THE POTENTIAL IMPACT OF RENEWABLE GASEOUS FUEL ON OPTIMIZING THE CALIFORNIA RENEWABLE PORTFOLIO

RESOLVE Model Scenario Analysis

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Introduction and Overview

The California Public Utilities Commission (CPUC) integrated resource planning (IRP) modeling tool RESOLVE[1] projects in its reference scenarios that more than 50 GW (nameplate power rating) of storage will be needed to meet the requirements of SB 100 in 2045 and, even with this magnitude of storage, curtailment will reach nearly 20% of renewable power produced. However, as illustrated in Figure 1 and Figure 2, if renewable hydrogen and/or methane reach price points below $24/MMBtu injected onto the natural gas grid, the optimal resource portfolio selected by RESOLVE (30 MMT base scenario) begins to select the use of renewable fuel in existing natural gas plants while reducing the deployment of battery storage. New solar build also declines and curtailment is reduced [although note that potential solar (or wind) additions to produce renewable fuel are not included within the RESOLVE resource portfolio.[2]] While not reflected in RESOLVE, use of renewable fuel for power generation provides reliability and resiliency benefits by providing renewable power during randomly-occurring, long-lasting shortfalls in wind and solar production that are known to occur due to weather variability[3] and other extreme events.

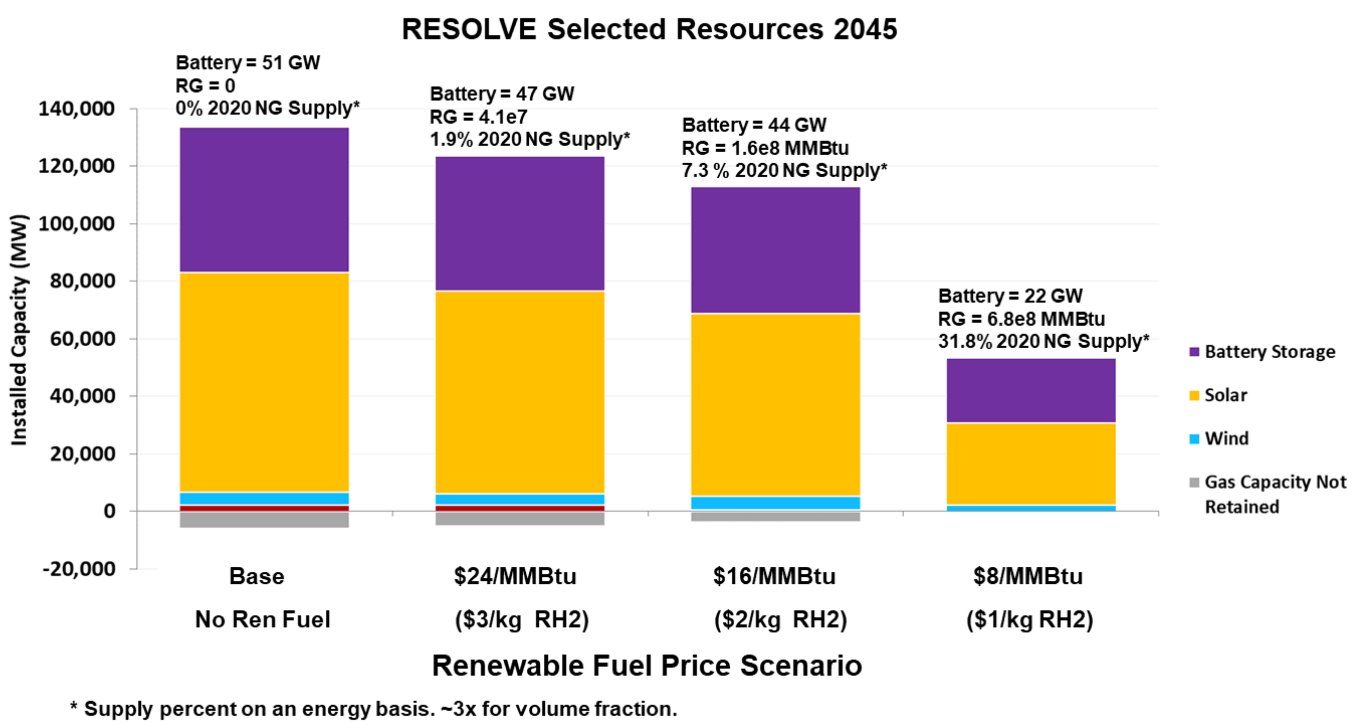

Figure 1. 2045 Selected Resources in UCI APEP RESOLVE Renewable Fuel Scenarios

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[1] RESOLVE is the CPUC Integrated Resource Planning (IRP) tool. CPUC. "RESOLVE Model CPUC Web Page." 2019. http://cpuc.ca.gov/General.aspx?id=6442457210.

[2] Substantial new solar and or wind resources would be needed to serve the electrolytic renewable hydrogen or methane selected by the model. However, this depends on the fraction of electrolytic versus biogenic renewable fuel used. In the current approach, the amortized investment in renewable generation to supply electrolytic renewable fuel production is embedded in the fuel cost. E.g. $2/kg hydrogen would include the cost of both renewable electricity and the capital cost of the electrolyzer.

[3] Shaner, Matthew R, Ken Caldeira, Steven J Davis, and Nathan S Lewis. 2018. "Environmental Science Geophysical Constraints on the Reliability of Solar and Wind Power in the United States †," 914–25. https://doi.org/10.1039/c7ee03029k.

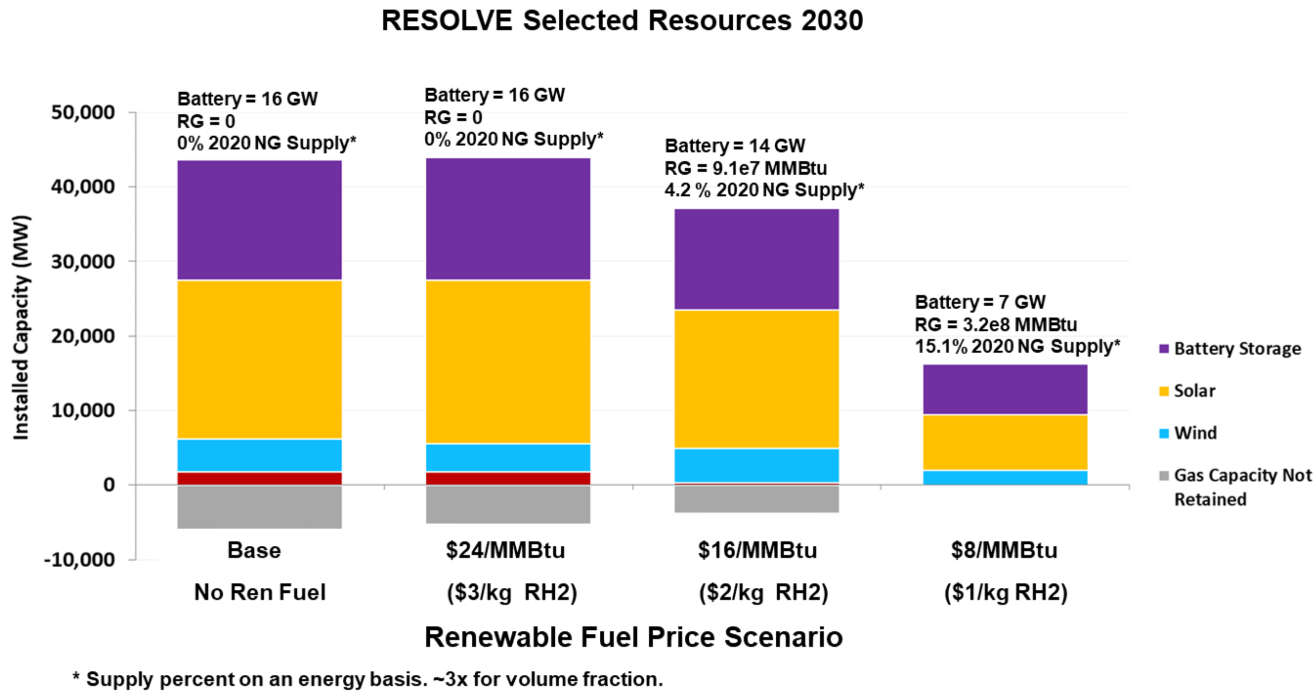

Figure 2. 2030 Selected Resources in UCI APEP RESOLVE Renewable Fuel Scenarios

The RESOLVE model selects optimal resource portfolios to meet electric-system demand and environmental constraints. Within RESOLVE, a scenario is defined by 52 input parameters in 8 categories covering load, costs, resource types and other parameters. 42 RESOLVE scenarios are pre-run and archived as part of the open source model. Within that set, there are several framing scenarios representing broad policy and technology themes within which parameters are selected consistent with the theme. The use of gas-grid supplied renewable fuel for dispatchable power generation is not considered in any of the pre-developed cases ("Can Switch to RPS Eligible Fuel" set to FALSE) whereas the scenarios presented here specifically include that option. The cases presented here use the 30MMT_Base_20191001_2045 assumptions for all parameters except: 1) the ability to blend renewable fuel on the gas grid; 2) the cost of that renewable fuel, and; 3) the available supply of renewable fuel.

Renewable Gaseous Fuel Costs

The quantity of renewable fuel selected in the RESOLVE optimization depends strongly on the cost of the fuel. A growing number of forecasts project that electrolytic renewable hydrogen cost could reach levels as low as $1/kg ($8/MMBtu) by 2050 with some projecting that cost point by 2030.[4,5] More conservative forecasts project cost in the $3/kg ($24/MMBtu) range by 2030 declining to $2/kg by 2050. Figure 3

[4] Bloomberg New Energy Finance, *Hydrogen Economy Outlook, Key Messages*, p.4; March 2020 https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf

[5] Using analysis by McKinsey, the Hydrogen Council's *Path to Hydrogen Competitiveness – A Cost Perspective,* on p. 15, concludes: "Within five to ten years – driven by strong reductions in electrolyser capex of about 70 to 80 per cent and falling renewables' levelised costs of energy (LCOE) – renewable hydrogen costs could drop to about USD 1 to 1.50 per kg in optimal locations, and roughly USD 2 to 3 per kg under average conditions."

depicts a forecast band for the cost of renewable hydrogen injected onto the natural gas grid derived from recent UCI APEP analysis, particularly the CEC-sponsored Renewable Hydrogen Roadmap.[6]

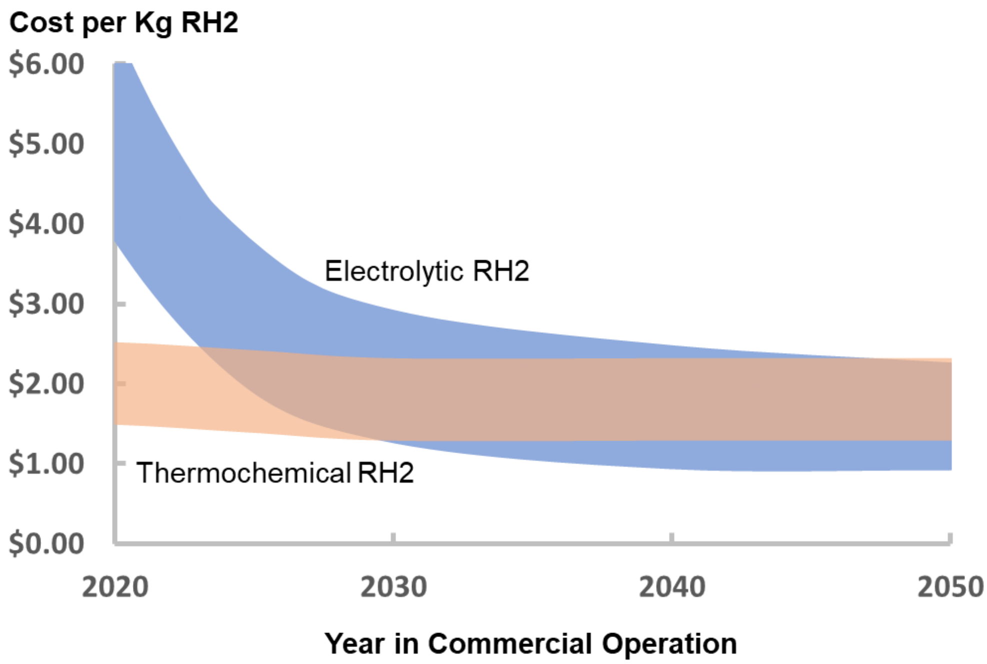

Figure 3. Evolution of Gas-System Injected Renewable Hydrogen Cost

The RESOLVE cases presented here make renewable fuel delivered via the gas grid available for use in gas-fired generation units. No costs for modifications to the gas system or electric generators to accommodate high hydrogen fractions or pure hydrogen are included in the analysis. Adding zero-emission, hydrogen-capable resources such as fuel cells to augment or replace existing generation should also be assessed. Whether making those modifications is cost-effective depends on the price differential between renewable hydrogen and renewable methane, the value of criteria pollutant emission reductions, and the system conversion costs. Analysis of this is ongoing.

Renewable methane cost from thermochemical pathways is approximately 20% higher than for hydrogen due to lower efficiency and additional equipment needed for methanation.[7] Renewable methane produced from electrolytic hydrogen and biogenic CO2 is estimated to cost between 30% and 40% more than renewable electrolytic hydrogen.[8] Figure 4 shows a representative cost build-up with a 20% energy penalty, 30% capital cost uplift for methanation and CO2 acquisition and processing cost of $30/ton yielding a 30% cost differential. The base case discussion below uses $16/MMBtu ($2/kg) for renewable fuel cost which is well within the forecast range for both hydrogen and methane by the late 2020's.

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[6] Reed, Jeffrey G, Emily E Dailey, Brendan P Shaffer, Blake A Lane, Robert J Flores, Amber A Fong, and G Scott Samuelsen. 2020. "Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California."

[7] Aas, Dan, Amber Mahone, Zack Subin, Michael A. Mac Kinnon, Blake Lane, and Snuller Price. 2020. "The Challenge of Retail Gas in California's Low-Carbon Future." https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-F.pdf. See App. C.

[8] Parra, David, Xiaojin Zhang, Christian Bauer, and Martin K. Patel. 2017. "An Integrated Techno-Economic and Life Cycle Environmental Assessment of Power-to-Gas Systems." *Applied Energy* 193: 440–54. https://doi.org/10.1016/j.apenergy.2017.02.063.

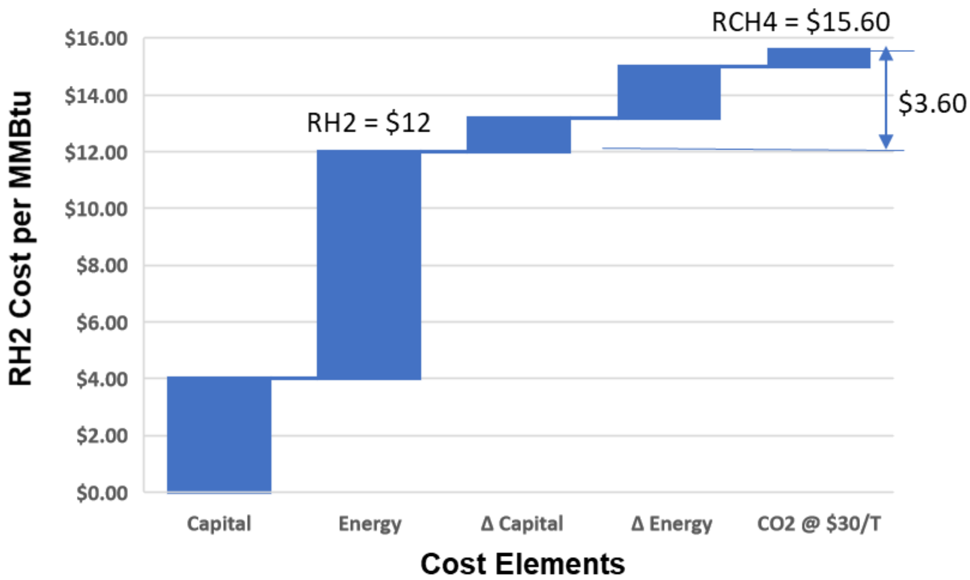


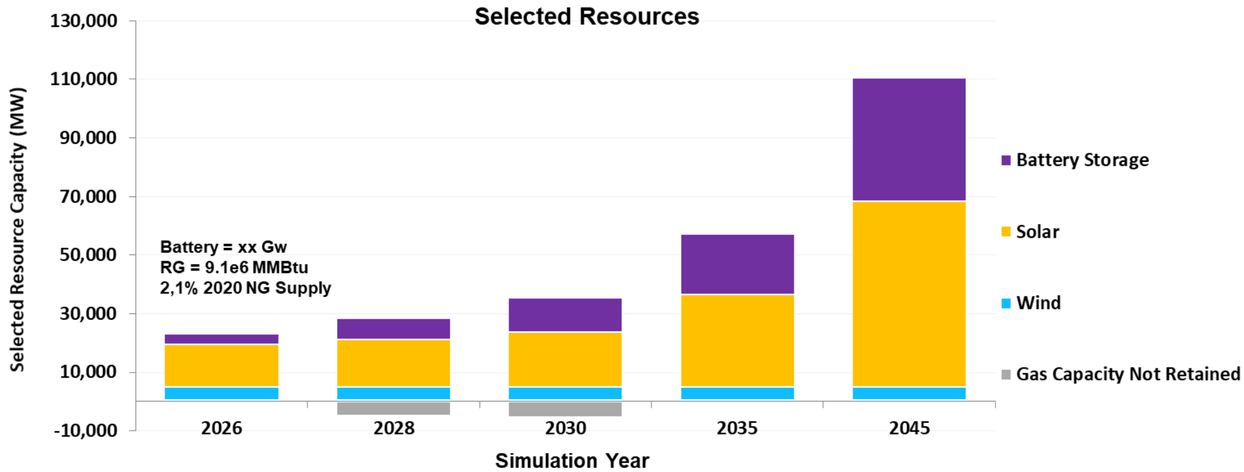
Figure 4. Cost of Electrolytic Renewable Hydrogen versus Methane Illustration

Note on RESOLVE Treatment of Costs for Electrolyzers and Input Electricity

The RESOLVE model has a selectable feature allowing the user to add electrolyzers as a load (this is done in the high hydrogen framing scenario). For reasons explained below, the present analyses do not use the electrolyzer load feature to represent electrolytic fuel production but rather include those costs in the cost of delivered renewable fuel. Implicitly, the electric supply for fuel production is off-grid electricity. The RESOLVE electrolyzer load feature in the model can be adjusted to add electrolyzer capacity for fuel production. However, beyond the uncertainty in the portion of renewable gaseous fuel that will be electrolytic versus biogenic, adding electrolytic load for fuel production inside the model would double count the cost of power for the electrolytic fuel (as RESOLVE would add renewable resources to serve the added load) and exclude the electrolyzer capex (RESOLVE does not track capital cost of any load).

Mid Case Renewable Gas Scenario

Figure 6 represents a mid-case scenario in which renewable gaseous fuel reaches and maintains an injected cost (price) of $16/MMBtu (or $2/kg for hydrogen) commodity cost injected onto the natural gas system by around 2030. The relative quantities of hydrogen and synthetic methane used for renewable generation will depend upon their relative cost and the hydrogen limits on the gas infrastructure and generation resources. Assuming the gas grid blend limit reaches 20% by volume without major modifications, this scenario shows that the gas system can receive renewable fuel in the form of injected hydrogen until after 2035, and could do so with a decline in flow on the gas system of nearly 20% (in line with projections in a recent E3 study (see footnote 8). Beyond 2035, the quantities of renewable gas consumed must include enough renewable methane to maintain the hydrogen fraction below the blend limit or incur costs for adapting the natural gas system and generation resources to accommodate higher hydrogen fractions. A renewable methane price of $16/MMBtu is within the forecast range by 2035.



Battery Capacity (GW)	3.7	7.2	12	21	42
Renewable Fuel Consumed (million MMBtu) / GWh gen	0 0	52 5,600	90 9,500	111 13,600	156 21,700
Ren Fuel Energy % 2020 Gas Demand / Vol. % if RH2	0 0	2.4 7.7	4.2 13.3	5.2 16.4	7.3 23.1
Gas Generation Capacity GW / RG Capacity Factor %	25.1 0	20.4 3.1	19.9 5.5	19.9 7.8	19.9 12.4

Figure 5. RESOLVE Case with 30 MMT Base Case Assumptions with $16/MMBtu Renewable Gas Available

Renewable Gas Supply and Competing Uses

The figure below shows the progression of electrolyzer capacity needed to serve the mid-case scenario above assuming a 25% capacity factor. The required build is substantial, particularly in the early years of the build out. However, the required facility additions are of the same magnitude as the additions for other types of facilities selected by RESOLVE and, in particular, the battery build-out that works in combination with renewable fuels to provide firming and other services. The renewable fuels element of the portfolio provides the added benefit of seasonal storage and multi-day (or longer) ride-through capability to address periodic weather events and other interruptions of variable renewable power production.

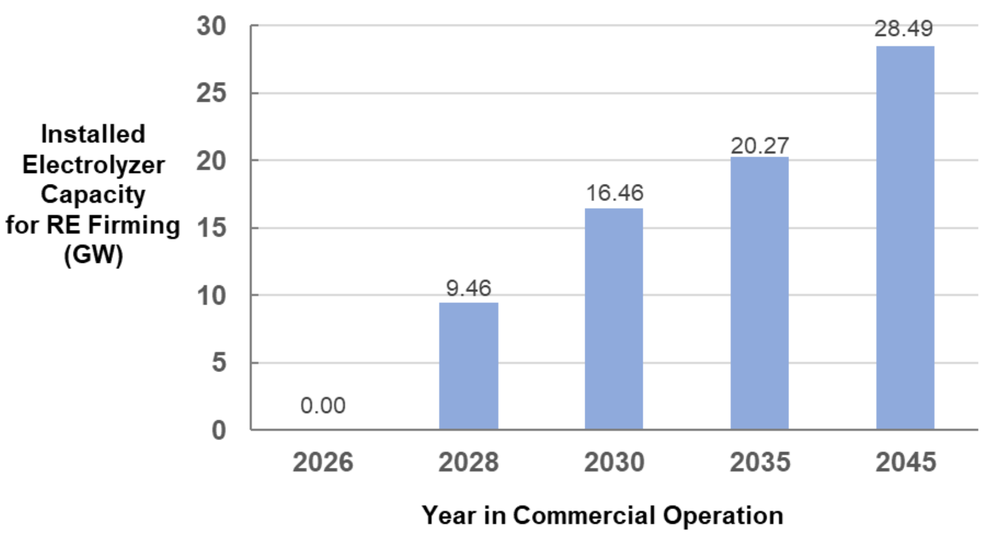


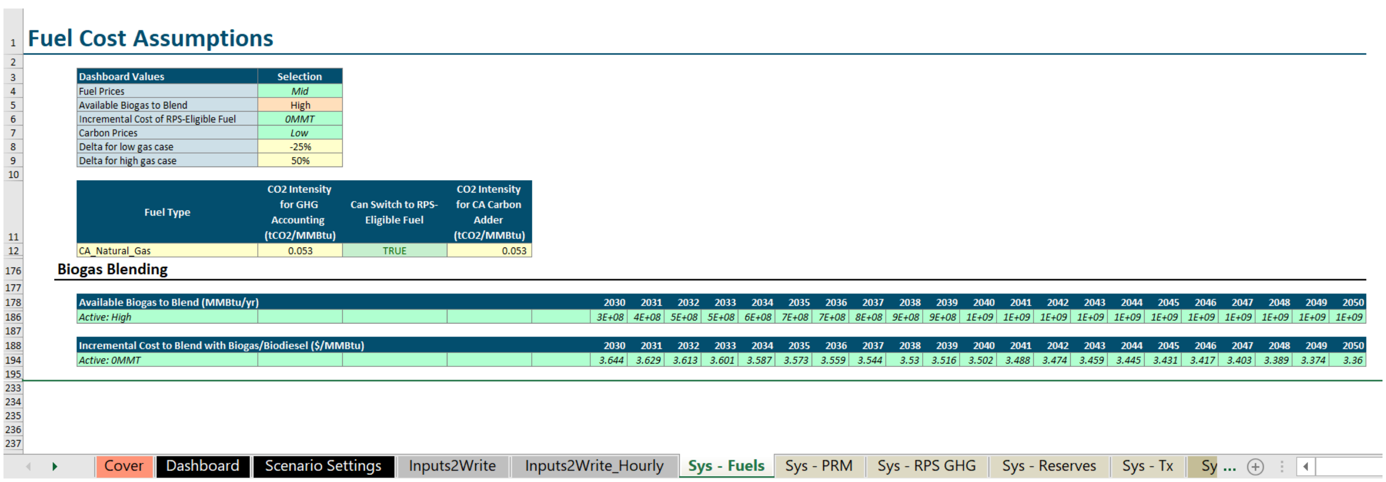
Figure 6. Electrolyzer Capacity Needed for Mid-case Renewable Gas Scenario

There are potential sources of demand for renewable hydrogen and methane outside the power sector with transportation likely to be the strongest competing demand for renewable gas. Currently, Low-Carbon Fuel Standard (LCFS) credit prices are an order of magnitude higher than other carbon and renewable credits. However, if policies are in place to ensure that robust competitive development markets form for the supply of renewable gaseous fuel, head-to-head competition for the supply of renewable gas should ensure that all sectors are served. In the early stages of market development, policy actions will likely be needed to initiate the build out of renewable gas facilities to serve the power sector.

RESOLVE Scenario Set Up

As noted in the introduction, the analyses and results presented here use the 30 MMT base case scenario assumptions for all parameters except: the cost of renewable fuel, the available supply of renewable fuel and the electrolyzer load. The renewable fuel assumptions are specified on the "Sys-Fuels" tab in the RESOLVE Scenario Tool as shown in Figure 7. The renewable gas scenarios were developed by changing the default costs and available supply on this tab as follows:

- Set "Cam Switch to Renewable Fuel" for CA_Natural_Gas to "TRUE"
- Modify "Available Biogas to Blend" table (set a high limit so that the supply is not a binding constraint)
- Modify the "Incremental Cost to Blend" table by entering the desired cost less the value of conventional gas (row 96 of the sheet if mid fuel cost case is selected)



Fuel Cost Assumptions

Dashboard Values	Selection
Fuel Prices	*Mid*
Available Biogas to Blend	High
Incremental Cost of RPS-Eligible Fuel	*0MMT*
Carbon Prices	*Low*
Delta for low gas case	-25%
Delta for high gas case	50%

Fuel Type	CO2 Intensity for GHG Accounting (tCO2/MMBtu)	Can Switch to RPS-Eligible Fuel	CO2 Intensity for CA Carbon Adder (tCO2/MMBtu)
CA_Natural_Gas	0.053	TRUE	0.053

Biogas Blending

Available Biogas to Blend (MMBtu/yr)	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Active: High	3E+08	4E+08	5E+08	5E+08	6E+08	7E+08	7E+08	8E+08	9E+08	9E+08	1E+09

Available Biogas to Blend (MMBtu/yr)	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Active: High	1E+09	1E+09	1E+09	1E+09	1E+09	1E+09	1E+09	1E+09	1E+09	1E+09

Incremental Cost to Blend with Biogas/Biodiesel ($/MMBtu)	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Active: 0MMT	3.644	3.629	3.613	3.601	3.587	3.573	3.559	3.544	3.53	3.516	3.502

Incremental Cost to Blend with Biogas/Biodiesel ($/MMBtu)	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Active: 0MMT	3.488	3.474	3.459	3.445	3.431	3.417	3.403	3.389	3.374	3.36

Figure 7. RESOLVE Scenario Tool Sys-Fuels Tab Set Up

Note on the RESOLVE High-Hydrogen Framing Scenario

For clarity, we point out that the High-Hydrogen Framing Scenario that is part of the set of pre-run scenarios in the RESOLVE Scenario Tool is a load scenario and not a fuel supply scenario. The high-hydrogen scenario adds a specified amount of power demand for electrolyzers with an assumed load shape and capacity factor. The scenario reduces system-average rates due to the favorable load shape assumed for the electrolyzers. However, the model does not include capital costs for the electrolyzers and does not use the produced fuel within the model.

Conclusions and Future Work

The scenarios presented here suggest that renewable gaseous fuel delivered over the existing gas grid has the potential to improve the cost-effectiveness and reliability of the California electric system. Further analysis is needed on the cost and supply trajectory of renewable hydrogen and methane in the context of other uses for those fuels and the overall cost effectiveness of increasing allowable hydrogen fraction on the gas system and/or developing dedicated hydrogen infrastructure to serve power generators. The analysis should include assessment of the cost and feasibility of retrofitting or replacing power blocks to accommodate high, potentially 100%, hydrogen. In addition, the potential cost-effectiveness of adding new zero and near-zero criteria and GHG emissions generation technologies such as fuel cells, and the potential commercialization of reversible cells that can function both as electrolyzers (producing hydrogen) and fuel cells (producing power) should also be investigated. These analyses are ongoing within the UCI APEP hydrogen and renewable fuels program. Quantification of the benefits of storage over long durations and the ability to ride through shortfalls in renewable power production is also ongoing

More information on APEP's renewable fuel research can be found here.

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