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TECHNO-ECONOMIC ANALYSIS OF GREEN HYDROGEN ENERGY STORAGE IN A CRYOGENIC FLUX CAPACITOR

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ABSTRACT

The Cryogenic Flux Capacitor (CFC) is a cold, dense energy storage core that is being studied in the cryo-compressed, about 300 bar and 80K, region of gaseous hydrogen (GH_2) storage and liquid hydrogen (LH_2) region near the normal boiling point. Hydrogen storage is improved by physically bonding the molecules within the nanoscale pores of the aerogel composite blanket material. The process of bonding or debonding is governed by principles of physical adsorption (physisorption) and thermodynamics. The large surface area afforded by the nanoporous aerogel (~1,000 m^2/g) allows its storage performance to easily exceed capacities of high-pressure GH_2 storage for an equivalent volume. With the integrated aerogel, subscale tests have shown that storage is increased by about 36% over a simple tank filled with GH_2 at the same operating temperature and pressure. For LH_2 conditions, the CFC is shown to operate at improved densities, but testing is ongoing.

For the techno-economic analysis (TEA), the source of hydrogen is compared between onsite steam methane reforming (SMR) and onsite solar photovoltaic (PV) panels providing power to electrolyzers to produce green GH_2. The TEA compares pure hydrogen produced at a small scale for a 25 MW power system and at a large scale in a 500 MW power system. The system allowed for hydrogen imports and exports at a set price with a tank sized for 10 hours of power production. The two power producing technologies are a combined cycle gas turbine (CCGT) and hydrogen fuel cells. The SMR system uses natural gas as an input and includes a carbon capture and storage (CCS) system. The levelized cost of electricity (LCOE), levelized cost of hydrogen (LCOH), and levelized cost of storage (LCOS) are developed based on the capital cost and operating cost of the systems.

The results are shown for current costs using a 2021 benchmark and DOE projections for cost improvements by 2030. The TEA showed that onsite hydrogen generation from SMR has an LCOH of about 1.4 to 2 USD per kg over the life of the plant and the PV hydrogen production LCOH is about 5.2 to 5.5 USD per kg. The LCOS of conventional GH_2 systems is estimated to be $210/MWh and cost of storage for LH_2 systems is $205/MWh for fuel cell systems and $249/MWh for CCGT systems. CFC improved the LCOS of all these systems to $198/MWh, $191/MWh and $233/MWh respectively. The LCOE also improved with conventional systems between $171/MWh and $228/MWh improved by CFC to between $167/MWh and $212/MWh. Using projections for improvement in costs following DOE's goals by 2030, green hydrogen improved to as low as $78/MWh LCOS and LCOE for conventional cases. CFC improved over conventional storage with the lowest LCOS being $62/MWh and the lowest LCOE being $73/MWh. These results correspond to an LCOH of $2/kg. Finally, the TEA shows how LCOE is improved for hydrogen conditioning and storage over conventional systems and caverns in the 10 to 50 hour range.

NOMENCLATURE

AACE	American Association of Cost Engineering
CCS	Carbon Capture and Sequestration
CFC	Cryogenic Flux Capacitor
DOE	Department of Energy
FC	Fuel Cell
GH_2	Gaseous Hydrogen
CCGT	Gas Turbine Combined Cycle

LCOE	Levelized Cost of Electricity
LCOH	Levelized Cost of Hydrogen
LCOS	Levelized Cost of Storage
LH_2	Liquid Hydrogen
LHe	Liquid Helium
LN_2	Liquid Nitrogen
NASA	National Aeronautics and Space Administration
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
PV	Photovoltaic
SAM	System Advisor Model
SMR	Steam Methane Reforming
TEA	Techno-economic Analysis

1. INTRODUCTION

The CFC broadly fits into the need for energy on a grid that has a high penetration of renewables. The stored energy for the CFC technology is represented by a stored mass of hydrogen physically bonded within the nanoscale pores within the aerogel composite blanket material, and the process of bonding or debonding is governed by principles of physical adsorption (physisorption) and thermodynamics. The large surface area afforded by the nanoporous aerogel (~1,000 m^2/g) allows for storage densities close to, or in some cases exceeding, that of normal boiling point liquids. Its performance easily exceeds what can be achieved via ambient temperature, high-pressure gas storage for an equivalent volume. CFC storage is predicted to be easily scalable, is constructed from readily available commercial materials, lends itself to a range of pressure applications, and is geometry insensitive.

The CFC design was originally developed by the team at the National Aeronautics and Space Administration (NASA) to provide a better way for storing cryogenic fluids using physisorption. The behavior of the storage system is similar to a gas container because it fills the entire volume with a cold gas, auto-pressurizing as it is warmed up. the physisorption process effectively compacts the gas molecules and densities of storage approaching LH_2 density can be achieved [1]. The CFC can also be used in modular designs, as shown in Figure 1, affording even more flexibility for potential deployment.

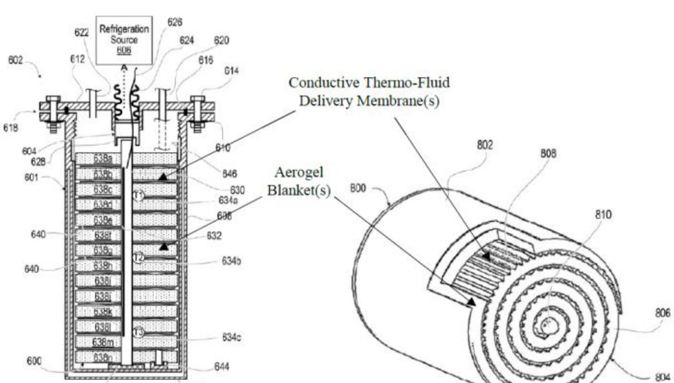

FIGURE 1. CFC PATENTED DESIGN PROTOTYPES [2]

In addition to the aerogel adsorbent within the blanket material, a CFC includes thermally-conductive membrane layered with the aerogel, which acts as a large-area, quick-response thermal management system. The system conducts heat throughout the volume to discharge the unit quickly. This same thermal management system can also be connected to a refrigeration system, or cold fluid such as liquid nitrogen (LN_2), neon, or helium (LHe) for even lower temperatures, to facilitate the charging up of the CFC. The charging and discharging rate can be set by controlling the cooling or heating supplied to the CFC.

This paper develops a TEA based on the microgrid and grid-scale applications of the technology for energy storage. The target profile is a baseload paired with intermittent renewables. The System Advisor Model (SAM) was used to model PV production based on NREL baselines.

1.1 Past Experimental Work

The team designed and manufactured the CFC, using LN_2 as the primary cooling fluid. Results were compared to data from previous NASA work. Figure 2 shows the experimental setup for the designs for the larger laboratory tests. Pressure containment of 25 bar was the on-design rating for the CFC vessel. The vessel is 53 liters in volume, assembled from 304 stainless steel, about 2 feet in length, and is sealed at the top by a 300# blind flange. The thermal management system has LN_2 passages that maintain the internal temperature at the desired value. The CFC system for the tests was constructed by layering a commercial silica aerogel, such as Cryogel® from Aspen Aerogels, with the thermal management network. Even though the minimum temperature for storage in the completed tests is 77K, which is readily and inexpensively available for an eventual commercialization process, future studies may look at the trade-off between a lower storage temperature and the techno-economic impacts of achieving denser storage.

FIGURE 2. TEST VESSEL WITH LIQUID NITROGEN CONNECTED TO COOLING CHANNELS

Figure 2 shows LN_2 being fed from a Dewar to the internal cooling channels. During chill-down, nitrogen leaves the CFC as a gas from the cooling channel vent. The operator noted during commissioning that the vent would eventually begin to emit small droplets of LN_2, indicating that the cold-mass was completely chilled and mostly filled with liquid. Thus, the internal cooling system was mostly at a constant temperature because the cooling is typically from the latent heat of vaporization. The coolant flow rate was controlled during loading of the hydrogen gas, and sustained holding of stored material, such that small amounts of LN_2 were emitted at the vent. Pressures and temperatures were also monitored to confirm this method of operation, creating an internal steady-state. The first cooling test used about 230 liters of LN_2.

Based on the results of testing at multiple scales, an improvement in storage is expected to be between 25-36%. This is the total stored mass compared to if the vessel had been filled with only hydrogen and had been brought to temperature and pressure. In the case of the vessel, the achieved stead-state CFC temperature and pressure was 115K and 20 bar. The density of hydrogen at these conditions is 4.42 g/L. The CFC stored 421.2g of hydrogen, which has an equivalent density of 5.54 g/L, a 25.3% increase.

2. COMMERCIAL APPLICATION SCENARIOS

The team assessed application scenarios for the use of hydrogen energy storage. In order to compare against dispatchable fossil technology, the team also examined SMR. The scales examined were 25 MW of baseload power produced, which corresponds to a micro-grid scenario, and 500 MW of baseload power produced, which is utility grid-scale. For the purposes of this analysis, the term "conditioning" is used to indicate a process performed on the atmospheric hydrogen coming from production. The SMR produced hydrogen requires some pressurization to be delivered to the power source, so the conditioning is pressurized GH_2. The electrolyzer produced hydrogen is stored in different ways. For commercial GH_2 storage in the microgrid system, the conditioning is pressurization up to 700bar and cooling. For commercial LH_2 at the utility grid-scale, the hydrogen must be cooled and liquified to 20K. For CFC, the hydrogen conditioning is refrigeration to 77K.

Two typical fossil assets are examined. For SMR, natural gas is a feedstock in addition to steam, as shown in Figure 3. The fuel cell (FC) is used as an efficient converter of hydrogen to power at the 25 MW scale. A 500 MW CCGT is used to assess grid-scale costs. Note that FC could be used at grid scale, but due to their modular nature, they do not typically see the advantages in cost scaling that a CCGT system does. Furthermore, CCGT systems exist that could be converted to hydrogen in a low-cost retrofit solution, although that is not examined here. The SMR basic process is the conversion of steam and natural gas to hydrogen and CO_2. Hydrogen is delivered to the power producer, and water is recovered and boiled to steam for the reformer. Power produced to the grid from a FC must go through an inverter.

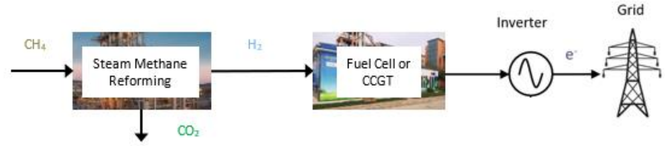

FIGURE 3. SMR POWER PRODUCTION PROCESS

The renewable energy process is more complex, as shown in Figure 4. The low cost of PV solar is advantaged whenever it meets load. Whenever the baseload is exceeded, the electrolyzers produce green hydrogen, which is then conditioned or stored. The hydrogen from storage is then used to produce power whenever PV does not meet baseload. The basic process can be described as producing solar, storing the excess using an electrolyzer and conditioning it, and then using the excess to produce power when solar is not available.

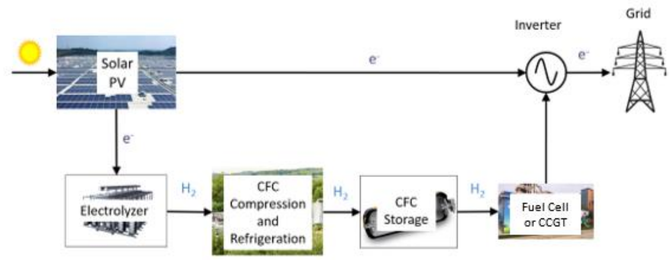

FIGURE 4. SOLAR PV WITH HYDROGEN ENERGY STORAGE PROCESS

One aspect of this approach is that without large, expensive storage tanks, it is difficult to meet all the energy demands. It was estimated that more than 100 hours of storage would be needed with a very large solar field to supply enough hydrogen to make the system completely cover baseload. The team was also directed to examine storage vessels for 10 hours, to line up with common energy storage duration sizing. Thus, in order to meet baseload, a hydrogen market mechanism was introduced. If the storage tank was ever near empty, hydrogen would be purchased from the market. If it were ever near full and extra hydrogen was produced, it would be exported to the market. The team adopted a fixed-price agreement approach to hydrogen importing and exporting. For near-term system costs, \$6/kg was adopted over the life of the plant. For a plant built in 2030, \$2/kg was the fixed price of hydrogen. When targeting a system design to settle on, the team wanted to ensure the LCOH after production and conditioning was 10% less than the market price. This drove up the cost of electricity by small amounts as larger solar and electrolyzer systems were required to ensure sufficient hydrogen production to keep the costs down.

3. DEVELOPMENT OF CAPITAL AND OPERATING COSTS

The scaling of the cost of installed equipment is done with the relationship shown in Equation 1. This is derived from the work of Weiland, et al [3]. Some equipment scales more than others; in fact, scale factors are very near 1 for a variety of equipment studied, meaning linear scaling with no benefit to cost by installing at a larger scale.

$$Capital\ Cost = Fit\ Coefficient * \left(\frac{Size}{Basis\ Size}\right)^{Scale\ Factor} \quad (1)$$

Equation 2 shows how costs are used to calculate a levelized cost of electricity. This is a commonly used equation for DOE baselines and similar analyses. The net present value (NPV) takes the 30-year cash flow for the life of the plant and brings it to first year values using a discount rate. Equation 2 defines the LCOE, which is the total NPV of plant costs over the NPV of total electricity produced by the plant over the 30-year period. The study also examines the LCOH, which is the NPV of solar, electrolyzer, and conditioning costs over the NPV of total hydrogen produced. The LCOS is also analyzed for the system, which is the NPV of the costs of the electrolyzer, conditioning, storage, and power dispatch costs over the NPV of the power produced only by the storage system.

$$LCOE\ \left(\$/_{MWh}\right) = \frac{Capital\ Cost\ (\$) + NPV\ Electric\ and\ Fuel\ Costs (\$) + NPV\ O\&M\ Costs\ (\$)}{NPV\ Generation\ (MWh)} \quad (2)$$

The cost and performance parameters were derived from literature in most cases, and both cost and performance typically came from the same source. Sources for SMR equipment and hydrogen compressors are from the DOE baseline on fossil-based hydrogen production [4]. CCGT cost and performance were defined in the DOE baseline on coal and gas power generation [5]. Fuel cell, electrolyzer, and GH_2 compression information was found in the DOE grand challenge report for 2022. The selection of 10 hours of storage was also derived from the grand challenge report, as a comparison for energy storage applications [6]. Cost and performance, including the necessary parameters to run a System Advisor Model and produce a solar profile for the model, were from the NREL PV baseline [7]. For renewable systems, this profile was used to meet a baseload profile. This meant either producing Parameters regarding GH_2 Storage, LH_2 Liquifying, and LH_2 Storage were derived from past papers from NREL [8]. The cost and performance for CFC refrigeration were calculated from the work of Green [9]. Typical scale factors for estimating the capital costs of various plant areas are from the work of Healey [10]. Estimates of engineering procurement and construction (EPC) costs are taken from DOE baselines and reports [4-7].The current cost of natural gas was taken from DOE baselines and is \$4.42/MMBTU [4-5]. The team estimated the cost of the disposal of CO_2 to be \$8/tonne, whether by tax or market, based on the work of Kearns [11].

PV location, performance, and financial parameters needed to complete the LCOE analysis were derived from the NREL baseline [7], such as, the loan interest rate of 5.06%, financing percentage of 50%, 20 year payback period, 9.51% nominal discount rate, and 6.52% real discount rate. The nominal discount rate is applied to all currency-related NPV analyses because it includes the inflation rate. Real discount rates were applied to the LCOE, LCOS, and LCOH, per NREL guidance on which rate to use for systems with longer periods of analysis [7]. System performance parameters are summarized in Table 1.

TABLE 1. PERFORMANCE PARAMETERS FOR MAJOR EQUIPMENT

System	Parameter	Value
SMR	Conversion Rate	0.267 (kg_{H2}/kg_{NG})
SMR	Power Requirement	2.02 kWh/kg_{H2}
SMR	CO_2 Production Rate	9.6k (kg_{CO2}/kg_{H2})
Solar PV	Efficiency	19%
Electrolyzer	Conversion Rate	54.3 kWh/kg_{H2}
Fuel Cell	Conversion Rate	26.0 kWh/kg_{H2}
CCGT	Conversion Rate	19.8 kWh/kg_{H2}
GH_2 Compression and Cooling	Power Requirement	5.01 kWh/kg_{H2}
LH_2 Liquefier	Power Requirement	10.0 kWh/kg_{H2}
CFC Refrigeration	Power Requirement	7.82 kWh/kg_{H2}
CFC Compression	Power Requirement	2.02 kWh/kg_{H2}

4. ANALYSIS RESULTS

The financial inputs and TEA results for present costs of fossil hydrogen systems are shown in Table 2.

TABLE 2. INPUTS AND TEA RESULTS FOR CURRENT FOSSIL HYDROGEN SYSTEMS

	SMR GH_2 25MW FC	SMR GH_2 500MW CCGT
SMR Capacity Cost (\$/kg/hr)	109,537	41,092
H_2 Conditioning Capacity Cost (\$/kg/hr)	1,041	542
Dispatch Capacity Cost (\$/kW_{AC})	1,320	952
SMR Capacity (kg/hr)	961.5	25,252.5
H_2 Conditioning Capacity (kg/hr)	961.5	25,252.5
Dispatch Capacity (MW_{AC})	25.0	500.0
CAPEX SMR	\$105.3 M	\$1,037.7 M
CAPEX H_2 Conditioning	\$1.0 M	\$13.7 M
CAPEX Dispatch	\$33.0 M	\$476.0 M
EPC and Owner's Costs	\$22.3 M	\$244.4 M
Total CAPEX	**\$161.6 M**	**\$1,771.7 M**
OPEX SMR	\$2.9 M	\$77.5 M
OPEX H_2 Conditioning	\$0.0 M	\$0.3 M
OPEX Dispatch	\$1.0 M	\$14.3 M
Total OPEX	**\$4.0 M**	**\$92.0 M**

	SMR GH_2 25MW FC	SMR GH_2 500MW CCGT
Annual Payment for 20-year Financing	$5.8 M	$63.3
Hydrogen Production ($tonne_{H2}$)	7,160	188,030
Net Annual Cost of Fuel ($)	$5.9 M	$154.5 M
Sequestration Cost	$0.5 M	$14.4 M
Levelized Cost of Unconditioned H_2 ($/kg)	2.03	1.38
Levelized Cost of Conditioned H_2 ($/kg)	**2.04**	**1.38**
Combined System LCOE ($/MWh$_{AC}$)	**125.1**	**113.8**

4.1 Natural Gas Price Sensitivity

After completing the LCOE estimates, the team explored the market impact of the variability of natural gas and CO_2 disposal cost. Nominal costs are the same as the results from Figure 7. The range of natural gas prices was taken to be between $1.93/MMBTU to $6.75/MMBTU based on historical data from Henry Hub pricing. The range of CO_2 disposal cost is taken to be $7/tonne to $10/tonne [11]. With this variation a range of LCOE is calculated for SMR and shown in Figure 5.

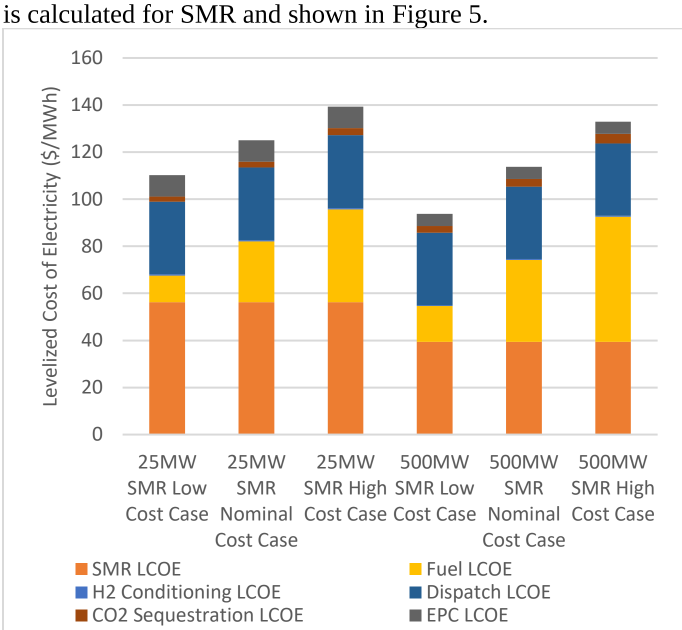

FIGURE 5. VARIATION IN SMR COSTS WITH CHANGES IN NATURAL GAS AND CO2 COSTS

Notably, even in the lowest cost case for 500MW, the costs are still not lower than the LCOE for a CCGT with CCS [5]. This analysis does not consider future costs of SMR. However, given that the process is a mature technology and precluding any disruptive technological development, future improvements may be incremental. With that in mind, the lowest cost case for SMR is $94 at the 500MW scale, assuming low cost of natural gas and hydrogen. This corresponds to a LCOH of $1.03/kg$_{H2}$.

4.2 Present Cost Renewable System Results

The analysis of renewable systems was completed, iterating on the size of the solar field until the LCOH targets were met at 10% below the fixed purchase price. The TEA input and results for commercial systems are shown in Table 3. When comparing renewable to fossil hydrogen, the variation in fossil is still below present-day renewable costs.

TABLE 3. INPUTS AND TEA RESULTS FOR CURRENT COMMERCIAL RENEWABLE HYDROGEN SYSTEMS

	Elec. GH_2 25MW FC	Elec. LH_2 500MW FC	Elec. LH_2 500MW CCGT
Solar Capacity Cost ($/kW$_{DC}$)	1,000	990	990
Electrolyzer Capacity Cost ($/kW$_{DC}$)	1,316	1,316	1,316
H_2 Conditioning Capacity Cost ($/kg/hr)	15,606	13,833	13,833
Storage Capacity Cost ($/$tonne_{H2}$)	822,000	577,922	,922
Dispatch Capacity Cost ($/kW$_{AC}$)	1,320	1,320	952
Solar Field Capacity (MW$_{DC}$)	167.5	3,752.0	4,422.0
Electrolyzer Capacity (MW$_{DC}$)	104.4	2,214.1	2,695.4
H_2 Conditioning Capacity (kg/hr)	1,922.7	40,775.5	49,639.8
Storage Capacity ($tonne_{H2}$)	9.6	192.3	252.5
Round Trip Efficiency (%)	**43.8%**	**40.4%**	**30.8%**
CAPEX Solar Field	$167.5 M	$3,714.5 M	$4,377.8 M
CAPEX Electrolyzer	$137.4 M	$2,913.8 M	$3,547.2 M
CAPEX H_2 Conditioning	$30.0 M	$564.0 M	$686.7 M
CAPEX Storage	$7.9 M	$111.1 M	$145.9 M
CAPEX Dispatch	$33.0 M	$660.0 M	$476.0 M
EPC and Owner's Costs	$60.1 M	$1,274.2 M	$1,477.4 M
Total CAPEX	**$435.9 M**	**$9,237.6 M**	**$10,711.0 M**
OPEX Solar Field	$1.7 M	$37.1 M	$43.8 M
OPEX Electrolyzer	$1.1 M	$23.3 M	$28.4 M
OPEX H_2 Conditioning	$0.6 M	$11.3 M	$13.7 M
OPEX Dispatch	$0.3 M	$19.8 M	$14.3 M
Total OPEX	**$3.6 M**	**$91.5 M**	**$100.2 M**
Annual Payment for 20-year Financing	$15.6 M	$330.0 M	$382.7 M

	Elec. GH_2 25MW FC	Elec. LH_2 500MW FC	Elec. LH_2 500MW CCGT
Hydrogen Imports ($tonne_{H2}$)	2,206	56,615	73,081
Hydrogen Exports ($tonne_{H2}$)	1,339	31,063	36,029
Hydrogen Production ($tonne_{H2}$)	3,391	73,173	91,031
Net Annual Cost of Fuel ($)	$5.2 M	$153.3 M	$222.3 M
Levelized Cost of Unconditioned H_2 ($/kg)	5.15	5.14	5.09
Levelized Cost of Conditioned H_2 ($/kg)	**5.61**	**5.51**	**5.45**
$LCOE_{DC}$ Solar Field ($\$/MWh_{DC}$)	**44.2**	**43.8**	**43.8**
Total LCOS ($\$/MWh_{AC}$)	**210.8**	**204.7**	**249.4**
Combined System LCOE ($\$/MWh_{AC}$)	**170.9**	**191.0**	**228.1**

CFC inputs and TEA results for current systems are shown in **TABLE 4**. The primary changes between cases are the round trip efficiency, cost of storage, and cost of conditioning. Changes in performance also impact the required solar field size. Overall, CFC provides improvements in LCOE and LCOS over commercial renewable systems, but does not approach the lower cost of fossil generated hydrogen.

TABLE 4. INPUTS AND TEA RESULTS FOR CURRENT CFC RENEWABLE HYDROGEN SYSTEMS

	Elec. CFC 25MW FC	Elec. CFC 500MW FC	Elec. CFC 500MW CCGT
Solar Capacity Cost ($\$/kW_{DC}$)	1,000	990	990
Electrolyzer Capacity Cost ($\$/kW_{DC}$)	1,316	1,316	1,316
H_2 Conditioning Capacity Cost ($/kg/hr)	8,647	3,135	2,948
Storage Capacity Cost ($\$/tonne_{H2}$)	577,898	577,898	577,898
Dispatch Capacity Cost ($\$/kW_{AC}$)	1,320	1,320	952
Solar Field Capacity (MW_{DC})	174.2	3,484.0	4,020.0
Electrolyzer Capacity (MW_{DC})	101.4	2,027.5	2,413.7
H_2 Conditioning Capacity (kg/hr)	1,867.0	37,339.6	44,451.9
Storage Capacity ($tonne_{H2}$)	9.6	192.3	252.5
Round Trip Efficiency (%)	**40.5%**	**40.5%**	**30.9%**
CAPEX Solar Field	$174.2 M	$3,449.2 M	$3,979.8 M
CAPEX Electrolyzer	$133.4 M	$2,668.2 M	$3,176.5 M
CAPEX H_2 Conditioning	$16.1 M	$117.0 M	$131.1 M
CAPEX Storage	$5.6 M	$111.1 M	$145.9 M
CAPEX Dispatch	$33.0 M	$660.0 M	$476.0 M
EPC and Owner's Costs	$58.0 M	$1,120.9 M	$1,265.5 M
Total CAPEX	**$420.3 M**	**$8,126.5 M**	**$9,174.8 M**
OPEX Solar Field	$1.7 M	$34.5 M	$39.8 M
OPEX Electrolyzer	$1.1 M	$21.3 M	$25.4 M
OPEX H_2 Conditioning	$0.3 M	$2.3 M	$2.6 M
OPEX Dispatch	$0.3 M	$19.8 M	$14.3 M
Total OPEX	**$3.4 M**	**$78.0 M**	**$82.1 M**
Annual Payment for 20-year Financing	$20.0 M	$387.1 M	$437.0 M
Hydrogen Imports ($tonne_{H2}$)	2,210	58,192	75,808
Hydrogen Exports ($tonne_{H2}$)	1,264	25,165	27,376
Hydrogen Production ($tonne_{H2}$)	3,313	66,266	80,538
Net Annual Cost of Fuel ($)	$5.7 M	$198.2 M	$290.6 M
Levelized Cost of Unconditioned H_2 ($/kg)	1.41	2.10	5.40
Levelized Cost of Conditioned H_2 ($/kg)	**1.63**	**2.13**	**5.47**
$LCOE_{DC}$ Solar Field ($\$/MWh_{DC}$)	**44.2**	**43.8**	**43.8**
Total LCOS ($\$/MWh_{AC}$)	**197.5**	**191.0**	**233.3**
Combined System LCOE ($\$/MWh_{AC}$)	**166.6**	**178.4**	**212.0**

4.3 2030 Cost Renewable Systems

The DOE has made projections for the improvement of renewable hydrogen technologies by 2030. These parameters are shown in Table 5 and are from the DOE grand challenge report from 2022 [6].

TABLE 5. DOE PROJECTED IMPROVEMENTS BY 2030 FOR RENEWABLE HYDROGEN

System	DOE 2030 Goal	% Improvement from Present
Solar CAPEX	\$555/kW	43.9%
Electrolyzer CAPEX	\$350/kW	73.4%
Fuel Cell CAPEX	\$435/kW	67.0%
Electrolyzer Efficiency	46 kWh/kg	15.3%
Price of Hydrogen	\$2/kg	66.7%

The improvements were applied to the TEA to show how renewable hydrogen could be improved by 2030. The results for a commercial system are shown in Table 6. In general, results are improved in commercial system to be much more similar to fossil generated hydrogen systems.

TABLE 6. INPUTS AND TEA RESULTS FOR 2030 COMMERCIAL RENEWABLE HYDROGEN SYSTEMS

	Elec. GH_2 25MW FC	**Elec. LH_2 500MW FC**	**Elec. LH_2 500MW CCGT**
Solar Capacity Cost (\$/kW_{DC})	555	555	555
Electrolyzer Capacity Cost (\$/kW_{DC})	350	350	350
H_2 Conditioning Capacity Cost (\$/kg/hr)	15,606	13,833	13,833
Storage Capacity Cost (\$/$tonne_{H2}$)	822,000	577,922	577,922
Dispatch Capacity Cost (\$/kW_{AC})	425	425	952
Solar Field Capacity (MW_{DC})	167.5	3,752.0	4,422.0
Electrolyzer Capacity (MW_{DC})	102.8	2,153.6	2,621.7
H_2 Conditioning Capacity (kg/hr)	2,235.5	46,816.4	56,993.8
Storage Capacity ($tonne_{H2}$)	9.6	192.3	252.5
Round Trip Efficiency (%)	**51.0%**	**46.4%**	**35.3%**
CAPEX Solar Field	\$93.0 M	\$2,082.4 M	\$2,454.2 M
CAPEX Electrolyzer	\$36.0 M	\$753.7 M	\$917.6 M
CAPEX H_2 Conditioning	\$34.9 M	\$647.6 M	\$788.4 M
CAPEX Storage	\$7.9 M	\$111.1 M	\$145.9 M
CAPEX Dispatch	\$10.6 M	\$212.5 M	\$476.0 M
EPC and Owner's Costs	\$29.2 M	\$609.2 M	\$765.1 M
Total CAPEX	**\$211.5 M**	**\$4,416.5 M**	**\$5,547.3 M**
OPEX Solar Field	\$0.9 M	\$20.8 M	\$24.5 M
OPEX Electrolyzer	\$0.3 M	\$6.0 M	\$7.3 M
OPEX H_2 Conditioning	\$0.7 M	\$13.0 M	\$15.8 M
OPEX Dispatch	\$0.1 M	\$6.4 M	\$14.3 M
Total OPEX	**\$2.0 M**	**\$46.2 M**	**\$61.9 M**
Annual Payment for 20-year Financing	\$10.1 M	\$210.4 M	\$264.2 M
Hydrogen Imports ($tonne_{H2}$)	2,154	55,692	71,919
Hydrogen Exports ($tonne_{H2}$)	1,839	40,993	48,362
Hydrogen Production ($tonne_{H2}$)	3,942	84,014	104,517
Net Annual Cost of Fuel (\$)	\$0.8 M	\$36.7 M	\$58.9 M
Levelized Cost of Unconditioned H_2 (\$/kg)	1.77	1.84	1.82
Levelized Cost of Conditioned H_2 (\$/kg)	**2.26**	**2.24**	**2.20**
$LCOE_{DC}$ Solar Field (\$/MWh_{DC})	**24.5**	**24.5**	**24.5**
Total LCOS (\$/MWh_{AC})	**83.3**	**77.9**	**109.3**
Combined System LCOE (\$/MWh_{AC})	**77.8**	**85.4**	**110.2**

The improvements by 2030 are also applied to CFC renewable systems and the costs are shown in Table 7. Results are further improved with all systems having a LCOE below \$100/MWh. The CCGT is more costly than a FC system, even at large scales. Improvements in the CCGT round trip efficiency would improve that system's cost performance.

TABLE 7. INPUTS AND TEA RESULTS FOR 2030 CFC RENEWABLE HYDROGEN SYSTEMS

	Elec. CFC 25MW FC	**Elec. CFC 500MW FC**	**Elec. CFC 500MW CCGT**
Solar Capacity Cost (\$/kW_{DC})	555	555	555

	Elec. CFC 25MW FC	Elec. CFC 500MW FC	Elec. CFC 500MW CCGT
Electrolyzer Capacity Cost ($/kW$_{DC}$)	350	350	350
H_2 Conditioning Capacity Cost ($/kg/hr)	8,647	3,135	2,948
Storage Capacity Cost ($/tonne$_{H2}$)	577,898	577,898	577,898
Dispatch Capacity Cost ($/kW$_{AC}$)	425	425	952
Solar Field Capacity (MW$_{DC}$)	174.2	3,484.0	4,020.0
Electrolyzer Capacity (MW$_{DC}$)	98.6	1,972.9	2,348.7
H_2 Conditioning Capacity (kg/hr)	2,144.5	42,890.1	51,059.6
Storage Capacity (tonne$_{H2}$)	9.6	192.3	252.5
Round Trip Efficiency (%)	**46.6%**	**46.6%**	**35.5%**
CAPEX Solar Field	$96.7 M	$1,933.6 M	$2,231.1 M
CAPEX Electrolyzer	$34.5 M	$690.5 M	$822.1 M
CAPEX H_2 Conditioning	$18.5 M	$134.4 M	$150.5 M
CAPEX Storage	$5.6 M	$111.1 M	$145.9 M
CAPEX Dispatch	$10.6 M	$212.5 M	$476.0 M
EPC and Owner's Costs	$26.5 M	$493.2 M	$612.1 M
Total CAPEX	**$192.5 M**	**$3,575.4 M**	**$4,437.7 M**
OPEX Solar Field	$1.0 M	$19.3 M	$22.3 M
OPEX Electrolyzer	$0.3 M	$5.5 M	$6.6 M
OPEX H_2 Conditioning	$0.4 M	$2.7 M	$3.0 M
OPEX Dispatch	$0.1 M	$6.4 M	$14.3 M
Total OPEX	**$1.7 M**	**$33.9 M**	**$46.2 M**
Annual Payment for 20-year Financing	$9.2 M	$170.3 M	$211.4 M
Hydrogen Imports (tonne$_{H2}$)	2,162	57,000	74,141
Hydrogen Exports (tonne$_{H2}$)	1,710	33,820	37,684
Hydrogen Production (tonne$_{H2}$)	3,806	76,116	92,510
Net Annual Cost of Fuel ($)	$1.1 M	$58.0 M	$91.1 M

	Elec. CFC 25MW FC	Elec. CFC 500MW FC	Elec. CFC 500MW CCGT
Levelized Cost of Unconditioned H_2 ($/kg)	1.90	1.97	1.97
Levelized Cost of Conditioned H_2 ($/kg)	**2.16**	**2.05**	**2.05**
LCOE$_{DC}$ Solar Field ($/MWh$_{DC}$)	**24.5**	**24.5**	**24.5**
Total LCOS ($/MWh$_{AC}$)	**68.8**	**62.0**	**90.2**
Combined System LCOE ($/MWh$_{AC}$)	**71.8**	**73.4**	**95.1**

5. LCOE SUMMARY CHARTS

The results for LCOE for current costs are shown in Figure 6 and the improvement by 2030, estimated based on DOE projections, are shown in Figure 6 and Figure 7. Commercial systems are on the left side of the charts and CFC systems are on the right side of charts. Generally costs are increased at grid-scale vs microgrid when comparing like technologies.

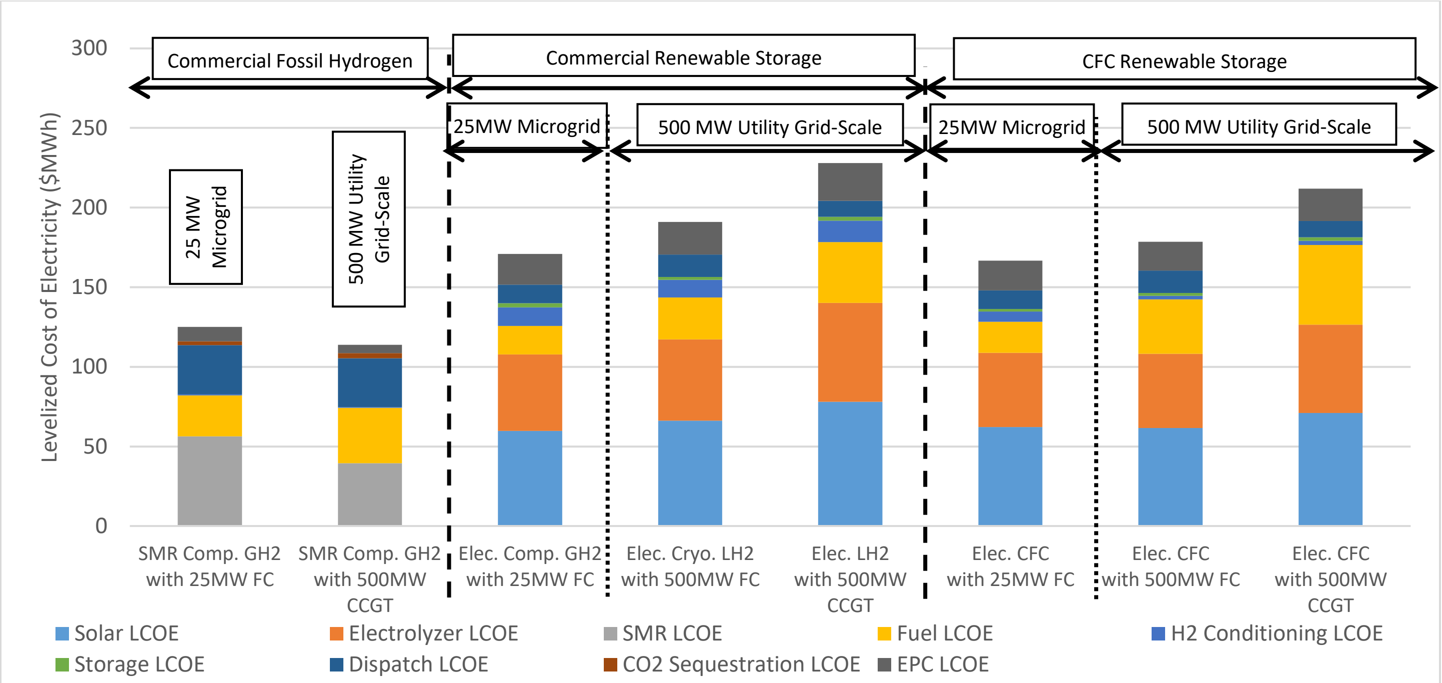

FIGURE 6. LEVELIZED COST OF ELECTRICITY AT PRESENT COSTS

The most notable trend in current costs is the high cost of hydrogen production and conditioning. With 2030 improvements, these costs become much less dominant over the overall costs. SMR is less expensive than current renewable hydrogen, but it is still less than DOE estimates for CCGT with carbon capture LCOE of $74.4 [5]. The only systems to achieve a cost below this are CFC systems with cost improvements by 2030. The CFC generally improves costs over commercial systems, but the change is most notable once production costs are reduced in 2030 and storage costs have a greater impact on the LCOE. Comparing the 2030 renewable hydrogen projections to this case, utility-scale FC systems, both commercial and CFC, are lower cost than the SMR case. When comparing to utility-scale CCGT, the commercial LH_2 system in 2030 is $110.2/MWh, which is 18% higher than the low-cost SMR case. However, CFC is much nearer the cost of the low-cost SMR case at $95.1/MWh, which is only a 1% difference.

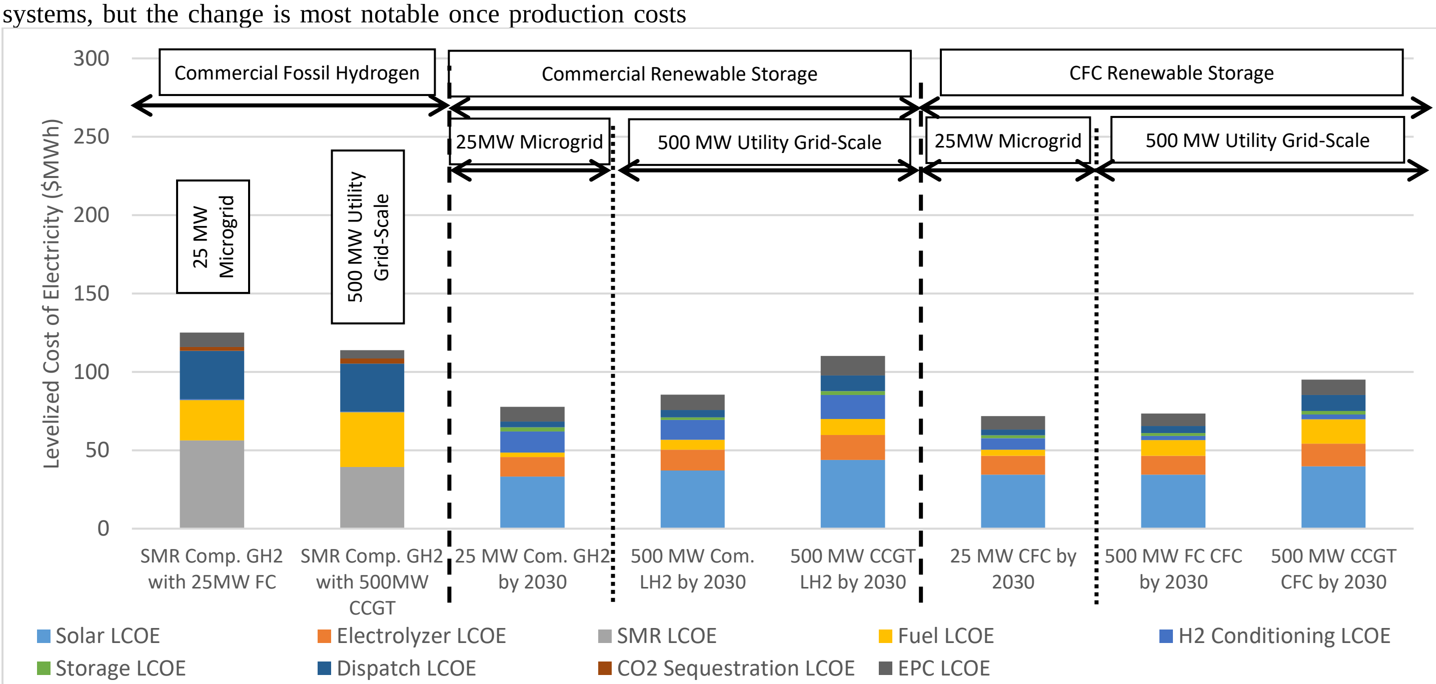

FIGURE 7. LEVELIZED COST OF ELECTRICITY ESTIMATE FOR 2030 RENEWABLE COSTS

6. THE COMBINED COST OF STORAGE AND CONDITIONING

For comparison to the costs of commercial storage for renewable hydrogen, it is useful for comparison to lump together the cost of conditioning with the cost of storage. This is because the storage type usually requires a unique combination of conditioning equipment (compressors, liquefiers, or refrigerators). Shown in Figure 8, the LCOE of just conditioning and storage was plotted versus variation in storage duration. The size of conditioning equipment does not change in this case, just the size of storage. Thus, the conditioning equipment affects LCOE more at lower sizes, but as storage size increase, storage costs begin to dominate. Cavern storage was included as a point of comparison based on the costs in the energy storage grand challenge [5]. The costs of conditioning are considered similar to compressed GH_2. Because of this, the trend of LCOE as storage size shrinks will be similar for caverns and GH_2. Thus, caverns only show impressively low costs for long durations such as from 50 to 1000 hours. Caverns also have the limitation of being geographically dependent. CFC provides a competitive alternative because it lowers conditioning costs. As such, CFC performs well between 10 and 50 hours of duration.

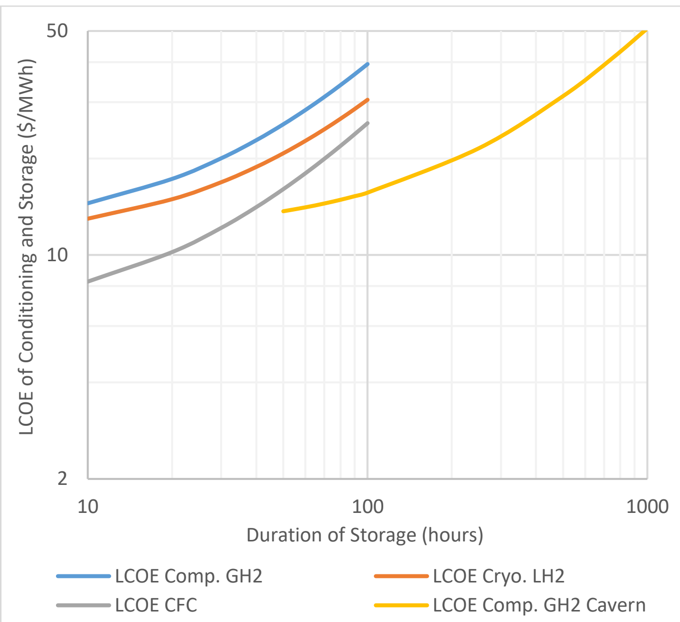

FIGURE 8. COMBINED CONDITIONING AND STORAGE COSTS FOR CHANGES IN DURATION

7. CONCLUSION

The team advanced a novel hydrogen storage technology originally developed by NASA, the CFC. The team tested the CFC for performance at 77K, cooled by LN_2. In order to benchmark indications of improved performance against conventional commercial systems, the team performed a TEA. The TEA examined fossil SMR systems producing hydrogen and renewable PV with electrolyzers.

The results for costs were analyzed using a 2021 cost benchmark and DOE projections for cost improvements by 2030. The TEA showed that onsite hydrogen generation from SMR has an LCOH of about 1.4 to 2 USD per kg over the life of the plant and the PV hydrogen production LCOH is about 5.2 to 5.5 USD per kg. The LCOS of conventional GH_2 systems is estimated to be $210/MWh and cost of storage for LH_2 systems is $205/MWh for fuel cell systems and $249/MWh for CCGT systems. CFC improved the LCOS of all these systems to $198/MWh, $191/MWh, and $233/MWh. The LCOE also improved with conventional systems between $171/MWh and $228/MWh improved by CFC to between $167/MWh and $212/MWh. Using projections for improvement in costs following DOE's goals by 2030, renewable hydrogen improved to $78/MWh LCOS and LCOE for different conventional cases. CFC improved over conventional storage with the lowest LCOS being $62/MWh and the lowest LCOE being $73/MWh. These results correspond to an LCOH of $2/kg. Finally, the TEA shows how LCOE is improved for hydrogen conditioning and storage over conventional systems and caverns in the 10 to 50 hour range.

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