CPUC IRP Zero-Carbon Technology Assessment

Final Report

September 2022

Energy+Environmental Economics

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Table of Acronyms

Acronym	Definition
45Q	Federal 45Q Tax Credit for Carbon Capture and Sequestration
A-CAES	Adiabatic Compressed Air Energy Storage
AEC	Low-Temperature Alkaline Electrolyzer
AFC	Allam-Fetvedt Cycle Power Plant
ATB	National Renewable Energy Laboratory Annual Technology Baseline
CAES	Compressed Air Energy Storage
CCGT	Combined Cycle Gas Turbine Power Plant
CCS	Carbon Capture and Sequestration
CES	Clean Energy Standard
CO_2	Carbon Dioxide
CPUC	California Public Utilities Commission
CT	Combustion Turbine Power Plant
DAC	Direct Air Capture of Carbon Dioxide
EGS	Enhanced Geothermal Systems
ELCC	Effective Load Carrying Capacity

EOR	Enhanced Oil Recovery
GW	Gigawatt
GWh	Gigawatt-Hour
HHV	Higher Heating Value (only applicable for hydrogen-containing fuels)
I&A	CPUC Inputs and Assumptions Document
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
ITC	Federal Investment Tax Credit
LADWP	Los Angeles Department of Water and Power
LCFS	California Low Carbon Fuel Standard
LCOE	Levelized Cost of Energy
LFC	Levelized Fixed Cost of Energy
MMT	Million Metric Tons
MW	Megawatt
NOx	Oxides of Nitrogen
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance Costs (Fixed or Variable)
PSP	Preferred System Plan
PTC	Federal Production Tax Credit
PV	Photovoltaic Solar Panel

R&D	Research and Development
RPS	Renewable Portfolio Standard
RTE	Round-Trip Efficiency
SMR	Small Modular Nuclear Reactor
SNG	Synthetic Natural Gas
TRL	Technology Readiness Level
TESPV	Thermal Energy Storage with Photovoltaic Cells
TW	Terawatt
TWh	Terawatt-Hour

1 Executive Summary

This report explores zero-carbon firm capacity generation technologies that could support California's efforts to decarbonize its electricity grid but have not yet reached full commercialization. The broader purpose of this report is to characterize emerging zero-carbon firm capacity technology options for the purpose of informing capacity expansion modeling to support long-term resource planning. Zero-carbon firm capacity technologies are those that can be dispatched during peak grid demand periods without restrictions on the duration for which power can be provided, and that do not emit carbon dioxide (CO_2) during their operation. These technologies may facilitate cost-effective achievement of electric decarbonization by providing firm capacity during extended periods of low wind and solar output. The need for these technologies would likely increase if California proactively seeks to eliminate its fleet of natural gas power plants from providing this firm generation function.

The report considers the following technologies:

- Long-duration iron-air batteries
- Adiabatic compressed air energy storage (A-CAES)
- Carbon-free hydrogen and carbon-neutral synthetic natural gas that can be combusted in conventional power plants
- Combined cycle and combustion turbine plants retrofitted with pre- and post-combustion carbon capture and sequestration (CCS)
- Enhanced geothermal systems (EGS)

- Small modular light water nuclear reactors (SMRs)

This report finds that these technologies exhibit the following characteristics:

- All technologies except EGS show promise as zero-carbon firm capacity, which can enable a carbon-free grid
- All technologies exhibit high technical potentials on total resource deployment, though achieving said technical potentials may be difficult in reality
- Most technologies require significant levels of Research and Development (R&D) to be mature enough to be deployed on the grid at scale

Many Technologies in this Report Face Significant Hurdles to their Deployment, which Arise from Legal and Operational Challenges

- Nuclear SMRs face siting challenges in California due to state legislation preventing new construction until a long-term nuclear waste storage facilities in the U.S. can be developed, though they could be located outside of California and coupled with firm transmission. It remains to be seen if modular construction can yield intended cost reductions relative to conventional nuclear reactors
- Hydrogen and synthetic fuels will be expensive relative to natural gas when used in combustion turbines, and large-scale hydrogen use will require the development of hydrogen transportation and storage infrastructure to be cost-effective at delivering large volumes of gas to generators.
- EGS is an early-stage emerging technology, and faces very high projected costs, which will impede its deployment

- CCS technologies will require the development of CO_2 transportation infrastructure if deployed at large scale
- Long-duration iron-air batteries are still an early-stage emerging technology with uncertain future costs
- A-CAES is less early-stage than iron-air batteries, but its technical potential in California may be limited by lack of suitable geologic formations for compressed air storage facilities

This report does not determine the "winning" technologies, but does provide the data needed to include emerging technologies in capacity expansion modeling.

This report includes forecasted cost, efficiency, and operational characteristic data for multiple promising but emerging zero-carbon firm technologies. This information on its own cannot determine the optimal technology for a zero-carbon California grid. Rather, the data presented provides a source of inputs to capacity expansion models, such as E3's RESOLVE Model,[1] that capture the costs of new technology, their operational characteristics, and their value to the grid under various policy scenarios. Future analysis can be used to determine the cost-optimal mixture of renewables, short-duration storage, and zero-carbon firm capacity resources. This was developed to inform capacity expansion modeling for exercises such as the CPUC IRP process to inform least-regrets resource planning, while mitigating against over-reliance on technologies not yet proven at scale.

[1] Energy and Environmental Economics, Inc. RESOLVE: Renewable Energy Solutions Model. 2021. https://www.ethree.com/tools/resolve-renewable-energy-solutions-model/

Table 1-1: Summary of All-In Levelized Fixed Costs and Data Sources for Technologies Considered in this Analysis (2022$/kW-yr)

Tech.	Storage Duration	High/Low All-In Levelized Fixed Cost (2022 $/kW-yr)			Primary Cost Data Source
		2030	2040	2050	
Combined Cycle + ~100% Carbon Capture + Sequestration (CCS)	n/a	$287-$350	$244-$330	$230-$309	National Renewable Energy Lab Annual Technology Baseline (NREL ATB), Various Scientific Literature
Allam Cycle CCS	n/a	$338-$370	$297-$333	$276-$309	Various Scientific Literature
Small Modular Reactor (SMR)	n/a	$832-$832	$787-$787	$738-$738	NREL ATB
Enhanced Geothermal Systems (EGS)	n/a	$783-$3,974	$756-$3,821	$731-$3,675	NREL ATB
Hydrogen	200 hrs	$257-$315	$209-$281	$190-$254	E3, NREL ATB, Various Scientific Literature
Synthetic Natural Gas (SNG)	1,000 hrs	$350-$457	$313-$434	$300-$415	Same as Hydrogen
Adiabatic Compressed Air Energy Storage (A-CAES)	24 hrs	$208-$234	$193-$235	$189-$237	Industry, Pacific Northwest National Lab
Long-Duration Iron-Air Battery	100 hrs	$210-$429	$158-$430	$111-$432	Industry

The data in Table 1-1 may be used in capacity expansion or production simulation models. More detail on citations are provided in Section 4 of this report. We note that this data **does not** include the impacts of the recently passed U.S. Inflation Reduction Act (IRA). The IRA's effects on resource costs will be reflected in the CPUC Inputs and Assumptions (I&A) document. The IRA will provide storage that enters construction prior to 2033 with an ITC regardless of how it is charged. This will generally reduce the levelized storage costs shown here on the order of 25%. Other technologies, such as advanced nuclear, CCS, hydrogen and enhanced geothermal will be eligible for production tax credits (PTCs) that would not be captured in levelized fixed costs, but would be reflected in RESOLVE or similar capacity expansion modeling.

Table 1-2: Summary of Global Deployment and Technology Readiness Levels (TRL)

Category	Technology	TRL	Global Deployment
Generation	Gas + ~100% CCS	8	38 Mt CO_2/yr large-scale CCS projects
	Allam Cycle CCS	7	~25 MW Allam Cycle
	SMR	7	n/a[2]
	EGS	5	n/a[3]
Storage	Hydrogen	9	168 MW
	SNG	7	12 MW SNG, >0.01 MMT CO_2/yr Direct Air Capture
	A-CAES	8	1.75 MW
	Long-Durat. Battery	5-6	n/a[4]

Further information on the efficiency, lifetime, ramping rate and technical potential of the resources that can be built are also necessary modeling inputs.

[2] There are 70 MW of marine based water cooled SMRs in Russia and 32.5 MW of gas cooled SMRs in China and Japan, but there are no operational land-based light water SMRs.
[3] E3 is not aware of any enhanced geothermal systems installed to date.
[4] E3 is not aware of any iron-air batteries installed to date.

This information can be found in Section 4.1 and 4.2 this report. Table 1-2 provides information on the current state of technology readiness level (TRL) and deployment of these technologies.

2 Introduction

2.1 Overview of Zero-Carbon Firm Capacity Technologies

In a growing number of locations globally, the levelized cost of energy (LCOE) from wind and solar energy has declined below those of all new fossil fuel-powered alternatives.[5] This cost advantage for wind and solar is likely to grow as their costs continue to decline relative to fossil fuel power plants.[6,7] Given this cost spread, the decarbonized electricity grid of the future will most likely rely on large amounts of wind and solar, as well as short-duration (4-6 hr) storage to serve electric load under most conditions.

In most locations globally, there can be occasional multiday periods with low output from solar and wind resources. In grids with only weather-dependent renewables and short-duration storage, these conditions will lead to sustained low renewable electricity production. To maintain reliability during these conditions, expensive "overbuilding" of renewables and short-duration storage would be required to ensure adequate electricity is generated to meet grid needs. Expanding transmission to neighboring regions within reasonable limits can help

[5] Bloomberg. Solar and Wind Cheapest Sources of Power in Most of the World. 2020. https://www.bloomberg.com/news/articles/2020-04-28/solar-and-wind-cheapest-sources-of-power-in-most-of-the-world

[6] U.S. Energy Information Administration. Levelized Costs of New Generation Resources in the Annual Energy Outlook 2021. 2021. https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

[7] International Energy Agency. Projected Costs of Generating Electricity 2020. https://www.iea.org/reports/projected-costs-of-generating-electricity-2020

reduce this effect but is unlikely to eliminate it. Resources that provide firm capacity – capacity that is not weather-dependent or use-limited – can provide a more cost-effective approach to maintaining reliability in deeply decarbonized systems. Because these resources have little dependence on weather and are not use-limited, a single unit of firm capacity can provide reliability services that would other require many units of variable renewable resources. This result has been shown by many studies, from different modeling teams, across many different climates, different jurisdictions, and using different modeling tools.[8,9,10,11,12,13]

In current practice in California, dispatchable natural gas power plants are the marginal source of firm capacity during peak load conditions. It has been shown that such thermal plants could provide firm capacity in a mostly, but not fully, decarbonized California grid at comparatively low cost.[14] However, in the future, these traditional natural gas plants could be supplanted by zero-carbon firm capacity resources. This would allow California to support its carbon neutrality

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[8] Ming, Z. et al. Resource Adequacy in the Pacific Northwest. 2019. **https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf**

[9] Shaner, M. et al. Geophysical constraints on the reliability of solar and wind power in the United States. 2018. **https://doi.org/10.1039/C7EE03029K**

[10] National Renewable Energy Laboratory. LA100: The Los Angeles 100% Renewable Energy Study Executive Summary. 2021. **https://www.nrel.gov/docs/fy21osti/79444-ES.pdf**

[11] Mettetal, L. et al. Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future. 2020. **https://www.ethree.com/wp-content/uploads/2020/11/E3-EFI_Report-New-England-Reliability-Under-Deep-Decarbonization_Full-Report_November_2020.pdf**

[12] Princeton University Net Zero America Interim Report. 2021. **https://netzeroamerica.princeton.edu/img/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf**

[13] Armond Cohen et al. Clean Firm Power is the Key to California's Carbon-Free Energy Future. 2021. **https://issues.org/california-decarbonizing-power-wind-solar-nuclear-gas/**

[14] California Public Utilities Commission. Attachment A: 2019-20 IRP: Proposed Reference System Plan. 2019. **https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M319/K128/319128759.PDF**

policy goal by allowing the electric sector to fully and cost-effectively decarbonize.

2.1.1 STORAGE AND GENERATION TECHNOLOGIES: CLASSIFYING GENERATORS BY THEIR PRIMARY ENERGY INPUT

This report classifies emerging zero-carbon technologies in two categories: (1) energy storage technologies that use electricity as an input source of energy, and (2) generation technologies that use a high-temperature energy source (natural gas, biogas, uranium, or geothermal heat) as an input source of energy, and then convert that to electricity. All technologies considered in this report should be able to mitigate potential multi-day energy shortage issues that might arise in California in a high renewable future. Such technologies are considered in this report to be “firm.”

This report makes the distinction between energy storage and generation resources to indicate that energy storage resources are still energy limited and may therefore be unable to operate with an 100% effective load carrying capacity (ELCC),[15] though proper modeling must be used to determine the ELCC of such resources.

[15] Expected Load Carrying Capacity is defined as the equivalent amount of “perfectly” dispatchable capacity that a generating or storage unit provides to ensure grid reliability, divided by the nameplate capacity of that unit. More information on ELCCs can be found elsewhere, e.g.: Schlag et al. Capacity and Reliability Planning in the Era of Decarbonization. 2020. https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf

Currently, the California grid primarily relies on pumped hydroelectric and, to a smaller extent, lithium-ion batteries to provide bulk energy storage. Emerging energy storage technologies considered in this analysis are:

+ Long-duration iron-air batteries
+ Adiabatic compressed air energy storage (A-CAES)
+ Carbon-free hydrogen generated via electrolysis, which can be stored and then combusted in conventional power plants
+ Carbon-neutral synthetic natural gas (SNG) generated from electrolysis and electrically powered direct air capture (DAC) of CO_2, which can be stored and then combusted in conventional power plants

At present, California's grid relies primarily on natural gas-fired combustion turbines (CTs) and combined cycle power plants (CCGTs), combined heat and power (CHP), wind and solar power, conventional geothermal and conventional nuclear power plants as generation sources. Emerging generation technologies considered in this report are:

+ Natural gas-fired CCGT plants with post-combustion carbon capture and sequestration (CCS)
+ Allam-Fetvedt (AFC) CT plants retrofitted with oxy-fuel CCS
+ Enhanced geothermal systems (EGS)
+ Small modular light water nuclear reactors (which we will refer to herein as SMRs, though other types of SMR exist, e.g. high-temperature molten salt reactors)

2.1.2 MODELING LONG-DURATION STORAGE

In the past, modeling long-duration storage has posed a challenge, but recent advances in modeling capability will enable one to properly model long-duration storage. It is important to be able to model long-duration storage because it may unlock a lower-cost pathway to fully decarbonizing a grid than overbuilding renewables and short-duration storage.

A decarbonized grid that primarily relies on wind and solar power exhibits a seasonal imbalance in the supply of electricity and the demand for electricity. In California, the future decarbonized electricity supply is likely to be dominated by solar photovoltaics (PV), resulting in periods of sustained high daily solar “oversupply” – when available carbon-free generation exceeds demand – during the spring and, to a lesser extent, fall. However, demand for electricity will peak in the summer and winter, especially as heating is electrified.[16]

Long-duration energy storage technologies such as A-CAES, long-duration batteries, or fuels such as hydrogen and SNG would provide the capability to shift some of this surplus renewable power from the spring and fall to the summer and winter. This would mean that more of the potential generation from solar would ultimately be delivered to the grid, thus reducing the effective net cost of solar additions. While one could achieve this same effect by overbuilding Li-Ion batteries, long-duration energy storage technologies are projected to cost less than Li-Ion batteries when configured to provide storage durations necessary for seasonal energy shifting. Ultimately, this may result in a lower system cost relative

[16] California Public Utilities Commission. Attachment A: 2019-20 IRP: Proposed Reference System Plan. 2019. **https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M319/K128/319128759.PDF**

to a system that relies only on short-duration storage and renewables. However, determining if this is true, and determining what mixture of generation and storage technologies delivers the lowest total system cost, requires capacity expansion modeling.

The versions of RESOLVE used for the 2019 Reference System Plan and 2021 Preferred System Plan had limited ability to model long-duration energy storage, particularly in relation to:

+ Capturing the multi-day and seasonal shifting of energy given the 37 representative dispatch days
+ Capturing the interactive effect of synthetic, zero-carbon fuel production (e.g., power-to-gas) and burning the synthetic fuels in other fuel-burning resources (e.g., hydrogen-burning CTs) in the system

To improve RESOLVE's representation of long-duration storage, E3 is developing an updated version of RESOLVE via funding from CEC EPIC grant EPC-19-056.[17] One of the objectives of this grant is to study and implement an improved representation of chronological energy dispatch to capture the seasonal and cross-resource energy shifting in a more robust fashion. This updated version of RESOLVE is expected to be available by the next CPUC IRP cycle.

[17] E3, California Energy Commission. EPC-19-056 Assessing Long Duration Energy Storage Scenarios to Meet California's Energy Goals; Kickoff Meeting. 2020. **https://www.energy.ca.gov/filebrowser/download/2270**

2.1.3 MOTIVATION FOR INCLUSION OF A LIMITED LIST OF ZERO-CARBON TECHNOLOGIES

Given the plethora of potential technologies that could be considered, this study only considers promising, relatively mature technologies for which cost and other pertinent performance data is currently available. This was done because the purpose of this report was not to survey every potential technology, but to identify a broad array of capabilities offered by emerging technologies that are approaching a maturity point where they may be able to be considered in state planning such as IRP. This framework may omit promising technologies while other technologies considered herein may ultimately not progress to commercialization.

While these technologies are the primary focus of discussion, their cost and performance characteristics are compared to those of more established or emerging non-firm capacity technologies such as conventional solar and Li-Ion batteries to give the reader context.

Though the technologies considered in this analysis are denoted as zero-carbon firm capacity technologies, *all* the technologies considered above, as well as all conventional "zero-carbon" technologies such as wind and solar PV exhibit lifecycle emissions due to material extraction, transportation, manufacturing, plant operations, plant maintenance and plant decommissioning. The reader is directed elsewhere for a more detailed discussion of the lifecycle emissions associated with zero-carbon technologies. However, the technologies considered in this report typically have lifecycle emissions that are an order of magnitude or more below those of conventional fossil fuel-powered facilities on a kg CO_2/MWh basis.[18, 19, 20]

2.1.4 TECHNOLOGIES NOT CONSIDERED IN ANALYSIS

Numerous technologies were omitted from this analysis. They were omitted for not exhibiting all the following criteria: technology readiness level (TRL) above 5 (see Section 4.1 for more discussion of the TRL of different technologies); having sufficient regulatory approval; showing clear benefits relative to other technologies detailed in this analysis; exhibiting the ability to be dispatched for the entirety of peak net demand conditions; and not already modeled in a robust manner in the current 2021 CPUC PSP RESOLVE model. Some of the specific technologies that were not considered are discussed below. Table 2-1 summarizes various technologies and why they were omitted from the analysis. Omission from this analysis does not mean that these technologies do not show promise or that they might not be considered in future analyses. Omission here simply means that they did not meet the criteria established for inclusion in this report.

2.1.4.1 Technologies Without Sufficient Benefits Relative to those Considered in this Analysis

Hydrogen and SNG derived from zero-carbon electricity and (for SNG) CO_2 paired

[18] Argonne National Laboratory. GREET Publications. **https://greet.es.anl.gov/publications**
[19] NREL. Life cycle Greenhouse Gas Emissions from Solar Photovoltaics. 2013. **https://www.nrel.gov/docs/fy13osti/56487.pdf**
[20] Wang. Y. and Sun, T. Life cycle assessment of CO2 emissions from wind power plants: Methodology and case studies. 2011. **https://doi.org/10.1016/j.renene.2011.12.017**

Table 2-1: List of Technologies Omitted from this Analysis

Reason for Omission of Technologies from Analysis			
Insufficient Benefits Relative to Technologies Considered in Analysis	Insufficient TRL and Regulatory Approval	Do not Provide Firm Generation Capacity	Sufficient Treatment of Tech. in Existing Capacity Expansion Models
(1) Hydrogen Stored in Chemical Carriers: Carbon-Neutral Ammonia, Formic Acid, Methanol, Liquid Organic Hydrogen Carrier (2) Hydrogen Stored in Non-Pressurized Form: Metal Hydrides, Metal-Organic Frameworks, Cryogenic Storage (3) Hydrogen Production from Natural Gas with Carbon Capture (4) Pre-Combustion Capture of CO_2 using coal (5) Thermal energy storage with photovoltaics (TESPV)	(1) Nuclear Fusion (2) Molten Salt Nuclear Reactors (3) Pre-Combustion Capture of CO_2 using biomass	(1) Wind or Solar Power (2) Thermal Ice Storage	(1) Demand Response (2) EV Charging Load Shifting (3) Flow Batteries (4) Lithium-Ion Batteries (5) Pumped Storage Hydro

with geologic storage in pressurized gaseous form are the two fuels derived from electricity (referred to in this report as electrofuels) considered in this analysis. However, multiple means of storing hydrogen exist, including metal hydrides, metal-organic frameworks, ammonia, other hydrocarbons such as formic acid and methanol. Additionally, multiple means of producing zero-carbon hydrogen exist besides using electrolysis. These were not considered due to these technologies suffering one or more of the following drawbacks:

- Safety: Ammonia, methanol and formic acid are toxic, whereas hydrogen and methane are not.
- Round Trip Efficiency: All technologies listed above involve extra energy conversion steps and thus are typically more expensive on a $/GJ basis than hydrogen.
- TRL: Technologies such as metal-organic frameworks and metal hydrides have too low of a TRL relative to storing pressurized gaseous hydrogen.[21] Ammonia combustion in power plants is still an emerging area of research.
- Infrastructure: SNG exhibits energy yield penalties relative to hydrogen. However, there is existing infrastructure in California for delivering natural gas, whereas the alternatives presented above do not have robust transportation and storage infrastructure already in place. It has been estimated that hydrogen could be *blended* with natural gas up to 5% by volume without significant infrastructural upgrades, depending on the location in the network.[22] However there are not extensive networks for transporting, e.g. formic acid in California.
- Cost: Currently, most hydrogen produced globally is sourced from steam methane reforming (SMR) or autothermal reforming (ATR), i.e. made using natural gas as the feedstock,[23] and there is a large amount of hydrogen currently produced in California for oil refineries close to population centers that could potentially be retrofitted with CCS.[24] However, E3 projects that the unsubsidized cost of SMR or ATR with CCS

[21] International Energy Agency. ETP Clean Energy Technology Guide. 2020. **https://www.iea.org/articles/etp-clean-energy-technology-guide**

[22] CPUC. Hydrogen Blending Impacts Study. **https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF**

[23] Stevens, J. Study of Global Hydrogen Generation and Consumption. 2018. Available upon request from the United States Trade and Development Agency.

[24] H2 Tools. Captive, On-Purpose, Refinery Hydrogen Production Capacities at Individual U.S. Refineries. 2020. **https://h2tools.org/file/9018/download?token=6HwLuhi1**

will be above that of unsubsidized renewable electrolysis-derived hydrogen starting in the 2030s in the U.S.'s Desert Southwest.[25] The Inflation Reduction Act (IRA) will likely accelerate the timetable for renewable hydrogen to cost less than hydrogen with CCS.

Various other storage technologies also exist that were not included in this analysis. There are many different battery chemistries that may prove attractive for long-duration energy storage, but generally these are either not selected during current RESOLVE modeling processes because of their higher cost relative to Li-Ion batteries, or were not sufficiently advanced on a TRL basis for inclusion in this report.

E3 did not present data on thermal energy storage with photovoltaics (TESPV) here because it was thought that they had similar qualities to iron-air batteries, such as round-trip efficiency, albeit with lower capital costs and higher storage costs[26,27,28] (i.e. better for shorter durations than iron-air batteries). If pilots planned by the industry are successful, E3 recommends considering TESPV in future versions of this document.

Pre-combustion CCS can be used to reduce CO_2 emissions at a generator, along with post-combustion and oxy-fuel CCS. While we modeled the two latter technologies, pre-combustion CCS is not modeled in this report. This process is typically too expensive and politically contentious (in the case of coal gasification)

[25]Mahone, A. et al. Hydrogen Opportunities in a Low-Carbon Future: An Assessment of Long-Term Market Potential in the Western United States. 2020. **https://www.ethree.com/wp-content/uploads/2020/07/E3_MHPS_Hydrogen-in-the-West-Report_Final_June2020.pdf**

[26] Amy, C. Seyf, H., Steiner, M., Friedman, D., Henry, A. "Thermal Energy Grid Storage Using Multijunction Photovoltaics." *Energy and Environmental Science.* 12, 2019: 334-343. **https://doi.org/10.1039/C8EE02341G**

[27] Sepulveda, N., Jenkins, J. Edington, A., Mallpragada, D., Lester, R. Nature Energy. 2021. The design space for long-duration energy storage in decarbonized power systems. **https://www.nature.com/articles/s41560-021-00796-8**

[28] Massachusetts Institute of Technology (MIT). 2022. The Future of Energy Storage: An Interdisciplinary Study. **https://energy.mit.edu/wp-content/uploads/2022/05/The-Future-of-Energy-Storage.pdf**

or too low TRL (in the case of biomass) to be considered as a candidate for the California generating mix in this report.

2.1.4.2 Technologies with Insufficient Technology Readiness Level or Regulatory Approval

Various nuclear fission and fusion technologies are under development. While molten salt reactors (MSRs) have a fairly high TRL,[29] at the time of writing, there are no MSR designs that have nuclear regulatory council (NRC) approval.[30] Light-water SMRs, on the other hand, exhibit similarly high TRL, are proposed to be deployed in the near term in the U.S.[31] and NuScale has NRC approval for their light water SMR.[32] Fusion reactors have an extremely low TRL.[29]

2.1.4.3 Non-Firm Capacity Technologies

Various emerging technologies that cannot provide firm generating capacity during low solar and wind-production conditions were not considered in detail. Offshore wind, onshore wind and solar PV fall into this category. Thermal ice energy storage is not an electricity generating technology, and thus does not provide firm capacity. Thermal energy storage without conversion to electricity is

[29] International Energy Agency. ETP Clean Energy Technology Guide. 2020. https://www.iea.org/articles/etp-clean-energy-technology-guide

[30] U.S. Nuclear Regulatory Commission. Pre-Application Activities: NRC Advanced Reactors (non-LWR designs). 2021. https://www.nrc.gov/reactors/new-reactors/advanced/ongoing-licensing-activities/pre-application-activities.html

[31] World Nuclear News. NuScale and UAMPS agreements progress plans for SMR plant. 2021. https://world-nuclear-news.org/Articles/NuScale-and-UAMPS-agreements-progress-plans-for-SM

[32] U.S. Nuclear Regulatory Commission. Small Modular Reactors. 2020. https://www.nrc.gov/reactors/new-reactors/smr.html

also captured under the existing DR modeling framework in RESOLVE, as discussed in Section 2.1.4.4.

2.1.4.4 Technologies Already Modeled in Sufficient Detail in the CPUC IRP RESOLVE Model

The purpose of this document is broadly to create a framework for including new technologies in the CPUC IRP RESOLVE model. Demand response is currently modeled with high fidelity in RESOLVE, and thus it was not included in this report. The reader is directed to existing reports that detail how DR supply curves were developed for use in the RESOLVE model.[33] EV charging load shifting is also included in the current RESOLVE model (though continued alignment work with the IEPR forecast is needed to analyze a range of VGI scenarios). Additionally, the current RESOLVE model already has reasonable modeling treatments of pumped storage, flow batteries, and lithium-ion batteries

[33] CPUC. Inputs and Assumptions: 2019-2020 Integrated Resource Planning https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/Inputs%20%20Assumptions%202019-2020%20CPUC%20IRP_20191106.pdf

3 Overview of Technologies

3.1 Introduction

The following section describes the zero- or low-carbon firm capacity technologies that E3 will consider in this report in greater technical detail.

3.2 Zero-Carbon Generation Technologies: Small Modular Nuclear Reactors, Enhanced Geothermal Systems, and Post-Combustion or Oxyfuel Carbon Capture and Sequestration Plants

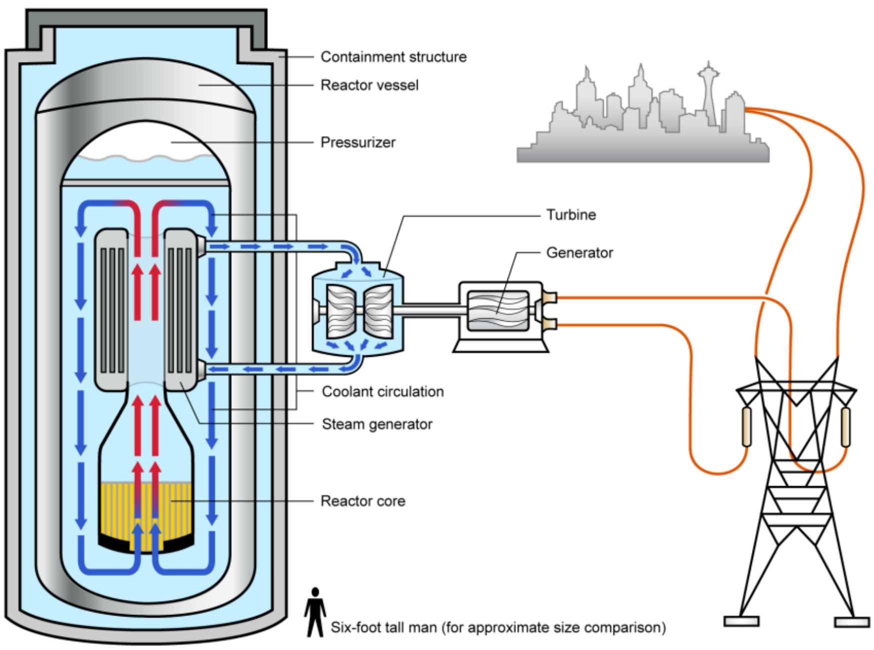
3.2.1 SMALL MODULAR NUCLEAR REACTORS

In this study, discussions on advanced nuclear technologies focus on SMRs due to recent developments and growing commercial interest in this technology group. SMRs are broadly defined as nuclear fission reactors with capacity up to 300 MW but may differ in reactor design.[34] This study focuses on light-water SMRs, which are the one of the more technologically mature types of SMRs currently under development.

[34] International Atomic Energy Agency. Advances in SMR Design and Technology Developments, 2020 Edition. https://aris.iaea.org/Publications/SMR_Book_2020.pdf

Light-water SMRs are similar to conventional light-water nuclear reactors in technology but smaller in size. A schematic of an SMR is sho4w in Figure 3-1. A key

Figure 3-1: Illustration of a Light Water Small Modular Reactor[35]



advantage of the smaller, modular design is increased flexibility in construction: individual units can be manufactured in a factory and aggregated at a power plant site incrementally as needed. This may allow for quicker technology learning and standardization through more iterations of building a standardized design, potentially resulting in shorter construction and permitting times. Shorter lead

[35] US Government Accountability Office, based on Nuclear Regulatory Commission documentation. GAO-15-652. https://www.gao.gov/assets/gao-15-652.pdf.

times could also reduce costs by reducing the risk of construction delays, possibility of design changes as required by evolving permitting requirements (which would lead to further delays), and financing risks, all of which have historically contributed to the high capital cost and cost overruns of traditional nuclear power plants.[36] SMRs can also incorporate enhanced safety designs, such as passive nuclear safety features that are made possible by the smaller reactor core.[37]

SMRs face some similar challenges in terms of policy and public acceptance to conventional nuclear power plants, as discussed in Section 4.5.2.1.

3.2.2 ENHANCED GEOTHERMAL SYSTEMS

Enhanced geothermal systems (EGS) are similar to current geothermal technologies, but access heat much deeper in the Earth's crust. Current and EGS geothermal plants operate on the same principle: by pumping water from the surface into heated rock reservoirs and pumping hot water back to the surface to the geothermal plant. At the geothermal plant, the heated water is used to make steam directly (in the case of flash systems) or via a heat exchanger (in the case of binary systems). This steam turns turbines to make electricity in the same manner as conventional steam-cycle thermal power plants.

Conventional geothermal plants have been developed commercially in California and other regions and have been operating for decades. Conventional plants are

[36] Lovering, J. R., Yip, A., & Nordhaus, T. (2016). Historical construction costs of global nuclear power reactors. *Energy Policy*, 91, 371-382.
[37] Nuclear Energy Agency. Small Modular Reactors: Nuclear Energy Market Potential for Near-term Deployment. 2016. NEA No. 7213. **https://www.oecd-nea.org/upload/docs/application/pdf/2019-12/7213-smrs.pdf**.

sited where there are reservoirs of permeable rock whose temperature is above approximately 210°C relatively close to the surface.[38] Sufficient reservoir permeability enables water to be continually pumped from the surface into geothermal fields and back to a geothermal plant.

EGS aims to drill geothermal wells up to seven kilometers deep, at which point the temperature of rock is generally considerably higher than in near-surface rock formations.[39] In addition to the depth of drilling, EGS intends to use techniques adopted from oil drilling to fracture non-porous heated rock to increase rock permeability, allowing water to be pumped through more easily.

The primary advantage of EGS is that by accessing heat much deeper in the earth's crust, the resource potential is dramatically higher. Estimates of the U.S.-wide technical EGS resource potential exceed 5.1 TW, approximately 100 times greater than CAISO's historical peak demand observed to date.[40,41] These resources are also more broadly distributed across the Western U.S. than conventional geothermal resources, as can be seen in Figure 3-1, which may facilitate geothermal plant siting at new locations and in new regions with high value to the grid.

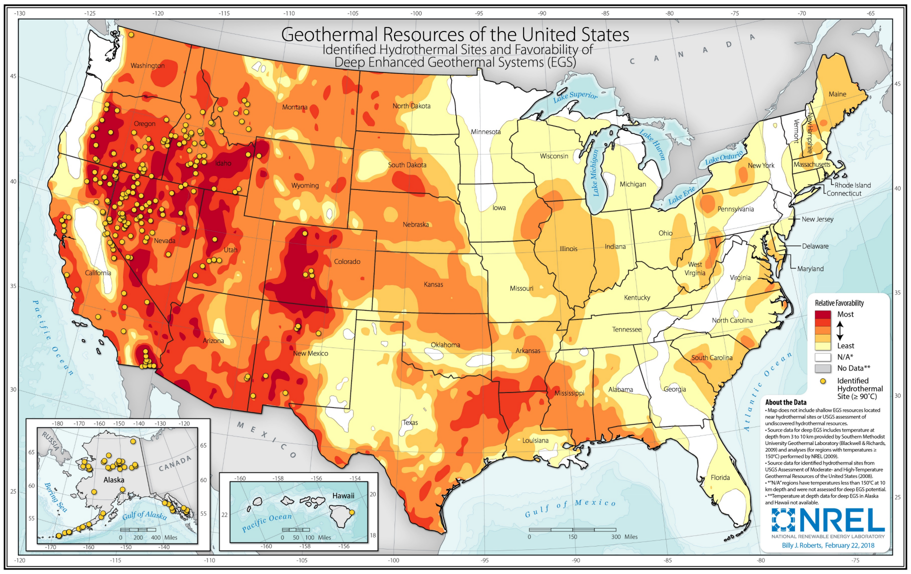
[38] U.S. Department of Energy. Geovision: Harnessing the Heat Beneath our Feet. **https://www.energy.gov/eere/geothermal/downloads/geovision-harnessing-heat-beneath-our-feet**

[39] National Renewable Energy Laboratory. Update to Enhanced Geothermal System Resource Potential Estimate. 2016. **https://www.nrel.gov/docs/fy17osti/66428.pdf**

[40] National Renewable Energy Laboratory. Update to Enhanced Geothermal System Resource Potential Estimate. 2016. **https://www.nrel.gov/docs/fy17osti/66428.pdf**

[41] California ISO. California ISO Peak Demand History. 2020. **https://www.caiso.com/documents/californiaisopeakloadhistory.pdf**

Figure 3-2: Enhanced Geothermal Resources Potential in the United States[42]



The most significant disadvantage of EGS is its extremely high capital cost relative to other low- or zero-carbon firm capacity resources. As shown below in Section 4.3.2, while there is a great deal of uncertainty on the future costs of EGS, EGS is potentially five times more expensive than SMRs and conventional geothermal, though they ostensibly provide the same generating characteristics as these other technologies. This reduces the likelihood that capacity expansion modeling

[42] National Renewable Energy Laboratory. Map of Potential Geothermal Resources across United States. 2021. https://www.nrel.gov/gis/assets/images/geothermal-identified-hydrothermal-and-egs.jpg

would select EGS resources in the next 10-20 years under current cost trajectories.[43]

EGS also exhibits risks of induced seismicity (earthquakes), lower risks of subsurface well leaks, and other potential issues common to hydraulic fracturing for oil and natural gas extraction.[44] EGS, like all geothermal, has long construction lead times (typically on the order of 7-10 years), with high project financing costs while exploratory wells are drilled in order to find productive sites.[45] Some of this risk would likely be mitigated by initially drilling EGS wells at or near known geothermal fields. Finally, geothermal systems emit small quantities of CO_2 and hydrogen sulfides due to the release of chemicals dissolved into the water in hydrothermal reservoirs. Binary systems release significantly less pollution than flash systems because the water that circulates through hydrothermal reservoirs is circulated in a closed, pressurized loop.[46]

3.2.3 POST-COMBUSTION CCS (FOSSIL AND BIOENERGY)

Post-combustion carbon capture refers to a process where CO_2 is separated from flue gas after fuel combustion in air. This review focuses on post-combustion carbon capture from natural gas or biomass/biogas power generation.

[43] California Public Utilities Commission. Attachment A: 2019-20 IRP: Proposed Reference System Plan. 2019. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M319/K128/319128759.PDF

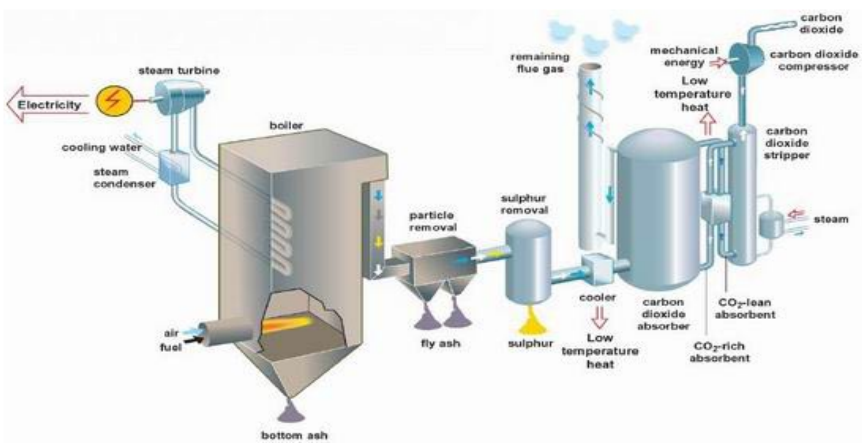
[44] U.S. Department of Energy. Geovision: Harnessing the Heat Beneath our Feet. https://www.energy.gov/eere/geothermal/downloads/geovision-harnessing-heat-beneath-our-feet

[45] U.S. Department of Energy. Geovision: Harnessing the Heat Beneath our Feet. https://www.energy.gov/eere/geothermal/downloads/geovision-harnessing-heat-beneath-our-feet

[46] U.S. Department of Energy. Geothermal Power Plants – Meeting Clean Air Standards. 2020. https://www.energy.gov/eere/geothermal/geothermal-power-plants-meeting-clean-air-standards

Because air is used for combustion, the resulting flue gas primarily consists of nitrogen gas, water vapor, and CO_2 (the latter consisting 3-5% by volume if burning natural gas or biogas). Separation of CO_2 is achieved via a chemical or physical process that is more selective towards CO_2 than nitrogen. Currently, the most mature technology for post-combustion CO_2 capture is chemical absorption using an alkaline solution (e.g., amine or chilled ammonia), which has been used in industry for natural gas processing for decades.[47] A fossil fuel (coal) boiler with a CO_2 absorber is illustrated in Figure 3-3.

Figure 3-3. Post-combustion carbon capture from flue gas using chemical absorption[48]



A key advantage of post-combustion CCS is that it offers an option for existing power plants to mitigate emissions through retrofitting, presenting an option to repurpose existing natural gas infrastructure. In addition, CO_2 in flue gas is

[47] IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

[48] Figure from: **http://www.rmcmi.org/education/clean-coal-technology**.

relatively concentrated, which makes post-combustion capture less energy-intensive and less costly than alternative capture pathways such as direct air capture (DAC) (CO_2 separation from air at atmospheric CO_2 concentration, i.e., 412.5 ppm as of 2020[49]).

Increasingly, policy discussions have centered on zero-carbon or climate-neutral energy systems. The exact language and definition may be critical for post-combustion CCS, which often does not mitigate 100% of the CO_2 emitted from a combustion process. Due to thermodynamical limits and economic trade-offs, current post-combustion systems are typically designed to capture 85-95% of the CO_2 in the flue gas.

Higher capture rates that are still within thermodynamic limits but are beyond 85%-95% are possible but require a CO_2 absorption reactor that can operate effectively at very low CO_2 concentrations, which adds cost. A recent modeling study[50] suggests that "CO_2-neutral" capture (i.e., outgoing flue gas at atmospheric CO_2 concentration) is achievable with a moderate cost increase (e.g., roughly 10% increase for natural gas combined cycle with CCS). More information on technology costs are provided in Section 4.3.2. Co-firing natural gas and biogas could be another option for post-combustion capture to be considered net-zero emission. Because biogas can have low or no emissions on a lifecycle basis, only

[49] NOAA Research. "Despite pandemic shutdowns, carbon dioxide and methane surged in 2020." April 7, 2021. **https://research.noaa.gov/article/ArtMID/587/ArticleID/2742/Despite-pandemic-shutdowns-carbon-dioxide-and-methane-surged-in-2020**.

[50] Feron, P., Cousins, A., Jiang, K., Zhai, R., Thiruvenkatachari, R., & Burnard, K. (2019). Towards zero emissions from fossil fuel power stations. *International Journal of Greenhouse Gas Control*, 87, 188–202.

the emissions from fossil natural gas need to be captured to be considered net-zero.

In any case, additional policy clarity would be helpful in determining whether any CCS technology would be considered as zero-carbon for planning purposes in California, as discussed in Section 4.5.2.2.

Post-combustion CCS is applied to flue gas after fuel combustion and does not reduce SO_2 and NO_x emissions from the combustion process. However, these acidic gases could cause degradation of the CO_2-capture solvent and increase capture costs. For this reason, pretreatment of flue gas may reduce these pollutants to very low levels before CO_2 removal, thus resulting in very low, albeit non-zero criteria pollutant emissions.

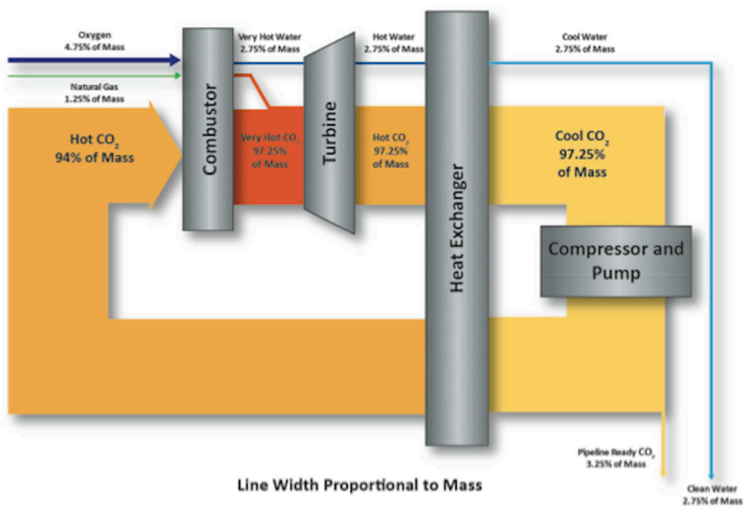
3.2.4 OXYFUEL-COMBUSTION CCS (ALLAM-FETVEDT CYCLE)

The Allam-Fetvedt cycle (AFC) is a power cycle that relies on oxyfuel combustion to produce electricity. Oxyfuel combustion is a form of combustion in which a fuel (typically natural gas for the AFC) is combusted in the presence of only oxygen. In typical power cycles, fuel is combusted in the presence of air, which contains predominantly nitrogen and oxygen. The high temperatures resulting from combustion can cause atmospheric nitrogen and oxygen gas to form NO_x in a typical power cycle.[51]

[51] Allam, R., Martin, S., Forrest, B., Fetvedt, J., Lu, X., Freed, D., Brown Jr., G. W., Sasaki, T., Itoh, M., Manning, J. Demonstration of the Allam Cycle: An update on the development status of a high efficiency supercritical carbon dioxide power process employing full carbon capture. *Energy Procedia*, 114, 5948–5966.

The second key feature of the AFC is that it uses nearly pure CO_2 as the working fluid to drive a turbine to produce electricity. Shown in Figure 3-4 is a simplified mass flow diagram of the AFC. It shows that majority of the fluid within the cycle consists primarily of CO_2, which is heated using oxyfuel combustion and is used to drive a turbine to produce electricity.

Figure 3-4. Simplified mass flow diagram of the Allam-Fetvedt cycle.[52]



The two key features—oxyfuel combustion and the CO_2 working fluid—affords the AFC advantages over traditional power cycles:[53]

[52] Modern Power Systems. "Breaking ground for a groundbreaker: the first Allam Cycle power plant." https://www.modernpowersystems.com/features/featurebreaking-ground-for-a-groundbreaker-the-first-allam-cycle-power-plant-4893271//featurebreaking-ground-for-a-groundbreaker-the-first-allam-cycle-power-plant-4893271-477349.html

[53] Allam, R., Martin, S., Forrest, B., Fetvedt, J., Lu, X., Freed, D., Brown Jr., G. W., Sasaki, T., Itoh, M., Manning, J. Demonstration of the Allam Cycle: An update on the development status of a high efficiency supercritical carbon dioxide power process employing full carbon capture. *Energy Procedia*, 114, 5948 – 5966.

1. As already noted, combusting fuel only in the presence of oxygen prohibits the formation of NO_x, allowing for higher peak power cycle temperatures that lead to higher efficiency

2. The primarily CO_2 working fluid in AFCs means that CO_2 capture can be performed using less energy than traditional post-capture combustion plants. Furthermore, the primarily CO_2 working fluid in AFCs results in higher theoretical thermodynamic efficiency than the primarily nitrogen gas working fluid in traditional post-combustion capture plants

3. The decreased CO_2 capture penalty enables reasonable efficiency despite needing to operate two processes. The first is necessary pre-combustion air separation needed to produce pure oxygen for oxyfuel combustion. The second is the post-combustion separation of water via condensation from the working fluid to produce pipeline-ready CO_2

As with post-combustion capture, SO_x may be separated from the exhaust stream prior to CO_2 compression. The key drawback is the novelty of the AFC, giving rise to financial and operational uncertainties. However, this technology is in the demonstration phase, which should alleviate some of these uncertainties.[54]

[54] PR Newswire. "NET Power Delivers Electricity to Grid in Major Technological Breakthrough" https://www.prnewswire.com/news-releases/net-power-delivers-electricity-to-grid-in-major-technological-breakthrough-301425894.html

3.3 Energy Storage Technologies: Hydrogen, Synthetic Natural Gas, Thermal Energy Storage with Multijunction Photovoltaics, Long-Duration Iron-Air Batteries and Adiabatic Compressed Air Energy Storage

3.3.1 OVERVIEW

Today, typical Li-Ion batteries that have been installed on the grid are rated for 0.5–6 hours of discharge at rated capacity.[55] Long-duration storage technologies span a wide array of discharge durations (8–1,000 hours), employ a variety of storage media (mechanical, thermal, chemical, or a mixture thereof), and have a range of operational and siting characteristics (round-trip efficiency, ramp rate, siting near caverns or geographies with significant elevation changes). This section focuses on long duration storage technologies with durations on the order of days to weeks.

3.3.2 ELECTROFUELS: HYDROGEN AND SYNTHETIC NATURAL GAS

The renewable, hydrogen electrolysis-derived fuels (referred to henceforth as "electrofuels") considered in this analysis are hydrogen derived from alkaline electrolysis (AECs) and SNG made from hydrogen and CO_2 in a Sabatier reactor. Other pathways for the production and use of electrofuels are discussed in Section 4.5.3.

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[55] U.S. Energy Information Administration. Battery Storage in the United States: An Update on Market Trends. 2020. https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

AECs, like all low-temperature electrolysis processes, use electricity and water as inputs to produce gaseous hydrogen and oxygen as illustrated in Figure 3-5. AECs were selected because they currently are the lowest cost and most mature scalable green hydrogen production technology, and it is projected that AECs will continue to decline significantly in cost.[56]

This study models using Direct Air Capture (DAC) plants as the source of CO_2 for SNG production, so as not to limit SNG fuel production by bioderived CO_2 availability. DAC is a technology to remove CO_2 from the air by passing large volumes of air over a CO_2-absorbing chemical. This chemical is then regenerated, for example via heating until it releases concentrated CO_2, after which the chemical is then reused to absorb more $CO_{2,}$ and the CO_2 is used as a feedstock for subsequent processes. This process is functionally very similar to that used for CCS but operates at much lower CO_2 concentrations than found in flue gas. A conceptualization of a DAC plant is shown in Figure 3-6.

A Sabatier reactor is a thermochemical process that reacts hydrogen and CO_2 to produce a chemical mixture that is predominantly methane, water and heat as illustrated in Figure 3-7. Methane would be able to serve as a drop-in fuel to replace natural gas. There are multiple methods to turn hydrogen and CO_2 into hydrocarbons, though these are not considered herein. Creating liquid hydrocarbons typically costs significantly more than SNG, due to high cost of capturing carbon via DAC and the higher carbon content per GJ of fuel in liquid fuels versus methane. Other, e.g., electrochemical means for synthesizing

[56] Bloomberg New Energy Finance. Hydrogen Economy Outlook: Key Messages. 2020. https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf

hydrocarbons from hydrogen and CO_2 are being developed but are more nascent.[57]

There are several benefits of electrofuels when used in the electricity sector. As a long-duration storage medium, AECs and DAC units could be operated as a flexible load to produce fuel during periods which would otherwise entail high seasonal renewable curtailment. Though curtailed electricity would provide an inexpensive feedstock for producing electrofuels, the overall amount of curtailment available to produce electrofuels is uncertain. Dedicated renewable plants could be built for electrofuels production if fuel demand exceeds that which can be generated from curtailed electricity alone. E3's updates to the RESOLVE model discussed in Section 2.1.2 will enable modeling producing fuels via curtailment, and E3 currently models dedicated production of hydrogen in RESOLVE as a drop-in fuel.

Other benefits of hydrogen and SNG are that the storage cost is very low on a $/GJ basis compared to many other storage technologies if proper geologic storage formations are available and are developed at large scale. Additionally, these fuels could potentially be used in much of the existing fossil-fuel power generation equipment, either directly (in the case of SNG) or in retrofitted equipment (in the case of hydrogen). This has the potential to reduce stranded thermal generator costs and may mitigate aversion to adopting new, untested technologies from the electric power generation sector. Finally, electrofuels would not contain sulfur, thus eliminating SO_x emissions.

[57] See, e.g.: Clark et al. 2017. Electrochemical CO_2 Reduction over Compressively Strained CuAg Surface Alloys with Enhanced Multi-Carbon Oxygenate Selectivity. **https://pubs.acs.org/doi/abs/10.1021/jacs.7b08607**

Figure 3-5: Alkaline Electrolyzer Schematic

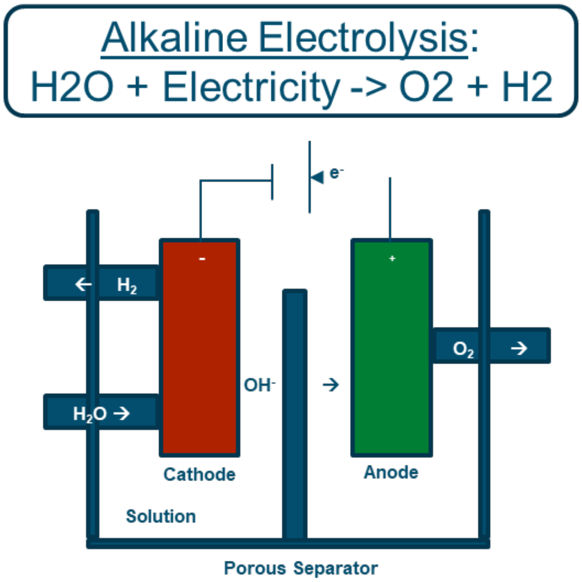
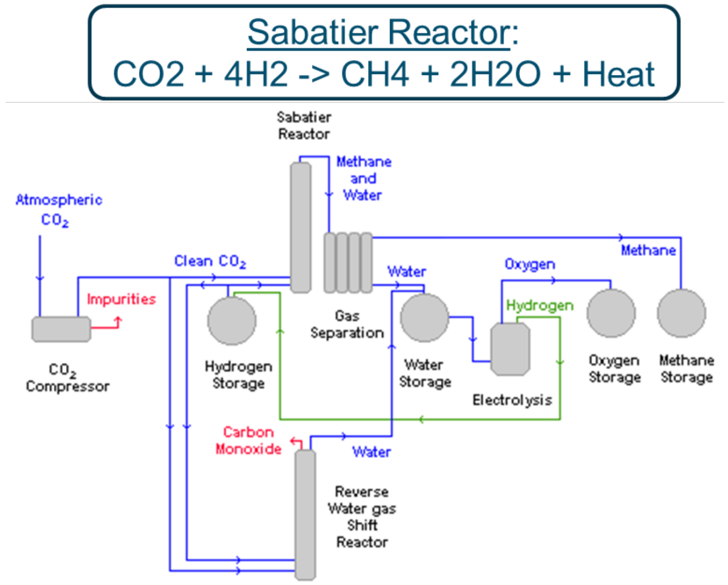


Figure 3-6: Direct Air Capture Plant Conceptualization[58]

Figure 3-7: Sabatier Reactor Line Diagram[59]



The primary drawbacks of electrofuels are that they are expensive relative to natural gas. While it is projected that hydrogen costs will decline greatly due to declining electrolyzer capital and feedstock electricity costs, zero-carbon hydrogen costs will likely remain several times more expensive than current electricity-sector natural gas prices by mid-century.[60] SNG is likely to cost significantly more than zero-carbon hydrogen.[61] While future commercially deployed hydrogen- and SNG-powered CTs and CCGTs are likely to meet

[58] Keith, D. et al. A Process for Capturing CO2 from the Atmosphere. 2018. https://doi.org/10.1016/j.joule.2018.05.006

[59] Synthesizing Fuel: Methane for Nothing and the Oxygen is Free?*. www.digipac.ca/chemical/mtom/contents/chapter3/sabatier2.htm

[60] Bloomberg New Energy Finance. Hydrogen Economy Outlook: Key Messages. 2020. https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf

[61] Mahone et al. Hydrogen Opportunities in a Low-Carbon Future: An Assessment of Long-Term Market Potential in the Western United States. 2020. https://www.ethree.com/wp-content/uploads/2020/07/E3_MHPS_Hydrogen-in-the-West-Report_Final_June2020.pdf

applicable NO_x emissions standards through advanced combustor design or other measures, they will exhibit non-zero NO_x emissions.[62] Finally, using hydrogen at any significant scale may require retrofitting existing natural gas storage and potentially transportation infrastructure, or constructing purpose-built hydrogen infrastructure.[63]

3.3.3 ADIABATIC COMPRESSED AIR ENERGY STORAGE

In A-CAES, electric energy is converted into mechanical energy by rapidly compressing air and storing it at high pressure. Energy is recovered by driving the pressurized air through a turbine, thereby generating electricity. The most mature forms of CAES are diabatic (around 400 MW total deployed in McIntosh, Alabama, and Huntorf, Germany),[64] which do not recover the heat released from the rapid compression of air, requiring reheating of air during discharge with fuel combustion and reducing the roundtrip efficiency of the plant (around 50%).[65]

A-CAES is an emerging technology that captures and stores the heat released by air compression in a thermal storage medium. A simplified process diagram can be seen in Figure 3-8. A-CAES has the advantages of eliminating fuel use (and subsequent potential carbon emissions) on discharge and having higher roundtrip efficiencies (up to 70%)[66] in comparison to traditional CAES. However, the prime

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[62] Power Engineering. Hydrogen substitution for natural gas in turbines: Opportunities, issues and challenges. 2021. **https://www.power-eng.com/gas/hydrogen-substitution-for-natural-gas-in-turbines-opportunities-issues-and-challenges/**

[63] H21 Leeds City Gate. 2016. **https://www.h21.green/wp-content/uploads/2019/01/H21-Leeds-City-Gate-Report.pdf**

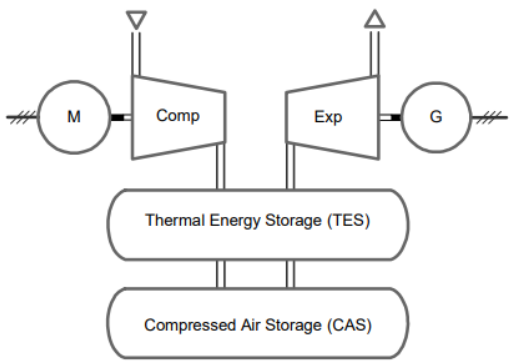
[64] Pacific Northwest National Laboratory. "Compressed Air Energy Storage," 2018. **https://caes.pnnl.gov/**.

[65] Pacific Northwest National Laboratory. "Compressed Air Energy Storage (CAES)". **https://www.pnnl.gov/compressed-air-energy-storage-caes/.**

[66] Wolf, D. Dynamic simulation of possible heat management solutions for Adiabatic Compressed Air Energy Storage. **http://publica.fraunhofer.de/eprints/urn_nbn_de_0011-n-1039740.pdf**.

disadvantage is the incremental cost of a thermal energy storage medium over traditional CAES.

Figure 3-8. Simplified process diagram of an adiabatic compressed air energy storage plant.[67]



Generally, the advantage of A-CAES is that it could provide emissions-free, long-duration operation with reasonably high round trip efficiency. The primary disadvantage of A-CAES is that it requires specific underground geologic formations to work, which may not be ideal points for grid interconnection. Additionally, A-CAES is a relatively immature technology.

3.3.4 LONG-DURATION IRON-AIR BATTERIES

E3 chose to consider novel aqueous iron-air batteries as a representative example of a novel long-duration battery. This class of batteries works by combining oxygen with an iron-containing anode, forming iron oxide on the cathode. A separator between the anode and cathode allows one to extract useful work from

[67] Wolf, D. Dynamic simulation of possible heat management solutions for Adiabatic Compressed Air Energy Storage. http://publica.fraunhofer.de/eprints/urn_nbn_de_0011-n-1039740.pdf.

the battery during this oxidation process. Upon recharging, the battery's cathode releases oxygen, and iron is redeposited on the battery anode.[68]

The primary advantage of long-duration storage relative to other energy storage technologies is that they exhibit lower energy storage costs than Li-Ion batteries, as well as higher round trip efficiencies than electrofuel synthesis-based energy storage. Furthermore, such batteries would be able to be located at convenient grid interconnection points rather than requiring underground storage as is necessary for A-CAES and electrofuels. The primary disadvantage of long-duration storage is that they are a nascent technology, and it is uncertain if they will hit the longevity, cost, and efficiency targets projected by industry.

[68] For a review of this technology, see: S. Sripad et al. "The Iron-Age of Storage Batteries: Techno-Economic Promises and Challenges." 2021. **https://ecsarxiv.org/a4se8/**

4 Technology Comparison

4.1 Current State of Technology Commercialization and Needed R&D Improvements

4.1.1 OVERVIEW

This section discusses currently planned or existing low-carbon firm capacity generation plants, the various R&D needs that must be satisfied for their broad deployment, the current TRLs and total capacity of deployed plants, the likely technical deployment potential limits by technology, and other operational characteristics that would have to be considered in a capacity expansion model.

4.1.2 DISCUSSION OF DEPLOYED OR PLANNED PLANTS

4.1.2.1 Carbon Capture and Sequestration Plants

To date, CCS has largely been deployed in the oil and gas sector as a means of providing enhanced oil recovery (EOR) and for removing excess naturally occurring CO_2 from natural gas. At the time of writing, the utility-scale power plants that used post-combustion CCS are the decommissioned 240 MW Petra Nova coal power plant in Texas (shut down in 2020 because, among other reasons, its captured CO_2 was used for EOR, and oil prices at the time were extremely low[69]) and the 115 MW Boundary Dam unit 3 coal power plant currently operating in Saskatchewan, Canada.[70] NET Power has constructed a 50 MW Thermal AFC demonstration plant in Texas (~25 MW electric) and plans to bring larger plants online, but these are not yet constructed.[71] Plants that use pre-combustion capture of CO_2 are not detailed in this report due to failing the screening criteria set forth in Section 2.1.4, but there are operational plants that use this technology for coal-burning power plants.[72]

Post-combustion CCS broadly requires R&D improvements to solvents, sorbents and membranes. Each of these technologies could be used to separate CO_2 from flue gas.[73] AFC R&D largely focuses on designing components to operate under the high pressure and high-temperature conditions required for efficient AFC operation using supercritical CO_2. This includes improving turbine blade materials and cooling passageway design, designing high pressure combustors and designing high pressure, high temperature heat exchangers.[74]

[69] Forbes Magazine. California Offers a Reality Check on Carbon Capture. 2020. **https://www.forbes.com/sites/andystone/2020/12/16/california-offers-a-reality-check-on-carbon-capture/?sh=f5cca516da36**

[70] Energy Futures Initiative and Stanford University. An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges and Solutions. 2020. **https://sccs.stanford.edu/sites/g/files/sbiybj7741/f/efi-stanford-ca-ccs-full-rev1.vf-10.25.20.pdf**

[71] The Atlantic Council. "Carbon capture and the Allam Cycle: The future of electricity or a carbon pipe(line) dream?" **https://www.atlanticcouncil.org/blogs/energysource/carbon-capture-and-the-allam-cycle-the-future-of-electricity-or-a-carbon-pipeline-dream/**.

[72] Dakota Gasification Company. CO2 Capture and Storage. 2021. **https://www.dakotagas.com/about-us/CO2-capture-and-storage/index**

[73] U.S. Department of Energy Office of Fossil Energy and Carbon Management. Carbon Capture R&D. 2021. **https://www.energy.gov/fe/science-innovation/carbon-capture-and-storage-research/carbon-capture-rd**

[74] Allam et al. Energy Procedia. 2017. Demonstration of the Allam Cycle: An update on the development status of a high efficiency supercritical carbon dioxide power process employing full carbon capture. **https://doi.org/10.1016/j.egypro.2017.03.1731**

4.1.2.2 *Electrofuels*

Electrolyzers are a mature technology that, while deployed in a limited fashion relative to fossil fuel-powered hydrogen production facilities, have been built in many different locations globally.[75] SNG has been produced at multiple different locations, but the plants over 100 kW in capacity that use chemical methanation are all located in Northwestern Europe.[76] The largest operating plant as of November, 2021 is the 6 MW facility at Audi's e-gas plant in Werlte, Germany.[77,78] At the time of writing, only very small-scale DAC plants have been built, totaling approximately 0.01 million metric tons (MMT) of CO_2 per year. A 1 MMT of CO_2 per year plant that could come online as early as 2023 is under consideration to be built by Carbon Engineering and Occidental Petroleum in the Permian Basin in Texas.[79]

Currently, there is one operational and several planned utility-scale hydrogen-powered combined cycle gas turbines (CCGTs), as well as many under consideration. Vattenfall's Magnum power plant in the Netherlands is an operational, hydrogen-ready 1.3 GW CCGT, though it is not known if there are plans to use hydrogen in this plant.[80] A notable example of a planned hydrogen-fueled plant is LADWP's 840 MW Intermountain Power Plant CCGT repowering

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[75] See, e.g.: U.S. Department of Energy. U.S. Hydrogen Electrolyzer and Capacity. 2021. **https://www.energy.gov/sites/default/files/2021-06/hydrogen-electrolyzer-locations-june-2021.pdf**

[76] Thema et al. Power-to-Gas: Electrolysis and Methanation Review. Renewable and Sustainable Energy Reviews, Vol 112. Sep 2019. Pp. 775-787. **https://doi.org/10.1016/j.rser.2019.06.030**

[77] Advanced Science News. Audi Opens Power-to-Gas Facility. 2013. **https://www.advancedsciencenews.com/audi-opens-power-to-gas-facility/**

[78] International Energy Agency. Hydrogen Projects Database. 2021. **https://www.iea.org/reports/hydrogen-projects-database**

[79] IEA. Direct Air Capture: Tracking Report – June 2020. 2020. **https://www.iea.org/reports/direct-air-capture**

[80] Power Magazine. MHPS Will Convert Dutch CCGT to Run on Hydrogen. 2018. **https://www.powermag.com/mhps-will-convert-dutch-ccgt-to-run-on-hydrogen/**

project. This plant, to be located at the site of the currently operational Intermountain Power Project coal plant in Delta, UT, will generate hydrogen using AECs and store it in an underground geological structure on-site. The plant will use a Mitsubishi CCGT that will initially operate on a blend of 90% natural gas and 10% hydrogen by energy starting in 2025, with plans to transition to 100% hydrogen power by 2045.[81] Power will be delivered to LADWP using existing high voltage direct current powerlines.[82]

Due to its unique geographical and geological features, the Delta, UT plant is likely to exhibit exceptionally low hydrogen storage and transmission infrastructure costs relative to other locations. This is likely why Mitsubishi and LADWP chose to site the plant there. However, there are other locations in California that may be suitable for similar plants. These locations would ideally be near underground geological formations that could potentially store hydrogen, electricity transmission lines, gas pipeline right of ways, water supplies, electricity demand centers, and/or have a good renewable resource. At a high level, this confluence of qualities exists in the desert north of Los Angeles, as well as in the Central Valley east of the San Francisco Bay Area,[83] though hydrogen storage to date has not been demonstrated commercially in the depleted fossil fuel reservoirs found in these locations. Salt domes located outside of California are known to be able to store hydrogen, which may serve as alternative storage deployment locations if hydrogen storage cannot be deployed in existing fossil fuel reservoirs in

[81] Los Angeles Department of Water and Power. Green Hydrogen and the Intermountain Power Plant. https://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Gas/Natural_Gas_Market/Nov13LADWP.pdf

[82] BusinessWire. El Paso Electric, Mitsubishi Power Americas Work to Help Decarbonize Region with New Gas Turbine. 2021. https://www.businesswire.com/news/home/20210119005634/en/El-Paso-Electric-Mitsubishi-Power-Americas-Work-to-Help-Decarbonize-Region-with-New-Gas-Turbine

[83] U.S. Energy Information Administration. U.S. Energy Map. 20201. https://www.eia.gov/state/maps.php

California.[84] The hydrogen costs in this report include modeled costs of pipelines to salt domes near Phoenix, AZ as detailed in Lord et al.[84] Determining which exact locations are feasible and optimal for siting hydrogen storage facilities and generators is out of scope for this analysis.

DAC deployment would require R&D similar to some aspects of CCS to improve its liquid solvents, solid sorbents, and/or membranes; to increase energy efficiency in the CO_2 desorption process, to enable electrification of the solvent heating/regeneration step for liquid-based DAC; to reduce the peak process temperature of solid sorbent heating/regeneration so that high-temperature heat pumps could be employed instead of resistance heating to reduce energy requirements; and to effectively pair DAC electricity with renewable generation across a variety of geographies.[85,86,87] Such R&D funding has been recently approved by the DOE. SNG deployment would require the development of low-cost Sabatier reactors or alternative R&D such as in highly selective catalysts and low-cost membranes for electrochemical methane production. Electrochemical methods for synthesizing SNG are in a significantly earlier R&D stage than Sabatier reactors.

[84] Lord, A. , Kobos, P., Borns, D. "Geologic Storage of hydrogen: Scaling up to meet city transportation demands." *International Journal of Hydrogen Energy*. 39 (2014): 15570-15582. **https://doi.org/10.1016/j.ijhydene.2014.07.121**.

[85] McQueen, N. et al. A review of direct air capture (DAC): scaling up commercial technologies and innovating for the future. *Progress in Energy*. 2021. **https://iopscience.iop.org/article/10.1088/2516-1083/abf1ce/pdf**

[86] U.S. Department of Energy. DOE Announces $12 Million For Direct Air Capture Technology. 2021. **https://www.energy.gov/articles/doe-announces-12-million-direct-air-capture-technology**

[87] U.S. Department of Energy. Materials and Chemical Sciences for Direct Air Capture (DAC) of Carbon Dioxide Award Selection. 2021. **https://science.osti.gov/-/media/bes/pdf/Funding/2021/FY2021_DAC_Awards_20210722.pdf?la=en&hash=253EEF11CC4CB90ED26DE3B721210DD90668F2B9**

Commercial deployment of hydrogen-enabled turbines will require continued improvements in combustor technology to enable the use of dry low-NO_x combustors that mitigate emissions without steam injection or post-combustion exhaust treatment. This is not an early-phase R&D need and will likely be realized in the mid-2020s given various gas turbine manufacturers' technology rollout plans.[88] Additionally, improving the cost and volumetric energy density of non-geologic hydrogen storage would potentially increase the number of power plants that could be repowered with hydrogen without needing access to geologic hydrogen storage.

4.1.2.3 Adiabatic Compressed Air Energy Storage

Hydrostor has built a 1.75 MW A-CAES plant with more than 5.7 hours of duration in Canada. Hydrostor plans to build another 500 MW plant with 8 hours of duration near Rosamond, CA, which would be slated for completion by 2028.[89] Hydrostor also recently announced that they have a 400-MW, up to 8-hour duration plant under active development in Morro Bay, CA,[90] and several other plants outside of the U.S.[91]

4.1.2.4 Small Modular Nuclear Reactors

At the time of writing, the 32 MW CAREM nuclear plant in Buenos Aires province, Argentina is the only land-based (i.e., not floating or in a nuclear submarine)

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[88] See, e.g. General Electric. Hydrogen Fueled Gas Turbines. 2021. **https://www.ge.com/gas-power/future-of-energy/hydrogen-fueled-gas-turbines**
[89] Hydrostor. Willow Rock Energy Storage Center. **https://www.hydrostor.ca/willow-rock/**
[90] Hydrstor. Pecho Energy Storage Center. **https://www.hydrostor.ca/pecho-energy-storage-center/**
[91] Hydrostor. Projects. **https://www.hydrostor.ca/projects/**

water-based SMR under construction,[92] and there are no operational plants. Various manufacturers are pushing to develop SMRs for deployment in various countries.[93] Other early-stage non-light water SMRs are under development within the U.S., though these are not currently under construction.[94] NuScale plans to pilot its reactors in Idaho.[95]

4.1.2.5 Other Technologies

At the time of writing, no known EGS or air-based long-duration storage battery plants are online or under construction. Deploying EGS will require many R&D innovations, broadly falling under improved drilling technology that can withstand high temperature conditions not typically observed during petroleum well drilling, and better mapping and modeling of subsurface rock formations in which wells would be drilled.[96]

Form Energy has announced a pilot to build a 1-MW, 150-hour duration long-duration iron-air storage plant with Minnesota's Green River Energy,[97] as well as

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[92] World Nuclear News. Nucleoelectrica Contracted to Complete CAREM-25. 2021. https://world-nuclear-news.org/Articles/Nucleoelectrica-contracted-to-complete-CAREM-25

[93] International Atomic Energy Agency. Advances in SMR Design and Technology Developments, 2020 Edition. https://aris.iaea.org/Publications/SMR_Book_2020.pdf

[94] U.S. Department of Energy. Next-Gen Nuclear Plant and Jobs are Coming to Wyoming. 2021. https://www.energy.gov/ne/articles/next-gen-nuclear-plant-and-jobs-are-coming-wyoming

[95] AP News. Eastern Idaho nuclear project goes from 12 to six reactors. 2021. https://apnews.com/article/technology-science-business-environment-and-nature-climate-change-3737699443a50ebc3a24fccde562fd3f

[96] U.S. Department of Energy. Geovision: Harnessing the Heat Beneath our Feet. https://www.energy.gov/eere/geothermal/downloads/geovision-harnessing-heat-beneath-our-feet

[97] Form Energy. Form Energy Announces Pilot with Great River Energy to Enable the Utility's Transition to an Affordable, Reliable and Renewable Electricity Grid. 2020. https://formenergy.com/wp-content/uploads/2020/05/Form-Energy_-GREPilotPress-Release.pdf

a 15 MW, 100 MWh-duration plant with Georgia Power, but both are at unspecified dates.[98]

Table 4-1: Technology Readiness Levels Definition from International Energy Agency[29]

CONCEPT	1	**Initial idea** Basic principles have been defined
	2	**Application formulated** Concept and application of solution have been formulated
	3	**Concept needs validation** Solution needs to be prototyped and applied
SMALL PROTOTYPE	4	**Early prototype** Prototype proven in test conditions
LARGE PROTOTYPE	5	**Large prototype** Components proven in conditions to be deployed
	6	**Full prototype at scale** Prototype proven at scale in conditions to be deployed
DEMONSTRATION	7	**Pre-commercial demonstration** Solution working in expected conditions
	8	**First of a kind commercial** Commercial demonstration, full scale deployment in final form
EARLY ADOPTION	9	**Commercial operation in relevant environment** Solution is commercially available, needs evolutionary improvement to stay competitive
	10	**Integration needed at scale** Solution is commercial and competitive but needs further integration efforts
MATURE	11	**Proof of stability reached** Predictable growth

Table 4-1[29] provides a summary of how the International Energy Agency (IEA) defines TRLs. Table 4-2 provides a summary of the current technology TRLs and known total existing global deployment at the time of writing. These TRLs were developed by the IEA for the technologies detailed herein, except for Long-Duration Iron-Air batteries, since these were not included in the IEA database.

[98] Utility Dive. Form Energy announces partnership with Georgia Power to test 100-hour iron-air battery. 2022. https://www.utilitydive.com/news/form-energy-announces-partnership-with-georgia-power-to-test-100-hour-iron-/618626/

Technology Category	Technology	TRL	Global Deployment
Generation	CCGT + ~100% CCS	8	38 Mt CO_2/yr large-scale CCS projects.[99]
	Allam Cycle CCS	7	~25 MW Allam Cycle[100]
	SMR	7	n/a[101]
	EGS	5	n/a[102]
Storage	Hydrogen	9	168 MW[79]
	SNG	7	12 MW SNG[79], >0.01 MMT/yr DAC[103]
	A-CAES	8	1.75 MW[104]
	Long-Durat. Iron-Air Battery	5-6	n/a[105]

Table 4-2: Technology Readiness Level and To-Date Deployment of Zero- or Low-Carbon Firm Capacity Technologies Considered in this Report

[99] Energy Futures Initiative and Stanford University. An Action Plan for Carbon Capture and Storage in California. 2020. https://sccs.stanford.edu/sites/g/files/sbiybj7741/f/efi-stanford-ca-ccs-full-rev1.vf-10.25.20.pdf

[100] Yellen, D. Carbon capture and the Allam Cycle: The future of electricity or a carbon pipe(line) dream? 2020. https://www.atlanticcouncil.org/blogs/energysource/carbon-capture-and-the-allam-cycle-the-future-of-electricity-or-a-carbon-pipeline-dream/

[101] There are 70 MW of marine based water cooled SMRs in Russia and 32.5 MW of gas cooled SMRs in China and Japan, but there are no operational land based light water SMRs. A 32 MW land based light water SMR plant under construction, with more under various stages of planning. International Atomic Energy Agency. Advances in Small Modular Reactor Technology Developments. 2020. https://aris.iaea.org/Publications/SMR_Book_2020.pdf

[102] E3 is not aware of any enhanced geothermal systems installed to date.

[103] International Atomic Energy Agency. Advances in Small Modular Reactor Technology Developments. 2020. https://aris.iaea.org/Publications/SMR_Book_2020.pdf

[104] Total is for existing adiabatic CAES deployment, not including all CAES. Hydrostor. Goderich Energy Storage Project. 2021. https://www.hydrostor.ca/goedrich-a-caes-project/

[105] E3 is not aware of any iron-air batteries installed to date.

4.2 Deployment Characteristics

Table 4-3 shows the approximate technical potential of deployment by technology, provided in terms of total installed nameplate capacity and total delivered electricity after efficiency losses. In the case of CCS technologies, deployment limits for fossil fuel-derived energy are derived from limits on annual amounts of carbon that can be sequestered in California. Technical biogas + CCS limits are derived from biomass production limits described in the CEC Future of Natural Gas Report.[106] For electrofuels and long-duration batteries, upper bounds of energy limits are derived from the limits of CA solar deployment in the CPUC IRP RESOLVE model, adjusting for typical round-trip efficiencies, while the lower limit for hydrogen is derived from a rough estimate made by Lord et al in a study of salt dome storage in Arizona, [84] plus typical round-trip efficiencies. The technical limits on A-CAES are based on planned deployments, but it is not known if these are the true technical limits. It is unlikely that there are limits to the technical potential capacity or energy of SMRs built in California that would be relevant to the CPUC IRP modeling. While EGS has an estimated resource potential of 5.1 TW in the 48 contiguous United States, this limit is so far above CAISO's[107] and WECC's[108] historically observed peak demand that it is deemed irrelevant to California's future resource planning needs. E3 was not able to

[106] Aas et al. The Challenge of Retail Gas in California's Low-Carbon Future – Technology Options, Customer Costs and Public Health Benefits of Reducing Natural Gas Use. 2019. https://www.energy.ca.gov/publications/2019/challenge-retail-gas-californias-low-carbon-future-technology-options-customer

[107] California ISO. California ISO Peak Load History 1998 through 2020. 2021. https://www.caiso.com/documents/californiaisopeakloadhistory.pdf p

[108] WECC. Demand: State of the Interconnection. 2021. https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/demand.aspx

Category	Tech.	Energy and Capacity Technical Deployment Limit	Rationale for Deployment Limits
Generation	CCGT + ~100% CCS	CCS Energy Limit: ~145 TWh/yr[109] Biogas Energy Limit: ~80 TWh/yr Capacity Limit: No Relevant Limit	CCS limit based on annual limit derived in Section 4.4.3. Biogas Limit Derived from data in CEC Future of Natural Gas Report[110]
	Allam Cycle CCS		
	SMR	No Relevant Limit	Likely no Relevant Physical Limits
	EGS	No Relevant Limit	5.1 TW U.S.-wide capacity limit[111] >> peak CA demand
Storage	Hydrogen	Energy Limit: 0.9-280 TWh/yr Capacity Limit: No Relevant Limit	Upper bound of energy limit dictated by CA Solar PV and onshore wind build limit in CPUC IRP RESOLVE model and RTE losses.[112] Lower bound derived from Lord et al[84] and RTE losses.
	SNG	Energy Limit: 190 TWh/yr Capacity Limit: No Relevant Limit	Energy limit dictated by CA Solar PV and onshore wind build limit in CPUC IRP RESOLVE model and RTE losses[112]
	A-CAES	Energy Limit: >= 0.0072 TWh/yr Capacity Limit: >= 0.9 GW	Limit derived from planned Hydrostor deployments; actual limit likely higher[91]
	Long-Durat. Iron-Air Batt.	Energy Limit: 450 TWh/yr Capacity Limit: No Relevant Limit	Energy limit dictated by CA Solar PV and onshore wind build limit in CPUC IRP RESOLVE model and RTE losses[112]

Table 4-3: Approximate Technical California Deployment Limits by Technology

[109] Energy Futures Initiative and Stanford University. "An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions." October 2020.

[110] Estimated using typical plant efficiencies and total (i.e. economy-wide) California renewable natural gas (RNG) potential shown in Figure 6 from: Aas et al. The Challenge of Retail Gas in California's Low-Carbon Future – Technology Options, Customer Costs and Public Health Benefits of Reducing Natural Gas Use. 2019.

determine EGS installation limits for California specifically, but it is extremely unlikely that one would reach anywhere close to California's technical resource potential in capacity expansion modeling efforts given EGS's high cost.

Further relevant operational characteristics for capacity expansion modeling are provided in Table 4-4. Relevant data sources are provided on the round-trip or one-way efficiency, ramp rate and lifetime.

4.3 Cost Comparisons

4.3.1 COST DERIVATION METHODOLOGY AND DATA SOURCES

We provide costs below for all the examined technologies. We convert these cost data from their original cost year to 2022 dollars using data from the U.S. Government's Bureau of Labor Statistics,[113] and also adjust generic costs using cost multipliers to arrive at "California-specific" costs. These cost multipliers are derived from the 2019 CPUC IRP's Inputs and Assumptions.[114]

We **do not** model the IRA's effects in this document, but will be updating the CPUC Inputs and Assumptions (I&A) document with the effects of the IRA prior to beginning the next round of CPUC IRP modeling. The IRA will not affect capital or

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https://www.energy.ca.gov/publications/2019/challenge-retail-gas-californias-low-carbon-future-technology-options-customer.

[111] C. Augustine. Update to Enhanced Geothermal System Resource Potential Estimate. 2016. https://www.nrel.gov/docs/fy17osti/66428.pdf

[112] California Public Utilities Commission. RESOLVE 2019 Reference System Plan (RSP) 46 MMT by 2030 Portfolio Scenario Tool. 2020. https://files.cpuc.ca.gov/energy/modeling/RESOLVE_TPP_PUBLIC_RELEASE_2020_12_10.zip

[113] U.S. Bureau of Labor Statistics. CPI Inflation Calculator. 2022. https://data.bls.gov/cgi-bin/cpicalc.pl

[114] California Public Utilities Commission. Inputs and Assumptions: 2019-2022 Integrated Resource Planning. 2020. https://files.cpuc.ca.gov/energy/modeling/Inputs%20%20Assumptions%202019-2020%20CPUC%20IRP%202020-02-27.pdf

O&M costs displayed below.[115] However, the IRA will have significant impacts on the levelized fixed costs of most of the technologies considered herein. Separately, the IRA will create a production tax credit (PTC) for many of the non-storage technologies. We comment further on the likely impact and relevant IRA policies for individual technologies below in Section 4.5.

Cost trajectories for conventional CCGTs and CTs, CCGTs with 90% CO2 capture, EGS, standard geothermal, nuclear SMRs, solar PV, onshore wind, and offshore wind were derived from the 2021 National Renewable Energy Laboratory's Annual Technology Baseline[116] (ATB) and E3 assumptions (cost levelization).

E3 used conventional nuclear costs from the 2021 ATB for SMR costs because the two technologies use similar light-water reactor designs, NREL's cost data are more optimistic than recent nuclear plants observed in the U.S., and NREL's costs were deemed more impartial than manufacturer data. Data from the ATB are "industry standard" costs, and typically exhibit a relatively high degree of certainty. SMR costs are available in the 2022 ATB and may be incorporated in future CPUC IRPs as necessary.

Cost trajectories for Li-ion batteries and pumped hydro are shown for comparison in figures below, and were derived from Lazard's Levelized Cost of Storage Analysis,[117] NREL's Cost Projections for Utility-Scale Battery Storage: 2020 Update

[115] There are provisions in the ATB for incentivizing U.S. and other North American-based green manufacturing factories, but it is very difficult to predict the effect on capital costs resulting from this.
[116] 2021 NREL ATB. National Renewable Energy Laboratory. Annual Technology Baseline. 2021. **https://atb.nrel.gov/**
[117] Li-ion battery costs are from Lazard's Levelized Cost of Storage Analysis v6.0. Pumped hydro costs are from Lazard's Levelized Cost of Storage Analysis v2.0; pumped hydro is not included in later versions.

(cost declines for Li-ion batteries),[118] and E3 assumptions (cost levelization). Another source of “industry standard” costs for storage are derived from Lazard’s Levelized Cost of Storage data.[119]

E3 determined fuel equipment synthesis cost and efficiency trajectories for hydrogen and SNG using work with UC Irvine that E3 first performed for a study on the future viability of natural gas in California.[120] For hydrogen to act as a long-duration storage technology, E3 assumed a combined system of hydrogen-burning aeroderivative CTs, electrolyzers, a 325-mile hydrogen pipeline, and salt-dome storage. For SNG, E3 assumed a combined system of direct air capture, electrolyzers, methane synthesis, aeroderivative conventional CTs, and underground salt-dome storage costs. E3 used NREL’s 2021 ATB to derive CT costs, utility IRP filings to determine the cost premium for CTs that can burn hydrogen,[121] assumptions on hydrogen pipeline length from Lord et al,[84] data on pipeline costs from ANL (which were normalized based on kW of peak gas flow capacity to generators),[122] data on the cost of salt domes from Ahluwalia et al,[123] and E3 assumptions on levelization and other parameters to combine these data. These data are less certain than Lazard or ATB costs, but the hydrogen costs have

[118] Cole, Wesley, and A. Will Frazier. 2020. Cost Projections for Utility-Scale Battery Storage: 2020 Update. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-75385. **https://www.nrel.gov/docs/fy20osti/75385.pdf**.

[119] Lazard. Levelized Cost of Energy, Levelized Cost of Storage, and Levelized Cost of Hydrogen. 2020. **https://www.lazard.com/perspective/levelized-cost-of-energy-levelized-cost-of-storage-and-levelized-cost-of-hydrogen/**

[120] California Energy Commission. The Challenge of Retail Gas in California’s Low-Carbon Future. 2021. **https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-F.pdf**.

[121] Public Service of New Mexico. 2020 Integrated Resource Plan. 2020. **https://www.pnmforwardtogether.com/irp**.

[122] Argonne National Laboratory. Hydrogen Delivery Scenario Analysis Model. **https://hdsam.es.anl.gov/index.php**.

[123] Ahluwalia et al. 2019. System Level Analysis of Hydrogen Storage Options. **https://www.hydrogen.energy.gov/pdfs/review19/st001_ahluwalia_2019_o.pdf**

been shown to be reasonable when compared to multiple other industry estimates.[27,28]

Cost trajectories for the Allam-Fetvedt cycle and carbon-neutral CCS technologies were derived from data found in scientific literature, E3 assumptions on levelization and other parameters, and data on the Broadwing Energy Complex.[124,125,126] These data are less certain than those for electrofuels given the less-mature nature of this technology and the reliance on fewer data sources.

Cost trajectories for long-duration iron-air batteries were informed by data from Form Energy, research by Evolved Energy Research, technoeconomic studies, and E3 assumptions on cost levelization and other parameters.[127,128,129] In particular, E3 assumed that the upper bound of capital, and fixed O&M costs displayed herein did not decline with time to reflect the uncertainty of these data, though financing assumptions do change with time. The uncertainty arises from the fact that we used Form's cost data, given the paucity of other available cost data for

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[124] Allam et al. Energy Procedia. 2017. Demonstration of the Allam Cycle: An update on the development status of a high efficiency supercritical carbon dioxide power process employing full carbon capture. **https://doi.org/10.1016/j.egypro.2017.03.1731**.

[125] Feron, P., Cousins, A., Jiang, K., Zhai, R., Thiruvenkatachari, R., & Burnard, K. (2019). Towards zero emissions from fossil fuel power stations. *International Journal of Greenhouse Gas Control*, 87, 188–202.

[126] "8 Rivers Capital, ADM Announce Intention to Make Illionois Home to Game-Changing Zero Emissions Project.". 2021. **https://www.prnewswire.com/news-releases/8-rivers-capital-adm-announce-intention-to-make-illinois-home-to-game-changing-zero-emissions-project-301269296.html**.

[127] Form Energy. Solving the Clean Energy and Climate Justice Puzzle. 2020. **https://formenergy.com/wp-content/uploads/2020/08/Form_Energy_NYGasReplaceWhitePaper_V2.pdf**.

[128] S. Sripad. The Iron-Age of Storage Batteries: Techno-Economic Promises and Challenges. 2021. **https://ecsarxiv.org/a4se8/**

[129] Evolved Energy Research, prepared for the Environmental Defense Fund. Unlocking Deep Decarbonization: An Innovation Impact Assessment. 2020. **https://www.evolved.energy/post/prioritizing-innnovation-for-decarbonization**.

this technology. E3 recommends revisiting Iron-Air battery costs once more data becomes available as they progress towards commercialization.

Cost trajectories for A-CAES were derived from data from the Pacific Northwest National Laboratory Energy Storage Cost and Performance Database,[130] data from HydroStor,[131] and E3 assumptions. As with Iron-air batteries, E3 did not assume cost declines for the upper bound of cost estimates for A-CAES, though financing assumptions change with time. Both the long-duration battery and A-CAES cost projections are the most uncertain given here, due to the lack of data sources and the use of cost and performance estimates from their respective manufacturers.

[130] Pacific Northwest National Laboratory. Compressed Air Energy Storage (CAES). 2020. https://www.pnnl.gov/compressed-air-energy-storage-caes.
[131] Hydrostor. Hydrostor 2020 Brochure. 2020. https://www.coursehero.com/file/63875505/Hydrostor-Brochure-2020pdf/.

Category	Tech.	Efficiency (One-Way or RTE, HHV)	Ramp Rate Limit	Operational Lifetime
Gen.	CCGT + ~100% CCS	~ 30% - 45%[132] (One-way)	Modeling suggests CCS has minimal impact on ramping	Equivalent to plant without CCS
	Allam Cycle CCS	~40-50%[133] (One-way)	Unknown	30 years[133]
	SMR	30%[134] (One-way)	Unknown	30-80 years[134]
	EGS	10-22% (One-way)	Unknown	30-80 years[134]
Storage	Hydrogen	H_2: 70-80% (One-way), 25-45% (RTE in CT/ CCGT)[135]	Electrolyzer: 100%/Min.[136]	20 years for electrolyzer.[137]
	SNG	SNG: 40-50% (One-way), 15-25% (RTE in CT/CCGT)[138]	Electrolyzer: 100%/Minute.[139] DAC and Sabatier reaction flexibility unknown	20 years for electrolyzer; 20-40 years for DAC and Sabatier reactor[140]
	A-CAES	60% (RTE)[141]	Unknown	30-50 years[142]
	Long-Durat. Iron Air Battery	45-50%[143] (RTE)	Unknown	Unknown

Table 4-4: Comparison of Operational Characteristics of Technologies

[132] Adding CCS leads to a ~15% reduction in efficiency versus equivalent generic CT or CCGT, per 2021 NREL ATB. National Renewable Energy Laboratory. Annual Technology Baseline. 2021. https://atb.nrel.gov/

[133] White, C. and Weiland, N. Preliminary Cost and Performance Results for a Natural Gas-Fired Direct SCO2 Plant. 2018. http://sco2symposium.com/papers2018/power-plants-applications/083_Paper.pdf

[134] International Atomic Energy Agency. Advances in Small Modular Reactor Technology Developments. 2020. https://aris.iaea.org/Publications/SMR_Book_2020.pdf

[136] Eichman et al. Novel Electrolyzer Applications: Providing More than Just Hydrogen. 2014. https://www.nrel.gov/docs/fy14osti/61758.pdf

[137] Typical system lifetime sourced from: California Energy Commission. The Challenge of Retail Gas in California's Low-Carbon Future: Appendix A-G. 2021. https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-AP-G.pdf

4.3.2 RESULTS

In order to provide the reader with representative data that can be compared to conventional technologies and that do not contain implicit assumptions about capacity factors or fuel costs, this section presents capital, fixed O&M and all-in levelized fixed costs (LFC, i.e., the combined levelized capital and non-fuel O&M costs). Table 4-5 summarizes the LFC of all the technologies modeled in this report at the indicated duration.

The capital costs, fixed O&M costs, all-in levelized fixed costs, and storage duration-adjusted LFC of storage technologies are respectively shown below in Figure 4-1, Figure 4-2, Figure 4-3, and Figure 4-4. These plots indicate that 4-hour Li-Ion batteries are significantly less expensive than all other storage technologies on a capital and LFC basis, though 4-hour Li-Ion batteries cannot provide firm capacity. Conversely, SNG is the most expensive resource on an LFC basis. Figure 4-3 indicates that the LFCs of A-CAES do not decline significantly, which is due to

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[137] Typical system lifetime sourced from: California Energy Commission. The Challenge of Retail Gas in California's Low-Carbon Future: Appendix A-G. 2021. https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-AP-G.pdf

[138] Typical CT/CCGT efficiency assumed. SNG conversion efficiency based on information from: California Energy Commission. The Challenge of Retail Gas in California's Low-Carbon Future: Appendix C. 2021. https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-AP-G.pdf

[139] Eichman et al. Novel Electrolyzer Applications: Providing More than Just Hydrogen. 2014. https://www.nrel.gov/docs/fy14osti/61758.pdf

[140] Typical system lifetime sourced from: California Energy Commission. The Challenge of Retail Gas in California's Low-Carbon Future: Appendix A-G. 2021. https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-AP-G.pdf

[141] Hydrostor. Hydrostor 2020 Brochure. 2020. https://www.coursehero.com/file/63875505/Hydrostor-Brochure-2020pdf/

[142] Hydrostor. Hydrostor 2020 Brochure. 2020. https://www.coursehero.com/file/63875505/Hydrostor-Brochure-2020pdf/

[143] Form Energy. Solving the Clean Energy and Climate Justice Puzzle. 2020. https://formenergy.com/wp-content/uploads/2020/08/Form_Energy_NYGasReplaceWhitePaper_V2.pdf

Category	Tech.	Storage Duration	High/Low All-In Levelized Fixed Cost (2022 $/kW-yr)			Primary Cost Data Sources
			2030	2040	2050	
Gen.	CCGT + ~100% CCS	n/a	$287-$350	$244-$330	$230-$309	NREL ATB,[116] Various Scientific Literature[125]
	Allam Cycle CCS	n/a	$338-$370	$297-$333	$276-$309	Various Scientific Literature[100,124,126]
	SMR	n/a	$832-$832	$787-$787	$738-$738	NREL ATB
	EGS	n/a	$783-$3,974	$756-$3,821	$731-$3,675	NREL ATB
Storage	Hydrogen	200 hrs	$257-$315	$209-$281	$190-$254	E3/UC Irvine,[106] NREL ATB, Industry,[121] HDSAM,[122] Ahluwalia et al,[123] Lord et al[84]
	SNG	1,000 hrs	$350-$457	$313-$434	$300-$415	E3/UC Irvine, NREL ATB, HDSAM, Ahluwalia et al
	A-CAES	24 hrs	$208-$234	$193-$235	$189-$237	Industry[131], PNNL[130]
	Long-Durat. Iron Air Battery	100 hrs	$210-$429	$158-$430	$111-$432	Industry,[127] Scientific Literature[128,129]

Table 4-5: All-In Levelized Fixed Costs of Technologies Considered in this Report

assumed limited deployment. Long-duration iron-air batteries, SNG and hydrogen exhibit steep cost declines, though long-duration iron-air batteries are assumed to have a higher round trip efficiency than hydrogen or SNG (see Table 4-4). These plots include pumped storage hydro and standard Li-Ion batteries as a point of comparison, though these technologies are not modeled in this report.

The duration normalized LFC of hydrogen and SNG are both low because of the very low cost of geologic storage, but the extra cost of a DAC system and a Sabatier reactor make SNG more expensive than hydrogen. The LFCs for the long-duration iron-air batteries are the third lowest in the storage category when normalized by storage duration.

There are several main takeaways from these costs:

+ With innovation and learning from additional deployment, certain long-duration storage technologies (iron-air batteries, hydrogen, and SNG) may achieve significant cost declines.
+ Installed capital and fixed O&M (Figure 4-1 and Figure 4-2) costs tend to be higher for longer-duration storage in comparison to short-duration Li-Ion batteries. However, while Li-Ion batteries provide lower-cost capacity ($/kW), long-duration storage provides lower cost energy storage capacity ($/kWh). The ability to provide long-duration storage at low cost enables more sustainable reliability contributions via firm capacity provision (at sufficiently long durations), which may overcome its higher overall $/kW costs in a low- to zero-carbon grid.

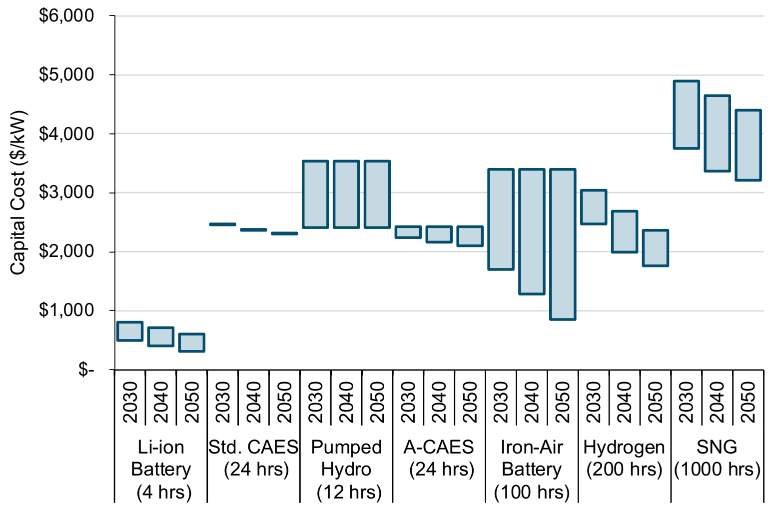

Figure 4-1: Installed Capital Cost of Energy Storage Technologies (2022 $/kW)

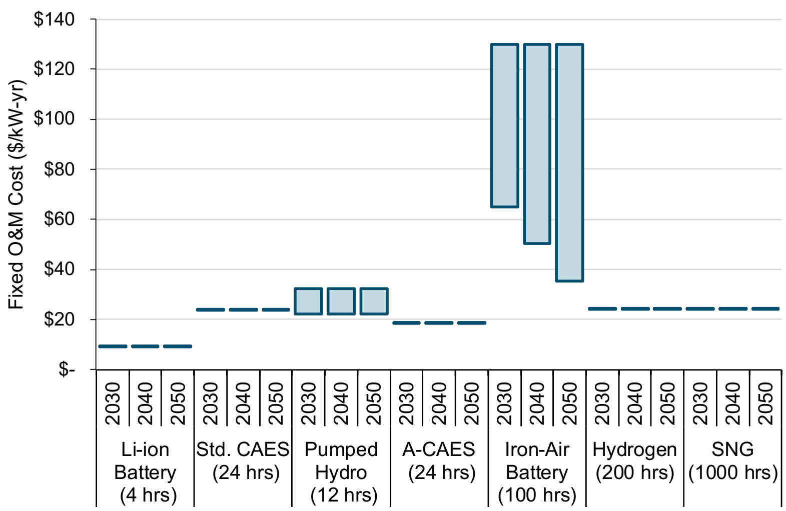

Figure 4-2: Fixed O&M Costs of Storage Technologies (2022 $/kW-yr)

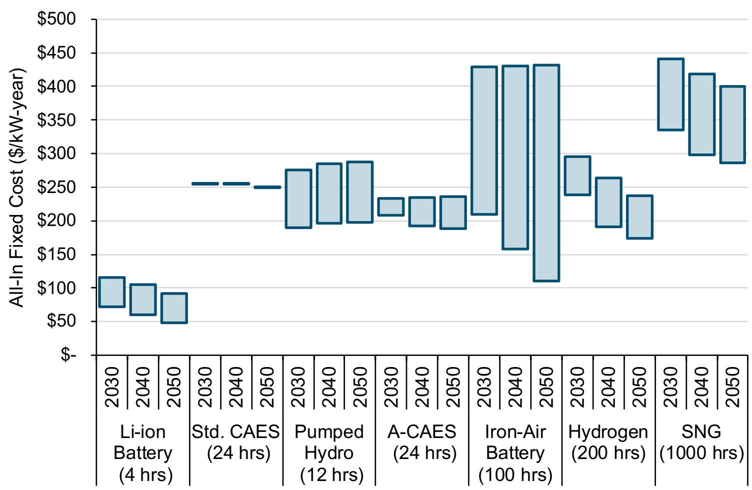

Figure 4-3: Levelized All-In Fixed Cost of Storage Technologies at Specified Duration (2022 $/kW-yr)

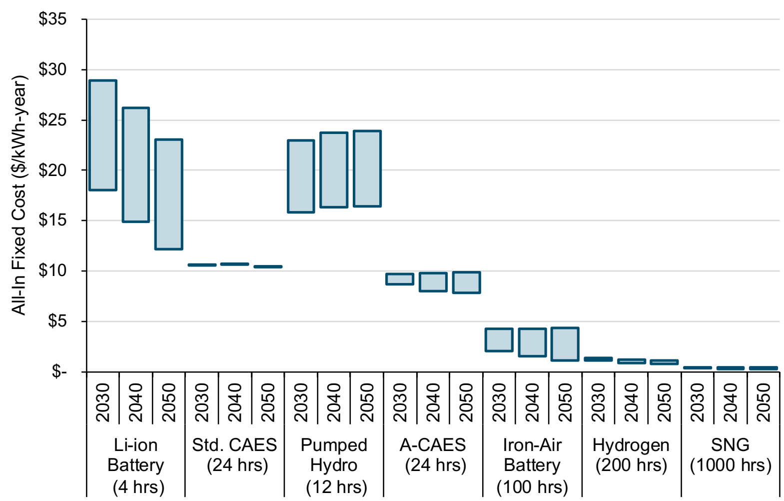

Figure 4-4: Levelized All-In Fixed Cost of Storage Technologies Specified Storage Duration, Normalized by Storage Duration (2022 $/kWh-yr)

Capital costs, fixed O&M costs, and LFCs of generation technologies are shown below respectively in Figure 4-5, Figure 4-6 and Figure 4-7. As for storage technologies, cost data for which there was less available literature (CCS technologies) have single point estimates for cost trajectories. The NREL ATB data did not have more than point estimate for SMRs. As expected, CCGTs without CCS exhibit the lowest LFCs. EGS has by far the highest costs (note break in y-axis in Figure 4-7). Standard binary geothermal is provided for comparison to SMRs and EGS and is found to have similar costs as SMRs. CCS technologies have similar cost trajectories and costs, with CCGTs with 100% CCS being slightly less expensive than AFCs, though it is difficult to say if this will be realized once more plants are deployed. These plots include conventional gas combined cycle (CC) power plants and standard geothermal as points of reference, though these technologies are not detailed in this report.

There are several key takeaways from these data:

+ Firm generators have a wide variety of costs. This is particularly true of EGS, whose very high costs could decline with intense investment in innovation (and hence are presented with a very uncertainty band), but may remain high

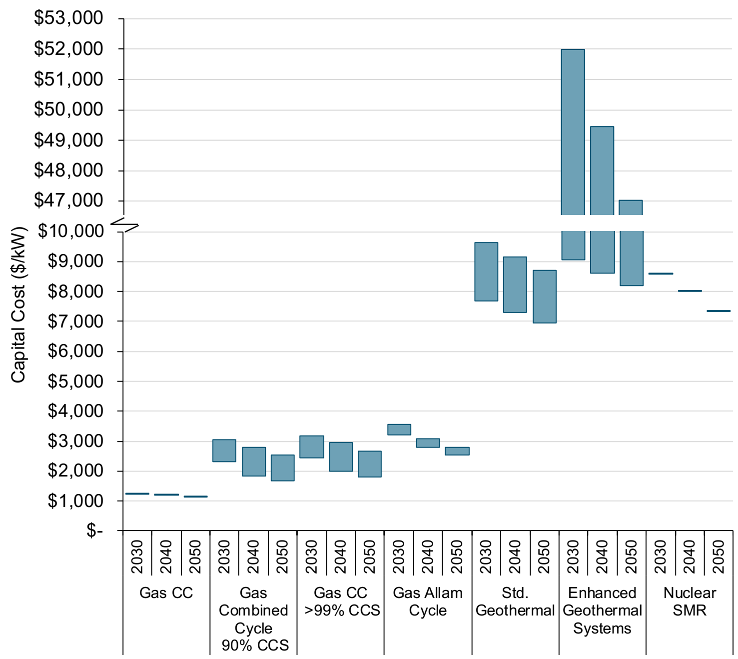

Figure 4-5: Installed Capital Costs of Generation Resources (2022 $/kW)

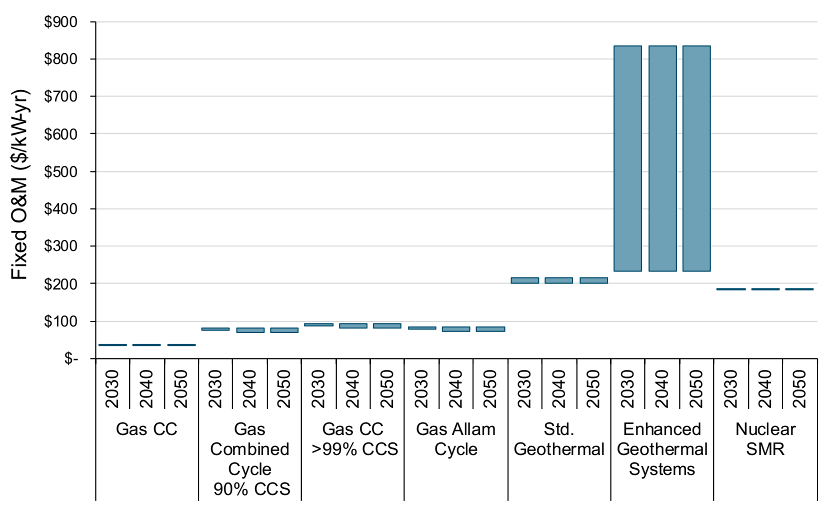

Figure 4-6: Fixed O&M Costs of Generation Resources (2022 $/kW-yr)

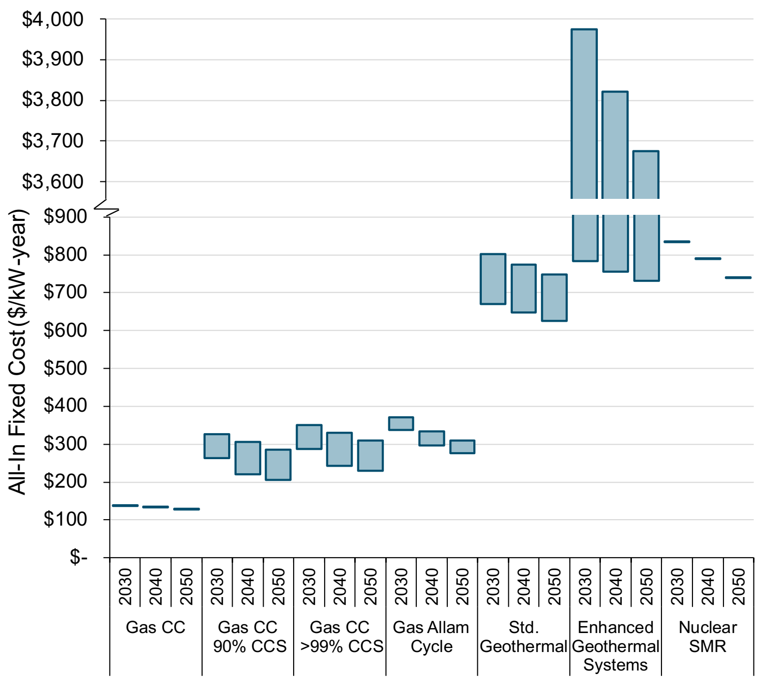

Figure 4-7: Levelized Fixed Costs of Generation Resource (2022 $/kW-yr)

+ Post-combustion CCS technologies have similar cost trajectories. Particularly, Gas CC >99% CCS plants may only represent a modest cost increase relative to CC-CCS plants that remove 85-95% of flue gas CO_2.
+ All zero-carbon firm capacity technologies are significantly more expensive than incumbent natural gas-powered CCGTs without CCS, which explains the dominance of this technology on the grid today

4.4 Infrastructure Risks and Other Considerations

The following section presents infrastructure and other risks for hydrogen, SMRs and CCS. We omitted other technologies because they either did not pose significant, unique infrastructure risks, or, as in the case of EGS, E3 could not find robust data sources with which to derive an assessment of the risks.

4.4.1 HYDROGEN TRANSPORT AND STORAGE

The high- and medium-pressure natural gas pipeline grid provides valuable peaking capacity in the electricity sector and to industrial end uses that are not easy to electrify. However, the majority of the rate base for California gas utilities is in the low-pressure distribution network, which is reflected in higher residential and commercial gas rates. The implications of this on the best deployment strategy for hydrogen pipelines is discussed in more detail in other studies.[106]

A recent UC Riverside study found that the safe limit for hydrogen blending in the California natural gas network was approximately 5% by volume (about 2% by energy), but this limit would need to be determined on a case-by-case basis through studies of hydrogen compatibility with the materials used in the pipeline network, and the stock of gas end-use appliances and industrial equipment in a gas utility's service footprint.[22] As such, it is unlikely that hydrogen blending in the natural gas pipeline system will result in significant GHG reductions. The ability to repurpose exiting natural gas pipelines to carry pure hydrogen will require feasibility studies that are beyond the scope of this work. In the more nascent stages of building a zero-carbon hydrogen market, it is likely that on-site production, or a trucking fleet and other gas storage infrastructure will need to be used to deliver gas from production sites to storage sites and end users.

Finally, recent work has shed light on hydrogen's indirect global warming potential (GWP). While hydrogen itself does not absorb and reradiate infrared radiation in the atmosphere as do direct GHGs such as CO_2, hydrogen's presence in the atmosphere is thought to slow the decay of other high GWP gases, such as methane, thus extending their warming effect. For example, Ocko and Hamburg found that Hydrogen leak rates of 10% would result in a 50% reduced short-term GHG benefit for using hydrogen in early in the early decades of deployment,[144] though this leak rate is greatly in excess of current natural gas system rates of 2-3% on a per unit energy basis.[145] Median ranges of hydrogen GWP are estimated to be roughly 15% of that of methane over both 20- and 100- year timeframes per unit energy leaked.[146] However, these findings imply that measures need to be taken to ensure that hydrogen leaks are minimized if hydrogen is used at scale, particularly for applications with boiloff losses (liquid hydrogen trucking and storage) and for applications that vent hydrogen.

4.4.2 NUCLEAR WASTE DISPOSAL

One of the most prominent challenges faced by nuclear power is spent fuel management, which would be a critical issue to address for any potential use of nuclear power in California. Since the mid-1970s, California law has forbidden the siting of new nuclear power plants until the federal government establishes a safe, long-term solution for disposal of spent nuclear fuel. With no such solution currently available, most decommissioned nuclear power plants in the US have spent fuel decaying on site with constant monitoring. The nuclear power plant decommissioning process is long and costly, potentially taking up to 60 years and

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[144] Ocko, I. and Hamburg, P. European Geosciences Union. Climate consequences of hydrogen emissions. 2022. https://acp.copernicus.org/articles/22/9349/2022/

[145] Environmental Defense Fund. What Influence will Switching to Natural Gas Have on Climate? 2020. https://www.edf.org/sites/default/files/US-Natural-Gas-Leakage-Model-User-Guide.pdf

[146] Warwick, N., Griffiths, P., Keeble, J., Acrhibald, A., Pyle, J. Shine, K. Atmospheric implications of increased hydrogen use. 2022. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1067144/atmospheric-implications-of-increased-hydrogen-use.pdf

costing more than $8 billion for California (including plants in operation and plants being decommissioned).[147] The authors of this report have not found any compelling evidence suggesting that the decommissioning process will be cheaper or less time-intensive for SMRs.[148]

The viability of SMR development in California would require the federal government to develop a safe, long-term solution for disposal of spent nuclear fuel, or a change to state law.

4.4.3 CARBON DIOXIDE TRANSPORT AND STORAGE FOR CCS

The CO_2 captured by CCS plants is typically compressed to a high-pressure, liquid state for pipeline transport or shipping, with pipelines being preferred for large amounts of CO_2 over longer distances (around 1,000 km). For permanent storage, CO_2 is injected into deep geologic reservoirs, such as oil and gas fields and saline formations, in depths below 800 meters.[47] In California, researchers from the Energy Futures Initiative and Stanford determined the potential for CO_2 transportation and storage. It was found that over 15% of emissions (corresponding to nearly 10 million metric tons) from eligible emitters, such as ethanol or combined heat and power plants, in California were within 10 miles of available geologic storage, requiring little to no transportation infrastructural development. Successful sequestration of remaining emissions (50 million metric

[147] SPUR. “Phasing Out Nuclear Power in California.” January 16, 2018. https://www.spur.org/news/2018-01-16/phasing-out-nuclear-power-california.
[148] Nuclear Energy Institute. Decommissioning Funding for Small Reactors. https://www.nrc.gov/docs/ML1030/ML103070135.pdf

tons) would require extensive development of dedicated CO_2 pipelines, with lengths up to 1,150 miles depending on the source of emissions.[149]

The risks of pipeline transport, injection, and storage of CO_2 needs to be properly understood and managed. Although there is still limited experience with geologic storage of CO_2 for climate change mitigation, natural CO_2 reservoirs and closely related industrial experience can provide a basis for risk management and remediation. The local risks associated with CO_2 pipelines could be comparable to or lower than those posed by existing hydrocarbon pipelines. Existing CO_2 pipelines, mostly located in areas of low population density, have shown low risks (e.g., very low accident numbers reported per kilometer of pipeline). Pipeline transport of CO_2 through more populated areas will require careful route selection and design choices. With appropriate site selection, monitoring, regulation, and remediation methods, local health, safety, and environmental risks of injection and geologic storage could be similar to those of current activities such as natural gas storage and enhanced oil recovery. In well-selected, designed, and managed geologic storage sites, CO_2 will be gradually immobilized through various trapping mechanisms. These storage sites could thus retain CO_2 on very long timeframes (e.g., millions of years) with minimal leakage.[47]

Temporary storage is also available if the captured CO_2 is used, for example, for enhanced oil recovery or in chemical processes that produce valuable carbon-containing products such as synthetic fuels. The use of captured CO_2 for enhanced

[149] Energy Futures Initiative and Stanford University. An Action Plan for Carbon Capture Storage in California: Opportunities, Challenges, and Solutions. 2020. https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5fda383062e28f00961c98db/1608136765723/EFI-Stanford-CA-CCS-FULL-rev2-12.11.20.pdf

oil recovery or industry is often termed “CO_2 utilization”. CO_2 utilization could potentially offer a revenue stream for carbon capture to help drive deployment, although the market for utilization would need to be comparable to the scale of CO_2 emissions for the financial incentives to be meaningful. At the moment, enhanced oil recovery could provide such a market, but is expected to decrease in size as global energy consumption continues to decarbonize. Low- or zero-carbon synthetic fuels may provide a promising future market for biomass-derived CO_2 utilization, although applications could be limited by economics and CO_2 pipeline infrastructure.

4.5 Policy Considerations

4.5.1 MARKET AND OTHER MECHANISMS TO SPEED LOW-CARBON FIRM CAPACITY TECHNOLOGY DEPLOYMENT

Various policy mechanisms are either currently in place or have been proposed that could incentivize the technologies considered herein, but further measures may be needed to encourage these technologies to enter the market.

There are multiple federal tax incentives that apply to the technologies considered in this report, many of which changed with the recent passage of the IRA. We do not model these effects in this document, but will model them in the CPUC I&A document. The relevant incentives in the IRA include:

+ 48-ITC investment tax credit (ITC) for energy storage and new nuclear[150]

[150] U.S. Congress. H.R. 5376 - Inflation Reduction Act of 2022. 2022. https://www.congress.gov/bill/117th-congress/house-bill/5376/text

- 45-PTC for solar, geothermal and new nuclear[150]
- 45Q CCS tax credit[150]
- 45V hydrogen tax credit[150]

At a high level, the IRA is likely to accelerate the deployment of SMRs, wind, solar, storage and geothermal due to the ITCs and PTCs that are now available to these technologies. We expect the levelized fixed cost of energy storage technologies to drop on the order of 25% relative to the data shown here once the 48-ITC is factored in. Additionally, there are PTC incentives that would not be captured in the capital, O&M and levelized fixed cost inputs shown here but would be captured in RESOLVE or a similar capacity expansion model.

The 45Q PTC may increase the rate of CTs and CCGTs with CCS deployed on the grid. The 45V PTC will incentivize the deployment of zero-carbon hydrogen. Finally, the IRA will allow entities with no or low tax burden to realize more benefits from these tax credits and will change the normalization rules in some cases. [150] If more nuclear, geothermal, wind, and solar are installed due to these credits, it will likely provide energy storage technologies with greater energy arbitrage opportunity. If more CCS and hydrogen generators are installed, it may reduce the value of long-duration energy storage and other forms of zero-carbon baseload generation. Many IRA provisions sunset for storage or generators constructed after 2032, but provisions providing direct incentives to renewable energy generation technologies expire once U.S.-wide grid emissions drop below 25% of their 2022 level, which E3 expects to happen in the mid-2040s. Overall, the effect of the IRA on the relative competitiveness of deploying zero-carbon firm generation technologies would need to be addressed by modeling.

4.5.2 TECHNOLOGY-SPECIFIC CONSIDERATIONS

The following section provides a detailed discussion of barriers to deploying these technologies and discusses specific measures that may incentivize deploying these technologies.

4.5.2.1 Nuclear

Under the IRA, up to a 30% ITC, or a $25/MWh PTC will be provided to new nuclear generators that begin construction from 2025-2032. This will have a substantial impact on new nuclear costs.

Public confidence in nuclear power has been low due to concerns over safety, such as leakage of radioactive materials, earthquake risks, and the risk of theft of nuclear materials leading to nuclear proliferation. Even with improved safety features in place, newer generations of nuclear technology such as SMRs could face similar public opposition.

Current California law bans new nuclear plant construction in California until a long-term nuclear waste storage facility is opened in the U.S. Despite this, out-of-state construction of nuclear power plants would potentially be an option, and could provide zero-carbon firm capacity at sites where firm transmission capacity exists. This may make sense at sites where transmission is being developed for other renewable projects (e.g. for Wyoming Wind).

Low public confidence in nuclear power could make it challenging to secure investment in SMRs, and nuclear technologies in general. The expense of maintaining plant security incurred by conventional nuclear plants would also apply to SMRs.

On the federal level, nuclear power plants are supported by the Price-Anderson Act. The Act aims to partially compensate the nuclear industry against liability claims from nuclear incidents while ensuring compensation for the general public. The Act was first passed in 1957 and currently applies to non-military nuclear facilities constructed in the US before 2026.[151]

In order for new nuclear power to be deployed in California, a long-term nuclear waste storage facility would need to be developed in the U.S., and the Price-Anderson act would also likely have to be extended, given the long lead time of new nuclear plant construction. Out of state SMR construction may require fewer hurdles, however.

4.5.2.2 CCS

CCS has received some policy support both in California and on the federal level, including eligibility under the Low-Carbon Fuel Standard (LCFS) and updated IRA tax credits provided via the 45Q. The IRA increased the 45Q, for projects that commence construction between 2023 until 2032 that meet the minimal annual CO_2 capture requirements and rates. Fossil-based systems can capture up to \$85/ton of CO_2 and DAC systems can capture up to \$185/ton CO_2.[150]

[151] Center for Nuclear Science and Technology Information. The Price-Anderson Act. 2005. https://cdn.ans.org/policy/statements/docs/ps54-bi.pdf

The LCFS and 45Q credit are policy mechanisms that provide financial incentives for eligible CCS projects, although uncertainties exist surrounding the value and duration of these incentives. The LCFS credit market can be volatile, which may cause long-term investments that require the LCFS to be solvent to be risky.[152]

The development of CCS in the state can benefit from further policy support and clarity. Regardless of the technology or capture rate, CCS is currently not included in modeling for long-term power sector planning, including SB 100 and the CPUC's Integrated Resource Plan (IRP). CARB has investigated CCS, which resulted in the development and adoption of a CCS Protocol under the LCFS.[153] To date, however, CARB has not adopted a CCS Protocol under the Cap-and-Trade program.[154]

CCS could potentially face a complex and untested regulatory process, as planning and permitting would involve multiple state agencies or jurisdictions for capture, transport, and storage processes. The regulatory complexity could lead to uncertainties in project timeline as well. In addition, similar to nuclear technologies, CCS also faces low public acceptance. Regardless of the technology, CCS by itself does not mitigate upstream environmental and climate impacts of fuel production (e.g., natural gas drilling, biomass harvesting) and transportation. Finally, CCS will need to be facilitated by the expansion of a CO_2 transportation network within California. As noted earlier in the report, just above 15% of eligible point emissions are located near geologic formations appropriate for carbon

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[152] Neste. California Low Carbon Fuel Standard Credit Price. 2022. **https://www.neste.com/investors/market-data/lcfs-credit-price**

[153] California Air Resources Board. "Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard." August 13, 2018. **https://ww2.arb.ca.gov/sites/default/files/2020-03/CCS_Protocol_Under_LCFS_8-13-18_ada.pdf**.

[154] Center for Climate and Energy Solutions. "California Decarbonization Partnership letter to CARB on Carbon Capture". July 202, 2020. **https://www.c2es.org/press-release/california-decarbonization-partnership-letter-to-carb-on-carbon-capture/**.

storage. The remaining emissions will require significantly expanding the CO_2 pipeline system to deliver captured CO_2 to a storage site.[155]

In order to overcome these barriers, CCS would need extensive policy support from state government agencies.

4.5.2.3 Long-Duration Storage

All new storage is eligible for up to a 10-year 30% ITC under the IRA that is begins construction between 2023 and 2032.

As longer durations of storage become available, a growing portion of their overall revenue stream in a Li-Ion battery-saturated market will be derived from capacity payments.[156] In order to evaluate the capacity eligibility of long duration storage technologies, proper assessment of their respective ELCCs must be performed that take into account both the duration and round-trip efficiency of a storage resource. These assessments must be updated regularly to track the declining capacity contribution of short-duration storage, and these assessments should affect resource adequacy credits to storage providers and the market compensation that ensues.

[155] Energy Futures Initiative and Stanford University. An Action Plan for Carbon Capture Storage in California: Opportunities, Challenges, and Solutions. 2020. https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5fda383062e28f00961c98db/1608136765723/EFI-Stanford-CA-CCS-FULL-rev2-12.11.20.pdf

[156] Generally, large deployments of Li-Ion batteries are expected for renewable integration. This will tend to reduce average prices on days of typical operation when either batteries or renewables are the marginal generation resource. This will increase the net cost of new entry of new firm capacity resources, because they will be unable to defray their costs by generating during high-cost hours. Capacity payments are derived as the net of the LCOE of a plant, minus its energy market earnings. Therefore, in the future, capacity payments will have to increase as a fraction of revenue for these plants.

While this report considers a specific type of long-duration storage, the CPUC's recent order for 1 GW of storage with greater than 8 hours of duration will provide a technology-neutral means to spur the deployment of long duration storage broadly.[157]

4.5.2.4 Electrofuels

Under the IRA's section 45V, hydrogen generation that begins construction between 2023 and 2032 will now be eligible for up to a \$3/kg incentive so long as the energy emissions upstream of the electrolyzer do not exceed 0.45 kg CO_2/kg hydrogen. The maximum tax credit amounts to approximately \$22/MMBTU, which is a substantial portion of the current modeled price of green hydrogen (typically on the order of \$30/MMBTU in 2022 in regions with good solar and wind resources, including geologic storage and short pipeline costs).[25] Electrolyzer operators can use RECs to offset the emissions of the electricity they consume.

At present, processes that *combust* zero-carbon hydrogen would not count as RPS-eligible in California, though using the same fuel in fuel cells would count as RPS-eligible.[158]

It is likely that geologic storage of hydrogen and SNG will be significantly less expensive than other means to store hydrogen,[123] and gas pipelines pose a much lower cost for hydrogen transportation at scale than other means.[122] However, pipeline network and underground storage construction is very expensive and only enables low costs when hydrogen demand exists at scale, and at high

[157] See Decision 21-06-035. https://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=389603637
[158] California Energy Commission. Renewable Portfolio Standard Eligibility Guidebook, Ninth Edition. 2017.

pipeline utilization rates. This may pose challenges while hydrogen demand for power generation is in a more nascent stage.

4.5.2.5 Enhanced Geothermal Systems

Under the IRA, all geothermal projects are now eligible for up to a $25/MWh PTC for plants that begin construction between 2023 and the greater of 2032 and the year at which U.S. electricity grid emissions reach 25% of their 2022 annual level. This same policy applies to wind and solar.

The challenges facing EGS, and the high degree of technological overlap with hydraulic fracturing, means policies that partner EGS firms with California's existing oil and gas industry may speed EGS development. Furthermore, de-risking EGS deployment at existing sites through, e.g., loan guarantees, may serve as a means to drive innovation while offsetting the aversion to risk from project developers. However, given the uncertainty of the financial viability of EGS, this report suggests that EGS may be a lower priority to characterize in capacity expansion modeling than other zero-carbon firm capacity technologies.

4.5.3 TECHNOLOGICAL DEVELOPMENTS THAT COULD DISRUPT THE DEPLOYMENT OF ZERO-CARBON FIRM CAPACITY RESOURCES

Broadly speaking, the weakness of each technology detailed in this report is their low TRL, and the risk that they are prevented from increasing their TRL by a competing resource option. Technological advancements for any competing zero-carbon firm capacity technologies not specifically considered in this report would potentially also be disruptive.

Improved means of scaling up sustainable carbon-neutral biomass fuels could potentially allow existing CCGT and CT resources to continue to operate in California. Alternatively, biomass gasification with CCS could be used to generate CO_2-negative hydrogen. This hydrogen could be used in the transportation and industrial sectors as a low-cost way to achieve negative emissions. This in turn may allow one to avoid fuel switching of natural gas CTs and CCGTs in the power sector.[159] Furthermore, other forms of energy storage, high temperature nuclear reactors, or very inexpensive fuel cells could also respectively disrupt the deployment of the technologies detailed in this report.

[159] Princeton University Net Zero America Interim Report. 2021. https://netzeroamerica.princeton.edu/img/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf

5 Recommendations on Incorporation of Technologies into IRP

Past California resource planning studies have shown that the incremental costs of reaching a low carbon electric system are generally modest as continued declines in solar, storage, and wind power costs enable steeper carbon reductions beyond 2030, but can grow at very deep levels of decarbonization. The technologies surveyed in this report represent potential options to contribute to further reductions of electric sector emissions while reducing a potentially costly and challenging overbuild of renewable and storage resources. Therefore, it is increasingly important to integrate them into the state's integrated resource planning processes as appropriate as the state continues to consider even more aggressive electric sector carbon reduction pathways in future planning cycles.

Many of the technologies discussed in this report can be classified as "emerging technologies" that still face commercialization challenges based on policy, cost, supporting infrastructure needs, and other key uncertain variables. Therefore, key variables to consider when incorporating them into resource planning include:

+ **Technical and operational characterization**: while some technologies have relatively simple operating characteristics that adapt easily into existing modeling tools (such as small modular nuclear reactors), other technologies (such as long-duration storage and power-to-gas) may require further capacity expansion model development to support accurate operational representation of both dispatch and reliability contributions across the planning horizon. The operational characteristics contained in this report can be used as inputs for future CPUC IRP modeling efforts.

+ **Technology screening based on operational characteristics**: as illustrated in the range of technologies included in this report, there are multiple technologies that provide the same types of services (e.g., long-duration storage and SMRs both provide clean firm capacity). An aggregation process may need to be utilized in capacity expansion modeling to ensure a diverse range of technologies with respect to operating characteristics and services provided while maintaining a tractable number of scenarios and realistic model runtime. A "screening" framework could also be developed to help determine which technologies have reached sufficient maturity to include in IRP analysis. Figure 5-1 below shows a framework that can be applied whereby technologies can be characterized and screened by standardized method (such as defining a TRL threshold for each category).

Figure 5-1 below shows a high-level framework for considering emerging technologies in long-term planning that may be useful for the CPUC IRP process to consider. It broadly groups technologies into three categories (mature, emerging, and experimental), though additional categories could be added if more distinctions are useful. It suggests that resource planning studies should consider emerging technologies in a manner that informs least-regrets planning but does not rely on them in core scenarios that guide near-term investment decisions.

Figure 5-1. E3's Emerging Technology Planning Framework

Emerging Technology Planning Framework

	Experimental	Emerging	Mature
Market Experience	No development	Limited development	Fully commercialized
Data: Costs	Theoretical (no real-world cost data)	Limited, possible near-term costs but speculative cost trajectories	Available (documented near-term costs and established trajectories)
Data: Potential	Theoretical	Limited	Available
Data: Operating Characteristics	Theoretical	Limited	Available
Examples	Advanced geothermal, novel long-duration battery storage technologies	Gas w/ CCS, advanced nuclear (e.g., modular reactors), direct air capture, BECCS, H_2 combustion / P2G	Solar, wind, battery storage, fossil gas
Proposed Approach	Do not model due to lack of data	Model in sensitivity scenarios	Model in all scenarios
Impact	***Informs R&D spending, pilot projects***	***Informs least-regrets planning, stranded asset risk***	***Drives results + near-term decision making***

E3 recommends that the CPUC IRP consider how an emerging technology planning framework that screens emerging technologies into the mature, emerging, and experimental categories based on their technology readiness level could be incorporated into future scenario design. Capacity expansion modeling of these resources will help to inform under what scenarios they become part of the optimal CAISO resource portfolio and enable the ability to more robustly model a zero-carbon electric system. "Least-regrets" planning can be utilized to compare how resource additions (such as the pace and scale of new solar, wind, short-duration storage, and transmission) and resource retirements (such as the scale and pace of natural gas plant retirements) change in different scenarios that include different sets of emerging technologies.

6 Conclusions

This report details cost estimates for various zero carbon firm capacity resources. The amount of these resources that would be built by capacity expansion modeling is likely to be less than their technical resource potentials. All technologies require significant levels of R&D to be deployed on the grid beyond present demonstration scale.

It is the intention that this report provides background and inputs for emerging zero-carbon technologies that could be added to capacity expansion models. Incorporating these data into such models would require a balance of aggregating similar technologies while maintaining sufficient diversity in technologies modeled to achieve tractable simulation and project timelines. Additionally, inclusion of these resources would have to be done in a way that recognizes the emerging nature of these resources so as not to recommend over-reliance on emerging technologies that are not yet commercialized.

Given the uncertainty around the cost and commercialization trajectories of the technologies considered in this report, E3 recommends revisiting this analysis in future years in order to keep the CPUC IRP process abreast of the latest technological advancements in the field.