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ILLUSTRATIVE PATHWAYS TO 100 PERCENT ZERO CARBON POWER BY 2035 WITHOUT INCREASING CUSTOMER COSTS

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Several illustrative pathways exist to reach 100 percent zero carbon electricity by 2035, which could keep electricity costs approximately the same as today.

The *2035 Report* used advanced grid modeling to explore a path to 90 percent zero carbon electricity by 2035. It found that the United States could dependably meet electricity demand in every hour and clean up the electricity sector, while decreasing customer costs approximately 10 percent compared to today's levels by 2035. We can decarbonize the electricity system more cost-effectively than we thought even five years ago due to plummeting costs of solar, wind, and batteries. This illustrates today's opportunity to begin decarbonizing the electricity system at scale, building massive amounts of zero carbon electricity and supporting more than half a million additional jobs each year.

Since releasing the *2035 Report*, we have naturally been asked about options for eliminating the remaining 10 percent of greenhouse gas (GHG) emissions from the power sector – reaching 100 percent zero carbon U.S. electricity. While some analysts and thinkers have explored this question in the 2050 timeframe, new questions have emerged about the possibility and cost of reaching 100 percent by 2035. This note summarizes our indicative assessment of the potential technological pathways and associated costs to realize net zero GHG emissions from the U.S. power sector by 2035 (Figure 1).

It is worth noting that the focus on squeezing the last 10 percent of emissions out of the electricity system may not be the most appropriate target for cost-effective decarbonization in 2035 – if 90 percent zero carbon electricity is achieved, electricity production will be contributing less than 5 percent of U.S. GHG emissions. Greater—and likely more cost-effective—opportunities exist to reduce GHGs from transportation, buildings, industry, or agriculture. On the other hand, of course, decarbonizing electricity has multiplicative benefits as lower-

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emissions electricity reduce emissions in transportation, buildings, and industry via electric cars, appliances, and industrial processes.

The technological pathways for eliminating the final 10 percent of GHG emissions from the electricity sector are **inherently speculative** at this time. This note uses today's best available information to assess whether it might be plausible to cost-effectively meet the goal of 100 percent clean power by 2035. It includes clearly documented assumptions about technological progress considered achievable in the next decade. Unlike the technologies considered in the *2035 Report*, which are all already well-established and commercially proven, this assessment includes technologies that are in earlier stages of testing and development or near-commercial, and thus have substantial cost and performance uncertainty associated with them. It is quite possible that once a goal of 100 percent clean power by 2035 is established in policy, private sector and government supported innovation could lead to cost-effective technologies that are not even on the horizon today. Hence, the technologies and pathways assessed in this note are just a few examples in a broader set of possibilities.

We estimate (in the *2035 Report*) that the wholesale rate for a 90 percent clean power system by 2035 would be about 4.6 cents per kilowatt-hour (kWh), which is about 10 percent lower than the 2020 average wholesale rate of about 5.2 cents/kWh. Hence, the cost to decarbonize the last 10 percent of the electricity sector can raise overall wholesale costs by about 0.5 cents/kWh in 2035 without raising wholesale electricity rates at all from 2020 levels. In other words, getting rid of the remaining GHGs from the last 10 percent of the electricity system could cost approximately twice as much (~10 cents/kWh) as the estimated average wholesale rate for the 90 percent clean system modeled in the *2035 Report* (4.6 cents/kWh), without increasing the average wholesale rates above 2020 levels (5.2 cents/kWh).

Given this cost constraint, we present several indicative pathways for achieving the last 10 percent of clean generation at a rate of ~9-13 cents/kWh. This would indicate overall average wholesale electricity rates around 5-6 cents/kWh for 100 percent clean power (see Figure 1) and means the U.S. could achieve 100 percent zero carbon electricity by 2035 at an average wholesale electricity rate similar to today.

Three of the indicative supply side pathways described here involve green hydrogen, which would be produced using zero carbon electricity to split water via electrolysis. Low cost renewable electricity and projected cost reductions in electrolyzers could to lead to cost-effective green hydrogen. Two other pathways include carbon capture, whose costs are also projected to decline with demonstration and deployment. Additional options may become viable as well—including flexible nuclear—but we have analyzed a subset of potential technology pathways here.

These supply side pathways can be complemented significantly by interventions on the demand side (which we do not assess here or in the *2035 Report*). For example, most of the natural gas generation in our 90 percent clean case from the *2035 Report* is during July and August because of increased air conditioning load coinciding with lower wind generation. More energy efficient air conditioning would help, potentially leading to lower gas generation and higher clean electricity share.

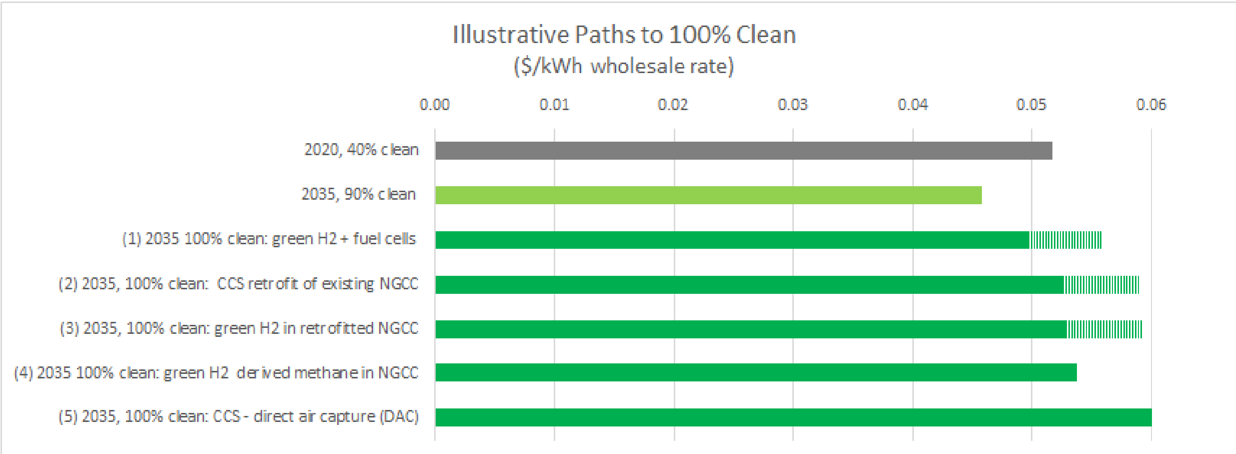

Figure 1: Wholesale electricity rates for 100% zero carbon electricity in 2035 could be similar to today's rates

INDICATIVE ESTIMATES OF THE COST OF SUPPLY-SIDE PATHWAYS TO DECARBONIZE THE LAST 10 PERCENT OF THE U.S. ELECTRICITY SYSTEM

These are approximate and based on the best available information today, which is uncertain since the performance and cost of these technologies have not been tested at scale in the real-world. This analysis assumes that technologies to eliminate the last 10 percent of power sector emissions from are deployed between 2030 and 2035, and cost estimates consider the cost reductions and performance improvement projected between 2020 and 2030 whenever such estimates are available.

In our 90 percent clean scenario, 10 percent of generation is from gas power plants (about 470 terawatt-hours (TWh) with an approximate gas capacity requirement of 350 gigawatts (GW). However, 50 GW of that approximate capacity is required less than 1 percent of the time. Given the extremely low utilization rate for this 50 GW of gas, it is highly likely to be more cost-effective to meet these system needs using demand-side options such as demand response. Thus, this analysis estimates costs of supply-side options for the last 10 percent based on 300 GW peak generation capacity need.

Three pathways using green hydrogen

Three of the supply side pathways analyzed here involve green hydrogen, which would be produced using zero carbon electricity to split water via electrolysis. The cost of hydrogen production from electrolysis using zero carbon electricity depends on three factors: the cost of electricity, the capital cost of electrolyzers, and utilization rate of those electrolyzers. Wind and solar costs have already plummeted and are projected to decline further. By 2030, the National Renewable Energy Laboratory projects the cost of utility scale solar PV will decline to about 1.5-2 cents/kWh (see Figure 2) in many locations across the U.S., and projects the cost of wind power will decline to 2-2.5 cents/kWh.

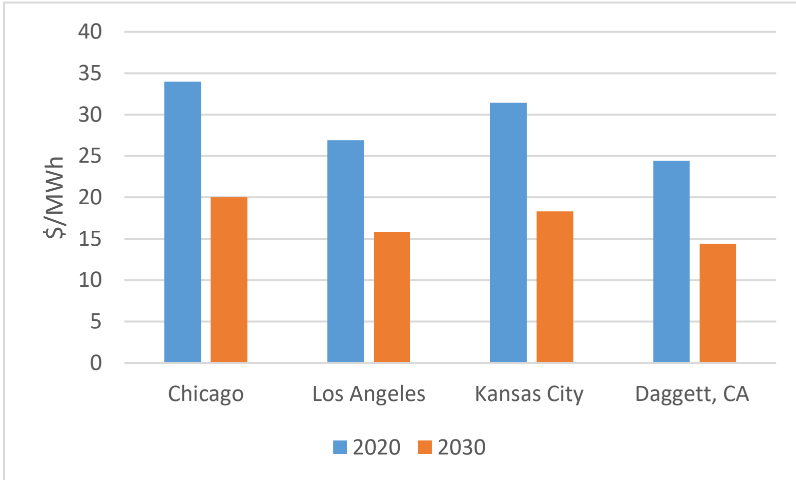

Figure 2: Projected cost of utility scale solar PV, according to NREL ATB 2020

Electrolyzers can operate in a bargain hunting mode where they draw power from the grid only when wholesale prices fall a below a certain threshold. Wind and solar have zero marginal cost – once built, they require no fuel to run, so they can offer into power markets at zero or even negative prices. When solar and wind dominate the electricity mix, several hours will exist throughout the year in which the overall wholesale market clearing price of electricity will be zero or even negative (for example, we find that more than 300 TWh of electricity is curtailed in the 90 percent clean electricity scenario from the *2035 Report*). Phadke et. al 2019 report that even historically in California and Texas markets, wholesale electricity prices were below 3 cents/kWh for at least 40 percent of the hours between 2012 and 2018.

Hence, for this analysis, it is feasible to assume average input electricity prices around 2 cents/kWh in 2030 (1.5 cents/kWh of zero carbon electricity cost plus 0.5 cents/kWh of spur line transmission cost to connect remote renewable energy resources to the bulk transmission system). We also show how our cost estimates change if input electricity prices increase to 3 cents/kWh. We assume that electrolyzers can cost-effectively avoid operating during hours when the power system is at capacity or most constrained so that they do not contribute to the costs of system expansion and avoid paying fixed transmission and demand charges. Market and tariff rules such as those implemented in ERCOT are required for electrolyzers to take advantage of their operational flexibility and realize these savings (see Phadke et. al 2019 for similar examples).

The cost of electrolyzers is projected to decline significantly with increased production volumes; from 2020 costs of about $500-$1,000 per kilowatt (kW) to $100-$300/kW in 2030 (BNEF 2019, DOE 2020 b, IRENA 2019). According to BNEF, electrolyzer manufacturers in China have already achieved costs of about $200/kW in 2020. BNEF projects that the cost of electrolyzers manufactured in the U.S. and Europe will converge with those of Chinese manufacturers by 2030, reaching approximately $130/kW (BNEF 2020, BNEF 2019). Several analyses (BNEF 2020, DOE 2020 b, IRENA 2019) show that with input electricity prices around 1.5 cents/kWh and electrolyzer costs of about $200/kW, hydrogen production costs of $1.50 per kilogram (kg) are possible. Note that these are significantly lower than most hydrogen production costs estimated for 2020, which tend to be around $3-5/kg.

Table 1 summarizes our assumptions about hydrogen production cost. The resulting estimates of hydrogen production costs in 2030 ($1.30/kg) are similar to several other analyses, including BNEF 2020 and DOE 2020 b. If we assume input electricity prices to be 50 percent higher than assumed above (3 cents/kWh instead 2 cents/kWh), the delivered cost of hydrogen increases by 33 percent (from $1.50/kg to $2/kg). We have included this sensitivity case as the high end of the range depicted by the striped sections in Figure 1. It is also worth noting that electrolyzers could also operate during hours with very low or zero marginal cost electricity, but we did not analyze the low end of this sensitivity here.

Parameter	Assumption		Notes
Year	2020	2030	
Electricity price ($/kWh)	$ 0.03	$ 0.02	2030: $0.015/kWh renewables cost (NREL Annual Technology Baseline 2020) + $0.005/kWh spur transmission line cost (2035 Report from UCB 2020)
Utilization factor (%)	40%	40%	Assumes renewables power ~35% capacity factor + ~5% additional low cost grid purchase
Electrolyser capital cost ($/kW)	$ 460	$ 130	2020 costs based on DOE 2019; 2030 costs based on BNEF 2020
Capital cost including stack replacement adder (15%)	$ 529	$ 150	The stack, a component of the electrolyzer, has a shorter life than the rest of the system and hence needs to be replaced before 30 years. This price adder accounts for that.
Life (Years)	30	30	
Weighted average cost of captial (real) (%)	6%	6%	
Fixed O&M ($/kW-year)	$ 30	$ 10	
Fixed capital ($/kW-year)	$ 38	$ 11	
Total fixed cost ($/kW-year)	$ 68	$ 21	
Fixed cost ($/kWh)	$ 0.020	$ 0.006	
kWh/kg H_2	55.8	51.3	DOE 2019
Fixed cost ($/kg H_2)	$ 1.09	$ 0.31	
Variable cost ($/kg H_2)	$ 1.67	$ 1.03	
Total production cost ($/kg H_2)	$ 2.76	$ 1.33	
Storage in a salt cavern ($/kg H_2)	$ 0.23	$ 0.11	BNEF 2020
Transport 100 km pipeline ($/kg H_2)	$ 0.10	$ 0.05	BNEF 2020
Total delivered cost ($/kg H_2)	$ 3.09	$ 1.49	

Table 1: Cost of hydrogen production from low-cost renewable electricity

We consider three pathways to use hydrogen as a fuel to replace natural gas generation:

1. Use fuel cells to generate electricity from hydrogen;
2. Retrofit existing natural gas combined cycle (NGCC) turbines to enable them to use hydrogen as a fuel;
3. Convert hydrogen to synthetic methane, which can be used in existing NGCC turbines.

The first two options will require significant seasonal storage of hydrogen because electricity demand in excess of renewable energy production predominantly occurs during summer months, whereas the curtailment of excess renewable electricity occurs primarily during spring. In the case of the third option, once hydrogen is converted to synthetic methane, it can use the existing natural gas storage and pipeline infrastructure.

Electrolyzers can operate flexibly to produce hydrogen when low-cost zero carbon electricity is available. This provides a great value to an electric grid with a high share of variable renewables

– electrolyzers can absorb "excess" zero carbon electricity that may otherwise have been curtailed. In a competitive electricity market, this could mean electrolyzers operate in a "bargain hunter" mode, running only when prices go below a certain threshold. This mode of operation may make it cost-effective to add enough additional renewable energy capacity so that most of the outstanding gas generation is directly replaced. Such a strategy would likely be cost prohibitive without electrolyzers to absorb the renewable energy generation that would otherwise have been curtailed. Hydrogen produced from these flexible electrolyzers could then be used beyond the power sector.[2] This cost analysis does not consider the flexibility value of electrolyzers on the grid, but these grid benefits can be significant.

Studies have shown that the underground storage of hydrogen in salt caverns is likely to be the lowest cost option for seasonal storage (BNEF 2020, Sandia 2009). In the U.S., two companies, ConocoPhillips and Praxair, currently store hydrogen underground. The hydrogen is stored in salt caverns, both which are located within the Clemens salt dome in Texas (Leighty, 2008), and ConocoPhillips has been storing hydrogen gas for several decades. Further, significant quantities of natural gas are stored in more than 40 salt cavern storage facilities around the U.S. (EIA 2020). Although a U.S.-wide study of hydrogen storage potential in salt caverns is not available, one such study (Caglayan et al. 2020) for Europe suggests hydrogen storage potential is orders of magnitude higher than typically needed for seasonal storage (7,300 TWh onshore; 83,000 TWh total including offshore whereas seasonal storage needs for 10 percent of generation are less than 1,000 TWh).

Generation from fuel cells using green hydrogen

We estimate the generation cost of about 470 TWh of electricity from 300 GW of fuel cell capacity. This fuel cell capacity would operate at less than 20 percent capacity factor on average (i.e. less than 1,500 hour per year). In 2030, automotive fuel cells are expected to be a fraction of the cost of stationary fuel cells (about $50-$100/kW for automotive vs. $1,000/kW for stationary), however, they are projected to have much lower durability. The U.S. Department of Energy (DOE) target for durability is 8,000-25,000 hours for automotive fuel cells vs. 80,000-160,000 hours for stationary fuel cells (DOE 2019).

Given that fuel cells powering the last 10 percent of electricity demand would operate less than 1,500 hours a year on average, automotive fuel cells in fact are likely to provide a cost-effective option for this kind of seasonal power generation. Thus, this analysis uses the DOE cost target for fuel cells for medium duty vehicles of $90/kW with a durability target of 25,000 hours as an estimate of cost and performance in 2030. Note that fuel cell costs of $120/kW are already observed today for on-road vehicles, although with much lower durability. We factor in an additional balance of system cost (BOS) of $100/kW for these fuel cells' use for stationary

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[2] Our back of the envelope estimate suggests that about 400-500 GW of additional solar capacity can replace most of the gas generation directly which primarily occurs during summer months. In such a scenario, about 30 percent of the solar generation will used to directly replace the last 10 percent of gas generation, whereas the rest is used to produce hydrogen cost-effectively.

power.[3] Table 2 summarizes several of the assumptions used to estimate generation costs from fuel cells using green hydrogen.

Parameter	Assumption	Notes
Year	2030	
Fuel cost ($/kg H_2)	$ 1.50	
Fuel cell efficiency	70%	DOE 2019
Variable fuel cost ($/kWh)	$ 0.06	
Variable O&M ($/kWh)	$ 0.005	
Total variable cost ($/kWh)	$ 0.07	
Fuel cell capital cost ($/kW)	$ 92	DOE 2019; Based on cost target for medium duty vehicle fuel cell with durability of 25,000 hours
Capacity (GW)	300	
Economic life (years)	17	Based on fuel cell in use 1,500 hours per year with durability of 25,000 hours
WACC (real)	6%	
Other BOS costs for fuel cell power plant ($/kW)	$ 100	BOS is balance of system
Other BOS life (years)	40	
Capital Recovery Factor (%) fuel cell	10%	
Capital Recovery Factor (%) BOS	7%	
Fixed capital cost ($/kW-year)	$ 15.53	
Fixed O&M ($/kW-year)	$ 10.00	
Total fixed cost ($/kW-year)	$ 25.53	
Total fixed generation cost ($/kWh)	$ 0.02	
Annual generation (TWh)	470	
Total generation cost, last 10% clean ($/kWh)	$ 0.085	
2020 wholesale cost ($/kWh)	$ 0.052	
2035 wholesale cost 90% clean ($/kWh)	$ 0.046	
2035 wholesale cost 100% clean ($/kWh)	$ 0.050	

Table 2: Clean electricity generation costs from fuel cells using green hydrogen

Reaching 100 percent zero carbon electricity in 2035 using green hydrogen in hydrogen fuel cells to provide the last 10 percent would imply generation rates of around 8.5 cents/kWh for the last 10 percent. This would mean total wholesale rates for the 100 percent zero carbon electricity system would come out to about 5 cents/kWh – approximately the same as today's average rate of about 5.2 cents/kWh.

If we instead consider the cost of stationary fuel cells ($1,000/kW) rather than automotive fuel cells (~ $200/kW including balance of systems costs), the generation rate for the last 10 percent increases to 12 cents/kWh. This would mean total wholesale rates for the 100 percent zero carbon electricity system would come out to about 5.3 cents/kWh, which is approximately the same as today's average rate of about 5.2 cents/kWh.

If, on top of the stationary fuel cell cost assumptions, we also consider the sensitivity case with electrolyzers needing to buy electricity at 3 cents/kWh rather than 2 cents/kWh, the total wholesale rates for the 100 percent zero carbon electricity system would come out to about 5.6 cents/kWh, which is just a bit higher than today's average rate of 5.2 cents/kWh.

[3] Based on estimates of balance of system costs of utility scale battery storage systems as estimated by NREL ATB 2020 advanced case.

Generation from existing NGCC retrofitted to enable the use of green hydrogen

Existing natural gas combined cycle (NGCC) plants can be retrofitted to enable using hydrogen as a fuel. General Electric (GE) already claims that several of their turbines are hydrogen ready,[4] stating their F and HA class turbines (which are most common models used in large CCGT plants) can burn up to 60 percent hydrogen whereas their B/E class and aeroderivative turbines can burn in excess of 90 percent hydrogen. According to GE, existing NGCC plant modifications may require switching to a new combustion system, which would require new fuel accessory piping and valves. It may also require new fuel skids, as well as enclosure and ventilation system modifications, and several other changes.

A new CCGT power plant costs about $1,000/kW (NREL ATB 2020). Based on the description of the retrofits, an estimate of retrofit costs is $300/kW. Some challenges in this strategy include location (availability of hydrogen storage capacity near gas generators), however, pipeline transport costs could pencil out. Table 3 summarizes our key assumptions used to estimate the generation cost from this option.

Parameter	Assumption	Explanation and references
Year	2030	
Hydrogen calorific value (MJ/kg)	120	
Hydrogen Production Cost ($/kg)	1.5	
Hydrogen cost ($/MMbtu)	13.08	
Heat Rate (Btu/kWh)	7000	
Variable fuel cost ($/kWh)	0.09	
Variable O&M ($/kWh)	0.002	NREL ATB 2020
Total variable cost ($/kWh)	0.09	
Retrofit cost/capital cost ($/kW)	300	Estimate based on General Electric 2019
Capacity (GW)	300	
Economic life (years)	30	NREL ATB 2020
WACC (real)	6%	
Capital Recovery Factor (%)	7%	
Fixed capital cost ($/kw-year)	22	
Fixed O&M ($/kW-year)	15	NREL ATB 2020
Total fixed cost ($/kW-year)	37	
Total fixed generation cost ($/kWh)	0.02	
Annual generation (TWh)	470	
Total generation cost, last 10% clean ($/kWh)	0.117	
2020 wholesale cost ($/kWh)	0.052	
2035 wholesale cost 90% clean ($/kWh)	0.046	
2035 wholesale cost 100% clean ($/kWh)	0.053	

Table 3: Clean electricity generation costs from NGCC plants retrofitted to enable hydrogen use

[4] See: https://www.ge.com/power/gas/fuel-capability/hydrogen-fueled-gas-turbines

For more details, see: https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20Power%20to%20Gas%20-%20Hydrogen%20for%20Power%20Generation.pdf

Reaching 100 percent zero carbon electricity in 2035 using green hydrogen in hydrogen-ready turbine retrofits to provide the last 10 percent would imply generation rates around 11.7 cents/kWh for the last 10 percent.

This would mean total wholesale rates for the 100 percent zero carbon electricity system would come out to about **5.3 cents/kWh**. This is approximately the same as today's average wholesale rate of about 5.2 cents/kWh.

Considering the sensitivity case with electrolyzers needing to buy electricity at 3 cents/kWh rather than 2 cents/kWh, the total wholesale rates for the 100 percent zero carbon electricity system would again come out to about **5.6 cents/kWh**, which is just a bit higher than today's average rate of 5.2 cents/kWh. Generation from existing NGCC power plants that use synthetic methane derived from green hydrogen.

This pathway involves producing green methane (CO_2 from direct air capture plus green hydrogen). The key benefit of using green methane rather than hydrogen directly is that existing gas generators, pipelines, and storage facilities could be used. An analysis of a 100 percent clean California power system found green methane to be the most cost-effective strategy for the last few percent of clean electricity.[5]

We estimate the cost of synthetic methane adjusting the estimates of IRENA 2020 (our hydrogen cost estimate is lower than IRENA given lower electricity price estimates). The CO_2 cost from direct air capture (DAC) is approximately $100/tonne of CO_2 due use of waste heat from electrolysis, as estimated by Fasihi et al. 2018. With these assumptions, our estimates of synthetic methane costs are about $17 per million British Thermal Units (MMBtu), which is similar to the cost estimated by Fasihi et al. 2018 and Gorre et. al 2020. More cost-effective ways to obtain green methane may exist, such as methane capture from landfills and dairies, so this represents a conservative estimate of cost. Table 4 summarizes our key assumptions and results.

[5] See: https://www.pathto100.org/wp-content/uploads/2020/03/path-to-100-renewables-for-california.pdf

Parameter		Assumption	Notes
Year		2030	
Fuel cost ($/kg H_2)	$	1.50	
CO_2 cost ($/kg)	$	0.10	DAC CO_2 cost ($100/tonne CO_2) w/ waste heat from eletrolysis
Resulting synthetic methane cost ($/MMbtu)	$	17	Based on IRENA 2020 with adjustments to H_2 cost
Heat Rate (Btu/kWh)		6500	NREL ATB 2020
Variable fuel cost ($/kWh)	$	0.110	
Variable O&M ($/kWh)	$	0.006	NREL ATB 2020
Total variable cost ($/kWh)	$	0.116	
Capacity (GW)		300	
Fixed O&M ($/kW-year)	$	15	NREL ATB 2020
Annual generation (TWh)		470	
Total fixed generation cost ($/kWh)	$	0.010	
Total generation cost, last 10% clean ($/kWh)	$	0.126	
2020 wholesale cost ($/kWh)	$	0.052	
2035 wholesale cost 90% clean	$	0.046	
2035 wholesale cost 100% clean	$	0.054	

Table 4: Clean electricity generation costs from NGCC plants using synthetic methane derived from green hydrogen

Reaching 100 percent zero carbon electricity in 2035 using green methane in existing gas infrastructure to provide the last 10 percent would imply generation rates of around 12.6 cents/kWh for the last 10 percent.

This would mean total wholesale rates for the 100 percent zero carbon electricity system would come out to about 5.4 cents/kWh. This is only marginally higher than today's average wholesale rate of 5.2 cents/kWh.

Considering the sensitivity case with electrolyzers needing to buy electricity at 3 cents/kWh rather than 2 cents/kWh, the total wholesale rates for the 100 percent zero carbon electricity system would again come out to about 5.6 cents/kWh, which is just a bit higher than today's average rate of 5.2 cents/kWh.

Two pathways using carbon capture and storage

Generation from existing NGCC plants retrofitted with CCS

It may be possible to retrofit the remaining 300 GW of existing NGCC capacity with carbon capture and sequestration (CCS). This remaining capacity would still be used to generate about 470 TWh with carbon capture rate of 90 percent or more. It is important to note that this pathway does not eliminate 100 percent of emissions. The uncaptured emissions from the natural gas with CCS would still need to be offset to truly hit zero emissions. Table 6 summarizes our key assumptions and results.

Parameter	Assumption	Notes
Fuel cost ($/MMbtu)	$ 3.50	NREL ATB 2020
Heat Rate (Btu/kWh)	7500	10% heat rate penalty over NGCC [NREL ATB 2020, NETL 2018]
Variable fuel cost ($/kWh)	$ 0.026	
Variable O&M ($/kWh)	$ 0.006	NGCC CCS variable O&M cost are higher than NGCC [NREL ATB 2020]
CO_2 compression, transport, sequestration cost ($/tonne)	$ 34	Mahdi et al. 2018
Variable CO_2 cost ($/kWh)	$ 0.02	
Total variable cost ($/kWh)	$ 0.05	
Retrofit cost ($/kW)	$ 1,000	NETL estimates for 2018 [NETL 2018]
Capacity (GW)	300	
Economic life (years)	30	NREL ATB 2020
WACC (real)	6%	
Capital Recovery Factor (%)	7%	
Fixed capital cost ($/Kw-year)	$ 73	
Fixed O&M ($/kW-year)	$ 27	NGCC CCS fixed O&M cost are higher than NGCC [NREL ATB 2020]
Total fixed cost ($/kW-year)	$ 100	
Total fixed generation cost ($/kWh)	$ 0.064	
Annual generation (TWh)	470	
Total generation cost, last 10% clean ($/kWh)	$ 0.114	
2020 wholesale cost ($/kWh)	$ 0.052	
2035 wholesale cost 90% clean ($/kWh)	$ 0.046	
2035 wholesale cost 100% clean ($/kWh)	$ 0.053	

Table 6: Clean electricity generation costs from NGCC plants retrofitted with CCS

Reaching nearly zero carbon electricity in 2035 by retrofitting existing gas infrastructure with CCS to provide the last 10 percent would imply generation rates around 11.4 cents/kWh for the last 10 percent.

This would mean total wholesale rates for the 100 percent zero carbon electricity system would come out to about **5.3 cents/kWh**. This is only marginally higher than today's average wholesale rate of 5.2 cents/kWh.

Direct Air Capture as an offset for remaining emissions

Direct air capture (DAC) involves extracting CO_2 from ambient air, and storing it long-term. The idea here would be to allow conventional natural gas to continue providing some portion of the last 10 percent of electricity needs in 2035, but ensure sufficient DAC capacity is running to offset any remaining natural gas emissions.

The benefit of using DAC is that it can be flexible, running whenever electricity is cheap and available, without substantial impact on the operation of the power system. It can also be placed anywhere land is available. DAC can complement other cost-effective technologies that help get us closer to 100 percent by absorbing remaining emissions. The additional cost of DAC therefore represents a ceiling on the cost of achieving net zero carbon emissions in the power sector.

DAC is currently in an early commercial stage, but has never been deployed at scale. Neither has wide-scale carbon sequestration outside of enhanced oil recovery, which depends on high oil prices (and continued use of oil) to pencil out. Therefore, significant uncertainty surrounds the costs of this pathway, leading us to adopt conservative estimates of these costs from a recent peer-reviewed techno-economic survey of DAC costs.[6] Table 5 summarizes our key assumptions and results.

Parameter	2020	2030
Natural gas annual generation for the last 10% (TWh)	470	470
Total variable cost of natural gas power ($/kWh)	0.03	0.03
Heat Rate (Btu/kWh)	7500	7500
Fuel Use (MMBTU)	3,525,000,000	3,525,000,000
Emissions Factor (lb CO2/MMBTU)	117	117
Total NG Power Sector Emissions (MT CO2/yr)	187	187
DAC Cost (HT) ($/tCO2)	356	177
CO2 Transportation Cost ($/tCO2)	18.62	5.852
CO2 Sequestration Cost ($/tCO2)	13.3	13.3
CO2 Compression Energy Demand (kWh/tCO2)	104	104
CO2 Compression Cost ($/tCO2)	4.76	4.76112
DAC Total Cost ($/tCO2)	393	201
DAC total cost	73,542,369,168	37,564,853,247
DAC Total Cost ($/kWh)	0.19	0.11
2035 100% clean cost ($/kWh)	0.060	0.052

Table 5: Cost of DAC and generation cost adder

Using today's DAC cost estimates of roughly $393 per tonne CO_2, we find that using DAC to capture the same amount of CO_2 emitted from a power sector operating with 90 percent clean and 10 percent natural gas implies an equivalent "generation" rate of around 19 cents/kWh for the last 10 percent.

This would mean total wholesale rates for the 100 percent zero carbon electricity system would come out to about 6 cents/kWh if we factor in paying for DAC at today's estimated costs – this is about 15 percent higher than today's average wholesale rate of 5.2 cents/kWh.

Fasihi et. al projects DAC cost declines in a scenario with significant deployment by 2030. This scenario relies on conventional methods to forecast cost declines as a function of deployment, resulting in DAC costs around $150/ton in 2030, including transport and sequestration.

If such near-term deployment and cost declines for DAC were to be realized, reaching 100 percent zero carbon electricity in 2035 using DAC at these speculative future costs to provide the

[6] See: https://www.sciencedirect.com/science/article/pii/S0959652619307772

last 10 percent would imply an equivalent "generation" rate of around 11 cents/kWh for the last 10 percent.

This would mean total wholesale rates for the 100 percent zero carbon electricity system would come out to about 5.2 cents/kWh if we assume DAC at these speculative future costs. This is surprisingly the same as today's average wholesale rate of 5.2 cents/kWh. We note that this scenario is *highly* speculative, and would depend on proving and scaling a very new technology quite quickly.

Using these pathways in combination can lower costs and address limitations

The five pathways outlined here are not mutually exclusive, but can in fact complement each other. For example, NGCC + CCS option could be more cost-effective for the natural gas power plants that operate at significantly higher capacity factor than average. At the same time, the low capital cost higher variable cost hydrogen fuel cells could be used to replace natural gas power plants that operate at lower capacity factors. Options that use hydrogen directly are likely to be most cost-effective in regions with the cheapest salt cavern storage potential, while synthetic methane can be an option in regions where hydrogen storage potential is limited. Using DAC for the last bit of clean-up is likely to act as a price cap on the last cost of mitigation, and benefits from not being tied to the location of existing gas plants – the DAC could be located wherever is most convenient and cost-effective.

Further work is required to assess all these options and their optimal combination to eliminate the last 10 percent of the emissions from the power sector. However, this indicative exercise provides some confidence in the conclusion that 100 percent clean power by 2035 is likely to be affordable, and such a target could spur significant innovation that could have large spillover benefits for climate mitigation and U.S. industry, manufacturing, and technology leadership in other important realms.

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