Comparison of conventional vs. modular hydrogen refueling stations, and on-site production vs. delivery

Ethan S. Hecht, Joseph Pratt
Sandia National Laboratories

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Albuquerque, New Mexico 87185 and Livermore, California 94550

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SAND2017-2832

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SAND2017-2832

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SAND2017-2832
Unlimited Release
Printed March 2017

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Abstract

To meet the needs of public and private stakeholders involved in the development, construction, and operation of hydrogen fueling stations needed to support the widespread roll-out of hydrogen fuel cell electric vehicles, this work presents publicly available station templates and analyses. These 'Reference Stations' help reduce the cost and speed the deployment of hydrogen stations by providing a common baseline with which to start a design, enable quick assessment of potential sites for a hydrogen station, identify contributors to poor economics, and suggest areas of research. This work presents layouts, bills of materials, piping and instrumentation diagrams, and detailed analyses of five new station designs. In the near term, delivered hydrogen results in a lower cost of hydrogen compared to on-site production via steam methane reforming or electrolysis, although the on-site production methods have other advantages. Modular station concepts including on-site production can reduce lot sizes from conventional assemble-on-site stations.

Executive Summary

For the wide-spread adoption of fuel cell electric vehicles (FCEVs), additional fueling stations need to be constructed in the U.S. A wide variety of private and public stakeholders are involved in the development of this hydrogen fueling infrastructure. Each stakeholder has particular needs to be met in the station planning, development, and operation process. A sample of stakeholders and needs is given here:

- **Station developers/operators (SD/Os)**: quick evaluation of potential sites and needs; lower investment risk; general cost and return estimates.
- **Local authorities**: understand devices, components in a typical station.
- **Code developers**: understand near-term needs for code refinement.
- **Other analysis groups**: new tool and baseline for economic studies.
- **Businesses/entrepreneurs and R&D organizations**: identification of near-term business solution and technology needs.
- **Local municipalities and the general public**: high-level understanding of typical stations lowering acceptance risk.
- **Funding and financing organizations**: understanding of current technological capabilities, costs, and market needs.

Hydrogen fueling station equipment, designs, and costs vary between developers and are often treated as proprietary information. While necessary from a business standpoint, this can hinder the ability to discuss station design details in a collaborative way.

Publicly available templates of representative station designs can be used to meet many of the stakeholder needs outlined above. These 'Reference Stations' help reduce the cost and speed the deployment of hydrogen stations by providing a common baseline with which to start a design, enable quick assessment of the suitability of a particular site for a hydrogen station, and identify contributors to poor economics and areas of research needed for certain station designs. This work presents five new reference station designs for use by the hydrogen infrastructure community. The Phase 1 Reference Station Design Task[†] examined four build-on-site stations which obtain hydrogen from compressed gas or liquid delivery trucks. The current work builds on the Phase 1 work by producing designs and economic analyses of factory built 'modular' stations and stations utilizing on-site generation, and also brings the cost of supplied hydrogen into the analysis. It includes one traditional design from the Phase 1 work to enable equal comparisons between all station types in the two works. For all station types, three capacities were examined: 100 kg/day, 200 kg/day, and 300 kg/day. The five station types developed in this work are:

- Conventional (assemble-on-site) stations with hydrogen:
  1. delivered as compressed gas from a centralized, already operational production facility (baseline)
  2. produced on-site through steam methane reforming (SMR)
  3. produced on-site through electrolysis

[†] J. Pratt, D. Terlip, C. Ainscough, J. Kurtz, and A. Elgowainy. H2FIRST reference station design task. Technical Report SAND2015-2660R, Sandia National Laboratories, April 2015. Available at http://energy.gov/eere/fuelcells/h2first

- Modular fueling stations with hydrogen:
  4. delivered as compressed gas from a centralized production facility
  5. produced on-site through electrolysis

The cost components of hydrogen fueling stations consist of capital cost of equipment, installation, site acquisition and development, and operating expenses. For conventional stations, capital costs of the equipment were estimated based on updated bills of material from the Phase 1 work. Capital costs for modular stations and modular hydrogen production units were based on discussions with several manufacturers. Operation costs, such as the cost of electricity and other utilities, if necessary, were estimated using data from several sources.

Revenue is assumed to be solely from the sale of hydrogen. Operating expenses and revenue calculations depend on the assumed throughput of hydrogen. The same utilization profile used in the Phase 1 work was used herein to calculate throughput, although it was delayed in the onset year. This utilization model estimates that starting in 2017, 5% of station capacity will be utilized. As the number of fuel cell vehicles on the roads continues to increase, the utilization of stations is projected to increase, up to a maximum of 80% in 2026. All costs were combined with revenue to determine the overall cost of hydrogen to the SD/O such that the station will break even on investments in 7 years. SD/O margin and retail fuel taxes will be added to the calculated hydrogen cost to determine the final price to the consumer, but both of these aspects are outside the scope of this work.

Because the costs in this work are estimated (typically averages of costs from various situations and/or a range of manufacturers), they will likely be different than that of an actual station. To correct for differences in up-front capital or installation costs, a graphical tool is included for the reader to estimate the resulting change in hydrogen cost for a given change in investment cost. For example, the tool can be used to show that a decrease of $300,000 in (depreciable) up-front costs from that estimated herein for a 300 kg/day station would result in a corresponding $1.00/kg decrease in hydrogen cost.

Economic results of the five different station concepts show that stations served by centrally produced, delivered gaseous hydrogen are more economical compared to those which generate hydrogen on-site via SMR or electrolysis. Higher capacity stations have a lower cost for hydrogen to break even at the same point in time compared to lower capacity stations. Using the economic model specifying that a station will break even in year 7, both 300 kg/day modular stations (at $1.5M for the uninstalled modular unit) and conventional stations with central hydrogen production and delivery in tube-trailers, have a hydrogen cost of $14.25/kg (a lower uninstalled modular unit price of $1M results in a hydrogen cost of $12.66/kg). On-site production stations, either through steam methane reforming or electrolysis, have significantly higher capital costs than delivered, centrally produced hydrogen. This increase in capital results in a hydrogen cost increase of $6-$10/kg depending on the station capacity. While SMR capital costs are higher than electrolyzer costs, the electricity cost ends up making electrolyzer-supplied stations the most expensive option in terms of resulting cost per kilogram of dispensed hydrogen under the assumptions of this work. Full cost results are shown in Table ES-1 and Fig. ES-1.

In addition to the economics, the station equipment was laid-out in typical land use arrange-

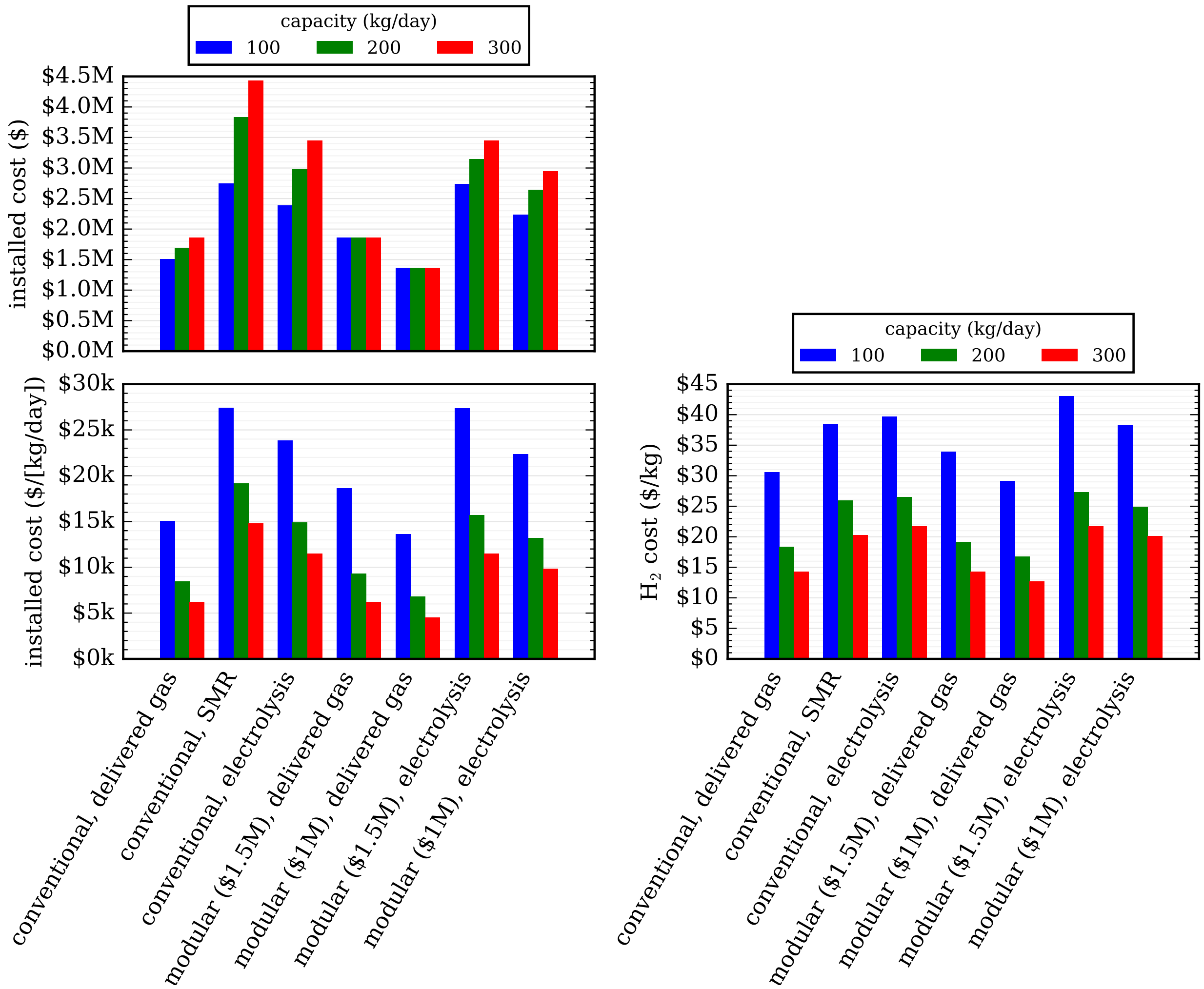

Figure ES-1. Installed cost (which includes site preparation, engineering & design, permitting, component capital and installation costs) are shown in the left frames. The top frame is the total investment in 2016$, while the bottom left frame is the installed cost per mass of hydrogen dispensed (kg/day). The hydrogen cost to break even at year 7 is shown in the right frame, for the stations analyzed in this work.

Table ES-1. Installed cost (which includes site preparation, engineering & design, permitting, component capital and installation costs), and resulting hydrogen cost to break even at year 7 for the stations analyzed in this work.

station capacity →	100 kg/day		200 kg/day		300 kg/day	
station type ↓	installed cost ($)	H_2 cost ($/kg)	installed cost ($)	H_2 cost ($/kg)	installed cost ($)	H_2 cost ($/kg)
conventional, delivered H_2	$1.51M	$30.53	$1.69M	$18.37	$1.86M	$14.26
conventional, SMR H_2	$2.74M	$38.47	$3.83M	$25.96	$4.43M	$20.23
conventional, electrolysis H_2	$2.38M	$39.66	$2.98M	$26.51	$3.45M	$21.74
modular ($1.5M), delivered H_2	$1.86M	$33.90	$1.86M	$19.16	$1.86M	$14.25
modular ($1M), delivered H_2	$1.36M	$29.12	$1.36M	$16.77	$1.36M	$12.65
modular ($1.5M), electrolysis H_2	$2.74M	$43.03	$3.14M	$27.30	$3.45M	$21.73
modular ($1M), electrolysis H_2	$2.24M	$38.25	$2.64M	$24.91	$2.95M	$20.13

ments. Modular stations and stations with on-site production show a substantial decrease in overall required lot size due to reduced equipment size, reduced truck access requirements, and reduced setback distances. The included piping and instrumentation diagram shows the system level requirements for components and instruments and includes an estimate of utility requirements which are intended to be useful for site screening.

This work details the economics of current hydrogen refueling stations, and includes some sketches of what these fueling stations might look like. It visually depicts the contributions to capital and operational costs of hydrogen for different station concepts, making it easy to find the largest contributors to a high cost of hydrogen to the consumer. This information can be used to devote research and development towards these high contributors. At the station, the dispenser, compressors, and chillers are expensive pieces where additional development, or higher volume production could reduce station costs. For electrolysis, the purchase of low-priced electricity could serve to make on-site production cost competitive with central production and delivery. This report enables the comparison of different station concepts that could be implemented in various market scenarios.

Acknowledgment

This work is funded by the U.S. Department of Energy (DOE) Fuel Cell Technologies Office in the Office of Energy Efficiency and Renewable Energy.

The Hydrogen Fueling Infrastructure Research and Station Technology Project (H_2FIRST) is a DOE project executed by Sandia National Laboratories and the National Renewable Energy Laboratory. The objective of H_2FIRST is to ensure that fuel cell electric vehicle customers have a positive fueling experience relative to conventional gasoline/diesel stations as vehicles are introduced (2015–2017) and transition to advanced refueling technology beyond 2017.

DOEs Fuel Cell Technologies Office established H_2FIRST directly in support of H_2USA, a public-private collaboration co-launched by DOE and industry in 2013 to address the key challenges of hydrogen infrastructure.

In addition to DOE, the team wishes to thank the H_2USA Hydrogen Fueling Station Working Group, California Fuel Cell Partnership, the California Energy Commission, the California Air Resources Board, and representatives from industry, including H2 Logic, Hydrogenics, ITM Power, Linde, Nuvera, PDC Machines, Proton OnSite, and Siemens AG for their input and support.

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1 Introduction

The Hydrogen Fueling Infrastructure Research and Station Technology Project (H_2FIRST) is a U.S. Department of Energy (DOE) project executed by Sandia National Laboratories and the National Renewable Energy Laboratory. The objective of H_2FIRST is to ensure that fuel cell electric vehicle (FCEV) customers have a positive hydrogen fueling experience relative to conventional gasoline/diesel fueling stations as FCEVs are introduced and to enable any needed transitions to advanced refueling technology in the future.

For the wide-spread adoption of fuel cell electric vehicles (FCEVs), additional fueling stations need to be constructed in the U.S. This work provides economic analyses and layouts of current-technology fueling station designs that utilize state-of-the-art components. These reference station designs can help reduce the cost and speed the deployment of hydrogen stations by providing a common baseline with which to start a design, enable quick assessment of the suitability of a particular site for a hydrogen station, and identify contributors to poor economics and areas of research needed for certain station designs.

This work is intended to address the needs of a wide variety of stakeholders. Some examples of stakeholders and applicability include:

- **Station developers/operators (SD/Os)**: quick evaluation of potential sites and needs; lower investment risk; general cost and return estimates.
- **Local authorities**: understand devices, components in a typical station.
- **Code developers**: understand near-term needs for code refinement.
- **Other analysis groups**: new tool and baseline for economic studies.
- **Businesses/entrepreneurs and R&D organizations**: identification of near-term business solution and technology needs.
- **Local municipalities and the general public**: high-level understanding of typical stations lowering acceptance risk.
- **Funding and financing organizations**: understanding of current technological capabilities, costs, and market needs.

1.1 Background and Contents

This is a follow-on work to the Phase 1 Reference Station Design Task [3]. That work screened 160 different station permutations and found 4 near-term station designs that were economically favorable, and one future station. The report provides thorough designs of these stations, with bills of materials, layouts on greenfields and co-located with gasoline stations, and piping and instrumentation diagrams. The resulting capital and hydrogen costs for the selected stations in that analysis are reprinted here in Table 1.

However, the cost of the hydrogen was not included in the analysis, only the capital and operating costs associated with the fueling station (i.e., compression, high-pressure storage, cooling, and dispensing). In addition, the Phase 1 Reference Station project did not consider on-site hy-

Table 1. Economically favorable station designs from the Phase 1 Reference Station Design Task [3] that were fully analyzed.

Target Market	Delivery Method	Daily Capacity (kg/day)	Maximum Consecutive Fills	Hoses	Hydrogen Cost* ($/kg)	Capital Cost (2009$)
high use	liquid	300	5	2	$7.46†	$1,486,557†
high use	liquid	300	5	2	–	$2,007,358‡
high use	gas	300	6	1	$6.03	$1,251,270
low use	gas	200	3	1	$7.82§	$1,097,560§
intermittent	gas	100	2	1	$13.28	$954,799

* Hydrogen cost in this table is only the station contribution to the cost of hydrogen and does not include the cost of hydrogen delivered to the station.

† Costs for this future station assume a high-pressure evaporator and cryopump, which are not currently commercially available.

‡ Consistent capital cost for a hydrogen fueling station that has hydrogen delivered as a liquid using currently available technology, but the cost of hydrogen could not be calculated using HRSAM [4].

§ A typography error in the first report has been corrected for the hydrogen and capital cost of this 200 kg/day station.

drogen generation nor the impacts of 'modular' stations where most components are pre-packaged in an assembly plant, potentially reducing footprint and cost compared to traditional build-on-site stations.

This work builds on the Phase 1 Reference Station work by producing designs and economic analyses of modular stations and stations utilizing on-site generation. It also re-evaluates one traditional design from the Phase 1 Reference Station work to enable equal comparisons between all station types in the two works.

In this report, we describe many facets of designing hydrogen fueling stations. In Section 1.2, Approach, the station concepts are described. In Section 1.3, Method Overview, the steps to building a fueling station are outlined, the sources of economic data needed to calculate station operating costs are reported, along with the station utilization profiles. The Method Overview section is intended for readers who are interested in the assumptions and data used to determine the cost of hydrogen, as the economic model is detailed in this section. In Section 2, Station Cost Components, further details of the economic assumptions made about specific pieces of hydrogen fueling stations are included. An experienced SD/O may wish to skip to Section 3, Results: Station Designs and Costs, which contains the detailed results of the economic model and includes sketches of hydrogen fueling stations.

The wide variety of stakeholders on hydrogen refueling infrastructure and their interests means that some parts of the report will be more useful than others to different readers. Rather than trying to simplify the report for one audience at the expense of another, it is inclusive of all assumptions, data, and methods, so that the reference stations described in this report can serve as a starting point for designs of real-world stations.

1.2 Approach

In this work, along with the costs associated with constructing and operating a hydrogen fueling station, we also consider the costs of producing hydrogen on-site or having hydrogen produced at a centralized facility and delivered. We also compare 'conventional' stations, where parts (e.g. compressors, tubing, valves, tanks) are assembled at the fueling station site to 'modular' stations, where parts (at least the compression and high-pressure storage, if not the dispenser) are assembled at a centralized facility into a single unit and delivered to the fueling station site on a skid or in a trailer. Five station concepts are considered herein:

- Conventional (assemble-on-site) stations with hydrogen:
  1. delivered as compressed gas from a centralized, already operational production facility (baseline)
  2. produced on-site through steam methane reforming (SMR)
  3. produced on-site through electrolysis
- Modular fueling stations with hydrogen:
  4. delivered as compressed gas from a centralized production facility
  5. produced on-site through electrolysis

For each of these concepts, 100, 200, and 300 kg/day stations are studied since these capacities are appropriate for current and near-term station builds, as identified in the Phase 1 Reference Station Design report [3]. Costs (capital and operating) for each of these stations were estimated, and the cost of hydrogen[1] was calculated. Components needed for each of these station concepts are specified, and potential layouts are presented.

1.3 Method Overview

Building a hydrogen fueling station requires several steps (which have associated costs and/or considerations):

1. Identification and acquisition of land where the station can be built.
2. Design of the station to account for the available space. If hydrogen is to be delivered, delivery routes for the large tube-trailers must be planned.
3. Design of utility connections, including electrical power, potentially water and/or natural gas.
   - Both conventional and modular stations require electrical power for the compressor and chiller. Trenching and conduit must be run, transformers and electrical panels often require upgrading/replacement.
   - On-site electrolysis requires a water supply (in addition to sufficient electrical power).

[1] In this work, we refer to the *cost* of hydrogen, rather than the *price*. Using the method and assumptions described herein, we calculate a per kg *cost* to a station developer/operator to provide hydrogen to consumers. Station operators will be responsible for setting *prices* at their station, which is what end consumers will pay for hydrogen and will vary based on local market demand, profit margins, retail fuel taxes, and other considerations, none of which are considered in this work. The *cost* of hydrogen could be considered a 'fixed minimum selling price' to meet the payback criteria assumed in this analysis.

- On-site SMR requires water and natural gas (and sufficient electrical power).

4. Permitting and approval of the site design with the authorities having jurisdiction.
5. Preparation of the site for station installation. For a conventional station, a concrete pad is required, and for modular stations, concrete footings are needed at a minimum on which to secure the components or modular housing. This concrete must be properly grounded and have a low electrical resistance to meet the fire code.
6. Installation of the fueling station.

In this analysis, the costs of land procurement (step 1) are neglected. Some costs in this analysis are based on the H2A Refueling Station Analysis Model (HRSAM) [4]. In HRSAM, the cost of installation of equipment (step 6) is 35% of the raw capital investment, and the cost of site preparation, engineering & design, project contingency, and upfront permitting costs (steps 2-5), are 31% of the raw capital costs. Accordingly, here installation was assumed to cost 35% of the station capital for the conventional stations. However, since many of the modular installation costs are tied into the cost of the unit, the cost of modular station installation is reduced to a flat cost of $60k (the details of this assumption can be found in Section 2.5). Also, rather than using the percentage (31%) for site preparation, engineering & design, project contingency, and upfront permitting costs, in this analysis we assume a flat $300k for these costs. This reflects the fact that these costs are linked more to the site itself, rather than the cost and size of the equipment that must be installed on the site. Since there is considerable variability in design, permitting, and site preparation costs, we include additional analysis and charts showing how variability in these costs can change the cost of dispensed hydrogen later in this section.

For all stations, capital costs of the equipment were estimated. Bills of materials for the conventional stations were assembled in the Phase 1 Reference Station Design Report [3]. In this work, we have updated these bills of material to estimate the cost of a conventional station today (2016). Capital costs for modular stations and modular hydrogen production units were based on discussions with several manufacturers. For both the conventional and modular stations, the design includes a single dispenser (i.e., credit card reader/user interface, valving, hose, and nozzle to connect to the vehicle) able to dispense both 350 and 700 bar hydrogen, located separately from the 'station' (that contains the compressor, high-pressure storage, chiller, programmable logic controller, and safety equipment). Costs for specific components (e.g., compressors, SMRs), are discussed in Section 2.

In order to evaluate the operation costs, the cost of several utilities and commodities, namely, diesel fuel, natural gas, electricity, and water, were needed. With the exception of water, these costs were estimated using pricing data from the U.S. Energy Information Administration (EIA) [1]. As shown in Fig. 1, both historical and projected prices were extracted from the EIA database. The data in the plots comes from the following series:

- Diesel
  - U.S. No 2 Diesel Retail Prices, Annual
  - Nominal Petroleum Prices : Transportation : Diesel Fuel, Reference, AEO2015
- Natural gas
  - Retail Price of Natural Gas in Commercial Sector, U.S. Average, Annual
  - Energy Prices : Nominal : Commercial : Natural Gas, United States, Reference
  - Retail Price of Natural Gas in Industrial Sector, U.S. Average, Annual

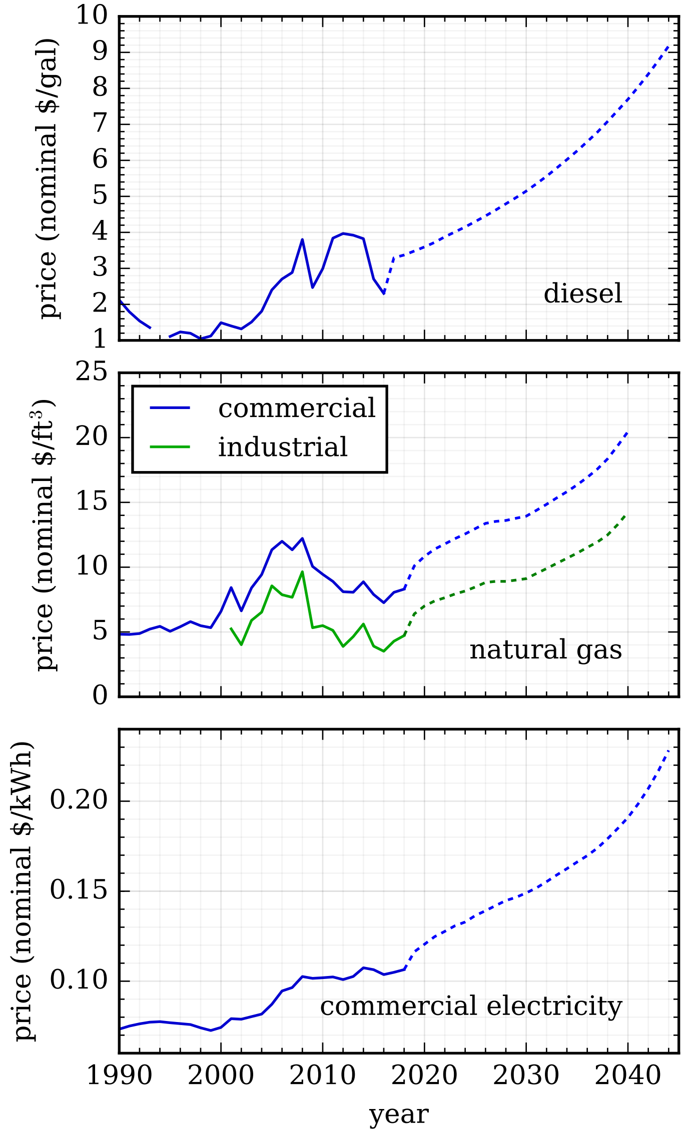


Figure 1. Historical and projected price of U.S. No 2 Diesel (top), natural gas (middle), and electricity (bottom), from EIA data [1].

  – Energy Prices : Nominal : Industrial : Natural Gas, United States, Reference, AEO2015
- Commercial electricity (U.S. grid mix, currently 13% renewable[2]):
  – Retail Price of Electricity in Commercial Sector, U.S. Average, Annual
  – Energy Prices : Nominal : Commercial : Electricity, United States, Reference, AEO2015

In all cases these data project out to 2045.

It should be noted that the electricity prices estimated by EIA and used in this work assume status-quo reliance on fossil fuel. In fact, further cost reductions in renewable electricity generation

[2] 2015 estimate from http://www.eia.gov/tools/faqs/faq.cfm?id=92&t=4

Table 2. Water costs in various locations in California.

Location	Price ($/100 ft^3)	source
East Bay	4.44	ebmud.com
Los Angeles	1.022-10.409	dpw.lacounty.gov
San Diego	5.02	sandiego.gov
San Jose	4.509	sjwater.com
San Francisco	7.14	sfwater.org
San Francisco Peninsula	7-8	midpeninsulawater.org

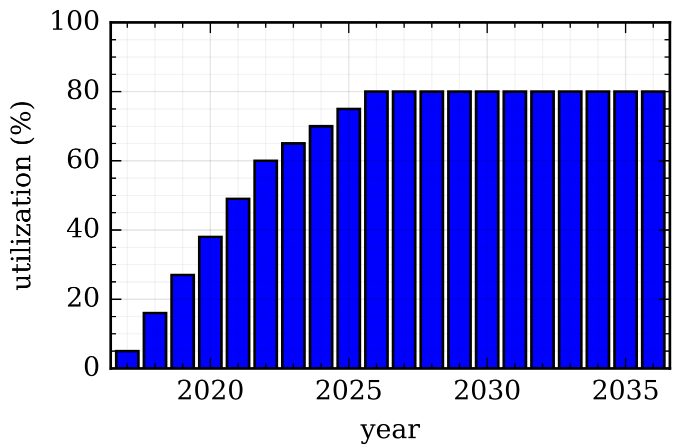


Figure 2. Utilization model from 2017 to 2036 of the theoretical hydrogen fueling stations in this report.

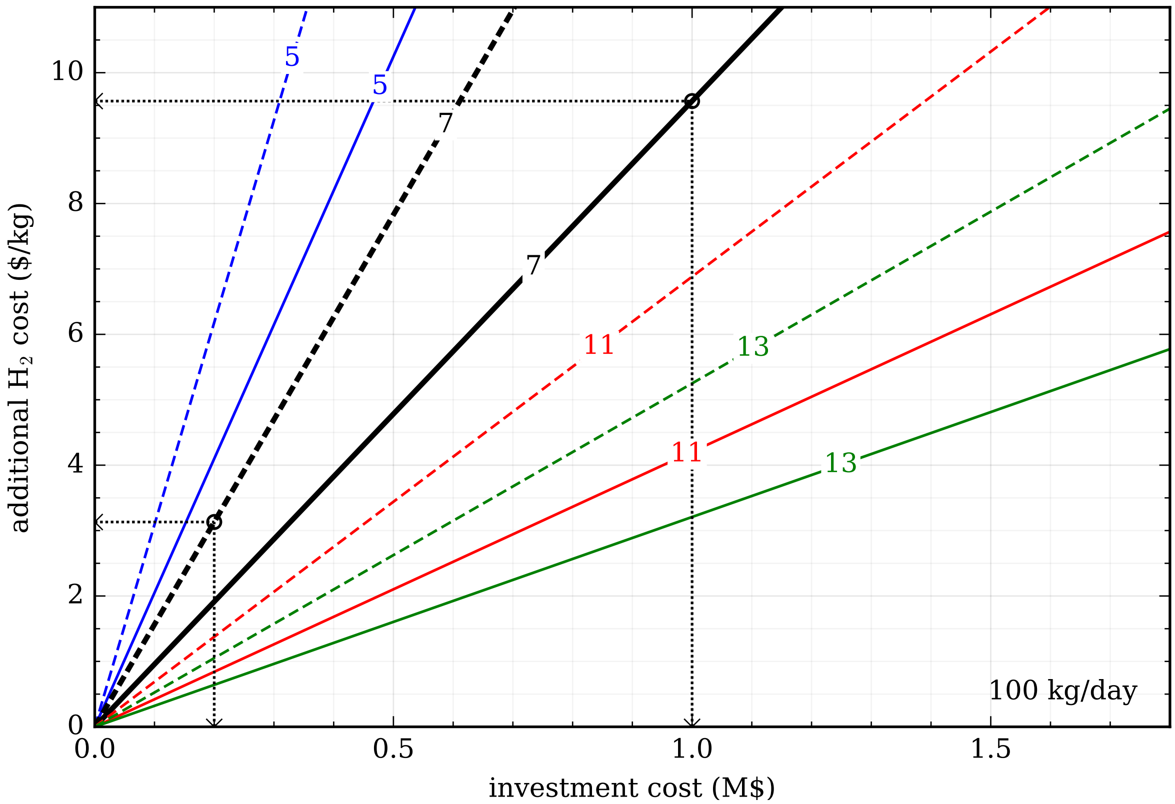
technologies and utilization of low-cost stranded assets such as large nuclear coupled with increasing fossil fuel costs may actually result in the opposite trend of future electricity rates. As will be seen in the results, variability in electricity rates can have a large impact on the cost effectiveness of on-site generation of hydrogen via electrolysis.

Water is needed for electrolysis or steam methane reforming. Water rates were estimated to be $8 per hundred cubic feet in 2016$, based on information from various sources of relevance to the California market shown in Table 2. While water rates can vary dramatically around the country, as will be seen in the results, the cost of water has a negligible impact on the resulting cost of hydrogen so using the California rates was deemed an acceptable approximation.

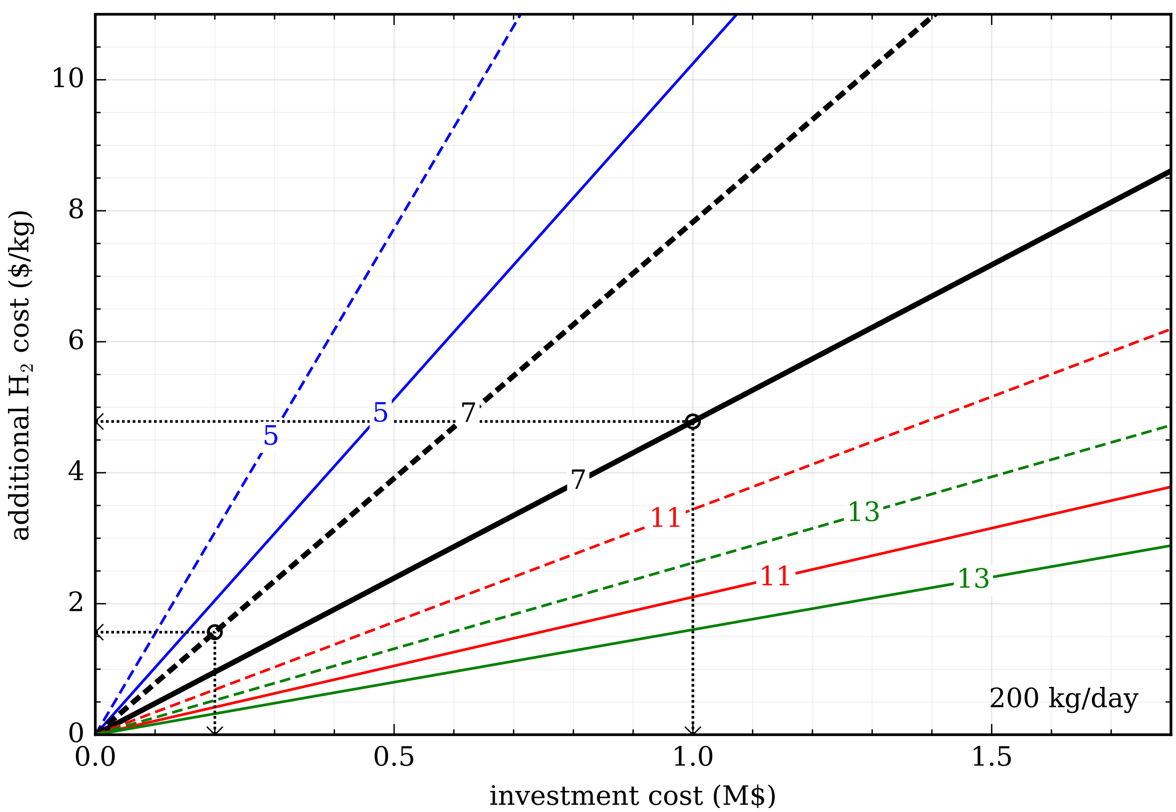
In order to use this cost information to calculate operational costs and revenues, a station utilization rate must also be specified. The same utilization profile used in Phase 1 of the Reference Station project [3] was used herein, except the profile ramp has a delayed start, as is suggested by a recent analysis by the California Air Resources Board [5]. This profile is shown in Fig. 2. As shown, this utilization model estimates that starting in 2017, 5% of station capacity will be utilized. As the number of fuel cell vehicles on the roads continues to increase, the utilization of stations is projected to increase, up to a maximum of 80%, in 2026. This means, for example, that in 2026, and in perpetuity after, a station sized for 100 kg/day will sell, on average, 80 kg/day hydrogen.

Site preparation, capital, installation, and operating costs were combined with hydrogen throughput and a required break-even time period on the initial investment to determine the overall cost of hydrogen to the SD/O. The estimates for these cost components are based on best-available information including consultation with station and equipment providers, prior studies, and government entities involved in publicly-funded stations. However, in most cases the estimated costs are averages and can vary in practice–for example, site preparation costs can vary widely, or different manufacturers will have different costs for equipment with similar specifications. If the reader has actual cost information that varies from that which is estimated in this report, Fig. 3 can be used to calculate the resulting change in hydrogen cost.

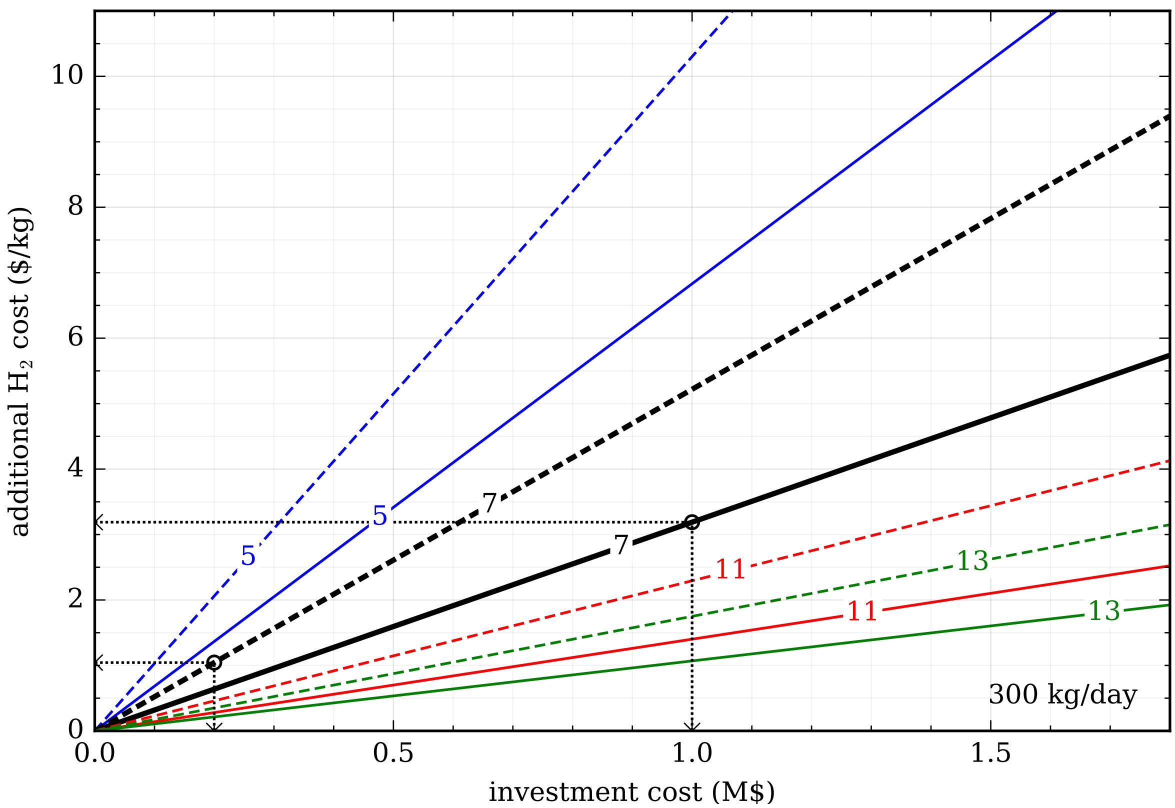
Figure 3 shows the cost of hydrogen as a function of the initial non-depreciable cost by the dashed lines (e.g., land purchase costs), and an initial depreciable cost (e.g., equipment) by the solid lines. Depreciation was estimated using a 7-year Modified Accelerated Cost Recovery System (MACRS) depreciation rate and an overall tax rate of 38.9% (35% federal and 6% state tax), the rate specified in HRSAM [4]. The numbers and different colors in the plot represent the numbers of years required to make back the cost of the asset. For example, if one were to purchase land (which is non-depreciable) for $200k, to make back that investment in 7 years the cost of hydrogen would be approximately $3/kg higher than without the purchase for a 100 kg/day station, or about $1/kg higher for a 300 kg/day station (note that this assumes the stations are utilized at the rate shown in Fig. 2). As a second example, if a $1M electrolyzer were aded to a station (a depreciable investment), it would add $9.57/kg for hydrogen to pay for that asset for a 100 kg/day station and just over $3/kg for a 300 kg/day station. (Note that the costs scale inversely with capacity because the same percentage station utilization rate shown in Fig. 2 is used in this analysis. In other words, we assume that customers at the 100 kg/day station are purchasing exactly 1/3 the hydrogen as at the 300 kg/day station.)



(a) Additional cost of hydrogen for a 100 kg/day station.



(b) Additional cost of hydrogen for a 200 kg/day station.



(c) Additional cost of hydrogen for a 300 kg/day station.

Figure 3. Additional cost of hydrogen given initial construction/capital investment for the station utilization profile shown in Fig. 2. Numbers on the graph lines are the years required to break even on the investment, solid lines are for a depreciable asset (on a 7 year MACRS schedule), and dashed lines are for a non-depreciable asset. Points on the plots are examples from the text.

2 Station Cost Components

This section describes the primary contributors to the cost of hydrogen:

- Centrally Produced Hydrogen and Delivery
- Hydrogen Produced On-site via Steam Methane Reforming
- Hydrogen Produced On-site via Electrolysis
- Compression, Storage, and Ancillary Equipment for a Conventional Station
- Packaged Compression, Storage, and Ancillary Equipment for a Modular Station
- Hydrogen Dispensers

Each subsection describes the technical details of the components and the rational for the assumed costs in the economic model.

2.1 Centrally Produced Hydrogen and Delivery

For delivered hydrogen, we included the cost of buying hydrogen from a centrally located production facility, delivering it in tube-trailers, and leasing tube-trailers for storage at the fueling station. Initially, the H2A Delivery Scenario Analysis Model (HDSAM) [4] was evaluated for its applicability to this project, but this model did not have enough flexibility in its scenarios. In this analysis, we wanted to consider a single station, and not consider savings from multiple station deliveries due to tractor/trailer sharing. In this analysis, we did not model the cost of tractor/trailer purchase and payment, but rather considered a very early market scenario (i.e., the current market conditions) where the industrial gas company would own and control the delivery tractors and lease the tube-trailers to the station owners (assuming that they are left on-site until empty). Some of the data from HDSAM was used in this analysis, including some parameters shown in Table 3. The delivery distance was assumed to be 200 miles, so that delivered hydrogen costs could be compared to estimates from industrial gas companies [6]. The trailers were assumed to have 300 kg of usable hydrogen. There are some jumbo, high-capacity tube-trailers in the market, with closer to 1100 kg usable hydrogen[3], but for these current market scenario simulations we assumed more conventional tube trailers with steel tubes and the smaller capacity. With a 300 kg usable H_2 capacity, the utilization scenario shown in Fig. 2 and a given station capacity were used to calculate the time to consume a tube-trailer. The trips per year were calculated, and fuel, labor, and other costs for delivering hydrogen were calculated. Frequent deliveries of hydrogen would be necessary, and it is likely that a fueling station would need to have multiple tube-trailers on site to ameliorate outages. Especially for the 300 kg/day station, as the peak nameplate capacity is approached it may become infeasible to get daily tube-trailer deliveries, and another type of hydrogen storage (i.e. liquid), or some on-site production would probably be required. Nonetheless, we performed the analysis with the assumption that the industrial gas companies would be able to provide near daily deliveries of tube-trailers in the out-years.

Figure 4 shows the costs components associated with delivering tube trailers to a single station. Because each station is assumed to follow the same utilization projections, the costs follow the

[3] http://www.the-linde-group.com/en/news_and_media/press_releases/news_20130925.html

Table 3. Data used to calculate delivered hydrogen costs.

description	value
average delivery gas mileage[1]	6 mpg
average delivery speed[1]	37.8 mph
tube-trailer capacity[2]	300 kg
tube-trailer maximum pressure[2]	250 bar
delivery labor cost[1]	21.21 $/hr
overhead on labor[1]	20%
insurance cost[1]	$0.106 /mile
licensing & permits[1]	$0.116 /mile
maintenance cost[1]	$0.078 /mile
lease price[3]	$3500 /month

[1] data from HDSAM [4]
[2] data from energy.gov
[3] data from personal communications

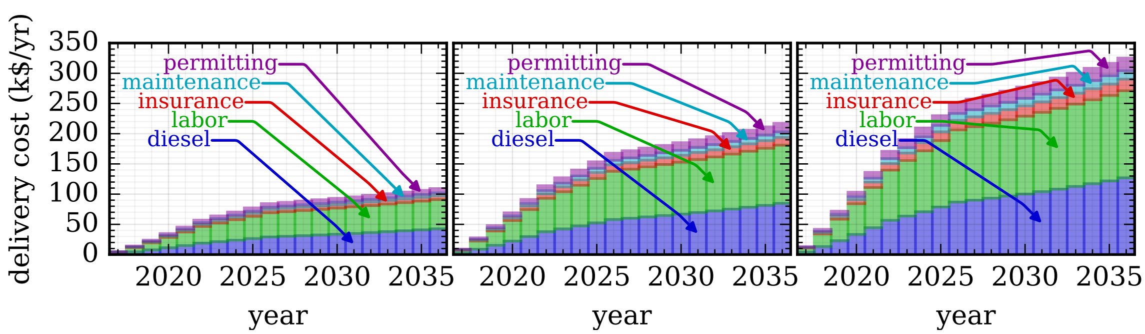


Figure 4. Breakdown of annual costs associated with delivery of hydrogen, for a 100 (left), 200 (center), and 300 (right) kg/day station. Does not include the cost of hydrogen production or transport trailer.

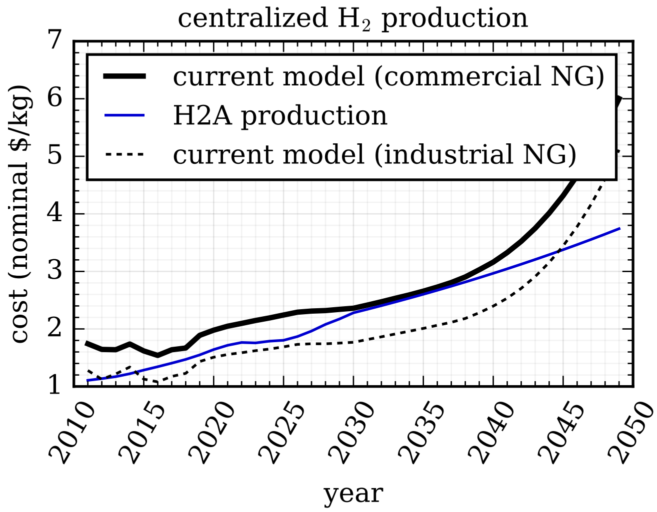


Figure 5. Cost for centralized production of hydrogen for the model used in this study and an H2A model (based on 380,000 kg/day production) [2].

same increasing trend out to 2026. The continued increase past 2026 is due to inflation, which is estimated at 1.9%[4], and the increasing cost of diesel fuel (Fig. 1). This chart shows that labor is the largest contributor to hydrogen delivery costs, followed by the cost of diesel to fuel the delivery truck. All of these delivery costs scale proportionally, if the delivery distance were to be smaller or larger than 200 miles. The costs also scale proportionally with the nameplate capacity, because the utilization scales with the nameplate capacity, causing the larger stations to require proportionately more deliveries, labor, maintenance, etc.

Along with delivery costs, in this analysis we also include the cost of the centrally produced hydrogen. The cost of centrally produced hydrogen was estimated using a correlation from Lemus and Duart [7]. Because the central hydrogen production plants that exist today make hydrogen from steam-methane reforming, they found that production was linearly dependent on the price of natural gas:

$$\mathrm{H}_{2\text{production cost}} = 1.2 \cdot \mathrm{NG}_{\text{price}} + 6,$$

where the cost and price are in $/GJ. Using the pricing data shown in Fig. 1 this centrally produced hydrogen cost was calculated. The DOE's H2A production model (version 3.0.1) [2] is compared to this calculation in Fig. 5, using both commercial and industrial costs for natural gas. As shown, the Lemus and Duart model agrees quite well with the H2A production model until about 2042. Thus the commercial natural gas price was selected for use in further calculations of the costs associated with hydrogen production for conventional, delivered hydrogen stations.

Finally, for delivered, centrally produced hydrogen, the cost of the tube trailer lease was included. Shown in Table 3, the lease price was estimated at $3500 per month. We assumed in

[4]Inflation rate taken from HRSAM [4].

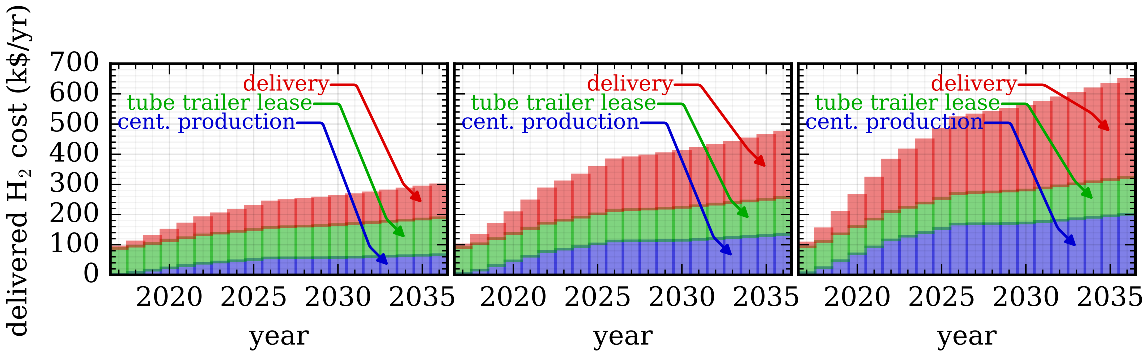


Figure 6. Total costs associated with central production of hydrogen, delivery, and storage in a tube-trailer for a 100 (left), 200 (center), and 300 (right) kg/day hydrogen refueling station.

this analysis that the stations would continually lease 2 tube trailers, at $7000 per month, so there would be no outages as the empty hydrogen tube trailers were exchanged. We assumed that the lease cost was not affected by the number of deliveries required. Figure 6 shows the total costs associated with delivered, centrally produced hydrogen. Within the red delivery bar are all of the costs shown in Fig. 4. All three of the costs broken out in the plot (central production, tube-trailer leasing, and delivery) are significant contributors to the cost of centrally produced, delivered hydrogen. As shown, the cost of the tube-trailer lease was fixed in this model, for any station capacity, resulting in a smaller percentage of the costs for 200 and 300 kg/day stations. This is far from a certain assumption. The high lease price might cause a station operator to think about purchasing a tube-trailer (or fleet of tube-trailers), but the estimated cost of a tube trailer within HDSAM [4] is around $1 million. At least two trailers would be required, unless the station were shutdown while the tube trailers were being refilled, so purchase might not make financial sense without an advanced network of stations and/or a long-term financial horizon. An additional option to eliminate the trailer lease expense is to install a similar amount of low pressure hydrogen storage on site, allowing the trailer to discharge its contents and depart. This would add several hundred thousand dollars of capital cost to the station (depending on the amount and type of storage installed).

2.2 Hydrogen Produced On-site via Steam Methane Reforming

Cost information for on-site reformers was gathered from several manufacturers. An estimate for capital cost is $1.15M for a 100 kg/day unit, $2.04M for a 200 kg/day unit, and $2.46M for a 300 kg/day unit. A functional fit was found to several data points, including the H2A production model [2] capital cost for a 1500 kg_{H_2}/day unit, which is $3.25M. As with most products, the per kg cost of production reduces as the production rate increases.

Feedstock consumption rates were also collected from manufacturers for several on-site reforming units. Based on this information, assumed rates of 3.9 kWh/kg_{H_2}, 96 l_{H_2O}/kg_{H_2}, and 3.5

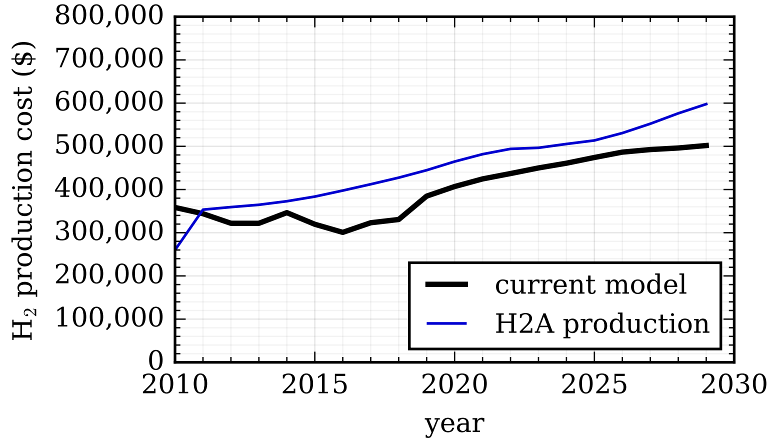


Figure 7. Annual production cost of 500 kg/day hydrogen from distributed steam methane reforming, as predicted by the current model, and using the H2A production model.

kg_{NG}/kg_{H_2} were used to estimate operating costs. The operating costs for the H2A production model for distributed SMR scaled down to 500 kg/day [2] was compared to the operating costs calculated using the current model (using the cost information shown in Fig. 1, and the commercial price of natural gas). This comparison is shown in Fig. 7. The annual operating costs of the current model, which is based on recent manufacturer information, are within 20% of the H2A model predictions.

One factor that is not taken into account in this analysis is startup and shutdown production efficiencies and losses. Because SMRs operate at high temperature, start-up is slow, and frequent shutdown/startup cycles can drastically reduce production efficiency. It may be cheaper to simply produce and vent hydrogen continuously rather than cycling the unit off and back on. The additional cost of running the SMR when it is not needed is not included in this analysis; it is assumed that this process occurs instantaneously, and without an efficiency penalty. The impact of this assumption is that the operational costs of the SMR may be under-predicted by this model.

2.3 Hydrogen Produced On-site via Electrolysis

The two most common type of electrolysis units on the market today are polymer electrolyte membrane (PEM) and alkaline. PEM electrolysis units use the same technology as PEM fuel cells (which are found in vehicles), but the cells are biased and protons move in the opposite direction from a fuel cell. Alkaline fuel cells have a liquid electrolyte solution that serves to transport ions from the electrodes. Alkaline electrolyzers are a more mature technology, can be cheaper, and may have a longer lifetime than PEM electrolyzers, but PEM electrolyzers produce higher purity hydrogen with less sensitivity to water purity, are smaller, can respond more quickly to changes in production rate, and can produce hydrogen at pressure, reducing compression needs. In this analysis, we are not specifying the type of electrolyzer since costs (which are not precisely quoted in any case) are reasonably similar.

Electrolyzer electricity consumption was estimated to be 5.6 kW-hr/$m^3_{H_2}$ = 62.4 kW-hr/kg_{H_2}. There is some variability in electricity consumption depending on each manufacturer's equipment, but this value is in line with an analysis by Ursua et al. [8] and is the average value from the Electrolyzer Energy composite data product (CDP)[5] from NREL. The municipal water consumption was calculated as just under 3-times the stoichiometric value required based on the reaction ($H_2O \rightarrow H_2 + 1/2O_2$) (which accounts for purification system losses and other cooling water needs) at 26.4 l_{H_2O}/kg_{H_2}. An informal survey of several companies led to capital cost estimates of $800k, $1.2M, and $1.5M for the 100, 200, and 300 kg/day stations. These capital costs are lower than the SMR capital costs used in this analysis for an equivalent hydrogen production capacity. For the modular electrolyzer units considered herein, the installation cost was assumed to be a flat $60k, regardless of the hydrogen production capacity, an estimate based on discussions from several companies.

Similar to the SMR, the efficiency penalty for shutting down the unit and restarting it is not taken into account in this analysis. This inefficiency is expected to be lower for electrolysis than SMR since the operation temperatures are much lower and the startup process is simpler. Nonetheless, there will be an efficiency penalty for cycling the electrolyzer off and back on, so the electrolyzer and storage sizes need to be optimized for the station utilization rates during station design.

2.4 Compression, Storage, and Ancillary Equipment for a Conventional Station

For conventional stations, most equipment costs from Phase 1 of the reference station design report [3] were used in this analysis. Shown in Table 4, costs for all but the compressor, dispenser, and chiller/cooling block were inflation adjusted from 2009$ to 2016$ at a 1.9% inflation rate. The cost of the compressor was not simply inflated, but rather re-estimated using the compressor size evaluated by HRSAM [4] and Fig. 2 from the Phase 1 Reference Station Design report [3]. The $100k–$150k capital cost estimates for the compressors given in the first report were based on a specific station design with a smaller compressor, rather than the compressor sizing evaluated by HRSAM. The HRSAM estimates for compressor needs for the 100, 200 and 300 kg/day stations are 6, 14, and 23 kg/hr as shown in the table. Compressor energy consumption was assumed to be 4.2 kWhr/kg_{H_2}. This is consistent with NREL's Compressor Energy CDP[6] and manufacturer specifications. This factor was used to calculate the energy utilization, and size the compressors at 25, 60, and 100 kW, for the 100, 200, and 300 kg/day stations, respectively. The electrical requirements are a bit more than those calculated by HRSAM, which assumes that the compressors have a 65% isentropic efficiency but correspond well with literature [9] and manufacturer data.

As with the Phase 1 report [3], the compressor is the only variable cost in different-sized station

[5] http://www.nrel.gov/hydrogen/images/cdp_infr_36.jpg
[6] http://www.nrel.gov/hydrogen/images/cdp_infr_35.jpg

Table 4. Equipment needed for a conventional hydrogen fueling station, and estimated costs (inflation adjusted from [3], or reassessed as described in the text).

description	quantity	cost	total
tanks [13 kg each, 945 bar MAWP, Type II]	3	$45,633	$136,899
pressure transducer and indicator	6	$1,141	$6,845
block and bleed valve	6	$570	$3,422
air operated valve	6	$2,282	$13,690
pilot solenoid valve	7	$57	$399
isolation hand valve	12	$570	$6,845
check valve	3	$456	$1,369
coolant pump	1	$1,369	$1,369
water chiller	2	$4,563	$9,127
coolant filter	1	$57	$57
instrument air compressor	1	$1,141	$1,141
instrument air dryer and filter	1	$2,909	$2,909
hydrogen compressor [2-stage, 950 bar outlet]			
100 kg/day station - 6 kg/hr, 25 kW		$189,827	$189,827
200 kg/day station - 14 kg/hr, 60 kW	1	$328,774	$328,774
300 kg/day station - 23 kg/hr, 100 kW		$453,010	$453,010
hydrogen dispenser [(1) 350 bar and (1) 700 bar hose]	1	$250,000	$250,000
hydrogen chiller and cooling block	1	$150,000	$150,000
IR flame detector	2	$1,711	$3,422
hydrogen filter	1	$2,852	$2,852
PLC	1	$5,704	$5,704
tubing	-	$22,817	$22,817
fittings	-	$17,112	$17,112
electrical upgrades	-	$57,041	$57,041
fencing	-	$5,704	$5,704
bollards	-	$5,704	$5,704
total (100 kg/day station)			$894,256
total (200 kg/day station)			$1,033,203
total (300 kg/day station)			$1,157,439

designs. The developers of HRSAM [4] found the minimum size of the commonly available high pressure ground storage tanks to be 13 kg, and three of these are needed for a cascade fill giving a minimum installed high-pressure storage amount of 39 kg. This size was found to be sufficient for each station modeled in this work. Since each station only has a single dispenser, that cost also remains constant. Using the varied compressor costs, the conventional station equipment costs range from $900k to $1.2M.

Costs for the hydrogen dispenser, and the hydrogen chiller and cooling block were separated out and updated in this report, where they were lumped together in the previous report. The chiller and cooling block was estimated to cost $150k, while the dispenser was estimated at $250k. These costs are based on discussions with manufacturers and station operators who have purchased these pieces of equipment, and are 15% higher than the estimated $350k combined cost in the previous report. Part of the reason for this update is the evolution of dispenser design from an industrial-type interface to one that provides a retail customer experience more similar to that at a gasoline station, and the associated cost of these newer dispensers.

One high cost subsystem shown in Table 4 is the hydrogen compressor, where cost savings can be realized by reducing the size of the compressor. However, the compressor size needs to be balanced by the high pressure storage and station utilization. The hydrogen dispenser is also a significant cost; as production volume increases on the components needed in the dispensers and the assembled dispensers, this cost will likely decrease. The same number and type (or at least cost) of dispenser, valves, pumps, filters, tanks, tubing, safety equipment, etc., are needed for the 100 kg/day station as the 200 and 300 kg/day stations.

2.5 Packaged Compression, Storage, and Ancillary Equpiment for a Modular Station

Modular stations have the compressor, hydrogen cooling block, chiller, high-pressure storage, and control electronics housed in and/or on a single container. Manufacturing and installing these components in this way reduces installation labor, allows leak and operation checking at a dedicated facility, and can potentially reduce equipment costs by enabling high volume production of standardized components. Most station designers and companies are currently producing modular units, and having at least some components in a modular, shippable, fashion is the preferred way of constructing stations at this time. Our research shows that the primary savings associated with modular stations are in the installation costs. Based on conversations with manufacturers, capital costs of modular stations are currently on par with conventional stations. This is likely because much of the same equipment is used in both types of stations. We estimate modular fueling stations to cost between $750k to $1.5M depending on the manufacturer and whether or not a dispenser is included. This price range is for a unit that can compress and provide 200-400 kg/day hydrogen and spans the $890k-$1.2M capital cost range of the conventional station equipment. While installation of conventional stations is expected to be about 35% of capital costs [4], installation of equipment for a modular station is expected to be very low, likely no more than 5% of the capital costs of the modular unit. In this report, installation cost was estimated to be $60k, regardless of station size, the same as the electrolyzer unit installation costs since the installation requirements are similar.

Most manufacturers make just one size of modular units, so there might not be potential to save by having a smaller nameplate capacity. In this analysis, we provide estimates for total station costs for two cases of modular unit costs ($1M, and $1.5M), to elucidate the effect of differing capital costs. These costs are assumed to include the cost of the dispenser even though is is shown as being separated from the modular system in the layout sketches. In the analysis below, these two different costs are also used as a further example to show how Fig. 3 can be used to adjust resulting hydrogen cost to account for variability in capital cost estimates.

2.6 Hydrogen Dispensers

Both the modular and conventional, on-site station components need to interface with a dispenser. The dispenser includes valving, high pressure break-away(s), hose(s), nozzle(s), flow metering, control electronics, and a customer interface (point of sale system). Stations often provide both 350 and 700 bar fills, requiring two hoses, break-aways, nozzles, and additional plumbing and control electronics. Dispensing units range in price from approximately $150k-$350k. For a high utilization area, where one would want to allow multiple, simultaneous fills, the cost of additional dispensers would need to be factored into an analysis. In this analysis, both the conventional station and modular station total cost estimates include the cost of a single dispenser with both a 350 and 700 bar hose.

3 Results: Station Designs and Costs

Multiple approaches exist to financially model fueling stations and determine the cost of hydrogen. One approach is to perform a discount cash flow analysis, specifying a return on investment that is desired after a given time-frame. This is the approach taken in HRSAM [4] and used in the Phase 1 Reference Station Design report [3]. Specifying a 30 year analysis period and a discount rate of 15%, the cost of hydrogen was determined for the different station designs. These specifications led to a payback period (break-even time) of approximately 7.5 years. In this work, an alternative approach to the discount cash flow analysis was used, wherein we calculated the cost of hydrogen considering a 7-year payback period. A solution for the cost of hydrogen is found such that the sum of all costs and revenues is zero at the end of a 7-year period. By taking this approach, we do not need to include replacement costs for components over the entire 20 or 30 year discount cash flow analysis, we only need to include replacement costs for components that need to be replaced within 7-year time-frame. While some maintenance costs will be required over this 7 year time-frame, we assume that no major component of the fueling station would need to be replaced in this period. The validity of this assumption varies with equipment type, manufacturer, and duty cycle. We project station costs and incomes out 20 years in this analysis, but these results are missing capital replacement costs.

As discussed earlier, site-preparation costs can vary widely. In this analysis we assume a flat \$300k to cover the site-preparation, including engineering and design, permitting, and a project contingency. The cost to install the conventional components is assumed to be 35% of the capital cost, while the cost to install the modular stations, electrolyzer, or SMR units is assumed to be \$60k, regardless of unit size or station capacity. It should be noted that should any of these assumed costs be different from a real-world station build, the black lines in the chart of Fig. 3 can be used to determine the resulting change in the cost of hydrogen for the 7-year payback period. For example, if the site preparation costs \$600k rather than the assumed \$300k, one could use Fig. 3 to determine that for a depreciable asset[7] the excess \$300k would add nearly \$3/kg to the cost of hydrogen for a 100 kg/day station, or approximately \$1/kg to the cost for a 300 kg/day station.

It is assumed that the station construction takes one year (the year of 2016), and utilization begins the following year (2017) at the rate shown by Fig. 2. Just like the analysis that was used to generate Fig. 3, when calculating the cost of hydrogen, depreciation was estimated using a 7-year Modified Accelerated Cost Recovery System (MACRS) depreciation rate, and an overall tax rate of 38.9% (35% federal and 6% state tax).

3.1 Conventional Station with Delivered, Centrally Produced Hydrogen

Figure 8 shows the cost and revenue model for a conventional, assemble-on-site station with delivered hydrogen. In 2016, there is no revenue, and the costs for building the station are incurred. The capital of the station (green bar) is the largest contributor to costs in 2016. The 35% of capital

[7] Site preparation is likely considered depreciable because it is preparing the land for business use and is closely associated with the station equipment.

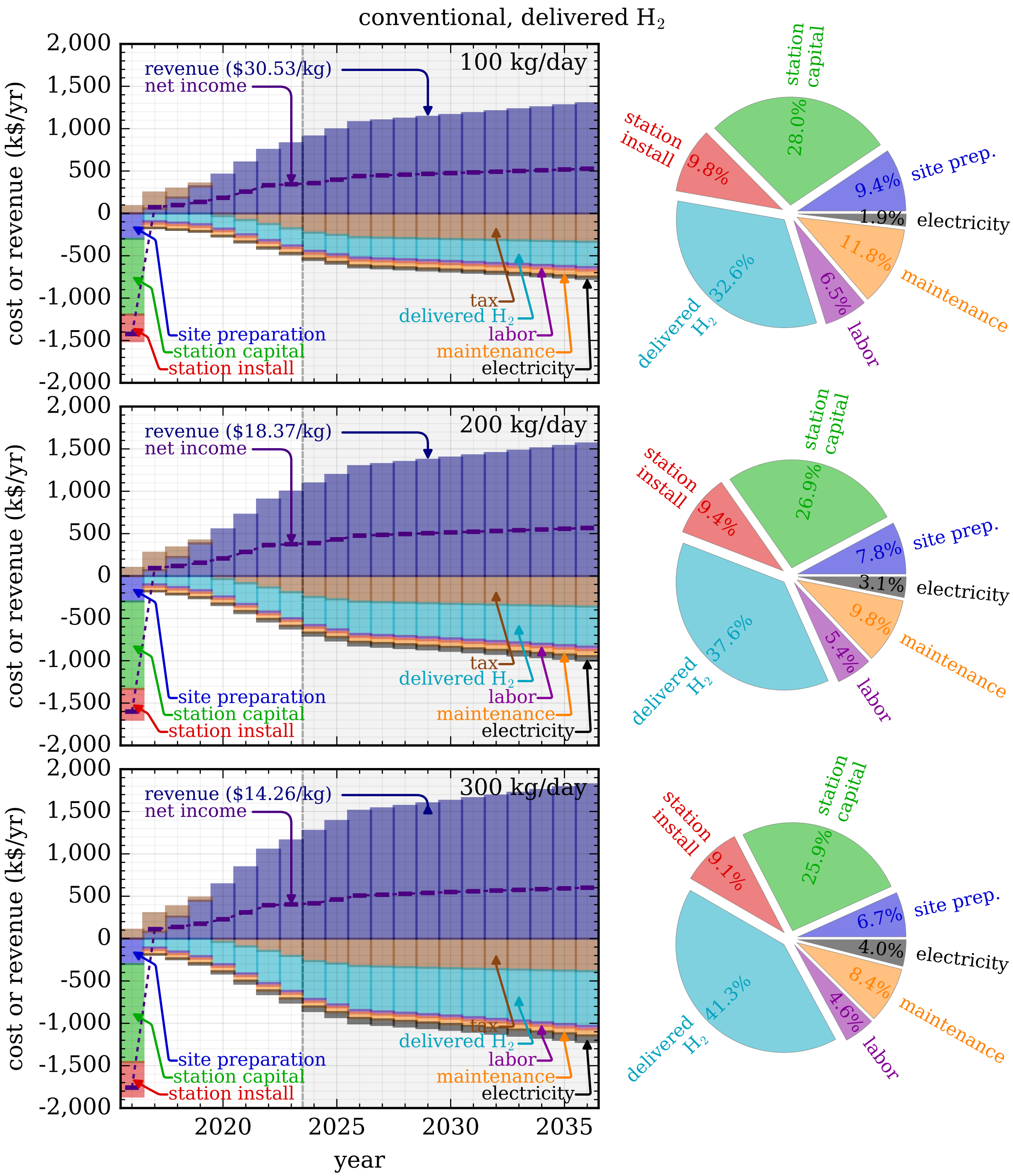


Figure 8. Cost and revenue associated with a conventional, assemble-on-site station, with centrally produced, delivered hydrogen, to break even at year 7 (2023). The net income includes the effects from depreciation and taxes. Capital replacement costs and intervals are not included in this model (accuracy past 2023 is limited). Pie charts on the right show the breakdown of cumulative capital and operating costs over the 7-year analysis period to the cost of dispensed hydrogen.

costs needed to install the station (red bar), and the \$300k site preparation cost (blue bar) make up the balance. As discussed earlier, land costs are not included in this analysis, and site preparation costs can vary quite widely. Figure 3 should be used to calculate the change in the cost of hydrogen given any land purchase costs, differences in real-world capital or site preparation costs. The total installed station costs range from \$1.5M to \$1.9M for the 100 to 300 kg/day stations.

In 2017, as hydrogen begins to sell at the station revenue begins to roll in, but operating costs are also incurred. The largest incurred operation cost is the hydrogen fuel supply, including the cost of production, delivery, and storage at the station, represented by the light blue bar in Fig. 8. This cost increases as the utilization of the station increases (due to more hydrogen required by the station), until 2026 when utilization stabilizes. After 2026, the delivered hydrogen costs continue to increase solely due to inflation. Contributors to the hydrogen production, delivery, and tube-trailer storage (labeled delivered H_2 in Fig. 8) are shown by Figs. 4 and 6, and are discussed in Section 2.1.

The purple labor bar in Fig. 8 makes up a small percentage of the operating costs. This value is calculated using a labor rate of \$13.70 /hr in 2016\$; the default rate in HRSAM [4]. This labor rate is fixed, regardless of the size of the station, or the amount of hydrogen sold. Maintenance, shown by the yellow bar, is a slightly larger operating cost contributor. Maintenance was estimated at \$50k/yr (in 2016\$, with increases due only to inflation over time), regardless of the station size. Maintenance costs can vary quite widely from station to station and from quarter to quarter, but this number is near the average annual cost suggested by NREL's Maintenance Costs Over Time CDP[8].

Electrical costs to run the compressor and chiller at the station make up the balance of the operational cost in Fig. 8, shown by the slim gray bar. The average compressor energy usage at stations is 4.2 kW-hr/kg_{H_2}, according to the Compressor Energy CDP[9] from NREL. An additional 20% of the compressor energy use was assumed for the refrigeration energy use, a factor consistent with HRSAM [4]. The cost for electricity shown in Fig. 1 was used with this assumed compression and refrigeration energy use to calculate the cost of electricity at the station. This cost increases with the amount of hydrogen dispensed, and is approximately the same as the maintenance costs, for the 300 kg/day station, after the 80% utilization rate is reached in 2026. For the 200 and 100 kg/day stations, the electricity usage is proportionately less.

For each of the three stations, the cost of hydrogen was calculated such that the capital and operating costs were recovered by revenue over 7 years. Shown in Fig. 8, and tabulated in Table 5, the cost of hydrogen is \$30.53/kg, \$18.37/kg, and \$14.26/kg for the 100, 200, and 300 kg/day stations, respectively. The decrease in hydrogen cost with increasing station capacity is consistent with the Phase 1 Reference Station results [3], and is because the increased revenue from hydrogen sales more than compensates for the increased cost of capital due to the larger station capacity. The decreasing hydrogen cost with station capacity also shows a trend of diminishing returns, also consistent with the Phase 1 work [3], and increasing the capacity further will not decrease the hydrogen cost so dramatically. In fact, increasing station capacity will eventually result in

[8] http://www.nrel.gov/hydrogen/images/cdp_infr_30.jpg
[9] http://www.nrel.gov/hydrogen/images/cdp_infr_35.jpg

Table 5. Installed cost (which includes site preparation, engineering & design, permitting, capital and installation costs), and hydrogen cost for conventional stations with centrally produced, delivered hydrogen.

capacity (kg/day)	installed cost ($)	H_2 cost ($/kg)
100	$1.51M	$30.53
200	$1.69M	$18.37
300	$1.86M	$14.26

added capital not considered in this analysis such as multiple dispensers and associated hydrogen chilling equipment, additional high pressure cascade storage, and additional compressors as station capacity exceeds the throughput of available single compressors.

The net income is shown by the purple lines in Fig. 8. In 2016, the net income (which is actually an expense in this year without revenue) is not quite the entire capital costs. This is due to the depreciation deduction (tax credit) on the capital investment, shown by the brown bar. In 2017, the net income is slightly greater than the revenue generated by selling hydrogen. Once again, this is the depreciation deduction on the capital investment, which is occurring on a 7 year schedule. The overall net expenses and income in all cases reaches a summed value of zero in year 7 (2023), and all income after that point would be earned by the investor (although as stated earlier, replacement intervals of equipment are not included in this analysis). Including capital replacement costs would not affect the revenue, but would affect the costs in replacement years, the tax burden (as this replaced equipment depreciated), and net income in the years past 2023. For all three capacity stations, the net income increases (due to inflation and varying operating costs) from about $300-400k /year in 2024 to $500-600k /yr in 2036.

The pie charts on the right in Fig. 8 show the contribution from the capital and operating costs over the 7 year payback period to the cost of hydrogen. For the 100 kg/day station, the delivered hydrogen is the largest contributor, at 33%, followed by the station capital (28%). Maintenance is also a large contributor to the cost of hydrogen, responsible for 12% of the $30.53/kg. Site preparation and station installation costs are each responsible for roughly 9.5% of the hydrogen cost. Labor accounts for 6.5% of the hydrogen cost, and electricity to run the compressor and chiller is a small contributor, at only 2%. Overall, taxes do not have a net effect on the cost of hydrogen (and therefore do not appear in the pie charts), due to the fact that the capital investment is depreciating on a 7 year schedule providing tax credits in the early years, and the fact that we are specifying the cost of hydrogen based on the operator breaking even on their investment in year 7. If we were to determine the cost of hydrogen using a different criterion or if there were capital investments that were not depreciating (or depreciating on an alternative schedule), taxes would have a role in the cost of hydrogen. Taxes will also have an impact on the revenue and return on investment over a longer analysis period. Note that in this analysis, we are not considering the tax to the consumer that is placed on the dispensed fuel.

Comparison of the pie charts in Fig. 8 shows that as the station capacity increases, the station capital reduces slightly as a percentage of the hydrogen cost, while the delivered hydrogen increases its share of the hydrogen cost. However, the overall cost of delivered hydrogen reduces with increasing capacity, from $9.95/kg for the 100 kg/day station, down to $5.89/kg for the 300 kg/day station. Electricity on the other hand, while increasing as a percentage of the hydrogen cost with increasing capacity, contributes approximately $0.57/kg to the cost of hydrogen, regardless of the station capacity, because the same amount of energy is required to compress and chill each dispensed kg of hydrogen.

Figure 9 shows how a conventional station with delivered hydrogen might be organized on a site. This is nearly the same layout sketched in the previous reference station design report [3]. As with the previous layout, the air compressor, dryer and cooling water equipment are located near the convenience station so that the air compressor inlet is at least 45 feet away from the hydrogen trailers, a prescriptive requirement of NFPA 2 [10]. This also prevents this equipment outside the wall from requiring electrical classification. The equipment in this layout is spaced out, and one could probably devise a smaller footprint. The largest contributors to the space requirement are the two tube trailers on-site, which would be necessary to prevent interruptions in service. The tube trailers drawn are 40' long, and sufficient space and delivery routes need to be designed into the layout so that the drivers can drop them off and pick them up.

Cost of Delivered Hydrogen

To gain insight into the cost of delivered hydrogen, its contribution to the overall cost of hydrogen was removed and the overall cost was recalculated. Without the delivered hydrogen cost, the cost of hydrogen would be $20.58, $11.47, and $8.37, for the 100, 200, and 300 kg/day stations, respectively. The difference between these two scenarios results in delivered hydrogen costs of $9.95, $6.90, and $5.89 per kg. Note that these costs includes the leasing two tube-trailers for storage on-site and the cost of delivered, centrally produced hydrogen (without the cost of the tube-trailer lease) is $3.87/kg, for all three capacity stations. The delivered hydrogen cost of $6–10/kg is in line with the $6–$8/kg (in 2014$) reported by Sutherland and Joseck [6] for centrally produced delivered hydrogen of 500–1000 kg/month with a delivery distance of up to 200 miles. The delivery distance (assumed to be 200 miles in this analysis) will have a large impact on the cost of delivered hydrogen, proportionately changing all of the associated delivery costs shown in Fig. 4 which are cumulatively shown as the red bar in Fig. 6. The tube-trailer lease price to store hydrogen on-site, which is fixed for all three capacity stations, is responsible for the decreasing cost of the centrally produced, delivered, and stored hydrogen as the station capacity increases. By having a higher throughput of hydrogen, the larger capacity stations are able to spread the cost of the tube trailer lease over a greater quantity of dispensed hydrogen.

Comparison of Costs to Previous Study

Neglecting the cost of the delivered hydrogen also allows a comparison to the results of the Phase 1 Reference Station Design report [3]. The calculated hydrogen costs without production

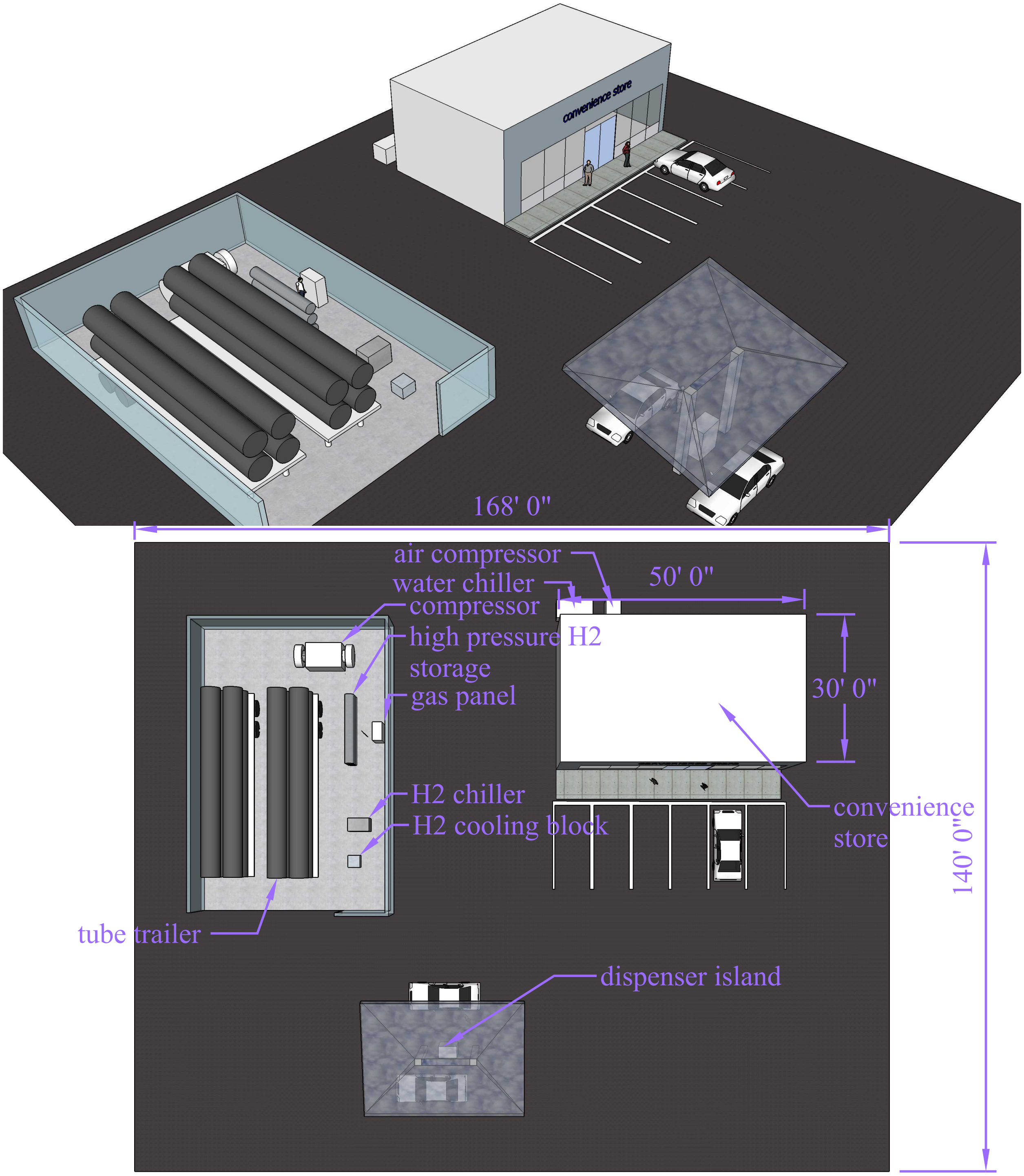


Figure 9. Renderings of a conventional station layout with delivered gaseous hydrogen.

and delivery of \$20.58, \$11.47, and \$8.37 are higher than the Phase 1 calculated costs of \$13.28, \$7.82, and \$6.03 for the 100, 200, and 300 kg/day stations (shown in Table 1). Several factors contribute to the differences in the calculated fuel cost. First, the installed capital costs of \$1.5M, \$1.7 and \$1.9M in this analysis are higher than those calculated previously of \$1.1M, \$1.2M, and \$1.3M (even after adjusting for inflation). Second, the previous analysis used HRSAM, in which the operating costs are calculated a bit differently than this analysis. Finally, in the previous analysis, the criteria for hydrogen cost was a 15% discount rate based on a 30 year analysis period, which led to a 7.5 year payback period. In this analysis, the payback period was set to exactly 7 years (and the discount rate was not considered). If, in this analysis the capital costs are reduced to match the previously reported capital costs (\$1.1M, \$1.2M, and \$1.3M), and the payback period is extended from 7 to 7.5 years, the cost for dispensed hydrogen (without including the cost of hydrogen production and delivery) is calculated as \$15.21, \$8.23, and \$5.90, for the 100, 200, and 300 kg/day stations, respectively. These costs are within 15% of the HRSAM values found in the previous analysis. The differences in this case must all be attributed to the second cause, of differing assumptions on operation costs in this analysis method vs. the HRSAM method. This exercise shows that the economic assumptions in this analysis are in-line with the HRSAM assumptions; albeit, not exactly the same. This exercise also demonstrates that solving for the hydrogen cost to match a payback period–as long as that payback period is less than the capital replacement interval on parts–is a valid alternative to the discount rate analysis used in HRSAM.

3.2 Conventional Station with Hydrogen Produced On-site via Steam Methane Reforming

The costs and revenue for a conventional, assemble-on-site station with an on-site steam methane reformer to produce hydrogen are shown in Fig. 10, with the installed costs and cost of hydrogen tabulated in Table 6. Inspection of the capital costs incurred in 2016 shows that the largest contributor is the SMR unit itself. As discussed in Section 2.2, these SMR units are estimated to cost from just over \$1M for a 100 kg/day capacity, to just under \$2.5M for a 300 kg/day capacity. Using Fig. 3, adding a \$1M capital investment (depreciable) to a 100 kg/day station will add nearly \$10/kg to the cost of hydrogen to make back that investment in 7 years. But for the 100 kg/day station with on-site SMR, the \$38.47/kg cost of hydrogen is only about \$8 higher than the \$30.53/kg for the conventional station with delivered hydrogen. The hydrogen cost is calculated based on

Table 6. Installed cost (which includes site preparation, engineering & design, permitting, capital and installation costs), and hydrogen cost for conventional stations with SMR on-site.

capacity (kg/day)	installed cost (\$)	H_2 cost (\$/kg)
100	\$2.74M	\$38.47
200	\$3.83M	\$25.96
300	\$4.43M	\$20.23

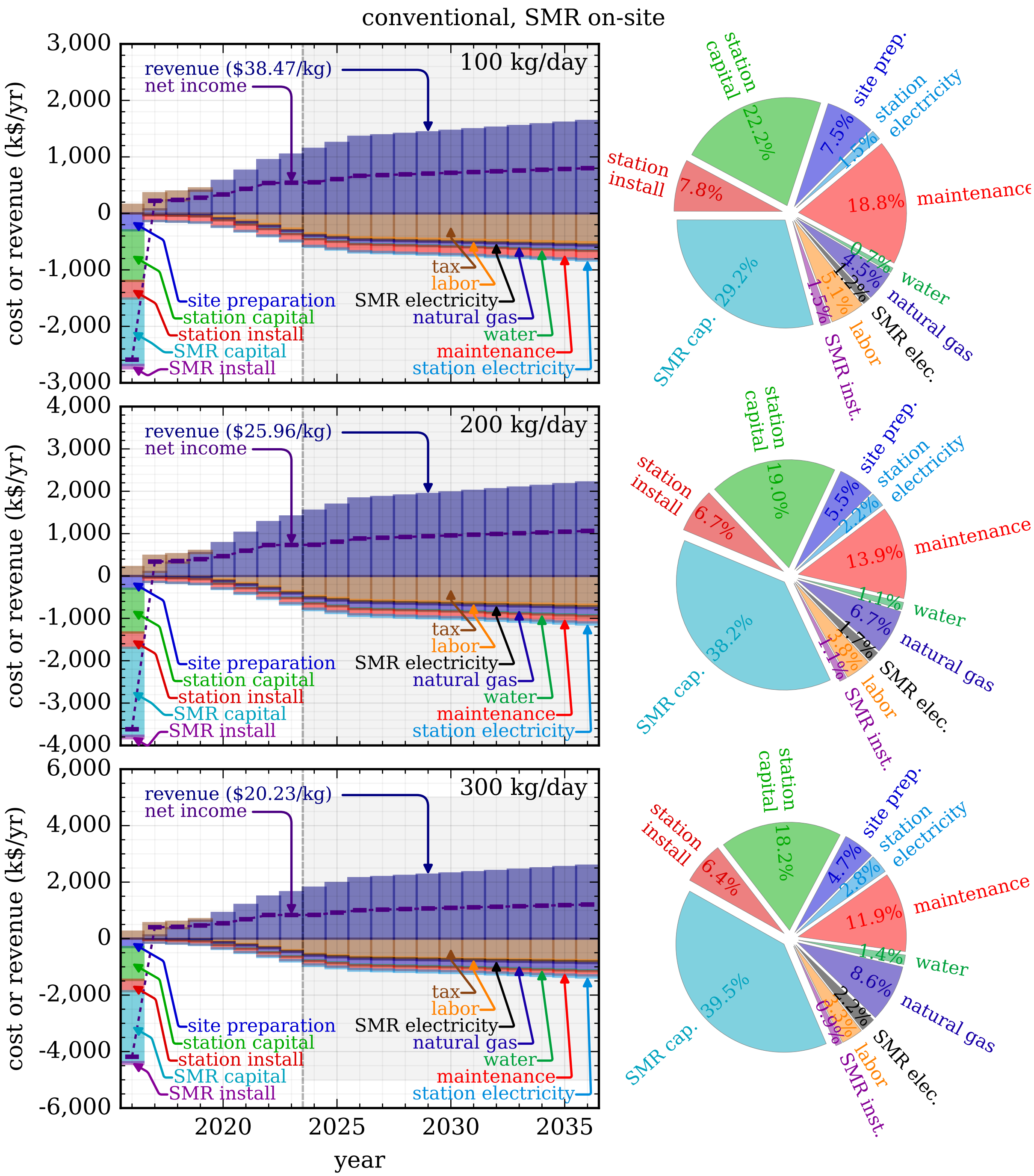


Figure 10. Cost and revenue associated with a conventional, assemble-on-site station, with on-site, steam methane reforming produced hydrogen, to break even at year 7 (2023). The net income includes the effects from depreciation and taxes. Capital replacement costs and intervals are not included in this model. Pie charts on the right show the breakdown of cumulative capital and operating costs over the 7-year analysis period to the cost of dispensed hydrogen.

both capital and operating costs, so we can conclude that the operating costs for the 100 kg/day SMR are less than the operating costs for the 100 kg/day delivered hydrogen station. In addition to the common costs for labor, station maintenance, and station electricity, the station with the SMR unit has a nominal operating cost for water for the SMR unit (nearly indistinguishable green bar), requires electricity and natural gas to run the unit (shown by the blue and black bars), and requires additional maintenance over the conventional station with delivered hydrogen (included in the red bar). Maintenance for the SMR unit is assumed to be \$50k/year, bringing total station maintenance costs to \$100k /yr. However, the sum of these costs is less than the cost to deliver and store centrally produced hydrogen for the 100 kg/day station. Operating costs for the SMR station neglect the inefficiencies in shutdown/startup cycles (or venting excess hydrogen) when production is not matched by demand, which would further increase costs.

The cost of hydrogen for the conventional 100, 200, and 300 kg/day stations with on-site SMR are \$38.47/kg, \$25.96/kg, and \$20.23/kg. These costs are 26%, 41%, and 42% higher than the costs of hydrogen for a conventional station with delivered gaseous hydrogen. As discussed, the increased cost of hydrogen comes from the high capital costs for the on-site SMR units, slightly offset by a reduced operating cost. This can be seen by inspecting the pie charts on the right side of Fig. 10, where the SMR capital costs is the largest contributor to the cost of hydrogen, accounting for approximately 30-40% of the hydrogen cost. For the 200 and 300 kg/day stations, the capital costs of \$2M and \$2.5M add approximately \$10/kg and \$8/kg. While the operating costs for these stations are lower than the same capacity delivered hydrogen stations, these differences fail to decrease the cost of hydrogen to the same level as the delivered hydrogen station. Overall, this analysis would suggest that while there may be some advantages to utilizing on-site SMR, there is not much of a financial case to produce hydrogen on-site using steam methane reforming, rather than having hydrogen delivered, for 100-300 kg/day hydrogen refueling stations, unless the capital cost can be reduced significantly.

A station with an on-site SMR unit could have a smaller footprint than a station with delivered hydrogen. One potential layout is shown in Fig. 11. By replacing the tube trailers with an SMR unit, significantly less space is required for the fueling station components (compare to Fig. 9). Since all hydrogen is produced on-site, delivery routes can also be neglected from consideration and walls can enclose all of the hydrogen components, reducing setback distances on all sides. The SMR unit is shown as being housed in a 20 ft. ISO container footprint, although to produce 300 kg/day, it may be possible to have a smaller footprint, and even smaller for the stations that only require 100 or 200 kg/day. For on-site SMR, the fueling station components (e.g., compressor, high pressure storage) take up relatively more space than the low pressure hydrogen source (because the SMR is much smaller than the two tube trailers), and laying out these components in a compact manner is important in space-constrained sites.

3.3 Conventional Station with Hydrogen Produced On-site via Electrolysis

Conventional stations with on-site electrolysis have the costs and revenues shown in Fig. 12. The installed capital costs and hydrogen costs at each of the three stations are tabulated in Table 7. Similar to the conventional station with a steam methane reforming unit on-site, each of these

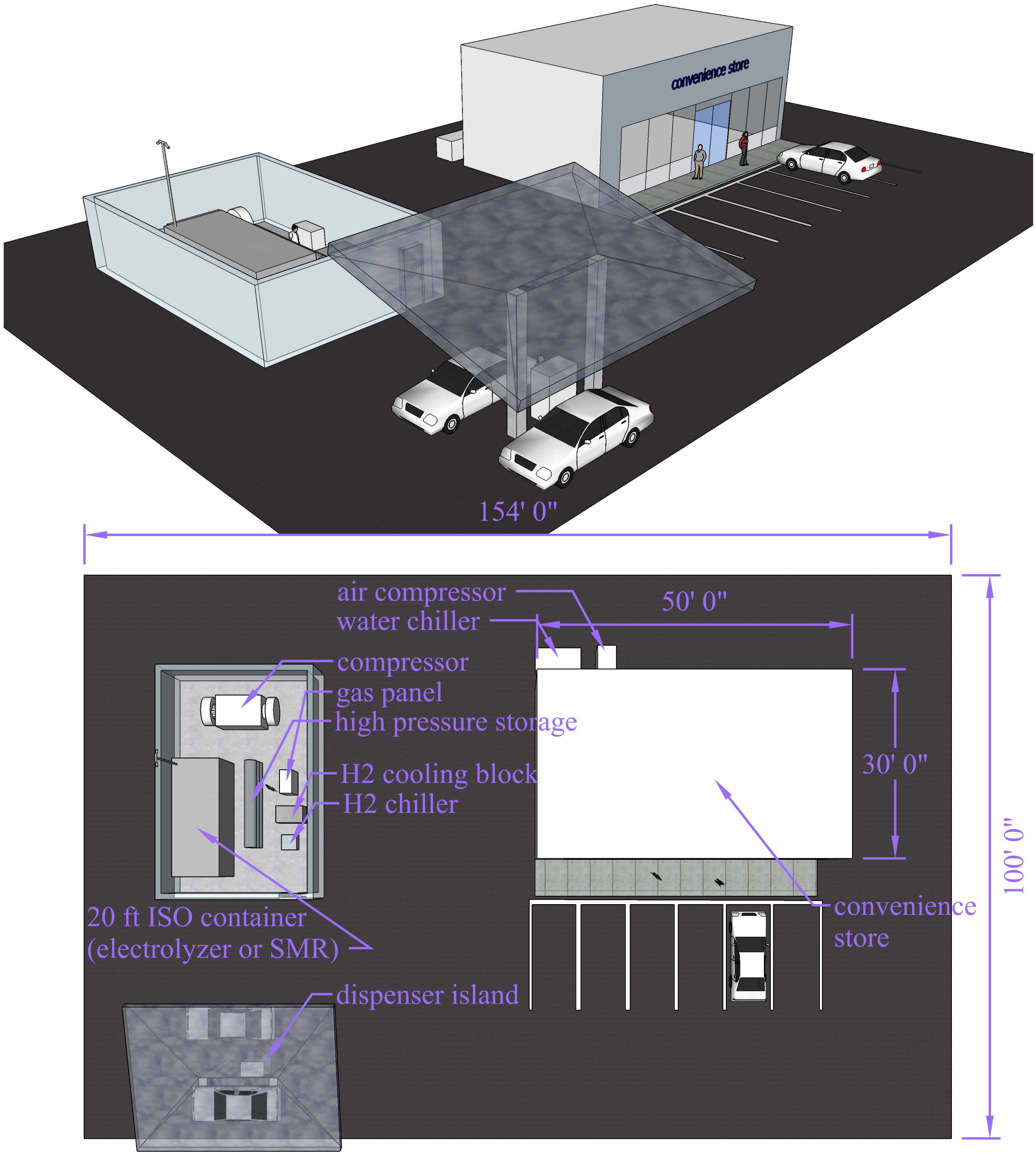


Figure 11. Renderings of a conventional station layout with on-site production of hydrogen.

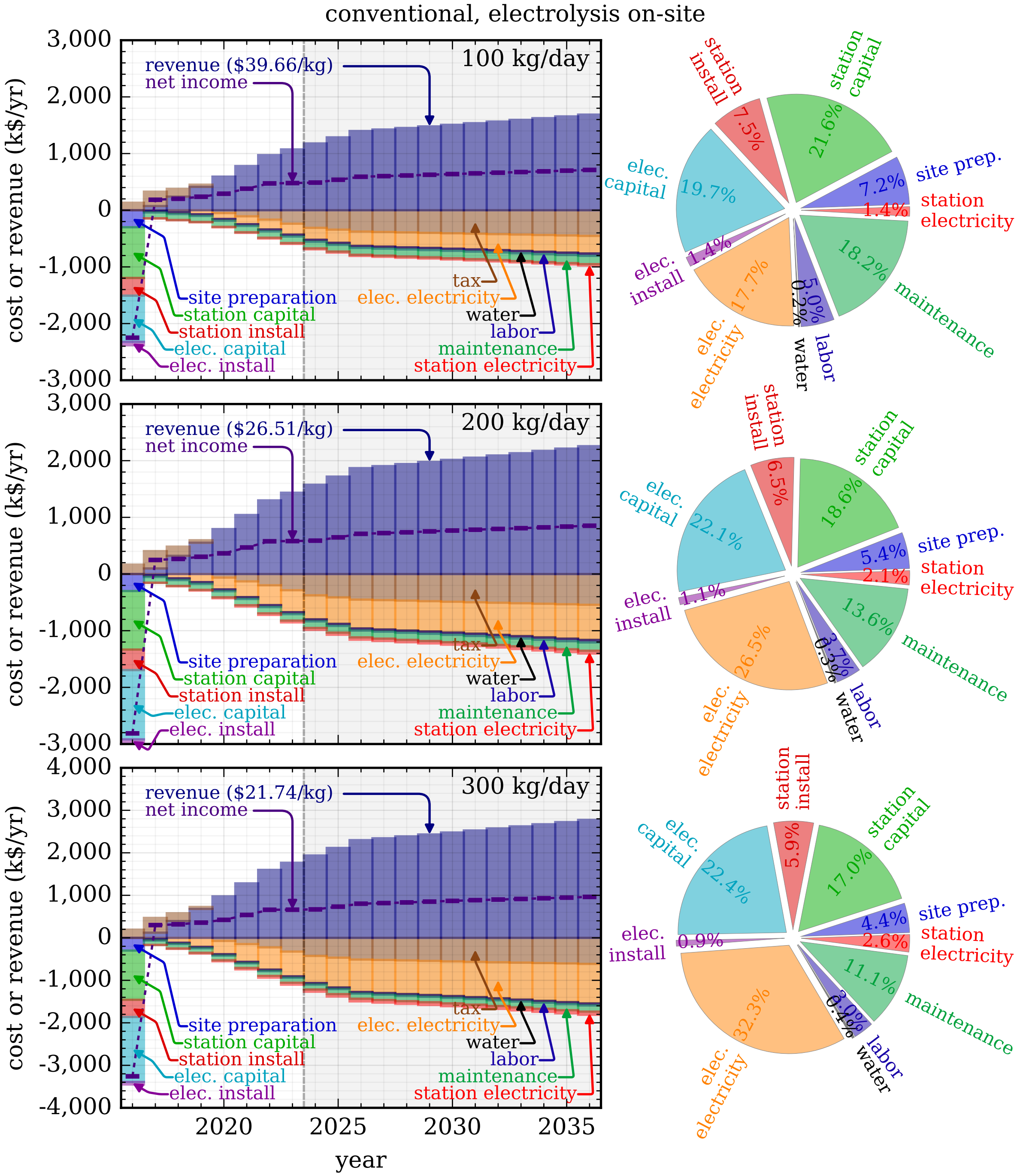


Figure 12. Cost and revenue associated with a conventional, assemble-on-site station, with on-site, electrolysis produced hydrogen, to break even at year 7 (2023). The net income includes the effects from depreciation and taxes. Capital replacement costs and intervals are not included in this model. Pie charts on the right show the breakdown of cumulative capital and operating costs over the 7-year analysis period to the cost of dispensed hydrogen.

Table 7. Installed cost (which includes site preparation, engineering & design, permitting, capital and installation costs), and hydrogen cost for conventional stations with electrolysis on-site.

capacity (kg/day)	installed cost ($)	H_2 cost ($/kg)
100	$2.38M	$39.66
200	$2.98M	$26.51
300	$3.45M	$21.74

station designs has a large capital cost due to the electrolysis unit. As discussed in Section 2.3, the electrolysis units cost approximately $800k, $1.2M, and $1.5M, for 100, 200, and 300 kg/day capacities. These capital investments will add approximately $8/kg, $6/kg, and $5/kg to the cost of hydrogen over a conventional station, assuming equivalent operating costs. During operation, there is a large cost associated with electricity to run the electrolysis unit (shown by the yellow bar). This cost scales with the amount of hydrogen produced and is a large factor in the station economics. The pie charts on the right show that this electricity accounts for approximately 20-30% of the cost of hydrogen. Other additional costs over the conventional, delivered hydrogen station are the cost of water to run the electrolysis unit and additional maintenance on the electrolyzer (assumed to be $50k annually, as with the SMR).

The electricity required for the electrolyzer costs approximately $300k, $600k, and $900k (for the 100, 200, and 300 kg/day stations) in 2036, where utilization has topped out at 80%. Centrally produced, delivered hydrogen by comparison as shown in Fig. 8, costs around $300k, $450k, and $650k in 2036, with overall operating costs for the delivered hydrogen station (neglecting taxes) topping out at approximately $400k, $600k, and $800k. In addition to the additional capital costs for the electrolyzer (and the other operational costs), it is clear that the economics of a station with an electrolyzer are challenging, due to the high electricity consumption even when the electricity is from the current national grid mix with 13% renewable content[10]. Higher renewable content may further increase this cost component in the near term, although fossil-fuel free electricity may become less expensive in the longer term.

The cost of hydrogen for the conventional station with an electrolyzer is $39.66/kg, $26.51/kg, and $21.74/kg, for the 100, 200, and 300 kg/day stations, receptively. These costs are on-par with the conventional station with SMR; within $1.50/kg for all three capacities. The cost of hydrogen for a station with on-site production is significantly higher than for a station with delivered hydrogen. Besides improvements in electrical efficiency, one strategy for minimizing operating costs is to only operate the electrolyzer at off-peak hours, enabling the purchase of lower priced electricity. However, this might require oversizing the electrolyzer to produce enough hydrogen at off-peak hours to meet demand, increasing the capital costs associated with the unit. Another method is intentionally oversizing the electrolyzer to enable operation at a higher efficiency, thereby reducing operating expenses.

[10] 2015 estimate from http://www.eia.gov/tools/faqs/faq.cfm?id=92&t=4

To estimate the impact of these methods of operation, and aslo gain insight into less expensive renewable electricity costs in the future, the model was run with the cost of electricity zeroed-out, to calculate the lowest possible cost of hydrogen with cheap electricity. In this scenario, the cost of hydrogen is \$32.64/kg, \$19.49/kg, and \$14.72/kg (for the 100, 200, and 300 kg/day stations). These costs are only slightly higher (by 3-7%) than the conventional, delivered hydrogen cost, due to the capital investment in the electrolyzer and the remaining electrolyzer maintenance and water costs.

A station with on-site electrolysis can also be represented by the layout shown in Fig. 11. Housing the components necessary for alkaline electrolysis of 100-300 kg/day hydrogen might be challenging in a 20 ft. ISO container, and the layout might need to be increased (to a 30 or 40 ft. ISO container). For PEM electrolysis, however, the components should fit in the 20 ft. ISO container, and potentially smaller containers for the 100 or 200 kg/day stations. Similar to the reforming layout, the hydrogen components fit in a much more compact space than for the conventional station with delivered hydrogen (shown in Fig. 9), and the lot size is reduced.

3.4 Modular Station with Delivered, Centrally Produced Hydrogen

Figure 13 shows the cost, revenue, and income model for a modular station with delivered, centrally produced hydrogen and an uninstalled modular unit cost of \$1.5M. The installed capital costs and hydrogen costs at each of the three capacity stations are tabulated in Table 8. Recall from Section 2.5 that the capital costs for modular stations do not follow the same trend as for build-on-site stations because modular stations come in discrete sizes. Table 8 shows the installed capital and hydrogen costs for two cases of uninstalled modular station costs of \$1.5M and \$1M. The only difference in costs between this scenario and the conventional station with delivered, centrally produced hydrogen (see Table 5 and Fig. 8) are in the capital costs. While the installed capital costs, including site preparation, station capital, and installation were \$1.5M and \$1.7M for the 100 and 200 kg/day conventional stations, it is \$1.86M for all three capacities of the modular

Table 8. Installed cost (which includes site preparation, engineering & design, permitting, capital and installation costs), and hydrogen cost for modular stations with delivered hydrogen for two cases of uninstalled modular cost, \$1.5M and \$1.0M.

capacity (kg/day)	uninstalled modular cost (\$)	installed cost (\$)	H_2 cost (\$/kg)
100	\$1.5M	\$1.86M	\$33.90
200	\$1.5M	\$1.86M	\$19.16
300	\$1.5M	\$1.86M	\$14.25
100	\$1M	\$1.36M	\$29.12
200	\$1M	\$1.36M	\$16.77
300	\$1M	\$1.36M	\$12.65

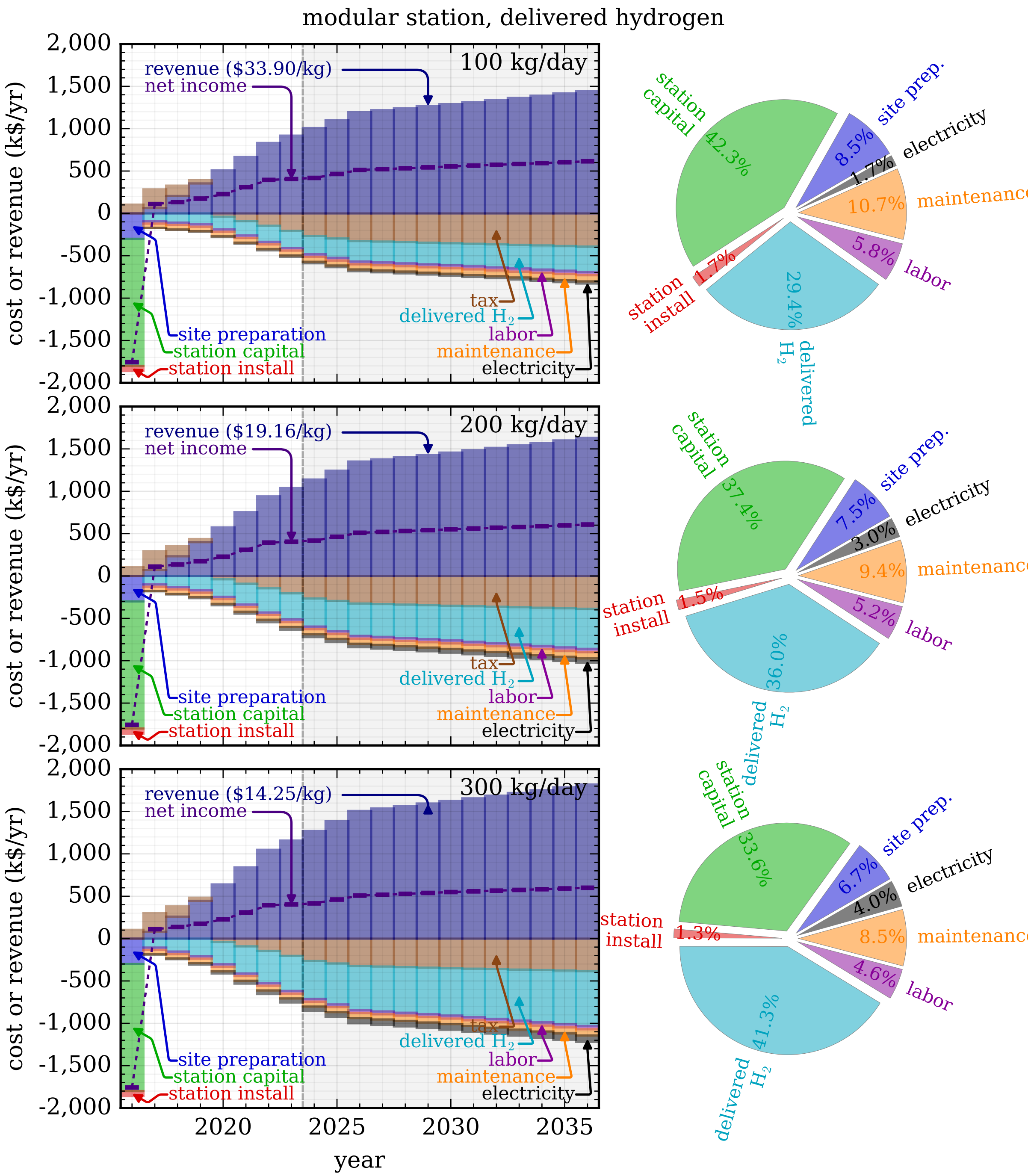


Figure 13. Cost and revenue associated with a modular station, with centrally produced, delivered hydrogen, to break even at year 7 (2023) assuming a $1.5M uninstalled capital cost of the modular station. The net income includes the effects from depreciation and taxes. Capital replacement costs and intervals are not included in this model. Pie charts on the right show the breakdown of cumulative capital and operating costs over the 7-year analysis period to the cost of dispensed hydrogen.

stations. This capital investment for a 300 kg/day modular station (including site preparation, station capital, and installation) is coincidentally the same as for a 300 kg/day conventional station.

If an estimate of $1M (as compared to the conservative estimate of $1.5M) for the uninstalled capital cost of the modular fueling station unit is used (note that this is still within the range of costs vendors estimated as described in Section 2.5), the cost of hydrogen will be $29.12, $16.77, and $12.65 for the 100, 200 and 300 kg/day capacities, respectively. These costs are all lower than the cost of hydrogen at the equivalent capacity conventional stations. As this technology matures and the installed capital cost of the modular units continues to decrease below the installed capital cost of the conventional stations, it will make economic sense to site modular stations rather than assembling components on-site. Parts standardization and the increased quality control that can be achieved by having modular station components may also lead to reduced maintenance requirements, but that potential benefit is not included in this analysis.

Figure 14 shows that a modular unit requires a slightly smaller installation area than the conventional station components shown in Fig. 9. However, the tube trailers acting as the hydrogen source and on-site storage still require significant space. Similar to the conventional station with delivered hydrogen, delivery routes must also be considered when siting a modular station with delivered hydrogen. The hydrogen components are shown as being housed in a 20 ft. ISO container, although some 300 kg/day modular stations are smaller than this. While a slightly overall reduced footprint (relative to as drawn in Fig. 14) could be realized, we show this layout on the same lot as before. Removing the need to store two 40-foot tube trailers by adding on-site low pressure storage could also drastically reduce the footprint by reducing the need to have an open wall for delivery. A discussion of how the separation distances can be impacted and the footprints might be reduced due to fire-rated walls is included at the end of the Section 3.5.

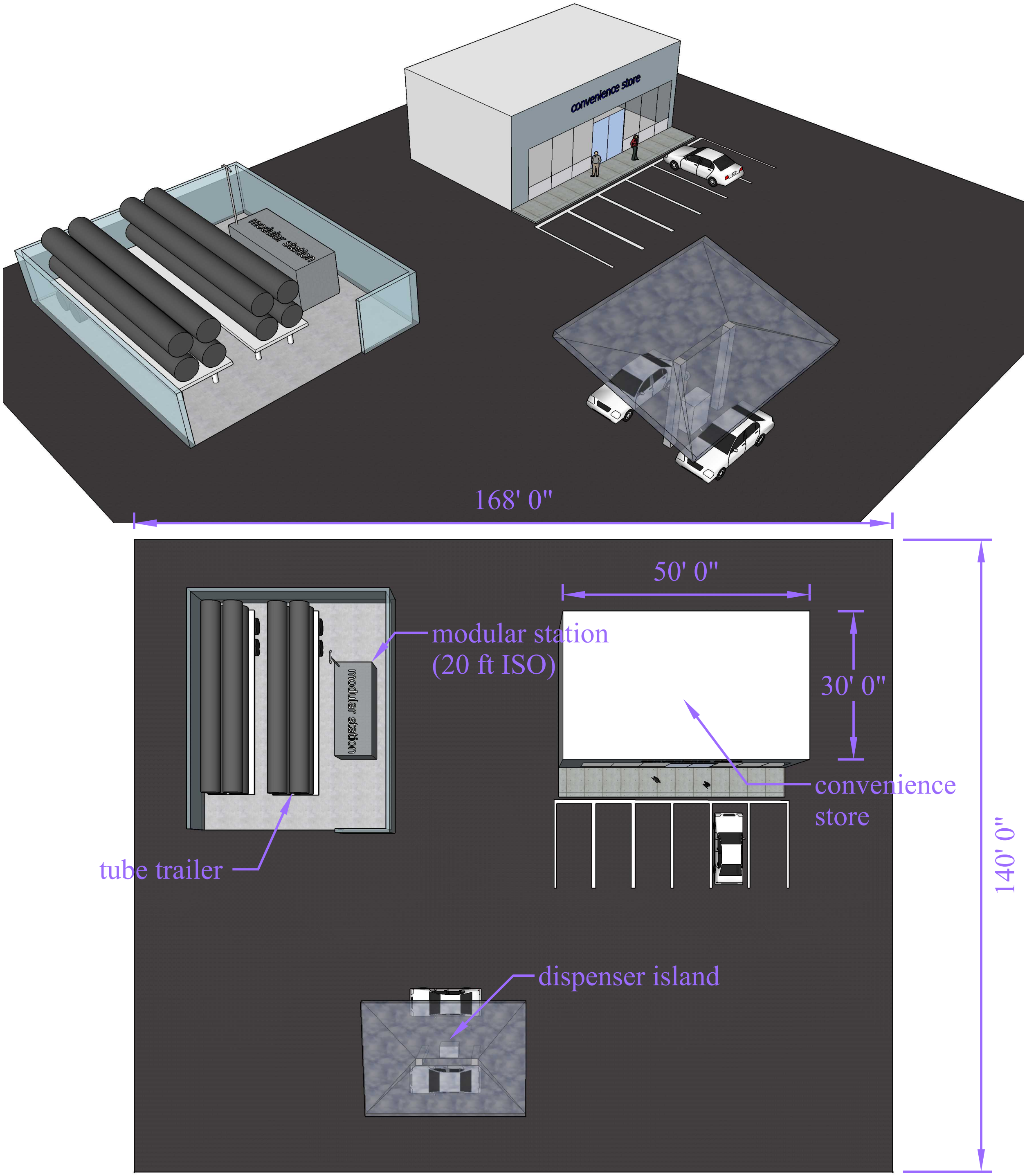


Figure 14. Renderings of a modular station layout with delivered hydrogen.

3.5 Modular Station with Hydrogen Produced On-site via Electrolysis

The final configuration considered in this analysis is a modular station with an electrolysis unit attached to produce hydrogen. The economics of this station design are shown in Fig. 15. The installed capital costs and hydrogen costs at each of the three capacity stations, with two different uninstalled modular unit costs, are tabulated in Table 9. Similar to the results in the previous section, the cost of hydrogen at the low volume, modular, electrolysis stations with an assumed \$1.5M uninstalled modular station cost are higher than at the conventional, electrolysis station counterpart. We find that the cost of hydrogen at these modular stations with electrolysis produced hydrogen will be \$43.03/kg, \$27.30/kg, and \$21.73/kg (for the 100, 200, and 300 kg/day stations). These costs are once again \$3.37/kg higher, \$0.79/kg higher, and the same (respectively) as the costs at the conventional stations with electrolysis produced hydrogen discussed in Section 3.3. This cost difference between the analogous conventional station is once again solely due to the differing capital cost of the installed modular station. If the capital cost of the modular unit is \$1M, the hydrogen costs reduce to \$38.25, \$24.91, or \$20.13/kg (for the 100, 200, and 300 kg/day stations), which are all lower than the cost at the similarly sized conventional stations with on-site electrolysis due to the lower installed station cost.

Having on-site production using an electrolyzer and modular fueling station components only requires a small footprint for installation, as shown in Fig. 16. The ISO containers can house appropriate fire-rated barrier walls, reducing separation distance for Group 1 and 2 exposures (except for air intakes) by half and eliminating separation distances for Group 3 exposures, as described in Section 7.3.2.3.1.2 of NFPA 2: The Hydrogen Technologies Code (2016) [10]. Group 1 exposures are lot lines, air intakes (HVAC, compressors, other), operable openings in buildings and structures, and ignition sources such as open flames and welding. Group 2 exposures are exposed persons (other than those servicing the system), and parked cars. Group 3 exposures include buildings, flammable gas storage, hazardous materials storage, ordinary combustibles, horizontal distance to overhead electrical wire, and piping containing other hazardous material. This means

Table 9. Installed cost (which includes site preparation, engineering & design, permitting, capital and installation costs), and hydrogen cost for modular stations with on-site electrolysis produced hydrogen for two cases of uninstalled modular cost, \$1.5M and \$1.0M.

capacity (kg/day)	uninstalled modular cost (\$)	installed cost (\$)	H_2 cost (\$/kg)
100	\$1.5M	\$2.74M	\$43.03
200	\$1.5M	\$3.14M	\$27.30
300	\$1.5M	\$3.45M	\$21.73
100	\$1M	\$2.24M	\$38.25
200	\$1M	\$2.64M	\$24.91
300	\$1M	\$2.95M	\$20.13

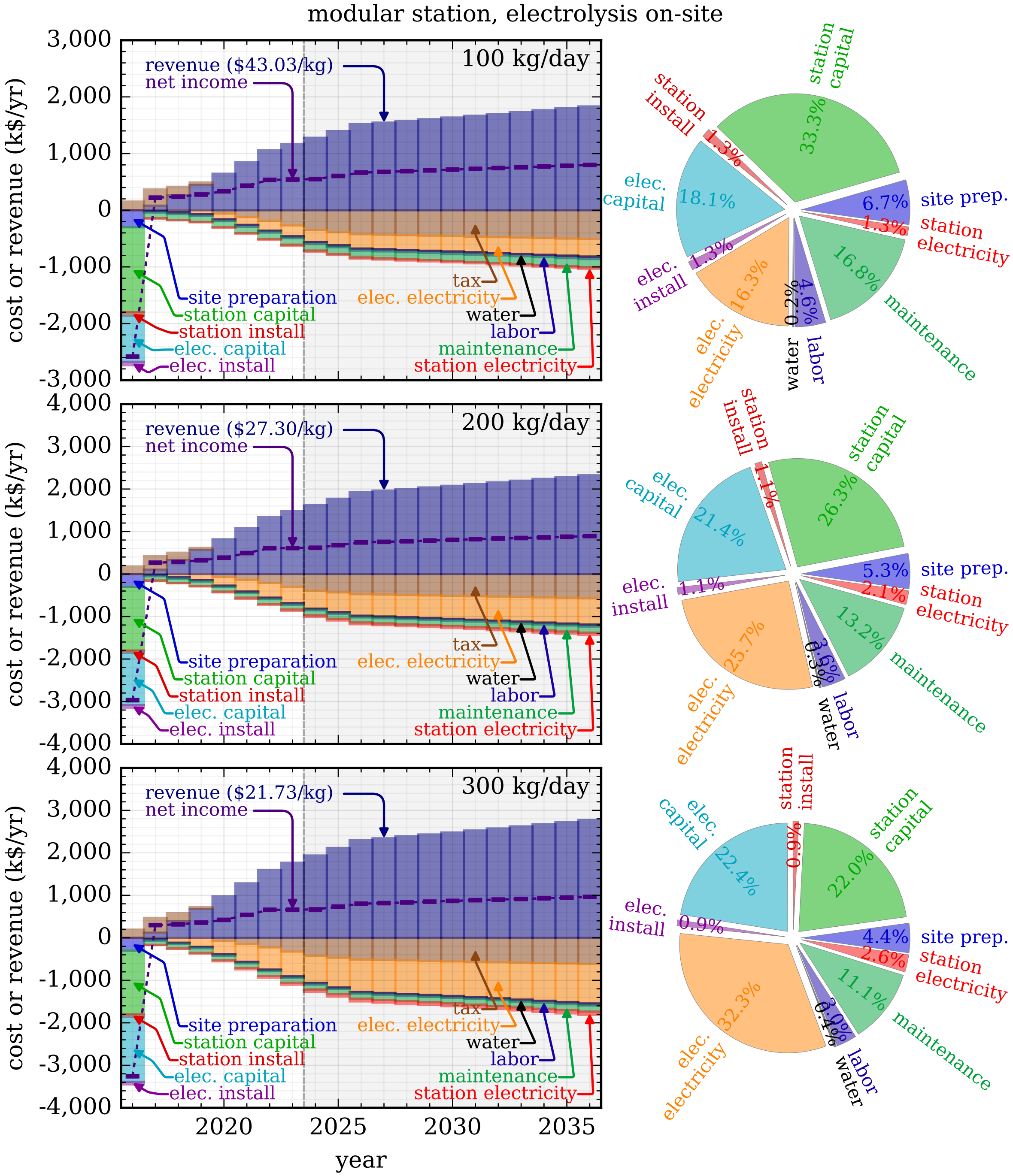


Figure 15. Cost and revenue associated with a modular station, with on-site, electrolysis produced hydrogen, to break even at year 7 (2023) assuming a $1.5M uninstalled capital cost of the modular station. The net income includes the effects from depreciation and taxes. Capital replacement costs and intervals are not included in this model. Pie charts on the right show the breakdown of cumulative capital and operating costs over the 7-year analysis period to the cost of dispensed hydrogen.

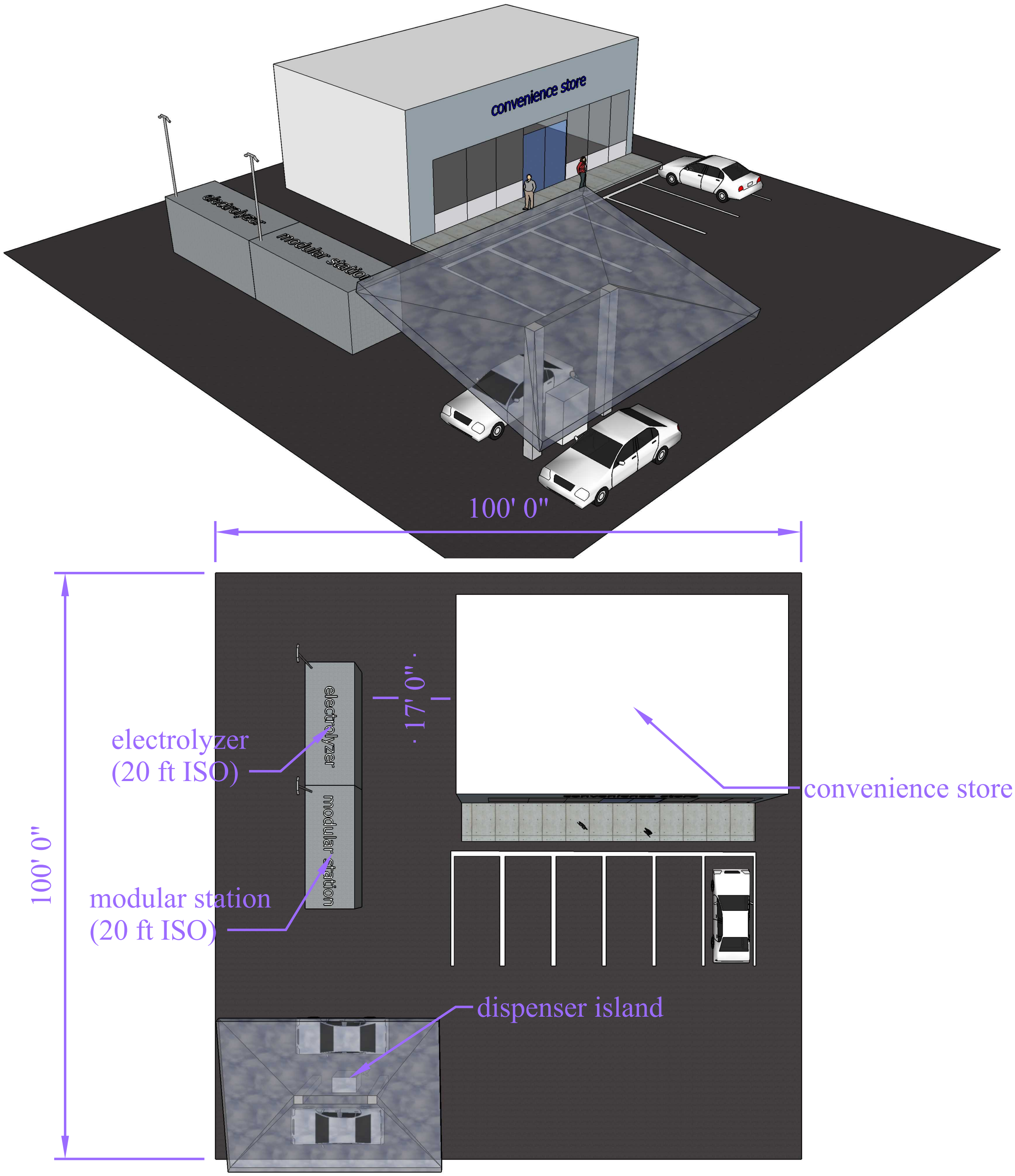


Figure 16. Renderings of a modular station layout with an electrolyzer for on-site production, with a small, reduced footprint.

for a typical pipe diameter of 0.28", and up to 15,000 psi pressure (within the operating range of the cascade storage at a refueling station), air intakes must remain 34 ft. from the containers, while lot lines, other building openings, or ignition sources only need 17 ft. of separation. Exposed persons and parked cars must be 8 ft. or more away from the containers, and other exposures (including other combustibles like gasoline) do not need any separation from the containers. This will allow a compact layout, an example of which is shown in Fig. 16.

4 Conclusions

Five station designs were considered in this analysis, with three capacities of each station design. With the current technology, the lowest cost hydrogen source assessed here[11] is tube-trailers delivering centrally produced gaseous hydrogen. Shown in Table 10, or graphically in Fig. 17, for either a conventional or modular station with a 300 kg/day capacity and delivered hydrogen gas (using our conservative, \$1.5M cost estimate for the modular unit), it would cost approximately \$1.86M to prepare the site and build the station, and at a dispensed hydrogen cost of \$14.25/kg, a station operator would break even on their capital investments and operational costs in 7 years. If the capital cost of the modular station unit is only \$1M, which is still in the range of cost estimates by manufacturers, a modular station with delivered hydrogen would cost \$1.36M to build, and for a 300 kg/day capacity, hydrogen would cost \$12.65/kg. Embedded in all of these analyses is the utilization profile shown in Fig. 2, which is the reason that the hydrogen cost increases as the capacity (and utilization) decreases for the modular stations with delivered hydrogen, although they have the same installed cost.

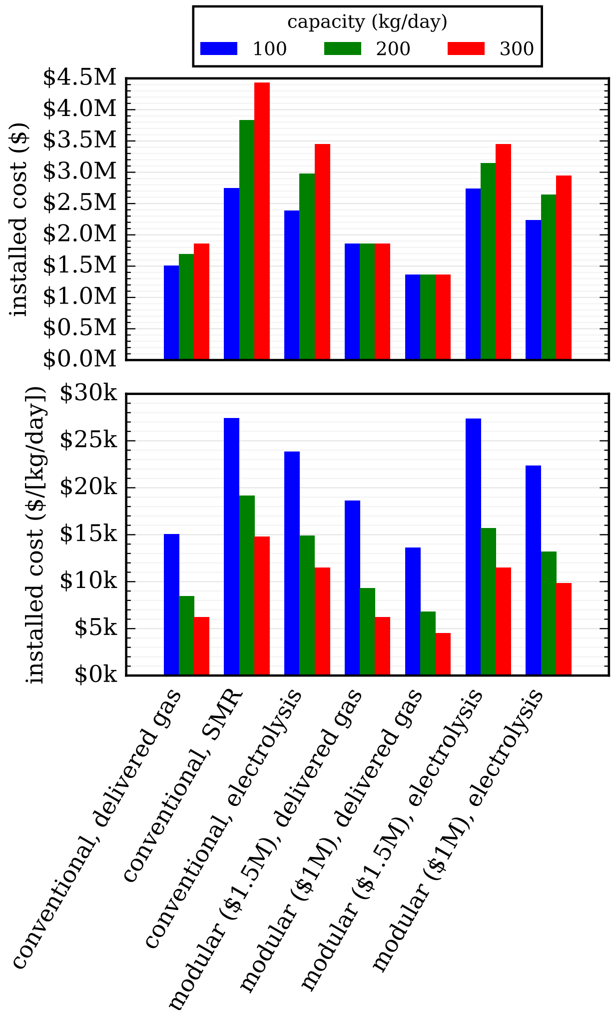
The specified 7-year return on investment results in higher cost hydrogen for smaller stations than for larger ones, due to less throughput and higher capital cost per kg of capacity (see the lower left frame of Fig. 17). If the SD/O charges customers a price lower than this cost, the result will be a longer return on investment. Setting the same price regardless of station capacity will result in the 100 kg/day station having the longest return on investment and the 300 kg/day having the shortest.

The addition of a steam methane reformer or an electrolyzer to a hydrogen refueling station increases the capital cost significantly, with the steam methane reformer estimated to have the

[11] The cost of liquid delivery was not included in this analysis

Table 10. Installed cost (which includes site preparation, engineering & design, permitting, component capital and installation costs), and resulting hydrogen cost to break even at year 7 for the stations analyzed in this work.

station capacity →	100 kg/day		200 kg/day		300 kg/day	
station type ↓	installed cost (\$)	H_2 cost (\$/kg)	installed cost (\$)	H_2 cost (\$/kg)	installed cost (\$)	H_2 cost (\$/kg)
conventional, delivered H_2	\$1.51M	\$30.53	\$1.69M	\$18.37	\$1.86M	\$14.26
conventional, SMR H_2	\$2.74M	\$38.47	\$3.83M	\$25.96	\$4.43M	\$20.23
conventional, electrolysis H_2	\$2.38M	\$39.66	\$2.98M	\$26.51	\$3.45M	\$21.74
modular (\$1.5M), delivered H_2	\$1.86M	\$33.90	\$1.86M	\$19.16	\$1.86M	\$14.25
modular (\$1M), delivered H_2	\$1.36M	\$29.12	\$1.36M	\$16.77	\$1.36M	\$12.65
modular (\$1.5M), electrolysis H_2	\$2.74M	\$43.03	\$3.14M	\$27.30	\$3.45M	\$21.73
modular (\$1M), electrolysis H_2	\$2.24M	\$38.25	\$2.64M	\$24.91	\$2.95M	\$20.13



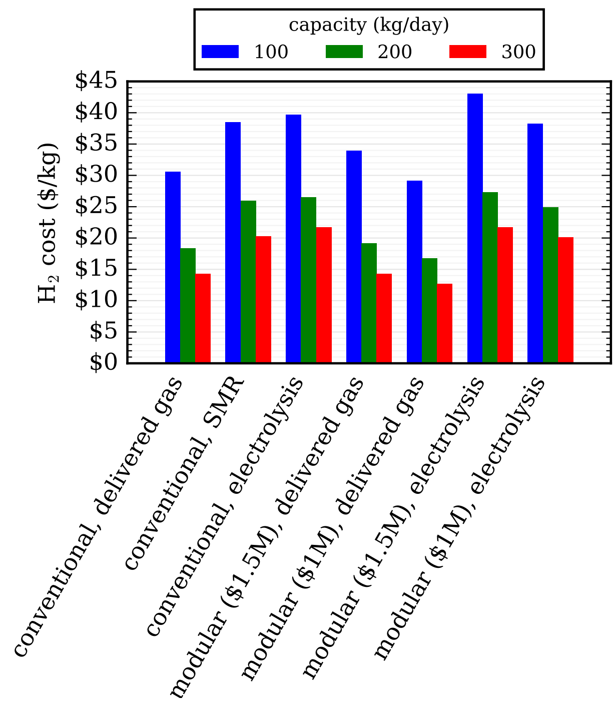


Figure 17. Installed cost (which includes site preparation, engineering & design, permitting, component capital and installation costs) are shown in the left frames. The top frame is the total investment in 2016$, while the bottom left frame is the installed cost per mass of hydrogen dispensed (kg/day). The hydrogen cost to break even at year 7 is shown in the right frame, for the stations analyzed in this work.

highest capital cost. On-site production does allow for a more compact station footprint, and does not require consideration for tube-trailer delivery routes. With current technology and projected utility prices, operating a steam methane reformer costs slightly less than operating an electrolyzer. These offsetting differences in capital vs. operational costs causes the price of hydrogen to be very similar for a station with SMR produced hydrogen and electrolysis produced hydrogen. In both cases, the cost of hydrogen is \$6-\$10/kg more for the stations that produce hydrogen on-site than the stations that have hydrogen delivered. This analysis does not include the startup and shutdown inefficiencies (and associated costs) for either the SMR or electrolyzer. The penalty for cycling a SMR is likely greater than for cycling an electrolyzer, potentially giving an electrolyzer an economic advantage for on-site production.

Electrolyzers also have the potential to produce less carbon dioxide than SMR's. By definition, SMR's require methane, which contains carbon, to produce hydrogen, releasing the carbon molecules as carbon dioxide and contributing to climate change. A reduced carbon footprint could be achieved by using bio-gas, or implementing carbon capture and storage (although this would incur an efficiency penalty). Electrolyzers on the other hand require only electricity and water, giving this technology the potential to be completely carbon free, given the right source of electricity, such as solar, wind, hydroelectric, or nuclear. The key to making on-site production more cost competitive with delivered hydrogen is reducing the utility costs. For electrolysis, this can be achieved through efficiency improvements (although around 50-70% efficiencies are achieved with current technology), through the purchase of low cost off-peak electricity, or by using electricity generated behind the meter. Of course, reducing capital cost and maintenance requirements of on-site production units will also improve the economics of this technology.

According to our research, current modular fueling stations where components are assembled and tested at a central production facility, have installed costs no higher than conventional stations. Using our high estimate of \$1.5M for the modular unit the installed cost of the 300 kg/day modular station is nearly the same as for a 300 kg/day conventional station. Using a lower cost estimate of \$1M for the modular unit the installed cost of a 100 kg/day conventional station is 11% higher than the modular station. With greater industry experience and higher volume production, we would anticipate the cost of modular stations to reduce in the near-future. Developing stations in this manner may lead to better quality control and reduced maintenance requirements for hydrogen fueling stations. It is also possible to achieve more compact station footprints by modularizing the station components by building in appropriate fire-rated barrier walls. Because of these potential benefits, we anticipate modularization and standardization to increase in the future.

This report details the economics of current hydrogen refueling stations and includes some sketches of potential layouts. We have visually depicted the contributions to capital and operational costs of hydrogen for different station concepts, making it easy to find the largest contributors to a high cost of hydrogen to the consumer. This information can be used to devote research and development towards these high contributors. At the station, the dispenser, compressors, and chillers are expensive pieces where additional development, or higher volume production could reduce station costs. For electrolysis, the purchase of low-priced electricity could serve to make on-site production cost competitive with central production and delivery. This report enables the comparison of different station concepts that could be implemented in various market scenarios.

A Piping & Instrumentation Diagram

The following pages show the piping and instrumentation diagram for the included reference stations. For the conventional stations, all components need to be assembled on-site. The dashed boxes show the components that are often modularized for the modular stations. For reference, the utility requirements shown in the P&ID are also included here in Table A.1.

Table A.1. Utility requirement estimates* for the stations in this report.

capacity	100 kg/day	200 kg/day	300 kg/day
compressor power	25 kW	60 kW	100 kW
electrolyzer power	260 kW	510 kW	770 kW
electrolyzer water	110 l/hr	220 l/hr	330 l/hr
SMR power	16 kW	33 kW	49 kW
SMR water	400 l/hr	800 l/hr	1200 l/hr
SMR gas	34 Nm^3/hr	68 Nm^3/hr	101 Nm^3/hr

* These are averages based on manufacturer specifications and literature and are meant to give an estimate of site requirements. For exact specifications to meet station requirements, consult a manufacturer directly.

	Measured Variable	Readout of function	Output Function	Modifier
A	Air	Alarm		
B	Burner	Storage	Users Choice	Users Choice
C	Compressor			Closed
D	Dispenser			
E	Electrolyzer	Sensor (primary Element)		
F	Flow	Filter		
G	Chiller	Glass, viewing		
H	Hand			High
I	Current	Indicator		
J	Power			
K	Time		Control Station	
L	Level	Light		Low
M	Conductivity			Middle
N	Users Choice	Users Choice	Hydrogen	Users Choice
O	Water	Orifice, restriction	Air	Open
P	Pressure			
Q	Quantity			
R	Reformer	Record, Reduce		
S	Speed, Frequency		Switch	
T	Temperature		Transmit	
U	Multivariate	Multifunction	Multifunction	Multifunction
V	Vibration		Valve	
W	Weight	Well	Water	
X	Unclassified	Unclassified	Unclassified	Unclassified
Y	State		Relay	
Z	Position		Actuator	

Line symbols

X”-XXX-XXXX-XXX-XXX

- Insulation (if applicable)
- Pipe Spec.
- Line Number (if assigned)
- Service
- Line size, nominal inches

Line Service Identification codes

CCA-CLEAN COMPRESSED AIR
CHW-CHILLED WATER
H-HYDROGEN
N-NITROGEN

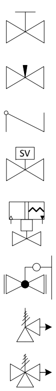
Insulation codes

F1- Soda-lime silicate glass (FOAMGLAS) 1" wall thickness
F2- Buna N Foam 3/8" thick

Pipe Specification Details

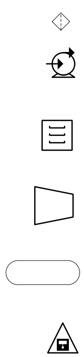
3000PSI	Min. pressure rating of 3,000 PSI 316/316L austenitic stainless steel tubing UNS S31600 (316), UNS S31603 (316L)
6500PSI	Min. pressure rating of 6,500 PSI 316/316L austenitic stainless steel tubing UNS S31600 (316), UNS S31603 (316L)
15000PSI	Min. pressure rating of 15,000 PSI 316/316L austenitic stainless steel tubing UNS S31600 (316), UNS S31603 (316L)
POLY	Polyamide (Nylon) pneumatic tubing, light and heat stabilized.
0.032CU	0.032" wall copper alloy 122 seamless tubing
SCH40	Schedule 40 iron pipe

VALVES



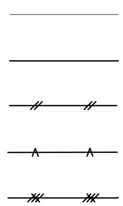
BALL VALVE
NEEDLE VALVE
CHECK VALVE
SOLENOID VALVE
AIR ACTUATED VALVE, SPRING RETURN CLOSE
PRESSURE REDUCING VALVE
TWO WAY PRESSURE RELIEF
THREE WAY PRESSURE RELIEF

EQUIPMENT



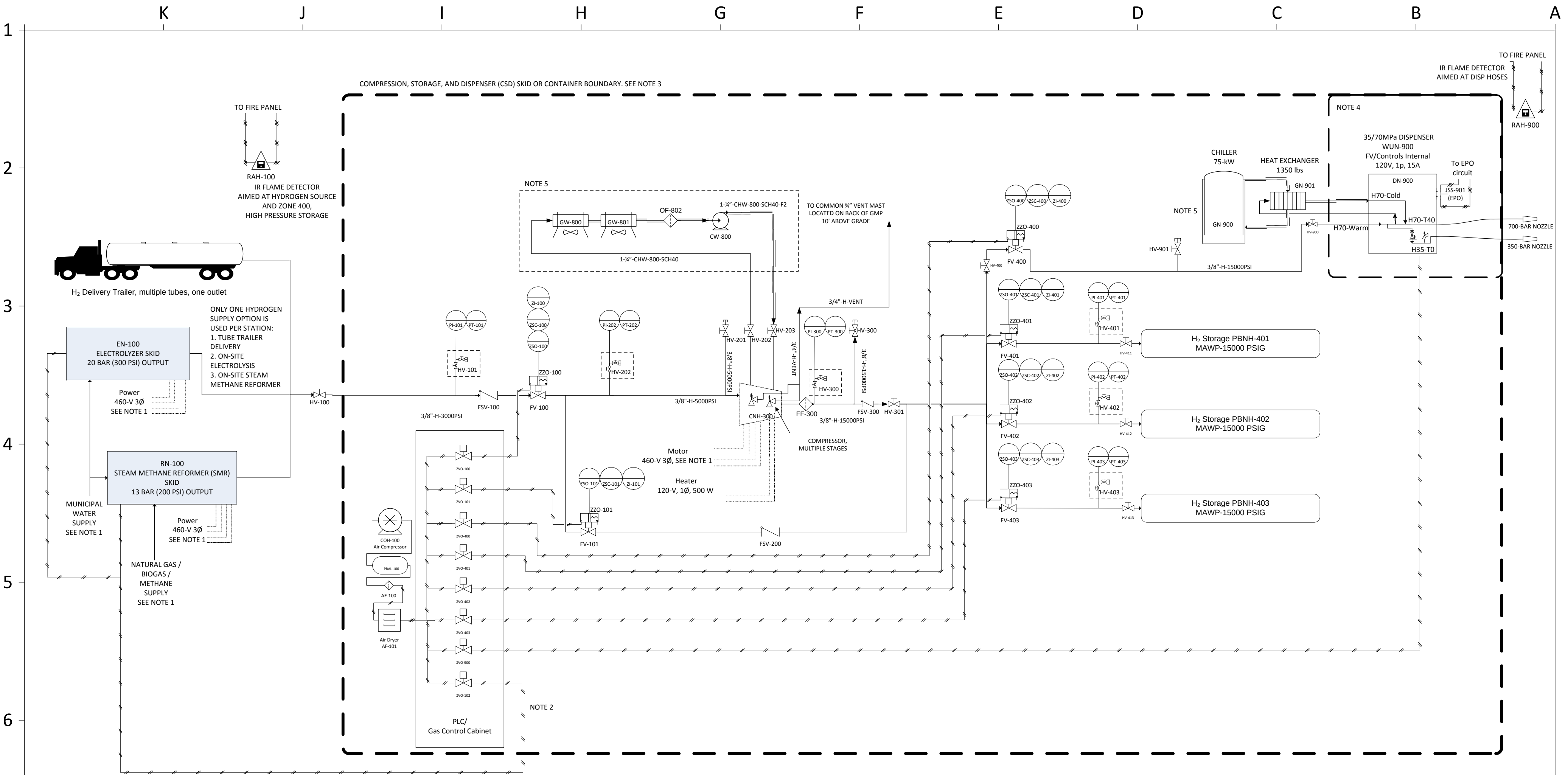
FILTER
PUMP
DRYER
HYDROGEN COMPRESSOR
STORAGE TANK
IR FLAME DETECTOR

PROCESS AND SIGNAL LINES



HYDROGEN PROCESS LINE
DEIONIZED WATER PROCESS LINE
PNEUMATIC SIGNAL LINE
NITROGEN SIGNAL LINE
ELECTRICAL SIGNAL LINE

LEGEND



NOTE 1: UTILITY REQUIREMENTS DEPEND ON STATION CAPACITY AND CAN BE ESTIMATED BASED ON THE FOLLOWING TABLE:

STATION CAPACITY:	100 KG/DAY	200 KG/DAY	300 KG/DAY
ELECTROLYZER POWER:	260 KW	510 KW	770 KW
ELECTROLYZER WATER:	110 L/HR	220 L/HR	330 L/HR
SMR POWER:	16 KW	33 KW	49 KW
SMR WATER:	400 L/HR	800 L/HR	1200 L/HR
SMR GAS:	34 NM3/HR	68 NM3/HR	101 NM3/HR
COMPRESSOR POWER:	25 KW	60 KW	100 KW

NOTE 2: ON-SITE PRODUCTION UNITS MAY INCORPORATE THEIR OWN INSTRUMENT AIR SYSTEM AND INTERCONNECTION WITH CSD SKID/CONTAINER MAY NOT BE NECESSARY.
NOTE 3: APPLIES TO MODULAR STATION ONLY. A BUILD-ON-SITE STATION WILL NOT HAVE A SKID-OR CONTAINER-MOUNTED, PRE-ASSEMBLED SYSTEM.
NOTE 4: IN SOME MODULAR STATIONS THE DISPENSER WILL BE A SEPARATELY-INSTALLED COMPONENT
NOTE 5: IN MANY MODULAR STATIONS THE HEAT EXCHANGE EQUIPMENT WILL BE ROOF-MOUNTED

REFERENCE STATION: 100-300 KG/DAY

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