CHARACTERIZATIONS OF SUPPLY SIDE OPTIONS

FINAL REPORT

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Table of Contents

LIST OF TABLES

LIST OF FIGURES

Acronym List

AA-CAES	Advanced Adiabatic Compressed Air Energy Storage
A-CAES	Advanced Compressed Air Energy Storage
ARDP	Advanced Reactor Demonstration Project
AWE	Alkaline Water Electrolysis
BESS	Battery Energy Storage System
BETO	Bioenergy Technologies Office
BOP	Balance-of-Plant
Btu/kWh	British Thermal Units per Kilowatt-Hour
Btu/scf	British Thermal Unit per Standard Cubic Feet
BWR	Boiling Water Reactor
CAES	Compressed Air Energy Storage
CCS	Carbon Capture and Sequestration
CCUS	Carbon Capture Utilization and Sequestration
CNSC	Canadian Nuclear Safety Commission
CP	Construction Permit
CSP	Concentrating Solar Power
CT	Combustion Turbine
CtF	Cycles-to-Failure
CTG	Combustion Turbine Generator
DLE	Dry Low Emissions
DoD	Depth of Discharge
DOE	Department of Energy
EHPP	Elk Hills Power Plant
EIA	Energy Information Administration
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
EPRI	Electric Power Research Institute
ESS	Energy Storage System
FCG	Fuel Cell Generator
FEED	Front-End Engineering Design
FOAK	First-of-a-Kind
FOG	Fats, Oils, and Greases
GE	General Electric
GGE	Gasoline Equivalent
GHG	Greenhouse Gas

H_2	Hydrogen
HALEU	High-Assay Low-Enriched Uranium
HP	High Pressure
HPC	High-Pressure Compressor
HPT	High-Pressure Turbine
HRSG	Heat Recovery Steam Generator
IDC	Interest During Construction
IP	Intermediate-Pressure
IPT	Intermediate Pressure Turbine
IRA	Inflation Reduction Act
KNO3	Potassium Nitrate
kW	Kilowatt
kWe	Kilowatt Electric
LAES	Liquid Air Energy Storage (N_2+O_2+other)
LCOS	Levelized Cost of Storage
LDES	Long Duration Energy Storage
LFG	Landfill Gas
LFP	Lithium Iron Phosphate, LIB
LHV	Lower Heating Values
LLWR	Large Light Water Reactor
LOCA	Loss-Of-Coolant Accidents
LP	Low Pressure
LPC	Low-Pressure Compressor
LPT	Low-Pressure Turbine
LWR	Light Water Reactor
MCFC	Molten Carbonate Fuel Cells
MFC	Microbial Fuel Cells
mg/kg	Milligram Per Kilogram
MMBtu	Million British Thermal Units
MMcfd	Million Cubic Feet Per Day
MSW	Municipal Solid Waste
MW	Megawatt
Mwe	Megawatt Electric – One million watts of electric capacity
MWh	Megawatt-Hour
MWth	Megawatt thermal; overall power of a nuclear reactor in megawatt
NaS	Sodium-Sulfur
$NaNO_3$	Sodium Nitrate

Nox	Nitrogen Oxide
NPM	NuScale Power Module™
NTP	Non-Thermal Plasma
O&M	Operations and Maintenance
OEM	Original Equipment Manufacturer
PAFC	Phosphoric Acid Fuel Cells
PEM	Proton Exchange Membrane
PHES	Pumped Heat Energy Storage
Platte River	Platte River Power Authority
ppm	Parts per Million
ppmvd	Parts per Million Volumetric Dry
PRPA	Platte River Power Authority
PSA	Pressure Swing Adsorption
PSH	Pumped Storage Hydropower
psig	Pounds per Square Inch Gauge
PWR	Pressurized Water Reactor
RFS	Renewable Fuel Standard
RICE	Reciprocating Internal Combustion Engine
RNG	Renewable Natural Gas
RTE	Round Trip Efficiency
SAC	Single Annular Combustor
SCC	Stress Corrosion Cracking
SCR	Selective Catalytic Reduction
SLR	Subsequent License Renewal
SMES	Superconducting Magnetic Energy Storage
SMR	Small Modular Reactor
SNG	Synthetic Natural Gas
SO_2	Sulfur Dioxide
SOC	State-of-Charge
SOFC	Solid Oxide Fuel Cells
SSO	Supply-Side Option
TEG	Triethylene Glycol
TES	Thermal Energy Storage
TPD	Tons per Day
TRL	Technology Readiness Levels
UPS	Universal Power Supply
USD	United States dollars

VDR	Vendor Design Review
WWTP	Wastewater Treatment Plant

1.0 Executive Summary

Black & Veatch was engaged by Platte River Power Authority (PRPA) to conduct an engineering study on power generation, energy storage, and low or no carbon fuel technologies to assist PRPA in proactively working towards the goal of 100 percent noncarbon energy mix goal by 2030. This study screened available technologies and assessed their availability and suitability for PRPA to meet its noncarbon energy goals.

This study included three tasks. Task 1 covers the landscape of dispatchable power generation technologies, Task 2 covers the landscape of long duration energy storage (LDES) technologies, and Task 3 covers low or no carbon fuels and carbon sequestration technologies. The purpose of this study was to recommend suitable options for commercial operation in 2028 for Platte River to fulfill the requirements of about 170 MW of generator capacity. Platte River's suitability criteria includes high reliability, relatively lower costs, operational flexibility to complement intermittent renewables under operations at an expected capacity factor around or under 20 percent; with 250 or more starts per year. The technologies must be commercially viable and proven with at least a few utilities having installed the technology and have experience operating the technologies for power generation. For LDES, Platte River will need to store enough energy to produce about 400 MW for seven days to ensure reliable supplies to its customers during extended periods of low or no renewable generation.

Of all the dispatchable technologies available today to meet Platte River's dispatchable capacity needs for backup and complementing of renewable energy, Reciprocating Internal Combustion Engines (RICE) and aero derivative gas turbines are the best choice. These technologies can initially be fueled with natural gas and can be progressively converted to non-carbon fuels like renewable natural gas or hydrogen when commercially available.

Heavy duty frame units (like SGT-800 and GE 7F) and traditional combined cycles are a poor fit for relatively low annual capacity factors applications with a high number of annual starts. Simple cycle aeroderivative combustion turbines and reciprocating engines are designed to start often and ramp frequently and do not experience similar negative effects during cyclic operation. The aeroderivative combustion turbines and RICE units meet the suitability criteria of high reliability, relatively lower costs, operational flexibility to complement intermittent renewables under operations at an expected capacity factor around or under 20 percent with 250 or more starts per year. The technologies are commercially viable and are proven, as a number of utilities are currently operating these technologies to meet their dispatchable capacity needs.

The nuclear fueled technologies that are available or expected to be available in the time frame of Platte Rivers' capacity needs do not meet the quick start, ramping abilities, and part load capabilities. Small modular reactor (SMR) nuclear technology is a new design technology, and it is not commercial yet. It has been reported that the first SMR is expected to be online in 2029. The history of nuclear generation technology in the US is that of delays and cost overruns and it is deemed likely that SMR technology commercial operations will not be available in time to meet Platte Rivers needs. Given the limitations associated with nuclear technologies, they are not recommended for further consideration as part of PRPA's supply side evaluation.

Fuel cell generation (FCG) technology has been developed by government agencies and private corporations. Fuel cells are receiving considerable attention as an alternative power source for automobiles. In addition, fuel cells continue to be considered for power generation to meet permanent and intermittent power demands. However, because of the early developmental status of several FCG technologies and uncertainty related to reliability and cost, they are not considered to be commercially proven alternatives to RICE and aeroderivative combustion turbine technologies for utility-scale power generation applications.

No useful undeveloped geothermal resources are known to exist within PRPA's service territory. Given the lack of availability of geothermal generation options within PRPA's service territory, geothermal generation options are not recommended for further consideration as part of PRPA's supply side evaluation and associated integrated resource planning.

Li-ion BESS installations are not ideal for utilities who are looking for more than four to eight hours of storage duration of large amounts of power. Given PRPA's need for longer duration storage options to provide energy to serve load during longer periods of little solar and wind generation, Li-ion BESS options are not recommended for further consideration as part of PRPA's supply side evaluation to fulfill the requirement for generation at an average power output of 400 MW for 7 days that is to be in service before 2030.

Challenges for new hydro power growth include long development lead times, large up-front capital investment, and the ability to permit a new facility. Most of the available hydro power locations have already been developed in the US. There are very few, if any, additional suitable locations available to build new hydro or pump storage facilities in the country. Even if a site is available, environmental concerns make it very difficult to build one. Based on the topology of the PRPA service area it is unlikely that new hydropower development is a viable generation expansion option for PRPA. Given those concerns associated with hydro technologies, hydro generation options are not recommended for further consideration as part of PRPA's supply side evaluation and associated integrated resource planning.

Several LDES technologies that can be discharged at an average power of 400 MW for 7 days were considered: PSH, hydrogen, CAES, advanced metal-based batteries, and flow batteries. Specific attention was given to how these technologies could be implemented in the local PRPA area. However, between the significant cost, regulatory lead times, and stage of development, these technologies are not likely to be able to be implemented by PRPA at the scale of 400 MW for 7 days before 2030.

- Battery storage technologies have numerous benefits including high round-trip efficiencies, favorable response times and ramp rates, and small footprints. The duration of energy storage and cost required to build up capacity over time will require regular and steady investment in multiple sites. Major use case for this technology is currently around 4 hours and comes with significant cost. While the technology is mature and commercial, the cost associated with implementation does not make it practical for supplying the LDES needed on the PRPA system.
- PSH is most technologically ready and suited for the region. It is a mature technology that has been proven to be effective and efficient over more than 75 years of operation in the United States. Identifying appropriate sites and permitting are challenges that will take time to resolve.
- The production, storage, and firing of "green" hydrogen is an emerging technology that shows significant promise in providing long-duration energy storage and "shifting" the availability of abundant renewable energy resources over seasons and years. It is conceptually feasible to begin incorporating hydrogen into present day investments in natural gas fired, dispatchable generators; and then slowly transition those assets to incorporating larger amounts of hydrogen in the generator fuels as the technology improves. The low round-trip efficiencies, unproven equipment life, and inferior dispatchability characteristics all indicate that it is not currently an appropriate choice for PRPA. With governmental support and industry interest, it is possible that green hydrogen could be commercially developed for long duration energy storge by the middle of the next decade.

- CAES would require additional research if pursued for PRPA LDES needs. The positives include potential storage durations (if underground geological storage is deemed feasible and cost effective), lifetime capacity, and asset dispatchability requirements. However, response time, aesthetics, and design life are all inferior attributes relative to other energy storage technologies. It is extremely unlikely this technology can be implemented in the PRPA territory by 2030.

The emerging low or no carbon fuels generation technologies needed for a 100 percent noncarbon energy mix goal by 2030 may not be commercially available at the scale required by PRPA by 2030. The technologies may become gradually available in the next decade or so, and Platte River should continue to assess and monitor the progress of the technologies so that Platte River can adopt them as the commercial viability progresses and are proven adaptable for peaking type operations. The following considerations for better assessing and defining the feasibility of integrating low or no carbon fuels in their Rawhide power generation assets and integrating CCS technology at Rawhide peaker units are recommended:

- PRPA should plan the use of liquid biofuels in their power generation assets through testing, evaluation, demonstration, and validation via equipment condition assessments, performance modeling, and corresponding with the appropriate original equipment manufacturers (OEMs).
- Communicate directly with RNG producers to learn about opportunities for off-take. PRPA should perform a cost benefit analysis to quantify their decarbonization goals given the high pricing of RNG relative to fossil-based natural gas.
- Consult directly with hydrogen producers to learn about opportunities for off-take and explore the potential for pilot projects at the Rawhide facility. PRPA should continue to monitor the hydrogen combustion capabilities of the major combustion turbine OEMs. There will be a lot of development in the next decade with many manufacturers expecting to have several models achieve 100 percent hydrogen (H_2) capability. As combustion capabilities improve it will be important to understand any local planned hydrogen hubs, improvements in on-site production technologies, or other means by which PRPA could acquire hydrogen.
- Carbon Capture Utilization and Sequestration (CCUS) comprised of a 90 percent capture rate, amine-based absorption CO_2 capture technology is a proven technology. However, it has not been deployed at a peaking simple cycle power plant. It is believed that this is due to amine-based carbon capture plants being most economically feasible on baseload, high-capacity, gas-fired combined cycle facilities as opposed to Rawhide’s simple cycle facility. The high-level CCUS facility costs presented in Table 5-13 show that it will not be feasible for a 2030 deployment. It is recommended that Platte River stay abreast of the development of this technology and its deployment in the power sector. Additionally, it is recommended that Platte River explore other economic solutions for disposing the CO_2 emitted from the Rawhide facility. Implementation of CCUS solutions may become economically favorable within the next decade, which could then provide Platte River with a CCUS solution for the Rawhide facility.

2.0 Introduction

Black & Veatch was engaged by Platte River Power Authority (PRPA) to conduct an engineering study on generation technologies to assist PRPA in proactively working towards the goal of 100 percent noncarbon energy mix goal by 2030. This study screens many power generation technologies, including low/no carbon fuels generation technologies, and energy storage technologies. The technologies define the options available to Platte River to choose a dispatchable power generation technology to complement renewable generation after Platte River retires its coal generation prior to 2030. The findings of this study will be used in Platte River's 2024 IRP.

2.1 Scope

This study included three tasks and the report summarizes each task in three separate sections following this introductory section and then concluding with a summary and conclusions section. Task 1 covers the landscape of dispatchable power generation technologies, Task 2 covers the landscape of long duration energy storage (LDES) technologies, and Task3 covers low or no carbon fuels and carbon sequestration technologies. The purpose of this study was to screen all the existing and emerging technologies in each of the above areas and to recommend suitable options for commercial operation in 2028 for Platte River to fulfill the requirements of about 170 MW of generator capacity. Platte River's suitability criteria includes high reliability, relatively lower costs, operational flexibility to complement intermittent renewables under operations at an expected capacity factor around or under 20 percent; with 250 or more starts per year. The technologies must be commercially viable and proven with at least a few utilities having installed and have experience operating the technologies for power generation. For LDES, Platte River will need to store enough energy to produce about 400 MW for seven days to ensure reliable supplies to its customers during extended periods of low or no renewable generation.

2.1.1 Task 1

For Task 1, various dispatchable power generation technology options are described and characterized. Their suitability for Platte River's needs for approximately 170 MW in 2028 and an additional 70 MW of dispatchable generation by the middle of the next decade is established. Dispatchable generation is defined as generation that can adjust power output based on market needs with response rates as good or better than traditional assets. The Task 1 section briefly addresses each technology and discusses its evolution, carbon footprint, and commercial viability, and its suitability for Platte River needs.

The following supply-side options (SSOs) are reviewed in Task 1:

1. Gas combustion turbines.
2. Reciprocating internal combustion engines (RICE).
3. Small modular nuclear reactor.
4. Geothermal power generation.
5. Hydroelectric.
6. Fuel cells.
7. Battery Energy Storage Systems (LiOn) with one-to-four-hour duration at full capacity output.

2.1.2 Task 2

Energy storage technologies were studied for Task 2 of this study. Energy storage technologies presented in this report are for devices that charge with AC-electricity from the grid, store the intermediate result, and then discharge AC-electricity back to the power grid. Over the last five years, there has been exponential growth in energy storage for the power grid. There are two primary reasons for this. First, the increased penetration of variable renewable energy generation (principally solar and wind) compounds the requirements for grid stability control, much more so than variable loads ever required; there is a need for technology that stabilizes grid frequency, and that balances sudden increases and/or decreases in generation due to variable energy resources. Second, the growth in the electric vehicle market has so dramatically increased the production of lithium-ion battery cells that their prices have come down more than ten-fold over the past decade.

Lithium-ion storage technology providing 2-4 hours of storage has dominated deployments over the past decade. As the market for grid energy storage has grown (doubling each year since 2018), a wide variety of energy storage technologies and equipment have begun development to challenge lithium-ion battery energy storage and to fill grid use-case gaps that those batteries cannot address (e.g., long duration energy storage, beyond eight hours). From Black & Veatch's perspective, several, if not all, of these technologies are technically viable alternatives to lithium-ion batteries. This is either because they hold the potential of being even lower in cost than lithium-ion batteries as they mature in the market (e.g., batteries based on earth abundant, commodity minerals like zinc, iron, and sodium) or because the equipment design is such that it can provide LDES of ten hours or more, as defined by the US Department of Energy (DOE).[1]

To meet the grid's needs at various time scales, different technologies are applicable. There are use cases for different power domains (smaller MW and larger MW) and energy domains (shorter durations and longer durations). Platte River's needs are for approximately 400 MW average power and 7-day (1 week) discharge duration. The technologies generally applicable to the 400MW, 7-day use-case are (1) Pumped Storage Hydropower (PSH), (2) CAES, and (3) Hydrogen (H_2). A companion storage technology emerging is Liquid Air Energy Storage (LAES). Another technology that is potentially applicable to the 400 MW, 7-day use-case for Platte River is electrochemical batteries. This includes technologies like lithium-ion, iron-air, and flow batteries.

With multiple LDES installations, the size and duration of each individual installation can be reduced such that the total system achieves the requested average power of 400 MW and discharge duration of 7 days. Current costs suggest fulfilling the PRPA needs with one installation, or even one technology, is beyond the ability of the typical Platte River budgetary constraints; in which case, a phased approach may be more manageable by starting with smaller battery installations and continuing to work up to larger total energy storage capacities over time and as longer duration technologies mature.

[1] US DOE Long Duration Energy Storage "Earthshot", https://www.energy.gov/eere/long-duration-storage-shot

Energy storage technologies presented in this report are for devices that charge with AC-electricity from the grid, store the intermediate result, and then discharge AC-electricity back to the power grid. These include the following energy storage classes and subclasses:

1. **Electro-Mechanical (kinetic and potential energy)**
   - Compressed Air Energy Storage (CAES)
   - Pumped Storage Hydropower
   - Advanced Mechanical
2. **Electro-Chemical (cell based and flow based)**
   - Lithium-ion Batteries, short duration (under 1 hour)
   - Lithium-ion Batteries, medium duration (1 to 8 hours)
   - Flow Batteries (6 to 12 hours)
   - Advanced (Metal-based) Batteries as Successors to Lithium-Ion
3. **Electro-Thermal**
   - Sensible Heat (Hot, high temperature) – (less than 4 to 15-hour durations)
   - Latent Heat (Cold, liquified gas) Energy Storage (6 to 10-hour durations or less)
   - Pumped Heat (Carnot) Energy Storage
4. **Other Developing/Emerging Energy Storage technologies**
   - Super / Ultra Capacitors (less than 1 hour discharge durations)
   - Superconducting Magnetic Energy Storage (less than 1 hour discharge durations)

For each of these technology classes and subclasses, a description of the technology and a summary of the applicable technical performance and cost characteristics are provided.

2.1.3 Task 3

Task 3 of this study looked specifically at emerging low or no carbon fuel technologies as well as explored the implementation of carbon capture and sequestration (CCS) facility at PRPA's Rawhide Energy Station. The Rawhide Energy Station is comprised of a 280-megawatt (MW) coal fired base load power plant, four 65 MW natural gas fired E-Class GE gas turbines (Units A through D), one 128 MW natural gas fired F-Class GE turbine (Unit F), and two solar fields (Flats Solar and Prairie Solar) with a combined capacity of 52 MW. The coal fired plant Rawhide 1, is planned for retirement at the end of 2029. The primary focus of the Rawhide assets will be the natural gas fired peaker units (Units A through D and F), with nameplate capacity of 388 MW and a future 170 MW peaking plant.

Black & Veatch's high level technical assessment evaluated the available no or low carbon fuels for use in the peaker units, as well as the post-combustion carbon capture technologies available to remove carbon directly from the Rawhide unit's combined flue gas emissions. Additionally, Black & Veatch evaluated the performance (thermal and emissions), the capital, operating, and maintenance costs; the opportunities, challenges, and risks; and the development timeline of the prospective low or no carbon fuel/CCS facility as it relates to the Rawhide peaker units.

3.0 Task 1: Dispatchable Power Generation Landscape

This section describes and characterizes various dispatchable power generation technology options and ascertains their suitability for Platte River's needs for approximately 170 MW in 2028 and an additional 70 MW of dispatchable generation by the middle of the next decade. Dispatchable generation is defined as generation that can adjust power output based on market needs with response rates as good or better than traditional assets. This section briefly addresses each technology and discusses its evolution, carbon footprint, and commercial viability, and its suitability for Platte River needs.

At a high level, the suitability criteria include:

1. High level of reliability and low cost.
2. Operational flexibility to complement intermittent renewables.
3. Expected capacity factor around 20% and 250+ starts per year.
4. Commercial viability defined as a handful of utilities are operating this technology before Platte River selects to install it.

The following supply-side options (SSOs) are reviewed in this task:

1. Gas combustion turbines.
2. Reciprocating internal combustion engines (RICE).
3. Small modular nuclear reactor.
4. Geothermal power generation.
5. Hydroelectric.
6. Fuel cells.
7. Battery Energy Storage Systems (LiOn) with one-to-four-hour duration at full capacity output.

3.1 General Assumptions

The capital cost estimates were developed on an engineering, procurement, and construction (EPC) basis. The EPC capital cost estimates presented in this report include both direct and indirect costs. These capital cost estimates are presented as "overnight" costs and do not include any allowances for escalation, financing fees, interest, or other general Owner's cost items.

3.1.1 General Capital Cost Assumptions

Unless otherwise discussed, the following general assumptions were applied in developing the conceptual-level estimates of cost and performance:

- The site has sufficient area available to accommodate construction activities, including, but not limited to, office trailers, laydown, and staging.
- Pilings are assumed under major equipment, and spread footings are assumed for all other equipment foundations.
- All buildings will be pre-engineered unless otherwise specified.
- Construction power is available at the boundary of the site.
- The plant will not be located on wetlands nor require any other mitigation.

- Potable, service, and fire water will be supplied from the local water utility.
- Wastewater disposal will utilize local sewer systems.
- Cooling water, if required, will be treated sewage effluent or groundwater. Allowances for pipeline costs should be included in the Owner's cost.
- Costs for transmission lines and switching stations should be included as part of the Owner's cost estimate.

3.1.2 Direct Costs Assumptions

Direct cost assumptions are as follows:

- Total direct capital costs are expressed in beginning of year 2023 United States dollars (USD).
- Direct costs include the costs associated with the purchase of equipment, erection, and contractors' services.
- Construction costs are based on a turnkey EPC contracting philosophy.
- Permitting and licensing are excluded from EPC costs. These items should be included in the Owner's cost estimate.

3.1.3 Indirect Costs Assumptions

Indirect costs are assumed to include the following:

- General indirect costs, including all necessary services required for checkout, testing, and commissioning.
- Insurance, including builder's risk, general liability, and liability insurance for equipment and tools.
- Engineering and related services.
- Field construction management services, including field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct cost construction contracts, safety and medical services, guards and other security services, insurance premiums, and performance bonds.
- Contractor's contingency and profit.
- Transportation costs for delivery to the jobsite.
- Startup and commissioning spare parts.

3.1.4 Owner's Costs Assumptions

Owner's costs are assumed to include the following:

- Initial inventory of spare parts for use during operation
- Allowance for funds used during construction and financing fees.

- Project Development costs such as: Site selection study, land purchase and rezoning for greenfield sites, transmission and gas pipeline rights-of-way, road modifications and upgrades, demolition, environmental permitting, public relations and community development, and legal assistance.
- Utility Interconnections costs such as: natural gas service, gas system upgrades, electrical transmission (including switchyard), water supply, wastewater, and sewer.

3.2 Combustion Turbines

Combustion turbine technologies are presented in this section. Suitability criteria includes commercial installation by a handful of utilities, maturation of technology, high level of reliability, reasonable cost and most of all, fitness for Platte River needs to provide back-up and complement intermittent renewable generation. Dispatchable power generation combustion turbine technologies which are currently available or will become available by 2028 to provide approximately 170 MW in 2028 and an additional 70 MW of dispatchable generation by the middle of the next decade are characterized in this section. Dispatchable generation is defined as generation that can adjust power output based on market needs with response rates as good or better than traditional assets. Documentation of each technology and its evolution, carbon footprint, and commercial viability, and its suitability for Platte River needs are presented. Addressing of each technology is at a high level and discussions of carbon footprint will be of a qualitative nature. Platte River seeks the most suitable dispatchable power generation technology to service Platte River customers as coal generation is retired and renewable generation is added to the supply portfolio. Black & Veatch conducted a study to compare Combustion Turbine technologies to provide 170 MW by 2028 and another 70 MW during the next decade. The options were reviewed against Platte River's future dispatchable capacity needs for a high level of reliability and flexibility to complement large amount of wind and solar. For each of these technologies, the following sections provide a general overview of the technology and a summary of the applicable technical performance and cost characteristics.

3.2.1 SCCT – GE LM2500 +G5

The General Electric (GE) LM2500 combustion turbine is derived from the TF39/CF6-6 turbofan aircraft engine with the summer capacity of about 28 MW. The LM2500 combustion turbine is a single-rotor gas generator and an aerodynamically coupled power turbine. The LM2500 includes a 16-stage, axial flow compressor; an annular combustor with 30 fuel nozzles; a two-stage, high pressure (HP) turbine; and a six-stage, high efficiency low pressure (LP) turbine. For this analysis, it has been assumed that the most recent model, the GE LM2500 +G5, will be dual-fueled and capable of firing either natural gas or ULSD. Platte River's dispatchable capacity needs of approximately 170 MW in 2028 can be met with a 6X0 configuration of the GE LM2500+ G5 combustion turbines. A 6x0 plant configuration will result in a net plant output of approximately 168.6 MW. The plant construction time is estimated to be about three years.

The GE LM2500 +G5 employs proven technology, is flexible, reliable, and can be readily configured to an approximately 170 MW sized plant. It can burn up to 35% hydrogen (H_2) now and GE plans to increase H_2 percentage to higher levels in the future.

The LM2500 will utilize dry-low nitrogen oxide (NO_x) combustors and selective catalytic reduction (SCR) to control NO_x to 2 parts per million volumetric dry (ppmvd) on natural gas. Dry-low NO_x combustors, water injection, and SCR will be used for NO_x control when firing fuel oil. Table 3-1 and Table 3-2 present the estimated costs, performance, and emissions characteristics of the LM2500 SCCT generating unit. The sum of the escalated EPC capital cost and the owner's cost equals the total project cost or the total capital requirement for the project. Owner's costs are not typically included in the EPC capital cost estimate and must be considered to determine the total capital requirement for the project. Owner's cost items include costs for "outside-the-fence" physical assets, project development, financing costs, and at times unique "inside-the-fence" costs. The order-of-magnitude of these costs is project-specific and can vary significantly, depending upon technology and project-unique requirements. Through discussions with Platte River, Black & Veatch estimated owner's costs specific to the Rawhide site and applied a 15 percent cost allowance to the overnight EPC cost. The 15 percent cost allowance includes a 5 percent adder for Interest During Construction (IDC).

Table 3-1 6x0 GE LM2500 +G5 Capital, Performance, and Non-Fuel O&M Cost Estimates

	6x0 GE LM2500 +G5
Commercial Status	Commercial
Typical Operating Life (years)	30
Performance (Summer, Full Load)	
Net Plant Capacity (MW)	168.6
Net Plant Heat Rate (Btu/kWh, HHV)	9,875
Economics	
EPC Capital Cost ($ millions)	$235.9
Owner's Costs and IDC ($ millions)	$35.38
Total Project Capital Costs ($ millions)	$271.3
Overnight Construction Cost ($/kW)	$1,609
Fixed O&M Cost ($/kW-yr)	$6.10
Variable O&M Cost ($/MWh)	$5.91
Costs are in 2023 USD. Capital costs are on an overnight basis. Fixed and Variable O&M costs assume a 20% annual capacity factor.	

Table 3-2 GE LM2500 +G5 Estimated Emissions(1)

Pollutant	Estimated Emissions
NO_x, ppmvd at 15% O_2	2
NO_x, lb/MMBtu	0.01
SO_2, lb/MMBtu	0.0006
Hg, lb/TBtu	Negligible
CO_2, lb/MMBtu	117.6
(1) Emissions are at full load at 90.8° F, reflect operation on natural gas, and include the effects of SCR.	

3.2.2 SCCT – GE LM6000 PF+

The GE LM6000 PF+ is a two-shaft gas turbine engine derived from the core of the CF6-80C2, GE's high thrust, high efficiency aircraft engine and provides about 40 MW during summer. The LM6000 consists of a five-stage low-pressure compressor (LPC), a 14-stage variable geometry high-pressure compressor (HPC), an annular combustor, a two-stage air-cooled high-pressure turbine (HPT), a five-stage low-pressure turbine (LPT), and an accessory drive gearbox. The LM6000 has two concentric rotor shafts, with the LPC and LPT assembled on one shaft, forming the LP rotor. The HPC and HPT are assembled on the other shaft, forming the HP rotor. The LM6000 uses the LPT to power the output shaft. The LM6000 design permits direct coupling to its generator. The gas turbine drives its generator through a flexible, dry type coupling connected to the front, or "cold," end of the LPC shaft.

A power augmentation option offered by GE for the LM6000 is the SPRINT system. SPRINT stands for "Spray Intercooled Turbine." From GE literature, the SPRINT cooling lowers the HP compressor inlet temperature, which in turn effectively lowers the compressor discharge temperature. The system consists of an interstage mist injection system, which cools the low-pressure (LP) booster discharge air. Water is injected into the airflow path through a series of 24 air-assisted spray injection nozzles located in the engine front frame. Air for the system is supplied from the engine's 8th stage customer bleed extraction port. By using the SPRINT spray intercooling system, the compressor pressure ratio can be increased, and additional air can be directed through the compressor to increase the gas turbine's output characteristics. According to GE's literature, with the SPRINT system, power output is increased by 9 percent (or more) at ISO conditions and over 20 percent at an ambient temperature of 90° F.

The LM6000 gas turbine generator set has the following attributes:

- Full power in approximately 10 minutes, fast start in 5 minutes.
- Synchronous condenser capability.
- Compact, modular design.
- More than 40 million operating hours.
- More than 1,320 turbines sold.
- Dual fuel capability.

The GE LM6000 technology meets the criteria specified to meet Platte River's needs. It is proven, flexible, and can be efficiently configured to a 170 MW sized plant. It can burn thirty-five percent Hydrogen now and the vendor plans to increase Hydrogen percentage to 100 percent by the year 2030.

The estimated costs, performance, and emissions characteristics of the GE LM6000 PF+ SPRINT are shown in the tables below.

Table 3-3 4x0 GE LM6000 PF+ Capital, Performance, and Non-Fuel O&M Cost Estimates

	4x0 GE LM6000 PF+
Commercial Status	Commercial
Typical Operating Life (years)	30
Performance (Summer, Full Load)	
Net Plant Capacity (MW)	158.8
Net Plant Heat Rate (Btu/kWh, HHV)	9,649
Economics	
EPC Capital Cost ($ millions)	$206.6
Owner's Costs and IDC ($ millions)	$30.99
Total Project Capital Costs ($ millions)	$237.6
Overnight Construction Cost ($/kW)	$1,496
Fixed O&M Cost ($/kW-yr)	$5.08
Variable O&M Cost ($/MWh)	$4.93
Costs are in 2023 USD. Capital costs are on an overnight basis. Fixed and Variable O&M costs assume a 20% annual capacity factor.	

Table 3-4 GE LM6000 PF+ SCCT Estimated Emissions[1]

Pollutant	Estimated Emissions
NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.01
SO_2, lb/MBtu	0.0006
Hg, lb/TBtu	Negligible
CO_2, lb/MBtu	117.6
[1]Emissions are at full load at 90.8° F, reflect operation on natural gas, and include the effects of SCR.	

3.2.3 SCCT – GE LMS100 PA+

The LMS100 is currently the most efficient simple cycle gas turbine in the world. It has summer net Unit output of about 90 MW. The LMS100 is available in two models, the LMS100 PA+ and the LMS100 PB+. The LMS100 PA+ model uses injection of demineralized water in the combustion system for NO_x control. The LMS100PB model uses a dry low emissions (DLE) combustion system for NO_x control. Exhaust gases are at a temperature of less than 800° F, which allows the use of a standard SCR system for NOx control.

In simple cycle mode, the LMS100 PA+ has an efficiency of 43.0 percent (LHV) while the LMS100 PB+ has an efficiency of 42.6 percent (LHV), both at ISO conditions. It has a high part-load efficiency, cycling capability (without increased maintenance cost), better performance at high ambient temperatures, modular design (minimizing maintenance costs), the ability to achieve full power from a cold start in 10 minutes, and is expected to have high availability. There are far more LMS100 PA models currently in service as compared to the LMS100 PB model.

The LMS100 is an intercooled aeroderivative turbine and has many of the same characteristics of the LM6000. The LMS100 uses off-engine intercooling within the turbine's compressor section to increase its efficiency. The process of cooling the air increases output efficiency. At 50 percent turndown, the part-load efficiency of the LMS100 is 40 percent, which is a greater efficiency than most simple cycle combustion turbines at full load.

The LMS100 has two compressor sections and three turbine sections. Compressed air exiting the low-pressure compressor (LPC) section is cooled in an air-to-water intercooler heat exchanger prior to admission to the high-pressure compressor (HPC) section. A mixture of compressed air and fuel is combusted in a single annular combustor (SAC). Hot flue gas then enters the two-stage high pressure turbine (HPT). The high-pressure turbine drives the high-pressure compressor. Following the high-pressure turbine is a two-stage intermediate pressure turbine (IPT), which drives the low-pressure compressor. Lastly, a five-stage low-pressure turbine (LPT) drives the electric generator. Major intercooler components include the inlet and outlet scrolls and associated ductwork to / from the intercooler and the external heat exchanger.

Many of the major components from the LMS100 are based on engine applications with extensive operating hours. The low-pressure compressor section is derived from the first six stages of GE's MS6001FA heavy-duty CTG compressor. The high-pressure compressor is derived from GE's CF6-80C2 aircraft engine and strengthened to withstand a pressure ratio of approximately 41:1. The single annular combustor and high-pressure turbine are derived from GE's LM6000 aeroderivative turbine and CF6-80C2 and CF6-80E2 aircraft engines.

The LMS100 is available in several configurations. Major variations include an intercooler heat rejection to atmosphere using dry cooling methods and DLE in lieu of water injected combustion for applications when water availability is limited.

There are two main differences between the LM6000 SPRINT™ and the LMS100. The LM6000 uses the SPRINT™ intercooling system to cool the compressor with a micro-mist of water, while the LMS100 cools the compressor air with an external heat exchanger. Unlike the LM6000, which has an HP turbine and a power turbine, the LMS100 has an additional intermediate-pressure (IP) turbine to increase output efficiency.

Key attributes of the GE LMS100PA include the following:

- High full and part load efficiency.
- Minimal performance impact at hot-day conditions.
- High availability.
- 50 MW / min ramp rate.
- 8 minutes to full power (excluding purge).
- Capable of turndown to 25 percent of full load.
- Ability to cycle on and off without impact of maintenance costs or outage schedule.
- Natural gas interface pressure requirement of 850 psig at the CTG inlet, downstream of the filters and regulating skid.
- Dual fuel capable.

The GE LMS100 technology meets the criteria specified to meet Platte River's needs. It is proven, flexible, and can be efficiently configured to a 170 MW sized plant. It can burn five percent Hydrogen now and the vendor plans to increase Hydrogen percentage to 100 percent by the year 2030.

Table 3-5 and Table 3-6 present the estimated costs, performance, and emissions characteristics of the GE LMS100 PA+ SCCT generating unit.

Table 3-5 2x0 GE LMS100 PA+ Capital, Performance, and Non-Fuel O&M Cost Estimates

	2x0 GE LMS100 PA+
Commercial Status	Commercial
Typical Operating Life (years)	30
Performance (Summer, Full Load)	
Net Plant Capacity (MW)	179.3
Net Plant Heat Rate (Btu/kWh, HHV)	8,820
Economics	
EPC Capital Cost ($ millions)	$167.6
Owner's Costs and IDC ($ millions)	$25.14
Total Project Capital Costs ($ millions)	$192.7
Overnight Construction Cost ($/kW)	$1,075
Fixed O&M Cost ($/kW-yr)	$3.69
Variable O&M Cost ($/MWh)	$5.94
Costs are in 2023 USD. Capital costs are on an overnight basis. Fixed and Variable O&M costs assume a 20% annual capacity factor.	

Table 3-6 GE LMS100 PA+ SCCT Estimated Emissions[1] at 100 Percent Load and 90.8° F

Pollutant	Estimated Emissions
NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.01
SO_2, lb/MBtu	0.0006
Hg, lb/TBtu	Negligible
CO_2, lb/MBtu	117.6
[1]Emissions are at full load at 90.8° F, reflect operation on natural gas, and include the effects of SCR.	

3.2.4 SCCT – MHI FT4000 – 3 Units

The MHI FT4000 combustion turbine has an ISO base rating of 55 megawatts (MW) with an associated heat rate of 9,629 British thermal units per kilowatt-hour (Btu/kWh) (HHV). It is an aero-derivative gas turbine. The MHI FT4000 employs proven technology, is flexible, reliable, and can be readily configured to an approximately 170 MW sized plant. It can burn up to 10% hydrogen (H_2) now with expectations to increase H2 cofire percentage to 100% in the year 2035.

Table 3-7 and Table 3-8 present the estimated costs, performance, and emissions characteristics of the MHI FT4000 SCCT generating unit.

Table 3-7 3x0 MHI FT4000 Capital, Performance, and Non-Fuel O&M Cost Estimates

	3x0 MHI FT4000
Commercial Status	Commercial
Typical Operating Life (years)	30
Performance (Summer, Full Load)	
Net Plant Capacity (MW)	165.2
Net Plant Heat Rate (Btu/kWh, HHV)	9,629
Economics	
EPC Capital Cost ($ millions)	$279.5
Owner's Costs and IDC ($ millions)	$41.93
Total Project Capital Costs ($ millions)	$321.4
Overnight Construction Cost ($/kW)	$1,946
Fixed O&M Cost ($/kW-yr)	$3.66
Variable O&M Cost ($/MWh)	$3.83
Costs are in 2023 USD. Capital costs are on an overnight basis. Fixed and Variable O&M costs assume a 20% annual capacity factor.	

Table 3-8 MHI FT4000 SCCT Estimated Emissions[(1)] at 100 Percent Load and 90.8° F.

Pollutant	Estimated Emissions
NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.01
SO_2, lb/MBtu	0.0006
Hg, lb/TBtu	Negligible
CO_2, lb/MBtu	117.6
[(1)]Emissions are at full load at 90.8° F, reflect operation on natural gas, and include the effects of SCR.	

3.2.5 SCCT – GE 7F.05

The GE 7F combustion turbine, originally introduced in 1986, is the result of a multi-year development program using technology advanced by GE Aircraft Engines and GE's Corporate Research and Development Center. The development program facilitated the application of technologies such as advanced bucket cooling techniques, compressor aerodynamic design, and new alloys for F-class gas turbines, enabling these machines to attain higher firing temperatures (2,400° F) than previous generating units.

The GE 7F.05 combustion turbine has an ISO base rating of 239 megawatts (MW) with an associated heat rate of 8,871 British thermal units per kilowatt-hour (Btu/kWh) (LHV). It is a single-shaft, single casing, advanced class machine. The 7F.05 compressor, with a pressure ratio of 18.8:1, consists of 14 stages. The fleet of 7F machines has significant operational service with over 950 installed units.

The 7F will utilize dry-low NOx (DLN 2.6+) combustors and an SCR to control NOx to 2 ppmvd when burning natural gas. The GE 7F.05 combustion turbine will be dual-fueled, with water injection used for NOx control when firing fuel oil.

Table 3-9 and Table 3-10 present the estimated costs, performance, emissions, and cash flow characteristics of the GE 7F.05 (7F 5-Series) SCCT generating unit.

Table 3-9 GE 7F.05 SCCT Capital, Performance, and Non-Fuel O&M Cost Estimates

	1x0 GE 7F.05
Commercial Status	Commercial
Typical Operating Life (years)	30
Performance (Summer, Full Load)	
Net Plant Capacity (MW)	221.7
Net Plant Heat Rate (Btu/kWh, HHV)	10,210
Economics	
EPC Capital Cost ($ millions)	$141.1
Owner's Costs and IDC ($ millions)	$21.17
Total Project Capital Costs ($ millions)	$162.3
Overnight Construction Cost ($/kW)	$731.9
Fixed O&M Cost ($/kW-yr)	$11.4
Variable O&M Cost ($/MWh)	$1.17
Costs are in 2023 USD. Capital costs are on an overnight basis. Fixed and Variable O&M costs assume a 20% annual capacity factor.	

Table 3-10 GE 7F.05 SCCT Estimated Emissions(1)

Pollutant	Estimated Emissions
NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.01
SO_2, lb/MBtu	0.0006
Hg, lb/TBtu	Negligible
CO_2, lb/MBtu	117.6
(1)Emissions are at full load at 90.8° F, reflect operation on natural gas, and include the effects of SCR and dry-low NO_x combustors.	

3.2.6 SCCT – Siemens SGT-800

The SGT-800 is a high-performance industrial gas turbine suitable for a variety of applications including simple cycle, combined heat and power, and combined cycle power plant. To ensure reliability in the SGT-800, its design philosophy has been based upon simplicity, robustness, and the use of proven technology. Modularization, few parts, long component life and easy inspection ensure high availability and low maintenance costs. The first SGT-800 was ordered in 1998 and has been in commercial operation since 1999.

The SGT-800 is a single shaft industrial type gas turbine with modular design and a vertically split compressor casing for ease of maintenance. The SGT-800 has a frame design with a minimum number of parts in a single-shaft arrangement. The compressor rotor and the three-stage bolted turbine module form a single shaft, which rests in two hydrodynamic bearings of the tilting pad type. The generator is driven from the cold end of the gas turbine which allows for a simple and efficient exhaust arrangement. Modularization, few parts, long component life and easy inspection ensure long time between overhauls and low maintenance costs.

The compressor is of a transonic type, with 15. The compressor rotor is built up from discs which are welded together into a robust unit using Electron Beam Welding a technology used for many years in the SGT-600 compressor rotor and proven to be a design giving minimum vibrations and very reliable in operation. Cooling air for the hot section of the turbine is extracted from the compressor at stages 3, 5, 8, 10 and 15.

The combustor is of the annular type and is made from welded sheet metal. The inner surface of the combustor liners and the front panel have a thermal barrier coating which reduces the level of heat transfer and extends the life of the combustor. This design concept has been validated in other gas turbines designed by Siemens. Siemens has recognized the strategic importance of environmental issues and has taken a lead in the control of gas turbine emissions. In 1990, Siemens introduced the 2nd generation DLE (Dry Low Emission) burner to the market. The combustor has 30 burners of the 3rd generation DLE design developed in-house. The 3rd generation DLE burner technology, as applied to the SGT-800, has NOx emissions capabilities of 15 ppm (15% O2) on natural gas and 42 ppm (15% O2) on liquid fuel and CO emissions capabilities of 5 ppm (15% O2) on natural gas and liquid fuel without the need for water or steam injection. The burner can be supplied either as single-fuel or dual-fuel.

The three-stage turbine is built as one module with tie-bolts for ease of maintenance and bolted to the stub shaft of the compressor. The airfoils of first and second stage vanes and blades are cooled, using the technology found in other gas turbines, designed by Siemens. The first blade is made of single-crystal material to ensure durability and long life. The turbine stator flanges are cooled by compressor air to reduce clearances and improve efficiency.

The gas turbine is connected to the generator via a speed reduction gear of the double helical parallel type, which reduces the 6600-rpm of the turbine shaft down to a generator speed of 1800 rpm (60 Hz). The variable speed electric starter motor is also connected to the speed reduction gear, via a self-synchronizing and switching clutch.

Table 3-11 and Table 3-12 present the estimated costs, performance, and emissions characteristics of the Siemens SGT-800 SCCT generating unit.

Table 3-11 4x0 Siemens SGT-800 SCCT Capital, Performance, and Non-Fuel O&M Cost Estimates

	4x0 Siemens SGT-800
Commercial Status	Commercial
Typical Operating Life (years)	30
Performance (Summer, Full Load)	
Net Plant Capacity (MW)	177.0
Net Plant Heat Rate (Btu/kWh, HHV)	9,707
Economics	
EPC Capital Cost ($ millions)	$193.4
Owner's Costs and IDC ($ millions)	$29.01
Total Project Capital Costs ($ millions)	$222.4
Overnight Construction Cost ($/kW)	$1,256
Fixed O&M Cost ($/kW-yr)	$7.14
Variable O&M Cost ($/MWh)	$14.11
Costs are in 2023 USD. Capital costs are on an overnight basis. Fixed and Variable O&M costs assume a 20% annual capacity factor.	

Table 3-12 Siemens SGT-800 SCCT Estimated Emissions[1]

Pollutant	Estimated Emissions
NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.01
SO_2, lb/MBtu	0.0006
Hg, lb/TBtu	Negligible
CO_2, lb/MBtu	117.6
[1]Emissions are at full load at 90.8° F, reflect operation on natural gas, and include the effects of SCR.	

3.2.7 Recommendations

A relatively low annual capacity factor with a high number of annual starts makes heavy duty frame units (like SGT-800 and 7F) and traditional combined cycles a poor fit. When compared with simple cycle heavy duty frame units and traditional combined cycle units, simple cycle aeroderivative combustion turbines and Reciprocating Engines (presented in the next section) are designed to start often and ramp frequently and do not experience similar negative effects during cyclic operation.

3.3 Reciprocating Engines

Modern reciprocating engines used for electric power generation are internal combustion engines in which an air-fuel mixture is compressed by a piston and ignited within a cylinder. RICE units are characterized by the type of combustion utilized: spark-ignited or compression-ignited, also known as diesel. The spark-ignited engine is based on the Otto thermodynamic cycle and uses a spark plug to ignite an air-fuel mixture injected at the top of the cylinder. A reciprocating engine uses the expansion of hot gases to convert the linear movement of the piston into the rotating movement of a crankshaft to generate power.

The size and power of a reciprocating engine is a function of the volume of fuel and air combusted. Therefore, the size of the cylinder, the number of cylinders, and the engine speed determine the amount of power the engine generates. The output of reciprocating engine generator sets is currently limited to approximately 20 MW. In a power plant, multiple units are grouped together in a power block to provide generating capacity in standardized sizes. Reciprocating engine power plants are highly efficient with SC efficiencies of 40 to 49 percent (LHV), generally surpassing the performance of SC CT power plants. The biggest concession with reciprocating engines is the operation and maintenance costs often make them less appealing in life-cycle cost analyses.

Many RICE units use a compressed air start system in which compressed air is used to initiate rotation of the crankshaft. RICE units can start quickly (approximately two hours after shutdown) and require a minimal amount of electricity and fuel during startup.

The technology selected to represent the RICE options was the Wartsila 18V50DF in SC configuration. Consideration of only the Wartsila RICE for this resource option is not intended to be an implicit recommendation of the Wartsila RICE. If this resource option is selected for implementation as a result of an IRP analysis, further investigation, and refinement of these estimates is recommended in subsequent stages of planning and development, including consideration of RICE from other manufacturers.

The Wartsila 18V50DF reciprocating engine is a turbocharged, four-stroke compression-ignited dual fuel engine. The DF is always started on liquid fuel and requires a small amount of liquid pilot fuel even during natural gas operation to maintain combustion. The 18V50DF utilizes 18 cylinders in a “V” configuration. Each cylinder has a bore diameter of 500 millimeters ($19^{11}/_{16}$ inches) and a stroke of 580 millimeters ($22^{13}/_{16}$ inches). Each engine operates at a shaft speed of 514 revolutions per minute. These engines employ individual cylinder computer controls and knock sensors for precise control of the combustion process, enabling the engine to operate more efficiently while minimizing emissions. These machines can change over from one fuel to the other as they operate. Generation from renewable fuels, when available, may be considered as renewable power generation.

Key attributes of the Wartsila 18V50DF include the following:

- High full and part load efficiency.
- Minimal performance impact at hot-day conditions.
- 5 minutes to full power (excluding purge); purge is performed during the shutdown sequence.
- Each engine is capable of turndown to 40 percent of full load.
- Minimal power plant footprint.
- Low starting electrical load demand.

- Ability to cycle on and off without impact of maintenance costs or outage schedule.
- Natural gas interface pressure requirement of 75 psig.
- Dual fuel capable.

Almost all RICE units sold today include an SCR and CO catalyst as their uncontrolled emissions are relatively high. The controlled emissions after treatment are the same order of magnitude as controlled CTG emissions, usually around 5 parts per million (ppm) NO_x. Cost and performance characteristics have been developed for a Wartsila 18V50DF RICE 10x0 simple cycle configuration. Table 3-13 and Table 3-14 present the estimated costs, performance, and emissions for the reciprocating engines.

Table 3-13 10x0 Wartsila 18V50DF RICE Capital, Performance, and Non-Fuel O&M Cost Estimates

	10x0 Wartsila 18V50DF RICE
Commercial Status	Commercial
Typical Operating Life (years)	30
Performance (Summer, Full Load)	
Net Plant Capacity (MW)	171.4
Net Plant Heat Rate (Btu/kWh, HHV)	8,510
Economics	
EPC Capital Cost ($ millions)	$230.2
Owner’s Costs and IDC ($ millions)	$34.52
Total Project Capital Costs ($ millions)	$299.5
Overnight Construction Cost ($/kW)	$1,747
Fixed O&M Cost ($/kW-yr)	$0.39
Variable O&M Cost ($/MWh)	$9.01
Costs are in 2023 USD. Capital costs are on an overnight basis. Fixed and Variable O&M costs assume a 20% annual capacity factor.	

Table 3-14 Wartsila 18V50DF RICE (Natural Gas) Reciprocating Engine - Emissions[1]

Pollutant	Estimated Emissions
NO_x, ppmvd at 15% O_2	6
NO_x, lb/MBtu	0.02
SO_2, lb/MBtu	0.0006
Hg, lb/TBtu	Negligible
CO_2, lb/MBtu	117.6
[1]Emissions are at full load at 90.8° F, reflect operation on natural gas, and include the effects of SCR.	

3.3.1 Recommendations

Of all the dispatchable technologies available today to meet Platte River's dispatchable capacity needs for backup and complementing of renewable energy, RICE and aero derivative gas turbines are the best choice. These technologies can initially be fueled with natural gas and can be progressively converted to non-carbon fuels like renewable natural gas or hydrogen when commercially available.

Heavy duty frame units (like the SGT-800 and GE 7F) and traditional combined cycles are poor fit for relatively low annual capacity factors with a high number of annual starts. Simple cycle aeroderivative combustion turbines and reciprocating engines are designed to start often and ramp frequently and do not experience similar negative effects during cyclic operation. The aeroderivative combustion turbines and RICE units meet the suitability criteria of high reliability, relatively lower costs, operational flexibility to complement intermittent renewables under operations at an expected capacity factor around or under 20 percent with 250 or more starts per year. The technologies are commercially viable and proven as a number of utilities are currently operating these technologies to meet their dispatchable capacity needs.

3.4 Small Modular Reactor Nuclear Technologies

Small modular reactor (SMR) nuclear technologies are characterized in this section a general overview of the technology and a summary of the applicable technical performance and cost characteristics are presented. SMR is a new design technology, and it is not commercial yet. Platte Rivers' capacity need includes the capabilities to start quickly and load-follow through frequent ramping up and down as a complement to intermittent and non-dispatchable renewable generation. The nuclear fueled technologies that are available or expected to be available in the time frame of Platte Rivers' capacity needs do not meet the quick start, ramping abilities, and part load capabilities. It has been reported that the first SMR is expected to be online in 2029. The history of nuclear generation technology in the US is that of delays and cost overruns and it is deemed likely that SMR technology commercial operations will not be available in time to meet Platte Rivers needs. Given those limitations associated with nuclear technologies, they are not recommended for further consideration as part of PRPA's 2023 supply side evaluation and associated integrated resource planning. Details regarding nuclear fueled electric generation technologies are provided in this section.

Nuclear generation provides an option for baseload clean energy; however, the technology is not suitable for frequent start-ups and shut-downs, part load operations, and frequent ramping needed to follow the variability associated with renewable generation. Light water reactor (LWR) nuclear technology is well understood and commercially proven; however, the long project cycles and large capital outlays for the large light water reactor (LLWR) plants have refocused the industry on Small Modular Reactors (SMRs), including both LWR or Generation III+ designs and non-LWR or Generation IV designs. These future nuclear plants will employ new technologies, passive design features, and more simplified construction, including the use of more factory assembled modules. The US nuclear renaissance that was projected to start about 15 years ago has not materialized because of reduced natural gas fuel prices and the complexity of the LLWR plants being considered. Of the two AP1000 projects that moved forward, only the Vogtle project will likely achieve commercial operation, with the first unit coming online in 2023, several years later than planned. The Vogtle units were completed at a cost more than double that initially anticipated and are being completed over five years later than projected at the time construction began.

3.4.1 Status of the Nuclear Industry

While LLWRs are still being built internationally, LLWRs are starting to fall out of favor because of their large capital cost and long construction schedules. The Vogtle units are the only new LLWRs expected to be come online in the United States. The V.C. Summer project has been canceled and will likely not be restarted. Other plants that were planned, such as North Anna 3 and Fermi 3, will not be built because of the high costs of LLWR implementation. For the nuclear supply side options SSOs, consideration was given to SMRs, which are typically less than 300 megawatt electric (MWe). This option is less capital intensive than LLWRs and could be pursued by PRPA in the future either directly or by participating in a PPA with a nuclear utility that develops them. Recent concerns about energy demand growth, climate change, energy independence and energy security, and relative costs of competing technologies has renewed public interest in nuclear alternatives. Environmentalists who once opposed nuclear are starting to encourage the development of new nuclear to aid in future decarbonization. Several environmentalists have indicated that for deep decarbonization to be achieved, new nuclear will need to supply a larger amount of emissions-free energy.

Considering the multiple plant retirements projected world-wide, an aggressive nuclear reactor build-out plan would be required simply to retain current emissions levels, even if many of these existing plants will receive license extensions. Subsequent License Renewal (SLR) is being done within the existing fleet to extend the life of nuclear an additional 20 years beyond their current 20-year extensions (40 years + 20 + 20). Moreover, in a carbon-constrained world, including taxes or cap-and-trade programs to control greenhouse gas emissions, the cost of nuclear power would be comparable to fossil fuel alternatives. The most recent Inflation Reduction Act (IRA) provides additional incentives for nuclear that may help to advance the newer SMR technology.

SMR, a new type of reactor design that is undergoing development, is not commercial yet, and is not expected to be commercial prior to 2030, while easier to build than LLWRs, are not without risks. First-mover or early adoption of SMR may entail added First-of-a-Kind (FOAK) design/development costs and development delays from the reactor original equipment manufacturers (OEMs) that would increase the cost and time to commercial operations. Waiting for the nuclear SSOs to mature further will reduce implementation costs, solidify the supply chain, and provide more schedule certainty. The Nth of a kind plant cost will avoid the FOAK costs and will be further aided by early learning and supply chain development on the early units. The time that this takes will depend on the nuclear technology. SMRs can be subdivided into Generation III+ (Gen III+) LWRs and Generation IV (Gen IV) or non-LWR advanced reactors. Gen III+ reactors are like the existing Gen III reactors that are operating in the fleet but have advanced features that are incremental improvements from existing technology. Technology risks with Gen III+ reactors are low. Gen IV reactors are very different from the existing fleet and may have technology risks that could impact the long-term operability of new designs. It is expected that Gen III+ LWR SMRs could be economically implemented with CODs starting no earlier than 2030 and Gen IV advanced reactors could be economically implemented with CODs starting no earlier than 2035. The Gen IV plants are still being designed and will also require development of new fuel fabrication facilities as most require the use of HALEU fuel (less than 20 percent enrichment)

Future implementation of nuclear SSOs requires foresight. For nuclear SSOs developed directly, PRPA would need to initiate project work at least 8 years ahead of the planned COD. Thus, assuming a desired 2035 COD, PRPA would need to start development in 2027. If PRPA pursues incremental nuclear capacity additions through the PPA route, this development time would not be required but coordination with a nuclear utility would be required to ensure that there is a valid PPA path forward. Platte River's identified need is for generation with extreme flexibility to follow the intermittency of wind and solar generation with an annual capacity factor of about 20 percent; and 200+ starts a year. Current and near-term nuclear generation designs do not meet this criterion. In addition, the Platte River criteria requires technology that has been proven based on commercial installations and operations by existing utilities, have proven reliability and economies. Considering all this, these nuclear generation technologies are not suitable for Platte River for 2028 commercial operation; the identified time of need for new capacity.

3.4.2 Status of New Fuel Availability and Spent Fuel Disposal Options

For the Nuclear SSO paths, the LWR SMRs utilize existing nuclear fuel that is widely available for both US and international fuel suppliers. No new fuel development is required. Some designs such as the NuScale LWR SMR require different length fuel assemblies, but this does not require any significant development. The LWRs will also be able to take advantage of slightly higher fuel enrichments going forward, typically 5 to 8 percent versus the 3 to 5 percent enrichment currently used. For the Gen IV or advanced nuclear plants, the majority are utilizing different forms of High-Assay Low-Enriched Uranium (HALEU) fuel, typically less than 20 percent enrichment. For this fuel, both the enrichment and the fabrication require development of potential suppliers. Currently Russia is the primary supplier of HALEU fuel outside of lower volumes that can be down blended by the US Department of Energy (DOE).

Because of the fuel availability restrictions, the Gen IV or advanced plants are more likely to be commercially viable after 2030.

3.4.3 Status of United States Government Support/Funding

In April 2012, the US DOE announced a $452 million grant program to facilitate the development and deployment of US-owned SMRs. The goal of the program was to promote the accelerated commercialization of United States developed SMR technologies that offer affordable, safe, secure, and robust sources of nuclear energy that can help meet the nation's economic, energy security, and climate change objectives. Program funding provided at a minimum of 50 percent industry cost-share to SMR vendor and utility partnerships and will be focused on FOAK engineering (FOAKE) costs associated with design certification and licensing efforts. The program was utilized to support two SMR designs: B&W mPower and the NuScale Power Module. Since the cost-share awards, B&W initially cut funding for its mPower program to less than $15 million per year, citing a lack of major investors and weak interest from potential customers. B&W later discontinued funding of the mPower program. NuScale continued its development of their SMR design.

The status of the more recent DOE Advanced Reactor Demonstration Project (ARDP) and DOE Technology or Risk-Reduction Awards from 2020 is shown in Table 3-15. DOE has provided a number of other funding awards for both fuel, reactor, and various research/materials development to accelerate the pace of new advanced reactor designs. The goal of this recent funding is to help bring the new technology to the US market as well as to provide for potential future export markets.

Table 3-15 DOE SMR ARDP and Technology Risk-Reduction Award Status

DOE Award Type	Reactor Technology Developer/Award Recipient	Type	Technology
ARDP	TerraPower LLC	Natrium Reactor	Sodium Cooled Fast Reactor
ARDP	X-energy	Xe-100	High Temperature Gas Reactor
Risk Reduction Award	Kairos Power	Hermes reduced-scale test reactor	Salt-Cooled High Temperature Reactor
Risk Reduction Award	Westinghouse	eVinci™ Microreactor	Heat Pipe-Cooled Microreactor
Risk Reduction Award	BWXT Advanced Technologies, LLC	BWXT Advanced Nuclear Reactor (BANR)	Transportable Microreactor
Risk Reduction Award	Holtec	SMR-160	LWR SMR
Risk Reduction Award	Southern Company	TerraPower MCRE	Fast-Spectrum Salt Reactor

SMRs are loosely defined as producing less than 300 MWe but can be combined in clusters to produce more megawatts. Light-water based SMRs more closely resemble their larger Gen III+ reactors and would therefore experience a shorter regulatory review/approval durations because of NRC familiarity. The light-water SMRs (shown in Table 3-16) are the primary candidates preparing for NRC regulatory review for DC and/or Construction Permit (CP). A number of non-light-water based SMRs, or advanced reactors have initiated pre-application activities with the NRC. Table 3-17 shows a list of nuclear reactors currently under construction. The NRC has recently granted Southern Company permission to load fuel into the Unit 3 AP1000 plant in preparation for startup in 2023.

Table 3-16 SMR Regulatory Review [2]

Vendor	Reactor	Size (MWe)	Status
B&W	mPower	180	Pre-Application (work halted)
GEH	BWRX-300	300	Pre-Application
Holtec Int.	SMR-160	160	Pre-Application
NuScale Power	NuScale	50-77 per module	DC
Westinghouse	SMR	225	NA – no engagement

Table 3-17 LLWR Reactors Under Construction

CO Date	Utility	Site / Location	Technology
2023/24	Southern Nuclear	Vogtle 3 and 4 / Georgia	2 x AP1000

For the purposes of this report Black & Veatch has focused on characterizing a representative SSO for each of the primary nuclear power plant technologies, the Westinghouse AP-1000 (LLWR), the GEH BWRX-300 SMR (LWR SMR), and the TerraPower Natrium Reactor (non-LWR advanced reactor). The Westinghouse SMR that was in previous reports is no longer considered a viable option since it is not being developed further by Westinghouse.

3.4.4 Nuclear SSO - Light Water Reactor Small Modular Reactors

Gen III+ SMRs are all LWRs and use conventional BWR or PWR fuel like the existing LLWR operating fleet. Study basis parameters for the selected nuclear SMR LWR SSOs are summarized in Table 3-18. Note, the three SMR LWR SSOs in the table represent the active LWR designs that could be developed by a utility in the U.S. market. Previously, the BWXT mPower™ SMR would have been a fourth LWR option; however, the Generation mPower partnership between BWXT and Bechtel was terminated in 2017. All three of the LWR SSOs are in the pre-application stage with the NRC. Of the three LWR SSOs, both the NuScale NPM-20 and the BWRX-300 designs have a licensing advantage since the NPM-20 is the updated version of the NuScale design that has gone through the design certification process and the BWRX-300 is a derivative SMR plant based on the larger ESBWR LWR design that has been through design certification. All three of the LWR SSOs below are also currently involved in the Canadian Nuclear Safety Commission (CNSC) Vendor Design Review (VDR) process. Thus, the three LWR SSOs have the ability to be deployed in a broader North American fleet that could provide both capital and operational savings. Table 3-18 provides a technology overview of three SMRs that are currently anticipated to be available for a 2030 COD, including the NuScale Power Module™ (NPM), the GEH BWRX-300, and the Holtec SMR-160.

[2] NRC.gov New Reactor Licensing Status for SMRs

Table 3-18 Study Basis Parameters for the Selected Nuclear SMR LWR SSOs

SSO	Plant Configuration	Plant Type	Reactor Rating (MWth)	Plant Output (MWE)	Licensed
NuScale Power Module™ Original (50 MWe) NPM-20 (77 MWe)	NuScale's scalable design—power plants that can house up to four, six, or 12 individual power modules—offers the benefits of carbon-free energy and reduces the financial commitments associated with gigawatt sized nuclear facilities. Fully factory fabricated NPM generates a gross output of 50 (or 77) MWe using a safer, smaller, and scalable version of pressurized water reactor (PWR) technology. Original power module = 160 MWth, 50 MWe; Each NPM-20 module = 250 MWth, 77 MWe (gross) Up to 12 modules in Reactor Building NPM 4-Module Plant – 308 MWe NPM 6-Module Plant – 462 MWe NPM 12-Module Plant – 924 MWe	Gen III+ iPWR	160 or 250 per module	50 or 77 per module	NRC (design certification)
General Electric-Hitachi (GEH) BWRX-300	The BWRX-300 is an approximately 300 MWe water-cooled, natural circulation SMR with passive safety systems. As the tenth evolution of the Boiling Water Reactor (BWR), the BWRX-300 represents the simplest, yet most innovative BWR design since GE began developing nuclear reactors in 1955.	Gen III+ BWR	870	300+	NRC (pre-application) CNSC – VDR Stage 2
Holtec SMR-160	SMR-160, developed by Holtec International (USA), is an SMR designed to produce 160 MW of electricity using low enriched uranium fuel.	Gen III+ PWR	480	160	NRC (pre-application)

3.4.4.1 Technology Overview: NuScale

NuScale originally developed their integral PWR (iPWR) to be a standalone reactor with a capacity of approximately 50 MWe. To take advantage of greater economies of scale, NuScale has designed their plant around having multiple reactor modules that can be operated depending on the load requirements. NuScale's scalable design—power plants that can house up to four, six, or 12 individual power modules—offers the benefits of carbon-free energy and reduces the financial commitments associated with gigawatt sized nuclear facilities. Fully factory fabricated NuScale Power Module™ (NPM) generates a gross output of 50 (or 77) MWe using a safer, smaller, and scalable version of PWR technology (the higher output resulted from NuScale uprating the reactor power to help with $/MW cost ratings).

- Original power module = 160 MWth, 50 MWe.
- Each NPM-20 module = 250 MWth, 77 MWe (gross).
- Up to 12 modules in a single Reactor Building.
- NPM 4-Module Plant – 308 MWe.

- NPM 6-Module Plant – 462 MWe.
- NPM 12-Module Plant – 924 MWe.

3.4.4.2 Technology Overview: GEH BWRX-300

The BWRX-300 is a 300+ MWe water-cooled, natural circulation SMR with passive safety systems. As the tenth evolution of the BWR, the BWRX-300 represents the simplest, yet most innovative BWR design since GE began developing nuclear reactors in 1955.

The BWRX-300 is based on the NRC-licensed, 1,520 MWe ESBWR and is designed to provide clean, flexible baseload electricity generation that is competitively priced and estimated to have the lifecycle costs of typical natural gas combined-cycle plants targeting $2,250/kW for NOAK (nth of a kind) implementations.

The BWRX-300 has the following benefits and features:

- World class safety mitigates loss-of-coolant accidents (LOCA) enabling simpler passive safety.
- Cost competitive: Projected to have reduced capital cost per MW when compared with typical water-cooled SMR.
- Passive cooling: Steam condensation and gravity allow BWRX-300 to cool itself for a minimum of 7 days without power or operator action.
- Quick Deployment: Deployable as early as 2028 thanks to proven know-how and construction techniques.
- Uses existing GNF2 fuel that is the primary BWR fuel in the current operating fleet, thus, no fuel development program is required.

3.4.4.3 Technology Overview: Holtec SMR-160

The Holtec SMR-160, developed by Holtec International (USA), is a SMR designed to produce 160 MWe using low enriched uranium fuel. The SMR-160 is a PWR with passive safety systems designed by SMR, LLC, a Holtec International Company. The reactor, steam generator, and spent fuel pool are located in containment with the reactor core well below grade. The SMR-160 was sized so that it would be possible to use either conventional cooling towers or air-cooled condensers for sites that have limited water availability.

3.4.5 Nuclear SSO - Advanced Reactor Small Modular Reactors

The Gen IV or advanced reactors are still in development now, with the technology developers working on the reactor technology, fuel technology, and nuclear licensing. While there are two technologies that were selected for the DOE ARDP with a goal for a 2028 COD, a more realistic date for commercially available reactors would be 2035. The four advanced reactors considered as part of this IRP are the Kairos Power FHR, the TerraPower Natrium reactor, the X-energy Xe-100 reactor, and the Terrestrial Energy IMSR®. Study basis parameters for the selected nuclear Advanced Reactors non-LWR SSOs are summarized in Table 3-19. All of these reactors have received some level of funding and/or have current customer interest. Note, the four SMR advanced reactor SSOs in the table represent the most probable advanced reactor designs that could be developed by a utility in the US market based on their current development and licensing status. All four of the advanced reactor SSOs are in the pre-application stage with the NRC. The X-energy and Terrestrial Energy advanced reactor SSOs are also currently involved in the CNSC VDR process.

Table 3-19 Study Basis Parameters for Nuclear Advanced Reactors (non-LWR Designs) SSOs

SSO	Plant Configuration	Plant Type	Reactor Rating (MWth)	Plant Output (MWE)	Licensed
Kairos Power FHR	The Kairos Power fluoride salt-cooled high temperature reactor (KP-FHR) is a novel advanced reactor technology that aims to be cost competitive with natural gas in the US electricity market and to provide a long-term reduction in cost. Higher process temperature allows for industrial heating in addition to power production. DOE Technology Demonstration Award	Gen IV FHR	311.1	140	No/Pre-Application Status with NRC
TerraPower Natrium Reactor	The TerraPower Natrium™ technology features a cost-competitive sodium fast reactor combined with a molten salt energy storage system. This unique combination will provide clean, flexible energy and stability, and integrate seamlessly into power grids with high penetrations of renewables. The integral salt storage allows the unit to produce a peak of 500 MWe for a period of 5.5 hours when needed to help balance renewables or supply peak demands. DOE ARDP Award Recipient	Gen IV Sodium Cooled Fast Reactor	767 est.	345	No/Pre-Application Status with NRC
X-energy Xe-100	X-energy's reactor designs are based on HTGR technology — a Gen-IV reactor technology with a proven operational pedigree. The Xe-100 plant is modular and scalable with up to four modules per group. Helium cooled with TRISO fuel. DOE ARDP Award Recipient	Gen IV HTGR	200 per module 800 per 4 module plant	80 per module 320 per 4 module plant	No/Pre-Application Status with NRC
Terrestrial Energy IMSR	The IMSR uses a molten salt as coolant and fuel. Molten salts are thermally very stable, making them superior coolants compared to water. This permits lower pressure and high temperature operation. When a molten salt coolant and molten salt fuel are used in combination, the reactor has the potential to incorporate the virtues of passive and inherent reactor safety as well. As a result, using molten salt technology in the IMSR design leads to a nuclear power plant that is "walk-away" safe and has transformative commercial advantages. Operating at greater than 44 percent thermal efficiency, an IMSR power plant generates 195 MWe with a thermal-spectrum, graphite-moderated, molten-fluoride-salt reactor system. It uses today's standard nuclear fuel – comprising standard-assay low-enriched uranium (less than 5 percent 235U) – critical for near-term commercial deployment. The IMSR power plant design incorporates many aspects of Molten Salt Reactor operation that were researched, demonstrated, and proven by test reactors at the Oak Ridge National Laboratory.	Gen IV MSR	443	195	No/Pre-Application Status with NRC

It is also important to note that in the 15 to 20-year time horizon, in addition to Gen IV SMRs, it would be possible to have large centrally located Gen IV reactors in the 600-1000+ MW size. When Gen IV technology was first being developed during the nuclear renaissance period, the Gen IV plants were all being sized in this range to take advantage of the economies of scale from the larger MWe outputs. Based on current industry thinking, the Gen IV technology will be proved out first on a smaller scale and then as the market demands, may be scaled up to larger outputs. This is raised here as another possible nuclear SSO could be a 100+ MW PPA share of a larger Gen IV reactor plant. This option would be more likely in a 2040 timeframe.

3.4.5.1 Kairos Power FHR

The Kairos Power fluoride salt-cooled high temperature reactor (KP-FHR) is a novel advanced reactor technology that aims to be cost competitive with natural gas in the US electricity market and to provide a long-term reduction in cost. Higher process temperature allows for industrial heating in addition to power production. The KP-FHR plant uses accident tolerant TRISO fuel to provide a high-degree of fuel safety. Use of TRISO fuel in the FHR plant also eliminates the complicated chemical processing plant that is required for more conventional MSR plants.

The Kairos Power FHR was a 2020 DOE Technology Demonstration award recipient. Kairos Power has started to submit Licensing Topical Reports and other documentation to support safety evaluations with the NRC.

3.4.5.2 TerraPower Natrium Reactor

The TerraPower Natrium™ technology features a cost-competitive sodium fast reactor combined with a molten salt energy storage system. This unique combination will provide clean, flexible energy and stability, and integrate seamlessly into power grids with high penetrations of renewables. TerraPower and GE-Hitachi Nuclear Energy developed the Natrium technology with a 345 MWe sodium fast reactor. The integral salt storage allows the unit to produce a peak of 500 MWe for a period of 5.5 hours when needed to help balance renewables or supply peak demands.

The TerraPower Natrium Reactor was one of the DOE ARDP award recipients.

3.4.5.3 X-energy Xe-100 Reactor

X-energy's reactor designs are based on HTGR technology — a Gen-IV reactor technology with a proven operational pedigree. The Xe-100 plant is modular and scalable with up to four modules per group. Helium cooled with TRISO fuel.

The X-energy Xe-100 Reactor was a 2020 DOE ARDP award recipient.

3.4.5.4 Terrestrial Energy Integral Molten Salt Reactor

The IMSR uses a molten salt as coolant and fuel. Molten salts are thermally very stable, making them superior coolants compared to water. This permits lower pressure and high temperature operation. When a molten salt coolant and molten salt fuel are used in combination, the reactor has the potential to incorporate the virtues of passive and inherent reactor safety as well. As a result, using molten salt technology in the IMSR design leads to a nuclear power plant that is "walk-away" safe and has transformative commercial advantages.

Operating at greater than 44 percent thermal efficiency, an IMSR power plant generates 195 MWe with a thermal-spectrum, graphite-moderated, molten-fluoride-salt reactor system. It uses today's standard nuclear fuel – comprising standard-assay low-enriched uranium (less than 5 percent 235U) – critical for near-term commercial deployment. The IMSR power plant design incorporates many aspects of MSR operation that were researched, demonstrated, and proven by test reactors at the Oak Ridge National Laboratory. The IMSR does require a chemical processing plant to remove the “spent” nuclear fuel from the molten salt.

3.4.6 Nuclear Cost Parameters

Every developer of new generation wants both cost and schedule certainty from a reactor technology; however, costs for new nuclear can vary significantly. When looking at new build cost data, the biggest issue is the relatively low amount of input data since very few new reactors have been built in the US Cost data from international projects is available, but it is not expected to represent what the cost of new nuclear will be in the United States. In international countries that have continued to build new nuclear in a repetitive manner, cost and schedule certainty has been obtained. These countries have often had either state-sponsored or state-controlled supply chains and construction entities to assist in the delivery of the units. In the United States, consistency in the cost and schedule certainty of new nuclear is important and will need to be developed through both disciplined execution and repeat projects. The global push to decarbonization may assist with having more repeat projects to improve learning and future delivery performance. The following section provides information on the expected capital cost and levelized cost for the different types of nuclear SSOs.

LLWR plants have large capital costs. Not only is the nuclear technology expensive but the balance-of-plant (BOP) and site infrastructure costs to support the large plants are also expensive. The previous target for LLWR plants during the nuclear renaissance period was $4,500 per kilowatt (kW); however, recent LLWR construction has not been able to achieve this target. Most new plant construction has resulted in cost overruns nearly doubling the original cost of the units. This is evidenced by capital costs of approximately $9,000/kW for recent LLWR AP1000 nuclear plant projects in Georgia and South Carolina. As a result, the AP1000 units in South Carolina have been canceled because of these cost overruns. The AP1000 units in Georgia at the Vogtle site are still in construction and costs are likely to go up further due to these further delays. The final cost for the Vogtle units will certainly be over $9,000/kW before they are fully commercial.

LCOE values for LLWR range from $100 per megawatt-hour (MWh) on the lower end to values of $160 to 180/MWh on the upper end. Capital costs and LCOE values for SMRs and advanced reactors can be estimated; however, actual as-built and actual operating values are not available. The following provides information on expected costs for various SMR and advanced reactor technology. Advertised capital costs and LCOE values should be reviewed carefully to understand the cost assumptions that went into developing the numbers. NOAK figures are often presented that make optimistic assumptions about cost savings for NOAK units that may or may not be realized.

NuScale NPM-20 has an NOAK overnight capital cost of approximately $3,600/kW, backed by their AACE Class IV cost estimate. The cost estimate for NuScale increased from $1,200 per kilowatt electric (kWe), an early preconceptual cost estimate, to $5,078/kWe (2014 USD) in Fluor’s estimates prior to the uprating to the NPM-20 size. The target LCOE for NuScale’s first 12-module power plant is $65/MWh. [Reference: NuScale website] An estimate of the NuScale NOAK LCOE is in the range of $51/MWh to $54/MWh calculated using NuScale’s design estimates. [Reference: PNNL-30225: Techno-economic Assessment for Generation III+ Small Modular Reactor Deployments in the Pacific Northwest, April 2021.]

For the BWRX-300, the NOAK overnight capital cost is in the range of $4,000/kW. The BWRX-300 LCOE is in the range of $44 to $51/MWh. This LCOE was calculated for the NOAK BWRX-300 using GE-Hitachi's (GEH's) design-to-cost and target pricing input. [Reference: PNNL-30225: Techno-economic Assessment for Generation III+ Small Modular Reactor Deployments in the Pacific Northwest, April 2021.]

Table 3-20 provides a cost summary for SMR advanced reactors. From Black & Veatch's work with different technology developers, the average costs below are reasonable for NOAK costs. FOAK and early plants will be higher as discussed previously. Costs for micro-reactors on a per kW or per MWh basis may be higher than this because of the smaller output; however, some of the micro-reactors will have low BOP costs and lower operational costs which may bring the levelized costs down. Very little data is available to support validation of these cost values for micro-reactors.

Table 3-20 Cost Summary for SMR Advanced Reactors

	Average	Minimum	Maximum
Capital Cost Total	$3,782/kW	$2,053/kW	$5,855/kW
Operating Cost Total	$21/MWh	$14/MWh	$30/MWh
Levelized Cost of Electricity	$60/MWh	$36/MWh	$90/MWh

The average LCOE of $60/MWh from the Energy Options Network (EON) study participants is 39 percent lower than the $99/MWh expected by the US Energy Information Agency for PWR nuclear plants entering service in the early 2020s (EIA 2017b). A realistic view of nuclear costs should consider past performance as well as reasonable NOAK expectations. Black & Veatch's recommendation would be to consider that nuclear costs will not approach the minimum values stated but instead should assume delivered costs will be between the expected average and the maximum cost.

An important consideration in the cost review of nuclear plants is that they are expected to have a minimum design/operating life of 60 years. Like the existing operating fleet, many of the LWR SMRs and the advanced reactors would be capable of additional life extension, likely out to 80 years. This is significantly longer than the operational life of other generation technologies.

3.4.6.1 Cost and Performance of Nuclear Alternatives

The estimated operating characteristics of the SMR nuclear units are presented in Table 3-21. The estimated capital costs and O&M costs for nuclear generation are also summarized in Table 3-21.

Table 3-21 Nuclear Unit – Performance and Costs

	GEH BWRX-300 LWR SMR	Terrapower Natrium Non-LWR Advanced Reactor
Commercial Status	Currently under pre-NRC application review	Currently under pre-application review with NRC
Construction Period (months) from First Safety Concrete	Approximately 36	Approximately 36
Performance		
Net Capacity (MW)	300	345
Net Plant Efficiency (percent)	33	45
Capacity Factor (percent)	95	90
NOAK Economics (2023 USD)		
Overnight Construction Cost ($M)	$1,500	$1,000 est.
O&M ($/MWh)	$44 to 51	$50 to 60

The capital cost is the estimated EPC cost inclusive of EPC and indirect costs for construction of each alternative utilizing a fixed price, turnkey type contracting structure. Additional costs such as escalation, financing fees, and interest during construction would need to be accounted for separately. Also note that the economic values for the LWR SMR and the non-LWR advanced reactor are for the NOAK plants, which would not have the FOAK engineering costs and would be able to take advantage of optimized manufacturing facilities, which would leverage the economics of mass manufacturing to reduce the costs of the modular components of the facility. For the manufacturing facilities to be built, a significant number of orders would need to be generated in the industry. Therefore, it should be understood that the first SMR plants to be constructed will cost considerably more, in the range of 50 to 80 percent above the NOAK cost.

There are no fossil emissions from the nuclear reactor directly connected to power generation. However, there are some incidental emissions related to periodic operation of standby equipment.

3.4.7 Summary Conclusions

Platte Rivers' capacity needs include the capabilities for the new generation to start quickly and load-follow through frequent ramping up and down as a complement to renewable generation. The nuclear fueled technologies that are available or expected to be available in the time frame of Platte Rivers' capacity needs do not meet the quick start and ramping abilities. Given those limitations associated with nuclear technologies, they are not recommended for further consideration as part of PRPA's 2023 supply side evaluation and associated integrated resource planning.

3.5 Fuel Cell Power Generation

Fuel cell generation (FCG) technology has been developed by government agencies and private corporations. Fuel cells are an important part of space exploration and are receiving considerable attention as an alternative power source for automobiles. In addition to these two applications, fuel cells continue to be considered for power generation to meet permanent and intermittent power demands. However, because of the early developmental status of several FCG technologies and uncertainty related to reliability and cost, they are not considered to be commercially proven alternatives to RICE and CTG for utility-scale power generation applications.

3.5.1 Operating Principles

Fuel cells convert hydrogen-rich fuel sources directly to electricity through an electrochemical reaction rather than combustion. Fuel cell power systems have the promise of high efficiencies because they are not limited by the Carnot efficiency that limits thermal power systems. Fuel cells can sustain high efficiency operation even at part load. The construction of fuel cells is inherently modular, making it easy to size plants according to power requirements.

Fuel cells are composed of two electrodes separated by an electrolyte. The specific reactions that occur at the electrodes depend on the type of electrolyte employed within the fuel cell. However, in general, ions are created at either the anode or cathode, then pass through the electrolyte; simultaneously, electrons flow between the electrodes through an external circuit, producing an electrical current. Catalysts are often employed to enhance the reaction kinetics at the electrodes. There are six prominent types of fuel cells, typically distinguished by the material that serves as the electrolyte within the fuel cell. These include the following:

- Proton Exchange (or Polymer Electrolyte) Membrane Fuel Cells (PEMFC).
- Phosphoric Acid Fuel Cells (PAFC).
- Molten Carbonate Fuel Cells (MCFC).
- Solid Oxide Fuel Cells (SOFC).
- Microbial Fuel Cells (MFC).

Fuel cell systems typically have electrical efficiencies on the order of 40 to 50 percent. Overall efficiency from cogeneration or CHP facilities can approach 90 percent when the thermal energy from the fuel cell is utilized for low-grade energy recovery, thereby making them particularly advantageous for distributed energy applications. Most FCGs have lower emissions and quiet operation relative to many RICE systems. However, fuel cells suffer from a number of shortcomings, including high capital costs, limited fuel cell stack life of approximately 5 to 10 years (which increases O&M costs), inability to directly ramp up and down with electrical load without use of a hybrid power system, and corrosion/breakdown of cell components, resulting in power generation degradation over the cell stack life. Natural gas fueled FCGs also exhibit long startup times because of the high temperatures required for operation, thus most FCGs generally operate primarily as baseload generation and cannot be dispatched to follow load.

Additionally, many FCG technologies are susceptible to poisoning by contaminants in the fuel stream, thereby requiring highly pure hydrogen. Thus, while most commercial fuel cell power plants use natural gas as a feedstock, it first must be converted to hydrogen in a reformer at temperatures of 1,100 to 1,500° F before being fed to the fuel cell stack. Lower-temperature FCGs (e.g., PEMFC and AFC) require highly-purified hydrogen as the direct feed. Because of the intricacies of these fuel cell chemistry-specific operating principles, any commercial deployment would require a more thorough study to examine costs/benefits of various FCG technologies while incorporating both capital/O&M costs as well as fuel costs. That all being said, distinguishing features for these FCG technologies are listed in Table 3-22.

Table 3-22 Distinguishing Features of Different Fuel Cell Chemistries [3]

Fuel Cell Technology	Electrolyte	Electrode Catalyst	Mobile Ion	Operating Temp. (°F)	Potential Fuels
PEMFC	Water-based, acidic polymer membrane	Platinum	H^+	<200	Hydrogen
PAFC	Phosphoric acid in silicon carbide structure	Platinum	H^+	300 to 400	Hydrogen
MCFC	Liquid carbonate salt suspended in porous ceramic	None	CO_3^{2-}	1,200	Hydrogen, natural gas, biogas
SOFC	Solid ceramic (e.g., zirconium oxide/ yttrium oxide)	None	O^{2-}	1,500 to 1,800	Hydrogen, natural gas, biogas
MFC	Buffer solutions of various types	Various	Various	<100	Various

3.5.2 Applications

MFC technology is a relatively new technology and not generally considered appropriate for power generation applications (rather small-scale waste remediation and trickle charging). PEMFC has become the favored chemistry for terrestrial applications and has been developed extensively for mobility (e.g., fuel cell electric vehicle, lift truck) applications. As a result of this development, the durability has significantly increased, and costs have fallen dramatically over the past 10 to 15 years. However, PEMFC remain susceptible to CO poisoning and have some of the most stringent hydrogen purity requirements of any technology, thereby limiting their applicability to power generation.

PAFC is a long-established fuel cell technology for power applications with many years of development and operational history. Because of relatively low operating temperatures, cell corrosion and degradation is limited and PAFCs have demonstrated long operating lifespans as high as 80,000 hours prior to stack replacement. However, the use of expensive catalyst material and stack design results in a relatively high cost for this technology. MCFC and SOFC have also been developed for stationary power generation applications and have a clear advantage over lower-temperature FCGs in their ability to operate on hydrogen, biogas/syngas, and natural gas directly with limited reforming. However, given their high operating temperatures they frequently suffer from lower durability, limited ramping/dynamic response characteristics, and higher costs.

[3] US Department of Energy. (2022, January 1). Types of fuel cells. Energy Efficiency and Renewable Energy, Hydrogen and Fuel Cell Technologies Office. Retrieved December 1, 2022, from https://www.energy.gov/eere/fuelcells/types-fuel-cells

3.5.3 Cost and Performance Characteristics

Given the aforementioned limitations associated with MFC technologies, MFC is not recommended for further consideration as part of PRPA's 2023 supply side evaluation and associated integrated resource planning. The performance and cost characteristics of a typical FCG plant, by technology type are shown in Table 3-23 for hydrogen only. Significant cost is required to replace the fuel cell stack every 5 to 10 years because of degradation. The stack alone can represent up to 40 percent of the initial capital cost, which has been modeled based on the number of replacements expected during the 20-year life of the unit.

Table 3-23 Fuel Cell Generation Technology Characteristics

	PEMFC	PAFC	MCFC	SOFC
Performance				
Typical Operating Life (years)	20	20	20	20
Stack Life (years)	10	10	7	5
Typical Duty Cycle	Baseload/Backup	Baseload/Backup	Baseload	Baseload
Net Plant Capacity (MW)	0.5	0.5	0.5	0.5
Net Plant heat Rate (HHV, Btu/kWh) based on hydrogen only	5,700	5,800	6,000	6,500
Capacity Factor (percent)	70 to 90	70 to 90	70 to 90	70 to 90
Economics (2023 USD)				
Overnight EPC Capital Cost ($/kW)	$3,000	$7,000	$8,500	$9,000
Stack Replacements over Life of Unit ($/kW)	$1,200	$2,800	$6,800	$10,800
Fixed O&M ($/kW-y)	$31.42			
Variable O&M ($/MWh)	$0.61			

The construction cost distribution schedule is shown in Table 3-24 and is expected to be roughly similar for all technologies. However, equipment lead times can vary substantially by vendor/technology but would be expected to generally hold to the schedule reflected.

Table 3-24 Construction Cost Distribution Percentages for Fuel Cell Generation Facility

type	Month of Construction[1]		
	(-9)-0	0-6	6-12
All Fuel Cells	10	40	50

[1]Construction is assumed to begin at Month 0. Construction costs and equipment costs will begin to be accrued in the nine months preceding Month 0.

3.5.4 Environmental Impacts

Because only hydrogen is considered, all FCG technologies would be expected to have negligible air emissions except for NOx emissions at 0.002 lb/MBtu for PAFC and SOFC technologies, given the need to combust hydrogen to sustain high temperatures.

3.5.5 Summary Conclusion

Platte River's capacity needs include the capabilities for the new generation to start quickly and load-follow through frequent ramping up and down as a complement to renewable generation, providing about 170 MW of capacity by 2028. Fuel Cell technologies available today or likely to be available by 2028 are not expected to fill this duty cycle, and therefore, do need meet Platte Rivers dispatchable capacity needs.

3.6 Hydroelectric Generation

There are two main types of hydropower projects: Run-of-river and storage. In run-of-river hydropower, a portion of the flowing water from a river is channeled through a canal to utilize the natural decline of the river bed elevation to spin a turbine connected to a generator. A run-of-river project will typically have little or no storage. Storage hydropower typically uses uses a dam to store water in a reservoir by blocking the river flow (also called impoundment facility). Electricity is produced by releasing water from the reservoir through a turbine, which powers a generator. Storage hydropower has the ability to be shut down and started up at short notices according the demands of the system. Large facilities may have enough storage capacity to operate without hydrological inflow for many days or even weeks.

Because hydropower uses water to generate electricity, plants are usually located on or near a water source. The energy available from the moving water depends on both the volume of the water flow and the change in elevation—also known as the head—from top of the reservoir to the bottom where the turbine is located. The greater the flow and the higher the head, the more the electricity that can be generated.

Hydropower plants range in size from small systems to large projects producing electricity for utilities. The water may be released from the reservoir to meet changing electricity demand or for other needs, such as flood control, recreation, fish passage, and other environmental and water quality requirements.

A form of storage hydropower is Pumped Storage Hydroelectric (PSH). PSH involves pumping a volume of water from a lower elevation during times of low electric demand to a higher elevation to be used during periods of high demand to generate electricity. The movement of the mass in the gravitational field stores the energy as potential energy that can later be harnessed as the water is released back down to the lower elevation reservoir through a turbine. The technology is not considered new or emerging like many other long duration energy storage systems. PSH is a mature long duration energy storage technology that has been utilized for over a century. The components that make up a PSH system are large heavy civil works that last for many decades.

There are two fundamental systems – closed loop and open loop. Closed loop systems do not interact with natural waterways such as rivers, lakes, or reservoirs that impound large amounts of natural runoff. Open loop systems differ in that the water used in the storage systems interacts with natural waterways.

The main features of a PSH project include two reservoirs (upper and lower), a penstock to convey the water between the two, a powerhouse with one or more hydro-electric pump/turbine generators and other auxiliary equipment, a switchyard, and utility intertie.

Typically, PSH powerplants use a Francis turbine coupled to a large diameter salient pole generator. Francis turbines operate best in the general range from a 100-200 feet of water column to 2000+ feet of water column. Traditional PSH favors larger elevation gains to maximize water pressure while minimizing the volume of water required (and size of the reservoirs). When identifying appropriate siting locations, the elevation between the lower and upper reservoir should coincide with the range for optimal use of the Francis turbine. The shape of the Francis turbine blade is designed for a specific water pressure. This means that if the variation in upper reservoir level from charged to discharged conditions should be minimized within reason. Other pump-turbines technologies can also be used depending on the site conditions. When operating in generating mode, the generators work like traditional hydropower. However, when in pump mode, accommodations are required for starting and maximizing efficiency such as reversing switches, starting pony motors, and variable speed drive electronics.

3.6.1 Summary Conclusions for Hydro Power Expansion

Challenges for hydro power growth include long development lead times, large up-front capital investment, and ability to permit a new facility. Most of the available hydro power locations have already been developed in the US. There are very few, if any, additional suitable locations available to build new hydro or pump storage facilities in the country. Even if a site is available, environmental concerns make it very difficult to build one. Based on the topology of the PRPA service area it is unlikely that new hydropower development is a viable generation expansion option for PRPA. Given those concerns associated with hydro technologies, hydro generation options are not recommended for further consideration as part of PRPA’s 2023 supply side evaluation and associated integrated resource planning.

3.7 Geothermal

Geothermal power is produced by using steam or a secondary working fluid in a Rankine Cycle to produce electricity. Geothermal energy was first used to make electricity at the beginning of the 20th century. In 1904, Prince Piero Conti, owner of the Larderello fields in Italy, attached a generator to a natural-steam-driven engine, which lit four light bulbs. This experiment led to the installation of the world’s first geothermal power plant in 1911, with a capacity of 250 kW. The government of New Zealand was the first significant producer of geothermal electricity, with the approximately 150 MW Wairakei power plant, which began operating in 1958. Shortly thereafter, the first power plants were installed at the Geysers in California. By 1975, the Larderello fields were capable of producing about

400 MW of power. By the mid-1980s, the Geysers' output had peaked at about 1,600 MW, after which it declined to its present output at about 850 MW.[4] Currently, roughly 70 geothermal power facilities are in operation in over 20 countries around the world.[5] There is a natural concentration of geothermal resources in regions characterized by volcanism, active tectonism, or both. For example, Indonesia and the Philippines have many large, high-temperature geothermal resources.

The most commonly used power generation technologies are direct steam (or dry steam), single-flash, dual-flash, and binary systems. In addition, efforts are underway to develop "enhanced geothermal" projects. The choice of technology is driven primarily by the temperature and quality of the steam/liquid extracted from the geothermal resource area. These geothermal technologies are classified as follows:

- Direct steam: For geothermal resources that provide slightly superheated steam, direct-steam technologies may be employed. Superheated steam (with temperatures exceeding 350° F) is gathered from the geothermal reservoir (via production wells) to drive a condensing steam turbine-generator. Following expansion in the steam turbine, the brine is scrubbed as necessary to remove acid gases and other contaminants, and re-injection wells are employed to return the geothermal brine to the geothermal reservoir.
- Single-Flash or Double-Flash: Flash systems are used in high temperature (i.e., greater than 350° F) liquid-dominated geothermal reservoirs. Upon extraction from the geothermal reservoir, the geothermal fluid is a pressurized two-phase mixture of liquid brine and steam. This two-phase mixture is routed to a separator, where the pressure of the mixture is reduced, causing the fluid to flash into steam. This steam is then expanded in STG. Double-flash systems flash the separated brine a second time. In double-flash systems, the lower temperature steam may be expanded through a separate steam turbine, or the steam may be introduced into the HPT through a second admission port. As in direct steam systems, the spent brine is scrubbed and re-injected into the geothermal reservoir.
- Binary: Binary cycle systems are employed for development of liquid-dominated geothermal reservoirs that do not have temperatures sufficiently high enough to flash steam (i.e., less than 350° F). In a binary system, a secondary fluid is employed to capture thermal energy of the brine and operate within a Rankine Cycle. Additional details regarding binary geothermal systems are discussed below.
- Enhanced geothermal (or "hot dry rock"): For geologic formations with high temperatures but without the necessary subsurface fluids or permeability, fluid may be injected to develop geothermal resources. Typically, the geologic structure must be hydraulically fractured to achieve a functional geothermal resource. While enhanced geothermal projects are currently being demonstrated around the world (including the Newberry Volcano EGS demonstration near Bend, Oregon), this technology is not yet considered commercial.

3.7.1 Resource Availability

Black & Veatch understands that no useful undeveloped geothermal resources are known to exist within PRPA's service territory. General geothermal resource characterizations for the United States have been assumed in the cost, performance, and environmental characteristics provided in this report. Given the

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[4] Sanyal, S. K. (2011) Fifty Years of Power Generation at The Geysers - The Lessons Learned. Proceedings, Thirty-sixth Workshop on Geothermal Reservoir Engineering, Stanford University, January 31 - February 2, 2011, SGP-TR-191.

[5] B. Matek, (2016). 2016 Annual US and Global Geothermal Power Production Report. Geothermal Energy Association. Washington, DC, USA.

lack of availability of geothermal generation options within PRPA's service territory, geothermal generation options are not recommended for further consideration as part of PRPA's 2023 supply side evaluation and associated integrated resource planning.

3.7.2 Cost, Performance, and Environmental Characteristics

Considering the temperatures associated with geothermal resource areas located in the United States, it is anticipated that geothermal developments would utilize either binary geothermal systems or enhanced geothermal systems. Because of the technical and cost uncertainty associated with enhanced geothermal systems, Black & Veatch has selected binary geothermal options for this characterization and has developed performance and cost parameters for a 50 MW-net binary geothermal facility.

In a binary plant, the thermal energy in the geothermal brine is transferred in a heat exchanger to a secondary working fluid for use in a fairly conventional Rankine cycle. The brine itself does not contact moving parts of the power plant, thus minimizing the potential of equipment fouling (e.g., scaling, corrosion or erosion). Binary plants may be especially advantageous for low brine temperatures (i.e., less than about 350° F) or for brines with high dissolved gases or high corrosion or scaling potential.

Most binary plants operate on pumped wells and geothermal fluid remains in the liquid phase throughout the plant, from production wells through the heat exchangers to the injection wells. Dry cooling is typically used with a binary plant to avoid the necessity for makeup water required for a wet cooling system. Dry cooling systems generally add 5 to 10 percent to the cost of the power plant compared to wet cooling systems. Because of chemical impurities, the waste geothermal fluid is not generally suitable for cooling tower makeup. There is a wide range of candidate working fluids for the closed power cycle. The working fluid of the binary system is generally selected to achieve good thermodynamic match to the particular geothermal temperature. The optimal fluid would provide high utilization efficiency with safe and economical operation.

Table 3-25 Geothermal Technology Characteristics

	50 MW Geothermal
Performance	
Typical Operating Life (years)	30
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	50
Net Plant Heat Rate (HHV Btu/kWh)	8,900
Capacity Factor (percent)	75 to 85
Economics (2023 USD)	
Overnight EPC Capital Cost ($/kW)	$3,100
Fixed O&M ($/kW-y)	$144
Variable O&M ($/MWh)	$1.25

Table 3-26 Construction Cost Distribution Percentages for Geothermal Facility

type	Month of Construction[1]						
	(-9)-0	0-6	6-12	12-18	18-24	24-30	30-36
MSW Mass Burn	10	20	25	20	17	7	1

[1]Construction is assumed to begin at Month 0. Construction costs and equipment costs will begin to be accrued in the nine months preceding Month 0.

3.7.3 Environmental Impacts

Because geothermal facilities do not combust a fuel regularly and all air emissions result from well drilling and other activities, there would be expected to have negligible air emissions except for SOx/CO_2 emissions at 0.1 lb/MBtu each.

3.7.4 Summary Conclusion

Black & Veatch understands that no useful undeveloped geothermal resources are known to exist within PRPA's service territory. Given the lack of availability of geothermal generation options within PRPA's service territory, geothermal generation options are not recommended for further consideration as part of PRPA's 2023 supply side evaluation and associated integrated resource planning.

3.8 Li-ion Battery Energy Storage Systems (One-to-Four-Hour Duration at Full Capacity Output)

Battery energy storage is grouped under a broader category of electrochemical energy storage. Electrochemical energy storage technologies include technologies ranging from various battery energy storage chemistries to capacitors. This section will focus on the battery technologies of Lithium Iron Phosphate batteries.

Various Li-ion battery systems are installed around the world, including projects in the United States. Currently there are Li-ion projects in the que or development phase that exceed 100 MW and over 1.0 GWh per installation. According to the DOE Energy Storage Database, the worldwide operational Li-ion capacity is over 3 GW and 4.2 GWh.

In the 4th quarter of 2019, more energy storge was installed on the grid than the cumulative amount to that point in time, more than doubling previous capacity. That inflection point growth has continued to 2023. Meeting the forecasted demand increases in the PRPA system of an average of 400MW discharged for 7 days (168 hours) with the relatively smaller size capacity of typical battery forms of LDES would require multiple systems. Technologies that can independently approach the 168 hours are limited in number. Power capabilities for the systems are scalable by putting multiple systems in parallel. Assuming a system size of approximately 20 MWhs per acre, approximately 3,360 acres would be necessary to meet the PRPA needs of 67,200 MWh. Power density can be much higher with some vendors suggesting 3 MW/acre is easily achievable. With respect to power density, the 700 MW peak power requirement on the PRPA system can be achieved with a much smaller footprint of around 250 acres; however, this would not achieve the energy discharge duration requirements of approximately 400 MW for 7 days. To meet PRPA's energy needs of 67,200 MWh, 16,800 MW of 4-hour duration battery storage will be needed. The cost will be approximately $22 Billion (assuming $1.3/W). The average total project costs for the combustion turbine and RICE options presented above is approximately $244 million. Because of the relatively higher cost compared to conventional generation technology, Li-ion BESS is not a recommended technology for Platte River's needs.

3.8.1 Operating Principles

Batteries are electrochemical cells that convert chemical energy into electrical energy. This is done by electrochemical oxidation-reduction (redox) reactions. The main components of a battery are the positive electrode (cathode), the negative electrode (anode), and the electrolyte. The resulting potential, or voltage, of the battery is based on the composition of the electrodes and the redox reactions that occur at the electrodes.

Batteries come in a wide range of sizes. The size of a battery is based on two parameters: power, usually in kW or MW, and energy, usually in kWh or MWh. The energy storage capacity of a battery designates how long a given energy storage system can discharge at a given power. Other parameters relevant for energy storage systems are:

- Ramp-rate: how quickly an energy storage system can change its power output, typically in MW/ min.
- Response time: how quickly an energy storage system can reach its rated power (constrained by power conversion system).
- Efficiency: the amount of energy discharged from an energy storage system relative to the amount required for charging.
- Discharge duration: how long a battery can be discharged at a given power.

- Charge/Discharge rate (C-rate): how quickly the battery can charge or discharge relative to a one-hour charge or discharge (for example, a 2C rate charges or discharges in 30 minutes).

Operational parameters associated with battery energy storage technologies include:

- State-of-charge (SOC): how much energy is stored in an energy storage system relative to the maximum energy storage capacity.
- Depth of discharge (DoD): how discharged an energy storage system is relative to the maximum energy storage capacity.
- Cycles-to-failure (CtF): the number of cycles at 100 percent DoD until the battery's energy storage capacity reaches 80 percent of its new capacity.
- Self-discharge rate: Self-discharge for Li-ion is on the order of 0.5-5% per month.

3.8.2 Applications

A summary of some of the common parameters for Li-Ion batteries are outlined in Table 3-27 for Li-ion and flow batteries.

Table 3-27 Li-Ion Battery Technology Overview

	Short (30 Minute – 1 Hour Duration)	Medium (2-4 Hour Duration)
Nominal Technology Type	Lithium Iron Phosphate	Lithium Iron Phosphate
Commercial Availability	Commercial	Commercial
Facility Power Rating, MW	0.1 to 400	0.1 to 400
Module Power Rating, MW	0.1 to 2	0.1 to 2
Facility Energy Capacity, MWh	0.1 to 1200	0.1 to 1200
Module Energy Capacity, MWh	0.1 to 4	0.1 to 4
Ramp Rate	Almost Instantaneous	Almost Instantaneous
Response Time(1)	20 to 120 ms	20 to 120 ms
Round-Trip Efficiency, %	80 to 87	80 to 87
Discharge Duration, hours	0.5	2-4
Charge/ Discharge Rate	2C	0.5C-0.25C
(1) Amount of time system takes to reach rated power		

Applications are often grouped into either power or energy applications. Power applications are generally shorter duration (approximately 30 minutes to one hour) applications that may involve frequent rapid responses or cycles. Frequency regulation or other renewable integration applications such as ramp rate control/ smoothing are good examples of power applications. Energy applications generally require longer duration (approximately 2 hours or more) energy storage systems and, as discussed above, longer duration to 4, 8, 12 hours and longer.

3.8.3 Lithium Iron Phosphate Batteries

Li-ion batteries are performing the following applications in the United States. The below list outlines some of the primary benefits being targeted according to the DOE Energy Storage Database. The definitions are adopted from the Electricity Storage Association.

- Spinning Reserve: the use of energy storage to supply generation capacity that is online and dispatchable within 10 minutes.
- Non-Spinning Reserve: a resource that follows spinning reserve dispatch during loss of generation or transmission events and usually required to respond within 10-15 minutes.
- Capacity Firming: the use of energy storage to fill in capacity (power) when variable energy resources, such as solar and wind, fall below their rated output.
- Voltage Support: the use of energy storage to manage and supply reactive power on the grid at or near a power factor of one (1).
- Frequency Regulation: the use energy storage to maintain grid system frequency with a resource that can respond within seconds.
- Ramping Service: using energy storage ramping to offset excessive ramping of other generating facilities, often variable energy resources such as solar or wind.
- Transmission and Distribution Upgrade Deferral: the use of energy storage to avoid expensive transmission and distribution upgrade costs.
- Energy Arbitrage: the use of buying energy in off-peak times and selling back during peak conditions.

Lithium Iron Phosphate (LFP) batteries are the optimal choice grid-scale storage when the discharge duration requirements are 1 to 4 hours based on cost and energy density considerations. Although more energy dense chemistries exist, LFP systems are less prone to thermal runaway and exhibit significantly better degradation profiles versus lithium ion.

- The advantages:
  - Established
  - Lowest cost per kWh of any ESS installation in the 1-4 hour range
  - Simple installation
- The disadvantages:
  - Risk of fire/explosion high
  - Toxic materials
  - Short discharge durations
  - Power and energy cannot be scaled separately, making LFP much more expensive for longer duration storage applications

3.8.4 Li-ion BESS Summary Conclusions

Li-ion BESS installations are not ideal for utilities who are looking for more than four to eight hours of storage duration. Given PRPA’s need for longer duration storage options to provide energy to serve load during longer periods of little solar and wind generation, LFP BESS options are not recommended for further consideration as part of PRPA’s supply side evaluation and associated integrated resource planning.

3.9 Task 1 Summary Conclusions

Of all the dispatchable technologies available today to meet Platte River's dispatchable capacity needs for backup and complementing of renewable energy, RICE and aero derivative gas turbines are the best choice. These technologies can initially be fueled with natural gas and can be progressively converted to non-carbon fuels like renewable natural gas or hydrogen when commercially available.

Heavy duty frame units (like SGT-800 and GE 7F) and traditional combined cycles are poor fit for relatively low annual capacity factors with a high number of annual starts. Simple cycle aeroderivative combustion turbines and reciprocating engines are designed to start often and ramp frequently and do not experience similar negative effects during cyclic operation. The aeroderivative combustion turbines and RICE units meet the suitability criteria of high reliability, relatively lower costs, operational flexibility to complement intermittent renewables under operations at an expected capacity factor around or under 20 percent with 250 or more starts per year. The technologies are commercially viable and proven as a number of utilities are currently operating these technologies to meet their dispatchable capacity needs.

The nuclear fueled technologies that are available or expected to be available in the time frame of Platte Rivers' capacity needs do not meet the quick start, ramping abilities, and part load capabilities. Small modular reactor (SMR) nuclear technology is a new design technology, and it is not commercial yet. It has been reported that the first SMR is expected to be online in 2029. The history of nuclear generation technology in the US is that of delays and cost overruns and it is deemed likely that SMR technology commercial operations will not be available in time to meet Platte Rivers needs. Given the limitations associated with nuclear technologies, they are not recommended for further consideration as part of PRPA's supply side evaluation.

Fuel cell generation (FCG) technology has been developed by government agencies and private corporations. Fuel cells are receiving considerable attention as an alternative power source for automobiles. In addition, fuel cells continue to be considered for power generation to meet permanent and intermittent power demands. However, because of the early developmental status of several FCG technologies and uncertainty related to reliability and cost, they are not considered to be commercially proven alternatives to RICE and aeroderivative combustion turbine technologies for utility-scale power generation applications.

Black & Veatch understands that no useful undeveloped geothermal resources are known to exist within PRPA's service territory. Given the lack of availability of geothermal generation options within PRPA's service territory, geothermal generation options are not recommended for further consideration as part of PRPA's supply side evaluation and associated integrated resource planning.

Li-ion BESS installations are not ideal for utilities who are looking for more than four to eight hours of storage duration. Given PRPA's need for longer duration storage options to provide energy to serve load during longer periods of little solar and wind generation, Li-ion BESS options are not recommended for further consideration as part of PRPA's supply side evaluation and associated integrated resource planning.

Challenges for new hydro power growth include long development lead times, large up-front capital investment, and ability to permit a new facility. Most of the available hydro power locations have already been developed in the US. There are very few, if any, additional suitable locations available to build new hydro or pump storage facilities in the country. Even if a site is available, environmental concerns make it very difficult to build one. Based on the topology of the PRPA service area it is unlikely that new hydropower development is a viable generation expansion option for PRPA. Given those concerns associated with hydro technologies, hydro generation options are not recommended for further consideration as part of PRPA's supply side evaluation and associated integrated resource planning.

4.0 Task 2: Long Duration Energy Storage Technologies

Over the last five years, there has been exponential growth in energy storage for the power grid. There are two primary reasons for this. First, the increased penetration of variable renewable energy generation (principally solar and wind) compounds the requirements for grid stability control, much more so than variable loads ever required; there is a need for technology that stabilizes grid frequency, and that balances sudden increases and/or decreases in generation due to variable energy resources. Second, the growth in the electric vehicle market has so dramatically increased the production of lithium-ion battery cells that their prices have come down more than ten-fold over the past decade; lithium-ion battery energy storage is now, often, a lower cost alternative to balancing the power grid than the cost of conventional equipment to do so; with the added benefit that some traditionally fossil-fueled equipment (engines and turbines) can be replaced with batteries, lowering the overall carbon emissions.

Lithium-ion storage technology providing 2-4 hours of storage has dominated deployments over the past decade. As the market for grid energy storage has grown (doubling each year since 2018), a wide variety of energy storage technologies and equipment have begun development to challenge lithium-ion battery energy storage and to fill grid use-case gaps that those batteries cannot address (e.g., long duration energy storage, beyond eight hours.) Figure 4-1 below provides examples of current technologies that are used to provide flexibility today to solve grid problems across varying durations, and how emerging long duration energy storage technologies can be used to fill these gaps.

Flexibility Duration	Power System Challenge	Dispatchable Generation	Grid Rein-forcement	Curtailment or Feed-in Management	Li-ion Batteries	LDES	Demand-side Response
Intraday	Intermittent Daily Generation	●		●	●	●	●
	Reduced Grid Stability	●			●	●	◐
Multiday, Multiweek	Multi-day Imbalances	●	◐	◐	◐	●	
	Grid Congestion	◐	●	●	◐	●	
Seasonal Duration	Seasonal Unbalances	●	●			●	
	Extreme Weather Events	●				●	

LEGEND ● FULL SOLUTION ◐ PARTIAL SOLUTION

Figure 4-1 Flexibility Solutions for Varying Durations

From Black & Veatch's perspective, several, if not all, of these technologies are technically viable alternatives to lithium-ion batteries. This is either because they hold the potential of being even lower in cost than lithium-ion batteries as they mature in the market (e.g., batteries based on earth abundant, commodity minerals like zinc, iron, and sodium) or because the equipment design is such that it can provide LDES of ten hours or more, as defined by the US Department of Energy (DOE).[6]

- Long: >8 hours (10-12 hours, 24-48 hours, 1 week, 1 month)
    - Resilience use cases: reserving stored energy for the following:
        - Planned and unplanned outages
        - Absence of weather related, sufficient renewable generation, either short (hours), days (medium) or weeks (long)
        - Infrastructure failures (equipment faults, weather related, intentional attacks)
- Seasonal: > 1 month
    - Use cases are those that collect (charge) energy over short periods of time when renewable generation (wind and solar) resources exceed the load. This energy is then discharged after long periods of time, at appropriate discharge rates to meet grid requirements.

To meet the grid's needs at various time scales, different technologies are applicable. There are use cases for different power domains (smaller MW and larger MW) and energy domains (shorter durations and longer durations).

Figure 4-2 illustrates the energy storage applications and technology types that are suitable for use across various power ranges and storage durations.

The segment for addressing PRPA's use-case is shown by the intersection of the 400 MW average power and 7-day (1 week) discharge duration on each of the two charts.

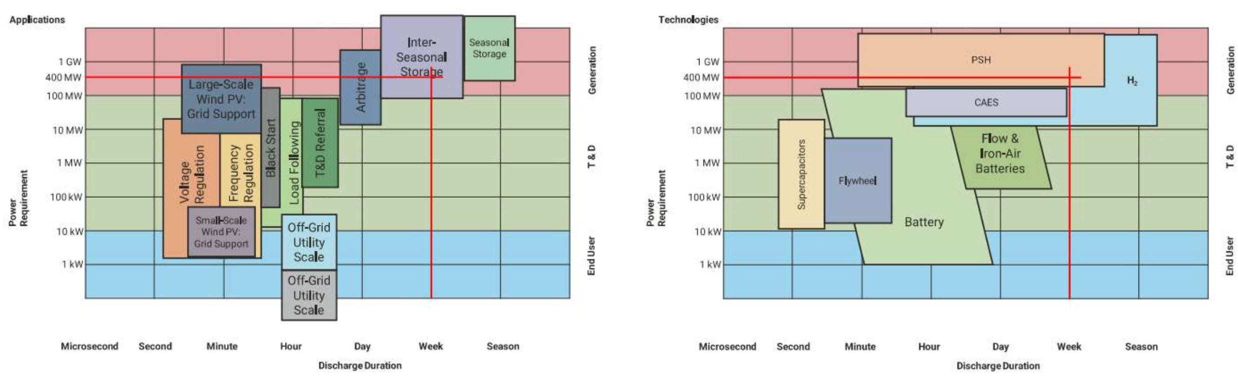

Figure 4-2 Energy Storage Applications and Technologies (By Power and Discharge Duration)

[6] US DOE Long Duration Energy Storage "Earthshot", https://www.energy.gov/eere/long-duration-storage-shot

The technologies generally applicable to the 400MW, 7 day use-case are (1) Pumped Storage Hydropower (PSH), (2) CAES, and (3) Hydrogen (H_2). A companion storage technology emerging is Liquid Air Energy Storage (LAES) which is also addressed below. The next most adjacent technology for PRPA would be electrochemical batteries. This includes technologies like lithium-ion, iron-air, and flow batteries. It should be noted that there are nuances for batteries depending on battery chemistry and duration requirements that are described in this report.

Additionally, with multiple LDES installations, the size and duration of each individual installation can be reduced such that the total system achieves the requested average power of 400 MW and discharge duration of 7 days. Current costs suggest fulfilling the PRPA needs with one installation, or even one technology, is beyond the ability of the typical PRPA budgetary constraints; in which case, a phased approach may be more manageable by starting with smaller battery installations and continuing to work up to larger total energy storage capacities over time and as longer duration technologies mature.

Energy storage technologies presented in this report are for devices that charge with AC-electricity from the grid, store the intermediate result, and then discharge AC-electricity back to the power grid. These include the following energy storage classes and subclasses:

1. **Electro-Mechanical (kinetic and potential energy)**
   - Compressed Air Energy Storage (CAES)
     - Advanced Adiabatic Compressed Air (AA-CAES) (12 Hour Duration)
   - Pumped Storage Hydropower
     - Existing facilities are typically used for 4-6 or sometimes up to 12-hour discharge durations; however, larger reservoirs and more constrained market conditions could see this technology used for significantly longer discharge times.
   - Advanced Mechanical
     - Gravity-based Systems (concrete blocks, well/mine shafts). Current pilot projects are being installed for 15-to-60-minute discharge cycles.
     - Geo-mechanical (underground pumped hydro). No utility scale pilots are known to have significant discharge durations.
2. **Electro-Chemical (cell based and flow based)**
   - Lithium-ion Batteries, short duration (under 1 hour)
     - Lithium Ion Battery (30-minute duration) (LTO, LFP, NMC)
   - Lithium-ion Batteries, medium duration (1 to 8 hours)
     - Lithium Ion Battery (2-hour duration) (NMC)
     - Lithium Ion Battery (4-hour duration) (LFP, NMC)
     - Lithium Ion Battery (8-hour duration) (LFP w/1500V bus)
     - High temperature batteries (NaS, Sb)
     - Sodium-Sulfur (NaS) BESS (8+ Hour Duration)
       - Antimony (Sb) BESS (6+ hour duration)

- Flow Batteries (6 to 12 hours)
  - Vanadium Redox
  - Zinc bromide
  - Iron Flow (ESS)
  - Redox Coordination Chemistry
  - GridStar Flow by Lockheed Martin (6+ hour duration)
  - Other emerging chemistries
  - Coordination Chemistry (MIT)
- Advanced (Metal-based) Batteries as Successors to Lithium-Ion
  - Sodium Ion
  - Abundant Mineral Batteries (Zinc, Iron, Sodium)
  - Nickle Hydrogen (12-hour duration) – diurnal time shifting.
    - Iron- Air (100-hour duration) – weekly time shifting.

3. Electro-Thermal

- Sensible Heat (Hot, high temperature) – (less than 4 to 15-hour durations)
  - Common, low-cost materials such as rock, concrete, ceramic
  - Thermal-Molten Aluminum (300° C)
  - Thermal-Molten Salt (500° C)
  - Thermal-Molten Silicon (1,414° C)
  - MIT/Thermal Battery (2,250° C)
- Latent Heat (Cold, liquified gas) Energy Storage (6 to 10-hour durations or less)
  - Liquid Air
  - Liquid CO_2
- Pumped Heat (Carnot) Energy Storage

4. Other Developing/Emerging Energy Storage technologies

- Super / Ultra Capacitors (less than 1 hour discharge durations)
- Superconducting Magnetic Energy Storage (less than 1 hour discharge durations)

For each of these technology classes and subclasses, the following sections provide a description of the technology and a summary of the applicable technical performance and cost characteristics. Black & Veatch selected a representative technology, including a range of variability for that item.

4.1 Electro-Mechanical (Kinetic and Potential Energy)

Electro-mechanical energy storage for the grid charges using AC-electricity from a power generator (renewable or conventional) or from the power grid. It stores that energy as either kinetic (moving) or potential (pressure or gravity). The device then discharges the stored energy through a means of converting it back into electricity.

Pumped Storage Hydropower (PSH) is a type of grid storage used for more than 30 years in regions where water availability and geological hills/mountains allow it. According to the 2021 US Hydropower Market Report, PSH currently provides 93% of the utility scale energy storage capacity in the United States. Almost as much PSH capacity was added from 2010 to 2019 (1,333 MW), mostly from upgrades to existing plants, as the combined installed capacity of all other forms of energy storage in the United States (1,675 MW).[7]

4.1.1 Compressed Air Energy Storage (CAES)

Compressed air energy storage (CAES) offers a method to store low-cost off-peak energy in the form of stored compressed air or other gas in an underground reservoir or an above ground piping/vessel system and to generate on peak higher priced electricity by:

1. Releasing the compressed gas from the storage system,
2. Heating the cool, high-pressure gas, and
3. Directing the heated gas into an expansion turbine driving an electric generator.

While essentially electro-mechanical in its nature via pressurized gas (air), the high efficiency designs for CAES involve a critical thermal element as well: recovering the heat of compression to be used in the expansion stages. CAES plants are either diabatic, adiabatic, or isothermal. Diabatic CAES includes heat addition from a combustion process, often involving natural gas as the fuel. Adiabatic CAES stores the heat of the compression process and upon extraction of the compressed air from storage, recovers the stored heat prior to expansion. Isothermal CAES technology removes heat continuously from the air during the compression process and heat is added continuously during expansion to maintain an isothermal process. While isothermal CAES systems are currently under development, there are currently no commercial isothermal CAES implementations. An intended use-case for diabatic CAES would be to pair with hydrogen-combustion turbines, using green (renewable) hydrogen to produce zero carbon power.

CAES is considered where longer duration storage (12-24 hours) is needed. CAES can deliver discharger durations that exceed 24 hours, however cost effectiveness is limited by the availability and design of underground storage caverns.

Adiabatic CAES is seeing increased interest as it does not include a combustion process to add additional heat, relying instead on the stored heat energy produced during the compression process.

While conventional CAES systems can require fuel to be combusted to heat the cavern discharge air, potentially producing greenhouse gas emissions, a CAES plant can use an adiabatic process referred to as Advanced CAES (A-CAES) which stores the heat of compression in thermal storage and utilizes a water column to create a constant pressure head when air is recovered from the cavern. The thermal storage removes the need for heating the discharge air with a combustible fuel or similar heat source enabling A-CAES to be a classified as a “green” technology. Current projects expect facility lifespans of 50+ years and are expected to require no more maintenance than a similar sized combined cycle power plant.

[7] https://www.energy.gov/sites/prod/files/2021/01/f82/us-hydropower-market-report-full-2021.pdf

A-CAES is commercially developed and available with a potential deployment size of 200-500 MW with a range of (8-24 hours) of discharge capability. Hydrostor is the current market leader in the A-CAES space with one project already in service, two under development, and two more additional projects undergoing feasibility studies. The first utility-scale conventional CAES plant (not A-CAES) has been in operation since 1991 and has 26 hours of discharge capability.

If economically and environmentally feasible, A-CAES will provide the equivalent power, energy storage, and grid benefits of a pumped storage project.

4.1.1.1 Operating Principles for CAES

An AA-CAES (advanced adiabatic) system is a Brayton cycle that uses electrical power from the grid during the charging mode and thermal energy storage in place of a gas turbine during discharge mode (as seen in some second generation diabatic CAES designs). Refer to Figure 4-3 for a schematic of an AA-CAES Cycle. Variations in heat recovery system configuration and storage media are offered by various OEMs.

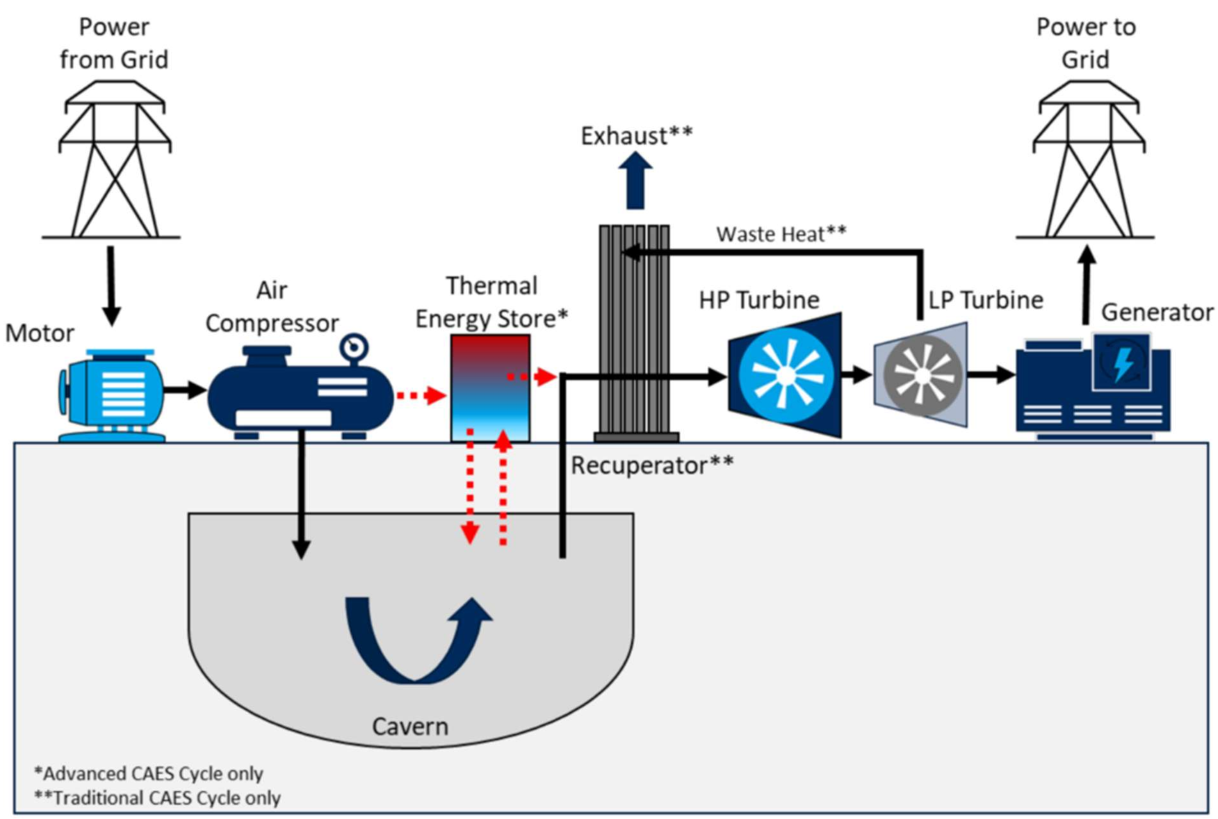

Figure 4-3 Compressed Air Energy Storage – Indicative Process

In a typical arrangement for AA-CAES, thermal energy produced during compression is removed from the air with the compression cycle's heat exchangers. The removed heat is transferred to the thermal energy storage (TES) working fluid, which is typically extracted from a cold tank, heated, and stored in a hot tank. The thermal energy is later transferred from the TES to the air by circulating the working fluid from the hot tank through the turbine cycle's heat exchangers before returning to the cold tank. Once heated, the air is expanded through the high pressure and low pressure turbines which drive a generator to produce power. Similar concepts are employed with systems using other thermal storage media such as concrete thermal storage, where heat transfer is directly from the compressed air to the thermal storage blocks and is then transferred to the discharged air directly from the thermal storage blocks. AA-CAES systems produce no CO2 emissions and are expected to have a round-trip-efficiency of 60-70%. Currently the largest AA-CAES plants under development is a 60 MWe demonstration plant in Jiangsu Jintan, China.

Compressed Air Storage Underground Facilities

An important consideration for siting a CAES plant is the method of storage. Above ground storage is cost prohibitive and impractical for large bulk storage systems. Therefore, geologic features near the proposed site must be favorable for the given CAES plant design. Characterization of storage includes the initial storage medium design basis (volume, geology, maximum and minimum operating pressures, dimensions of cavern roof and depth, etc.) and CAES technology being considered.

Underground storage may be in any of the following man-made and naturally occurring geological formations:

- Salt caverns created by solution mining,
- Underground rock caverns created by excavating rock formations,
- Naturally occurring porous rock formations from aquifers or depleted gas or oil fields, or
- Abandoned limestone or coal mines.

In general, a geological formation suitable for underground air storage must meet the following:

- The formation must have sufficient depth to allow safe operation at the required air storage pressure.
- For porous rock formations, the storage zone must be sufficiently porous to provide the required storage volume at the desired air pressure and flow rates.
- Porous rock formations need to possess a mineralogy that does not result in rapid chemical consumption of oxygen in the stored air through oxidation reactions.
- Geological studies performed under the supervision of the Electric Power Research Institute (EPRI) indicate that over 80% of the US territory has geological formations suitable for underground storage (the Southeast US is the one region that generally does not have appropriate geology).

The general scope of cavern development work, in the case of salt dome storage, includes development of a cavern design, a solution mining plan, an air production well design, cost estimates, and schedule estimates for the project. In addition to defining the ultimate CAES plant capacity and operating characteristics, storage system costs can vary widely.

4.1.1.2 Applications for CAES

The concept of diabatic compressed air energy storage is more than 40 years old. CAES was studied in the 1970s to provide load following and to meet peak demand while maintaining a constant capacity factor in the nuclear power industry.

Operating Diabatic CAES Plants

The first and longest operating CAES facility in the world is near Huntorf, Germany. The diabatic 290 MWe CAES plant has operated since 1978, functioning primarily for cyclic duty, ramping duty, and as spinning reserve in northwest Germany. The plant stores compressed air in two salt caverns with volumes of 4.94 million cubic feet and 6 million cubic feet. Compression requires 12 hours to fill the caverns and consumes 720 MWh of electrical power. On discharge, the plant preheats the compressed air in a natural gas fired burner before expansion and can generate power for nominally 2 hours.

The only large commercial CAES facility currently operating in the US is the diabatic 110 MWe AEC plant near McIntosh, Alabama. The CAES design reduces required natural gas fuel consumption by recovering waste heat with the addition of a regenerator at the exhaust of the expansion turbine. This plant has been in operation since 1991 and provides the following functions:

- Load management,
- Generation of peak power, and
- Spinning reserve duty.

The generator can produce up to 110 MWe within 14 minutes of startup and the plant can be operated from a remote off-site location. The facility can provide 110 Mwe for 26 hours. The time to recompress the storage cavern is 41 hours (cavern size is 19 million cubic feet). The plant generally operates between a cavern storage pressure of 650 and 1,078 psig.

Table 4-1 provides the status of various commercial scale, pilot, and demonstration CAES projects.

Table 4-1 Status for Selected CAES Projects

Site	Type	Status	Rated Power (kW)	Discharge Duration at Rated Power (hrs)	Storage Capacity (kWh)	Commissioned Date	Location	Energy Storage Technology Provider	Notes
Kraftwerk Huntorf	Diabatic	Operational	290,000	0	0	1/12/1978	Lower Saxony, Germany	BBC, Alstom	321-MW Plant Utilizes Nuclear-Sourced Night-Time Power
McIntosh CAES Plant	Diabatic	Operational	110,000	26	2,860,000	1/1/1991	Alabama	Dresser-Rand	Unit 1 Facility Stores Compressed Air in a Solution-mined Salt Cavern
Texas Dispatchable Wind		Operational	2,000	250	500,000	12/19/2012	West Texas	General Compression, Inc.	2.0 MW Wind Generation Project Located in West Texas with onsite CAES
SustainX Inc Isothermal Compressed Air Energy Storage	Isothermal	Operational	1,500	1	1,500	9/11/2013	Seabrook, New Hampshire	SustainX	1.5 MW pilot system
Toronto Hydrostor UCAES Demonstration Facility	Adiabatic	Operational	1,000	4	4,000	9/1/2014	Toronto Island, Canada	Hydrostor	1 MW/4 MWh Demonstration Facility
Toronto Hydro/HydroStor 660 kW Underwater Storage	Adiabatic	Operational	660	1	660	11/18/2015	Lake Ontario near Toronto, Canada	Hydrostor	660 kW Underwater Storage
Pollegio-Loderio Tunnel Demonstration Plant	Adiabatic	Operational	500	4	2,000	6/1/2016	Pollegio, Switzerland	ALACAES	ALACAES - Adiabatic Compressed Air Energy Storage Concept

Site	Type	Status	Rated Power (kW)	Discharge Duration at Rated Power (hrs)	Storage Capacity (kWh)	Commissioned Date	Location	Energy Storage Technology Provider	Notes
Promontory Microgrid CAES – ATK Launch Systems	Diabatic	Operational	80	0.75	60	-	Promontory, Utah	-	Over 540 Buildings on a Sprawling 19,900-Acre Site
Hydrostor UCAES Aruba Project	Adiabatic	Contracted	1,000	6	6,000	-	Aruba	Hydrostor	Low-Cost Air Cavity to the Bottom of a Lake or Ocean
Jiangsu Jintan National AA-CAES Demonstration Project	Adiabatic	Under Constructio n	60,000	5	300,000	-	China	Tsinghua University	AA-CAES Demonstration Project - 60 MWe
TICC 500 kW - An Hui, China	Adiabatic	Operational	500	1	500	-	China	-	
Solar-thermal Hybrid Compressed Air Energy Storage (STHC-100)	Adiabatic Solar-Thermal Hybrid	Operational	100	0.5	50	-	China	Tsinghua University	

Notes:

1. Data derived primarily from Sandia National Laboratories, DOE Global Energy Storage Database, https://sandia.gov/ess-ssl/gesdb/public/.
2. Technology Efficiency ranges are as follows: Diabatic 25%-60%, Isothermal 55%-75%, Adiabatic 55%-75%. Actual project efficiencies were not published.

4.1.1.3 Resource Availability for CAES

Charging of the CAES system is based on available electricity. Siting considerations include need for available space for the storage and electrical power production system.

4.1.1.4 Cost and Performance Characteristics for CAES

Table 4-2 presents typical performance and cost estimates for AA-CAES.

Table 4-2 AA-CAES Technology Characteristics

	AA-CAES 100 MW (12 h Duration)
Typical Operating Life (years)	50+
Typical Duty Cycle	Peaking – Intermediate
Net Plant Capacity (MWe)	100
Round Trip Efficiency (%)(1)	55-75
Integrated Storage	12 hours
Capacity Factor (percent)	5-25
Total Project Cost ($/kW) (1)	1,500-2,500
Fixed O&M ($/kW-yr)	17.00
Variable O&M ($/MWh)	--
Commercial Status	Commercial
Installed US Capacity (MW)	0
Note: 1. Evaluating emerging long-duration energy storage technologies (https://doi.org/10.1016/j.rser.2022.112240)	

Project development period is very project and site specific. Project development may take one to two years while construction can take two to four years exclusive of the permitting process.

4.1.1.5 Environmental Impacts for CAES

Initial construction may involve solution mining of salt formations. During normal operation for AA-CAES, no emissions from combustion products will occur.

4.1.1.6 Grid Integration for CAES

The grid integration use case for CAES is for long duration energy storage applications. In deployed applications using natural gas, it lowers the carbon footprint of the generator by removing the compressor parasitic load. In the future, co-firing with bio-fuels and hydrogen will improve the efficiency of the discharge cycles for these technologies.

4.1.2 Pumped Storage Hydropower (PSH)

Pumped Storage Hydro-electric has a long history of providing energy storage. The technology is not considered new or emerging like many other long duration energy storage systems. PSH is a mature long duration energy storage technology that has been utilized for over a century. The components that make up a PSH system are large heavy civil works that last for many decades.

4.1.2.1 Operating Principle for PSH

The fundamental principle of PSH involves moving a volume of water from a lower elevation to a higher elevation. The movement of the mass in the gravitational field stores the energy as potential energy that can later be harnessed as the water is released back down to the lower elevation reservoir.

There are two fundamental systems – closed loop and open loop. Closed loop systems do not interact with natural waterways such as rivers, lakes, or reservoirs that impound large amounts of natural runoff. Open loop systems differ in that the water used in the storage systems interacts with natural waterways.

The main features of a PSH project include two reservoirs (upper and lower), a penstock to convey the water between the two, a powerhouse with one or more hydro-electric pump/turbine generators and other auxiliary equipment, a switchyard, and utility intertie.

Typically, PSH powerplants use a Francis turbine coupled to a large diameter salient pole generator. Francis turbines operate best in the general range from a 100-200 feet of water column to 2000+ feet of water column. Traditional PSH favors larger elevation gains to maximize water pressure while minimizing the volume of water required (and size of the reservoirs). When identifying appropriate siting locations, the elevation between the lower and upper reservoir should coincide with the range for optimal use of the Francis turbine. The shape of the Francis turbine blade is designed for a specific water pressure. This means that if the variation in upper reservoir level from charged to discharged conditions should be minimized within reason. Other pump-turbines technologies can also be used depending on the site conditions. When operating in generating mode, the generators work like traditional hydropower. However, when in pump mode, accommodations are required for starting and maximizing efficiency such as reversing switches, starting pony motors, and variable speed drive electronics.

4.1.2.2 Applications for PSH

Frequency of cycling can be from daily to seasonal. PSH can be configured with generation sources that have low dispatchability. This includes constant sources like nuclear power – the PSH storage absorbs energy from the power gird during periods of low demand (typically at night) and injects power into the grid during periods of high demand (typically day and evening). This allows the nuclear facility to operate at constant power output while the PSH evens out the fluctuations from the load demand. This also includes variable generation sources like wind and solar. Just as PSH can even out fluctuations in demand, it can also be used to even out fluctuation in generation. Fluctuations in generation from variable resources can be harder to predict and often is not exclusively on a daily cycle; however, PSH is able to store energy over much longer cycles that exceed typical weather patterns such as extended periods of low sun or low wind.

Hydroelectric powerplants frequently provide seasonal water storage; which directly results in seasonal energy storage. Current economics of PSH do not yield benefits for seasonal operation based on power markets (existing power markets yield benefits for adjusting other generation sources, like conventional coal and natural gas, for balancing variation in seasonal demand). If one was to eliminate the other generation sources, hydroelectric power (including PSH) could be a significant source of seasonal load balancing, provided the storage reservoir(s) and elevation difference(s) are large enough.

For reference, the Bath County PSH has a total capacity of 24,000 MWh. At the average discharge of 400MW, this capacity would last for 60 hours or 2.5 days. There is not a significant lower limit to the discharge rate. To last 7 days, it could be discharged at 142MW accounting for about one third of PRPA's storage needs. Bath County Upper Reservoir is 35,559 acre-feet. For comparison, Horsetooth Reservoir outside of Fort Collins, Colorado is 156,735 acre-feet. This suggests that an upper reservoir volume of similar size as Horsetooth, and with similar elevation difference as the Bath County PSH, would be capable of meeting or exceeding the LDES requirements needed by PRPA. The largest reservoir in Colorado is Blue Mesa at 940,000 acre-feet. Blue Mesa Dam and reservoir is utilized for seasonal water storage on the Colorado river system and employs traditional hydro power generation, not PSH.

Most hydroelectric facilities operate seasonally based on water supply and demand. If the PSH is installed exclusively for power/energy purposes, the facility could be operated based on seasonal power supply/demand instead of driven by the water resource.

Salient pole synchronous generators can be used for a myriad of ancillary services including voltage support and spinning reserves. The large amount of inertia is generally considered a positive for grid stability.

PSH powerplants have very quick ramp rates – on the order of less than a minute, or in some instances 10 seconds, from 0 to 100% power. If a generator is already online producing a small amount of power or providing spinning reserve, the governor operates the wicket gates that control the flow volume of water over the turbine. The rate at which the gates operate is generally only limited by the size of the governor and the transient responses to flow on the penstock. Additional time is needed when switching from the pumping mode to the generating mode, but this is typically still on the order of minutes.

4.1.2.3 Resource Availability for PSH

The primary resources needed for PSH include water, site elevation difference, appropriate land and geology for the reservoirs, and a power source.

Colorado has a well-developed water rights legal system making water availability a process that needs to be started early to ensure availability. There needs to be a river or other good source of water and elevation change to make PSH feasible. Platte River is on flat land, a few miles from the mountains. Even if PSH was determined to be conceptually feasible for meeting PRPA future storage needs, the critical path on development of PSH projects is often licensing and permitting.

The licensing and permitting process includes many studies and approvals from multiple agencies. The process can take many years if not decades. For these reasons, PSH is not considered a feasible energy storage solution on the timeline PRPA is forecasting demand capacity increases and the decommissioning of existing generation at the Craig and Rawhide power centers. If, however, PRPA is anticipating significant future capacity needs beyond the current 2030 goals, it may behoove PRPA to initiate discussion with partner organizations and regulators to explore any future possibilities for PSH in meeting PRPA future energy storage needs.

4.1.2.4 Cost and Performance Characteristics for PSH

Primary costs are often heavy civil earthworks and excavation. This includes the upper and lower reservoir. The powerhouse is often located underground to ensure it is slightly below the lower reservoir (to facilitate priming and suction efficiency during pump operation). This underground powerhouse often involves a significant cost of excavation.

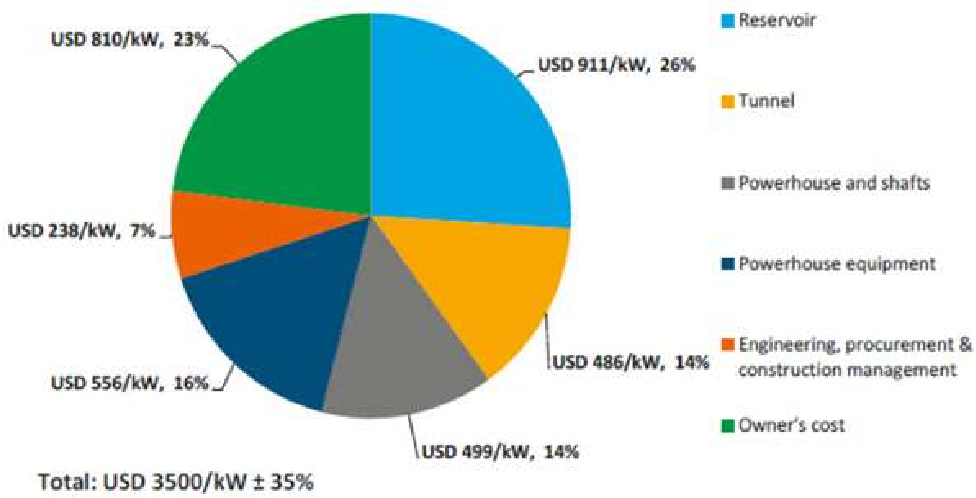

Figure 4-4 Cost Breakdown for Typical PSH

Performance is very well known and proven. The round-trip efficiency (RTE) of pumped hydro is typically between 70 and 80 percent. The primary variables are the length of the water conveyance and the efficiency of the pump-turbine equipment. For long periods of energy storage, there are some losses through absorption to the local ground water and evaporative losses. These losses would be more relevant to long term usage of a closed-loop system that would require periodic additions to maintain total water volume in the storage reservoirs. Losses are dependent on the local geography and climate.

Table 4-3 Typical PSH Technology Evaluation

Evaluation Criteria	Traditional PSH Technology
Estimated Project Cost	Estimated at $2,500-$5,000 per kW ($110-$170/kWh) of installed capacity
Estimated Levelized Cost of Storage (LCOS)	$135-$209 per MWh
Construction Time	Estimated 4 to 6 years
Project Development Risk	Licensing, permitting, regulatory approval
Scalability and Applicability	Plant size estimated at 16-320 MW, based on multiples of unit sizes (4-40 MW per unit)
Operational Flexibility	The plant can provide very flexible operation by engaging multiple units. If connected to flow or level-regulated natural waterways (rivers and recreational reservoirs), the operations are often limited by flow regulation on the natural waterways.

Evaluation Criteria	Traditional PSH Technology
Environmental Impacts	Minimal for closed-loop systems; Open-loop systems may affect natural waterways.
Physical Siting Limitations	Site must have appropriate topography and geology for two reservoirs separated by a short but steep vertical grade; The Colorado and southern Wyoming Rocky Mountains have a number of potential sites but need to be confirmed by geographic and geologic surveying. Land ownership should also be considered in determining feasible sites. Large reservoirs often require environmental review as well as historic landmark and heritage review prior to agency approval.
TRL	Estimated TRL is 9. TRL is a type of measurement system used to assess the maturity level of a particular technology. TRLs are based on a scale from 1 to 9 with 9 being the most mature technology.

4.1.2.5 Environmental Impacts for PSH

Environmental impacts are related to the regulation of water flow through the system, development of two lakes and construction of power generation and pumping equipment. Numerous environmental studies are often prepared in advance of approval including impacts from the reservoirs and future impacts on water flows. Closed loop PSH has a lower environmental impact, but still requires review and approval by various agencies for the size and scale PRPA is considering. Construction has an environmental impact in line with other heavy civil earthworks and will be similar for both closed and open-loop systems.

4.1.2.6 Grid Integration for PSH

The grid integration use cases are primarily for storing energy during periods when the generation capacity exceeds the load, to be used later to load-level or resource-gap-fill conventional and renewable generators respectively.

4.1.3 Advanced Mechanical Energy Storage Systems

Advanced Mechanical energy storage systems (AMESS) are emerging technologies with broad-based application such as: renewable shifting, peak capacity reduction, transmission and distribution grid investment deferral, and frequency regulation. Currently these technologies are in the early-stage demonstration deployment phase, with commercial projects announced but not yet constructed. Two types of advanced mechanical energy storage systems will be covered: gravity-based systems and geo-mechanical systems.

4.1.3.1 Operating Principles for Advanced Mechanical

There are several types of gravity-based energy storage systems, all of which convert stored energy into kinetic energy to generate electricity. These types of systems vary in design; some utilize pressurized water that lifts a piston within a mined shaft, while others lift heavy bricks to store energy. The stored energy is released and converted to electricity via generators. These systems, like other types of long duration energy storage, offer the potential for scalable energy outputs. Doubling shaft depth increases stored energy content by a factor of four; whereas, for storage based on lifting heavy blocks, scaling with respect to energy is enabled by increasing the mass of each block or the number of blocks comprising the system.

Block and piston-based energy storage systems are advantaged over some other types of long duration storage in there is little to no self-discharge of stored energy, increasing efficiency. Modularity is another advantage, with system sizes ranging from 100-kWh to multi-GWh.[8]

Gravity-based energy storage systems are mostly used for energy applications ranging from 1-200 hours of discharging duration; however, faster response time allows for power applications including frequency regulation.

Geomechanical PSH energy storage is a novel approach to storing energy much like traditional pumped hydro. The main idea is to pump water from a surface reservoir down into the ground, between rock layers where the water would be kept under pressure. The natural elasticity of certain rock formations will act like a spring and keep the water under pressure until the valve is opened and the water is released through a hydroelectric turbine to generate electricity.

While there are geologic requirements for siting of these systems, large areas of the world meet the requirements, allowing for a much broader deployment of this technology than traditional pumped storage hydropower. Technology developers claim that rock formations suitable for geo-mechanical PSH are quite common and can be found in most parts of the United States.[9] These systems offer a modular design and scalable energy outputs, with storage modules ranging from 4 to 40 MW and plant sizes from 16 to 320 MW for 10 hours. 20-30 hours of discharge duration is possible with minimal additional investment. In principle, geo-mechanical PSH technology would operate as a closed-loop PSH plant. It is highly scalable and modular because each surface reservoir may be able to serve multiple generating units. As each generating unit can be cycled separately, operational flexibility for these plants is high.

Like block and piston-based energy storage systems, geo-mechanical systems are advantaged over some other types of long duration storage in there is little self-discharge of stored energy, increasing efficiency. These technologies are constrained by underground infrastructure but can use existing underground infrastructure to lower total system cost. The construction techniques for these systems leverage existing oil and gas skillsets and established federal and state permitting structures, reducing deployment time, cost, and complexity.

Although there are currently many different energy storage options available, pumped storage hydro is still the one with generally the lowest LCOS value and able to provide long-duration storage, which will be essential for integrating high levels of variable wind and solar generation and achieving power grid decarbonization goals. Geo-mechanical PSH systems offer the possibility of extending the advantages of PSH to areas of the grid where it was not previously possible.[10]

Geo-mechanical energy storage systems can provide highly flexible dispatchable generating capacity, which can balance supply and demand and provide a variety of grid services.

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[8] Evaluating emerging long-duration energy storage technologies, Renewable and Sustainable Energy Reviews, https://doi.org/10.1016/j.rser.2022.112240

[9] A Review of Technology Innovations for Pumped Storage Hydropower, Argonne National Lab, https://publications.anl.gov/anlpubs/2022/05/175341.pdf

[10] A Review of Technology Innovations for Pumped Storage Hydropower, Argonne National Lab, https://publications.anl.gov/anlpubs/2022/05/175341.pdf

4.1.3.2 Applications for Advanced Mechanical

Once fully developed and commercially deployed, advanced mechanical energy storage systems can be generally used for peak shifting, load balancing, and variable renewable energy support due to their ability to store energy for long periods of time, operational flexibility, capacity for long duration dispatch, and 65-85% round trip efficiency. Some technologies in this area also allow for fast response time, with the ability to provide frequency regulation services.[11]

4.1.3.3 Resource Availability for Advanced Mechanical

Charging of advanced mechanical systems is based on excess available electricity. Siting considerations include need for available space for the storage and electrical power production system.

4.1.3.4 Cost and Performance Characteristics for Advanced Mechanical

Argonne National Lab completed a study of multiple innovative PSH technologies in April 2022. Table 4-4 provides a summary of their evaluation criteria for geo-mechanical PSH.

Table 4-5 compares LCOS for a range of high and low project investment costs for geo-mechanical PSH to reference projects for traditional PSH and battery technologies.

Table 4-6 presents typical performance and cost estimates for gravity-based energy storage.

4.1.3.5 Environmental Impacts for Advanced Mechanical

By sequestering waste materials into solid blocks and beams used for energy storage, block energy storage systems can have a positive environmental impact. Initial construction involves onsite creation of blocks from waste material. During normal operation for block energy storage, no emissions will occur.

Compared to conventional PSH plants, geo-mechanical PSH technology has lower environmental impacts because it is a closed-loop system that needs only one relatively small reservoir, which is at ground level. Brownfield oil and gas fields can also be used. The civil works for the construction of plant are also small, because there is no need for an underground powerhouse, water conveyance systems, access tunnels, and other structures. The project footprint is practically equal to the size of the surface reservoir.[12]

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[11] Evaluating emerging long-duration energy storage technologies, Renewable and Sustainable Energy Reviews, https://doi.org/10.1016/j.rser.2022.112240

[12] A Review of Technology Innovations for Pumped Storage Hydropower, Argonne National Lab, https://publications.anl.gov/anlpubs/2022/05/175341.pdf

Table 4-4 Geo-mechanical PSH Technology Evaluation [13]

Evaluation Criteria	Geomechanical PSH Technology
Estimated Project Cost	Estimated at $1,000-$1,500 per kW ($100-$150/kWh) of installed capacity for early systems.
Project Development Risk	Potential to lower project development risks: less civil works (no underground powerhouse), smaller plant footprint, no excavation for underground reservoir.
Scalability and Applicability	Plant size estimated at 16-320 MW, based on multiples of unit sizes (4-40 MW per unit)
Operational Flexibility	Because it is modular, the plant should be able to provide very flexible operation by engaging multiple units.
Potential Market Size in the United States	Hundreds of potential installations, totaling about 5-10 GW of capacity (assuming 40 MW average plant size): Quidnet estimates that total resource potential in the United States would exceed 500 GW, assuming 10-hour energy storage.
Environmental Impacts	Minimal; Uses an underground reservoir, and the surface reservoir is relatively small; brownfield oil and gas fields can also be used.
Physical Siting Limitations	Site must have appropriate subsurface rock geology; Quidnet claims that geology with appropriate geo-mechanical characteristics is ubiquitous in the United States.
TRL	Estimated TRL is 5. TRL is a type of measurement system used to assess the maturity level of a particular technology. TRLs are based on a scale from 1 to 9 with 9 being the most mature technology.

Note:

1. These Project Cost estimates are based on the study as reported in the report referenced in footnote 13 and are interpreted to be in 2020$. The costs have not been independently verified by Black & Veatch because Geo-mechanical PSH technology is not yet mature enough to be recommended for consideration for PRPA's long duration energy storage requirements for generation at an average power output of 400 MW for seven days that is to be in service by 2028.

[13] A Review of Technology Innovations for Pumped Storage Hydropower, Argonne National Lab, https://publications.anl.gov/anlpubs/2022/05/175341.pdf

Table 4-5 Comparison of LCOS values for Geo-mechanical PSH and Reference PSH and Battery Technologies[14]

Parameters	Geomech, PSH (low CAPEX)	Geomech, PSH (high CAPEX)	PSH 100 MW 4 hours	PSH 100 MW 10 hours	Li-Ion 1 MW 4 hours	Li-Ion 10 MW 4 hours	Li-Ion 100 MW 4 hours
Plant generating capacity, MW	40	40	100	100	1	10	100
RTE, %	75	75	80	80	86	86	86
Plant Life	30	30	40	40	10	10	10
TIC, $/kW	1,000	1,500	2,046	2,623	1,793	1,643	1,541
LCOS Total, $/MWh	**128**	**158**	**209**	**135**	**254**	**238**	**227**

Notes:

1. Noted in the report referenced in Footnote 14 is that some of the key parameters describing the reviewed innovative PSH technologies, including their estimated unit/plant size, LCOS values, and TRLs should not be compared directly to each other because the proposed innovative PSH technologies are at different stages of TRL development and many of them are at early TRL stages and will eventually need demonstration projects to confirm the effectiveness of the technology advancements, and potentially pilot projects to further refine the technology and develop accurate, scalable estimates for construction costs and schedules. Demonstration and pilot projects in the field would significantly help PSH technology developers advance their concepts toward higher TRLs and ultimately to commercialization.
2. Capital Cost estimates and the LCOS estimates are based on the study as reported in the report referenced in footnote 14 and are interpreted to be in 2020$. The costs have not been independently verified by Black & Veatch because Geo-mechanical PSH technology is not yet mature enough to be recommended for consideration for PRPA's long duration energy storage requirements for generation at an average power output of 400 MW for seven days that is to be in service by 2028.

[14] A Review of Technology Innovations for Pumped Storage Hydropower, Argonne National Lab, https://publications.anl.gov/anlpubs/2022/05/175341.pdf

Table 4-6 Gravity-based Energy Storage Performance and Costs

Comparison Criteria[15]	Block	Piston
Commercial Status	Demonstration[16]	Conceptual Development
Typical Operating Life (years)	35	25-50
Construction Period (months)	TBD	TBD
PERFORMANCE		
Plant Capacity (MW)	20 to 1000	25 to 100
ECONOMICS (2021 USD)[17]		
Average Capital Cost ($/kWh)	200 to 300	50 to 75[18]
Fixed O&M ($/kW-yr)	Approx. 20	50
Variable O&M ($/MWh)	TBD	TBD

[15] Evaluating emerging long-duration energy storage technologies, Renewable and Sustainable Energy Reviews, https://doi.org/10.1016/j.rser.2022.112240
[16] Pilot demonstration projects are currently under development. ARES is constructing a demonstration project in Nevada (50MW/12.5MWh) and EnergyVault is commissioning a project in Rudong, China (25MW/100MWh), with agreements for six additional China facilities announced.
[17] Cost is converted into 2021 USD based on US inflation rate and exchange rate between EUR and USD as 1:1.15
[18] Includes payment from oil and gas companies to remediate inactive wells

4.1.3.6 Grid Integration for Advanced Mechanical

The grid integration use cases for mechanical storage are like that from pumped storage hydroelectric systems: storing energy during periods when the generation capacity exceeds the load, to be used later to load-level or resource-gap-fill conventional and renewable generators respectively.

Please note that no commercial advanced mechanical projects are currently known to be in construction. At this time, the development of this technology is limited to conceptual desktop studies and small scale pilot projects only.

4.1.4 Summary for Electro-Mechanical

Electro-mechanical LDES technologies have a high degree of readiness when used for small applications (up to 400 MW for 4-12 hours). Of these, PSH is the most used worldwide and has the longest proven record of applicability for the energy storage amounts needed by PRPA; however, several challenges are encountered such as identifying the most appropriate landscape for the storage reservoirs and obtaining the necessary licensing and permits for the projects. Neither existing nor future Electro-Mechanical systems based on current designs meet the multiday energy storage requirements of PRPA.

4.2 "Green" Hydrogen (H_2)

Hydrogen produced from electrolysis process is considered "green" when the electricity consumed is provided by renewable energy resource(s), such a solar photovoltaic panels and wind turbines. Green hydrogen has been previously considered for long-duration energy storage applications but has only recently emerged as a viable alternative due to the growth of the water electrolysis industry and versatility of hydrogen for many different end-uses. Green hydrogen can be stored and used in small percentages in traditional combustion turbine power generation equipment (after some modifications) to generate power when needed. In this cycle, green hydrogen acts an energy storage medium.

4.2.1 Operating Principle for H_2

Electrolyzers, like fuel cells and batteries, have electrodes (i.e., anodes and cathodes) separated by an electrolyte that make up cells, with multiple cells integrated to form stacks. The two most well-established electrolyzer technologies include Proton Exchange Membrane (PEM) and Alkaline Water Electrolysis (AWE).

Because hydrogen is the lightest and least dense gas and is an energy carrier rather than a primary energy resource, it can be challenging to store large quantities in terms of both mass and volume. The pressures and temperatures required to store large quantities of hydrogen in a reasonable manner are more challenging than that of liquefied natural gas. Two potential physical hydrogen storage methods include compressed gas hydrogen storage and cryogenic liquid hydrogen storage.

Hydrogen would need to be converted back into electricity. This can be accomplished using a variety of energy conversion technologies including electrochemical Fuel Cell Generators (FCGs) or electromechanical systems such as Combustion Turbine Generators (CTGs) or Reciprocating Internal Combustion Engines (RICEs). FCGs are highly energy efficient but are typically only appropriate for small-scale, distributed generation (e.g., telecom tower backup) or mobility (e.g., light-duty fuel cell electric vehicle) applications. Figure 4-5 shows a schematic of green hydrogen production and utilization in power production and other possible uses.

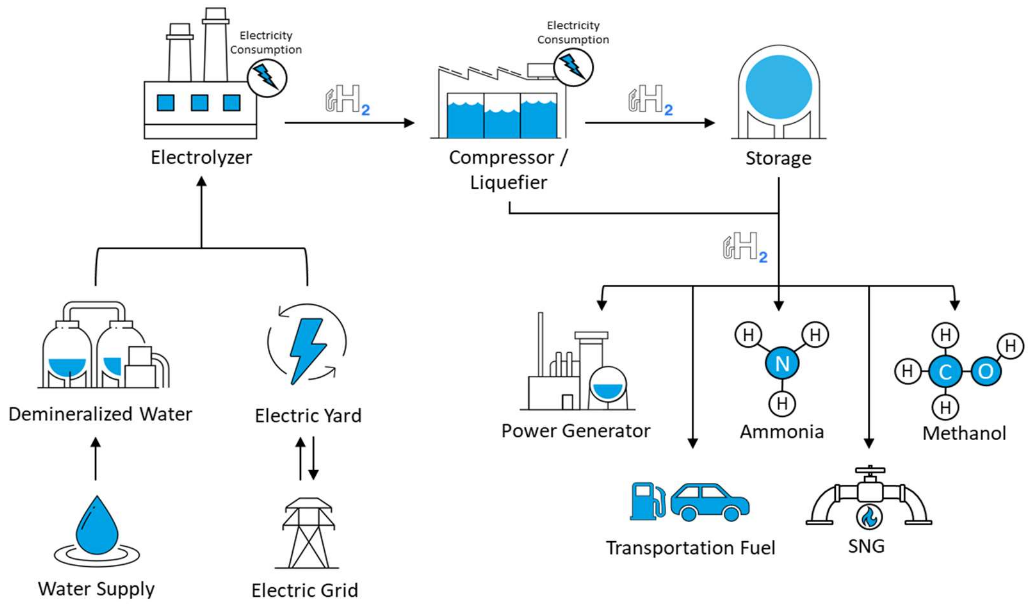


Figure 4-5 Power to Gas (Hydrogen) - Indicative Process

An issue that is presently a challenge to commercial storage and utilization of large volumes of hydrogen is hydrogen's low density and wide flammability range making it difficult to combust in a stable manner while avoiding flashback. The utilization of hydrogen as a fuel in existing gas-fired power plants is currently an area of intense research and development. Many equipment vendors claim that the current models can blend up to 30% of hydrogen with natural gas and within the next decade, they will be able to burn 100% hydrogen.

4.2.2 Applications for H_2

Hydrogen can be burned as one component in a fuel blend to be used in combustion turbine generators or RICEs. The application of such combustion driven generators includes all the same features of traditional combustion turbine generators such as peak shaving.

Hydrogen energy storage plants are expected to have similar dispatchability as other electromechanical technologies with response times comparable to CAES. However, ramp rates may be challenging in the near term in instances where hydrogen-fueled CTGs require start-up on natural gas and then slowly switching to hydrogen within CTG limitations of rate of change in fuel quality (i.e., Wobbe index). This is expected to improve over time with hydrogen-fueled power generation facilities able to achieve ramp rates comparable to CAES and pumped hydro.

Hydrogen can also be stored as a chemical derivative such as methanol, ammonia, or methyl cyclohexane; however, this is typically only used for long distance gas transportation and is rarely explored for energy storage applications. Selection of storage type may depend on a variety of factors, including the quantity of hydrogen to be stored and the end use applications of each storage option. For energy storage applications, this typically includes round-trip energy efficiency, turn-down/part-load operation, and dispatchability.

4.2.3 Resource Availability for H_2

The primary resources required for using hydrogen for LDES includes a clean water source to supply the electrolyzers, a green power source (usually purchased from the electric grid), and a means to store the large volume of hydrogen. The water and power source appear readily available to PRPA. Some treatment of the water may be necessary but could be obtained relatively easily. The power would likely come from the numerous clean energy sources PRPA has already developed (notably wind, solar, and hydropower). Some modification to existing substations and/or transmission lines may be necessary.

Storage of hydrogen could utilize geological formations such as salt caverns, rock caverns, and depleted natural gas fields, which present an opportunity to store large volumes of hydrogen (and therefore energy) in existing geologic features.

Figure 4-6 shows the natural gas wells near the Rawhide Energy Center (Denver Post).19 Salt caverns present the most suitable and proven means of geological storage, whereas other options are being explored for their technical feasibility to store hydrogen. Figure 4-7 shows rock-salt deposits in the Norther Denver geological region. 20 Additional geographical and geological studies would need to be conducted to confirm if these resources are suitable for LDES sites. Hydrogen's fast molecular velocity and small size often warrants the installation of physical barriers (e.g., liners) into the wells/caverns to minimize leakage. Another consideration associated with geological storage is contamination from compounds such as methane, water, or nitrogen. Additional clean up equipment upon discharge of hydrogen from the storage system may be required depending on the geographic location and the hydrogen user quality requirements.

[19] Here's a Map of Every Oil & Gas Well in the State of Colorado, Denver Post, https://www.denverpost.com/2017/05/01/oil-gas-wells-colorado-map/

[20] Johnson, Kenneth & Gonzales, Serge. (1978). Salt Deposits in the United States and Regional Geologic Characteristics Important for Storage of Radioactive Waste Y/OWI/SUB-7414/1.

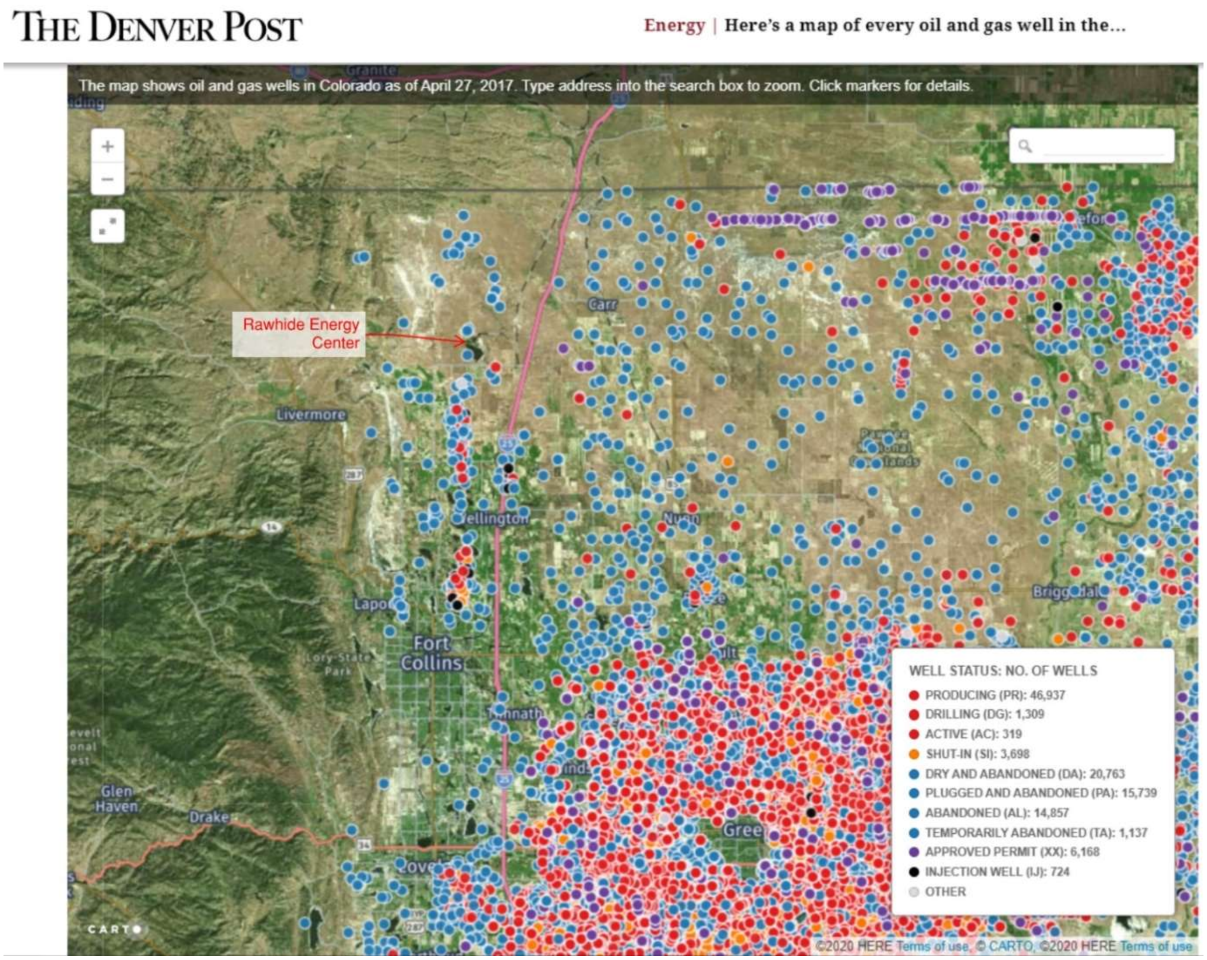
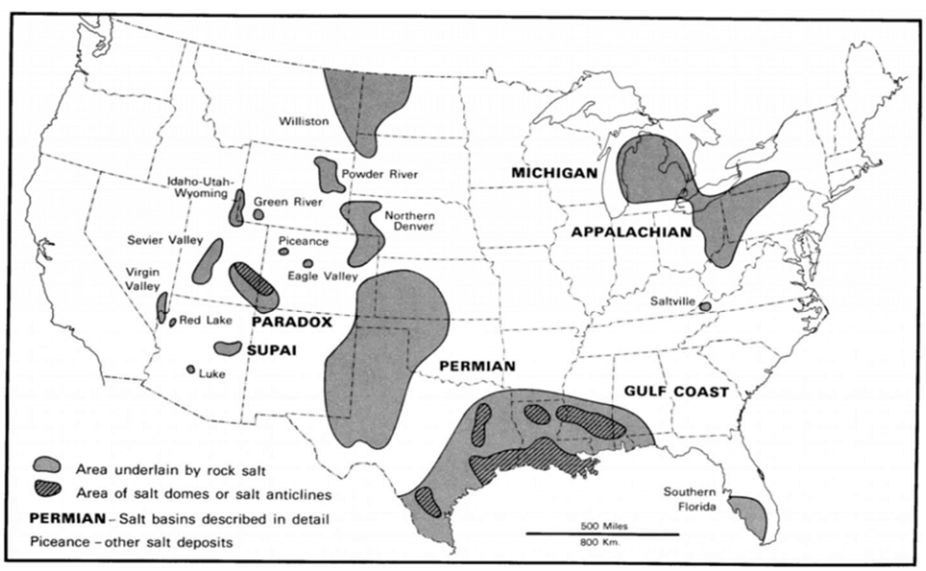


Figure 4-6 Oil and Gas Wells in Colorado (2017)



Map showing rock-salt deposits in the United States.

Figure 4-7 US Rock Salt Deposits

4.2.4 Cost and Performance Characteristics for H_2

If a 500 MW CTG could effectively and safely burn 100 percent hydrogen today, the resultant round-trip energy efficiency would be only around 20 to 30 percent, which is considered inferior to other alternatives. The regulatory aspects of large-scale hydrogen energy storage are still being explored across the world and are considered an emerging area of public policy formation that will require many more years to facilitate the development of safe and technologically practical projects.

Although water electrolysis and hydrogen combustion are both considered mature technologies, their application to energy storage projects at the capacities of interest are still in their nascency. System design life and key component cycle life that constitute effective system lifetime operability metrics have not yet been demonstrated at the scales considered for the PRPA project. It is believed that the plant(s) themselves could be designed for a 20-to-30-year life; however, it is expected that key components such as electrolyzer stacks would need to be replaced every 7 to 10 years while major components of the power generation plant (i.e., CTGs) would require overhaul every 10 to 15 years.

4.2.5 Environmental Aspects for H2

When hydrogen is derived from “green” energy sources (i.e., the energy sources that power the electrolyzers are from renewable resources) then there are no significant environmental aspects.

4.2.6 Grid Integration for H_2

If hydrogen storage was feasible at or near the PRPA site, it would also need to be converted back into electricity. This can be accomplished using a variety of energy conversion technologies including electrochemical FCGs or electromechanical systems such as CTGs or RICEs. Grid integration is largely dependent on the technology selected to convert the gas back into electricity.

4.2.7 Summary for H_2

Hydrogen fuel technologies are rapidly evolving and are being explored worldwide for LDES. Generating hydrogen from an electric power source and converting back to electricity is a fully proven technology. It is demonstrated to be highly relevant when burnt in conventional combustion generators on small scales. The stability and efficiency of this application is actively being developed for large scale deployment. The US government is supporting production of H_2 through rebates and through $7 billion of funding for six to ten hydrogen hubs via the Department of Energy Clean Hydrogen Hub program. Similarly, the EU is providing a high level of governmental support. These efforts will likely help the maturation of green hydrogen. Commercial applications are likely to begin to be deployed by 2035.

The largest constraint for using hydrogen for LDES is proper geologic conditions for underground storage. The geographic area presents two interesting opportunities – local salt deposits and abandoned natural gas wells. Both local resources appear abundant; however, a significant amount of additional study needs to be performed to fully demonstrate applicability for this LDES storage method.

4.3 Electrochemical (Battery) Energy Storage

Battery energy storage is grouped under a broader category of electrochemical energy storage. Electrochemical energy storage technologies include technologies ranging from various battery energy storage chemistries to capacitors. This section will focus on the battery technologies of Lithium Iron Phosphate batteries and flow batteries.

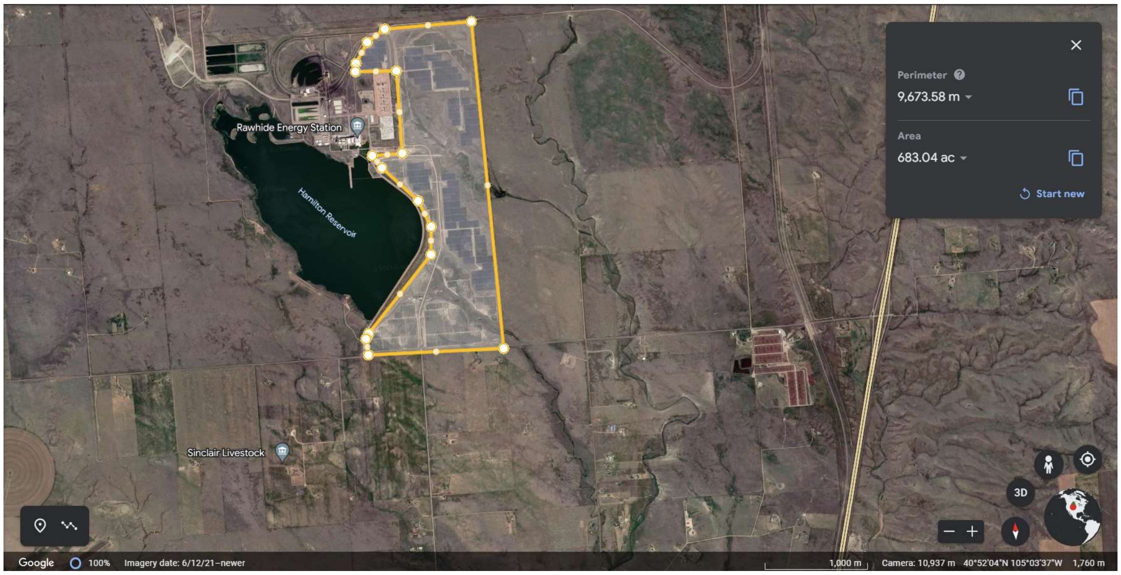
Various Li-ion and flow battery systems are installed around the world, including projects in the United States. Currently there are Li-ion projects in the que or development phase that exceed 100 MW and over 1.0 GWh per installation, but most of these are intended for short term discharge durations in the 2-4 hour range. There are various operational flow battery facilities in the United States including a 1.0 MW, 3.2-hour vanadium redox flow battery project in Washington State. According to the DOE Energy Storage Database, the worldwide operational Li-ion capacity is over 3 GW and 4.2 GWh. Flow battery installations are more limited, but the worldwide installed capacity is estimated to be over 318 MW and 1.2 GWh.[21]

In the 4th quarter of 2019, more stationary battery-based energy storage was installed on the grid than the cumulative amount to that point in time, more than doubling previous capacity. These installations were primarily intended for short duration energy storage. That inflection point growth has continued through 2023. The case is not the same for flow batteries. While the technology is strong and evolved, they are still installed at small scale as demonstrations and pilots, and as cost-shared projects when the state and federal incentives allow the financials of those projects to compete with the lowest-cost form of new energy storage on the grid, lithium-ion batteries.

Meeting the forecasted storage demand in the PRPA system of an average of 400 MW discharged for seven days (168 hours) with the relatively smaller size capacity of typical battery forms of LDES would require deployment of multiple systems. A technology that can independently approach the 168 hours is not currently available. Power capabilities for the systems are scalable by putting multiple systems in parallel. Assuming a system size of approximately 20 MWhs per acre of currently available Li-ion systems, approximately 3,360 acres would be necessary to meet the PRPA needs of 67,200 MWh. The cost of stacking banks of 4-hour system to provide 168-hour duration will also be astronomically high. Due to the high cost and land area requirements of current Li-ion BESS designs, Li-ion battery energy storage is not recommended to be considered to meet PRPA system requirements of 67,000 MWh.

[21] Sandia National Laboratories, DOE Global Energy Storage Database, http://www.energystorageexchange.org /

For perspective, the approximate area of the solar fields near Rawhide Energy Station is about 680 acres.



Below is the approximate size area needed to achieve the LDES needs of PRPA through the exclusive use of Metal Air batteries (further discussed below). This could be achieved with multiple installation sites, distributed across the PRPA service territory.

4.3.1 Operating Principles for Electrochemical Storage

Batteries are electrochemical cells that convert chemical energy into electrical energy. This is done by electrochemical oxidation-reduction (redox) reactions. The batteries of interest for this report are secondary batteries that can be recharged (i.e., the redox reaction can be reversed). The main components of a battery are the positive electrode (cathode), the negative electrode (anode), and the electrolyte. The resulting potential, or voltage, of the battery is based on the composition of the electrodes and the redox reactions that occur at the electrodes.[22]

Flow batteries are another form of electrochemical storage. Vanadium redox flow batteries are the most commercial developed technology of the various flow battery technologies. In these systems, the energy is captured within a liquid electrolyte which is typically stored in large tanks. The electrolyte can be scaled to produce the desired energy storage capacity; the power cells (where the reactions happen) can be scaled separately to produce the desired power output.

Batteries come in a wide range of sizes. The size of a battery is based on two parameters: power, usually in kW or MW, and energy, usually in kWh or MWh. The energy storage capacity of a battery designates how long a given energy storage system can discharge at a given power. Other parameters relevant for energy storage systems are:

- Ramp-rate: how quickly an energy storage system can change its power output, typically in MW/ min.
- Response time: how quickly an energy storage system can reach its rated power (constrained by power conversion system).
- Efficiency: the amount of energy discharged from an energy storage system relative to the amount required for charging.
- Discharge duration: how long a battery can be discharged at a given power.
- Charge/Discharge rate (C-rate): how quickly the battery can charge or discharge relative to a one-hour charge or discharge (for example, a 2C rate charges or discharges in 30 minutes).
- Operational parameters associated with battery energy storage technologies include:
- State-of-charge (SOC): how much energy is stored in an energy storage system relative to the maximum energy storage capacity.
- Depth of discharge (DoD): how discharged an energy storage system is relative to the maximum energy storage capacity.
- Cycles-to-failure (CtF): the number of cycles at 100 percent DoD until the battery's energy storage capacity reaches 80 percent of its new capacity.

[22] Linden's Handbook of Batteries. Edited by Thomas B. Reddy.

4.3.2 Applications for Electrochemical Storage

In general, performance characteristics for Li-ion batteries and flow batteries are similar. A summary of some of the common parameters are outlined in Table 4-7 for Li-ion and flow batteries.

Table 4-7 Li-Ion and Flow Battery Technology Overview

	Medium (2-4-8 hour shortest discharge duration)	Long (8-12-24-168 hour shortest discharge duration)
Nominal Technology Type	Lithium Iron Phosphate	Flow or Metal air
Commercial Availability	Commercial	Emerging Commercial
Facility Power Rating, MW	0.1 to 400	0.1 to 5
Module Power Rating, MW	0.1 to 2	0.1 to 0.5
Facility Energy Capacity, MWh	0.1 to 1200	0.2 to 500
Module Energy Capacity, MWh	0.1 to 4	0.1 to 2
Ramp Rate	Almost Instantaneous	Almost Instantaneous
Response Time(1)	20 to 120 ms	20 to 100 ms
Round-Trip Efficiency, %	80 to 87	40 to 85
Discharge Duration, hours	4	12
Charge/ Discharge Rate	0.25C	0.25C
(1) Amount of time system takes to reach rated power		

The sections below discuss the energy storage applications and benefits that are being provided by Li-ion and flow battery systems and emerging advanced batteries systems according to the DOE Energy Storage Database, published industry perspectives, and Black & Veatch experience.

It should be noted that the applications are often grouped into either power or energy applications. Power applications are generally shorter duration (approximately 30 minutes to one hour) applications that may involve frequent rapid responses or cycles. Frequency regulation or other renewable integration applications such as ramp rate control/smoothing are good examples of power applications. Energy applications generally require longer duration (approximately 2 hours or more) energy storage systems and, as discussed above, 4, 8, or 12+ hour durations.

4.3.2.1 Lithium Iron Phosphate Batteries

Li-ion batteries are performing the following applications in the United States. The below list outlines some of the primary benefits being targeted according to the DOE Energy Storage Database. The definitions are adopted from the Electricity Storage Association.

- Spinning Reserve: the use of energy storage to supply generation capacity that is online and dispatchable within 10 minutes.

- Non-Spinning Reserve: a resource that follows spinning reserve dispatch during loss of generation or transmission events and usually required to respond within 10-15 minutes.
- Capacity Firming: the use of energy storage to fill in capacity (power) when variable energy resources, such as solar and wind, fall below their rated output.
- Voltage Support: the use of energy storage to manage and supply reactive power on the grid at or near a power factor of one (1).
- Frequency Regulation: the use energy storage to maintain grid system frequency with a resource that can respond within seconds.
- Ramping Service: using energy storage ramping to offset excessive ramping of other generating facilities, often variable energy resources such as solar or wind.
- Transmission and Distribution Upgrade Deferral: the use of energy storage to avoid expensive transmission and distribution upgrade costs.
- Energy Arbitrage: the use of buying energy in off-peak times and selling back during peak conditions.

Lithium Iron Phosphate (LFP) batteries are the optimal choice grid-scale storage when the discharge duration requirements are 1 to 4 hours based on cost and energy density considerations. Although more energy dense chemistries exist, LFP systems are less prone to thermal runaway and exhibit significantly better degradation profiles versus lithium ion.

- The advantages:
  - Established
  - Lowest cost per kWh of any ESS installation in the 1–4-hour range
  - Simple installation
- The disadvantages:
  - Risk of fire/explosion high
  - Toxic materials
  - Short discharge durations
  - Power and energy cannot be scaled separately, making LFP much more expensive for longer duration storage applications

4.3.2.1.1 Summary for Lithium Iron Phosphate Batteries

For LDES applications, LFP BESS installations are not ideal for utilities who are looking for more than four to eight hours of storage duration and should not be considered for this application.

4.3.2.2 Flow Batteries

Flow batteries can generally perform the following applications.

- Spinning Reserve: the use of energy storage to supply generation capacity that is online and dispatchable within 10 minutes.
- Non-Spinning Reserve: a resource that follows spinning reserve dispatch during loss of generation or transmission events and usually required to respond within 10-15 minutes.

- Capacity Firming: the use of energy storage to fill in capacity (power) when variable energy resources, such as solar and wind, fall below their rated output.
- Voltage Support: the use of energy storage to manage and supply reactive power on the grid at or near a power factor of one (1).
- Ramping Service: using energy storage ramping to offset excessive ramping of other generating facilities, often variable energy resources such as solar or wind.
- Transmission and Distribution Upgrade Deferral: the use of energy storage to avoid expensive transmission and distribution upgrade costs

Flow batteries are a new and upcoming solution for energy storage with many OEM's looking to move from the small pilot installations to full grid-scale solutions within the next few years. In a flow-battery system, the charge carriers are circulated in a liquid from tanks, using pumps and electrolyte solutions to pump the electrolytes through an ion selective membrane. Flow batteries typically target the medium duration storage market of 6-12 hours.

Flow batteries are not as energy dense as lithium-ion installation, however, provide some advantages over a typically lithium-ion system. First, the electrolyte solutions for many of the market-ready chemistries are not flammable and pose almost no risk of thermal runaway or explosion, a big advantage over their LFP counterparts. Second, these systems typically exhibit little to no system degradation, requiring no overbuild or augmentation to maintain the nameplate rating of the site through the plant's operating lifetime. Finally, flow batteries allow for the decoupling of power and energy. In theory, a flow batteries capacity to provide the nameplate power rating for the system should only be limited by the size of the tanks storing the electrolyte, which is advantageous for utilities who expect their demand for energy storage capacity to grow significantly over the next decade.

Flow batteries do have some disadvantages as well. Due to the external equipment required to facilitate the delivery of the electrolyte, these systems often suffer from lower roundtrip efficiencies versus LFP. As stated above, these systems also exhibit a poor energy-to-volume ratio in comparison to other popular batteries chemistries, which is why flow batteries are most likely to be used to provide stationary storage at grid scale.

4.3.2.2.1 Summary for Flow Batteries

Overall, flow batteries represent an exciting next step in the world of grid-scale energy storage systems. The technological maturity of these technologies is still relatively undeveloped and Black & Veatch expects the performance characteristics to improve as the technology matures. There currently are no flow battery systems available on the market that can provide a duration of greater than 12 hours or with a power rating larger than 5 MW. While we do expect to see those numbers grow in the coming years, it is our prediction that flow battery manufacturers are still years away from developing even a conceptual design that would meet the 400 MW with 7-day duration capability. Therefore, we do not recommend flow battery technologies as a feasible solution for Platte River's application.

4.3.2.3 Advanced (Metal-based) Batteries

Given the growth in lithium-ion and flow batteries, many other technology developers either developed, or are developing competing technologies. As an example, sodium-ion battery cells – announced in 2021 by the largest supplier of lithium-ion batteries in the world[23] – are expected to surpass lithium-ion in power density and possibly cost.

The general trends observed in patent literature, publications, and product offerings are observed:

- Inventing stable electrochemical reaction based on 1) common, 2) abundant, and 3) low-cost materials like zinc, iron, and sodium.
- Establishing design cost targets with values below 1/10th the cost of lithium-ion batteries (less than $20/kWh versus over $200/kWh).
- Performance characteristics having 1) no capacity fade per cycle, 2) capability of ten times the cycles of lithium ion, and 3) long-facility life (over 25 years versus 20 years or fewer).
- Examples of established applications in other markets that are sometimes expected to evolve into the stationary storage markets and applications are: uninterruptible power supply (UPS), military, and outer-space (e.g., EnerVenue's nickel-hydrogen battery chemistry). For stationary BESS, this transition will only happen if cost can attain or surpass that of the 2023 incumbent technology, lithium-ion. The markets are seeing considerable gains in this regard; however, the technologies are still emerging and do not yet have a significant track record of performance.
- Most developments are in the emerging stage, with no established financials. Other technologies, such as Form Energy's long-duration (100 hours) iron-air batteries24, have achieved demonstration stage.

The approach for PRPA among these competing technologies will be to convey the expected target cost per kWh, and the approximate time of completion that the developers expect to enter the market. Most are working toward commercialization dates consistent with industry and government announced plans for decarbonization goals[25].

4.3.2.3.1 Summary for Advanced (Metal-based) Batteries

Of all the advanced metal-based battery chemistries on the market today, Metal-air has the best chance at meeting the requirements set for by PRPA for their intended application when developed and commercially available. Currently, Form Energy has brought a 100-hour metal-air battery to market with plans to install this system in two different interconnection applications within the US electric grid. Form Energy's website suggests their new factory will begin commercial operation in mid-to-late-2024. The 100-hour discharge duration is significantly higher than any other BESS technology currently available and provides an option for customers looking for multiple days of energy storage. This 100-hour duration at maximum discharge still falls short of the requirement set forth by PRPA's 168-hour discharge duration. Through dispatch control, it is possible to reduce the power output and/or stagger the discharge of multiple 100-hour batteries to obtain the 168-hour requirement or longer for PRPA while still maintaining maximum discharge rates. Although Form Energy has reported building a factory, the technology has undergone limited testing in a commercial environment. It is deemed risky for PRPA to consider advanced metal-based battery chemistries for deployment at the scale needed to meet PRPA requirements in the timeframe anticipated. Therefore, it is not recommended that advanced

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[23] https://www.catl.com/en/news/665.html

[24] https://www.energy-storage.news/form-energy-raises-us450-million-for-100-hour-iron-air-rust-battery-technology/

[25] https://blogs.microsoft.com/blog/2021/10/27/supporting-our-customers-on-the-path-to-net-zero-the-microsoft-cloud-and-decarbonization/
https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030

metal-based battery chemistries be considered to meet PRPA needs for 2028 deployment. If testing goes well, it is perceived that advanced metal-based battery chemistries could be commercially available by the middle of next decade.

4.3.3 Resource Availability for Electrochemical Storage

Deployments of battery energy storage rely on either 1) transmission/distribution grid power to store energy or 2) adjacent generators (solar, wind, conventional) to provide charging power. Those resources may be carbon free (as with solar) or have some dimension of carbon emissions related to its generation. When selecting energy sources for charging the batteries (either purchased from the markets via transmission lines or from PRPA-owned generation), it is important to consider the cost of the power and any additional tariffing or wheeling charges that may be incurred. Connecting LDES on the generator side of the transmission system decreases wheeling charges that occur when energy is transferred from one electrical system to another.

4.3.4 Cost and Performance Characteristics for Electrochemical Storage

Table 4-8 presents typical characteristics of battery energy storage systems operating to provide power and energy applications. The typical distribution of costs during construction is shown in Table 4-9.

Table 4-8 Battery Energy Storage Performance and Costs

	Medium (2-4-8 hour shortest discharge duration)	Long (8-12-24-168 hour shortest discharge duration)
PERFORMANCE		
Typical Operating Life (years)	10-20	20-30
Typical Duty	Energy Applications, short to medium duration	Energy Applications, medium to long duration
Net Plant Capacity (MW)	1 to 100	1 to 5
ECONOMICS (2022 USD)		
Overnight EPC Capital Cost ($/kW)(1)	1,807	2,438
Fixed O&M ($/kW-yr)(2)	6.00	8.00
Variable O&M ($/MWh)(2)	1 - 2	1 – 2
TECHNOLOGY STATUS		
Commercial Status	Commercial	Commercial and emerging
Installed/Under Construction US Capacity (MW)	1,783	38.9

Note:

3. These estimates are based on cost information provided in PNNL's Energy Storage Cost and Performance Database, as well as Black & Veatch's industry experience.
4. These estimates are based on cost information provided in PNNL's Energy Storage Cost and Performance Database, as well as Black & Veatch's industry experience.

Table 4-9 Battery Energy Storage Cash Distribution Schedule by Month, % of Total Capital Costs

	6 months	12 months	18 months
Lithium-Ion (2-4 Hour Duration)	60	30	10
Flow (8-12 Hour Duration)	70	20	10

4.3.5 Environmental Impacts for Electrochemical Storage

No environmental impacts other than those associated with charging power have been identified.

4.3.6 Grid Integration for Electrochemical Storage

The grid integration use cases for batteries are many and varied. Sometimes referred to as the "Swiss army knife" for the grid, batteries can perform in many applications as good as, or better than conventional solutions. With the cost reductions seen from 2010 to 2020, batteries have surpassed conventional solutions. For example, as non-wires solutions for distribution system upgrades; that is installing a $5 million BESS in place of upgrading for $20 million a distribution circuit to a remote location that has a peak load in the summer lasting only a few weeks.

4.3.7 Summary for Electrochemical Storage

Batteries are gaining traction due to decreasing costs and increases in discharge durations. Some of the longest discharge duration technologies include advanced metal-based batteries and flow batteries. The most commonly used stationary electrochemical batteries that are commercially available (lithium-ion) continue to have high costs. While lithium-ion technology can be applied to LDES, the extremely high performance of the battery technology increases the costs making it less attractive than other proposed technologies. The benefit of lithium-ion technology is the relative availability in current markets.

Lower cost alternatives such as iron-air batteries are not currently commercially available. Once the lower cost alternatives become commercially available, it is expected that there will continue to be bottlenecks in the manufacturing which may lead to reduced availability. The power and energy requirements sought by PRPA can be achieved with multiple large installations. These installations do not need to be located all in the same area but will need land and local substations for interconnection. Manufacturing capacity is limited but expected to rapidly increase. The large capacity of LDES sought by PRPA, within the timeframe it is needed, may need to be met with numerous battery manufacturers and technologies to spread the production capacity out to multiple factories. This may include technologies such as lithium-ion, iron-air, and flow batteries, some of which are not currently commercially available, but availability is forecast by 2030 for piloting and perhaps commercial deployment later.

4.4 Electro-Thermal (Sensible and Latent)

Thermal energy storage mimics the way electric power has been generated for decades. This type of energy storage is emerging in various forms to challenge the other types of energy storage for power grid applications. In thermodynamics, sensible heat is related to the change in temperature of a material (degrees Celsius), whereas latent heat is related to the change of phase (gas to liquid). In addition, an emerging class of thermal storage, that evolves both a hot substance and a cold substance, where both are then used as the temperature difference in a thermodynamic power cycle (typically a Brayton cycle), is nearing the pilot plant stage.

4.4.1 Molten Salt (Sensible)

Electro-thermal energy storage technologies convert electricity to thermal energy for the later production of electricity, heat, or cooling. The application of thermal energy storage (TES) can help balance electricity supply and demand on a daily or weekly basis. In the discharge cycle for electric generation, the heat is transferred to a fluid which is then used to power a heat engine and associated generator. Thermal energy storage is classified into sensible heat (increasing the temperature of a solid or liquid medium), latent heat (changing the phase of a material), or thermochemical heat (based upon endothermic and exothermic reactions).

For this evaluation the following sensible heat TES alternatives will be considered.

- Resistive Heating and Thermal-Molten Salt
- Resistive Heating and Thermal-Molten Silicon

4.4.1.1 Operating Principles for Thermal Energy Storage

Figure 4-8 demonstrates the general process of thermal energy storage. It can be as simple as using electricity to heat molten salt with resistance heaters, to a complex arrangement of high and low temperature thermal storage elements coupled with a heat engine (Brayton, Rankine, Stirling) to generate shaft power to turn a generator.

Different mediums to store the heat such as molten salts, concrete, aluminum alloy, hot water and ice or rock material can be used depending on the plant configuration and technology.

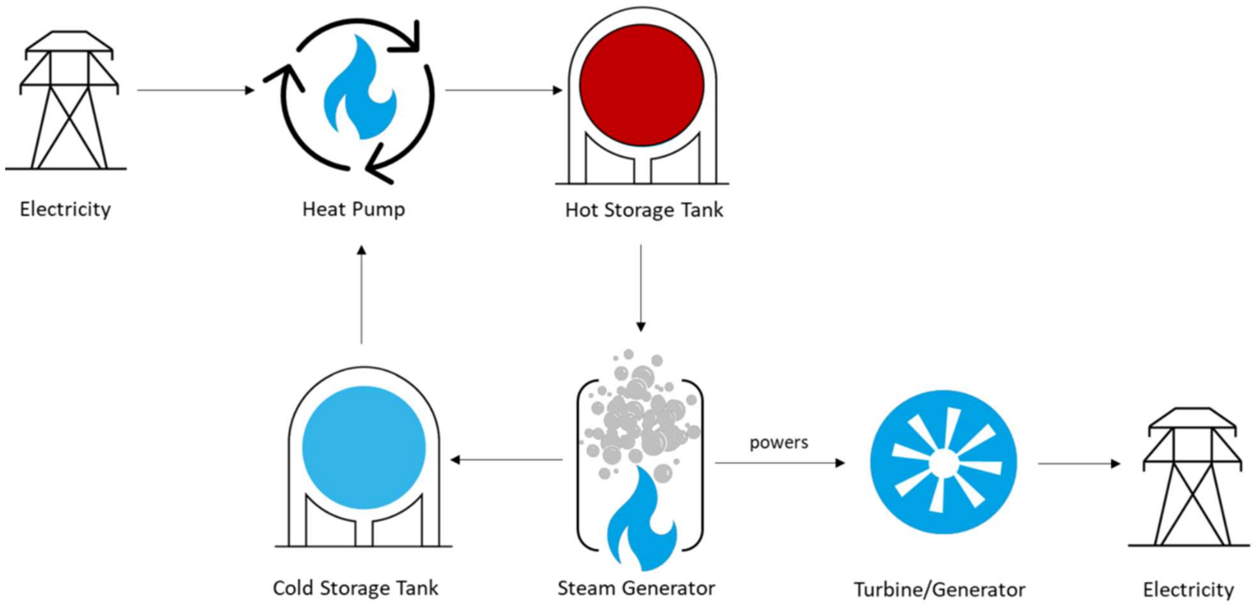

Figure 4-8 Thermal Energy Storage – Sensible and Pumped-Heat Indicative Processes

Sensible heat storage operates by heating or cooling a single-phase liquid or solid medium, such as water, salts, sand, or rocks. It is the simplest method for TES. Different storage materials will have different thermal properties (e.g., storage density, temperature range), which results in different use-cases. Currently, sensible heat storage technologies are widely used in Concentrating Solar Power (CSP) facilities and is being considered for nuclear reactors to add operating flexibility. As such it has been demonstrated for high power and large energy capacity.

Sensible heat storage technology uses relatively inexpensive materials and is capable of being cost-efficient when it comes to large economies of scale and longer durations. Costs are estimated based upon storage material, operation costs, and technical equipment costs.

4.4.1.2 Applications for Thermal Energy Storage

Several sensible heat storage methods are discussed below.

4.4.1.2.1 Molten Salt Thermal Storage

Molten salt energy storage uses salt as a storage medium. Molten salts with high heat capacity, such as a 60% sodium nitrate ($NaNO3$) and 40% potassium nitrate ($KNO3$) mixture, are heated and stored in an insulating container during off-peak hours at up to nominally 580° C, and later converted into steam to feed the end user or to power a steam turbine for electricity generation. This technology has been applied in CSP plants, such as the Gemasolar facility in Spain, which is a 19.9 MWe solar thermal power plant with 120 MWt molten salt central receiver for 15 hours of production. The heat stored in this media would then be transferred to water in a series of heat exchangers to produce high-grade steam to power a conventional steam turbine.

4.4.1.2.2 Crushed Rock Thermal Storage

Crushed rock thermal storage is achieved via storing heat in insulated containers filled with crushed rock at high storage temperatures of 500° C to 750° C. A heat exchanger, in-situ or external, then extracts steam from the containers and the steam is passed through a steam turbine generator to produce electricity. A pilot testing project that used crushed rock thermal storage system to store wind energy was performed in Demark in 2019. Some developers are considering using sand as well. The differences in permeability to air-based heat exchange are a key selection criterion. The heat stored in these media is transferred to air which then heats water in a boiler to produce medium-grade steam to power a conventional steam turbine. Alternatively, some systems use motor driven compression and hot gas expanders with a hot tank and cold tank rock storage system to charge the thermal storage and produce power when needed. While still in demonstration, RTE is expected to be ~60%.

4.4.1.2.3 Concrete/Ceramic Thermal Storage

Modular, containerized blocks of concrete or higher temperature ceramic bricks with in-situ resistive heaters store thermal energy at high temperatures of 500° C to 1,650° C. Heating circuits to heat gas or produce steam for process heat or electrical steam generation can be embedded in the modules. Concrete block energy storage technology from StorWorks that uses steam from existing fossil fired generating plants is currently undergoing testing at a 10 MWh-e pilot facility located at Southern Company's Plant Gaston.

4.4.1.2.4 Molten Aluminum Thermal Storage

Molten aluminum thermal storage uses molten aluminum as storage medium. Molten, or recycled aluminum is heated via electricity from a wind or solar plant to temperatures of up to 600° C. When power is needed from the storage unit, the thermal energy is fed into a Stirling engine that produces electricity by running a generator. Waste heat reaches temperatures up to 65° C and can be sold. When both the electricity and waste heat are used and the process works at the higher temperature end to avoid cooling aluminum, the round-trip efficiency can reach 90 percent. This pilot technology is being tested at the 580 MW Noor Ouarzazate solar complex in Morocco. Phase III was commissioned in 2019. Through phases I, II, and III, the facility has commissioned storage for up to 5 hours at full capacity[26].

4.4.1.2.5 Molten Silicon Thermal Storage

Surplus electricity is stored as heat in molten silicon at temperatures as high as 1,414 °C, which is the melting point of silicon. Silicon's high energy density means it can hold much more energy than other phase change materials. Heat is recovered as hot air and can be used for process heat or power generation. The technology is conceptual with only one known 1MWh pilot facility in Australia[27].

4.4.1.2.6 Resource Availability for Thermal Energy Storage

Charging of the thermal storage system is based on excess available electricity. Siting considerations include need for available space for the thermal storage and electrical power production. Cooling systems for steam powered generation can include wet mechanical draft cooling towers or, if required, air cooled condensers.

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[26] https://www.afdb.org/fileadmin/uploads/afdb/Documents/Project-and-Operations/MOROCCO-AR_-_Ouarzazate_Solar_Complex_Project-_Phase_II_-_12_2014.pdf

[27] https://www.pv-magazine.com/2023/08/15/australia-commissions-molten-silicon-energy-storage-system/

4.4.1.3 Cost and Performance Characteristics for Thermal Energy Storage

Table 4-10 presents typical performance and cost estimates for electro-thermal storage.

Table 4-10 Electro-Thermal Technology Characteristics

	Molten Salt 100 MW (12 h Duration)	Molten Silicon 100 MW (12 h Duration)
Typical Operating Life (years)	30-35	Aspires to Same
Typical Duty Cycle	Peaking - Intermediate	Peaking – Intermediate
Net Plant Capacity (MW_e)	100	100
Round Trip Efficiency (%)[(1)]	30-35	Aspires to Better
Integrated Storage	12 hours	12 hours
Capacity Factor (percent)	5-25	5-50
Total Project Cost ($/kW)	3,165	Aspires to Better
Fixed O&M ($/kW-yr)	32.50	Aspires to Better
Variable O&M ($/MWh)	-	
Commercial Status	Commercial	Pilot
Installed US Capacity (MW)	0	1

Notes:

1. Round trip efficiency of 60% is targeted for advanced thermal storage systems under development/demonstration.
2. Pacific Northwest Laboratories, Energy Storage Cost and Performance, DOE/PA-0204(2020) update 2022. https://www.pnnl.gov/download-reports

4.4.1.4 Environmental Impacts for Thermal Energy Storage

Charging of sensible heat thermal storage is based on excess available electricity. Siting considerations include need for available space for the storage and electrical power production system.

4.4.1.5 Grid Integration for Thermal Energy Storage

The grid integration use cases for sensible heat thermal storage are like those for generators. These systems provide medium and long duration storage use-cases for handling renewable integration and resiliency applications.

4.4.1.6 Summary for Thermal Energy Storage

Thermal Energy Storage shows promise for both grid-scale energy storage and for providing process heat where required in other decarbonization efforts. These types of technologies are currently being deployed as demonstration or pilot projects but are not yet deployed at the scale needed to meet PRPA's requirements.

4.4.2 Liquid Air Energy Storage (LAES)

Originally invented as a possible energy source for powering vehicles[28] , this technology has since been developed for the power grid, charging with electricity, then discharging as electricity back to the grid. The original focus was on air as the low-cost material to liquify in an open-loop (once through) system. In recent years, systems that use carbon-dioxide in a closed-loop (recycled) system have been developed. Given the maturity of the air system, liquid air energy storage (LAES) will be considered below as representative of this class of storage technology. An emerging, second alternative, liquid carbon-dioxide, is also considered in this assessment. Whereas the air version works as an open-loop system (air from the atmosphere is liquified, then expanded, then exhausted), the carbon dioxide version works as a closed loop system (liquified carbon dioxide is heated, expanded to gas, operates a turbine, stored as gas then is liquified again).

4.4.2.1 Operating Principles for Liquid Air Energy Storage

LAES is a thermo-mechanical storage solution that uses electricity to liquify cool air to -321° F and is stored in an insulated, unpressurized vessel; the liquid air is then warmed to convert back to a gaseous state and be used to operate a turbine and generate electricity. LAES technology is conceptually suitable for large-scale storage and offers a duration storage of 10 hours once demonstration projects have been in operation and tested. This stage is not expected to be achieved for several more years. Its main benefits are the simplicity of the technology, flexibility, high energy density and attractive costs. LAES is near to market and is currently prepared to be deployed in various locations.

4.4.2.2 Applications for Liquid Air Energy Storage

Table 4-11 provides the status of various commercial scale, pilot, and demonstration LAES projects.

[28] https://jestec.taylors.edu.my/Vol%2011%20issue%204%20April%202016/Volume%20(11)%20Issue%20(4)%20496-515.pdf

Table 4-11 Status for Selected LAES Projects

Site	Status	Rated Power (kW)	Discharge Duration at Rated Power (hrs)	Storage Capacity (kWh)	Commissioned Date	Energy Storage Technology Provider	Notes
University of Birmingham Cryogenic Energy Storage (CES) Pilot	Operational	350	7	2,450	12/11/2015	Highview Power Storage	Pilot
Pre-Commercial Liquid Air Energy Storage Technology	Operational	5,000	3	15,000	6/5/2018	Highview Power Storage	Demonstration at Pilsworth Landfill facility in Bury, Greater Manchester
Carrington - Manchester, UK	Under Construction	50,000	6	300,000	2024	Highview Power Storage	
Yorkshire, UK	Under Construction	200,000	12.5	2,500,000	Late 2024	Highview Power Storage	

4.4.2.3 Resource Availability for Liquid Air Energy Storage

Charging of the LAES system is based on excess available electricity. Siting considerations include need for available space for the storage and electrical power production system.

4.4.2.4 Cost and Performance Characteristics for LAES

Table 4-12 presents typical performance and cost estimates for LAES storage.

Table 4-12 Liquified Gas Technology Characteristics

	Liquid Air 100 MW (10 Hour Duration)	Liquid CO2 100 MW (10 hour duration)
Typical Operating Life (years)[(1)]	30	Same
Typical Duty Cycle	Peaking - Intermediate	Same
Net Plant Capacity (MWe)	200	Same
Round Trip Efficiency (%)	50	Aspires to Same
Integrated Storage	10 hours	Aspires to Same
Capacity Factor (percent)	5-50	Aspires to Same
Total Project Cost ($/kW) [(2)]	770	Aspires to Same
Fixed O&M ($/kW-yr)	16.00	Aspires to Same
Variable O&M ($/MWh)	-	Aspires to Same
Commercial Status	Commercial	Aspires to Same
Installed US Capacity (MW)	0 (5 MW in UK)	Aspires to Same

Notes:

1. Evaluating emerging long-duration energy storage technologies (https://doi.org/10.1016/j.rser.2022.112240)
2. USEA & EPRI: Seasonal Energy Storage Workshop, 81452-EPRI SES Workshop Presentations 11-09-2022.pdf

4.4.2.5 Environmental Impacts for Liquid Air Energy Storage

There are no emissions from LAES when co-located (as in specifications) with a facility that has low-grade, waste heat such as a landfill or industrial facility. Otherwise, some of the heat needed to expand the liquid air to atmosphere would come from renewable electricity, or possibly fossil fuel.

4.4.2.6 Grid Integration for Liquid Air Energy Storage

The grid integration use cases for sensible heat thermal storage are similar to those for generators. These systems provide medium and long duration storage use-cases for handling renewable integration and resiliency applications.

4.5 Other Energy Storage Emerging over the Horizon

Energy storage is a very active area of research, design, and development for grid power systems. The fundamental shift away from carbon-emitting fossil fuels, coal and oil and natural gas (some of the most energy dense, stable forms of long-term energy storage), to variable renewable energy (with solar and wind commercialized, and bio-fuels with ocean/wave/tidal/thermal power under continued research) is the impetus for this.

The Black & Veatch focus for this report was on those technologies that are 1) established and growing, 2) emerging and applicable to power generation, or 3) plausibly commercialized within the planning horizon of the PRPA needs, for which there are publicly available cost and performance data that have been vetted, and adjusted for calendar time price adjustments.

Above and beyond those described in previous sections, the following technologies are in early the early development stage. They may, with appropriate invention and innovation, begin to surpass the other technologies described above. While a single reference may be given below, there are typically several developers of each of these technologies, seeking patents, capital, breakthroughs, and utility partners to enable the potential of such systems.

- Super- and ultra-capacitors. These are electricity storage devices, for storing charge (Coulombs) of electrons, to a 1000x greater extent than conventional capacitors in the electronics industry. These are a very short duration storage device meant to support the electric grid during transient events. These devices would rival flywheels for power use-cases, storing seconds of electricity for frequency response, minutes for frequency regulation, and providing voltage control (Volt/VAR) grid ancillary services.
- Superconducting magnetic energy storage (SMES). These are electricity storage devices, using a current flowing through a circular toroid of superconducting material at very high currents forming a magnetic field with very low losses that yield very high storage efficiencies. The device is discharged using the magnetic field to drive the shaft of an electric generator. These devices are meant to be used in high power, short duration and low energy density applications such as grid support.
- Pumped Heat Energy Storage (PHES). Power generation has been accomplished with thermodynamic cycles for generations, sometimes called “Carnot Cycles” after its inventor. A combination of high temperature (from combustion of fossil fuels) and low temperature (from bodies of water or through evaporative cooling towers) is used as a temperature difference over which the Carnot-cycle can operate, creating mechanical power that turns a generator to produce electricity.
- Ultra-high Thermal Energy Storage (MIT)29. This system uses electricity to create molten metal at temperatures approaching 3000° C. At that temperature, thermal radiation imparts photons to photovoltaic panels for regenerating the electricity.
- Geo-plasticity. These are systems that use the earth’s crust to contain very high-pressure water, pumped underground. Then to discharge, the high-pressure water passes through pumped-hydroelectric style turbines to regenerate the electricity. Such systems are dependent on the appropriate geology.

4.6 Task 2 (LDES) Summary Conclusions

This section provided PRPA with an overview of LDES technologies that could be discharged at an average power of 400 MW for 7 days. Specific attention was given to how these technologies could be implemented in the local PRPA area.

[29] https://www.thewellnews.com/in-the-news/mit-researchers-seek-long-term-storage-solution-for-wind-solar-sectors/

Several technologies stand out as being applicable – notably: PSH, hydrogen, CAES, advanced metal-based batteries, and flow batteries. However, between the significant cost, regulatory lead times, and stage of development, these technologies are not likely to be able to be implemented by PRPA at the scale of 400MW for 7 days before 2030.

- Battery storage technologies have numerous benefits including high round-trip efficiencies, favorable response times and ramp rates, and small footprints. The duration of energy storage and cost required to build up capacity over time will require regular and steady investment in multiple sites. Major use case for this technology is currently around 4 hours and comes with significant cost. While the technology is mature and commercial, the cost associated with implementation does not make it practical for supplying the LDES needed on the PRPA system.
- PSH is most technologically ready and suited for the region. It is a mature technology that has been proven to be effective and efficient over more than 75 years of operation in the United States. Identifying appropriate sites and permitting are challenges that will take time to resolve.
- The production, storage, and firing of "green" hydrogen is an emerging technology that shows significant promise in providing long-duration energy storage and "shifting" the availability of abundant renewable energy resources over seasons and years. It is conceptually feasible to begin incorporating hydrogen into present day investments in natural gas fired, dispatchable generators; and then slowly transition those assets to incorporating larger amounts of hydrogen in the generator fuels as the technology improves. The low round-trip efficiencies, unproven equipment life, and inferior dispatchability characteristics all indicate that it is not currently an appropriate choice for PRPA. With governmental support and industry interest, it is possible that green hydrogen could be commercially developed for long duration energy storge by the middle of the next decade.
- CAES would require additional research if pursued for PRPA LDES needs. The positives include potential storage durations (if underground geological storage is deemed feasible and cost effective), lifetime capacity, and asset dispatchability requirements. However, response time, aesthetics, and design life are all inferior attributes relative to other energy storage technologies. It is extremely unlikely this technology can be implemented in the PRPA territory by 2030.

In conclusion, the LDES needs of PRPA may need to be met with a basket of multiple technologies. This will require early identification of sites, discussions with interconnected agencies, and budgetary planning.

5.0 Task 3: Low or no Carbon Fuels and Carbon Sequestration

Task 3 of this study looked specifically at emerging low or no carbon fuel technologies as well as explored the implementation of carbon capture and sequestration (CCS) facility at PRPA's Rawhide Energy Station. This section presents the low or no carbon fuel and CCS technology assessments, which include an introduction to the technology; performance; capital and operations and maintenance (O&M) costs; development timeline; opportunities, challenges, and risks; and conclusions. The following technologies are included in this section:

- Liquid Low-Carbon Fuels (Biofuels)
- Gaseous Low-Carbon Fuels (Biogas, Syngas, RNG)
- Hydrogen (Blue and Green)
- Ammonia
- Carbon Capture Utilization and Sequestration (CCUS)

Black & Veatch has been engaged by Platte River Power Authority (PRPA) to conduct an engineering study on emerging generation technologies to assist PRPA in proactively working towards the goal of 100 percent noncarbon energy mix goal by 2030. Black & Veatch's high level technical assessment evaluated the available no or low carbon fuels for use in the peaker units, as well as the post-combustion carbon capture technologies available to remove carbon directly from the Rawhide unit's combined flue gas emissions. Additionally, Black & Veatch evaluated the performance (thermal and emissions), the capital, operating, and maintenance costs; the opportunities, challenges, and risks; and the development timeline of the prospective low or no carbon fuel/CCS facility as it relates to the Rawhide peaker units.

As part of the review of the technology assessment, a TRL[30] is assigned to each technology. A TRL is a measurement system used to assess the maturity of a technology. It was developed by NASA during the 1970s and has been used across many different industries, including the power industry. The relative risk associated with these new technologies may be identified by its TRL. Each TRL level is typically associated with an order of magnitude increase in scale and associated development, up to TRL 9, which represents a fully developed, commercially available technology at industrial scale. TRL Levels 1 to 3 represent lab-scale technologies with an increasing understanding of proven concepts, repeatability, and cost. TRL Levels 4 through 6 represent pilot-scale technologies with a more detailed understanding of material balances and simulations at scale, detailed techno-economic analysis, and optimization based on process data. TRL Levels 7 to 8 prove the technology with long-term continuous operation, understanding and mitigation of engineering and process risks, finalized operating conditions, detailed modeling, and investor validation. TRL 9 represents the technology's final commercial form in application, with operations meeting cost, yield, and productivity estimates. Table 5-1 summarizes the basic phases, size, timeline, and cost associated with each TRL.

[30] Technology Readiness Level. (2012, Oct). Retrieved from NASA: https://www.nasa.gov/directorates/heo/scan/engineering/technology/technology_readiness_level

Table 5-1 Typical Development Pathway for Technology Readiness

TRL	Phase	Scale	Duration	Investment
1	Research	1/100	3 to 6 months	$500,000
2	Technology	1/10	3 to 6 months	$500,000
3	Feasibility	1	6 to 12 months	$500,000
4	Pilot-Scale Development	10	6 to 12 months	$1,000,000
5	Technology Development	100	6 to 12 months	$1,000,000
6	Viability Demonstration	1,000	1 to 2 years	$1,000,000+
7	Transition to Commercial	10,000	1 to 2 years	$1,000,000+
8	Commercial Demonstration	100,000	1 to 2 years	$10,000,000+
9	Commercial Deployment	1,000,000	2 to 3 years	$100,000,000+

5.1 Liquid Low-Carbon Fuels for Generation (Biofuels)

The production of low carbon liquid fuels (i.e., liquid fuels with low carbon intensity) from renewable, non-food feedstock materials has been emphasized over the past two decades for several key reasons, including the promotion of domestic energy security, increasing sustainability while decreasing carbon dioxide emissions, and creating local employment in often struggling economies. The United States Energy Information Administration (EIA) estimates that the transportation sector represents the highest percentage end-use for delivered energy consumption as well as the sector with highest carbon emissions.[31]

The United States is currently the largest producer of biofuels in the world, accounting for about 43 percent of the global biofuels production capacity.[32] Brazil, Germany, and China are also sizeable producers of liquid biofuels. The policy driver to produce biofuels in the United States is known as the Renewable Fuel Standard (RFS), which is administered by the United States Environmental Protection Agency (EPA), originated with the Energy Policy Act of 2005, and was extended under the Energy Independence and Security Act of 2007. The current goal under RFS is the production of 36 billion gallons of advanced renewable transportation fuels by 2022.[33] The United States Department of Energy (DoE) Bioenergy Technologies Office (BETO) is responsible for establishing relationships with industry, academia, and other stakeholder government agencies to encourage the research, development, demonstration, and eventual production of biofuels to meet the goals formulated by the RFS.

5.1.1 Progression of Biofuels Technologies

Although there are many ways the evolution of biofuel technologies has been depicted, there are generally three classifications: commercial, near-term, and long-term. Commercial technologies include those that have already been deployed in substantial numbers. Near-term biofuels have been commercialized to a minimal extent and few commercial installations exist. Many technologies that are being demonstrated or scaled up to noteworthy capacities constitute this classification. Long-term technologies are generally not considered viable in the near-term because of major technological and economic impediments. Such biofuel technologies require significant advancement prior to deployment. In many biofuel industry publications and presentations, these general classes of technologies are referred to as “generations” where commercial is considered “first generation,” near-term is known as “second generation,” and long-term technologies are described as “third generation.”

First-generation biofuels are considered controversial by some because they often rely heavily on government subsidies to yield suitable profit margins, regularly use food crops as feedstocks, and provide negligible greenhouse gas (GHG) savings compared with their fossil fuel equivalents. Despite the disagreements surrounding these aspects of their commercialization, most would agree that the pursuit of these types of fuels has generally benefited energy security to a minor extent. Most of the focus in first-generation biofuels has been paid to traditional fermentation of corn kernels (starch) and sugar cane to ethanol as well as the transesterification of fats, oils, and greases (FOG) to biodiesel.

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[31] Energy Information Administration, 2015. Annual Energy Outlook 2015, Washington, DC: US Government Publishing Office.

[32] Energy Information Administration, 2021. International Energy Statistics: Renewables - Biofuels Production. Available at: https://www.eia.gov/international/data/world/biofuels/biofuels-production.

[33] Overview for Renewable Fuel Standard . (2023, Feb). Retrieved from United States Environmental Protection Agency: https://www.epa.gov/renewable-fuel-standard-program/overview-renewable-fuel-standard

Second-generation biofuel technologies rely on a more versatile set of feedstock materials that are generally avoidant of the “food versus fuel” interaction, which include, but are not limited to, energy crops (crops specifically grown for biofuel feedstock, e.g. switchgrass, wheatgrass, and bamboo), agricultural residues, urban and non-urban wastes, and forestry biomass. GHG savings (compared with fossil fuel usage) have been shown to be much greater and reliably tabulated for these types of biofuels with a host of various pathways by which they can be produced. The primary fuel products that result from these processes include ethanol, iso-butanol, dimethyl ether, and so-called “drop-in” advanced hydrocarbon fuels (e.g., “green” gasoline/diesel/jet).

Finally, third-generation biofuels embody the greatest amount of GHG savings and utilize abundant raw materials such as water, carbon dioxide, algae, and agricultural residues. However, these feeds are notoriously difficult and costly to convert into useful products such as biofuels or so-called “electro-fuels,” and while there is a host of pathways being considered for their implementation, they are generally considered by most experts to be more than 10 years away from any serious commercialization activities. Fuel products include alcohols and advanced hydrocarbon fuels as well; but given the technical risks and fiscal obstacles associated with third-generation biofuels, attempting to predict their economic characteristics at this early stage would prove futile.

5.1.2 Biofuel Feedstocks

The different types of biomass feedstocks that could be used to produce biofuels are far too numerous to name them all in this report. However, the principal groupings and some examples of each are included to provide a general appreciation for the breadth of potential biomass feedstocks that could be used for biofuel synthesis. These are provided in Table 5-2 where the materials in the first row constitute primary feedstocks under consideration in this study.

Table 5-2 Various Biomass Feedstocks Used for Biofuel Production

Food Crops	Energy Crops	Agricultural Residues	Forestry Biomass	Waste Materials	Manures
Corn Starch	Switchgrass	Corn Stover	Forest Thinnings	Urban Wood Waste	Cow Manure
Sugar Cane	Miscanthus	Wheat Straw	Slash (Tops and Limbs)	Municipal Solid Waste (MSW)	Swine Waste
Soybeans	Banagrass	Orchard Prunings	Shrubs	Tire Crumb	Poultry Litter
Vegetable Oils	Arondo Donax	Bagasse	Chaparral	Sewage Sludge	

In general, first-generation biofuels are largely produced from food crops because sugars and lipids therein can be easily extracted and converted into ethanol or biodiesel, respectively. By contrast, second- and third-generation biofuels often use some of the other feedstocks listed, collectively known as lignocellulosic (or simply cellulosic) biomass, which are more abundant but also more difficult to process and convert into fuels. This is because of the lignin content of cellulosic feedstock materials, which often requires chemical pretreatments or thermal destruction to yield “fermentable” sugars. Despite these differences, the attributes of an ideal biomass resource for biofuels production are as follows:

- Low moisture, high-energy content.
- High yield, non-food, marginal land usage, wide availability.

- Sustainable growth: low water/fertilizer use, retention of biodiversity, minimal erosion, balanced soil, and nutrients.
- Low lifecycle (direct and indirect) carbon emissions.
- Minimal processing to achieve densification for transportation and on-site storage.

In summary, a variety of possible biomass feedstocks exists to produce liquid biofuels via numerous pathways. An ideal feedstock largely depends on the process, but several characteristics such as low moisture, high energy, extensive availability, sustainable growing conditions, low carbon emissions, and compact densification are among the most important.

5.1.3 Feedstock Availability

Reports from the Department of Energy shows that there is over 222,000 dry tons of potential biomass resources at $60/dt annually available within the Larimer County, CO that could be used. [34] Most of the feedstock for Larimer County is sourced from forestry and waste and much small quantities from agriculture sources. Using a yield of 85 gallons per ton of biomass, this would potentially supply nearly 19 million gallons of biofuels for use in transportation, power generation, heating, etc. The Larimer County biomass feedstock availability is expected to also increase over 2% by 2030 and over 2% between 2030 and 2040. Therefore, the feedstocks in Larimer County alone would not be able to sufficiently supply biofuels for all peaker and combined cycle operations but could be sourced from other locations or still be used as a piece of the overall goal for zero carbon energy.

5.1.4 Biofuel Pathways

Numerous pathways exist between feedstocks and fuels and these pathways represent a variety of conversion technologies, interfaces, and approaches that have been evaluated by both industrial as well as government entities for extended periods of time. Black & Veatch has studied the most promising pathways identified previously on behalf of several clients, including a variety of chemical (e.g., transesterification), biochemical (e.g., anaerobic digestion, fermentation), and thermochemical (e.g., gasification, pyrolysis) pathways to produce a range of different biofuel end products.

5.1.5 Biofuel End Products

A mixture of liquid alcohols and/or hydrocarbons is not a “fuel” until it meets a specification, particularly for transportation applications but also for power generation. ASTM International (ASTM) is a principal authority on “voluntary consensus standards” for petroleum products, liquid fuels, and lubricants. In recent years with the development and advent of various biofuel end products, ASTM has updated their standards for more traditional fossil-based liquid fuels to include blending standards for biofuels that do not themselves meet those standards. These biofuel products are also known as blendstocks and would be required to meet the standards outlined in Table 5-3. However, it should be noted that some biofuel pathways produce blendstocks that do not completely meet the ASTM standards, thus there are limitations to which they can be blended with petroleum-based fuels.

[34] 2016 Billion-Ton Report. Bioenergy Technologies Office. Retrieved from https://www.energy.gov/eere/bioenergy/2016-billion-ton-report

Table 5-3 Fuel Types and Applicable ASTM Standards

Fuel Type	ASTM Standard(s)
Ethanol	D4806, D4814, D5798
Biodiesel	D6751, D7467
Automotive Spark-Ignition Engine Fuel (Gasoline)	D4814
Aviation Turbine Fuel (Jet)	D7566, D1655
Diesel Fuel	D975

5.1.6 Performance (Thermal and Emissions)

Low-carbon liquid fuels can have a variety of performance characteristics that may make them appropriate or inappropriate for power generation applications. For example, in comparison with traditional fossil-based diesel fuel oil, renewable diesel has comparable energy content, a lower density, and a very high cetane number when it has been tested/confirmed to meet the requirements of ASTM D975. Renewable diesel blended with fuel oil should result in similar distillation/evaporation characteristics and use of similar additives should allow for comparable cold weather characteristics (i.e., pour point, pumping/atomization). Renewable diesel could be used in both compression-ignition engines as well as combustion turbines to replace fossil-based fuel oil for power generation.

In contrast, ethanol is an alcohol-type fuel that is currently used as an additive to gasoline in spark-ignition engines, which boosts octane and decreases soot emissions. Relative to unblended gasoline, ethanol has lower energy content, is more corrosive, and has a higher affinity for dirt and moisture, the latter of which can cause fuel system/engine damage. In the United States, blending of ethanol into the broader gasoline supply has to-date been limited to 10 percent by volume, indicating that gasoline mixtures with higher than 10 percent ethanol by volume (i.e., “E10”) could potentially cause damage to older engines for the aforementioned reasons. For engines produced after 2001, the United States EPA has approved “E15” (i.e., gasoline with up to 15 percent ethanol by volume), but many automobile warranties generally do not cover E15 (or greater blends of gasoline/ethanol) usage, which is a major concern for many consumers. This is similar for biodiesel use in compression-ignition engines, which are frequently limited to blending percentages of up to 5 percent by volume (i.e., “B5”) by engine manufacturers. Biodiesel can have significant negative impacts on performance because of its lower energy content and viscosity/lubricity characteristics; however, these challenges may be overcome in some cases via the use of additives and special engine design.

The blending of biofuels, such as renewable diesel, with fossil-based liquid fuels has been shown to have a positive impact on criteria air pollutants in a variety of applications. Sulfur content of the biofuel oil itself is typically less than 1 milligram per kilogram (mg/kg); however, can become contaminated as part of normal logistics via fuel oil supply chains, thus the specification for the biofuel oil itself is often set at 5 mg/kg. Additionally, ash and metal content of biofuel oil, because of its source feedstock characteristics, is typically less than 0.001 percent. Since biofuel oil includes only paraffinic hydrocarbon compounds, a 50/50 blend with fossil-based fuel oil will lower the overall aromatic hydrocarbon content of the final fuel, thereby decreasing the emissions of some criteria air pollutants.[35]

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[35] Neste Corporation. Neste Renewable Diesel Handbook, www.neste.com/sites/default/files/attachments/neste_renewable_diesel_handbook.pdf.

It is important to note that air emissions testing with renewable diesel has primarily focused on passenger vehicles and internal combustion engines, rather than combustion turbine (CT) generators. While much testing has clearly demonstrated a reduction in air emissions such as carbon monoxide (40 percent), hydrocarbons (30 percent), and particulate matter (10 percent),[35] there is still some controversy surrounding the benefits of renewable diesel with respect to nitrous oxide emissions.[36] It is clear that additional testing is needed to clarify any potential benefits and any required after treatment in both internal combustion engines as well as CT generators.

The primary focus of the production and use of liquid biofuels, such as renewable diesel, is the reduction of GHG emissions. Once again, however, much of the research surrounding the reduction in GHG emissions when using blends of biofuel oil with fossil-based fuel oil has focused on the transportation industry, rather than power generation. The prevalence of renewable transportation fuel standard programs across the globe has been steadily increasing since the mid-2000s with a variety of frameworks being established (i.e., US, UK, Canada, California) through which GHG emissions from source to final disposition (i.e., "well to wheel") are characterized in terms of carbon intensity. No such framework yet exists for characterizing renewable fuels used in the power generation sector, and because of the fact that GHG emission reductions are largely dependent on feedstock source, conversion process, transportation logistics, and end use application, such a framework would be needed to accurately characterize the carbon intensity of biofuel oil use by PRPA.

However, based on the available literature, it has been estimated that biofuels, such as renewable diesel derived from FOG feedstocks and processed via hydrotreatment, can result in GHG emissions reductions of around 50 to 90 percent relative to fossil-based fuel oil, particularly for waste cooking oil type feedstocks and renewable/low-carbon sources of hydrogen.[35] It is expected that other advanced biofuels can achieve similar GHG emissions reductions. In summary, there are several environmental performance benefits associated with the use of biofuel oil; however, additional research, analysis, and demonstration would be needed to fully characterize those benefits to PRPA.

5.1.7 Capital and O&M Costs

Capital, O&M, and levelized costs associated with different liquid biofuels can vary considerably depending on the plant capacity, feedstock, conversion pathway, end product, and end use. In general, it is expected that the non-fuel capital/O&M costs associated with various power generation equipment that has been designed specifically for these fuels will not be considerably different for biofuels compared with fossil-based fuels. This includes the transportation of biofuels to a given PRPA power generation facility via the same means and cost as fossil-fuel based liquids. However, it is expected that power generation facilities originally designed for a specific type of fossil-based liquid fuel will ultimately require capital expenditures to modify the equipment to ensure operability with liquid biofuels, which will also impact O&M expenses. Such a scenario would have to be explored on a case-by-case basis in close coordination with PRPA and the appropriate engine/CT manufacturers.

Given the relatively minor differences in capital/O&M costs associated with power generation equipment (e.g., RICEs and CTs) that utilize biofuels and fossil-based fuels, Black & Veatch recommends that PRPA consider modeling these systems in the same manner (e.g., capacity, capital/O&M costs, heat rate) with the main difference being in fuel pricing. Fuel pricing for the major types of biofuels and biofuel blends are shown in US dollars (USD) per gallon of gasoline equivalent (GGE) in Table 5-4 and in USD per million British thermal units (MMBtu) in Table 5-5.

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[36] Alsultan, Abdulkareem Ghassan, et al. "Combustion and Emission Performance of CO/NOx/SOx for Green Diesel Blends in a Swirl Burner." ACS Omega, vol. 6, no. 1, 2020, pp. 408–415., doi:10.1021/acsomega.0c04800.

Table 5-4 Liquid Fuel Pricing for 2016 through 2023 (USD per GGE)

Fuel Type[1]	Minimum	Maximum	Average
Gasoline/E10	$1.91	$4.70	$2.73
E85	$2.28	$5.10	$3.05
Diesel/B5	$1.90	$5.02	$2.81
B20	$2.01	$4.8	$2.71
B100	$2.76	$5.48	$3.60
Renewable Diesel[2]	$2.47	$6.51	$3.92
Other Advanced Second Generation Biofuels[3]	$3.65	$5.47	$4.35

Notes:
1) All pricing given in 2023 USD per GGE. All pricing represents average retail based on data from Alternative Fuels Data Center unless otherwise noted.[37]
2) Pricing based on Black & Veatch analysis and confidential market data.
3) Pricing based on Black & Veatch analysis.

Table 5-5 Liquid Fuel Pricing for 2016 through 2023 (USD per MMBtu)

Fuel Type[1]	Lower Heating Value	Min.	Max.	Avg.
Gasoline/E10	114,300 Btu/gal	$16.71	$41.12	$23.91
E85	87,900 Btu/gal	$25.94	$58.02	$34.64
Diesel/B5	128,700 Btu/gal	$14.76	$39.01	$21.83
B20	127,000 Btu/gal	$15.83	$37.80	$21.34
B100	117,100 Btu/gal	$23.57	$46.80	$30.73
Renewable Diesel[2]	124,800 Btu/gal	$22.44	$52.16	$31.40
Other Advanced Second Generation Biofuels[3]	Varies (114,300 Btu/gal)	$31.93	$47.86	$38.06

Notes:
1) All pricing given in 2023 USD per MMBtu. All pricing based on data from Alternative Fuels Data Center unless otherwise noted.[6]
2) Pricing based on Black & Veatch analysis and confidential market data.
3) Pricing based on Black & Veatch analysis.

[37] "Fuel Prices." Alternative Fuels Data Center: Fuel Prices, March 2023, https://afdc.energy.gov/fuels/prices.html.

5.1.8 Development Timeline

Many types of liquid biofuels are already commercially available; however, these biofuels are predominantly used in the transportation sector and are only used in niche scenarios for power generation applications because of their high costs relative to other types of fuels and the low availability in the volumes needed for power generation. As far as other "second-generation" or advanced biofuels, it is expected that the supply of such biofuels (e.g., renewable diesel) will grow rapidly in the next 5 to 10 years as additional production plants come online. Yet, once again, these fuels are likely to be used primarily in transportation applications over the decades to come and would only typically be considered as a backup fuel for power generation. Third-generation liquid biofuels are not expected to be commercially available in the next two or more decades without major breakthroughs in research and development and are therefore not considered for the purposes of this road-mapping study.

5.1.9 Opportunities, Challenges, and Risks

The most significant opportunity for the use of liquid biofuels within the PRPA generation portfolio as a means of reducing key air emissions criteria pollutants and decarbonization is primarily in reducing or displacing the use of fossil-based liquid fuels for backup purposes. Otherwise, the more promising use of such fuels is for the decarbonization of service vehicle fleets and/or support equipment that use liquid fuels. However, GHG emissions reductions are highly dependent on feedstock source, conversion process, transportation logistics, and end use application.

PRPA would need to carefully consider the use of liquid biofuels in their power generation assets since much of the research to-date has focused on the transportation sector. Although minimal performance impacts are expected relative to fossil-based fuels for drop-in biofuels such as renewable diesel, this would need to be validated through rigorous fuel quality analysis in addition to a test, evaluation, demonstration, and validation program. The use of first-generation biofuels such as ethanol or biodiesel are not recommended because of the high potential for performance challenges and relative high pricing for the level of decarbonization offered. Other challenges in the near-term include sourcing of low-carbon biofuels, such as renewable diesel, given their availability is not expected to increase significantly over the next 5 to 10 years.

From a risk perspective, PRPA would also need to evaluate the use of liquid low-carbon fuels relative to equipment age, condition, and warranties at all specific power plants where such a fuel may be used. It is recommended that PRPA conduct equipment condition assessments, construct performance models, and correspond with the appropriate OEMs, as needed. Finally, availability/pricing risks would need to be mitigated through direct correspondence with biofuel producers.

5.1.10 Conclusions

The following are the major conclusions for biofuels:

- Numerous fuel production pathways exist between biomass feedstocks and liquid fuel end products. These pathways represent a variety of conversion technologies, interfaces, and approaches that have been evaluated by both industrial as well as government entities for extended periods of time.
- First-generation biofuels (e.g., ethanol and biodiesel) are not expected to provide a reasonable balance between performance, price, and decarbonization to be beneficial to PRPA for the purposes of road-mapping. Biofuels developers are looking at transportation sector, not power sector as the main user.

- Second-generation biofuels (e.g., renewable diesel) show the most promising benefits for PRPA after the next 5 to 10 years as their availability increases and pricing stabilizes, particularly as a backup fuel for generation assets.
- Rawhide peakers would require significant capital cost to retrofit for burning biodiesel and the quantity of available feedstock in Larimer County alone would not be able to sufficiently supply biofuel for all peakers, therefore, this does not seem to be a viable option for Platte River in the near future.

5.2 Gaseous Low-Carbon Fuels (Biogas, Syngas, and Renewable Natural Gas)

The field of gaseous low-carbon fuels is vast and encompasses several different alternatives, including biogas, synthetic gas (or syngas), RNG, and hydrogen, the latter of which will be discussed in Section 5.3 of this report. Biogas, syngas, and RNG (or biomethane) are produced primarily through the conversion of organic/biogenic substances via biochemical (i.e., anerobic digestion or AD) or thermochemical (i.e., gasification) degradation processes. Biogas is composed primarily of methane and carbon dioxide, is typically produced via anerobic digestion, and can subsequently be upgraded to RNG by means of a variety of cleaning processes. Syngas is primarily composed of hydrogen and carbon monoxide, is typically produced via gasification, and can then be upgraded by means of methanation to RNG. Biogas, syngas, and RNG can all be used in electromechanical (e.g., RICEs or CTs) or electrochemical (e.g., fuel cells) for the production of electricity with varying degrees of cleaning requirements for each alternative.

5.2.1 Biogas Production

Biogas production from anerobic digestion largely encompasses two feedstock sectors: agricultural sources and municipal/industrial sources. Agricultural sources of organic feedstocks include the following:

- Animal byproducts/manure from dairy, swine poultry, beef, and equestrian operations.
- Agricultural/food processing residues from the growth, harvest, and/or production of foodstuffs.
- Energy crops grown specifically for energy production such as grass, clover, cereals, and maize, including whole plants, as well as rape of sunflower and others.
- Municipal/industrial sources of organic feedstocks include the following:
- Municipal biosolids processed in a wastewater treatment plant (WWTP).
- Residential and commercial waste (i.e., landfilled MSW, source-separated organics, pre-/post-consumer organics, organic fraction of MSW, FOG).
- Industrial byproducts from food processing and component production (e.g., dairy processing, slaughterhouse wastes, glycerin and thin stillage, beverage, and other high-strength wastes).

It is important to note that landfilled MSW produces a specific type of biogas referred to as landfill gas (LFG), while the other types of aforementioned organic feedstocks are often converted via anerobic digestion in a digester system specifically designed for that particular feedstock. Typical compositions for different types of biogases are shown in Table 5-6.

Table 5-6 Typical Biogas Compositions for Various Feedstocks (by Volume)

Application	CH_4	CO2	H_2O	N_2	O_2	H_2S	NH_3	Si from Siloxanes
LFG	53%	28%	6%	10%	2%	100 ppm_v	10 ppm_v	12 mg/Nm^3
Organic Waste	65%	28%	6%	0%	0%	500 ppm_v	200 ppm_v	7 mg/Nm^3
Manure	60%	33%	6%	0%	0%	2,000 ppm_v	500 ppm_v	0 mg/Nm^3
WWTP	59%	32%	6%	2%	0%	200 ppm_v	30 ppm_v	14 mg/Nm^3

ppm - parts per million
mg - milligrams
Nm^3 - normal cubic meters

5.2.2 Biogas Upgrading to RNG

To inject RNG into the existing natural gas infrastructure, biogas must be upgraded to meet standards as defined by individual gas utilities' pipeline specifications. The primary cleaning, conditioning, and upgrading processes that must occur to meet such pipeline specifications include the removal of moisture, hydrogen sulfide, siloxanes, nitrogen, oxygen, and carbon dioxide, resulting in a relatively pure stream of mostly methane. The removal of carbon dioxide is the primary focus of leading biogas upgrading suppliers; however, within their processes these suppliers include the necessary gas conditioning systems to also remove other contaminants and diluents. From a technical perspective, these processes are well established and there are a number of commercial operating facilities in both North America and Europe, among other countries. The following are the key technologies for biogas upgrading:

- Membrane separation.
- Pressure swing adsorption.
- Water scrubbing.
- Amine scrubbing.

Beyond the removal of these components, there are other considerations that need to be taken into account when developing a biogas upgrading system. Separation of non-methane components (with minimal amounts of methane losses) typically results in an off-gas stream that must be remediated to meet environmental regulations, which frequently requires the inclusion of a thermal oxidizer. Additionally, if moderate levels of inert constituents (i.e., nitrogen and carbon dioxide) remain in the gas stream following the upgrading process, a higher-energy hydrocarbon gas (such as propane) may need to be blended to raise the heating value and Wobbe Index to compliant levels. Finally, the gas leaving the biogas upgrading process is likely to be at relatively low pressure and will often require further compression for pipeline injection.

5.2.3 Syngas Production

Renewable feedstocks, such as those listed above, can be used to create low carbon fuels using syngas production. Syngas production via gasification occurs when any carbonaceous material is brought into contact with an oxidant (e.g., air, oxygen, steam) and elevated to high temperatures (approximately 1,200° F to 2,900° F) in a reducing environment. Solid feedstocks to the gasifier can be dry or slurried and the heat required for gasification is usually supplied by combustion or partial oxidation of the feedstock, but it can also be supplied indirectly by heat transfer through the reactor wall or by introducing a heated material to the gasifier. Gasifiers can use oxygen, steam, or air for partial fuel oxidation. Gasifiers that use purified oxygen produce a medium heating value gas and minimize the syngas volume, which reduces the size and cost of the gas cleanup equipment downstream of the gasifier. Gasifiers that use steam also produce a medium heating value gas but require supplemental heat addition. Gasifiers that use air for partial oxidation produce a low heating value syngas with large amounts of nitrogen. Air-blown gasification is viable for power generation or regional heating applications; however, for the production of liquid fuels, chemicals, or RNG, oxygen/steam-blown gasification is generally required.

The syngas that is produced from gasification is composed primarily of carbon monoxide and hydrogen, with varying amounts of carbon dioxide, methane, and higher hydrocarbons. For air-blown gasifiers, nitrogen makes up about 50 percent of the syngas. For nitrogen-free syngas, the carbon dioxide component in the syngas varies from as little as 1 percent to more than 30 percent and depends primarily on the equilibrium of the gasification reactions and the amount of fuel that is oxidized for the heat requirement. The amount of methane contained in the syngas depends on the operating temperature and pressure of the gasifier, as well as the gasifier geometry/design. Gasifiers that operate at lower temperatures and higher pressures produce more methane.

5.2.4 Syngas Cleaning and Methanation

The exact composition of syngas depends on the operating characteristics of the gasification system (e.g., temperature, pressure, and residence time) as well as the composition of the biomass or other solid feedstock. The raw syngas exiting the gasifier also contains varying amounts of undesirable constituents including chloride, nitrogen, and sulfur compounds (e.g., hydrogen chloride, hydrogen sulfide, carbonyl sulfide, ammonia, hydrogen cyanide), vapor-phase alkali, condensable hydrocarbons (i.e., tars), and particulate matter such as entrained ash. Concentrations of these syngas constituents must be reduced to some extent prior to combustion for power applications or prior to further chemical processing. The removal or reduction of these undesirable constituents within the syngas is commonly referred to as syngas cleaning or cleanup. Common syngas cleaning processes include the following:

- Tar removal (e.g., thermal/catalytic cracking, solvent absorption).
- Acid gas removal (e.g., chemical, biological, or physical absorption).
- Water gas shift.

Methanation is the hydrogenation of either carbon monoxide or carbon dioxide in syngas (or from other sources) to produce methane and water vapor. Both reactions are exothermic and is often used to produce steam that is needed in other parts of the overall RNG production facility. Methanation thermodynamic equilibrium experiments suggest that higher pressures and moderate temperatures favor the production of methane. Syngas methanation projects have been developed primarily since the 1970s and 1980s as a result of interest in the production of substitute/synthetic natural gas (SNG) from coal, which have given rise to several demonstration projects as well as a couple of commercialized concepts. The most noteworthy commercial methanation scheme is the adiabatic fixed bed concept advanced by companies such as Haldor Topsøe (TREMP), Clariant (Vesta), and Johnson Matthey. Fluidized bed methanation concepts have also been pursued in the past but have found limited success because of issues such as catalyst attrition, mechanical stresses during transients, and de-fluidization.

5.2.5 Biogas Availability

According to the American Biogas Council, Colorado ranks 27th out of the 50 states for its biogas production potential at over 23 billion cubic feet of biogas per year. Currently, there are already a few sites in Colorado that are processing and using biogas and most of the biogas is sourced from wastewater processing and landfills. However, there is great potential of sourcing more biogas from wastewater, manure, food waste, and landfill sources. Given the ability for biogases utilize existing infrastructure for distribution, the biogas producing and/or processing facility would not need to be centrally located with the power generation facility.

5.2.6 Performance (Thermal and Emissions)

The utilization of biogas, syngas, and RNG for power generation is typically done in either a RICE, a heat recovery steam generator (HRSG), or CT depending primarily on the energy content/cleanliness of the fuel and the construction of the energy conversion system. Given the small-scale of most biogas sources, they are most often used in a RICE for applications less than 5 MW, while syngas is frequently coupled with a HRSG or directly coupled gasifier/combustor for applications in the 5 to 50 MW range. RNG can be utilized in all of these technologies and would be expected to perform similarly to fossil-based natural gas both on a thermal performance as well as an emissions basis, assuming the RNG meets local pipeline quality requirements.

The utilization of biogas or syngas directly can result in an increase in criteria air emissions such as carbon monoxide, hydrocarbons, particulate matter, sulfur oxides, and nitrous oxides, if not cleaned pre-combustion or coupled with appropriate air quality control equipment post-combustion. Furthermore, given the fact that biogas methane content is typically between 50 to 65 percent by volume, this results in an LHV of around 450 to 585 British thermal unit per standard cubic feet (Btu/scf) compared with around approximately 990 Btu/scf for fossil-based natural gas. Syngas, on the other hand, can have a wide variety of compositions and associated lower heating values (LHVs) depending on the feedstock, gasifier design, and oxidant used. In general, syngas derived from air-blown gasifiers for most power generation applications have an LHV around 90 Btu/scf while syngas from steam- or oxygen-blown gasifiers (typically used in the production of fuels, chemicals, and RNG) result in a syngas LHV of about 225 Btu/scf. The LHVs expected for RNG can range from 855 Btu/scf (produced from biogas) up to 945 Btu/scf (produced from syngas).

Biogas and biogas-derived RNG can have a range of carbon intensities, depending primarily on its source, with LFG being the most carbon intensive and dairy manure being the least carbon intensive. Relative to fossil-based natural gas, utilizing LFG for power generation directly would be expected to represent a 30 to 40 percent reduction in carbon emissions, while biogas from manure would result in a 500 to 550 percent reduction in carbon emissions (due to avoided methane emissions that have about 28 times the global warming potential relative to carbon dioxide). Biogas from WWTP and organic waste anerobic digestion applications would likely fall somewhere in between these two extremes.

The lifecycle GHG emissions avoidance of syngas/RNG derived from biomass has only been studied to a minor extent and is less well understood compared with biogas applications. Furthermore, depending on the type of biomass used, including its associated harvesting/transportation/regrowth characteristics, lifecycle carbon intensity can be a controversial topic in many geographies. Regardless, prior studies have shown the potential for approximately 80 percent reduction in GHG emissions for a woody biomass to RNG pathway in California relative to fossil-based natural gas.[38]

[38] Gas Technology Institute, 2019, pp. 54–58, Low-Carbon Renewable Natural Gas from Wood Wastes.

5.2.7 Capital and O&M Costs

Capital, O&M, and levelized costs associated with different gaseous low-carbon fuels can vary considerably depending on the production operation capacity, feedstock, conversion pathway, end product, and end use. Utilization of biogas/syngas directly in power generation equipment would have to be explored on a case-by-case basis in close coordination with PRPA and the appropriate turbine manufacturers to determine the cost of retrofit which is dependent on the composition of the biogas It is generally expected that RNG that meets pipeline quality requirements will perform similar to fossil-based natural gas and therefore would not require any major retrofits and would only result in minor differences in capital and O&M costs. Therefore Black & Veatch recommends that PRPA consider modeling these systems in the same manner (e.g., capacity, capital/O&M costs, heat rate) with the main difference being in fuel pricing. Given the difficulties in establishing fuel pricing for different sources of biogas/syngas, the analysis herein has focused on RNG, which has a much more well-established market. Thus, fuel pricing for the major types of RNG are shown in USD per MMBtu in Table 5-7.

Table 5-7 Natural Gas and RNG Pricing for 2023 (USD per MMBtu)

Fuel Type[1,2]	Minimum	Maximum
Natural Gas	$4.07	$7.28
LFG to RNG	$5.00	$10.00
Organic Waste to RNG	$10.00	$30.00
Manure to RNG	$15.00	$40.00
WWTP to RNG	$10.00	$20.00
Woody Biomass to RNG	$15.00	$35.00

1) All pricing given in 2023 USD per MMBtu.
2) Pricing based on Black & Veatch analysis and confidential market data.

One of the complexities, with respect to RNG specifically, is the fact that most of the RNG currently produced in the United States is being consumed in the transportation market, particularly the least carbon-intensive fuel derived from manure. This has driven prices for RNG and would complicate the market dynamics of RNG moving forward, particularly as the market becomes saturated and RNG producers are looking for alternative markets to sell their low-carbon fuel, particularly for the power generation sector. It is recommended that PRPA consider modeling both pricing extremes as part of their integrated resource planning to discern what benefits may be possible over the long-term.

5.2.8 Development Timeline

As mentioned, many types of RNG are already commercially available and used in the transportation sector. However, gaseous low-carbon fuels are only used in niche scenarios for power generation applications because of their high costs relative to other types of fuels. Yet, once again, these fuels are likely to be used primarily in transportation applications over the decades to come and would only typically be considered as a backup fuel for power generation. Although it is difficult to predict what the future may hold for RNG from a pricing and availability perspective, it is important to note that the domestic RNG has grown by 267 percent over the past 5 years and represented around 53 percent of natural gas vehicle fuel.[39] Just like the virtual market for transportation fuels, as RNG infrastructure and supply continues to expand, including pipelines, delivery, and other transportation methods, the location of the production with respect to the end use will become less of a barrier for use. It is expected that the RNG industry will continue to grow at a significant pace over the next 10 years and the power generation sector will become a logical progression for off-take once the transportation market is fully saturated.

5.2.9 Opportunities, Challenges, and Risks

One of the most promising opportunities for the use of gaseous low-carbon fuels within the PRPA generation portfolio as a means of reducing key air emissions criteria pollutants and decarbonization is primarily in reducing or displacing the use of fossil-based natural gas. Another promising use of such fuels is for the decarbonization of service vehicle fleets and/or support equipment that use natural gas and where incentives are already in place (i.e., the federal RFS program). However, as with liquid biofuels, GHG emissions reductions for each type of RNG are highly dependent on feedstock source, conversion process, transportation logistics, and end use application.

PRPA would need to carefully consider the use of RNG in their power generation assets since much of the research to-date has focused on the transportation sector. Although minimal performance impacts are expected relative to fossil-based natural gas, the extent of decarbonization (and cost thereof) would need to be evaluated based on the availability of RNG (e.g., from sources such as manure) and the pricing needed to lure the fuel away from transportation markets. Black & Veatch expects minimal technical risks in using RNG, particularly compared with use of liquid biofuels. However, it is not recommended to use biogas/syngas directly in existing assets. Finally, availability/pricing risks would need to be mitigated through direct correspondence with RNG producers.

5.2.10 Conclusions

The following are the major conclusions for gaseous low-carbon fuels:

- Biogas can be produced from numerous high-moisture feedstocks via anerobic digestion or collected from landfills, while syngas is produced from lower-moisture feedstocks primarily via gasification. The resultant biogas/syngas can then be upgraded to RNG for pipeline injection and utilization across numerous power generation assets.
- Although the direct use of biogas/syngas in RICE/CT systems is feasible, this would primarily be considered for relatively small-scale (<50 MW), greenfield projects with RICE/GTG equipment specifically designed for these fuels. Direct use of biogas/syngas in existing assets is not recommended because of technical risks associated with their compatibility with existing equipment and the associated reliability/air quality control implications.
- RNG can be used in existing equipment and at large scales, but is very dependent on availability and pricing and with minimal expected impact performance. Black & Veatch recommends PRPA consider consulting directly with RNG producers to learn about opportunities for off-take and quantification of the extent to which decarbonization goals can be achieved in balance with higher pricing for RNG relative to fossil-based natural gas. Currently there are only a few locations in Colorado that are processing biogas and most are using local to the site, so RNG may not be a feasible fuel for Rawhide at this time. However, Colorado is 27th of 50 states for its availability for potential biogas production.

[39] "53% Of US Natural Gas Vehicle Fuel in 2020 Was Renewable Natural Gas." Bioenergy Insight, 20 Apr. 2021, www.bioenergy-news.com/news/53-of-us-ngv-fuel-in-2020-was-rng/.

5.3 Hydrogen

Hydrogen is a versatile chemical substance used across numerous industries globally and is being considered as a leading low-carbon fuel for power generation, however, there are some technical and economic challenges. Currently, hydrogen is mainly used in refining, petrochemical, and commodity chemical industries. However, it is also being used to a minor extent as a transportation fuel in fuel cell electric vehicles and has been positively viewed for long-duration energy storage applications. The full hydrogen value chain is depicted on Figure 5-1 to demonstrate the wide variety of feedstocks, production processes, and end uses for hydrogen. Although industry-standard definitions do not exist yet, Table 5-8 describes some of the typical definitions for the different "colors of hydrogen" associated with each of the different production pathways shown in the value chain image. Today, the majority of hydrogen is used in the refining and industrial industries and the vast majority is produced via steam methane reforming or gray hydrogen. However, green hydrogen, produced via electrolysis with renewable energy, and blue hydrogen, produced with steam methane reforming or gasification and carbon capture, are expected to grow.

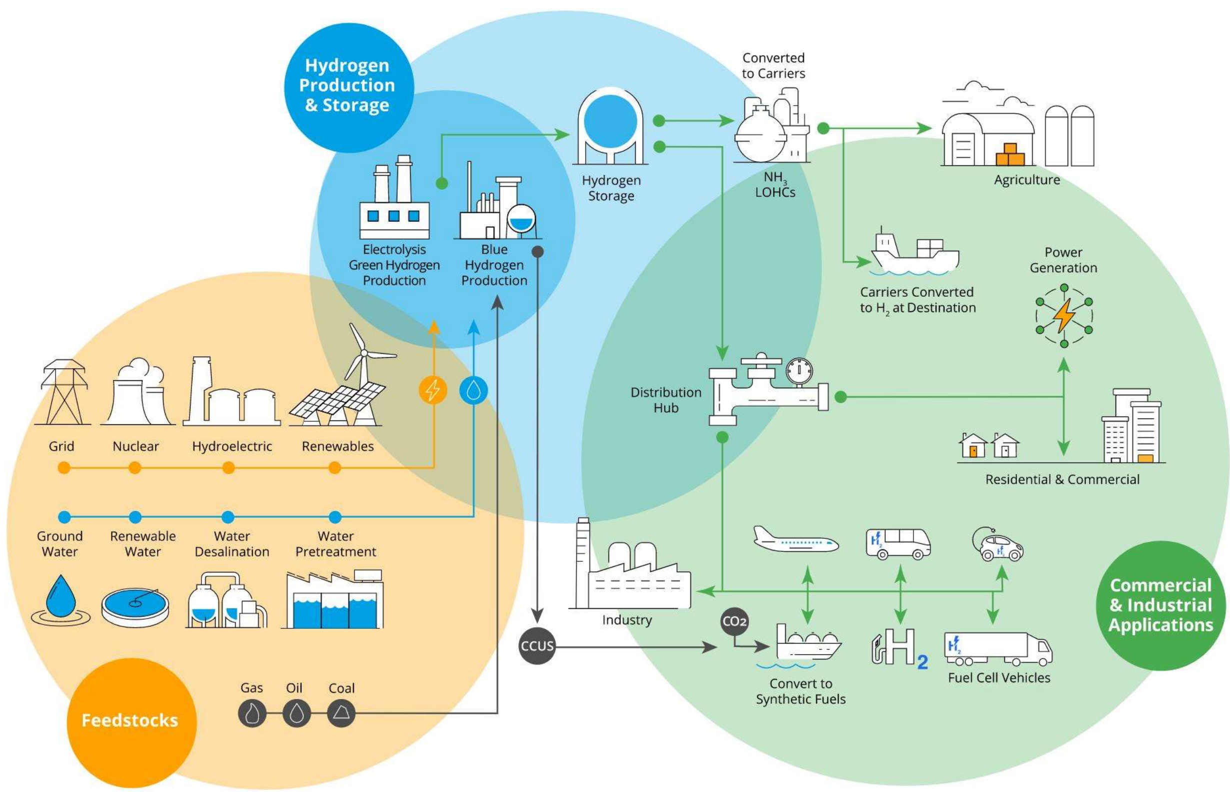

Figure 5-1 Hydrogen Value Chain

Table 5-8 Typical Definitions for Colors of Hydrogen

Hydrogen Color	"Typical" Definition[1]
Green	Water electrolysis using renewable energy resources
Blue	Gray or brown hydrogen combined with carbon capture
Gray	Steam methane reforming using natural gas with no carbon capture
Brown	Gasification using fossil fuels such as coal/petcoke
Yellow	Water electrolysis using grid energy
Pink	High-temperature water electrolysis using nuclear energy
Turquoise	Methane pyrolysis using natural gas
White	Byproduct of industrial process such as chlor-alkali electrolysis

Notes:
1. Lack of industry-wide agreement on colors/definitions warrants caution in application.

Although a number of the pathways described on Figure 5-1 and in Table 5-8 could be considered as low carbon, the scope of this report primarily focuses on "green" hydrogen from electrolysis and "blue" hydrogen from steam methane reforming coupled with CCUS technologies.

Figure 5-2 highlights the high-level process flows of utilizing and storing hydrogen as described in the following sections.

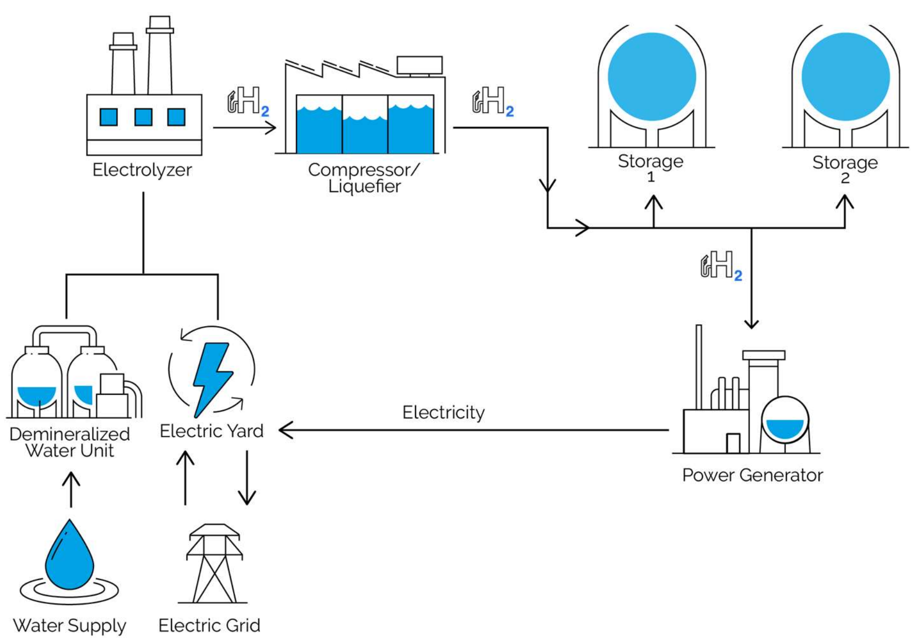

Figure 5-2 Hydrogen Energy Storage and Power Generation Schematic

5.3.1 Electrolysis – Production of "green" Hydrogen

Electrolysis is the process of splitting water into hydrogen and oxygen using electricity in an electrochemical cell. Electrolyzers come in a variety of capacities and chemistries, but the fundamental concept remains the same. Electrolyzers, like fuel cells, have electrodes (i.e., anodes and cathodes) separated by an electrolyte. The combination of electrodes and electrolyte vary by the type of chemical reactions taking place. Unlike steam methane reforming, electrolyzers are considered "green" sources of hydrogen when the electricity consumed is provided by a renewable energy resource. Instead of using carbon as an energy carrier, electrolysis-derived hydrogen uses the splitting and combining of water. For this study, two types of electrolyzers are examined: proton exchange membrane (PEM) and alkaline water electrolysis (AWE).

As the name suggests, PEM electrolyzers exchange a proton through the electrolyte between the electrodes. In a PEM electrolyzer, water is split into oxygen and hydrogen, with the hydrogen ions traveling from the anode to the cathode and exiting out the cathode side of the stack. Oxygen, in turn, exits out of the anode side of the stack. Recent research and development initiatives have optimized the catalytic activity of the cell while minimizing the amount of expensive electrocatalysts, thereby lowering the cost. [40] Figure 5-3 shows a high-level schematic of a PEM electrolyzer.

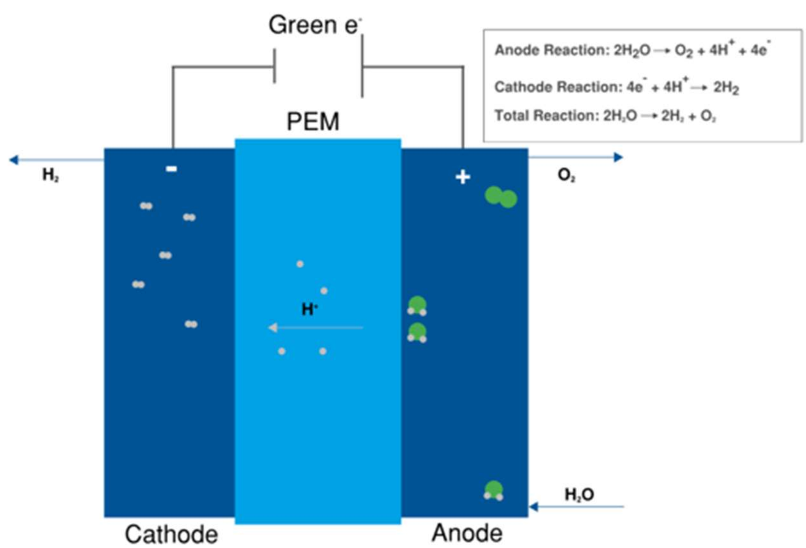

Figure 5-3 PEM Electrolyzer

[40] Vichard, L., et al. "Degradation Prediction of PEM Fuel Cell Based on Artificial Intelligence." International Journal of Hydrogen Energy, vol. 45, no. 29, 16 Apr. 2020, pp. 14953–14963., doi:10.1016/j.ijhydene.2020.03.209.

AWEs fundamentally function similarly to PEM electrolyzers; however, the ion transported in the electrolyte is OH^- and travels from the cathode to the anode. The hydrogen then exits out the cathode side of the stack and the oxygen exits out of the anode side of the stack. Since AWEs have a lower current density, they also require a larger footprint compared to PEMs. However, the AWE technology is considered more mature for large-scale hydrogen production.[41] Figure 5-4 shows a high-level schematic of a PEM electrolyzer.

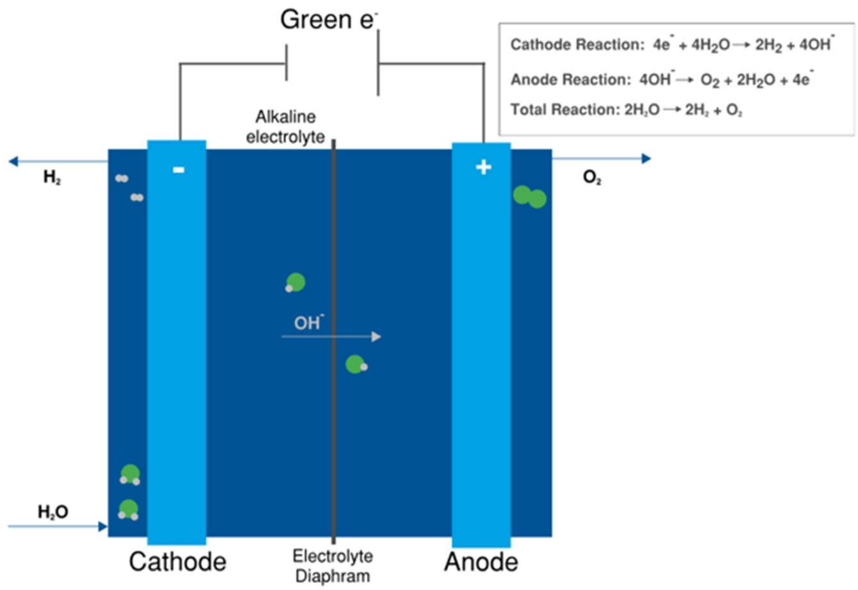

Figure 5-4 AWE Electrolyzer

5.3.2 Steam Methane Reforming – Production of "gray" and "blue" hydrogen

In the steam methane reforming process, natural gas reacts with steam over a catalyst and in presence of heat to produce syngas, which is subsequently cleaned/upgraded (via water-gas shift and pressure swing adsorption) to hydrogen. The process can generate large quantities of hydrogen that are typically utilized in production of various petrochemicals and ammonia for fertilizers. Waste heat from the burner flue gas is recovered for feed pre-heating and boiler feed water heating and steam production. Heat for steam production is also recovered from the process gas exiting the reactor in a waste heat boiler.

Steam methane reforming processes also generate large amounts of carbon dioxide emissions and can be counterproductive to electric utility industry efforts of generating low-carbon electricity via hydrogen fuel blending and co-firing solution (i.e., the carbon intensity of "gray" hydrogen from steam methane reforming is roughly 80 to 90 percent higher than that of fossil-based natural gas). Steam methane reforming is the most common approach for hydrogen production at scale in the industry, although autothermal reforming and partial oxidation technologies (or combinations thereof) are also used in some cases for lower cost hydrogen. A typical steam methane reforming process is illustrated on Figure 5-5.

[41] Brauns, Jörn, and Thomas Turek. "Alkaline Water Electrolysis Powered by Renewable Energy: A Review." Processes, vol. 8, no. 2, 2020, p. 248., doi:10.3390/pr8020248.

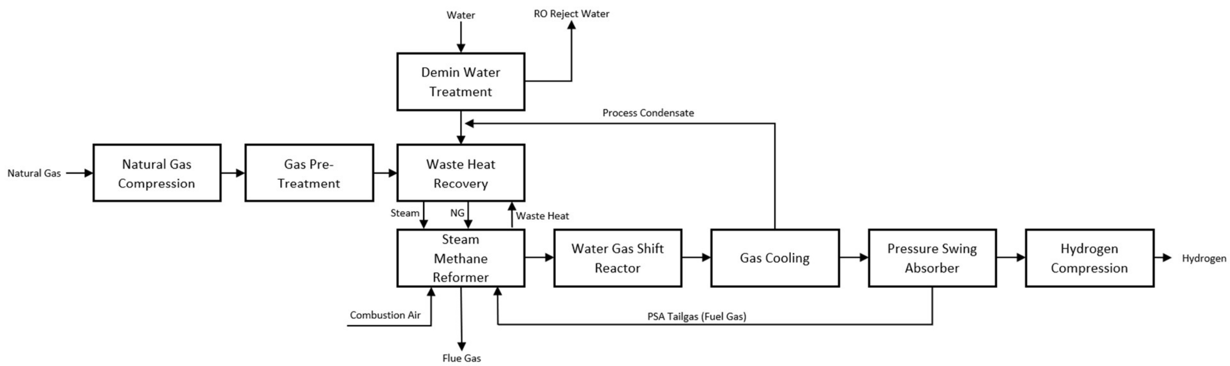

Figure 5-5 Typical Steam Methane Reforming Process Flow Diagram

The use of CCUS technologies to capture and utilize/sequester the carbon dioxide emissions from steam methane reforming operations is technically feasible but has been rarely implemented because of the historically high levelized cost involved. More recently, CCUS technologies have advanced and become more efficient, making CCUS integration with steam methane reforming plants cheaper and more economically feasible. When hydrogen is produced using a steam methane reforming process coupled with CCUS, the hydrogen produced is commonly referred to as “blue” hydrogen and is expected to have a carbon intensity that is only marginally higher than that of “green” hydrogen produced via electrolysis in combination with renewable energy resources. A detailed discussion of CCUS is provided in section 2.5.

5.3.3 Hydrogen Storage and Transportation

Because hydrogen is typically produced and consumed on-demand, there has not been a lot of development in the area of storing large amounts of hydrogen. There is a need to store large amounts of hydrogen for later use in power generation/energy storage applications, especially when hydrogen power generation complements with wind and solar generation, as in the case of Platte River. Since hydrogen is the lightest element, it can be challenging to store large quantities. Methane is about eight times denser than hydrogen at standard conditions on a gravimetric basis, so the pressures and temperatures required to store hydrogen in an economical manner are more extreme than that of natural gas.

Compressed hydrogen storage is the most common method of storage for today’s industrial hydrogen consumers. Depending on the amount of hydrogen being stored, pressures can range from 2,000 to 10,000 pounds per square inch gauge (psig) with the high end of this range more suitable for small cylinders used in the transportation sector rather than large bulk tanks for industrial users. Depending on the pressure and storage volume, many smaller vessels may be more economical than one large bulk tank. Hydrogen also presents an issue with leakage. Some compressed storage applications may require special materials to line the inside of the vessel to prevent leakage.

Hydrogen liquefaction is more energy intensive than compressed storage; however, depending on the amount of hydrogen storage needed, it can be an attractive option. The storage volumes for liquefied hydrogen would be much smaller than the storage volumes for compressed at the same mass. However, liquefied hydrogen requires far more complex auxiliary equipment and requires cryogenic temperatures, boil-off compressors, and other ancillaries. An additional consideration with the liquefaction equipment is the thermal cycling and ramp time.

Another potential method to store hydrogen takes advantage of existing geological formations. Geological formations such as salt caverns, rock caverns, and depleted gas fields present an opportunity to store large volumes of hydrogen in existing features. Conceptually, hydrogen is compressed and stored in an existing geological formation and then withdrawn for later use. Salt caverns present the most suitable geological storage feature followed by rock caverns and then depleted gas fields as the least suitable of the three. Depending on the geological feature, upgrades such as a liner may need to be added to prevent leakage. Another consideration associated with geological storage is contamination from substances such as methane or water. Additional clean up equipment may be required depending on the geographic location and the hydrogen user quality requirements.

Finally, pipelines are the most cost-efficient way to transport large quantities of hydrogen over long distances. There are currently approximately 1,600 miles of hydrogen pipelines installed in the United States, primarily in the Gulf Coast region, which are predominantly owned/operated by major industrial gas companies. Hydrogen pipelines are considered mature technologies and can typically cost approximately up to 10 percent more than a traditional natural gas transmission pipeline. For dry hydrogen service, the use of carbon steel is perfectly acceptable for the typical temperatures/pressures associated with most electrolysis projects. In instances where corrosive contaminants or condensate are present, a stainless-steel pipeline material would be selected instead, which can drive costs even higher.[42]

One attractive option is to blend hydrogen in the existing United States natural gas pipeline network, which includes over 400,000 miles of infrastructure. It is estimated that at typical pressures and diameters associated with natural gas pipelines, approximately 21 tons of hydrogen could be stored per linear mile. Hydrogen is generally thought to be limited to 5 to 10 percent blending throughout most of the United States, primarily because of safety and pipeline integrity concerns (e.g., embrittlement, pressure cycling, strain). While greater percentages may be possible if natural gas pipelines and supporting infrastructure are converted for use with hydrogen, these costs and the required modifications are the subject of significant research and development.43Performance (Thermal and Emissions)

5.3.4 Hydrogen for Power Generation

Hydrogen can be utilized directly in fuel cell power generation equipment and is currently being developed for 100 percent firing in RICE/CT equipment, although most CT OEMs have only achieved up to approximately 60 percent hydrogen by volume with natural gas (or as part of a biogas/syngas stream fed directly to a CT). In many cases, Black & Veatch expects that hydrogen co-firing will be limited to 35 percent by volume in existing plants to avoid costly modifications to the CT island. Some of the technical challenges in hydrogen firing and/or co-firing in traditional power plants include the following:

- Rate of change in Wobbe index and associated monitoring equipment.
- Design of mixing drum and blending skid.
- Replacement of combustors, including premixing devices (e.g., flashback, fluid dynamics/pressure fluctuations, combustion stability).

[42] Chen, Tan-Peng. "Hydrogen Delivery Infrastructure Options Analysis." DOE Hydrogen Program, FY 2006 Annual Progress Report; March 2007, US Department of Energy, Mar. 2007, www.hydrogen.energy.gov/pdfs/progress07/iii_a_1_chen.pdf.

[43] Domptail, Kim, et al. Pipeline Research Council International Inc., 2020, Emerging Fuels - Hydrogen State of the Art, Gap Analysis, and Future Project Roadmap.

- Higher density exhaust gas and air quality control implications.
- Increased nitrogen oxide production.
- Hazardous gas detection.
- Hazardous area classification.

Hydrogen yield from electrolysis is in the range of 55 kWh/kg and compression of the hydrogen for storage or transportation requires about 1-5 kWh/kg of energy depending on the beginning and ending state. Turbines cofiring with hydrogen blending typically only see extremely minor changes in efficiency assuming that heat input remains consistent between blending percentages.

Beyond the energy conversion system itself, hydrogen is known to cause embrittlement in piping, which is typically constructed from low strength carbon steel designed for lower operating stress (i.e., lower pressures or thicker pipe walls). Pressures great than 650 psig and temperatures greater than 400° F have been shown to accelerate the effects of embrittlement, particularly in high strength carbon steels and harder steels that may be present in an existing power plant. Fully welded piping is preferred for hydrogen with very limited number of flanges. In many cases, stainless steel piping is used in high cleanliness applications, such as gas turbine fuel piping; however, 304 stainless steel is more likely to embrittle while 316 stainless is the preferred grade because of better performance and higher resistance to the degradation mechanism. Additionally, firing 100 percent hydrogen can change pipe velocities by factor of 3.5 relative to natural gas on a calorific value basis and at same pressure/temperature conditions, thus plant fuel gas piping areas must increase to maintain velocity conditions. As expected, pipe sizing impacts a power plant's stress analysis, pipe hangers, pipe racks, and OEM enclosures and requires the evaluation of specialty equipment in some cases.

Hydrogen has a higher flame temperature than that of natural gas; therefore, blending hydrogen into the fuel will result in the CT burning at a higher temperature. This higher temperature correlates directly to a higher production of nitrogen oxide emissions (e.g., at 35 percent hydrogen in natural gas, nitrogen oxide emissions are estimated to increase by 20 percent). Steam can be injected into the CT to reduce burner temperature and prevent increased nitrogen oxide emissions, but at a cost to efficiency. Alternatively, increased ammonia feed to the selective catalytic reduction unit may be required to keep nitrogen oxide emissions within the limits of the plant's air permit. However, other criteria air pollutants are expected to improve as a result of firing higher percentages of hydrogen.

From a decarbonization perspective, it is important to note that carbon dioxide emissions are not proportionally decreased by an increase in volumetric hydrogen in the fuel. Since carbon emissions are measured on a mass basis, consideration for the mass of carbon displaced by hydrogen needs to be accounted. In general, co-firing of hydrogen with natural gas up to 35 percent by volume is only expected to result in an approximate 15 percent reduction in GHG emissions. Greater reductions in GHG emissions will only be possible when RICE/CT manufacturers are able to achieve suitable performance/reliability using higher blends of hydrogen with natural gas, up to 100 percent hydrogen.

5.3.5 Capital and O&M Costs

Capital, O&M, and levelized costs associated with different types of hydrogen, similar to liquid and gaseous low-carbon fuels, can vary substantially depending on the production capacity, storage/transportation requirements, and range of feedstock (i.e., natural gas, electricity, water) costs. For co-firing hydrogen in an existing power plant up to 35 percent hydrogen by volume (corresponding to an LHV of 666 Btu/scf or 75 percent of the volumetric energy density of pure natural gas), Black &

Veatch recommends that PRPA consider modeling these systems in the same manner (e.g., capacity, O&M costs, heat rate) as traditional natural gas fueled plants with the main difference being in fuel pricing, however, retrofitting existing turbines may require up to 5-10% of the turbine capital costs. It also may be warranted to also include a $5/kW increase in capital cost and 10 percent increase in variable O&M costs to account for minor modifications in air quality control equipment and associated reagent consumption.

For a greenfield power generation station with 100 percent hydrogen fueling, the capital, O&M, and levelized costs are not yet well understood, given they have not been constructed or operated to-date. However, in the near term, it may be advisable to include a 10 percent increase in capital cost (relative to natural gas fueled plant) and 25 percent increase in variable O&M costs to account for differences in air quality control equipment differences and associated reagent consumption as well as additional regulatory requirements associated with this significant quantity of hydrogen. Finally, hydrogen production and on-site storage fuel pricing are shown in USD per MMBtu in Table 5-9.

Table 5-9 Hydrogen Production and Storage Fuel Pricing (USD per MMBtu)

Fuel Type[1,2]	Minimum	Maximum
Green Hydrogen, 2021-2030	$58.35	$74.26
Green Hydrogen 2030+	$10.61	$25.46
Blue Hydrogen, 2021-2030	$19.10	$37.13
Blue Hydrogen, 2030+	$18.04	$27.58
Hydrogen Storage (All Options)[3]	$2.12	$42.44

Notes:
1) All pricing given in 2023 USD per MMBtu.
2) Pricing based on Black & Veatch analysis and confidential market data.
3) Represents the cost of on-site hydrogen storage in various tank configurations as per reference site and application.

It is expected that a hydrogen price of approximately $0.50 to $0.75 per kg (or $4.40 to $6.60 per MMBtu) will be required to make hydrogen competitive with fossil-based gaseous fuels used in the power generation industry.

5.3.6 Development Timeline

Large quantities of low-carbon hydrogen are not yet available to enable large-scale hydrogen power generation applications. This is expected to remain the case at least through 2030 while the industry continues to ramp up to address this emerging market and CT manufacturers continue to pursue the research and development needed to enable 100 percent hydrogen fueled systems. The price of “blue” hydrogen is expected to fall faster in the next 7-10 years than the price of “green” hydrogen, primarily driven by economies of scale in the CCUS industry. However, the availability of low-cost electrolysis equipment coupled with low-cost, abundant electricity from interconnected renewable energy resources are expected to drive low prices for “green” hydrogen in the 2030 to 2045 timeframe and beyond.

5.3.7 Opportunities, Challenges, and Risks

While the probability of commercial quantities of green and blue hydrogen being available for power generation is lower, hydrogen fuel shows substantial promise to achieve long-term decarbonization goals. Hydrogen has broad utility across multiple end use sectors, thus PRPA could explore a pilot program to evaluate (green or blue?) emerging technology. There are numerous challenges facing the low-carbon hydrogen power generation/energy storage industry, the most important of which is associated with the high costs associated with production, storage, and transportation. There are also a number of challenges in terms of utilizing hydrogen in RICE/CT equipment up to appreciable quantities to achieve deep decarbonization. From a risk perspective, PRPA would also need to evaluate the use of hydrogen fuels at any existing facilities relative to equipment age, condition, and warranties at all specific power plants where such a fuel may be used. Furthermore, a site-specific assessment of hydrogen safety/handling/combustion risks will likely be needed while utilizing best practices and lessons learned from organizations such as the Center for Hydrogen Safety.[44] It is recommended that PRPA conduct equipment condition assessments, construct performance models, and correspond with the appropriate OEMs, as needed. Finally, availability/pricing risks would need to be mitigated through either direct correspondence with potential off-site hydrogen producers or consideration of on-site production pilot projects.

5.3.8 Conclusions for Hydrogen Fuels

- Hydrogen can be produced via numerous pathways and has utility across many different end use applications. Most of the focus on low-carbon hydrogen is with respect to hydrogen produced via steam methane reforming coupled with CCUS or produced via water electrolysis using renewable energy resources.
- Co-firing of hydrogen with natural gas in existing power plants is expected to be limited to 35 percent by volume, which only corresponds with a 15 percent reduction in GHG emissions and 20 percent increase in nitrogen oxide emissions. Pursuit of such a project in the near-term is feasible but could be very expensive relative to other decarbonization options.
- If the current pace of industry interest and policy support continues, hydrogen can potentially be used at large scales and may become feasible in 100 percent hydrogen fueled power generation stations beyond the 2030 timeframe. Black & Veatch recommends PRPA stay abreast of the technology evolution and explores the potential for pilot projects at existing facilities.

[44] "Center for Hydrogen Safety." American Institute of Chemical Engineers, 25 Aug. 2021, www.aiche.org/chs.

5.4 Ammonia

Ammonia is considered a leading hydrogen carrier chemical that can overcome the challenges associated with storage and transportation of hydrogen while taking advantage of existing infrastructure. It stores hydrogen in an energy-dense form as NH_3. Although ammonia has historically been used exclusively as a precursor chemical feedstock for a variety of applications (e.g., fertilizers, pharmaceuticals, cleaning products), its role as a hydrogen carrier is also envisioned to support a variety of new applications, such as transportation fuel, energy storage, and power generation. Conceptually, after ammonia is synthesized it can be transported from regions with abundant renewable energy resources to those without such resources. Once there, it can be converted back to hydrogen via cracking for the end-user to utilize directly.

While ammonia was first discovered in the late 19th century, the modern ammonia process that is attributed to commercial-scale production was developed by German chemist Fritz Haber in the early 20th century. This process produced ammonia from the reaction of nitrogen gas and hydrogen gas over a catalyst at high temperature and high pressure, per the following chemical equation:

Ammonia Synthesis Reaction

$$3H_2 + N_2 \rightarrow 2NH_3$$

The patents to Haber's process were purchased by BASF, and the process was further commercially developed, including catalyst improvements contributed by company chemist Carl Bosch. Hence, where the second name in the Haber-Bosch ammonia process originated. The first commercial production of ammonia using the Haber-Bosch process began at a German BASF plant in 1913. The Haber-Bosch ammonia process has been modernized to increase process efficiency and ammonia production. Ammonia production technology is well proven and commercial designs range from about 45 metric tons per day (TPD) to 3,500 TPD production rates. Ammonia is typically produced using hydrogen generated from natural gas, which is readily available in large quantities and allows for large-scale ammonia production.

Due to potential role of ammonia as an energy carrier, many attempts have been made to find the most energy efficient, environmentally friendly, and economically viable production process for ammonia synthesis. There are several technologies for ammonia production such as electrochemical ammonia production, Non-Thermal Plasma (NTP) synthesis for ammonia production and nitrogenase motivated peptide-functionalized catalyst for electrochemical ammonia production.

Electrolyzers play a key role in the production of green ammonia. Electrolyzer capacity is decided accordingly to support the annual ammonia production required to produce the desired H_2 consumption at the power generation asset (post NH_3 transportation and cracking). It is assumed that all the hydrogen produced is converted into ammonia.

5.4.1 Haber Bosch Ammonia Synthesis (Ammonia)

Haber Bosch process is the oldest and most widely used ammonia process in industry. In the Haber process, nitrogen and hydrogen are mixed in 1:3 ratio. This mixture is called synthesis gas. This synthesis gas is then compressed up to 2,175 – 2,900 psig in a centrifugal compressor. This compressed synthesis gas is then fed to the ammonia convertor where ammonia synthesis reaction takes place at approximately 750 - 1,000 ^{o}F. The gases are passed through beds of catalyst, with cooling taking place in each pass, maintaining equilibrium. While different levels of conversion occur in each pass where unreacted gases are recycled. Normally an iron-based catalyst is used in the process, and the whole procedure is conducted by maintaining a temperature of around 750 - 1,000 °F and a pressure of 2,175 – 2,900 psi(g). The synthesis loop operating pressure, synthesis reactor temperature range and type of ammonia convertor varies among different ammonia process licensors. The reactor effluent is then cooled through a series of heat recovery exchangers and then finally through a refrigerant exchanger or chiller. In final chilling step, the liquid ammonia is condensed and separated. Unreacted gaseous mixture is recycled back to the reactor. In the final stage of the process, the ammonia gas is cooled down to form a liquid solution which is then collected and stored in storage tanks. Figure 5-6 shows the block flow diagram for a green ammonia synthesis unit.

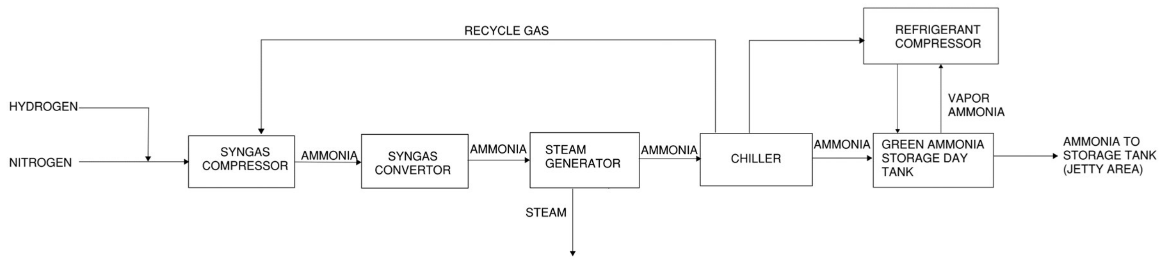

Figure 5-6 Block Flow Diagram of Ammonia Unit

5.4.2 NH_3 Cracking

Ammonia decomposition (cracking) is simply the reverse of the synthesis reaction. The ammonia cracking process typically has three steps, ammonia vaporization, ammonia cracking catalytic reactor and hydrogen purification unit. The hydrogen purification is typically carried out using pressure swing adsorption (PSA) type process to remove nitrogen from product hydrogen.

Ammonia Decomposition Reaction

$$NH_3 \rightarrow 0.5N_2 + 1.5H_2$$

The reaction is endothermic and external heat is required to be supplied for reaction to takes place. The temperature required for efficient cracking depends on the catalyst. There are a wide variety of materials that have been found to be effective, but some (e.g., supported Ni catalysts) require temperatures above 1800°F. Others have high conversion efficiency at temperatures in the range of 1,250-1,300°F. If no other energy source were available, at least 15% of the available hydrogen energy content would have to be burned to supply the heat of reaction.

As the reactor temperature increase, susceptibility of the reactor materials to stress corrosion cracking (SCC) and high temperature hydrogen embrittlement increases and costly alloys need to be used for reactor construction.

5.4.3 Performance

The mass energy density of hydrogen is 0.52 MMbtu/lb as compared to 0.008 MMBtu/lb for ammonia, hence its popularity as an energy carrier. However, once the energy losses due to heating, cracking, and post polishing (i.e., removal of residual ammonia) is considered, the available energy of the hydrogen from cracked ammonia is nearly the same as that of original ammonia. Energy input for ammonia synthesis is in the range of 10-12 kWh/kg and energy input for ammonia crack is in the range of 1-2 kWh/kg. There are different technology providers for ammonia employing different catalysts and reactor configurations. However, most of the offerings are still on small scale and not suitable for large scale applications. The cost of an ammonia cracking unit is more uncertain, especially at large sizes that aren't currently commercially available.

5.4.4 Opportunities, Challenges, and Risks

The production of hydrogen from cracked ammonia is straight forward, and commonly done for industrial applications, such as metal nitriding applications, using heterogeneous catalysis. Existing cracker technology is readily available in the 1-2 ton/day range from companies such as Lindberg/MPH, CI Hayes, Koyo Thermo, and Sergeant & Wilbur, Inc. Small scale cracking applications have been proposed but are not commercially available. The challenges faced for cracking technology advancements is twofold. First, existing crackers use a nickel-based catalyst which is not efficient and requires high temperatures. Current research is focused on ruthenium, cobalt, and lithium catalysts that can operate at lower temperatures. Secondly, as the crackers become larger, developers are faced with the challenge of achieving the proper heat transfer to the catalyst. Another ammonia decomposition method that is still in the research phase is plasma decomposition. Similarly, hydrogen can also be produced from ammonia using ammonia electrolysis. In this mechanism, an alkaline electrolytic cell is used to couple ammonia electro-oxidation and hydrogen evolution. To date, the process has been determined to be too slow for practical implementation.

The primary means of transporting ammonia produced off-site from the power generation asset are rail and truck. Transporting ammonia via rail is less popular as rail operators are not as interested in the shipment of ammonia due to the safety concerns. With the potential release of ammonia near multiple communities through the rail path, the potential safety concern and therefore additional insurance and liabilities costs increases the overall cost to ship ammonia via rail. Rail has a high initial fixed cost due to the items mentioned above, but the cost to transport per mile is relatively low due to the efficiency of the rail system for large distances. Rail is beneficial at distances over 300 miles.

Trucking provides an alternative solution for short distances as it has a lower fixed cost, but higher cost per mile to transport. Based on truck mileage efficiency and gas prices, the cost to transport ammonia is around $2-3/mile/ton.

5.4.5 Capital and O&M Costs

While ammonia is considered a leading hydrogen carrier chemical that can overcome the challenges associated with storage and transportation of hydrogen, the costs associated with the production, transportation, and cracking of the ammonia do not make it economically feasible or competitive as an alternative drop-in fuel for power generation assets. This coupled with the safety hazards associated with rail and truck transportation, as well as the net energy density of the end-use hydrogen at the power generation asset, do not warrant the cost analysis associated with producing or collecting ammonia for use as a drop-in fuel in lieu of hydrogen.

5.4.6 Conclusions for Ammonia Technologies

Ammonia can be produced from numerous pathways with high purification. The resultant ammonia can then be transported to a power-generation facility and cracked to produce hydrogen to be utilized across numerous power generation assets.

Ammonia cracking has been proven at small scale for commercial applications; however, cracking for large scale applications (e.g., the quantities required to use hydrogen in excess of 30% fuel replacement in power generation assets) has yet to be commercialized. The economics surrounding large scale cracking have yet to be proven economically feasible, especially when compared to traditional hydrogen transportation costs for use in power generation assets.

The transportation of ammonia provides an easier means of transportation as opposed to hydrogen. However, considering the remaining challenges, the associated risks, costs, and intermediate process steps (e.g., NH3 cracking), ammonia transport is not currently deemed an economically viable option to meet Platte River's near term needs.

5.5 Carbon Capture Utilization and Sequestration

Black & Veatch assessed post-combustion CCUS as a potential technology solution to help PRPA achieve decarbonization goals for power generating fleet, ultimately supporting the journey to towards 100% non-carbon operations by 2030. As part of this exercise, the Black & Veatch team identified commercially available technologies considered applicable for post-combustion CO_2 capture integration at PRPA's Rawhide Energy Station, developed order-of-magnitude capital and operational cost inputs, and evaluated potential operational and efficiency impacts presented from technology integration. The Black & Veatch team conducted the activities listed below and identified the findings as reported herein. Primary focus during this evaluation was to assess post-combustion CCUS technology implementation on simple cycle Units A through D, Unit F, and a potential future 170MW peaking facility at the Rawhide Energy Station. The findings related to performance, cost inputs, and operational impacts would be similarly applicable to most of PRPA's future gas-firing simple cycle operations or other future combined cycle operations.

While this section primarily focuses on post-combustion CO_2 capture, there are methods available for pre-combustion CO_2 capture. Section 5.3 covers pre-combustion CO_2 capture on steam methane reforming systems. While technically feasible, capturing CO_2 from a steam methane reforming process is not an economically feasible option.

5.5.1 CO_2 Capture Technology

Carbon removal applications are typically classified as either pre-combustion or post-combustion. Pre-combustion technologies are used when removing CO_2 from the byproduct streams of a chemical or biological process such as at hydrogen and bioethanol facilities. Post-combustion technologies remove CO_2 from the flue gas of natural-gas and coal fired power plants. The majority of the world research and projects (64 percent of patents and 54 percent of projects) have been related to post-combustion carbon capture systems and this will be the focus of this analysis for the Rawhide facility.

The primary methods for the capture and separation of CO_2 from post-combustion systems can be classified into for CO_2 separation technologies:

- Solvent-based [amine] absorption
- Physical adsorption
- Separation membranes
- Cryogenic separation

5.5.2 Liquid Solvent Absorption

Amine-based solvent CO_2 capture systems are the most common and proven technology with a TRL as high as 9. This technology is capable of separating CO_2 from even low concentration streams.

Chemical absorption separation using an amine-based solvent is the most common and proven method for the separation of CO_2. In this method, CO_2 is selectively captured in the bulk phase of an amine solvent material. The gas is then stripped using heat or steam, regenerating the solvent. The uptake is selective based on the increased solubility of CO_2 in the solvent relative to the other constituents in the gas mixture. Chemical absorption systems utilizing an amine-based solvent technology typically use an absorber column for the gas mixture to contact the solvent, and a regenerator/stripper column where the CO_2 rich solvent is heated to release the CO_2 and regenerate the solvent for reuse in the absorber. The absorption process has been proven at all scales of operation and has demonstrated that it can separate CO_2 from even dilute streams that can contain as little as 3 to 4 percent CO_2, by volume. Figure 5-7 depicts a high-level process flow arrangement for an absorber system using an amine-based solvent.

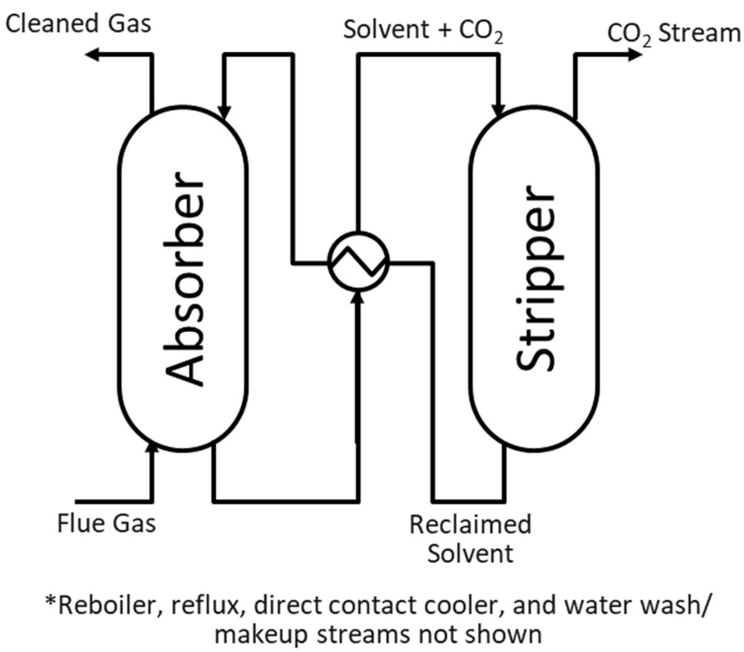

Figure 5-7 Representative Solvent Absorption CO_2 Capture Process Flow Diagram

In a complete absorber system, the flue gas is carried through the system via a booster fan, where it is fed first to a direct contact cooler or pre-scrubber to sub-cool the flue gas before sending it to the CO_2 absorber. A direct contact cooler typically cools the gas to 35 to 40° C to knock out free liquids and sub-cool the flue gas to improve the CO_2 absorption capacity of the absorbent. Caustic may also be used in the cooler to reduce the sulfur dioxide (SO_2) content in the flue gas as this can degrade the amine solvent. After the direct contact cooler/pre-scrubber step, the CO_2 contained in the flue-gas is exposed to the lean amine-based solvent found in the packing section of the absorber. The processed flue gas is released, while the rich amine, capturing 80 to 95 percent of the CO_2, is carried to the stripper column for regeneration. Heat from the reboiler breaks the chemical bond between the amine-solvent and CO_2 carrying it upwards as a CO_2-rich vapor. Residual amine vapor is condensed and reintroduced to the column, while CO_2 product is removed from the system. After conditioning and drying via Triethylene Glycol (TEG) or molecular sieve processes, the captured CO_2 is ready to be compressed for pipeline transportation. The amine collected at the bottom of the stripper is free of CO_2 and can be reclaimed and re-introduced in the absorber section.

Generally, the effectiveness of an absorber system is a function of the initial CO_2 concentration, the desired capture rate, and the desired final purity. By increasing the absorber size and number of stages, the gas-liquid contact is increased, allowing for a greater capture efficiency even with low initial purity, but with a corresponding increase in capital cost. Likewise, a larger stripper column with increased reflux/reboiler can produce a higher purity CO_2 product, but these variables directly correspond to increased capital and utility costs.

5.5.3 Solid Sorbent Absorption

Solid adsorption systems are also well proven for post-combustion systems with a TRL as high as 7. Generally, solid-adsorption systems benefit at smaller scale and are more easily modularized, while liquid-solvent absorption systems are better suited for larger scale CO_2 capture with industrial-sized absorber towers.

Adsorption is an emerging method for the separation of CO_2 similar in principle to absorption. In this process, CO_2 is captured on the outer surface of a solid sorbent material, either by weak Van Der Walls interactions known as physisorption, or strong covalent bonding via chemisorption. The sorbent material may be packed or fluidized for optimal gas-surface contact. The sorbent surface is selective for the capture of CO_2, allowing the remaining gas mixture to pass through. After the column is saturated with CO_2, the gas flow is typically switched to a secondary column, while the first column is regenerated to release the CO_2. Regeneration can occur via a temperature-swing, pressure-swing, or vacuum-swing process. Pressure and vacuum-swing regeneration are typically used for the weaker physisorption systems, while temperature-swing is used for chemical sorbents with regeneration temperatures near 80 to 150° C. Adsorption systems are still in the demonstration stages but are applicable in all areas that absorption is available for all CO_2 feed concentrations. Adsorption has the potential for modular design and greater energy efficiency than solvent absorption systems in smaller operations. Further research and development are necessary to fully optimize. Adsorption can also be used for low CO_2 concentrations and can be more cost-effective than absorption for smaller flow rates because of the potential for modular design. Figure 5-8 depicts a high-level process flow arrangement for a solid adsorption system.

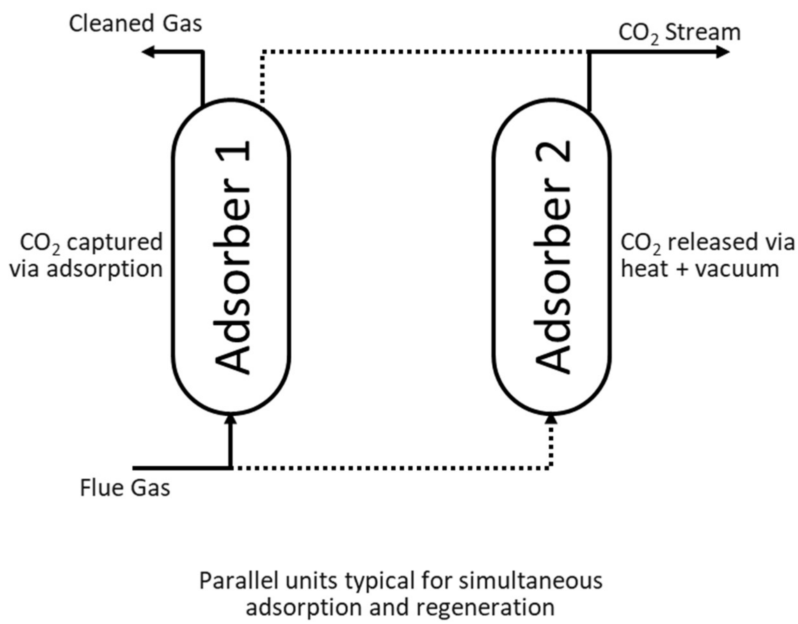

Figure 5-8 Representative Physical Adsorption CO_2 Capture Process Flow Diagram

5.5.4 Gas Separation Membranes

Membrane systems separate CO_2 from the remaining gas mixture using a selective membrane material. Depending on the membrane structure, the permeability of CO_2 through the membrane can be greater or lower than other gasses in the mixture, allowing CO_2 to be concentrated on either the upstream (retentate) or downstream (permeate) side. Several types of membranes are in development and range from polymeric, dense metallic, or porous inorganic (PIM). PIMs include silicas, zeolites, and metal organic frameworks. Dense metallic membranes and PIMs can be operated at higher temperatures and with greater stability in normal process conditions, and have greater permeabilities, making them more suitable than polymeric systems, but they are an emerging technology in development. Membrane systems offer several advantages over absorption and adsorption systems, including reduced system complexity and opportunities for modular design that can reduce cost. However, membrane systems are limited in their applicability, typically only available for systems with a high initial CO_2 concentration and pressure. Similar to adsorption technologies, membrane technology can be effective for smaller flow rates, particularly when CO_2 concentrations and gas pressures are higher. Figure 5-9 depicts a high-level process flow arrangement for a membrane separation system.

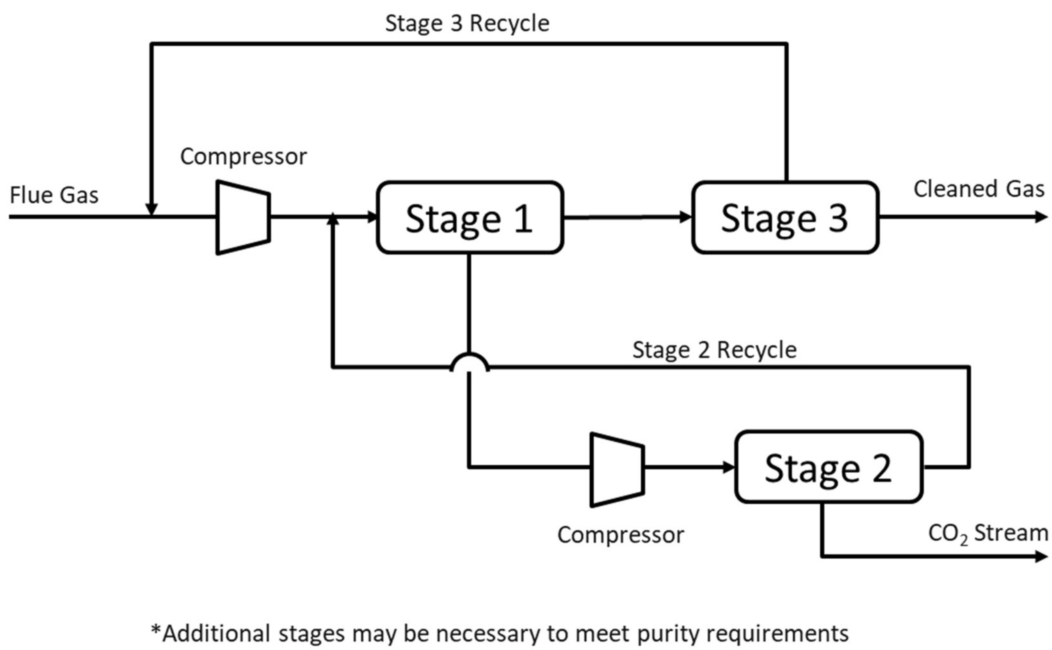

Figure 5-9 Representative Membrane Separation CO_2 Capture Process Flow Diagram

Gas separation membranes are well demonstrated with a TRL as high as 7 to 8, but generally do not provide sufficient separation for low concentration and low partial pressure CO_2 sources. On the other hand, they offer a low-complexity solution for purifying low volume, high-pressure gas streams. Given that the Rawhide peaker units produce low concentration CO_2 (approximately 4 percent CO_2), membrane separation would not be applicable at this time.

5.5.5 Cryogenic Separation

Cryogenic processes remove CO_2 via its boiling point by chilling the gas stream and condensing or sublimating CO_2 as a liquid or solid phase. This process is highly sensitive to impurities, which could condense or freeze during the chilling process. Water and icing are of particular concern, requiring the gas mixture to be dehydrated prior to chilling. Cryogenic separation avoids the need for chemical interaction and does not require any replaceable solvent, sorbent, or membrane material. However, the effectiveness of this process relies on efficient heat transfer for the cooling of the gas mixture and an effective collection method for the solid or liquid CO_2 product. Cryogenic capture is a young technology, and as such, has not been demonstrated on a significant scale. System integration and efficient energy usage will be important in the development of this technology. Cryogenic processes are theoretically applicable for all flow rates and concentrations, but because of its added complexity, will be most cost-effective for large flow rates. Figure 5-10 depicts a high-level process flow arrangement for a potential cryogenic separation system.

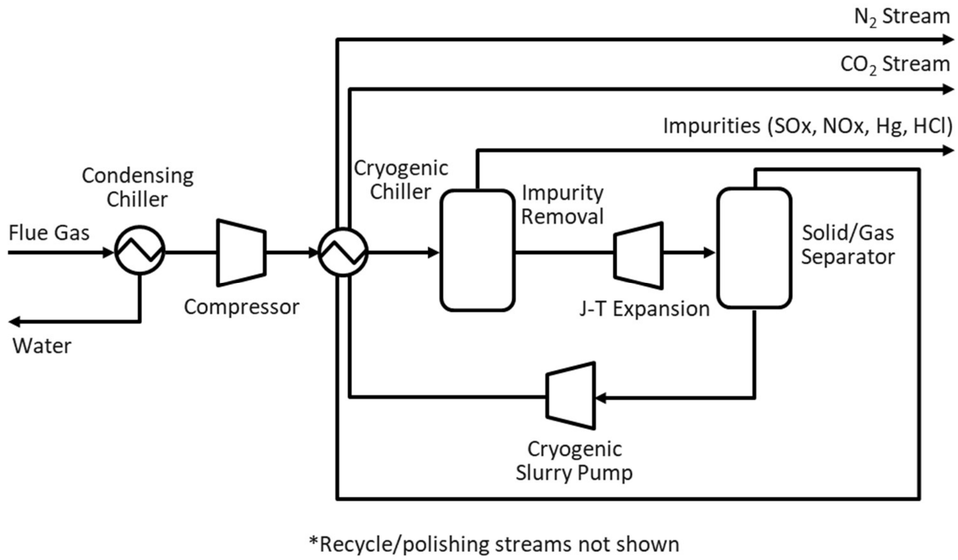

Figure 5-10 Representative Cryogenic Separation CO2 Capture Process Flow Diagram

Lastly, cryogenic methods are an emerging technology with a TRL as high as 6, with the potential to be used in post-combustion environments. This method benefits from not requiring chemical interaction or the need of a replaceable solvent or material. However, the technology requires efficient heat transfer and collection techniques to operate effectively at large scale. While cryogenic CO_2 capture technology can provide similar results as with amine-based solvent absorption, the technology has yet to be demonstrated/piloted at the commercial scale and as such would not be an appropriate alternative to amine-based solvent absorption capture at the Rawhide facility.

5.5.6 Developmental Timeline

Given the anticipated combined emissions of Rawhide's peaker natural gas units A-D and F at 5 percent capacity factor (~128,000 tpy), solid adsorption systems would provide adequate CO_2 capture given the current technology maturity. Solid adsorption systems are currently operational on the order of 4,000 tpy. It is anticipated that solid adsorption technology will be on the order of 100,000 tpy by approximately 2030. Table 5-10 below shows that solid absorption technologies will be in the same magnitude of capital costs to solvent absorption but are projected to have higher O&M costs. While the preliminary timeline suggests that solid adsorption systems could be a potential method for capturing 90 plus percent of the CO_2 emitted from the currently existing Rawhide peaker plant operations, this application may not end up being economically feasible.

5.5.7 Technology Readiness

Emerging CO_2 capture technologies considered to be transformational show potential to achieve up to a 40 percent overall cost reduction, an improved CO_2 capture rate of up to 95 percent and 99 percent CO_2

product purity.[45] Most of these emerging technologies are designated with a TRL of 5 or less and are still considered to be under the research and development phase at this time. These technologies could be available for demonstration-scale testing around 2030 to 2035, with commercial deployment potentially starting around 2035 to 2040.

Amine-based absorption is the only commercially available CO_2 capture technology with several demonstrated applications and has achieved a TRL of 9. Physical adsorption systems are the next most mature technology, with the potential to offer lower energy and utility usage than absorption systems in a modular design. The technology is not yet ready for commercial application, however, and is currently being demonstrated in lab and pilot-scale facilities with a TRL between 2 and 7. Similar to physical solvent adsorption systems, calcium looping systems have an approximate TRL readiness of 7 and have a high CO_2 removal efficiency. Calcium looping systems have been demonstrated at the pilot scale (approximately 365 tpy) but have yet to be proven at large scale. Cryogenic processes are the youngest of the four separation technologies, with a TRL between 3 and 6.

All near-term (5 to 10 years) CO_2 capture technologies are solvent-based, involving either ammonia or proprietary amines. The technology developers are targeting a reduction in the cost of CO_2 capture to an estimated $40 per metric ton, and a 40 percent lifecycle cost reduction compared to conventional CO_2 capture technologies within the next decade. Near-term commercial technologies with a TRL designation of 5 or greater, including next-generation solvent absorption processes, are projected to become available for demonstration-scale testing around 2025 and can be commercially operational before 2030. These technologies are expected to offer overall lower carbon capture costs while maintaining the same performance characteristics as existing commercially available technologies. However, all this is pending ongoing development efforts and increased efforts to demonstrate the emerging proprietary ammonia and amine-based solvents in this space that Black & Veatch is following and, in some cases, supporting directly. Black & Veatch notes that while next-gen solvents and ammonia-based solvent technologies are currently working towards commercialization, amine-based carbon capture is considered commercially available. Amine licensors are continuing to develop their next-generation proprietary solvents to further decreases the costs associated with their system.

A comparison summary of the CCS technologies described above and their associated TRLs can be seen in Table 5-10.

Table 5-10 Comparison of Carbon Capture Technologies

Comparison Metric	Solvent Absorption	Solid Adsorption	Calcium Looping	Membrane Separation	Cryogenic Separation
Commercial Readiness (TRL)	9	7	7	8	6
Removal Efficiency (% Captured)	>90%	>90%	>90%	50 to 80%	>90%
Applicable flue gas CO_2 concentrations (% CO_2)	≥3	≥12	≥12	>15	>15

[45] National Petroleum Council. March 12, 2021. *Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage, Chapter 5 – CO_2 Capture*.

Comparison Metric	Solvent Absorption	Solid Adsorption	Calcium Looping	Membrane Separation	Cryogenic Separation
Current Scale (tpy)	≥1.4 million	4,000	365	60,000	NA
Scaling Capabilities (Modular or Scalable)	Scalable	Modular	Scalable	Modular	Scalable
Footprint Requirement (Equipment)	Large: Adjacent arrangement of absorber tower and stripper tower; fans, compressors, heat rejection system	Medium: Adjacent and stacked arrangement of adsorber modules; fans, compressors, cooling system	Large: Adjacent arrangement of carbonator and calciner reactors, fans, compressors, cooling system	Medium: Adjacent and stacked arrangement of membrane banks, fans, compressors	Large: Adjacent arrangement of cryogenic system, separation systems, fans, compressors
Utility Demand (Thermal, electrical, water)	High: Blowers, heating, solvent recycle and reflux, water	Medium: Blowers, vacuum, and heating	Medium: Material handling equipment, heating	High: Compressors and cooling	Medium: Compressors and cooling
CapEx Consideration (Equipment)	Medium: Relatively simple absorber/stripper towers	Medium: Several modules benefiting from economies of scale	High: Durable materials and equipment for physical handling of material	High: High-pressure compressors and banks of special material membranes	High: Complex cryogenic cooler system equipment rated for cryogenic use
O&M Consideration (Maintenance, durability)	Low: Solvent makeup, vessel maintenance	Medium: Adsorbent durability, module maintenance	High: Pellet durability, vessel maintenance from physical handling	High: Membrane durability	High: Complex cryogenic system
Overall	Commercially available, proven technology with well understood costs and risks, expensive utility demand because of large-scale applications	Emerging technology with opportunities for modularization, not yet demonstrated at large scale, durability of adsorbent is a risk	Emerging technology with opportunities for reduced utility costs, not yet demonstrated at large scale, durability of pellet structure is a risk	Proven technology for low-efficiency CO_2 concentration, requires high compression, membranes may require additional maintenance	Unproven technology at scale, offers many potential benefits, but requires investment in complex equipment

All the carbon capture technologies compared in Table 5-10 above, highlight the capital and O&M costs associated with each technology when compared to one another. All costs associated with carbon capture are currently expensive and currently limits mass adoption. It is anticipated that these costs will drop in the coming decades and allow for mass adoption across various industries.

5.5.8 Carbon Capture Technology Selection

The findings from the CO_2 capture technology screening effort are shown in Table 5-11. Only technologies with a minimum TRL Level of 8 are shown, as well as the technology providers that offer these commercial solutions. Their capture rate efficiency, TRL, current projects, and facilities where they are or currently being planned for utilization are highlighted in Table 5-11.

As conveyed in Table 5-11, amine-based solvent CO_2 capture technologies are currently the most commercial-ready and proven technologies, demonstrating to have already achieved a TRL of 9 in most post-combustion applications, including those at natural gas fired power generation plants. The technology has been demonstrated and operated at various capacities and is deemed most suitable for large-scale CO_2 projects, capturing more than 90 percent of the CO_2 emissions from existing operations. For the Rawhide peaker units, amine-based solvent technology is currently the most mature post-combustion carbon capture technology (TRL 9) that can maintain a CO_2 capture rate greater than 90 percent in low (<10 percent) CO_2 flue gas concentrations. It is currently the only capture technology that has been proven at the commercial scale (>1 million tpy). However, given the Rawhide operating profile (e.g., low-capacity factor on a peaker facility), amine-solvent technology may not be the best technology solution given that they are most economically feasible on high-capacity, base-load operations. While solid adsorption may be commercially feasible and applicable for the Rawhide facility in 2030, it is currently not deployed at the required scales. The largest solid adsorption capture system currently deployed is 4,000 metric tonnes per year. While the most commercially mature, amine-based carbon capture may not be the most technically applicable technology for the Rawhide peaker units. Solid adsorption may provide a more technically applicable solution for the Rawhide peaker units. This applicability will be contingent on solid adsorptions ability to scale-up to the 100,000 metric tonnes per year milestone by 2030. Table 5-11 also reflects the names of the different technology providers and licensors that offer these technologies commercially, their capabilities (capture rate efficiencies), and their current progress in demonstrating their technical offerings.

Table 5-11 Summary of Post-Combustion CO_2 Capture Technology Screening

Company Name	Separation Type	Technology	TRL*	Capture Rate (%)	Scaling Capabilities	Facilities
Carbon Clean Solutions	Amine-Based Liquid Absorbents	APBS-CDRMax	8-9	95 to 99.9	Unproven	• Four demonstration plants in Europe • One demonstration plant in the United States • One commercial plant in India
Fluor	Amine-Based Liquid Absorbents	Econamine FG and Econamine FG Plus	9	>90	Proven	• Front-End Engineering Design (FEED) study consideration at Elk Hills Power Plant (EHPP), Kern County, California • 350 tpd captured from 1991 to 2005 at Bellingham Co-Generation Facility, Massachusetts
ION Clean Energy	Liquid Absorbents	ICE-31	7-8	>90	Unproven	• Engineering-scale demonstration planned at Los Medanos Energy Center Demonstration (10 tpd) • FEED study consideration at Nebraska Public Power District's Gerald Gentleman Sta. Sutherland, Nebraska
Akers Solutions	Amine-Based Liquid Absorbents	JustCatch JC40 (40 ktpy) JC100 (100 ktpy) Big Catch (1.2 Mtpy)	8	>90	Unproven	• FEED study for capture at the Norcem Heidelberg Cement Plant in Brevik, Norway • Delivery contract for a carbon capture and liquefaction facility for a waste-to-energy plant in the Netherlands (100,000 tpy) to be delivered EOY 2022
Mitsubishi Heavy Industries	Amine-Based Liquid Absorbents	Advanced KM-CDR	9	>90	Proven	• Up to 3 Mton/CO_2 captured at NRG's Petra Nova Carbon Capture plant near Houston, Texas, which was operational from January 2017 until May of 2020. • FEED study consideration at Prairie State Generating Company's (PSGC's) coal fired plant in Marissa, Illinois

Company Name	Separation Type	Technology	TRL*	Capture Rate (%)	Scaling Capabilities	Facilities
Shell CANSOLV Technologies	Amine-Based Liquid Absorbents	CANSOLV DC-103 and DC-103B	9	>90	Proven	• In operation at Boundary Dam power station in Saskatchewan, Canada • Planned for integration at Gorgon Carbon Capture and Injection Project, Australia • Northern Lights Carbon Sequestration Project, Norway • Planned for integration at Fortum Oslo Varme's Klemetsrud WTE plant • Six FEED studies currently ongoing, including: Calpine Deer Park Power Station, Net Zero Teesside, and VPI Immingham Power
Linde-BASF RWE-Power	Amine-Based Liquid Absorbents	PCC Technology	8	>90	Unproven	• Three demonstration plants (one in Germany, two in the United States) • In operation at Gaston Power Plant in Wilsonville, Alabama, since 2015 (30 tpd) • Turnkey PCC plant in Springfield, Illinois (260 tpd), for United States DoE • FEED study for US DoE in Sweeny, Texas
*TRL rating from 1 to 9 is used to rank current technology readiness and capability to reach commercial operation (TRL 9).						

Black & Veatch identified that a single amine-based carbon capture unit for all five individual flue gas streams would be most suitable for the Rawhide peaker units as it is the most commercial ready and proven CO_2 capture technology available at this time.

5.5.9 Performance (Thermal and Emissions)

Black & Veatch team has become familiar with the Rawhide Energy Station and the simple cycle units there as part of other recent and related study work. As result, the team has gathered gas turbine performance data and used those to run a steady state emissions evaluation. Gas turbine performance and inputs, along with the fuel composition and required characteristics, were used to calculate the emissions generated by the gas turbines at Rawhide, including CO_2 concentrations. A summary of the Rawhide CO_2 emissions rates and CO_2 concentrations is outlined in Table 5-12.

Table 5-12 Rawhide CO_2 Emissions Rates and CO_2 Concentrations

Rawhide Unit	Name-plate Capacity (MW)	Heat Rate (Btu/ kWh)[1]	LHV/HHV (MMBtu/h)	Capacity Factor	CO_2 Flue Gas Flow Rate (lb/h)[2]	CO_2 Emission Rate (tpd)[3]	CO_2 Capture Rate (tpd)[4]
Unit A	65	13,400	871/967	5.0%	5,658	61.6	55
Unit B	65	13,400	871/967	5.0%	5,658	61.6	55
Unit C	65	13,400	871/967	5.0%	5,658	61.6	55
Unit D	65	13,400	871/967	5.0%	9,562	61.6	55
Unit F	128	11,500	1,472/1,635	5.0%	9,562	104.1	94
Future Peaker	170	13,400	2,278/2,529	20%	59,190	644.4	580
Total	**558**				**32,193**	**995**	**895**

Notes:

1. https://www.prpa.org/generation/rawhide-energy-station/
2. Assumes approximately 4 percent CO_2 concentration from each simple cycle unit. Represents annual CO_2 emissions flow rate as per the unit capacity factor.
3. Represents the CO_2 emissions rate from the simple cycle stack in short tons per day (tpd).
4. Assumes a 90 percent CO_2 capture efficiency by the carbon capture unit. Represents the final product stream that is comprised of 95+ percent CO_2 product. CO_2 capture efficiency refers to the amount of CO_2 captured from the flue gas. The remaining CO_2 is exhausted from the absorber stack.

As shown in Table 5-12, the post-combustion amine-based CO_2 capture technology considered can capture up to 90 percent of the CO_2 emissions from the Rawhide peaker units. Implementing the technology to the Rawhide operations would see a reduction of CO_2 emissions, reaching a much more manageable 36,000 tons of CO_2 emitted per year from Rawhide Units A through D, Unit F, and the future 170MW peaker unit. This kind of reduction in emissions output from existing operations like Rawhide is not easily achievable from integration of other low-carbon technologies and, if considered, will play a significant role in helping PRPA achieve their carbon reduction goals.

The Black & Veatch team also evaluated issues and challenges related with adoption and implementation of post-combustion CO_2 capture technology and assessed potential impacts to PRPA simple cycle operations and efficiencies. It was determined that because of the power and steam requirements to operate the CO_2 capture system, the performance of PRPA's simple cycles would be impacted, and nominal net output would decrease.

Steam is typically required by most CO_2 capture technologies to achieve CO_2 stripping and solvent reclaiming as part of the technology process. In most cases, the required steam typically originates from existing plant operations and may have some impact on the steam turbine output. For the Rawhide peaker units, it was assumed that the CO_2 capture process steam would be provided via an auxiliary boiler to avoid derating the Rawhide Unit 1 facility. In addition, power is required to operate the CO_2 capture equipment and CO_2 compressors, as well as generate additional water and air cooling required for the process. This power demand would increase the auxiliary power load typically seen by the Rawhide simple cycle operations. It was estimated that adding CO_2 capture system to capture emissions from Units A through D and F at Rawhide could increase the auxiliary load by approximately 50 MW (assumes peaking facilities are operating at 100 percent CF). The energy consumption of the CO_2 capture system is approximately 180-200 kWh/tCO_2.

. It is observed that because of the increase in steam and power demand by the CO_2 capture system and CT designed output remaining to be fixed, an overall reduction in net plant LHV efficiency and a subsequent increase in net plant heat rate (relative to non-CO_2 capture plant heat rate) is to be expected.

5.5.10 Capital and O&M Costs

Black & Veatch has completed numerous detailed studies considering the use of various CO_2 capture technologies and are familiar with the capital, operating, and maintenance costs associated with the technology. This experience has helped develop internal cost references, data, and benchmarks that the team considered and used for this evaluation.

Capital costs evaluated with this effort were considered as total overnight costs and include the cost of procuring and installation of the equipment, materials, direct and indirect labor, engineering, construction management, home office expenses, and associated Owner’s and typical engineering, procurement, and construction (EPC) contingencies.

In discussions with PRPA, it was noted that the annual capacity factor of the peaker units was approximately 5 percent (approximately 1 percent in the winter and 4 percent in the summer). While traditional amine-based carbon capture systems can turndown with the adjacent power generation system, the typical equipment sizing for the CO_2 capture facility offered by the technology licensors is sized for base load flue gas emissions flow rate. As such, the capital costs outlined in Table 5-13 are independent of plant capacity factor and are intended to represent a plant capable of taking 100 percent of the Rawhide peaker units emissions at base load.

Black & Veatch also developed annual O&M costs associated with expenses and costs of operating the CO_2 Capture system equipment. Incremental annual O&M costs include expected fixed O&M costs, which is independent of power generation and variable O&M costs, which are proportional to power generation. Fixed O&M costs include incremental costs for operating and maintenance labor as well as administrative and support labor required. Property taxes and insurance cost estimates were not included. Variable O&M costs include incremental costs for maintenance material, consumables, and waste disposal. The variable O&M costs were based on a weighted average capacity factor of 9.66% for the facility (A capacity factor of 5 percent was utilized for Rawhide Units A through D and F and a capacity factor of 20 percent was utilized for the new 170MW peaker unit).

Table 5-13 Capital and O&M Cost Considerations[1,7]

Cost Category	$/kW-net[2,3]	$/MWh[2,3]	$/tCO2[5]
Capital - Total Installed Cost	$2,328	$2,777.3	$3,957.47
Fixed O&M	$20.01[6]	$23.87	$34.17
Variable O&M[4]	$3.60[6]	$4.29	$6.15

Notes:

1. All costs Q2 2023 USD and per EIA *Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook March 2022*
2. These costs are incremental costs associated with deploying and operating the CCS plant, not the existing Rawhide power generation operations.
3. Does not include CO_2 transportation or sequestration costs.
4. Based on a weighted average capacity factor of 9.66% for the facility [Units A through D and F at 5 percent capacity factor and the future 170MW unit at 20 percent capacity factory].
5. Dollar per short ton of CO_2 captured.
6. $/kW-year
7. Table values shown for information. Traditionally, capital total installed cost is reported in $/kW-net, fixed O&M cost reported as $/kW-year, and variable O&M cost reported as $/MWh.

As noted above, the capital costs for the CO_2 capture facility are independent of the operational profile of the Rawhide peaking plants; however, the fixed and variable O&M costs are not. The fixed and variable O&M costs for the CO_2 capture facility correlate to the annual tonnage of CO_2 captured.

Fuel costs and CO_2 transportation and sequestration costs were not included directly into the capital and operational costs reported above. Those costs are very dependent on the specifics of fuel cost rates and site/regional conditions for each client's assets and therefore this may be best defined by PRPA.

Although deployed in more than 150 facilities worldwide and with more projects coming down the pipeline, CO_2 capture deployed and integrated in a multi-unit gas-fired, simple cycle facility operation like Rawhide are still considered emerging technology and a first of a kind deployment. Commercial scale CO_2 capture has not been proven or deployed for a multi-unit, simple cycle facility and has only been deployed on base load power generation facility (predominantly coal facilities). A CO_2 capture facility on the Rawhide peaking units would be a first of a kind facility. Accounting for unexpected and undefined costs can be difficult to estimate for emerging technologies. Cost estimates for technologies that are not yet fully proven at scale typically use the same cost estimating methodology as those for mature technologies with additional process and overall project contingency. This methodology attempts to account for the unique cost premiums associated with the initial, complex integrations in commercial applications. Therefore, initial deployments of this technology may incur costs higher than those reflected above. Other factors can also impact cost estimates such as project- and site-specific considerations (e.g., contracting strategy, local labor costs and availability, seismic conditions, water quality and availability, financing parameters, local environmental concerns, weather delays) that may make construction more costly.

In addition to the CO_2 capture facility, additional consideration and planning must be done to account for the costs associated with CO_2 pipeline transportation and sequestration. This includes pipeline construction and permitting costs, Class VI well injection permitting, and the capital and O&M costs associated with the operation of a pipeline and well injection facility.

5.5.11 Opportunities, Challenges, and Risks

Challenges with implementing CCS technologies for achieving decarbonization goals are typically associated with limitations of existing carbon capture technology, the technology performance risks, and the lack of available CO_2 transportation infrastructure and storage locations near most CO_2 emissions sources. The carbon capture process proposed for the Rawhide facility is facing the following three primary challenges for optimal performance: high capital and O&M costs ($/t$CO_2$ removed) , high energy demand and the degradation of physical materials.

The first challenge is the high capital and O&M costs associated with a CO_2 capture system. The capital costs associated with the CO_2 capture system and the ancillary support systems directly correlate to a high $/kW equivalent. The high O&M costs are driven by the additional personnel required to operate the CO_2 capture system, the additional maintenance materials required to upkeep the system, and the chemical consumption (service water, demineralized water, solvent makeup, caustic, etc.) required by the CO_2 capture system.

The second challenge is the high energy demand for the process. The regeneration of the solvent/adsorbents used in the process requires a large thermal duty. For the Rawhide facility, steam will need to be produced via an auxiliary boiler or via a heat recovery steam generator (HRSG). Both options rework additional kit to be deployed at the Rawhide facility. These additional costs would greatly impact the capital costs required for the capture system.

The CCUS process also has several significant auxiliary power requirements to run the flue gas booster fans, CO_2 compressors, heat rejection equipment, and other miscellaneous pumps and equipment.

The third challenge is the degradation of the physical materials from the contact with impurities found in the exhaust gases. High degradation results in high solvent makeup rates, increased operating expenses, increased waste products, and decreased process efficiency. Research and development efforts are focused on the development of novel materials, including liquid solvents, solid sorbents, and membrane materials, which address these issues.

Technology risk and challenges aside, CCUS projects face another feasibility and economic challenge originating from absence of available transportation infrastructure, regional geological storage, and lack for utilization of large-scale captured CO_2. CO_2 captured from post-combustion, amine-based absorption technologies is typically dehydrated and compressed for pipeline transmission to area and regions where geological sequestration and storage is available and possible. CO_2 storage can be safely and permanently achieved through deep injection in saline formation or depleted oil wells. In addition to EOR practices, CO_2 is also utilized as a feedstock for industrial processes, stand-alone product manufacturing and services. While the technologies associated with the latter are considered novel and currently not suitable for large-scale applications, EOR currently offers the only feasible and economical way to utilize and permanently utilize large capacities of captured CO_2. As part of the EOR practices, hundreds of miles of CO_2 pipeline feeder (small diameter) and trunkline (large diameter) are currently installed and in-operation along parts of western United States, lower Midwest, and southeastern United States. The majority of the existing CO_2 pipelines are utilized for EOR and have a common destination, the Permian Basin. As such, the majority of the existing CO_2 pipelines are located across the majority of the southeast where refineries and oil extractions are found along with favorable geological formations suitable to store large capacities of CO_2.

The nearest existing major CO_2 pipelines to the Rawhide Facility are the Sheep Mountain CO_2 Pipeline and the Shute Creek CO_2 Pipeline. The Sheep Mountain CO_2 Pipeline delivers CO_2 to the Permian basin for CO_2-EOR from the natural CO_2 field located near Sheep Mountain. The Sheep Mountain CO_2 pipeline is owned and operated by Occidental and has an estimated flow capacity of 590 million cubic feet per day (MMcfd).[46] The Sheep Mountain CO_2 Pipeline is approximately 225 lineal miles from the Rawhide Facility and would require significant CO_2 pipeline infrastructure to deliver CO_2 to the existing pipeline.

The Shute Creek CO_2 Pipeline is operated by ExxonMobil and has an estimated flow capacity of 220 MMcfd.[8] The nearest pipeline trunk tie-in relative to the Rawhide Facility is approximately Three Forks, Wyoming, which is approximately 160 lineal miles away. As with the Sheep Mountain CO_2 Pipeline, significant CO_2 pipeline infrastructure would be required to deliver Rawhide CO_2 to the existing pipeline.

Unlike the CO_2 pipeline infrastructure listed above, the potential for long-term geological sequestration of CO_2 via Class VI injection well on the Rawhide site or in the surrounding area would be the most economically feasible option. The geological characterization of the Rawhide site and surrounding area was not conducted as part of this study; however, if on-site geology was favorable, it could provide an economically viable sequestration site for the captured CO_2 from the Rawhide facility.

5.5.12 CCUS Conclusions

CCUS is an area that encompasses a multitude of commercial-ready technologies and processes capable of capturing CO_2 from concentrated point-source emissions, transporting using pipeline conveyance and sequestering it in underground geological formations. Black & Veatch evaluated a potential scenario of integrating CO_2 capture technology at the Rawhide operations and considered potential pipeline transportation tie-ins relevant to the Rawhide site. As part of the effort, the team assessed the operational and cost impacts and captured the findings in Table 5-13. It was found that implementing an amine-based CO2 capture technology at the Rawhide facility would have an approximate cost of $2,300/kW with a fixed O&M cost of $20/kW and a variable O&M cost of $3.60/kW or about $4,000 of capital cost per ton of CO2 . These findings show that while CCUS is a possible technical solution, it has yet to be implemented for peaking facilities as it will result in a very high cost of CO2 removal. The economic and technical challenges of implementing a CCUS unit for the peaking units at the Rawhide facility do not make it feasible at this time. CO_2 capture technologies demand high heat (in the form of steam) and power (electricity) to regenerate the solvents/absorbers, therefore negatively impact efficiencies and output of existing power generating operations. Although currently considered significantly high cost (when compared to existing operations without carbon capture), there is a general industry and market outlook projecting that next generation carbon capture technologies and economies of scale associated with its increased deployment can potentially achieve as high as 40 percent reduction in cost of capture within the next decade.

Additionally, Black & Veatch found that the Rawhide Energy Station does not have suitable geology for on or near-site CO_2 sequestration via Class VI injection wells. The most applicable technical option for PRPA is to utilize long-distance CO_2 transportation via pipeline to an existing CO_2 trunkline, the closest of which is in 160 miles NW in Three Forks, Wyoming. While technical applicable, the costs associated with the construction and permitting of a long-distance CO_2 pipeline make this option not feasible.

Black & Veatch can conclude that CCUS comprised of 90 percent capture rate, amine-based absorption CO_2 capture technology is a proven technology. However, it has not been deployed at a peaking simple cycle power plant. It is believed that this is due to amine-based carbon capture plants being the most economically feasible on baseload, high-capacity, gas-fired combined cycle facilities as opposed to

[46] (2015). A Review of the CO2 Pipeline. Office of Fossil Energy. Nation Energy Technology Laboratory. Retrieved from https://www.energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20-%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20U.S_0.pdf

Rawhide's simple cycle facility. The high-level CCUS facility costs presented in Table 5-13 show that it will not be feasible for a 2030 deployment. Black & Veatch recommends that Platte River stays abreast of the development of this technology and its deployment in power sector. Additionally, Black & Veatch recommends that Platte River explore other economic solutions for disposing the CO_2 emitted from the Rawhide facility. Implementation of CCUS solutions may become an economically favorable within the next decade, which could provide Platte River with a CCUS solution for the Rawhide facility.

5.6 Task 3 - Low/No Carbon Fuels and Carbon Sequestration Summary Conclusions

The emerging generation technologies needed for a 100 percent noncarbon energy mix goal by 2030 may not be commercially available at the scale required by 2030. The technologies may become gradually available in the next decade or so, and Platte River should continue to assess and monitor the progress of the technologies so that Platte River can adopt them as the commercial viability progresses and are proven adaptable for peaking type operations. Summary conclusions for each of the Task 3 technologies are provided in the following subsections.

5.6.1 Liquid Low-Carbon Fuels for Generation

Numerous fuel pathways exist between various feedstocks and liquid biofuel end productions. Biofuels[47] are gas or liquid fuels derived plant material (biomass). First-generation biofuels (e.g., ethanol and biodiesel) are not expected to provide promising opportunity for decarbonization of power generation assets; however, second-generation biofuels such as renewable diesel will likely be infeasible for use as primary fuel but could be appropriate as a backup fuel for certain generation assets. Renewable fuels[48] include liquid and gaseous fuels derived from renewable biomass energy sources. The availability of easily substituted, drop-in, low carbon liquid fuels (i.e., liquid fuels with low carbon intensity) for power generation assets is not expected to be significant until at least 5 to 10 years from present. While there are some sources of biofuels feedstock from forestry and waste sourcing, total available biofuel feedstock in Larimer County alone would not be able to sufficiently supply biofuels for all of Rawhide operation. However, biofuels could be sourced from other locations or still be used as a fraction of the overall fueling goals.

Fuel pricing can vary significantly for first- and second-generation biofuels but is generally expected to be approximately 30 to 40 percent higher for renewable diesel relative to fossil-based diesel fuel on a dollar per unit energy basis, see section 5.1.7 for more pricing details. It is expected that power generation facilities originally designed for a specific type of fossil-based liquid fuel will ultimately require capital expenditures to modify the equipment, to ensure operability with biofuels, which will also impact O&M expenses, but will ultimately vary with respect to turbine supplier, fuel type, blending percentages, etc. Oil, particularly for waste cooking oil type feedstocks and renewable/low-carbon sources of hydrogen. However, available literature has estimated that biofuels can result in GHG emissions reductions of around 50 to 90 percent relative to fossil-based fuel.

5.6.2 Gaseous Low-Carbon Fuels for Generation

Biogas, gas formed during anaerobic digestion when microorganisms break down organic materials in the absence of air, and syngas, a gas mixture composed primarily of hydrogen, carbon monoxide, and

[47] Biofuels and the Environment. (2023, Feb). Retrieved August 2023, from United States Environmental Protection Agency: https://www.epa.gov/risk/biofuels-and-environment

[48] What is a Fuel Pathway? . (2023, March). Retrieved from Environmental Protection Agency: https://www.epa.gov/renewable-fuel-standard-program/what-fuel-pathway

hydrocarbons from the thermochemical decomposition of organic or inorganic materials, can be produced from a variety of feedstocks and subsequently upgraded to renewable natural gas (RNG) for utilization across numerous power generation assets at any scale. The utilization of biogas/syngas directly for power generation is expected to be limited to <50 MW because of the limited market availability. Many types of RNG are already commercially available and biogas/syngas is already in use for power generation. It is expected that the markets for low-carbon gaseous fuels will continue to grow over the next 10 years. Low-carbon gaseous fuels are generally expected to be at least 2 to 5 times more expensive than fossil-based natural gas on a dollar per unit energy basis. Colorado has a biogas production potential at over 23 billion cubic feet of biogas per year[49]. While the current availability of biogases is lower, there is great potential of sourcing more biogas from wastewater, manure, food waste, and landfill sources than what is currently being produced. However, it will likely remain more economic to convert this biogas to power locally than to transport to a large generation facility like Rawhide.

5.6.3 Hydrogen Fuel for Generation

Hydrogen can be produced via numerous pathways such as electrolysis or steam methane reforming and has utility across many different end use applications as a fuel, feedstock, or energy carrier. The production of low-carbon hydrogen via electrolysis and steam methane reforming with carbon capture is expected to grow significantly over the coming decades. Co-firing of hydrogen in existing power plants is expected to be limited to 35 percent in the near term through 2025; however, firing of 100 percent hydrogen is expected to be achievable at large scales starting in 2030. Pricing for low-carbon hydrogen is expected to decrease over time but is currently 3 to 10 times higher than fossil-based natural gas on a dollar per unit energy basis, for reasons including the high cost of storage and transportation. Additionally, there will be significant cost to retrofit existing gas turbines to enable them to burn hydrogen.

5.6.4 Ammonia Fuel for Generation

Ammonia produced from low-carbon sources of hydrogen is an emerging energy carrier; however, the additional risks, processing steps, energy loss and cost do not make it an economically favorable option for use as a transport medium for hydrogen. As such, Black & Veatch deemed this alternative fuel as not feasible as a low carbon fuel alternative at present.

5.6.5 Post-Combustion Carbon Capture and Sequestration

It can be concluded that CCUS comprised of 90 percent capture rate, amine-based absorption CO2 capture technology is a proven technology. However, it has not been deployed at a peaking simple cycle power plant. It is believed that this is due to amine-based carbon capture plants being the most economically feasible on baseload, high-capacity, gas-fired combined cycle facilities as opposed to Rawhide's simple cycle facility. The high-level CCUS facility costs presented in Table 5 13 show that it will not be feasible for a 2030 deployment. Black & Veatch recommends that Platte River stays abreast of the development of this technology and its deployment in power sector. Additionally, Black & Veatch recommends that Platte River explore other economic solutions for disposing the CO2 emitted from the Rawhide facility. Implementation of CCUS solutions may become an economically favorable within the next decade, which could provide Platte River with a CCUS solution for the Rawhide facility.

[49] State Profiles: Colorado. (2023, August). Retrieved from American Biogas Council: https://americanbiogascouncil.org/resources/state-profiles/colorado/