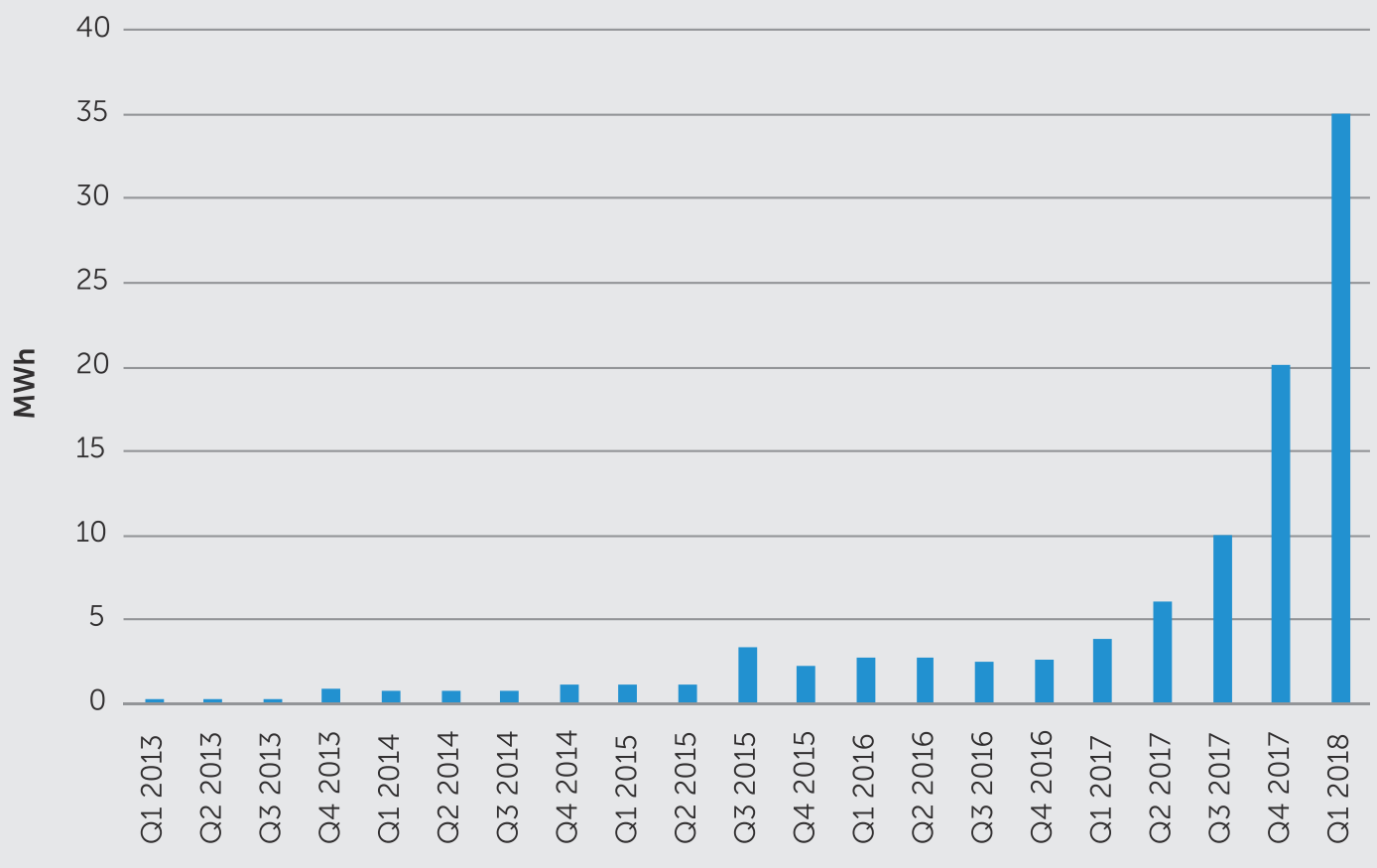
Significant recent events in distributed energy storage include:

- FERC Order 841-requires regional grid operators to develop market rules for energy storage to participate in the wholesale energy, capacity and ancillary services markets that recognize the physical and operational characteristics of the resource.
- Colorado SB18-009 establishes the right of consumers to install, interconnect and use energy storage systems on their property.
- California's Self-Generation Incentive Program promotes the installation of behind-the-meter energy technologies and is expected to fund 600 to 1,200 MW of battery storage by 2020.[25]

- Tesla has been contracted to install systems comprised of 5 kW solar panels and 13.5 kWh Powerwall 2 Li-ion batteries in 50,000 Australian homes over the next five years.
- Massachusetts recently adopted an energy storage mandate, and may incorporate alternative ownership models, leading the way for the development of distributed energy storage systems.

Platte River recognizes the importance that distributed energy storage systems will play in the evolution of its generation system and will include assumptions for storage in the 2020 IRP models.

Growth in residential energy storage deployments[26]



Energy efficiency

Energy efficiency (EE) refers to utility-sponsored initiatives to modify consumer demand for energy through various methods, such as financial incentives and behavioral change through education.[27] EE programs include rebates for higher-efficiency equipment, such as appliances, heating, ventilating, air conditioning (HVAC), lighting and motor systems. They also include rebates for refrigeration and building control modifications, and energy-efficient building design. Additionally, EE programs include energy assessments for buildings and "upstream" rebates to retailers selling energy-efficient lighting, such as LEDs. Such upstream rebates help retailers sell products at agreed-upon discounted prices.

Energy efficiency facts

- U.S. electric utilities spent $3.6 billion on energy efficiency customer incentives in 2016, or an average of $24 per customer
- 57 percent of organizations in the U.S plan to increase investment in energy efficiency in 2019
- Energy efficiency has the potential to significantly reduce CO_2 emissions

Energy efficiency has the capability to provide significant reductions in greenhouse gas emissions by reducing the need for power generation. The National Resources Defense Council states that residential energy efficiency can be the single-largest source of CO_2 reduction from a single intervention technique, followed by the electrification of transportation.[28]

Although there are no federal or state regulatory requirements to offer energy efficiency programs for municipal utilities or rural electric cooperatives in Colorado (including Platte River), some have established extensive energy efficiency programs on their own (including Platte River and its owner communities, Colorado Springs Utilities and Holy Cross Energy).[29] Some states recognize that energy efficiency has played a central role in the decarbonization in their regions, especially in California, where the emission equivalent of 1 million cars has been eliminated through energy efficiency programs alone.[30]

Platte River has a suite of existing EE programs and continues to make investments in cost-effective EE options. EE will be an important component of the 2020 IRP evaluation process.

Transformational technologies

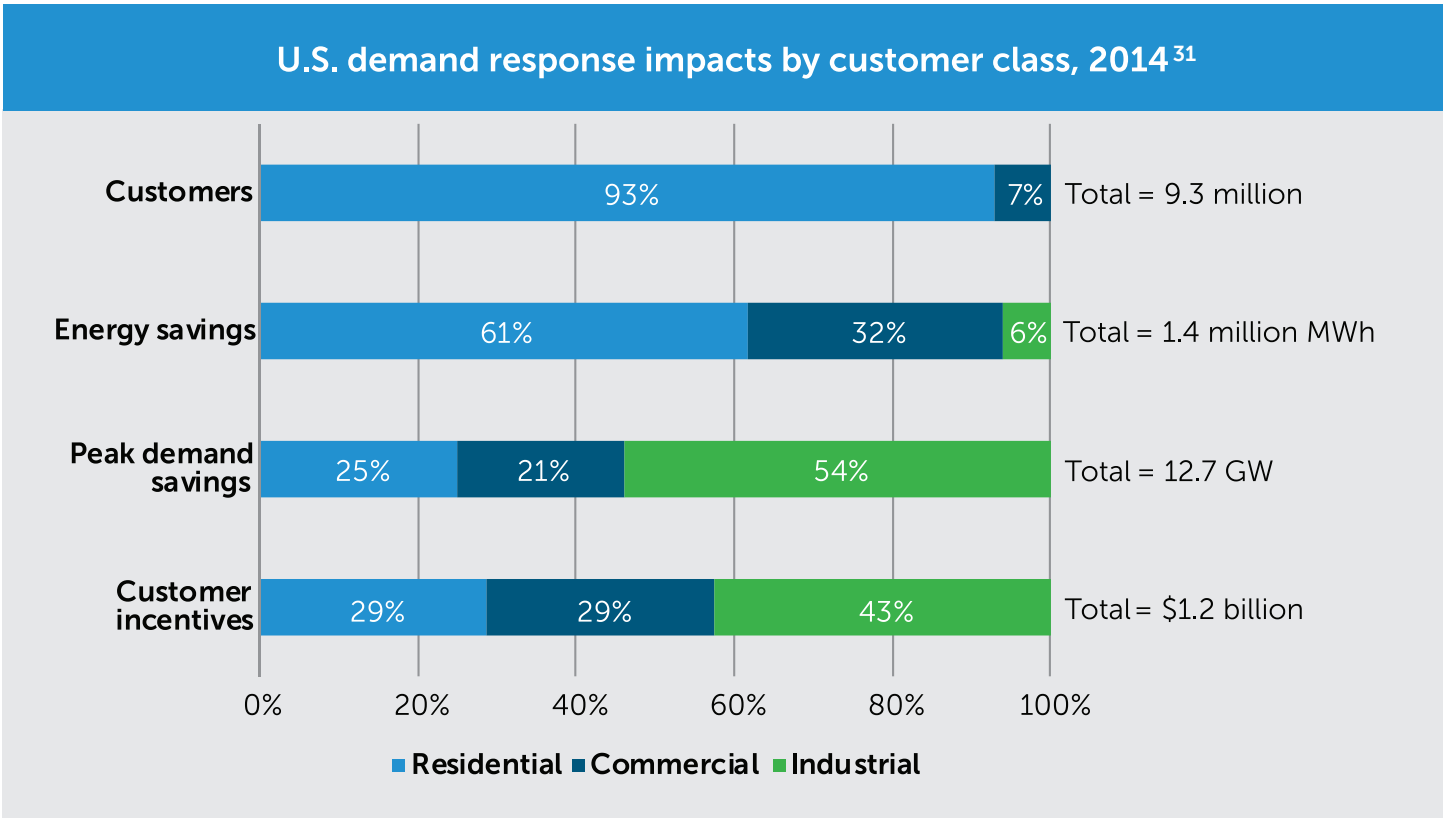
Demand response

Demand response (DR) refers to programs that seek to influence when customers use electricity to provide system benefits. Influence of customer behavior may be achieved using financial signals facilitated by communication and control technologies. DR tends to fall into one of two broad categories: price responsive or direct control load management. Price responsive DR relies on retail rates that are designed in part to influence when a customer uses energy. Ideally, these rates will reflect system costs and benefits. Customer responsiveness to such rates can be improved using technologies that provide automatic control of electric devices. Direct control load management refers to programs in which the utility controls selected loads with the customer's permission, typically in exchange for an incentive. When employed reliably and on a large scale, DR has the potential to provide firm capacity. This capacity can be used in a variety of ways for operational needs and can reduce the cost of providing electric service:

- **Capacity deferral:** Dispatching DR to reduce peak loads and avoid investment in generation, transmission or distribution capacity.
- **Economic dispatch:** Operating DR to capitalize on prevailing market prices to avoid purchases or enable a market sale of energy.
- **Non-carbon resource integration / flex reserves:** Operating DR to support intermittent resources, such as wind or solar, when they experience a large drop in output.
- **Supplemental reserves:** Maintaining DR to provide reserves required by the area's balancing authority to provide spare, rapid-responding capacity in the event of system emergencies.
- **Smart grid support:** Operating DR to manage loads and overall energy use when incorporated as part of a smart grid system.

Demand response facts

- Nearly 9.3 million customers in the U.S. participated in demand response programs in 2014
- Demand response has limited potential for CO_2 mitigation on its own but can make loads more responsive, facilitating the ability to integrate more non-dispatchable, non-emitting, non-carbon resources



DR has the potential to provide Platte River with firm capacity that can be used in a variety of ways for operational needs and to reduce the cost of providing electric service. Based on a 2015 assessment of DR costs and benefits, Platte River estimates that 19 to 49 MW of demand response can be achieved in the four municipalities. Platte River will include an updated DR estimate in its 2020 IRP modeling cases.

Transformational technologies

Electric vehicles

The market for electric vehicles (EVs) is evolving rapidly. Many factors are contributing to the increased interest in EVs, including concerns over greenhouse gas emissions, the unpredictability of fuel prices and overall interest from consumers in the emerging technology.

Tesla is likely the most prominent of the EV producers in the U.S. and has received accolades from auto reviewers for its electric vehicles. Tesla is working to bring affordable EVs to market and has invested in a battery production facility known as the "Gigafactory" to provide it with a competitive advantage over other EV producers. However, traditional auto manufacturers have more production experience, and may be able to bring EVs to market more affordably in the future.

The growing desire for EV options from consumers has spurred many auto manufacturers to make long term commitments for up to 100 percent electric vehicle production. These manufacturers include Volkswagen, Nissan and Volvo. Domestically, Ford has proclaimed that it is "all-in" on vehicle electrification and will offer 40 new hybrid and all-electric vehicles by 2022. The emergence of autonomous vehicles paired with EV technology has the potential to radically transform the transport industry.

EVs as mainstream vehicle options still have obstacles to navigate, including cost and driving distance. Although battery technology continues to improve (density is growing at 5 to 7 percent per year[32]), traditional gas-powered vehicles still appeal to customers who want to have longer driving ranges without having to recharge.

EVs provide a significant amount of potential benefit for utilities and their customers. Of interest to the utility industry will be gauging the growth of EV charging needs, particularly as battery sizes and range increase, and managing the supply of energy to this growing segment of the grid. EVs can also provide storage or demand response services for utilities to optimize their energy positions—particularly excess wind power that can occur during night hours when customers are likely to charge their vehicles. This represents an opportunity for the development of "transactive markets" that can allow customers to optimize the value of their EVs as distributed energy resources.

Platte River includes electric vehicles as a crucial part of its demand forecasting process for the 2020 IRP and is piloting the state's first smart EV charging study to measure charging patterns of EV owners as well as the increased power consumption that may arise as ownership increases. The study enables participants to proactively manage their charging while providing valuable data to Platte River. To gain as much data as possible, Platte River is encouraging EV owners to purchase WiFi-enabled chargers by providing rebates for qualified charging systems.

The forecasts for EV growth nationwide vary widely, but the market is generally optimistic. A Bloomberg forecast, based on an outlook from the U.S. Energy Information Administration, estimates that EV sales will grow from about 2 percent of total light duty vehicle sales to 55 percent in 2040. A portion of this sales growth will stem from a structural shift that is expected between 2025 and 2030, when EVs are anticipated to become cheaper to produce than gasoline-powered vehicles.

Electric vehicle facts

- EVs are on pace to exceed 1.6 million in the U.S. in 2018, and about 2,500 in Platte River's service area
- Penetration of EVs is higher in northern Colorado than in most other areas of the country

Transformational technologies

Combined heat and power

Combined heat and power (CHP), also known as co-generation, refers to a generation system that uses a fuel—typically natural gas or biofuel—to generate electricity and employs a heat recovery system to capture heat from the combustion system's exhaust. The exhaust heat drives a secondary process, such as making steam or hot water. Units with CHP have higher overall efficiency than power generation units that do not use the waste heat. CHP system efficiencies can be roughly double the efficiency of the underlying simple cycle generation resources.

CHP has traditionally been implemented by larger industrial users with high steam and power demands (chemicals, paper, refining), as well as by smaller institutional applications (universities and hospitals).[33] CHP systems typically have a use for the power and waste heat at least 75 percent of the hours in any given year.

Combined heat and power facts

- CHP accounts for nearly 7 percent of all U.S. power generation
- Combined heat and power can fill an important niche in energy supply systems
- CHP can help reduce but not eliminate CO_2 emissions

The technology choice for a CHP facility depends on available fuel and the amount of generating capacity needed. Reciprocating internal combustion engines are widely used in smaller applications (less than 10 MW). Larger systems use industrial boilers, simple cycle steam turbines, gas turbines and combined cycle systems that are similar in design to those used specifically in power production.[34]

While the technologies and statistics discussed above often refer to large utility-scale projects, a sizable portion of current CHP research is devoted to small-scale CHP, particularly microturbines—compact, lightweight units of 25 to 500 kW in capacity that could be used in homes and other buildings.

Twenty-three states recognize CHP in one form or another as part of their non-carbon portfolio standards or energy efficiency resource standards. Several states, including California, New York, Massachusetts, New Jersey and North Carolina, have initiated specific incentive programs for CHP.[35]

Platte River's 2020 IRP will include an evaluation of the potential for CHP as a distributed energy resource within the member communities.

Smart grid

A smart grid is a combination of many of the distributed technologies described elsewhere in this document with advanced metering infrastructure, or AMI. AMI is an integrated system of smart (or advanced) electric meters, communications networks and data management systems that enable energy-consumption data to be shared between utilities and customers. AMI may also be combined with new electric rate structures, like time-of-use rates or real-time pricing, to provide more accurate price signals to customers. When combined with distributed energy resources like solar generation and demand response programs, AMI provides a better way to match real-time generation, transmission and distribution to loads for improved reliability, resource use and integration. Effective use of a smart grid can increase overall power system efficiency and defer the need for new generation.

Smart grid concepts evolved in response to the power outage in the Eastern U.S. in 2003 and rely on electronic controls to support operators in the power system management decision process. Intelligent communication systems can control customer loads, switch power transmission and distribution and modulate generation resources. Smart grid concepts are also quickly evolving to provide greater controllability and reliability at the distribution level. Eventually, many household appliances and devices may be connected to a smart grid and managed jointly by the utility and its customers in a market-based environment.

Components of a smart grid can include any of the following:

- Computers
- Software
- Advanced meters
- Battery storage
- Rooftop solar
- Control relays
- Automated switches and circuit breakers
- Appliances that can be modulated or cycled
- In-home or internet-based display of customer's current and historical energy consumption

Current directions in smart grid applications include:

- Vehicle-to-grid (V2G) applications: applications that involve bidirectional flow from an electric vehicle's battery pack to the grid to enhance system stability and take advantage of market opportunities. V2G pilots have been completed and show some promise for this application, but questions remain regarding the effect on battery life and warranties and customers' willingness to submit their EV battery to utility use.

- Grid-interactive water heaters: controls embedded in water heaters that permit bidirectional temperature regulation, allowing utilities to control an aggregated fleet of water heaters as a flexible energy storage source.
- Transactive energy markets: With transactive, peer-to-peer energy systems, customers can respond to local conditions on the distribution grid to make real-time economic decisions with their DERs, such as distributed solar or storage. The real-time nature of transactive energy markets means that customers do not have to rely on subsidies to create value with their DERs.

Smart grid technologies are rapidly evolving and will play a critical role in the utility of the future. Platte River will continue to evaluate the implication that smart grids will have for ongoing operations. The 2020 IRP does not include assumptions for smart grid capabilities.

Smart grid facts

- Through the 2009 American Recovery and Reinvestment Act, $4.5 billion was committed to smart grid initiatives to modernize the U.S. power grid

Microgrid

Microgrids are a combination of distributed energy resources that can operate in "grid-connected" mode or autonomously in "island mode". In island mode, microgrids are capable of balancing local distributed generation and demand by using controls, distributed storage and demand response to maintain stable service without grid support. Microgrids can be comprised of more than one generation technology and include non-carbon energy with parallel onsite power generation that can be dispatched by the owner. For example, a microgrid can contain PVs and a power generation unit, such as a natural gas-fired CHP unit or a microturbine. A microgrid can bundle distributed energy resources with software solutions, such as DERMS, with advanced power electronics and microgrid controllers.

Key benefits of microgrids include the potential for improved reliability and resiliency, particularly for customers that are intolerant of outages or where risk of extended outages is high. Microgrids may be most effective when a customer's desire for higher reliability and resiliency can be combined with a utility's ability to defer or avoid generation, transmission and distribution investment. In such cases, responsibility for owning and operating the microgrid and allocation of the costs, benefits and risks of the project among its participants will require attention.

Microgrid facts

- The Fort Collins Microgrid (part of the larger Fort Collins Zero Energy District) is a regional example of a microgrid demonstration project
- New Belgium Brewery, InteGrid Labs, City of Fort Collins, Larimer County and Colorado State University are part of the Fort Collins Microgrid

In September 2017, the DOE announced $50 million in grid resilience funding, of which $12 million will go toward innovation on networked microgrids. Most funding of microgrids has come from the state level with over $200 million in funding since 2012. Colorado has not announced state funding specific to microgrid development.

As of 2017, the U.S. has over 3 GW of microgrid operational capacity that is largely fossil fuel driven, with 12 percent of capacity from non-carbon sources. However, non-carbon sources are expected to account for 42 percent of the capacity for microgrid development in the U.S. by 2027. [36] Colorado has five operational microgrid projects with roughly 10 MW of total capacity.

Like smart grids technology, microgrid technology is rapidly advancing, and will play a critical role in the utility of the future. Platte River will continue to evaluate the implication that microgrid applications will have for ongoing operations. The 2020 IRP does not include assumptions for microgrid capabilities but will include assumptions for aggregate distributed energy resources.

Transformational technologies

Natural gas simple cycle combustion turbines

Natural gas-fired combustion turbines (CTs) are rotary engines that ignite an air-gas mixture in a combustion chamber, creating a gas flow directed at the blades of a turbine which turn a shaft. The shaft is connected to an electrical generator that produces power.

Overall, the U.S. has over 138 GW of CT summer capacity with another 3 GW of capacity under construction. Despite the significant amount of total capacity, CTs produced just 1.5 percent of total U.S. generation in 2017.[37] The high operating costs and low efficiency of CTs (around 40 percent) typically keep annual capacity factors below 10 percent and limit their primary use to peaking purposes. However, CTs start up quickly and play a key role in grid stability, providing reserve capacity and ancillary services. The responsiveness of CTs makes them viable candidates to manage intermittent resources on a broad scale.

Simple cycle combustion turbine facts

- Low capital-cost resource provides reliability and ancillary services
- Primarily used as a resource to meet peaking needs
- Improvements in startup time and ramp rates can help provide stability with the growth in non-dispatchable energy

CTs range in capacity from roughly less than 10 MW to more than 400 MW, depending on application. Typically, CTs are classified as larger frame units (80 to 400 MW) and smaller aeroderivative CTs (4 to 100 MW).

Historically, frame CTs have been used as peaking resources for utilities; whereas, aeroderivative CTs have been used primarily for industrial and jet aircraft applications. Over the last decade, large frame CT generating efficiency has improved due to innovations across the industry. Newer frame CT models are designed for higher capacity (300 to 400 MW) and increased efficiency (heat rates of 8,000 to 8,500 Btu/kWh). Aeroderivative CTs have a wider range of efficiency (heat rates between 8,000 to 10,500 Btu/kWh) and are less cost-effective on a $/kW basis.

However, with an influx of intermittent energy resources and lower growth in load demand, the need for more flexible resources has brought increased interest in aeroderivative CT technologies as a peaking resource option. Newer models are designed for faster startup, higher ramp rates, and integration with other technologies. In 2017, Southern California Edison (SCE) implemented the first CT-plus battery hybrid technology. In this case, integrating 10 MW of lithium-ion batteries with the 50-MW aeroderivative CT with advanced control systems is expected to improve the plant's ability to provide ancillary services, reduce startup times and reduce plant greenhouse gas emissions by up to 60 percent.[38]

The Energy Information Administration's 2018 Annual Energy Outlook estimates a 1.3 percent annual growth rate in installed CT capacity through 2040. The Colorado Air Quality Control Commission traditionally adopts federal New Source Performance Standards (NSPS) which have set emissions targets in non-attainment zones determined by the EPA. Pending zoning requirements, simple cycle CTs may need to include emissions reduction technology, such as selective catalytic reactors (SCRs), which could increase costs.[39] Cost for CTs vary depending on capacity, but typically fall within a range of $700 to $1,732 per kW.

The 2020 IRP will include the consideration of simple cycle CT options as a potential flexible resource to strengthen system reliability.

Transformational technologies

Natural gas combined cycle combustion turbines

Natural gas combined cycle plants (CCs) pair CTs with steam turbines to reuse waste heat from the combustion process and generate more electricity per unit of fuel. In a CC application, natural gas is combusted in a CT, generating electricity and producing high temperature exhaust gas. Instead of venting the exhaust, the waste heat passes through a heat recovery steam generator (HRSG), creating high pressure steam that drives the paired steam turbine. There are many CC plant options available with capacities ranging from approximately 60 to 1,000 MW depending on configuration (multiple CTs can be combined with a steam turbine).

CCs provide a reliable source of capacity and energy for relatively lower total plant capital investment. CCs have slower ramp rates than simple cycle CTs, which can make them less advantageous for integration with intermittent resources in certain situations. However, advanced CCs now achieve operating efficiencies above 62 percent, compared to conventional generation technologies (including simple cycle CTs) that range from 30 to 44 percent. With the recent low cost of natural gas, CCs have been the preferred replacement options for less efficient, higher-emission coal resources across the U.S.

Favorable capital costs, operational flexibility, lower CO_2 emissions, and high plant efficiencies have allowed CCs to expand their role in power generation, serving as either baseload or intermediate generators. CCs are expected to be the dominant fossil fuel generation option over the next 20 years under current gas price forecasts and tightening emissions standards (particularly for CO_2). CCs provide over 270 GW of capacity in the U.S. and produced power at an average capacity factor of 53 percent nationwide in 2017.

Combined cycle combustion turbine facts

- Efficiencies at new plants can exceed 62 percent
- Flexibility to operate as baseload or intermediate resource
- Relatively low capital costs and gas prices are driving the growth in CC installations across the U.S.

Platte River's 2020 IRP planning options will include combined cycle configurations as a transitional technology toward a non-carbon future.

Natural gas reciprocating engines

Reciprocating internal combustion engines (RICE) operate under the same principle as automobile engines where an air-fuel mix is combusted inside cylinders to drive a shaft. In the production of electricity, this shaft is connected to an electrical generator.

A RICE plant is typically constructed of multiple engines, each ranging in size from approximately 2 to 18 MW. Most large RICE plants are fueled with natural gas only; however, some systems may be fired using a combination of natural gas and fuel oil.

A RICE plant plays a similar role to a small CT plant. Typically, construction and operation and maintenance (O&M) costs for a small RICE plant are higher than a simple cycle CT plant ($1,124 to $1,599 per kW). However, RICE units typically operate more efficiently than smaller CTs, especially when operating below full capacity. Some energy providers view the installation of RICE plants as a good fit for regions with high wind or other intermittent energy resources. RICE units have higher partial load efficiencies than CTs and may provide enough operational benefits to overcome the higher up-front capital costs and annual O&M costs. For these reasons, RICE power plants have gained popularity in recent years.

As a transitional measure to a non-carbon future, Platte River's 2020 IRP options will include RICE plants in various configurations. RICE units are smaller than CTs or CCs and therefore more closely align with Platte River's load-stepping requirements.

Distributed energy storage facts

- Engine sizes of 2 to 18 MW make it easy to construct a wide range of power plant sizes
- Higher up-front capital costs, and annual O&M costs than CTs, but provide higher average and partial load efficiencies
- Engines provide fast response

Conventional and other technologies

Nuclear

Nuclear power is produced from a fission reaction that generates heat and radiation. The heat produces pressurized steam, which then generates power via a steam turbine. Uranium typically fuels a thermal nuclear reactor. During nuclear fission, the fuel's "atoms split apart, releasing energy and producing heat as they separate into smaller atoms. The process repeats itself through a fully controlled chain reaction."[40]

Conventional nuclear reactor sizes are most often in the 900 or 1,200 MW range. Of the 99 U.S. nuclear reactors currently in operation, all but one became operational from 1969 to 1996, and all started construction prior to 1979.[41] The Three Mile Island accident in 1979 and changing market economics led to over 100 cancellations in reactor orders, and a slowdown in the growth of nuclear power.

With growing concern over CO_2 emissions, interest in nuclear power revived in the 2000s. Economic challenges and Japan's 2011 Fukushima accident led to renewed opposition, closures of existing plants and cancellations of planned projects in the U.S. Reactors in California, Florida and Wisconsin closed in 2013, mostly due to economic performance and safety concerns. Additional reactors in Vermont and Nebraska closed in 2014 and 2016, respectively. As of May 2018, nine nuclear power plants with a combined 11 GW of capacity have announced plans to retire by 2025, and 24 plants totaling 32.5 GW of capacity are either scheduled to close or don't make enough money to cover their operating costs.[42]

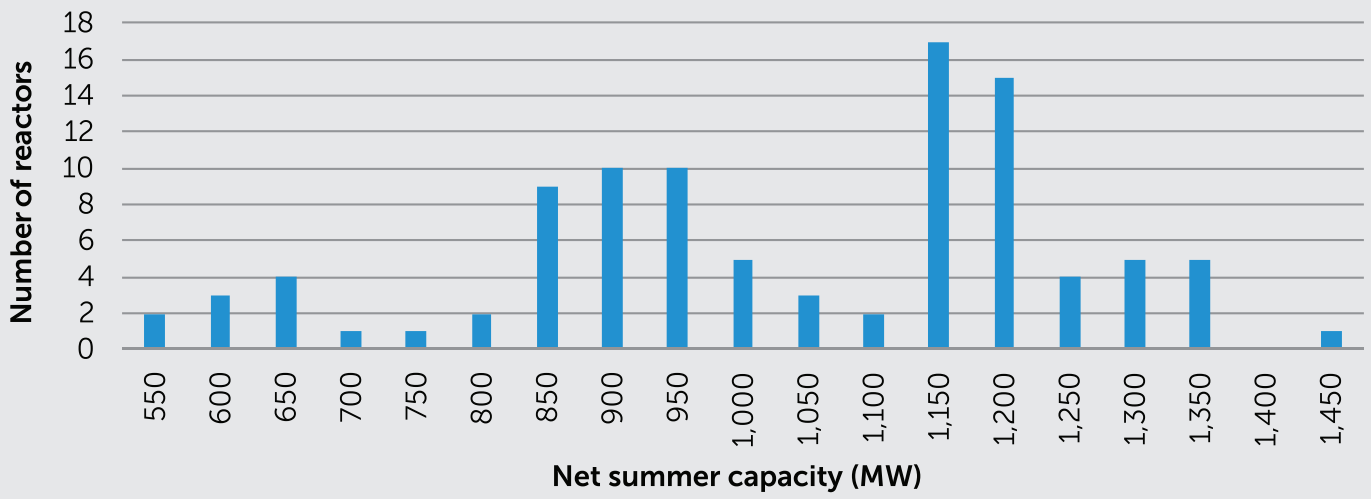
Nevertheless, in 2016, Tennessee Valley Authority's Watts Bar Unit 2 was the first new nuclear reactor to enter service in the U.S. in two decades. Four additional nuclear units began construction in 2013—Georgia Power's Vogtle 3 and 4, and SCANA and Santee Cooper's V.C. Summer 2 and 3—but development of the Summer plant was halted in July 2017 due to delays, cost overruns and the bankruptcy of the engineering contractor, Westinghouse.

Colorado's only nuclear power plant, the 336-MW Fort Saint Vrain Generating Station, originally operated from 1979 to 1989. Although technically and commercially viable, the effects of an economic downturn led to the early closure of the facility. The reactor was fully decommissioned by 1992, followed by conversion to a natural gas combined cycle plant in 1996.

The main challenges for additional large-scale nuclear development include capital costs, permitting and construction time and public opposition. Estimated capital costs for new nuclear reactors are estimated to range from $6,180 to $11,800 per kW. U.S. Nuclear Regulatory Commission permits can take up to eight years for approval, plus up to eight more years for plant construction.

Platte River's 2020 IRP portfolios do not include a traditional nuclear generation primarily due to reactor sizes, high capital costs and long lead times.

Number of U.S. nuclear reactors by capacity



Conventional and other technologies

Small modular nuclear reactors

Small modular reactor (SMR) technology was initially developed for naval and shipping purposes and is being adapted for utility-scale generation; however, it has not yet demonstrated commercial viability in the U.S. SMRs can be scaled to meet load needs and can be delivered fully constructed. Much of the key equipment for SMRs can be manufactured off-site, reducing plant construction time by 40 percent or more. They also provide potential improvements in safety from their underground containment designs and passive cooling systems. However, underground installations could make maintenance more challenging during a malfunction.[43]

Small modular nuclear reactor facts

- Reactor sizes range from 10 to 300 MW
- Modularity is expected to lower costs, reduce construction duration, and allow for scalability
- No units (for power) are in operation or under construction in the U.S.

SMRs range in size from 10 to 300 MW compared to roughly 900 to 1,200 MW for conventional nuclear reactors. Some SMRs, by virtue of their smaller size and other operational features, can offer greater capability to conduct load following operations than larger nuclear power plants. An SMR could be coupled with an intermittent source of non-carbon energy, such as a wind farm, to meet the typical daily rise and fall in electricity demand.

SMR generation varies by coolant technologies, including light water designs, fast reactors, heavy water reactors and molten salt reactors. SMR light water reactors are smaller versions of conventional, pressurized water reactors. Water is a coolant and moderator that regulates the speed of the neutrons. In fast reactors, plutonium is typically the fuel while sodium is typically the coolant. This allows for neutrons to move more rapidly during fission, increasing the energy yield from a single fuel charge within a reactor.[44] The result is longer refueling intervals, decreased volumes of fuel to be mined, transported, and processed and less radioactive waste. Heavy water (D2O), gas or molten salt can also be used as a reactor coolant.

NuScale Power LLC is aiming to put an SMR into commercial operation in Utah, comprised of a dozen 50 MW reactors. It is the only company with an SMR design certification pending before the U.S. Nuclear Regulatory Commission (NRC). The NRC is also reviewing two SMR pre-applications from BWXT mPower, Inc. and SMR Inventec, LLC. TVA has submitted an early site permit application for an SMR facility on the Clinch River near Oak Ridge, Tennessee.[45] SMR capital costs are not well known, but prototype SMR capital cost estimates range from $5,260 to $9,843 per kW. SMRs have appeal as potential future non-carbon resources to complement renewable resources. Platte River concluded that the technology should not be modeled in the 2020 IRP due to expected cost, regulatory uncertainty and an unproven track record.

Coal

Until 2016, coal was the primary generation resource in the U.S. However, in 2016, low natural gas prices and regulatory-induced coal retirements caused natural gas power production to surpass that of coal. In 2018, coal is expected to provide 28.7 percent of U.S. electricity generation compared to 33.6 percent from natural gas.[46] Federal or state regulations to reduce CO_2 emissions will likely decrease the amount of energy produced from coal in the future. While federal plans for curbing CO_2 emissions are currently on hold, the State of Colorado issued an executive order in support of a 35 percent reduction of 2012 CO_2 emissions from the electricity sector by 2030, as compared to 2012.[47]

Coal generation remains competitive relative to baseload technologies on an unsubsidized levelized cost of energy (LCOE) basis, ranging from $60 to $143/MWh.[48] There are three main coal mining basins in the US—Central Appalachian Basin (CAPP), Illinois Basin (ILB), and Powder River Basin (PRB). Coal is typically delivered to power plants via rail (least cost), barge, or truck (most costly).

At the plant, coal is pulverized into a powder which is used as a fuel source in a boiler to produce steam. The steam is fed into a turbine attached by a shaft to a generator. The turbine turns the generator to produce electricity.

Because of fuel cost advantages, plant mechanics and equipment design, coal plants are best used as baseload resources and are difficult to cycle to meet frequent increasing or decreasing demand.

Most of Platte River's energy comes from coal, which was about 62 percent of power generated in calendar year 2018. No additional coal plants are being considered in Platte River's 2020 IRP.

Coal facts

- Reliable and baseload generation with on-site fuel supply
- Coal is the world's most abundant fossil fuel and one of the cheapest, averaging $2.11/MMBtu in 2016 vs. $2.87/MMBtu for natural gas and $5.24/MMBtu for oil

Conventional and other technologies

Integrated gasification combined cycle

Integrated gasification and combined cycle plants (IGCC) use coal (most common) or other carbon-based feedstock as fuel.[49] Major equipment in an IGCC plant includes a gasifier in addition to the traditional combined cycle generation components. In the IGCC process, coal is transformed into synthesis gas (syngas) under pressure and temperature. The syngas is processed to remove impurities, such as sulfur and particulates. The cleaned syngas is then fired in a combustion turbine that drives a generator to produce electricity. A steam turbine reclaims lost heat in the exhaust.

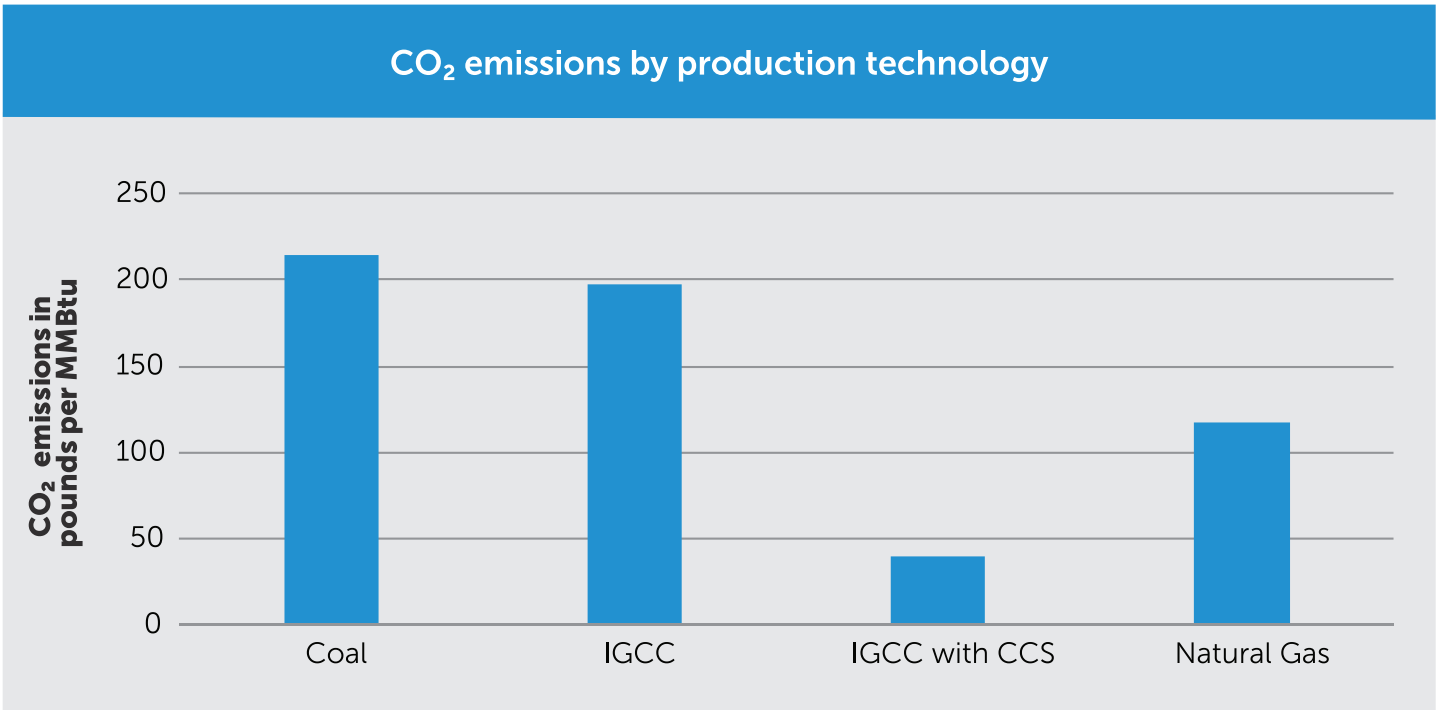
IGCC plants have the capability to operate at efficiency rates that are as high as 43 percent vs. 35 percent for conventional coal plants.[50] This increased efficiency reduces CO_2 emissions by 10 to 20 percent over conventional coal plants. IGCC plants offer several other advantages over conventional coal plants. A major advantage is the ability to more easily remove SO2, NOx mercury and particulates prior to the combustion process. Additionally, the ability to integrate carbon capture and storage (CCS) technology can lead to CO_2 emission reductions of more than 80 percent relative to conventional coal plants. The chart on the right shows comparative CO_2 emissions for various coal plant technologies. In addition to CO_2 emission reductions, IGCC plants use 20 to 50 percent less water than conventional coal plants.[51] However, when CCS is added, water consumption increases by 50 percent relative to conventional coal plants.

Integrated gasification combined cycle facts

- IGCC efficiencies can provide lower CO_2 emissions than conventional coal plants
- High capital costs and complex plant design are barriers to entry for IGCC

The Department of Energy's original Clean Coal Technology Program (1986-1993) and the Clean Coal Power Initiative (CPPI) have been key drivers of IGCC projects in the U.S. Of the three projects commissioned in the U.S. as part of the CPPI, two are still in operation.[52] The Hydrogen Energy California Project and the Summit Texas Clean Energy Project are both 400-MW IGCC plants designed to enhance oil recovery. Each of the plants captures approximately 90 percent of CO_2 emitted. The Kemper County Energy Facility in Mississippi was originally designed to be an 830-MW IGCC to enhance oil recovery. After significant cost overruns, Southern Company announced the suspension of startup and operations involving the lignite gasification portion of the project. The combined cycle plant will continue to operate using natural gas. Changes to the project economics were primarily driven by the dramatic decrease (more than 70 percent) in the long-term price forecast for natural gas since the project was approved in 2010.

IGCC technology currently remains a speculative energy technology, with significant government subsidization required. Capital costs for coal IGCC plants range from $1,700 to $4,000 per kW. The expected high capital costs, plant complexity and low availability factors led Platte River to exclude IGCCs in its 2020 IRP.



Conventional and other technologies

Carbon capture and storage

Carbon capture and storage (CCS) is the process of collecting CO_2 from fossil fuel energy production, and then transporting the CO_2 to an underground storage location to prevent its entrance into the atmosphere. Captured CO_2 is often used for enhanced oil recovery (EOR) to improve CCS project economics. CCS technology can be incorporated into new or existing fossil fuel plants but can significantly add to capital investments—estimated to be 40 percent higher than the same plant without CCS. Moreover, additional fuel must be burned in the process of carbon capture (called the parasitic load), which reduces the benefit of designed CO_2 reduction.

There are three primary methods to perform carbon capture: (1) post-combustion, which involves sending the power plant's emissions through an absorption process where a solvent captures up to 90 percent of the CO_2. The recovered CO_2 goes through a regenerator that strips the CO_2 from the solvent while the remaining emissions (primarily nitrogen) are vented to the atmosphere; (2) pre-combustion, where the fossil fuel is turned into syngas consisting of relatively pure hydrogen and CO_2; and (3) oxyfuel combustion, in which the fossil fuel is burned in pure oxygen instead of air, resulting in the capture of nearly pure CO_2.

Carbon capture and storage facts

- CCS could play a larger role if CO_2 regulations or a carbon price are implemented
- High capital costs are preventing widespread adoption

In a conventional coal or natural gas plant, post-combustion CCS captures CO_2 from the exhaust gases. Chemical solvents or other filtration separation techniques are used to absorb CO_2 from the exhaust which is heated to separate the CO_2 for storage. These post-combustion methods are energy intensive and expensive to implement. NRG Energy's $1 billion Petra Nova project is a post-combustion CCS retrofit of an existing coal facility and one of only two operating power plants in the world with CCS.[53] Petra Nova captures CO_2 from a 240-MW slipstream of flue gas from WA Parish Unit 8 and pipes it 82 miles for use in enhanced oil recovery (EOR).

In an IGCC plant with CCS, CO_2 is removed during pre-combustion by converting coal or other fossil fuels to syngas. The syngas reacts to produce a H2 and CO_2-rich syngas mixture. The CO_2 concentration in this mixture ranges from 15 to 50 percent and can be captured and stored. However, the high cost of IGCC with CCS is the biggest obstacle to industrial viability and requires a carbon price or regulatory framework to provide development incentives. The flagship IGCC with CCS demonstration plant, the 582-MW Kemper project in Mississippi, was downgraded in 2017 to only a combined cycle natural gas plant due to a tripling in costs to $7.5 billion.

Oxyfuel combustion CCS uses pure oxygen in place of air to support combustion. The resulting flue gas is mostly CO_2 and water vapor, from which the CO_2 can easily be captured. The challenge is that oxygen must first be extracted from air, which is both energy intensive and expensive.

Regardless of capture method, sequestered CO_2 can be transported by pipeline, road tanker or ship to be used for industrial purposes like EOR or permanently stored underground. Permanent storage of CO_2 generally involves injecting the gas into rock formations one mile or more underground. Enough experience does not exist to determine if storage sites can effectively contain the CO_2 without leakage. Until specific incentives are available, or costs begin to fall for CCS, the only projects developed will likely be for pilot or demonstration purposes.

Platte River's 2020 IRP portfolio options do not include carbon capture and storage.

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