Hydrogen Station Network Self-Sufficiency Analysis per Assembly Bill 8

November 2020

CALIFORNIA
AIR RESOURCES BOARD

List of Acronyms

AB 8	Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013)
BAU	Business as Usual
CAFCR	California Fuel Cell Revolution
CARB	California Air Resources Board
CHIT	California Hydrogen Infrastructure Tool
EO	Executive Order
FCEV	Fuel Cell Electric Vehicle
GFO	Grant Funding Opportunity
GHG	Greenhouse Gas
HRI	Hydrogen Refueling Infrastructure (provision of Low Carbon Fuel Standard)
HSCC	Hydrogen Station Cost Calculator
LCFS	Low Carbon Fuel Standard
MIRR	Modified Internal Rate of Return
PPNI	Pre-Profit Network Investment
ZEV	Zero-Emission Vehicle

Table of Contents

Executive Summary

California's Assembly Bill 8 (AB 8; Perea, Chapter 401, Statues of 2013) has been a central driving force in the development of an in-state hydrogen fueling network for light-duty Fuel Cell Electric Vehicles (FCEVs). The program was first authorized in 2013 and through 2019 co-funded the development of 64 hydrogen fueling stations. In 2020, up to an additional 120 stations were proposed for award through the latest grant solicitation in the program. These developments have enabled the launch of FCEV sales in California and the state has led the world in FCEV deployment through 2019.

In addition to funding for hydrogen fueling stations, AB 8 includes provisions for analysis and reporting, especially for annual reports that track progress and update projections for future growth. In addition to these annual reporting provisions, AB 8 asks the California Air Resources Board (CARB) and the Energy Commission to evaluate the economics of hydrogen fueling station development and operation against a standard of financial self-sufficiency[i]. This evaluation helps determine whether State funds continue to be necessary for further network development and how additional funds beyond AB 8 help bring the network to self-sufficiency at a future date.

This report is the culmination of a multi-year effort to analyze the financial performance of hydrogen fueling stations in today's market and potential future scenarios. The study detailed in this report adopts a scenario analysis methodology based on future network development as presented in the 2018 *Annual Evaluation of Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Station Network Development* and the California Fuel Cell Partnership's *Revolution* document. Scenario-defining data draw heavily from a series of surveys and interviews with representatives of companies actively involved in the development and operation of hydrogen fueling stations in California and around the world. Other information resources consulted in this study include data from stations built and operated in the AB 8 program, prior academic literature, industry-provided literature, and ongoing research and development efforts.

Hydrogen station network self-sufficiency is achievable, within the decade, with additional State support beyond AB 8

By analyzing a wide array of potential scenarios for progress in California's station network development, FCEV deployment, and cost reduction trajectories, this study finds that financial self-sufficiency is indeed possible in the near future. Estimates for

[i] AB 8 provides up to $20M per year to fund development of at least 100 hydrogen fueling stations or until "the private sector is establishing hydrogen-fueling stations without the need for government support."

FIGURE 1: SUMMARY OF SELF-SUFFICIENCY STUDY CONCLUSIONS

Self-Sufficiency Achieved by:

2030

With State Support up to:

300M

Self-Sufficiency support amount and timing is ensured by:

- Early network development
- Larger network development targets
- Larger hydrogen stations
- High FCEV deployment and station utilization
- Focus on reducing localized operational costs

State support amount may increase due to:

- Accelerating pump price reduction
- Slow capital cost reductions
- Slow operational cost reductions
- Focus on global market cost reductions

Opportunities exist to deliver cost savings to the consumer through State action

the amount of State support that enable this outcome vary significantly across the scenarios investigated. The most likely estimates indicate that additional support of up to $300M beyond AB 8 may be required, as shown in Figure 1. This additional support could ensure self-sufficiency occurs between the late 2020s and 2030.

Station network growth that emphasizes rapidly developing economies of scale provides the most effective use of State funds

The scenario evaluations completed in this study also point to considerations that may guide the strategy and implementation of any potential future support program. The most important consideration is to focus on developing economies of scale through in-state network development and utilization. More ambitious strategies for more stations, of larger capacity, entering the market sooner, typically provide a greater benefit per investment dollar. At the same time, stations must be highly utilized in order for cost reductions to be fully effective. Slower development at the business-as-usual pace can lead to support amounts that are as much as ten times higher on a per-unit basis (expressed as either dollar per kilogram of network fueling capacity or dollar per vehicle deployed).

Because station operation costs outweigh capital expenses, California's leadership in developing an in-state hydrogen fueling network enhances the effectiveness of State support

Station operational costs are typically four to seven times capital costs. Since operational costs compose such a large proportion of total station costs, economies of scale in operations are more effective at reducing total network development costs than economies of scale in capital costs. Operational cost reductions are driven by local development, as greater network density and higher utilization drive the per-unit cost of selling hydrogen lower. For this reason, faster network development within California leads to more effective station network cost reductions than strategies dependent on capital cost reductions.

Capital cost reductions may be driven by development of economies of scale and technology improvements outside of California, but they are less impactful than operational cost reductions even for the fastest rates of capital cost reduction.

Hydrogen-fueling consumers gain significant benefit from State support to achieve network self-sufficiency

State action to support the development of a self-sufficient hydrogen fueling network could provide significant benefits to hydrogen fueling consumers. Compared to a scenario that only funds development of the minimum 100 stations mentioned in AB 8, State funding to self-sufficiency may reduce customers' fueling costs by as much as $4,000 each over a period of approximately five years. Even greater consumer benefit is possible by increasing the State aide by a modest amount that would reduce prices paid at the pump and either a) achieve price parity with gasoline ten to fifteen years earlier than base assumptions or b) achieve price parity five to ten years early and further reduce price to $5/kg (equivalent to approximately $2.50/gallon).

State support catalyzes and accelerates the path to self-sufficiency, even as private industry commits the majority of funds to build and operate the hydrogen fueling network

The magnitude of investments identified in this study are non-trivial. But they provide benefits to the State and consumers, ensuring the development of a self-sustaining hydrogen fueling station network where further investment and network expansion will be driven entirely by private investment. At the same time, State investments can set the course for reducing total cost of ownership in the early FCEV market. In addition, the State support identified in this study represents a small fraction of the expenditures required to develop and operate as many as 1,700 stations supporting 1.8 million FCEVs on the road by 2035. Even at $300M of State support, nearly 90% of network development and operations would be funded through private capital. Through early investment demonstrated in this study, the State may reduce early market risk by providing only a minor portion of the total funds necessary for a successful FCEV market launch.

The study presented in this report demonstrates that a self-sufficient hydrogen fueling network is achievable in California in the next decade. If achieved, this network could provide multiple benefits, including growth of the FCEV market so that it may contribute upwards of 20% of broader Zero-Emission Vehicle (ZEV) deployment targets. At this market size, and with the potential for State investments to translate to consumer savings, FCEVs could be a viable vehicle option for broad segments of California citizens. Network development as shown in this study can therefore strengthen a significant portion of the State's ZEV strategy through 2030 and contribute to the State's full decarbonization goal for 2045.

Background and Motivation

Zero Emission Vehicles, Climate Change, and Air Quality

California has long held a leadership role on issues of ecological preservation, maintaining healthy living environments for residents, sustainability, and careful management at the intersection of human activity and the natural world. Particular areas of concern and focal activities have shifted over the years as improved science and understanding uncovers new challenges, leading to both corrective and proactive actions [1].

More recently, since at least the 1980s, there has been growing recognition of and concern over the emission of gases with long-term and enduring potential to invoke climate change. Often referred to as Greenhouse Gases (GHGs), these pollutants have long lifetimes in our atmosphere and enhance the planet's natural greenhouse effect to potentially dangerous levels. Today, there is broad consensus among the world's scientists in recognizing the potential serious effects caused by continued emission of GHGs into our atmosphere. As a result, reduction of GHG emissions (and ultimately concentration) has been a major focus of efforts in countries worldwide.

Greenhouse gases and criteria pollutants that degrade air quality and adversely affect human health are emitted by activities in all sectors of the economy. Within California, the transportation sector accounts for a significant portion of these emissions. In addition, more recent investigations have found that health-degrading pollutant emissions, especially of chemicals like diesel particulate matter, are emitted at higher rates in or near communities with greater prevalence of additional socioeconomic and health-based risk factors. The combination of these factors presents a heightened burden on overall community health and livelihood that disproportionately impacts residents. In California, the transportation sector accounts for approximately 40% of statewide GHG emissions. Passenger vehicles alone account for 28% of statewide GHG emissions [2]. California's transportation sector accounts for 80% of smog-forming NO_x emissions, more than 40% of SO_x emissions, and more than 20% of PM2.5 (particulate matter smaller than 2.5 microns in length) emissions [3] [4].

In an effort to alleviate these concerning emissions and concentration of greenhouse gases and air pollutants, the State of California has enacted a suite of policy, regulation, and incentive mechanisms to initiate and nurture the development of long-lasting solutions. Emphasis is often placed on the transport sector, given its large role in statewide emissions. Since 1990, CARB's LEV and ZEV programs, which place emissions limits on vehicles sold in California and require auto manufacturers to deploy increasing numbers of ZEVs into the state, have become a cornerstone of the State's strategy to reduce emissions from the light-duty transportation sector [5]. Paired with the Low Carbon Fuel Standard, emissions reductions are enabled for the full vehicle and fuel lifecycle of automobiles sold in California. More recent developments have seen the strategy extended to other states and the medium- and heavy-duty transportation sector within California [6] [7] [8].

California policies place particular emphasis on the need for full-scale transition to zero-emission, electrified transportation. In 2012 then-Governor Brown signed EO B-16-12, setting a target of 1.5 million ZEVs on the road by 2025 [8]. Six years later, Governor Brown extended this goal through EO B-48-18, with a target of five million ZEVs on the road by 2030 [8]. On September 23, 2020, Governor Gavin Newsom strengthened the State's focus on ZEVs by signing EO N-79-20, which establishes a target that 100 percent of new light-duty vehicle sales must be ZEVs by 2035. Drayage trucks (those that primarily operate within ports and similar facilities) and off-road vehicles (where feasible) must meet a 2035 deadline, for conversion of all in-use vehicles to zero-emission options. Meanwhile, the medium- and heavy-duty transportation sectors must meet an in-use fleet conversion target by 2045. The Executive Order directs California's State agencies to leverage existing authorities in order to reach these goals and specifically tasks CARB, the Energy Commission, and the Public Utilities Commission (along with other relevant State agencies) to "accelerate deployment of affordable fueling and charging options for zero-emission vehicles," with particular focus on low-income and disadvantaged communities [9].

On a broader scale, the recently passed SB 100 (de Leon, Chapter 312, Statutes of 2018) establishes a target of full economy-wide decarbonization by 2045 [10]. With these guiding principles, State agencies including CARB and the Energy Commission recognize the near-complete turnover implied for existing vehicles, equipment, and installed infrastructure. Moreover, the timelines are aggressive and require rapid acceleration of associated technology development, deployment, and market expansion programs. These efforts collectively focus on deployment of BEVs and FCEVs and their associated fueling infrastructure as necessary to successfully meet ZEV targets. A wide array of support programs now exist across several agencies and at several levels of government from local, city-wide measures up through the State initiatives and even at the federal level.

Still, ZEV deployment is in the early stages. In 2019, approximately 150,000 ZEVs were sold in California, or about seven percent of the 1.2 million new registrations in 2019 estimated by the California New Car Dealers Association [11] [12]. The vast majority of ZEV sales in 2019 were BEVs and PHEVs. In its latest *Annual Evaluation*, CARB estimates that approximately 1,200 FCEVs were deployed in California between April 2019 and April 2020 [13]. All ZEV technologies are therefore in the early adopter phase of deployment, but FCEVs (being the most recent ZEV technology to initiate market development) are particularly early in the market adoption and development process.

Assembly Bill 8 and Other Supporting Programs and Goals

ZEV deployment is essential to achieving California's climate change mitigation and air quality improvement goals, and, support programs have thus far been necessary to launch and expand the state's ZEV customer base. Several programs are currently underway, with a wide variety of structures including regulations, incentives, and equity programs. One of the most influential efforts for hydrogen fueling station network development in California is provided by AB 8, a broad transportation-funding bill that provides a financial resource to several programs through a fee applied to vehicle and vessel registrations [14].

Among the several provisions of AB 8 is the establishment of the Clean Transportation Program (CTP- also referred to as the Alternative and Renewable Fuel and Vehicle Technologies Program). The CTP is able to dedicate up to $20M per fiscal year to co-fund the development of hydrogen fueling stations within the state of California. These funds have been made available during the period of 2014-2024. The bill calls for these funds to establish at least 100 hydrogen fueling stations by 2024 [14].

The California Energy Commission is tasked with administration of these funds. To date, the Energy Commission has primarily relied on competitively bid capital expenditure grants as the funding mechanism used in AB 8, though Operations and Maintenance grants have also been administered. The Energy Commission develops its funding programs in cooperation with the California Air Resources Board, especially regarding the location, capacity, and technical specifications of stations receiving grants under the program.

In addition to cooperating on AB 8-related funding programs, the bill requires CARB and the Energy Commission to regularly analyze historical and projected progress, and both current and future needs for station network development. These analyses come in the form of two annual reports related to hydrogen fueling network development and fuel cell electric vehicle deployment in California. Every June, CARB provides the Energy Commission with an *Annual Evaluation* of progress and needs, focusing on the information required to effectively develop and manage future hydrogen station funding programs. These reports are generally made available to the public later in the summer, as well. The Energy Commission and CARB also collaborate on a *Joint Agency Staff Report on AB 8* that is published every December. *Joint Agency Staff Reports* focus more closely on progress in station network development and utilization and the cost (to the State) and time required to achieve the 100 station milestone of AB 8.

While AB 8 is written with the intent of financially supporting the establishment of a hydrogen fueling station network in California, it also references the eventuality of a financially self-sufficient hydrogen fueling station industry. Such a network would no longer require State funding to ensure ongoing station operations and continued expansion of the network. Evaluation of the cost and timing to achieve this state of network and industry development is a central task under AB 8.

AB 8 has long been the primary source of development targets and State financial support for hydrogen fueling station deployment, but more recent efforts have added to its provisions. As mentioned above, EO B-48-18 expanded the State's Zero Emission deployment and fueling infrastructure effort. The EO added to earlier targets by calling for the deployment of 5 million ZEVs by 2030 and new targets for ZEV fueling infrastructure development by 2025. With respect to hydrogen, the EO tasks CARB and the Energy Commission with supporting the development of 200 hydrogen stations by 2025. Compared to AB 8, the EO calls for doubling the number of hydrogen fueling stations in California's network with up to two years of extra development time. In order to achieve such a target, total development pace must significantly accelerate [13].

In 2019, the LCFS program administered by CARB adopted new infrastructure crediting provisions for both direct current fast charging and hydrogen refueling stations [15]. The new provisions were developed in part to foster accelerated development of both ZEV fueling networks and potentially achieve other related goals such as reduced GHG emissions associated with ZEV fueling and reducing ZEV customers' fueling costs at publicly accessible retail fueling locations. With respect to hydrogen stations, the HRI provision allows station operators to generate LCFS credits equal to the station's total design capacity (within certain program limitations), independent of the amount of hydrogen fuel actually sold. Due to the provision, station operators receive some financial protection against low station utilization rates during the early phases of FCEV deployment. In addition, the program provides an incentive to station operators to build more stations sooner, with larger capacity, and dispense hydrogen with lower carbon intensity and more renewable content.

Hydrogen Station Network Development in California

The AB 8 program and the LCFS HRI provision are the State's most influential methods of providing direct monetary support to the development of light-duty hydrogen fueling stations in California. As of the beginning of 2020, the AB 8 program had funded 62[1] of the 71 stations included in California's hydrogen fueling station network; 42 of these stations are Open-Retail as of July 21, 2020. Station development has begun at an additional nine future station locations as a result of the LCFS HRI

[1] The Energy Commission has awarded funds to more stations than this, but some never began development and therefore never received fund disbursements; a few other stations funded in the early years of the program became Open-Retail and operated for at least the contracted number of years but have since closed.

program; eight of these nine stations have to date not requested or received additional funding through the AB 8 program. These 71 stations have a total fueling capacity of 36,730 kg/day: enough hydrogen to fuel approximately 50,000 FCEVs [13].

On September 4, 2020, the Energy Commission released the Notice of Proposed Awards for GFO 19-602 [16]. This grant solicitation was a first-of-its-kind for the Energy Commission within the AB 8 program. Prior solicitations considered individual applications for each proposed station location and were issued roughly every other year. GFO 19-602 was developed as a response to industry requests for a solicitation design that was longer-lasting, provided greater certainty of funds availability, and enabled development of economies of scale through network-level and multi-year planning. The solicitation was therefore designed with approximately $45M immediately available, but a potential commitment to a total of approximately $115M to be disbursed over the remaining years of the AB 8 program. Applicants were asked to provide a description of their multi-year network plans, with specific addresses required only for the first batch of stations (applicants were given flexibility to determine the number of stations per batch and number of batches) [17].

In total, eight applicants successfully passed administrative screening and proposed station network development that far exceeded the available scope of funds. Altogether, applicants requested over $200M in Energy Commission funds for more than 170 stations [16]. The capacity of all stations, if they could have been funded, was sufficient to support the deployment of more than a quarter million additional FCEVs. With available funds, the Energy Commission selected projects to develop three applicants' networks, including up to 123 stations. The awarded stations may enable the deployment of more than 110,000 FCEVs in addition to those enabled by stations funded previously. Station development will be spread over the next several years, with all funded stations completing development by 2026.

Included in the awarded stations are a subset of five stations that will receive funds from the Environmental Mitigation Trust Fund established by Appendix D of the Consent Decree approved by the United States District Court, Northern District of California as a result of Volkswagen's use of an illegal defeat device in certain diesel vehicles [13]. Under the requirements of the Consent Decree, these stations will help fill in gaps of network coverage and market need not addressed by other efforts. Specifically, these stations will be developed at locations within or benefitting disadvantaged communities.

Benefits of a Self-Sufficient Hydrogen Fueling Market

While the early market development of ZEVs and their associated fueling infrastructure has involved State financial support and methods to reduce risk of entry into the marketplace, a successful market launch would not rely on ongoing State financial support. An enabling policy structure may need to remain in place in order to maintain a fair marketplace for consumers and industry members alike, but reliance on perpetual public funds implies a business venture that has not succeeded in developing a viable consumer market.

New vehicle technologies often enter the market at higher prices in their initial deployment years due to limited production and distribution scale and other factors. This has proven true of ZEVs and their related fueling infrastructure markets. The additional cost typically means that adoption is limited to a subset of consumers usually characterized by several factors, including higher than average disposable income and an interest in being an early adopter of new technologies [18] [19]. State ZEV support efforts work to address this disparity by developing means to reduce costs to consumers so that a broader and expanding set of the population can choose to adopt the new technology [20]. A self-sufficient ZEV fueling industry could enable State efforts to focus on bringing these technologies to disadvantaged or low-income communities earlier than they might otherwise be able to.

A major aspect of achieving self-sufficiency is the development of scale. Increased scale of production and deployment is necessary to reduce unit costs of equipment and operations. The growth of scale itself implies a broadening consumer base. A self-sufficient hydrogen station network is also therefore a network that enables its own continuation and growth based on growing consumer demand. State-assisted growth by definition addresses a more limited situation in which market demand is less certain. Targeting the development of a financially self-sufficient hydrogen fueling market is therefore synonymous with an intent to reach an expanded consumer base beyond the earliest adopters.

As the consumer market grows, reduced costs and other market forces may also improve the ownership proposition. A broader consumer base requires a more accessible value proposition than the more limited early adopter market, reflecting lower overall total costs to the consumer on average. Enhanced and broader demand can accelerate the development of innovative and more cost-effective solutions for FCEVs, hydrogen fuel production, station equipment, and operational practices. With a self-sufficient market, the consumer may therefore have a greater voice in guiding the market development of prices paid toward greater affordability.

Defining Self-Sufficiency

AB 8 requires assessment of network development and funding against the reference of self-sufficiency. However, the statute itself did not provide a definition or metric to serve as a basis of evaluation. CARB considered several possibilities, such as: marginal station economics (when the next station's development can be funded by proceeds from previous stations' operations), development of the first net-profitable station(s), development of the first annually profitable station(s), development of minimum returns across stations, profitability for sub-networks of stations representing multiple competing operators' networks, and other definitions.

Early research into FCEV and hydrogen fueling station market development tended to advance the argument that self-sufficiency was primarily defined as the point at which hydrogen fuel could be sold at a retail price that is equivalent (on a per-mile traveled basis) to conventional gasoline fuel [21] [22] [23]. This customer-centric definition has several merits, including the precondition that FCEV adoption would be an economically attractive alternative to conventional vehicles. This implies a higher probability of sufficient FCEV deployment to maintain demand at hydrogen fueling stations and provide a consistent revenue stream.

However, CARB determined early on in this study to adopt a broader perspective in analyzing the approach to self-sufficiency. CARB's methodology focused on the various business entities operating and supporting hydrogen fueling station networks as the decision point for self-sufficiency. A variety of types of entities have built and operated stations in California's network, representing a variety of motivations and evaluation of opportunities for current and future business. In CARB's estimation, these entities have all developed some assessment around a value proposition for continued business within their respective financial and operating structures. In the current policy environment, that value proposition likely considers existing State financial support like the AB 8 and LCFS HRI programs and most likely focuses on short-term demonstration of future profit potential. Long-term self-sufficiency could similarly be assessed from the perspective of value propositions, especially when considering the potential for more traditional investment entities to interact with the industry and supplant public funding mechanisms.

This perspective also makes it clear that while cost parity with the incumbent fuel is a positive indicator of emerging market development, it is not a necessary condition. Consider modern gasoline stations. Customers fueling at today's gas stations are presented with several octane options with which their vehicle may be compatible. In general, higher octane fuel provides improved performance (if the vehicle is designed to accommodate the fuel grade) and costs more than lower-octane fuels. At a typical station, 90-octane gasoline is not cost-competitive with 87-octane. However, station owners still find a sufficient value proposition in order to carry the higher fuel grade and there is a large enough population of customers to ensure sufficient demand that warrants the station operator's continued sale of the product.

Hydrogen fueling station economics are considered in this study within a similar framework. With this perspective, self-sufficiency may occur at a point along an industry development path when costs and prices are above, below, or at parity with gasoline. If station economics are favorable at this point, development may continue to occur even as prices and costs continue to decline throughout the marketplace as long as the future outlook provides a compelling proposition for continued private investment.

All companies endure risk, loss, and re-investment constantly as the normal course of conducting business. The key to determining self-sufficiency for the hydrogen fueling station market would therefore need to determine the point at which these types of activities could be self-supported through revenue and support mechanisms other than direct public financial assistance. Sufficient revenues and returns enable continuing station network development and potentially attract additional outside private investment. These monetary sources then reduce or eliminate the need for State direct financial support.

In addition, the customer-centric methodology inherently assumes FCEV market development is unknown. While this is true, several reference scenarios are now available, especially through the *Annual Evaluation* process initiated by AB 8 and the California Fuel Cell Partnership's *Revolution* document [24]. CARB developed a methodology with the capability to investigate several FCEV deployment trajectories and estimate their impact on the question of determining the amount and timing of State support that leads to self-sufficient network operations. Still, the customer perspective remains important to hydrogen fueling station network and FCEV market development overall. For this reason, the methodology in this study analyzes several scenarios of accelerated reduction of price at the pump for the consumer and quantifies the impact of State station support on FCEV owners' fueling costs.

Network development to the point of self-sufficiency is likely a complex process, dependent on and interacting with the coordinated development of upstream supply chain industries and the FCEV ownership market in California and elsewhere across the globe. Evaluation of an approach to network self-sufficiency is similarly complex, requiring significant market development data and projections of future potential paths across the related industries in development. At the time of AB 8's passage, evaluation of self-sufficiency was limited, given that network development was largely restricted to research and demonstration projects. Today, with several years of retail fueling station development and operation and millions of miles of FCEV driving experience within California, this evaluation can be better-informed. CARB's methodology also allows for investigation of many of these considerations through sensitivity analysis. These capabilities provide a new opportunity to develop policy-informing insights on factors influencing the path to hydrogen fueling self-sufficiency.

Self-Sufficiency Report

This report details the investigative efforts of CARB and the Energy Commission over the past five years to evaluate the concept of self-sufficiency. Prior *Joint Agency Staff Reports* and *Annual Evaluations* provided periodic updates and notable observations from earlier steps in the overall self-sufficiency evaluation effort. Information gained from hydrogen industry surveys and interviews have previously been detailed. This report briefly summarizes the most relevant information and provides a thorough description of the final steps in the overall study: developing a hydrogen station network financial evaluation methodology, defining analysis scenarios to capture the likely range of potential future market developments, and synthesizing the results of the full suite of scenario evaluations. This report focuses on the metrics of cost (to the

State) and timing to achieve self-sufficiency within the array of scenarios investigated. Specifically, this report estimates the likely amount of financial support that yields a self-sustaining light-duty hydrogen fueling network and the timeframe in which this support would be most effective.

The scope of this report is limited to light-duty hydrogen fueling stations. This report does not address development towards a broader implementation of hydrogen as a fuel or energy storage medium in other sectors of the economy. Therefore, integration with the renewable grid, integration into industrial and manufacturing processes, or expansion of hydrogen fuel into the medium- and heavy-duty sectors are not explicitly accounted for in this study. Deployment progress in these additional sectors of the economy may have an impact on the costs to build and operate light-duty hydrogen fueling stations. For example, if fuel cell technology is broadly adopted in the heavy-duty transportation sector, demand for hydrogen fuel in the heavy-duty sector may grow more quickly than the light-duty sector because of the higher fuel demand per vehicle. Economies of scale in the fuel supply chain may therefore develop more rapidly and enable hydrogen fuel cost reductions across multiple transportation sectors. This study does evaluate the possibility of fuel cost reductions, but does not necessarily associate those reductions with developments in the light-duty transportation, heavy-duty transportation, or any other sector that may integrate hydrogen fuel.

Study Structure

Study Goals and Limits

The study described in this report has been designed around a specific, narrowly-defined question within the context of California ZEV policy. Influenced by language related to evaluation of hydrogen fueling station funding in AB 8, this report analyzes the development needs and potential State support to enable financial self-sufficiency for the in-state light-duty hydrogen fueling network. Similar to analyses performed in annual *Joint Agency Staff Reports*, the analyses undertaken in this study focus on quantifying the cost to the State and timing to achieve the target of self-sufficiency. The State support amounts identified in this report represent a hypothetical financial support program to support development beyond the current State-funded network of hydrogen fueling stations. The timing aspect refers to the period over which those funds would be dispersed to station operators and developers in order to support the up-front capital expenditures and/or ongoing operations and maintenance costs.

The self-sufficiency study necessarily performs evaluations related to future development of the FCEV and hydrogen fueling markets in California. In general, evaluations are provided for station network growth and operation through 2050. Although the study assesses scenarios this far into the future, it is important to understand many scenarios achieve self-sufficiency prior to 2050. Many factors are considered within the evaluations, such as cost to procure fuel and price paid by the consumer at the pump. Scenarios are described and evaluated for changes in these parameters over time. Future values for these parameters are taken in the study as exogenous estimates, and this study does not perform evaluation of the upstream factors that lead to these variable values. Instead, the values themselves are based on surveys and interviews of industry experts, publicly available studies, and data from operating stations.

With respect to results and outcomes, this study intends to serve solely as a quantification tool to evaluate the cost and timing metrics. This study is not intended to be used as a predictive tool. This study also does not intend to decide whether or not the funding amount should be met by any future State program, nor the form, structure, and implementation practices of any such new direct funding program. The study does make a simplifying assumption that the form would be a 5-year grant program to enable quantification. However, neither CARB nor the Energy Commission endorse this particular hypothetical program structure. Figure 2 outlines these and other bounds of the self-sufficiency study.

Finally, this study solely evaluates the economics of light-duty hydrogen fueling stations. It does not assess the economics of light-duty vehicle purchase, any aspects of medium- and heavy-duty vehicles and their related infrastructures, or any economics of hydrogen fuel production and distribution.

FIGURE 2: BOUNDS OF THE STUDY

This Study Does	This Study Does Not
• Estimate cost and timing to reach self-sufficiency of hydrogen fueling network	• Attempt to predict the future trajectory of FCEV and hydrogen industry economics
• Evaluate many scenarios to develop probable ranges of cost and timing	• Determine that a cost of $5/kg in 2030 is more or less likely than a cost of $10/kg (as an example)
• Assume State has an interest in establishing a self-sufficient hydrogen fueling network	• Determine whether or not the State should support establishing a self-sufficient hydrogen fueling network
• Assume an equilibrium between price and cost exists	• Develop a traditional cost-price equilibrium model
• Assume the equilibrium point can be influenced by State support	• Specify or explicitly model the mechanisms that may force prices and costs lower or higher
• Estimate the additional State support needed to reach this equilibrium	• Determine the form of the support that should be used

Study Phases and Timeline

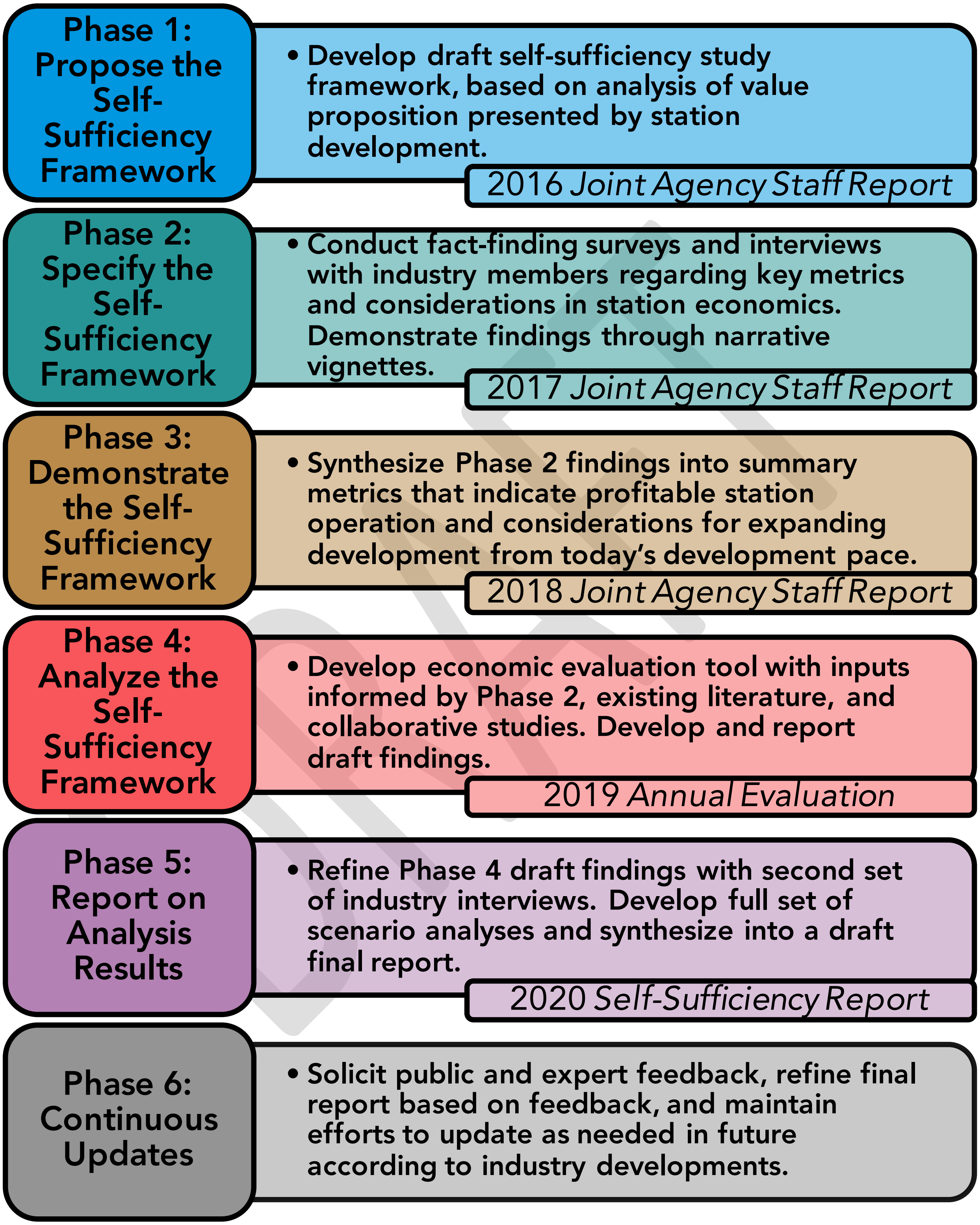
This report is the culmination of several years of investigation into understanding hydrogen fueling station and network economics and conditions enabling successful market launch. The study began in 2016 with the development of an analysis framework based on the premises outlined in the section Defining Self-Sufficiency, above. Figure 3 outlines all study phases and the State reports that address their outcomes. First reported in the 2016 *Joint Agency Staff Report*, the proposed framework emphasized the concept of value propositions to various business entities involved in station network development [25]. Core features of this framework have remained, and earlier phases of the project continued to report findings specific to different types of entities in California's station network development effort. As the study progressed, the need to differentiate between entities in quantitative evaluation became less apparent, based particularly on the consistency of industry member feedback provided through a survey and interview process.

Following conceptualization and proposal of the study's approach and thesis to assess value propositions, CARB and the Energy Commission completed a series of surveys and interviews with representatives from more than a dozen businesses involved in station deployment in California. As reported in the 2017 *Joint Agency Staff Report*, these representatives included industrial gas companies, independent station operators, auto manufacturers, station equipment providers, and energy and fuel companies. Only the independent station operators were considered to have business ventures solely focused on station development. All other groups include hydrogen station development as part of their business (or in the case of auto manufacturers, have dedicated personnel and financial resources directly to the effort) but generally have a larger business focus.

The 2017 *Joint Agency Staff Report* provided more qualitative insights on these business entities' roles in California's station network development and indicators they may consider when making further investment decisions. These findings were expanded in the 2018 *Joint Agency Staff Report* with quantitative evaluation of successful station operation parameters. At the same time, CARB began developing a draft economic evaluation methodology and computation tools, relying heavily on the industry feedback and published studies of hydrogen station construction and operation costs. CARB published draft values for most key input variables in the 2019 *Annual Evaluation*. The report also included a collection of early findings based on this study's early pilot investigations.

Concurrent with publication in the 2019 *Annual Evaluation*, CARB also contacted industry members that had previously participated in the Phase 2 survey process for further review of initial results and proposed methods. Based on feedback, CARB further refined scenario inputs and broadened the set of scenarios to be evaluated. This report serves as the product of Phases 1 through 5 in Figure 3. Upon release of this report, CARB plans to solicit public and expert feedback and complete at least one revision in the final Phase 6, with future updates completed as necessary.

FIGURE 3: PHASES OF SELF-SUFFICIENCY STUDY PROCESS



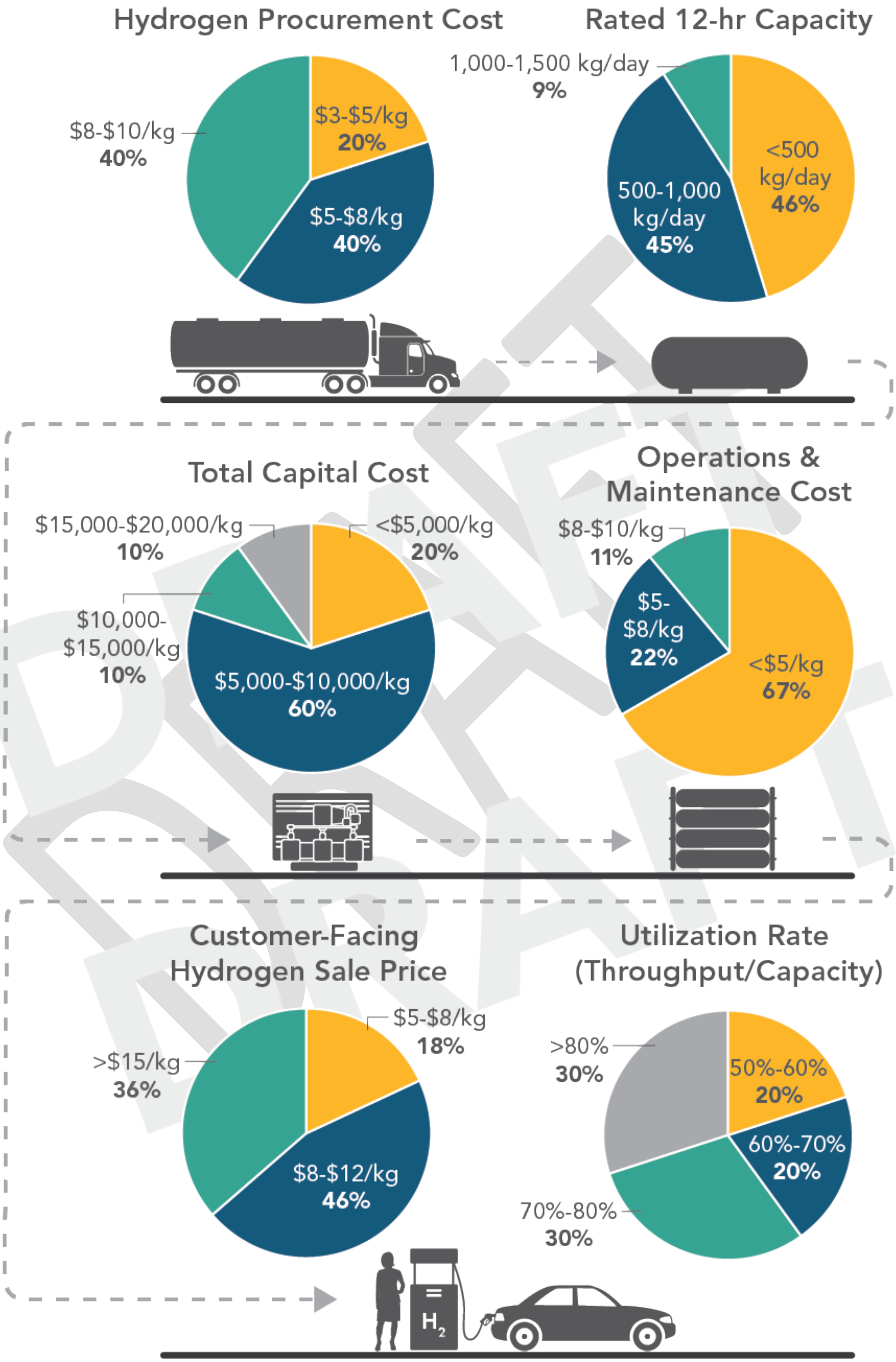
HIGHLIGHTS FROM INDUSTRY MEMBER INPUT

Two phases of this project helped CARB and the Energy Commission gain greater insight into industry member organizations' views on hydrogen station economics. The first occurred in Phase 2, when the agencies contacted over a dozen representatives from companies currently involved in California's station network development. The *2018 Joint Agency Staff Report* described several parameters that representatives from these companies considered requirements for an individual station to become profitable [26]. Figure 4 repeats a key summary figure from that report. The image displays the path of hydrogen from procurement and transportation via truck to delivery to the consumer at a station. Each step highlights a related key parameter for a profitable station and displays the distribution of responses in the survey to the necessary value for that parameter. For example, in the first step of hydrogen procurement, 40 percent of companies surveyed reported hydrogen procurement cost must be between $5 and $8 per kilogram in order for an individual station to be profitable. Some key takeaways include:

- Stations likely need to be 400 kg/day or above in capacity (12-hour peak-to-peak) in order to be profitable
- Station utilization likely needs to be high (above 70 percent) for profitability
- Customer-facing prices likely don't need to be below $8/kg (nominally equivalent to gasoline parity) for profitability

Multiple respondents stressed that their responses should be taken as a self-consistent, but not necessarily unique, set. That is, each respondent could envision multiple combinations of costs and revenues that result in a profitable station. In some of these hypothetical cost and revenue sets, costs may be high and offset by high price at the pump, resulting in a station with net profits. In other sets, costs might be low and a correspondingly lower price at the pump could implemented and again result in a net profitable station. Even though respondents may have envisioned multiple options for combinations of costs and revenues that lead to profitability, they each responded according to only one of these possibilities. The responses provided on the survey were therefore not the only possible responses, but were indicative of the respondents' vision for station operations.

FIGURE 4: METRICS OF INDIVIDUAL STATION PROFITABILITY



Industry representatives also provided valuable feedback based on the initial draft financial evaluations completed in Phase 4 and reported in the 2019 *Annual Evaluation*. Industry feedback incorporated into revisions to the evaluation tool included:

- Price parity with gasoline was confirmed to be most commonly viewed at a hydrogen sale price around $8/kg, assuming constant gasoline prices. This study has adopted this metric.
- Operations and maintenance expenses need to quantify both a fixed and variable portion, and are now more heavily weighted towards fixed costs. The first draft version of the report included only a single variable component. CARB relied on AB 8 program data and prior studies to estimate the major portions of operations and maintenance costs and developed a cost structure that includes both fixed and variable portions.
- Operations and maintenance costs need to include a periodic major maintenance component.
- Network effects (densifying stations) could reduce station operations and maintenance costs.
- Capital cost reductions can be as high as an order of magnitude with relatively small increases in production volume. Draft rates of one percent reduction per year for 10 years (as reported in the 2019 *Annual Evaluation*) are too slow to capture this potential rate of cost reduction.
- Capital cost reductions may follow a Moore's Law type of trajectory, but with a cost reduction of less than 50 percent per doubling of production volume of station equipment.
- State financial assistance programs are often viewed as reducing the risk that is presented to new entrants and investors into the industry. As the station network grows and economic performance improves, the amount of risk mitigation that private entities need will decrease.

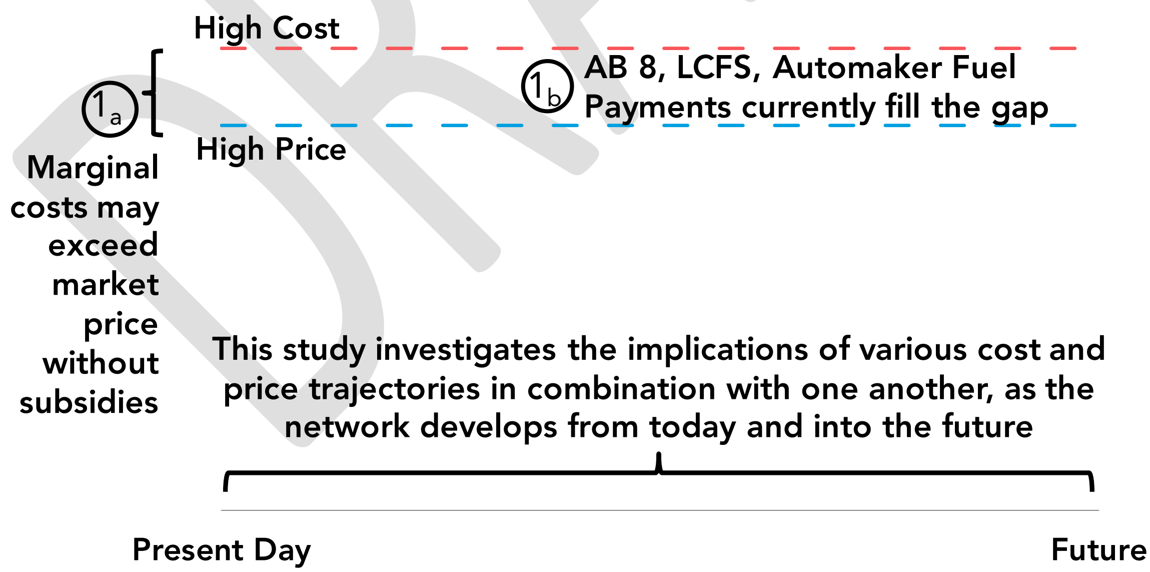
Details of implementation for these considerations are included in later chapters of this report as appropriate.

Economic Model Methods

Economic Fundamentals

Evaluation of the balance between hydrogen station costs and revenues lies at the core of this study. In today's emerging hydrogen fueling station network, these factors are likely imbalanced. As shown in Figure 5, the costs to install and operate hydrogen fueling stations in California are currently high. Fuel prices paid by the consumer are also high, but likely not high enough to fully offset the costs and generate an income stream sufficient to enable continued investment in an ever-growing station network. Several sources of financial support currently fill the gap to keep the hydrogen fueling network in operation. These include the grant funds available through AB 8, credit generation opportunities available through the LCFS program (both credits based on fuel sales and HRI credits), and auto manufacturers' fuel payments[2] for FCEV drivers.

Figure 5: Illustrative Economics of Early Hydrogen Fueling Market in California



This imbalanced situation is not sustainable for ongoing station operation and largely precludes private investment into further development of the state's hydrogen fueling

[2] Since the deployment of the Hyundai Tucson Fuel Cell, auto manufacturers have provided FCEV drivers with some form of payment (either a pre-paid fuel card or a reimbursement process) that covers fuel costs up to as much as $15,000 over the first three years of lease or ownership.

network. In order for a more financially sustainable future to evolve, station economic factors need to develop to a situation similar to that shown in Figure 6. As shown, both costs for developing and operating stations and prices paid by fueling consumers need to decrease. However, a sustainable forward path requires a balance between price and cost that provides some margin of profit to the station operator. This study attempts to quantify the range of likely State intervention necessary to maintain network development while other industry-led factors (such as equipment cost reduction) progress along feasible trajectories representing high and low rates of change. This study primarily focuses on cases in which both costs and prices decrease over time. This study additionally investigates cases where price reduction occurs more swiftly due to intense State intervention targeted at improving the FCEV owner's value proposition. This study does not analyze cases where costs decline but prices remain high, as this represents the undesirable result of consumers' FCEV ownership value propositions not improving as station network development progresses.

FIGURE 6: FRAMEWORK TO ANALYZE FUTURE STATION NETWORK ECONOMICS

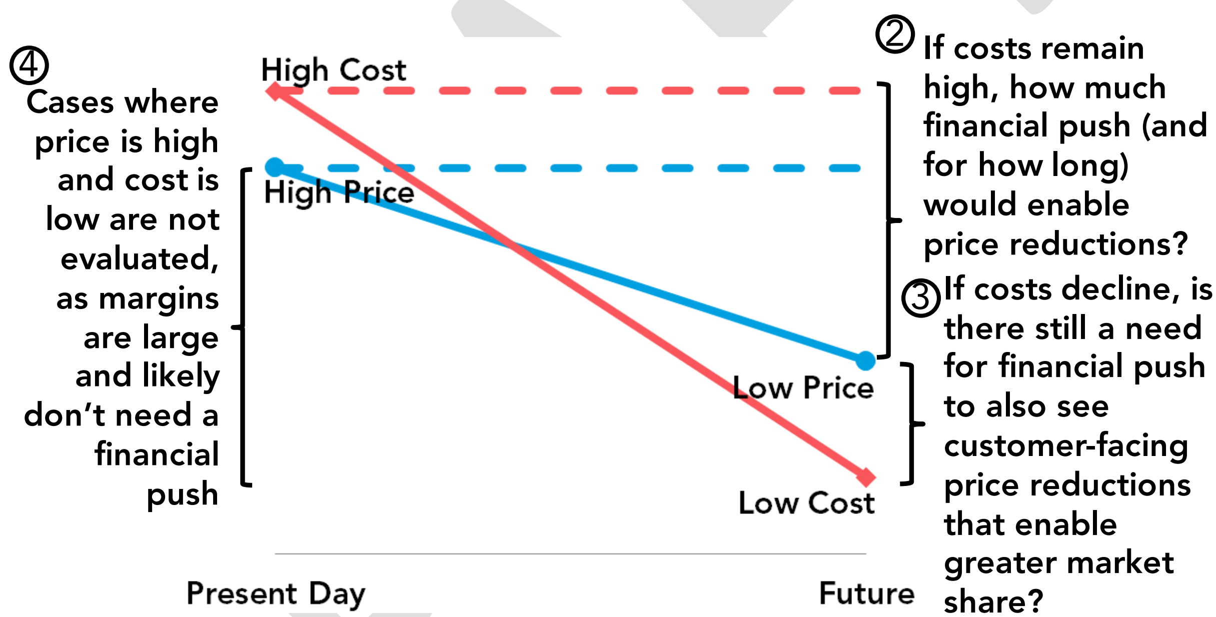


Figure 7 demonstrates the metrics quantified by this study: the amount of State support and time required to achieve self-sufficiency. As costs and price decline, a self-sufficient market will require an inversion of their relative amounts; costs will need to fall below price. In the figure, the cost (to the State) is indicated as the difference between cost and price until the time when profits first develop. This represents a highly idealized case in that it infers private investor interest as soon as the first marginally profit has been achieved. In reality, this is not the value proposition that investors are likely to seek. Instead, private investors weigh this along with assessments of risk, potential for near-term and long-term returns on investment, and the time it would take to achieve these financial returns. This study accounts for this additional consideration by defining the cost to achieve self-sufficiency to include a minimum return that attracts private investment. The date to achieve self-sufficiency is defined similarly to the situation shown in Figure 7, evaluated at the network level. Further details are provided below.

FIGURE 7: ILLUSTRATION OF THE ECONOMIC EVALUATIONS OF THIS STUDY

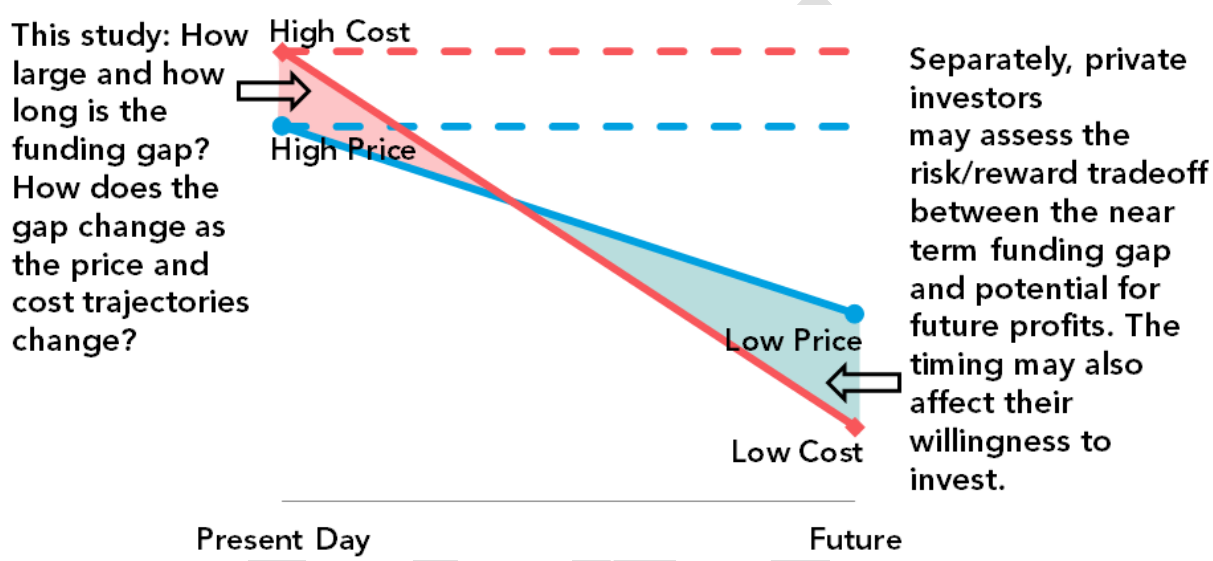


Figure 5 through Figure 7 display simplified economics, reduced to two major forces of theoretical macroeconomics- cost and price. This study investigates the effect of several more factors that determine these major forces. For the core set of results, five key considerations define the set of scenarios to be evaluated. For each of these, multiple possibilities are investigated; for example, price of hydrogen at the pump may be specified as one of three cases (prices remain high and decline slowly to 150 percent of parity with gasoline, prices decline steadily to parity in 2040, and prices decline on an accelerated schedule, achieving parity in 2030). Combining all possible cases of the key variables results in 840 scenario evaluations that comprise the core results. The variables explored are:

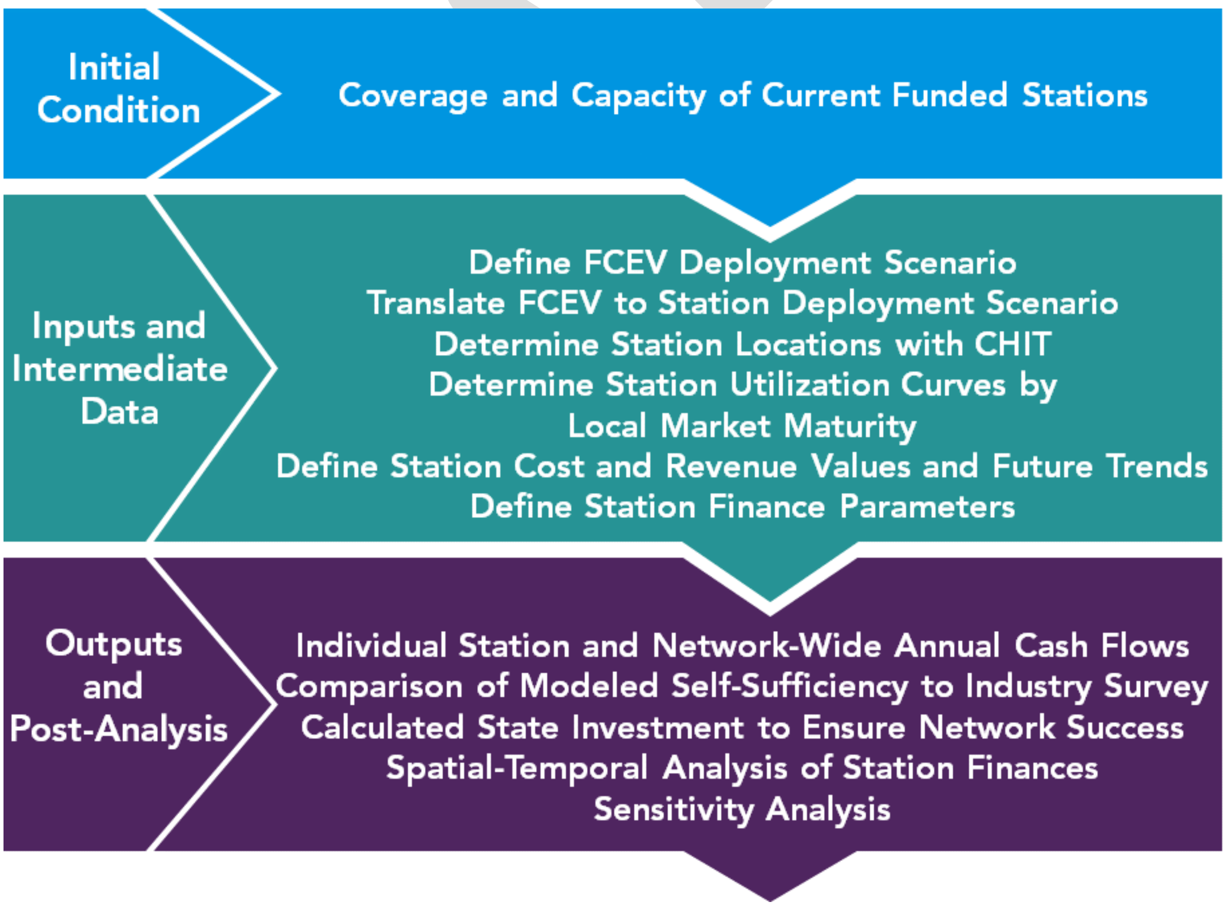
- **Deployment Scale:** What FCEV volume do the State and industry plan for and how should a station fueling network be structured to meet the fuel demand?
- **Individual Station Utilization:** How will individual station utilization progress, based on local network maturity and deployed vehicles?
- **Station Development and Operations Costs:** How will capital and operational expenditures vary by station size and industry development?
- **Customer-Facing Price:** How can/will price at the pump change over time?

- **Station Finances:** What returns need to be achieved to keep development going?

Model Structure

Evaluation of station and network-wide financial performance in this study is a multi-step process, as demonstrated in Figure 8. First, the existing funded hydrogen fueling station network is evaluated for coverage, capacity, and other metrics used in intermediate steps of the evaluation process. Next, input data are selected, based primarily on the choice of FCEV and hydrogen station network growth rates. These input values typically represent key variable parameters that change over time. Based on these input values, individual station economic performance is evaluated from the date the station is built to the end of the economic evaluation. In this study, all financial evaluations are reported through 2050.

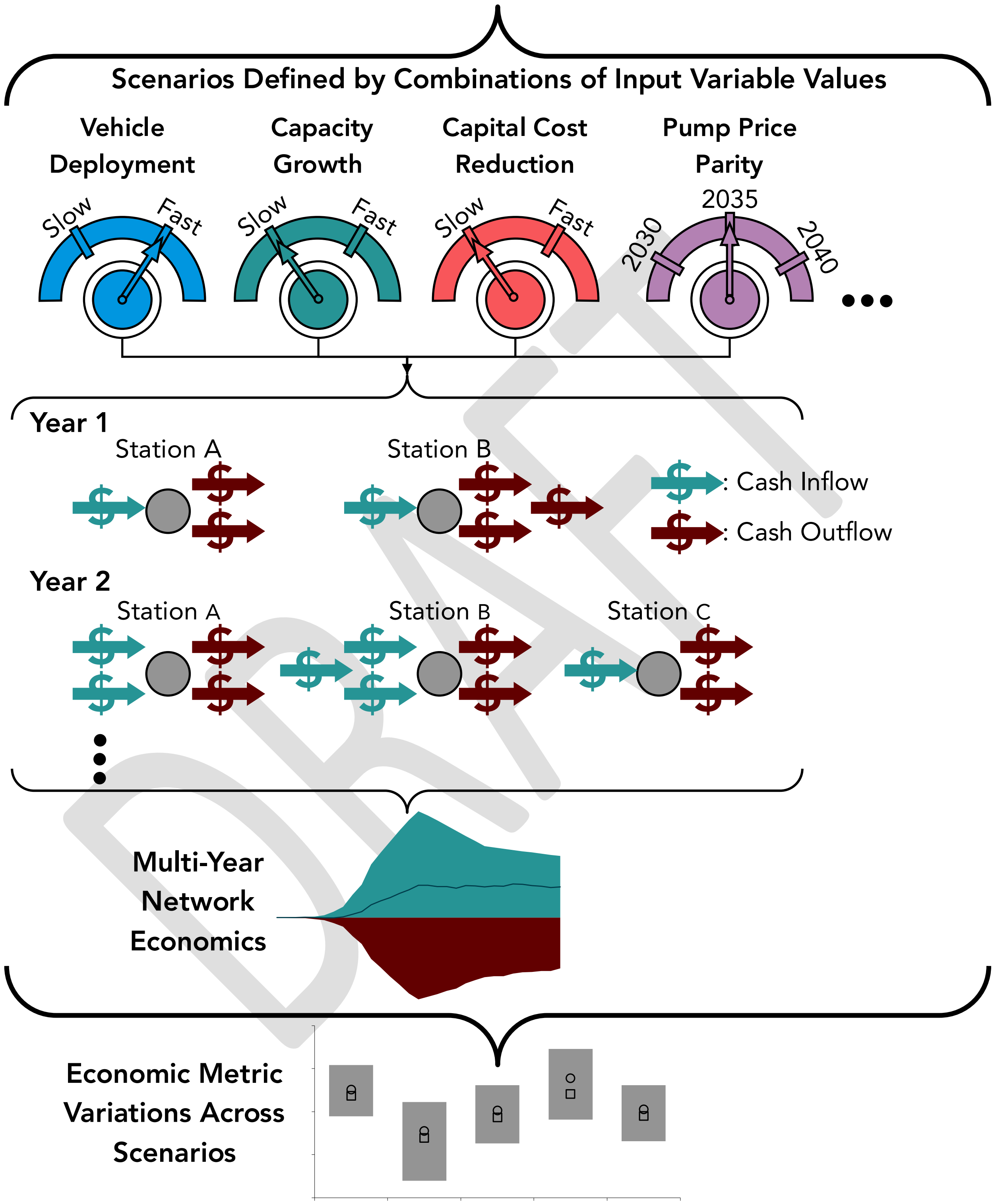
Figure 8: Evaluation Process Key Steps



The first key outcome is the individual cash flow assessed for each station in the network. Post-analysis synthesizes these station-level results into several observations about the conditions that make individual stations profitable. Individual station economic performance is then aggregated to the network level and the primary cost and timing metrics for self-sufficiency are developed. Additional steps may occur in the last portion of the evaluation process, including: comparison of results to input provided by industry members during Phase 2 of the overall project (see Figure 3), spatial mapping and analysis of station financial performance, and sensitivity analyses to determine the input variables that most strongly impact economic observations.

As Figure 9 illustrates, the process of Figure 8 is repeated multiple times, with different combinations of input values. For each of the input values, this study assumes at least two possible values or trajectories for future development. For example, FCEV deployment may be assumed to be "fast" (in this study, achieving one million vehicles deployed by 2030) or "slow" (approximately 200,000 by 2030). Most input variables have a range of selectable and pre-defined values, each of which affects some portion of the overall economic evaluations for each station. These settings affect station placement, cost, utilization, and revenue. A collection of settings is then taken as an individual scenario, within which individual station and network financial performance are evaluated.

Figure 9: Overview of Scenario Evaluation Methodology



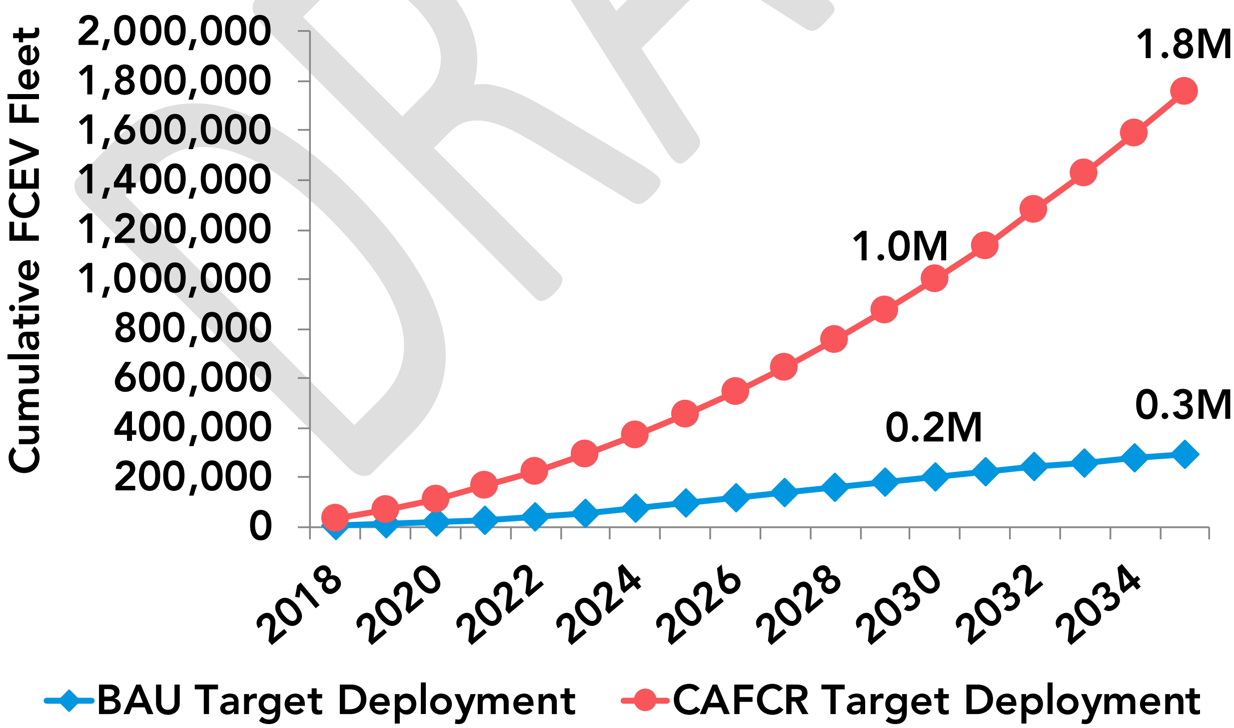
Each scenario is uniquely defined by the combination of variable settings. The bounds of this study are then defined by the set of scenarios investigated. A sensitivity analysis is performed by comparing results across scenarios and investigating the changes in State support amount and timing as each individual variable is adjusted while all others remain the same. The scenario evaluation structure is vital to properly interpreting the outcomes of this study. As mentioned earlier, this study does not attempt to predict the future trajectory of FCEV and hydrogen station industry economics. Instead, this study should be viewed as a method to provide an estimate of cost and timing to self-sufficiency under various and flexible assumptions regarding industry development. Conclusions indicating the likely State support to achieve self-sufficiency are based on the range and distribution of resulting self-sufficiency metrics.

Input Variables and Values

FCEV deployment

In any given scenario evaluation, some input variables are at least partially determined by or related to other input variables' values. The order of input variable definition for a given scenario is as presented in the "Inputs and Intermediate Data" portion of Figure 8, beginning with determination of the FCEV deployment planning trajectory. Figure 10 displays the FCEV deployment trajectories investigated in this study.

Figure 10: FCEV Deployment Planning Trajectories



In this study, the assumed FCEV deployment planning trajectory represents the vehicle population that the State and industry members anticipate and must plan appropriate infrastructure development to support. In this study, the planned FCEV population is not the same as the actual number of FCEVs assumed to be on the road in any given scenario evaluation. Additional input variables (to be described later), in combination with the planned FCEV deployment schedule as shown in Figure 10, determine the number of FCEVs on the road and fueling at any given station in any given year. The distinction is important as it allows flexibility to investigate the risk of overbuild and quantify the economic benefit of ensuring high station utilization.

In this study, two FCEV deployment planning scenarios are considered to bound the potential trajectories moving forward. The Business-As-Usual (BAU) case is based on DMV registration data reported in past *Annual Evaluations*, extrapolated to 2035. According to this trajectory, California's FCEV population grows to 200,000 by 2030 and 300,000 by 2035. Some industry members have indicated during interviews that adhering to this business-as-usual deployment pace may be a possible outcome but is not representative of successful market development. CARB takes this case to represent a minimum amount of FCEV deployment against which more ambitious scenarios can be evaluated.

On the other hand, this study also looks at the ambitious FCEV deployment planning scenario presented by the California Fuel Cell Partnership's *Revolution* document and extended an additional five years. In the *Revolution*, the members of the California Fuel Cell Partnership present the case for targets of developing 1,000 hydrogen fueling stations by 2030, enabling deployment of up to one million FCEVs by the same time [24]. Conceivably, station network self-sufficiency could be achieved by the time 1,000 stations are deployed. However, with the range of input variables proposed for this study, CARB extended the station deployment to 2035 for all cases, to ensure that self-sufficiency would be evaluated on the basis of a sufficiently large set of stations. For the case from the *Revolution* (henceforth referred to as the CAFCR case), the state's FCEV population grows to 1.8 million by 2035.

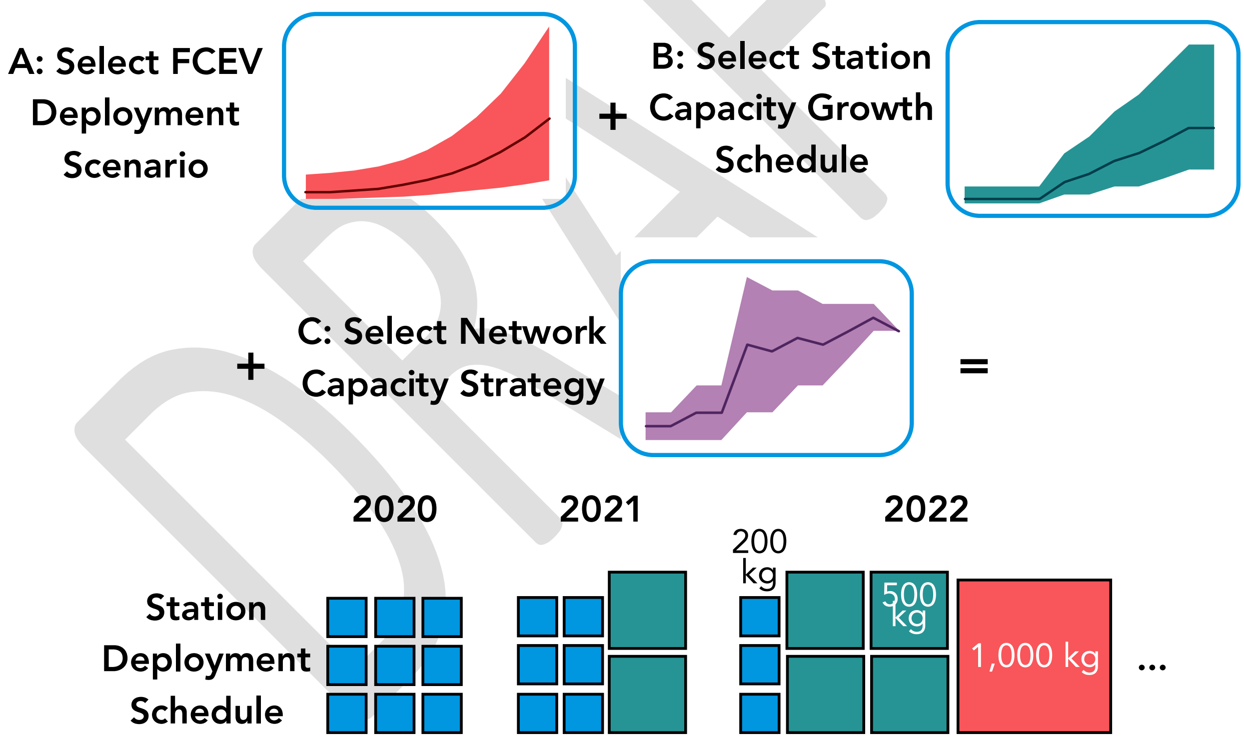
Station Deployment Schedules

The schedule of new station development is determined in part by the anticipated FCEV deployment. Two additional pieces of information are considered to develop the station deployment schedule. As shown in Figure 11, station development in a given scenario is defined by the combination of the FCEV deployment plan, selection of the individual station capacity growth schedule, and selection of a network buildout strategy. The station capacity growth schedule defines the years at which progressively larger stations are introduced into the network, the pace and magnitude of adoption of each capacity of station, and the persistence of each station capacity in future years' development.

The network capacity strategy sets the pace for total new capacity growth across the statewide network. One option is based on a more direct match of new station capacity to fuel demand growth. The other is an intentional "back-loading" of station deployment. This option takes advantage of the larger average station capacity in later years, allowing for the same capacity to be developed by the end of the evaluation period with fewer numbers of stations. This option also acknowledges that upstream supply chains may require some time to develop manufacturing capacity scale.

Various schedules of new station development result from combinations of these three factors. In each scenario, the number and capacity of new stations built in each year from 2020 to 2035 are specified by this schedule. In the example of Figure 11, nine new stations are built in 2020, each with 200 kg/day capacity. In 2021, an additional six 200 kg/day stations are built along with two 500 kg/day stations. In 2022, new station development includes three 200 kg/day, four 500kg/day, and one 1,000 kg/day station, and so on.

Figure 11: Demonstration of Defining Station Deployment Schedule



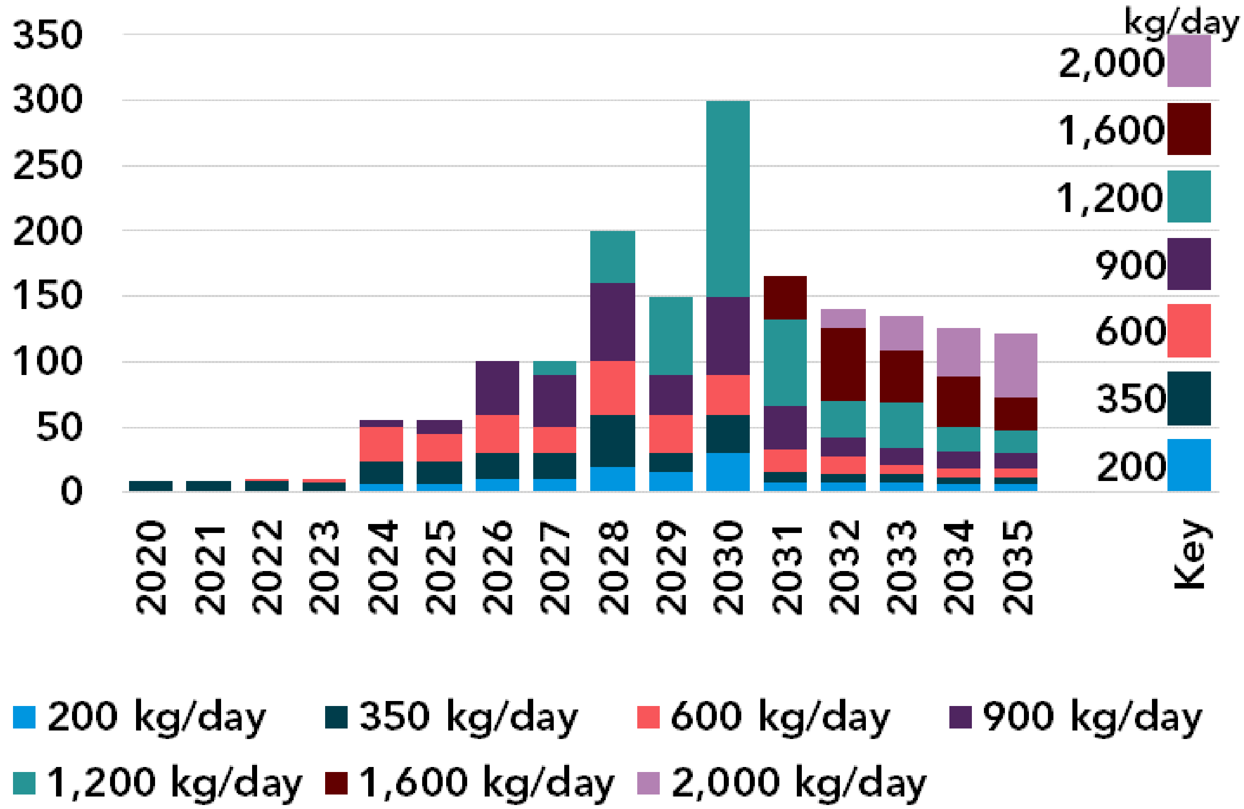
Among the many possible combinations of values for the three station-determining factors, CARB has selected four to form the basis of this study's evaluation. Excluded combinations represent scenarios lacking self-consistency. For example, any scenario with BAU FCEV deployment planning combined with rapid station capacity growth is inconsistent. If expected FCEV deployment remains low, there is little motivation for station operators to plan to deploy larger station designs on an accelerated schedule.

Thus, CARB does not consider these scenarios. Table 1 provides an overview of the four basis station deployment scenarios considered in this study. Figure 12 through Figure 15 present the station deployment schedules for all four scenarios.

TABLE 1: DESCRIPTIONS OF STATION DEPLOYMENT SCENARIOS

Scenario	Description
CAFCR	Follows the vehicle and station deployment scenario outlined in the California Fuel Cell Partnership's *Revolution* document and Appendix D of the *2018 Annual Evaluation*. This scenario anticipates 1.8 million FCEVs on the road by 2035, supported by a network of approximately 1,700 stations. Deployment in the first few years follows the historical AB 8 program business-as-usual rate of stations per year, with new station capacities starting at 200 kg/day and 350 kg/day. Additional capacity added each year is calculated based on the 2030 target, but allows greater proportion of the gap to be built in later years, relying more heavily on larger stations built in later years to meet total need. Average capacity and emphasis on larger stations increases with time, with a maximum of 2,000 kg/day for an individual station.
CAFCR Early	Adopts the same vehicle target and the schedule of station capacity growth as the CAFCR case, but modifies the station deployment pace by allowing greater portions of the early network capacity growth to be met in earlier years. Slightly more stations (1,800 total) are deployed in this case.
CAFCR Large	Adopts the same vehicle target and total capacity growth as the CAFCR case, but modifies the progression of individual station capacity in two ways. First, the earliest stations are assumed to be larger and indicative of more recent developments like the LCFS HRI program. The earliest stations in this scenario are 350 to 1,200 kg/day in capacity. In addition, a larger proportion of stations built in later years are 1,600 and 2,000 kg/day. This case deploys approximately 1,370 stations.
BAU	The only scenario that adopts a smaller FCEV target in 2030 and makes corresponding changes to the station deployment assumptions. The total number of FCEVs is assumed in this case to be 300,000 in 2035. Because of the smaller number of vehicles, it is assumed that the largest station sizes (1,600 and 2,000 kg/day) are not required. Smaller station sizes also comprise a larger portion of new stations in early years than the CAFCR case. A total of approximately 310 stations are built in this case.

FIGURE 12: CAFCR STATION DEPLOYMENT SCHEDULE



In this study, the CAFCR deployment schedule through 2030 matches exactly with the scenario presented in the *Revolution* and Appendix D of the 2018 *Annual Evaluation*. In those earlier evaluations, station deployment was only carried out to 2030, and the total capacity developed by 2030 was designed to meet customer fuel demand at that time, with a back-loaded capacity growth strategy. In order to extend the scenario the additional five years, CARB assumed that the station network deployment strategy shifts to building new capacity to exactly meet the additional fueling demand in each year from 2031 to 2035.

In addition to the station deployment schedule for the CAFCR case, Figure 12 also displays some assumptions that are true across all station deployment scenarios. Whenever stations of a given capacity first enter the network, they represent a small portion of the new stations built in that year. Over the next three to four years, the proportion of new stations of that capacity grows to its peak value. After this peak, stations of this capacity make up a successively smaller proportion of newly built stations over a period of another three to four years. For all remaining years, the minimum proportion of stations of each capacity is then maintained at five percent or more. This pattern of rise and fall in new station market share occurs for all station capacities. Through 2035 and in even the most ambitious scenarios, this study assumes that the smallest stations remain necessary in select locations to serve either as connector or destination stations or to act as a first entry into new market areas.

FIGURE 13: CAFCR EARLY STATION DEPLOYMENT SCHEDULE

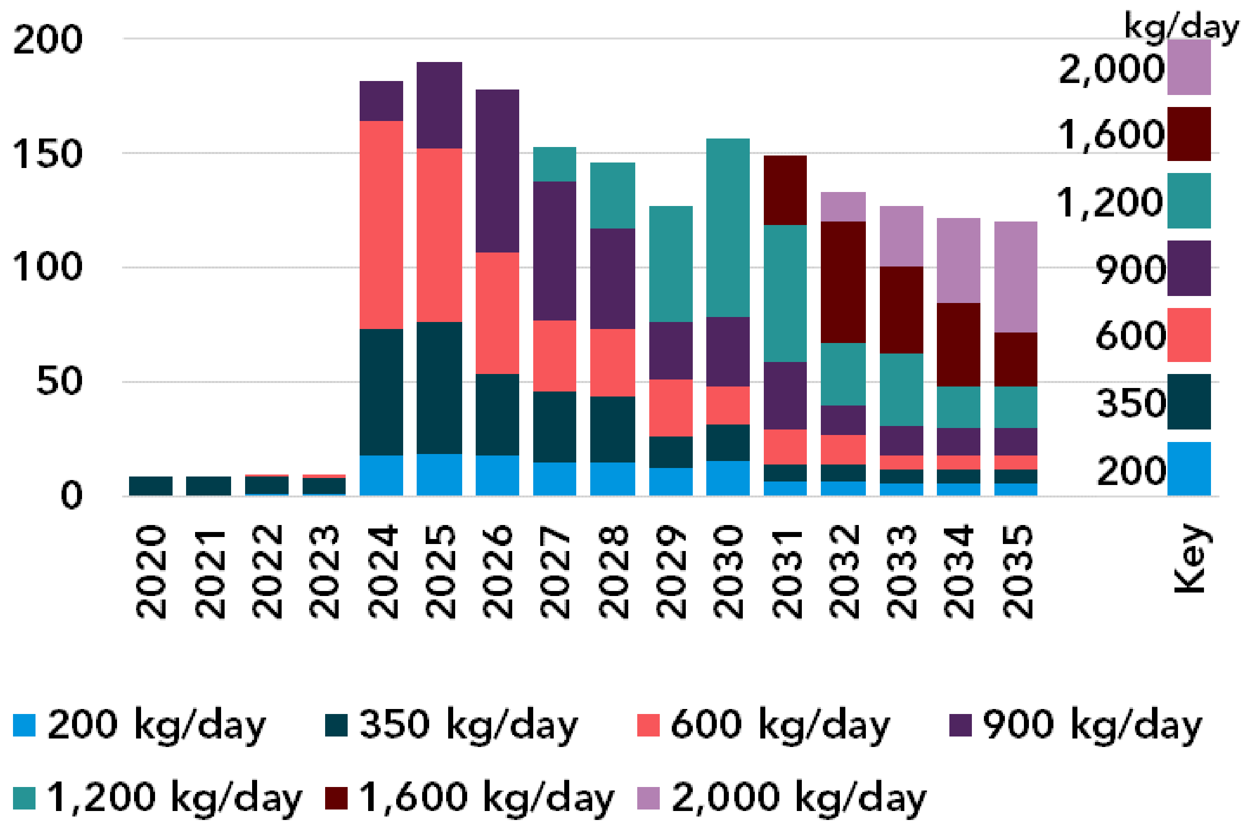
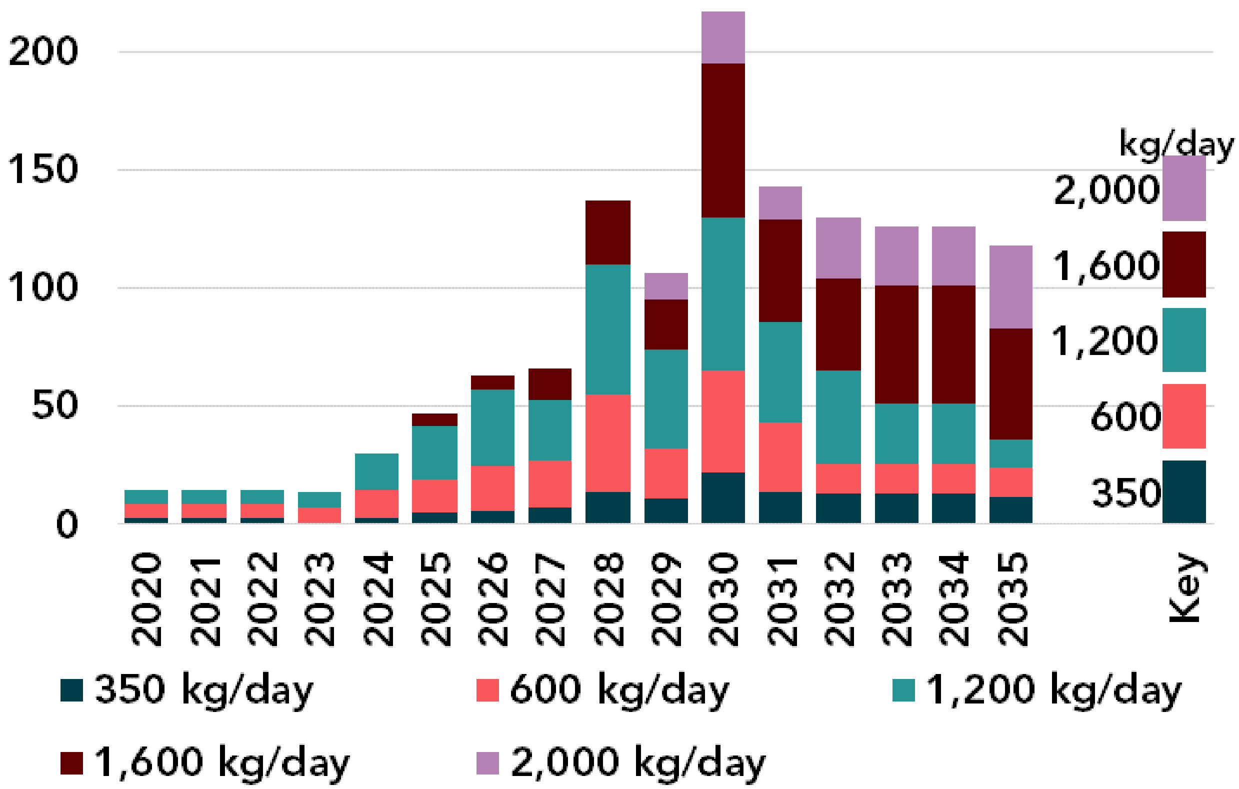


Figure 13 displays the station deployment schedule for a scenario that plans for the same FCEV population as the CAFCR case, but does not adopt the back-loaded network capacity strategy. This case is termed the CAFCR Early scenario throughout the remainder of this report. Comparison of Figure 13 to Figure 12 demonstrates the impact of these station development assumptions. In the CAFCR Early scenario, the number of stations developed in a single year increases much more dramatically in 2024 than in the CAFCR case and remains higher than the CAFCR for most years through 2030. However, development in years 2020 through 2023 are the same. This is because all scenarios, regardless of future FCEV planning, assume that AB 8 will remain the primary means of station deployment through 2024. The rates of station deployment are based on business-as-usual deployment from the history of the program. Small differences exist between scenarios during this period because stations must be built in whole integer increments.

Figure 14: CAFCR Large Station Deployment Schedule



The CAFCR Large station deployment schedule is depicted in Figure 14. This scenario adopts the same annual capacity growth as the CAFCR scenario but makes several adjustments to the individual station capacities employed. First, no 200 kg/stations are assumed; instead, 350 kg/day is assumed to be the smallest station capacity that will be developed. These stations persist into the future, serving the same connector and market initiation role as 200 kg/day stations in the other scenarios. In addition, development during the AB 8 period through 2024 includes stations as large as 1,200 kg/day, based on recent developments like the LCFS HRI program. Finally, stations of 1,600 and 2,000 kg/day enter the network earlier and therefore contribute a larger portion of the network capacity than in other scenarios.

This is a highly aggressive scenario. It is similar to the target development strategy discussed by some industry stakeholders, but is not representative of all perspectives. It is also unclear whether the upstream supply chain is currently able to support such large-scale deployment of large stations in the early years. This scenario therefore represents an aspirational benchmark to compare against currently known market development trends.

FIGURE 15: BAU STATION DEPLOYMENT SCHEDULE

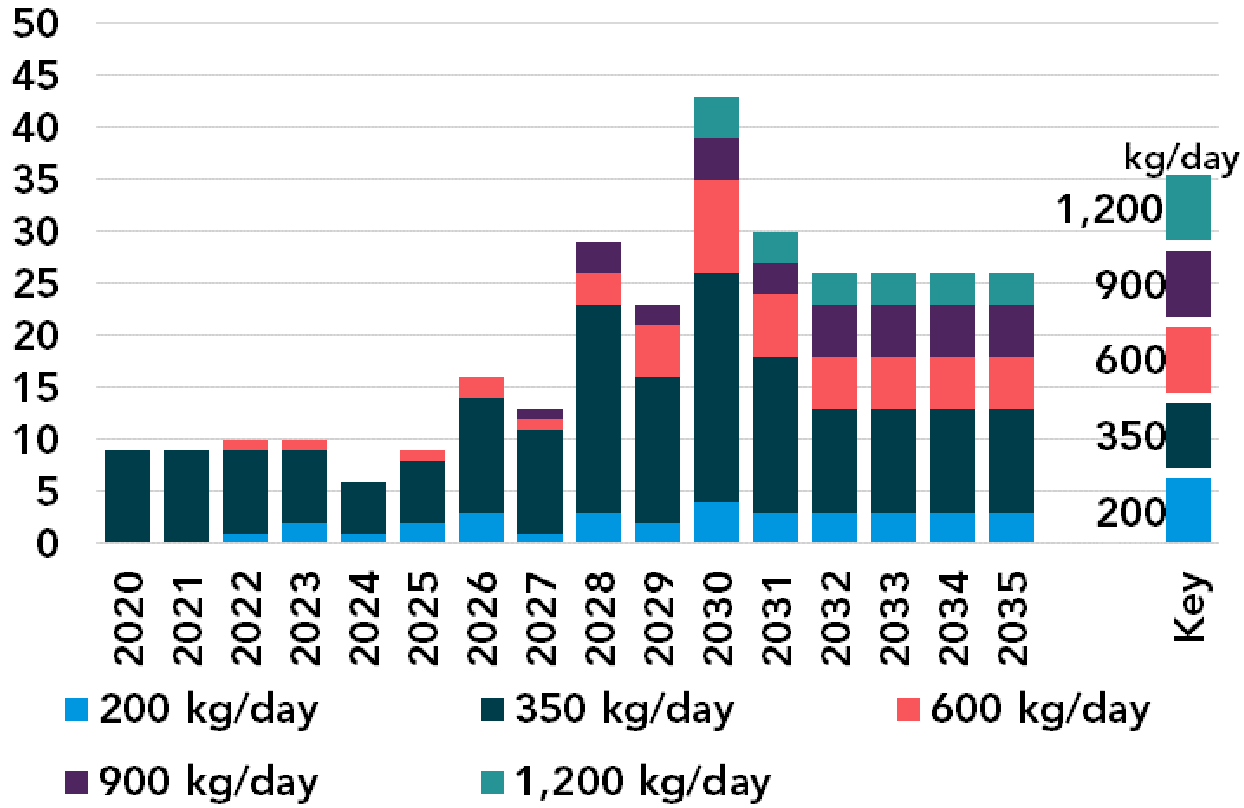


Figure 15 displays the station deployment schedule for the BAU scenario, which represents the smallest and slowest deployment scenario. In the BAU scenario, stations with capacity of 1,600 and 2,000 kg/day are not built prior to 2035. Stations of 350 kg/day, which may be marginally profitable according to industry member interviews, compose the majority of the network. The total number of stations and the fueling capacity built in this scenario is much smaller than any other scenario. Data tables in this study's Appendix display counts of stations built of each capacity in all evaluation years for each of these deployment scenarios.

INDIVIDUAL STATION PLACEMENT

Determination of the station deployment schedules is followed by corresponding geographic placement of each station within the scenario. The methods for this step, and evaluation of its application to the CAFCR scenario through 2030, are described in detail in Appendix D of the 2018 *Annual Evaluation*. In brief, the geographic placement process begins with evaluation of the current station network's capacity and coverage in order to identify coverage and capacity gaps to determine the placement of the first stations in the schedule. In this work, the initial condition is based on the 2018 hydrogen fueling network; small changes in the network have occurred since that time, but should not represent large potential for error. For simplicity, all stations in the initial 2018 network were assumed to be constructed by 2020, and all new development would occur from 2020 onward. The iterative station placement process then placed stations according to the annual schedule, in order of increasing capacity. Each station was placed in sequence according to a combined metric that considers both coverage gap and the match between capacity gap and the station capacity.

Based on the combined metric, a set of priority areas were identified for placement of new stations, and stations were placed at the highest-need location within each priority area, as long as the location was not locked out by earlier placement of a nearby station. Additional priority areas were generated any time all priority areas were filled, the capacity of the next set of stations under consideration changed, or all new stations in a given year had been assigned a location. This process continued for all stations scheduled for a given year and for all years in the scenario evaluation from 2020 to 2035.

The available areas for station placement in all scenario evaluations were tuned according to the existing gasoline station network. California's gasoline station network includes approximately 8,000 stations with operations similar to the station design model anticipated for retail light-duty hydrogen fueling. The geospatial distribution of these stations has been informed by approximately a century of business operations to sufficiently serve the demands of California's driving public. CARB assumed that this market development serves as a template for the future hydrogen station network distribution. By using the existing gasoline station network as a template, the hydrogen station placement process was simplified to considering a set of known candidate locations and choosing the subset that best meets coverage and capacity needs of the projected future FCEV deployment. This is a more efficient algorithm than generating a hydrogen station network by choosing locations from the infinite possibilities available at any and all locations in the state.

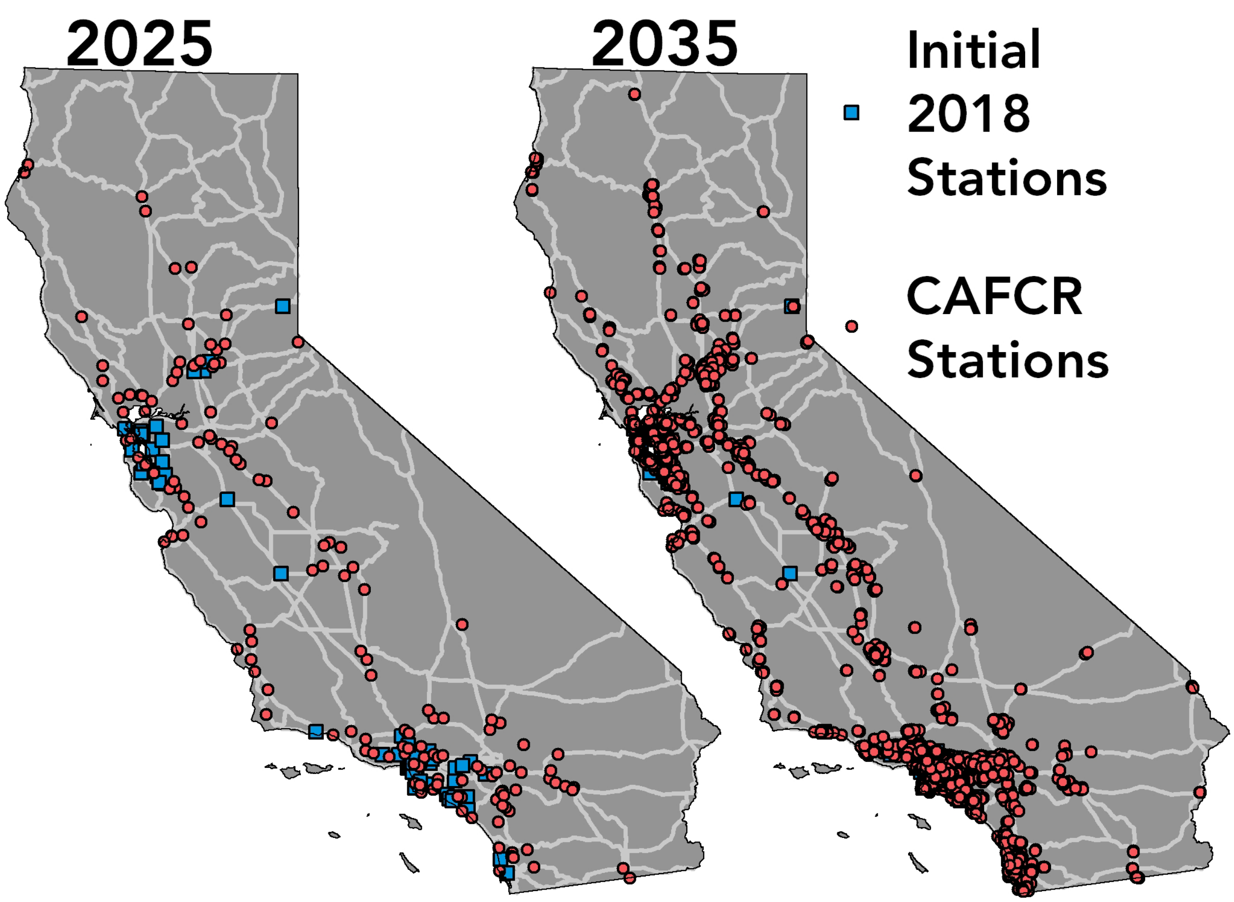
The 2018 *Annual Evaluation* highlighted that this station placement methodology identified a 1,000-station hydrogen fueling network design that provided nearly the same coverage as the 8,000-station gasoline fueling network. While the number of hydrogen stations and their equivalent fueling capacity is less than the gasoline fueling network, it is still sufficient to support one million FCEVs and provides access to 63 percent of Californians within a six-minute drive and 94 percent of Californians within a fifteen-minute drive. This was achieved in part by following the gasoline station density template and by explicitly assuming that FCEV adoption expands to a broader consumer base than the first-adopter market by 2030.

Figure 16 displays the result of the station placement methodology for the example of the CAFCR scenario. The panel on the left shows the station network development in 2025. The panel demonstrates how even as early as 2025, network development could expand into markets outside of the core areas that have been developed to date in and around Los Angeles, Orange County, the San Francisco Bay Area, and Sacramento. This scenario certainly projects continued station development in these core regions, but significant new development is also projected in the San Joaquin

Valley, in San Diego, along the Central Coast, and in inland Southern California cities like Riverside and near Palm Springs. As shown in the right panel, by 2035, the hydrogen station network is quite extensive, reaching almost all corners of the state.

This methodology was developed over an approximately year-long collaborative process between CARB and the public and private industry members of the California Fuel Cell Partnership. CARB explored several concepts and variations for guiding principles and considerations to include in the methodology. Many were developed internally by CARB staff, while others were proposed by members of the California Fuel Cell Partnership. Several opportunities for review and feedback from stakeholders refined the methodology. Interested readers are encouraged to consult the California Fuel Cell Partnership's *Revolution* document and Appendix D of the 2018 *Annual Evaluation* for further context and details of the process that developed this station placement methodology.

FIGURE 16: STATION NETWORK PLACEMENT EXAMPLE FOR CAFCR



Individual Station Utilization

Each station's annual average utilization rate was determined based on its location in the network. In this study, each station was assigned an individualized utilization trajectory, accounting at least for the station's age. Several options for accounting for local network size and age of nearby stations were also developed. These methodologies for generating individualized station utilization trajectories enable market effects to be explicitly captured in station financial performance. For example, the first few stations in a new market area would likely face a longer ramp to full utilization than say the 15th or 20th station deployed in an established market. By the time these later stations are deployed, it can be assumed that local FCEV market development is more mature and the feedback cycle between station development and increased local hydrogen demand is accelerated.

CARB based all of its station utilization calculation methods on a Standard Curve used by researchers at the National Renewable Energy Laboratory for prior *Joint Agency Staff Reports* and other research efforts. This Standard Curve is depicted in Figure 17 [27] [28] [29]. Absent any network effects, a new station may experience very low utilization in its first year of operation (especially considering operations may commence late into the first year). Station utilization then grows with an initial acceleration through year five of operation, followed by slower utilization growth with saturation at 85 percent utilization in year ten of operation. Utilization of 85 percent is taken in this study to represent full utilization, based on prior arguments that this represents an optimal balance between high revenue-generating demand and overly long customer wait times at the fueling station. The value of 85 percent is also based on observations from the gasoline station operating experience. Early pilot investigations in the self-sufficiency study utilized the Standard Curve directly for all stations in network evaluations, but modifications were added based on industry member feedback pointing to a need to consider local network development effects.

FIGURE 17: MARKET HEURISTIC METHOD FOR INDIVIDUAL STATION UTILIZATION

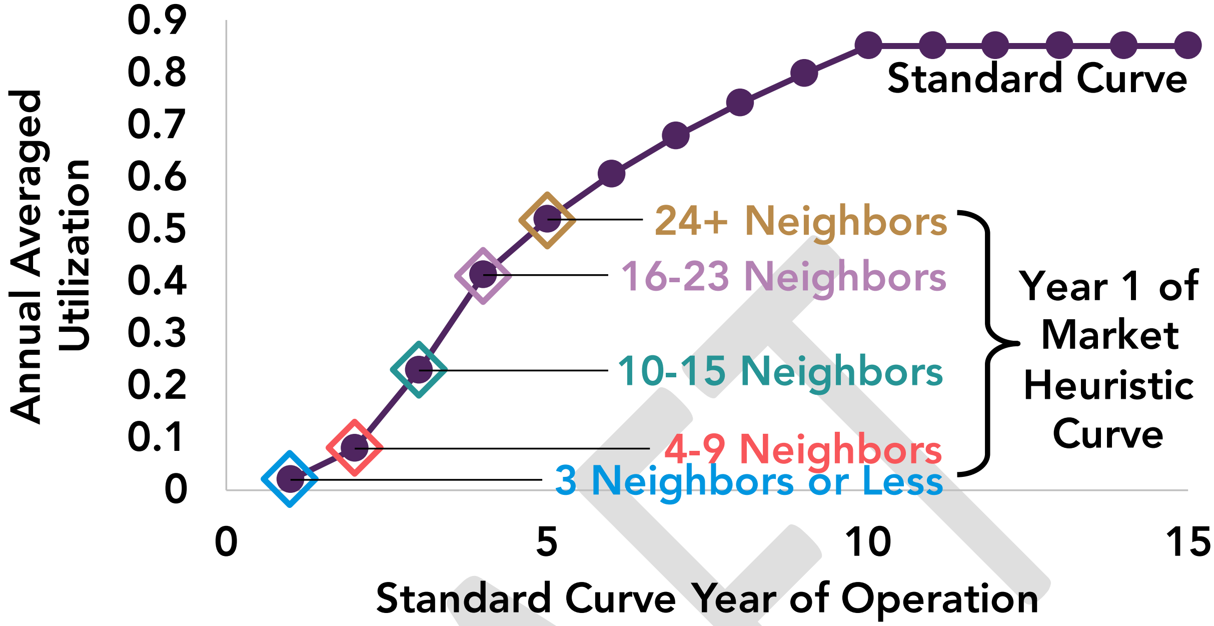
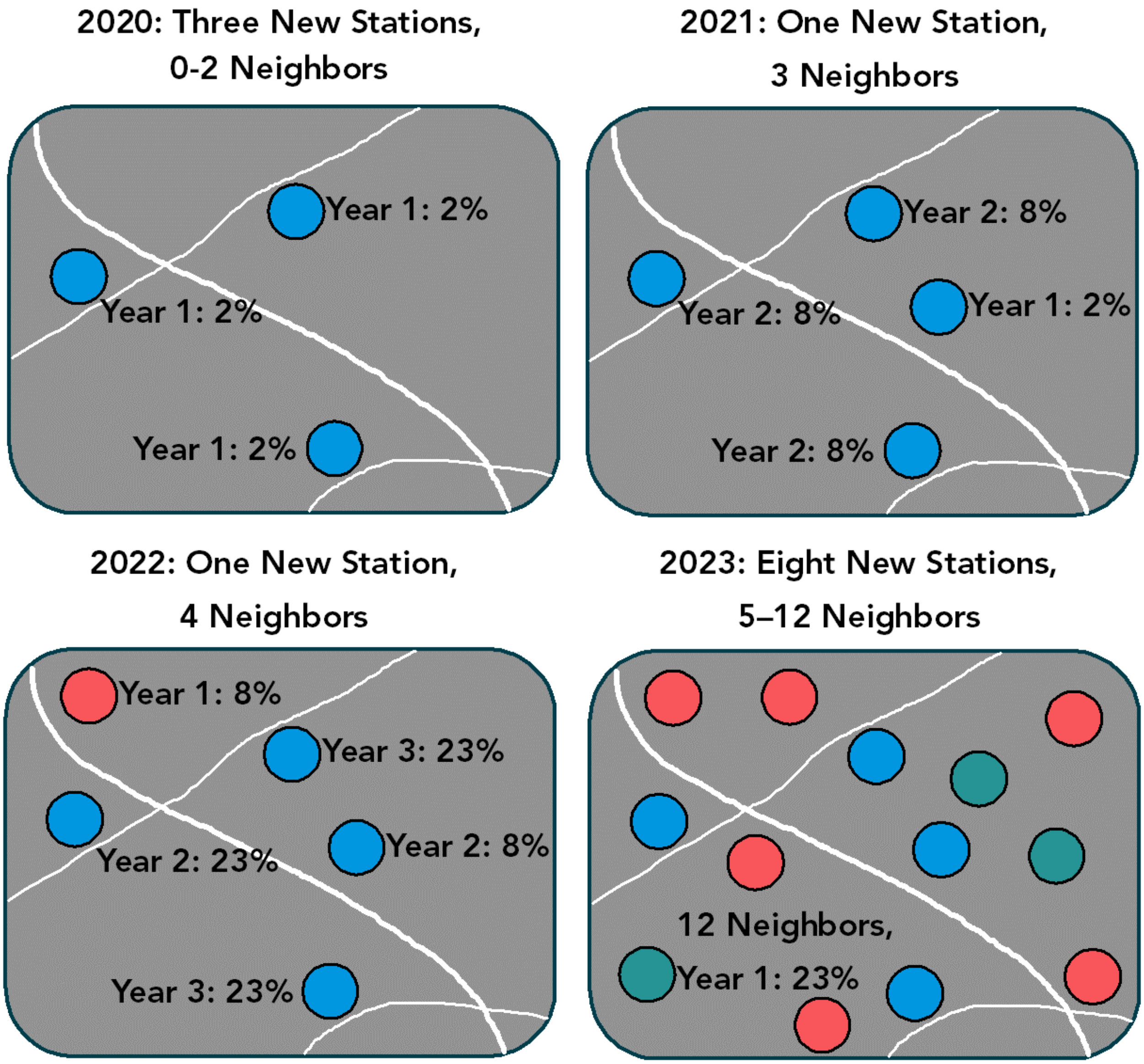


Figure 17 and Figure 18 demonstrate the structure of the simplest method to account for local market effects that was investigated in this study, the Heuristic method. In pilot investigations of the CAFCR scenario, CARB analyzed the number of neighbors (pre-existing stations within a 15-minute drive) for each station. In this analysis, the number of neighbors tended to cluster into well-defined groups. These groupings are shown in Figure 17: 3 or less, 4-9, 10-15, 16-23, and more than 23 neighbors. In the Heuristic method, these groupings are used to determine the utilization in the first and subsequent years according to the Standard Curve. While utilization for all stations follows the Standard Curve, those with more neighbors are assumed to have first-year utilizations at later points of the curve and therefore require fewer years to reach the maximum. For example, a station with 18 neighbors would have its first year average utilization set to the value of the fourth point on the Standard Curve, or approximately 41 percent. It would then reach the maximum utilization in seven years. By contrast, the first station in a market (with zero neighbors), would have its first-year utilization set to approximately two percent and take ten years to reach the maximum.

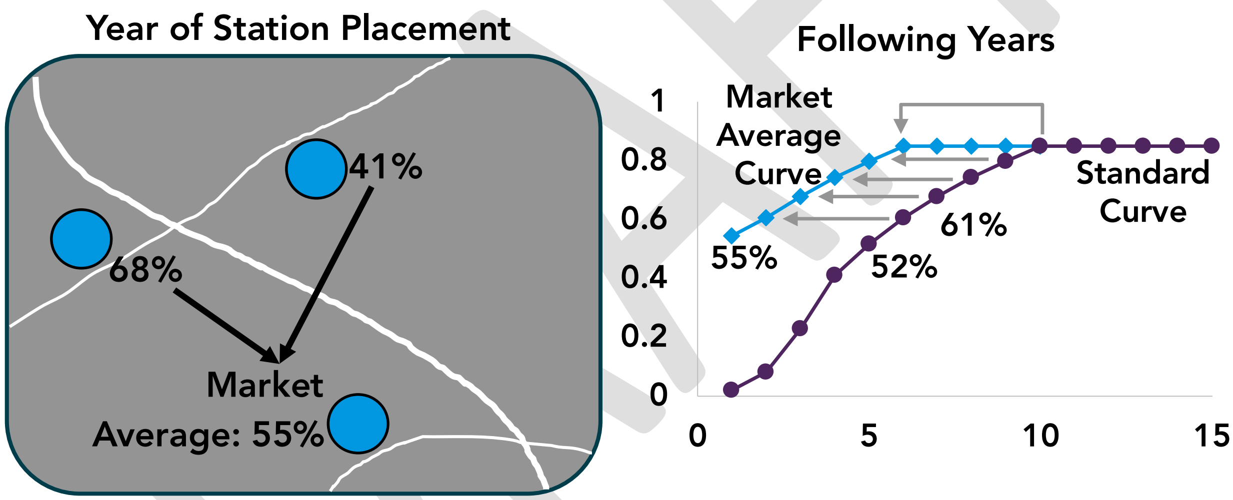
Figure 18: Market Heuristic Method Example



An example for a small local network of stations is shown in Figure 18. In this example, three stations are developed in 2020 and begin their utilization growth at the origin of the Standard Curve, at two percent utilization in the first year of operation. In 2021, these three stations move to the next step on the Standard Curve, or eight percent utilization. An additional station is built in 2021; since it has less than four neighbors, it also starts operations at the origin of the Standard Curve, or two percent. In 2022, all four of the previously built stations advance one more step along the Standard curve, and a new station enters the market. This station has four neighbors and therefore starts operations accelerated along the Standard Curve, at the Standard year two value of eight percent utilization. In 2023, eight additional stations are added to the local network, each with between five and twelve neighbors. The last three stations all fall within the third group of the Heuristic method and therefore start at 23 percent utilization in their first year of operation.

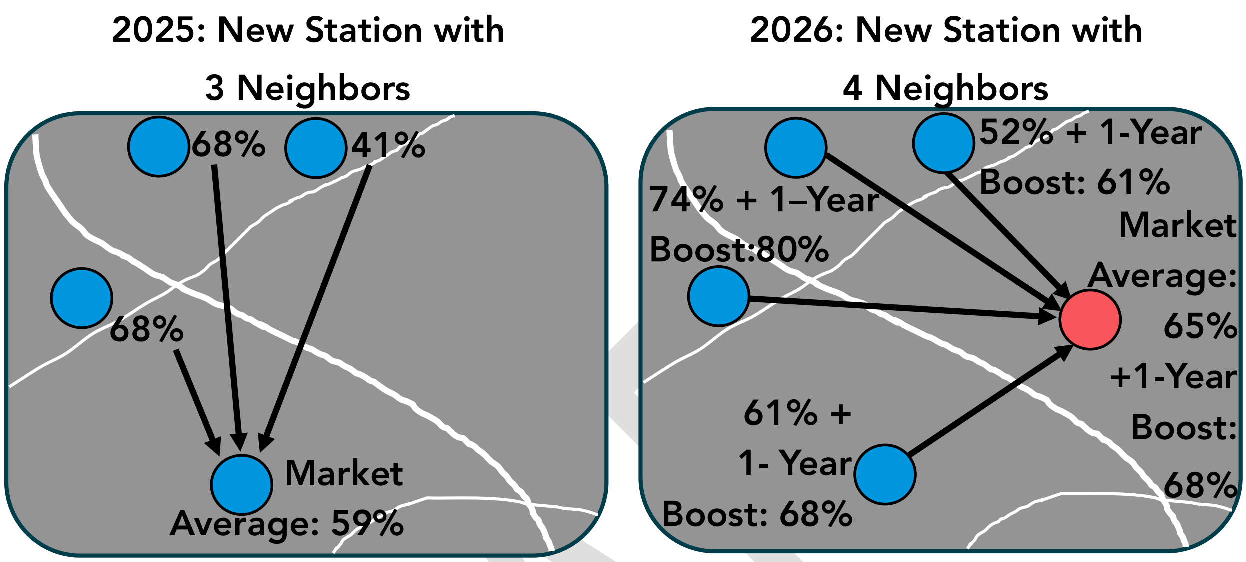
Two additional variations built from the Heuristic method were investigated based on feedback provided by industry members. In the first of these variations (the Average method), the first station in a local market has no neighbors and progresses along the Standard Curve. For all other stations that enter the local market after the first, their initial utilization is set equal to the average of their neighbors as shown in Figure 19. After the first year of operations, these stations follow a slightly modified version of the Standard Curve, termed the Market Average Curve in Figure 19. As shown in the example, the new station's utilization in its first year is more than likely not exactly equal to the stepwise values on the Standard Curve. The Market Average Curve therefore begins with the neighbor-driven average in the first year and then proceeds to the next-highest value on the Standard Curve before proceeding to all remaining values from the Standard Curve in order with each passing year.

Figure 19: Market Average Method Example



The second variation on individual station utilization is the Boosted method, shown in Figure 20. This method is similar to the Average method, except that it assumes that advanced market maturity can provide a boost on all local stations' utilization. In the Boost method, this additional advancement is taken as a one-year acceleration for all local stations and occurs only when the local network advances to the next market size per the same definitions shown for the Heuristic method in Figure 17. In the example of Figure 20, a single new station is placed in 2025 into a local network that already contains three stations. Its starting utilization is based on the average of these three stations, at 59 percent. In 2026, another new station is added to the local network. Because the local network has now grown larger than the three neighbor maximum, a local boost is triggered. This fourth station's utilization is set to be equal to the neighbors' average, plus one year's acceleration along the Standard Curve. In addition, all neighboring stations receive a similar one-year boost.

FIGURE 20: BOOSTED METHOD EXAMPLE



CARB does not make any determination about which of these individual station utilization modeling methods – Standard Curve, Heuristic, Average, or Boosted – is the most appropriate or realistic. However, these methods are all built upon feedback from industry representatives and provide a method to assess differences in local FCEV population growth as affected by the local station network development. The effect of these various methodologies on network-wide aggregate utilization is demonstrated in Figure 21. Note that Figure 21 presents data for a utilization rate that saturates at what is considered to be high (but not full) station utilization of 75 percent. Such a situation represents approximately ten percent fewer FCEV deployments than the full utilization case.

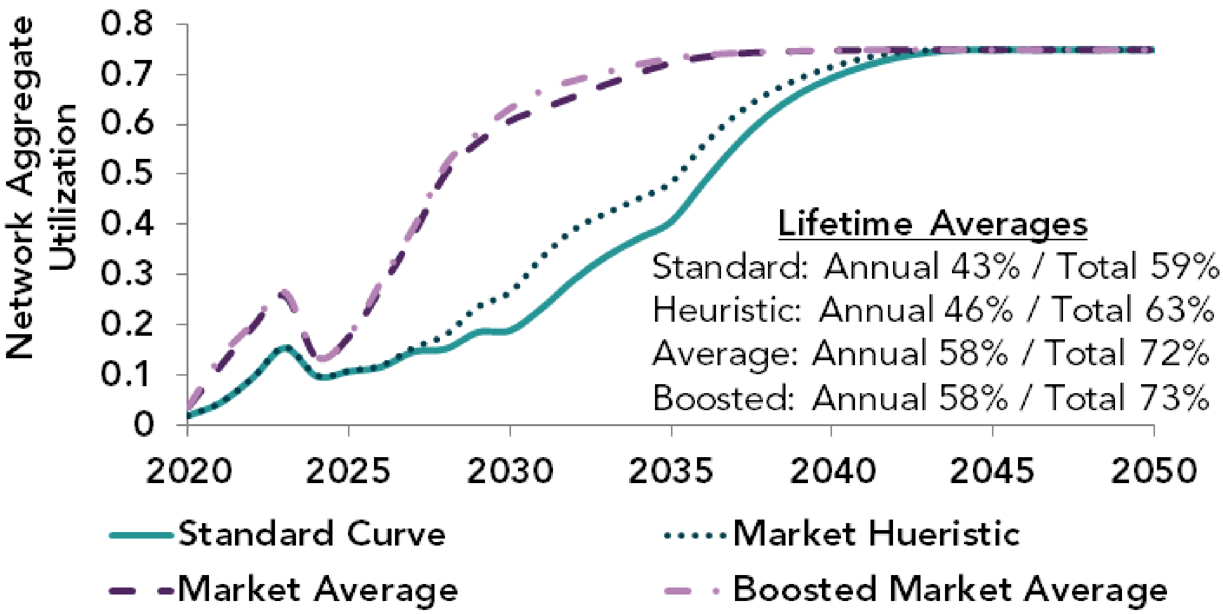
It is clear that the Average and Boosted cases significantly increase aggregate network demand compared to the Standard Curve and Heuristic cases. All cases reach aggregate utilization at the maximum possible value by 2045, as this is ten years after the final station is built. Even the slowest utilization curve (the Standard Curve) achieves the highest level of utilization after ten years. Two lifetime summary network statistics are also provided. The Annual Lifetime Average is defined as:

$$\frac{\sum_{i=2020}^{2050} Sales_i}{\sum_{i=2020}^{2050} Capacity_i}$$

where $Sales_i$ is the total number of kilograms sold in year i, and $Capacity_i$ is the total capacity of the network in the same year (including all stations built in that year and earlier). The Total Lifetime Average is defined as:

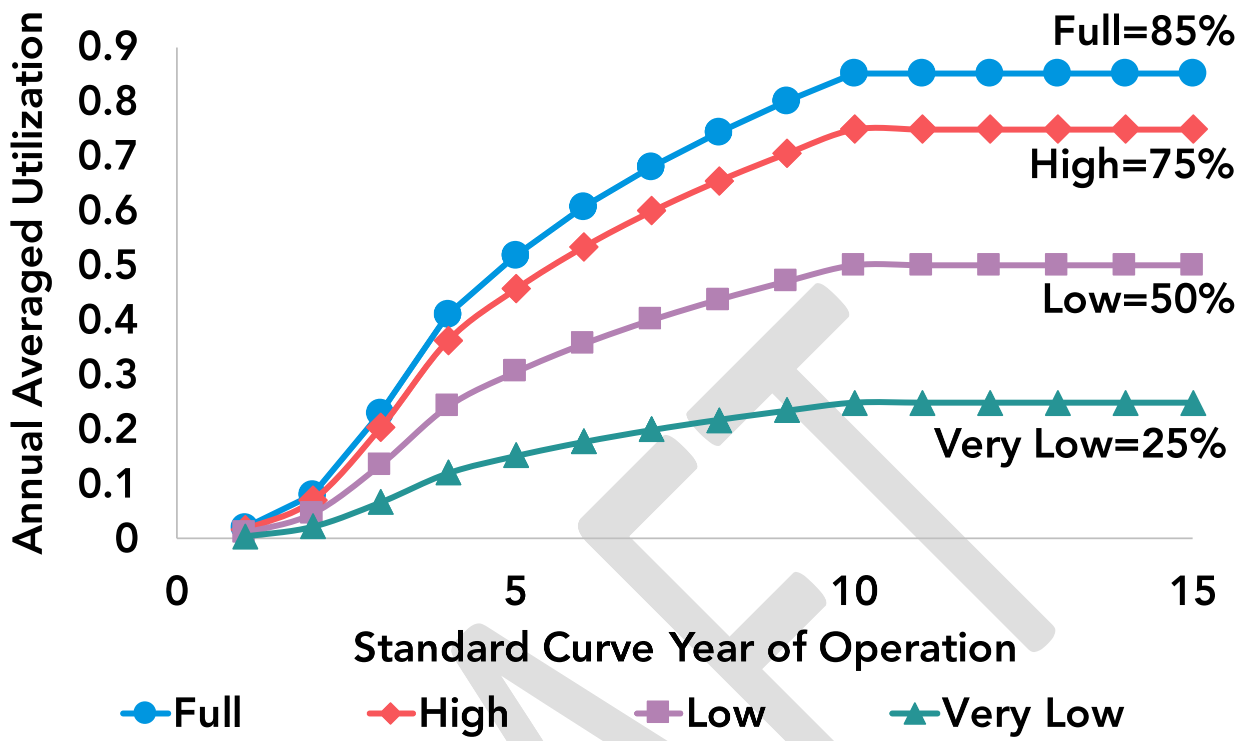
$$\frac{\sum_{i=2020}^{2050} \frac{Sales_i}{Capacity_i}}{31}$$

FIGURE 21: COMPARISON OF NETWORK-WIDE EFFECT OF UTILIZATION METHOD (FOR 75% MAXIMUM UTILIZATION IN CAFCR SCENARIO)



In addition to the full and high utilization scenarios shown in Figure 17 and Figure 21, scenarios were also evaluated with low (saturation at 50 percent) and very low (saturation at 25 percent) utilization. Figure 22 depicts the Standard Curve for all four of these variations in utilization trajectories. High, low, and very low utilization values were based on the ratio of the saturation value to full utilization at 85 percent.

FIGURE 22: MAXIMUM UTILIZATION VARIATIONS

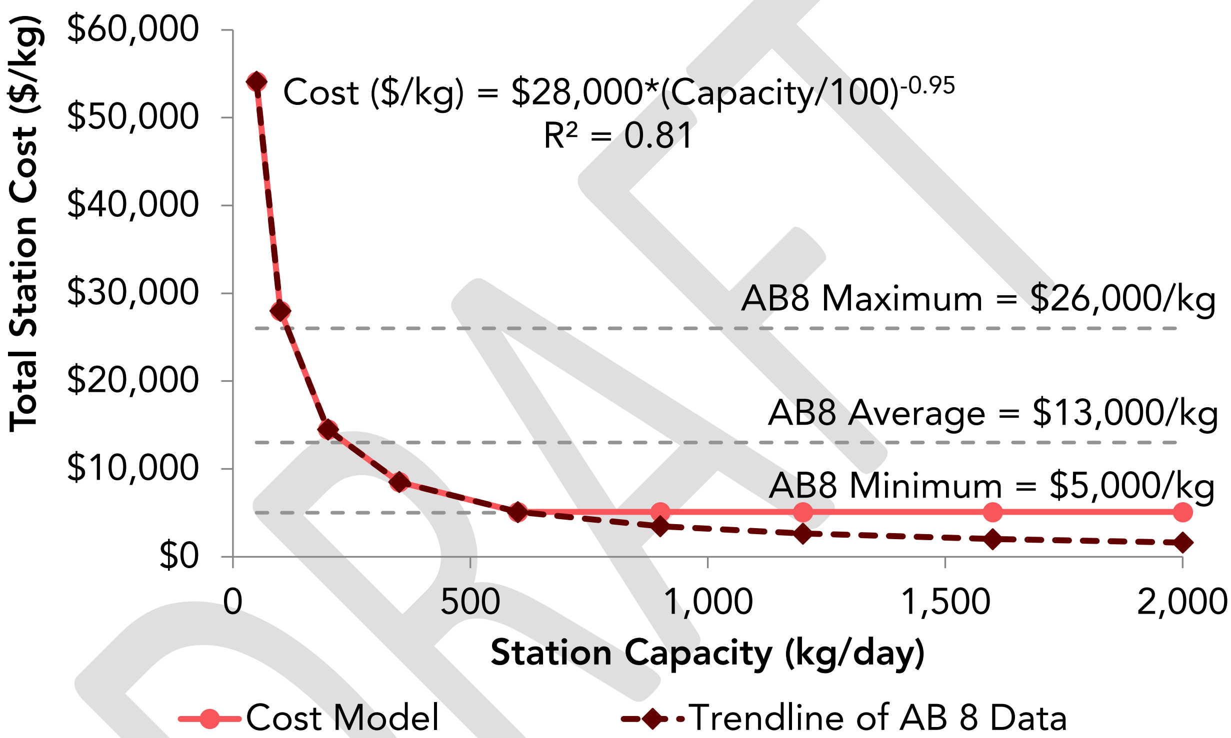


All scenario inputs to this point varied primarily by the combination of FCEV and station deployment and could be fully generated prior to any station or network economic evaluation. For example, whether costs for capital equipment were assumed to decline slowly or quickly for a given scenario, the individualized utilization schedule at all stations could be evaluated and would remain the same, independent of any financial assumptions. Therefore, in the completion of this study, all input variables described so far were provided to the financial calculation tool via pre-processed input files that reflected combinations of scenario assumptions. For example, input files that described every individual station's progression of utilization were maintained for the CAFCR Large station deployment scenario and high maximum utilization along with analogs for all other combinations of station deployment and maximum utilization. This allowed for streamlined processing of financial evaluations, as the processes of placing stations and evaluating local network maturity were many times more computationally intense and time-consuming than any of the financial calculations.

INITIAL CAPITAL COSTS AND CAPITAL COST REDUCTION

Financial input variables include specification of costs, revenues, and financial performance metrics that are deemed attractive to ongoing private investment. Costs in this study are separated into Capital Expenses and Operations and Maintenance Costs, with the latter further divided into Fixed and Variable portions. Figure 23 displays the basis function for station Capital Expenses. The cost curve utilized in this study is based on the history of total installed station cost for stations previously funded by the AB 8 program. These costs are based on the total projected costs (including both State and private funds) from application materials when no further information is available. However, a significant number of the stations have also reported actual costs that include expenses beyond their original projections at the time of grant application and these costs are included in this study.

FIGURE 23: FULLY INSTALLED STATION CAPITAL EXPENSE MODEL



Note: Does not include 2 outliers (verified by Grubbs' test at 0.05 significance) , 1 Null (Incomplete) data point, nor mobile fueler

As shown in Figure 23, the cost to install station fueling capacity falls rapidly on a per-kg per day fueling capacity basis up to stations of approximately 600 kg/day. Beyond this, the reduction in cost per-kg is more modest. Based on the available AB 8 data, a power law nearly identically proportional to the inverse of capacity is a good estimate for station total installed cost. This function is represented by the dashed dark red line with diamond symbols. At large capacities, this function implies that total station installed cost is almost independent of the total station capacity, which is not realistic. In addition, any projection for stations larger than 600 kg/day is based on extrapolation beyond the observed AB 8 program data. Therefore, CARB adopted a truncated cost model that modified the AB 8 trend line by assuming cost per kilogram was the same for all stations larger than 600 kg/day. At this size, all stations are assumed to have an installed capital cost of $5,000 per kilogram of daily capacity.

This cost estimate is representative of the very first hydrogen fueling stations built in California's network. These stations have also been some of the first retail fueling stations to be developed anywhere in the world. Therefore, their costs are likely representative of the relatively immature market development phase in which they were built. At the time of their construction, equipment supply chains were extremely limited with little cost reduction having occurred due to either technology progression or economies of scale. As station network development progresses into the future, it is expected that both of these factors will reduce equipment capital costs, similar to cost reductions that have occurred for other new technologies like solar and wind electricity generation and battery costs for Battery Electric Vehicles.

CARB investigated two methods of accounting for future cost reductions. The first method is based on prior research from the National Renewable Energy Laboratory and their Hydrogen Station Cost Calculator (HSCC) [30]. In that work, researchers advanced a hydrogen station cost equation that included a multiplier accounting for industry-level cost reductions based on the total deployed hydrogen station capacity to date. This factor accounts for economies of scale as total network development grows. For any new hydrogen fueling station, its capital expense was modeled as[3]

$$Cost = Cost^0 \left(\frac{V'}{V^0}\right)^{\beta}$$

where *Cost* represents the total installed station capital expense accounting for industry-wide cost reductions, $Cost^0$ is the cost based on the station capacity but not accounting for cost reductions (as shown in Figure 23), V' is total installed station capacity to date, V^0 is a reference station capacity of 25,000 kg/day, and β is the learning factor describing the rate of cost reduction. In the original NREL work, researchers estimated β to be -0.106. However, the prior work also mentioned that the cost reductions achieved by this model were fairly conservative compared to other new technologies. CARB therefore also investigated cases with the β factor doubled to -0.212.

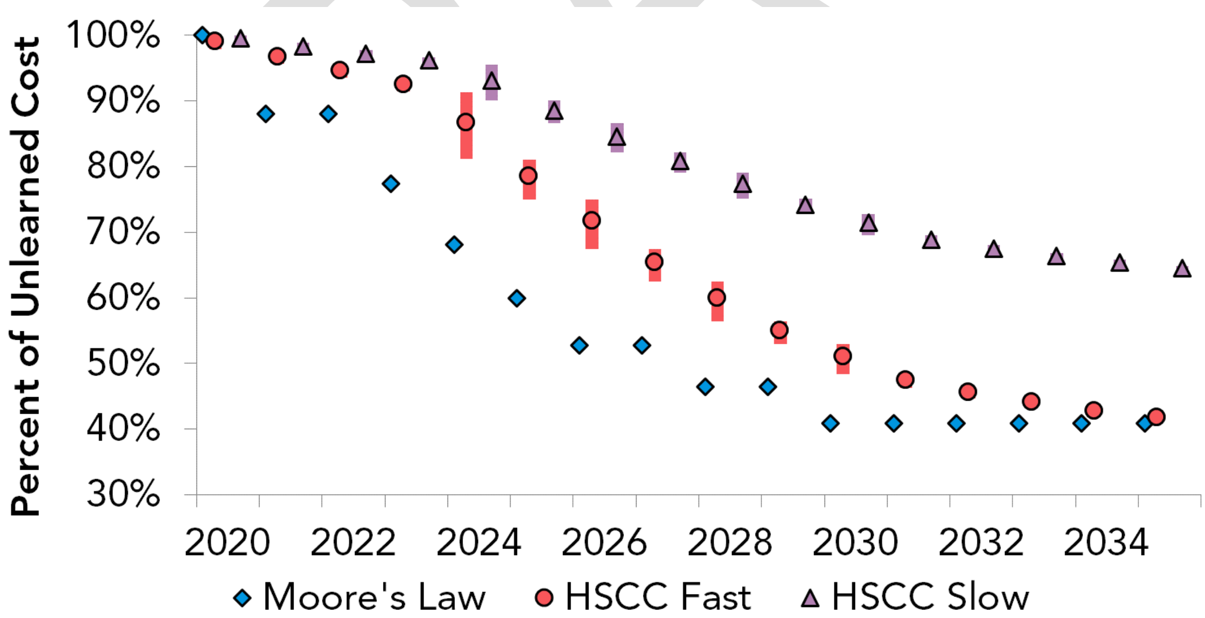
In addition to the HSCC method, CARB also developed a capital cost reduction model based on feedback from industry members. In several members' view, new technologies (including examples like electrolyzers and renewable electricity production equipment) follow a cost reduction trajectory similar to the cost reductions that occurred for integrated circuits and described by Intel co-founder Gordon Moore in 1965 based on empirical evidence. According to Moore's Law the number of transistors integrated onto a microchip doubles every two years, while simultaneously

[3] The equation shown is slightly modified from the reference work due to this study's separate method of calculating base station cost as a function of installed capacity.

reducing cost by approximately 50 percent. This observation has appeared to hold true for microchips from the 1960s to today.

To model hydrogen station cost reductions according to a similar law, CARB assumed a constant cost reduction per doubling of deployed volume that ultimately provided similar cost reductions to the accelerated HSCC model CARB also investigated. Through pilot investigations, CARB found this rate to be 12 percent reduction in cost per doubling of installed capacity. This rate of cost reduction is similar to reported values in recent studies assessing future hydrogen industry development. The Hydrogen Council recently published a roadmap to hydrogen cost competitiveness and reported learning rates for several clean power technologies [31]. The study found cost reduction rates of 9-13 percent for electrolyzers, 11-17 percent for transportation-based fuel cell systems, 10 percent for hydrogen tanks, 19 and 25 percent for onshore wind and solar power respectively, and 39 percent for batteries. In a recent workshop to support development of the Energy Commission's next Integrated Energy Policy Report, representatives from Bloomberg New Energy Finance presented similar findings [32]. BNEF reported learning rates of 19.8 percent for Japan's Ene-Farm project (a fuel cell-based combined heat and power system for homes), 15 percent for onshore wind, and 22 percent for solar power with tracking. A 12 percent cost reduction rate is slow compared to other clean energy technologies, but similar to technologies specifically related to fuel cells and hydrogen.

Figure 24: Network-Based Capital Cost Reductions for CAFCR



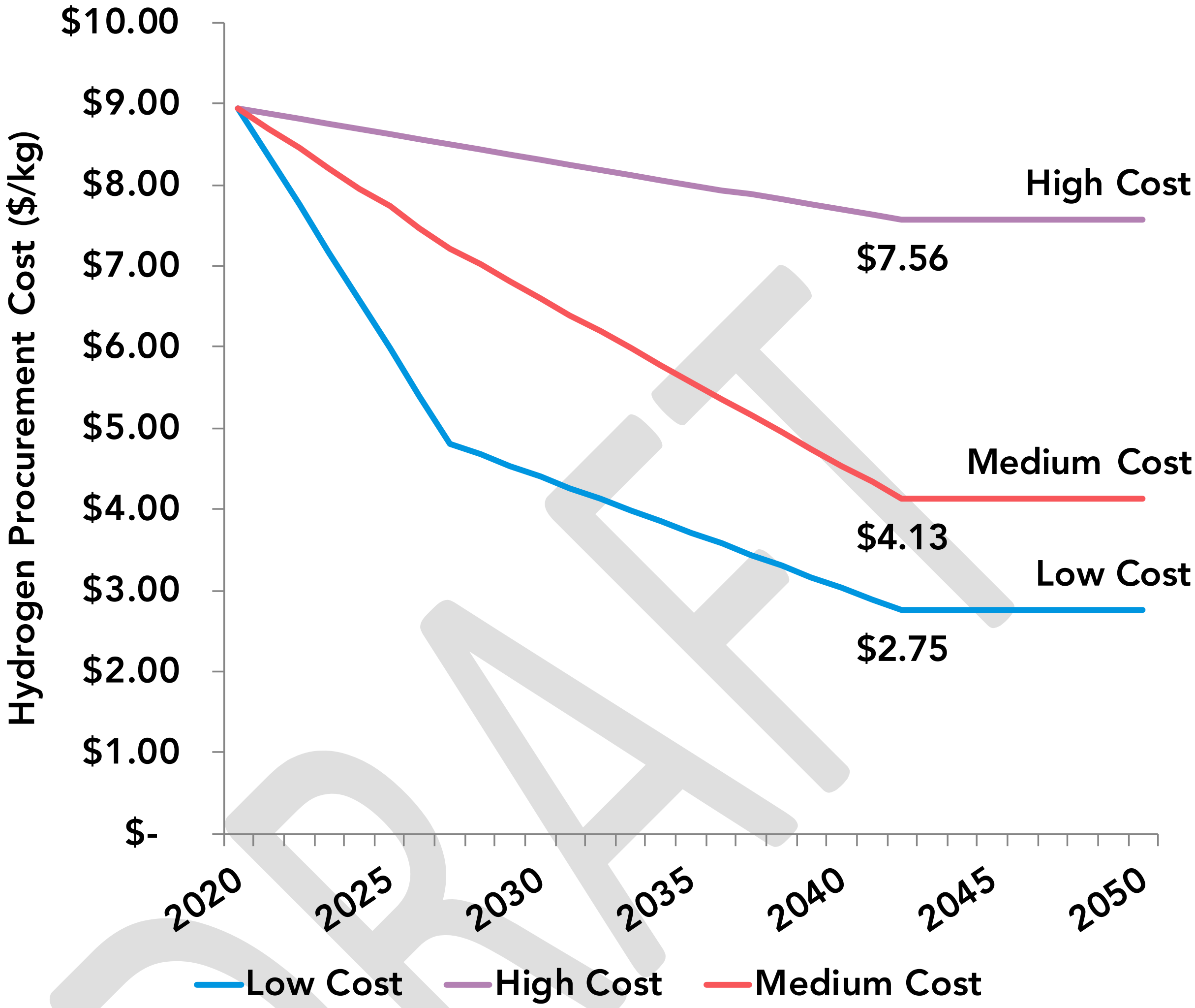
The cost reductions enabled by each of these three estimation methods (HSCC Slow with β set to -0.106, HSCC Fast with β set to -0.212, and Moore's Law at 12 percent reduction per doubling of installed capacity) are shown in Figure 24 for the CAFCR case. When calculating cost reductions for both of the HSCC methods, each individual station's capital costs are assumed to be different, given the form of the governing equation. Therefore, the cost reductions (as a percentage of unlearned cost) are presented as a range in each year for these methods (though the range is small in some years). For the Moore's Law basis of cost reductions, each station was also evaluated individually but cost reductions were only assumed to occur once the cumulative station deployment doubled from the previous cost-reduction level. The Moore's Law method therefore exhibits less variability in projected cost reduction in each year than the HSCC method. HSCC Fast and Moore's Law methods in this case achieve slightly more than 50 percent cost reduction by 2035, while the HSCC slow methods achieves approximately 30 percent cost reduction over the same time.

Initial Operational Costs and Operational Cost Reduction

In addition to capital equipment and installation expenses, CARB modeled costs incurred due to the operation of each station in each year. Four major components contribute to this portion of costs: hydrogen procurement (the cost to have hydrogen delivered to the station), fixed operations and maintenance costs (costs that do not vary depending on the amount of hydrogen sold), variable operations and maintenance costs (costs that do vary proportionally to the amount of hydrogen sold), and periodic major maintenance. Costs estimated for each of these categories are based on consideration of: 1) feedback from industry during the interview process, 2) AB 8 program data, 3) prior AB 8 station cost evaluations, 4) Department of Energy targets, 5) estimates and projections from prior studies, and 6) data from the National Fuel Cell Technology Evaluation Center [21] [26] [33] [34] [35] [36] [37] [38]. Estimates were vetted through direct feedback from industry members participating in the extended interview process.

Trajectories for hydrogen procurement cost are shown in Figure 25. All three begin with estimates of approximately $9/kg for current stations. The high cost trajectory represents moderate reductions through 2040 to $7.56/kg, and remains at this price through the end of the evaluation period. The low cost trajectory anticipates rapid cost reductions in early years and continued, but slower reductions for 2030 to 2040. In the low cost case, procurement costs settle at $2.75/kg in 2040. The medium cost case falls almost linearly to $4.13/kg in 2040. The trajectories assumed are simplified estimates based on consideration of the reference materials cited above.

FIGURE 25: HYDROGEN PROCUREMENT TRAJECTORIES



Fixed operations and maintenance costs include payment for internet services, fixed electricity costs, permits, hydrogen quality tests, insurance, property tax, rent, and fixed operations and maintenance labor. For this analysis, hydrogen procurement costs are not counted as operations and maintenance and are considered a separate operational cost. The estimates used in this study for operations and maintenance costs are shown in Table 2. Variable operations and maintenance costs include sales tax, credit card fees, and variable electricity costs. The estimates used in this study for these costs are shown in Table 3. Periodic major maintenance is equal to 10 percent of the original station capital expenditure incurred once every five years.

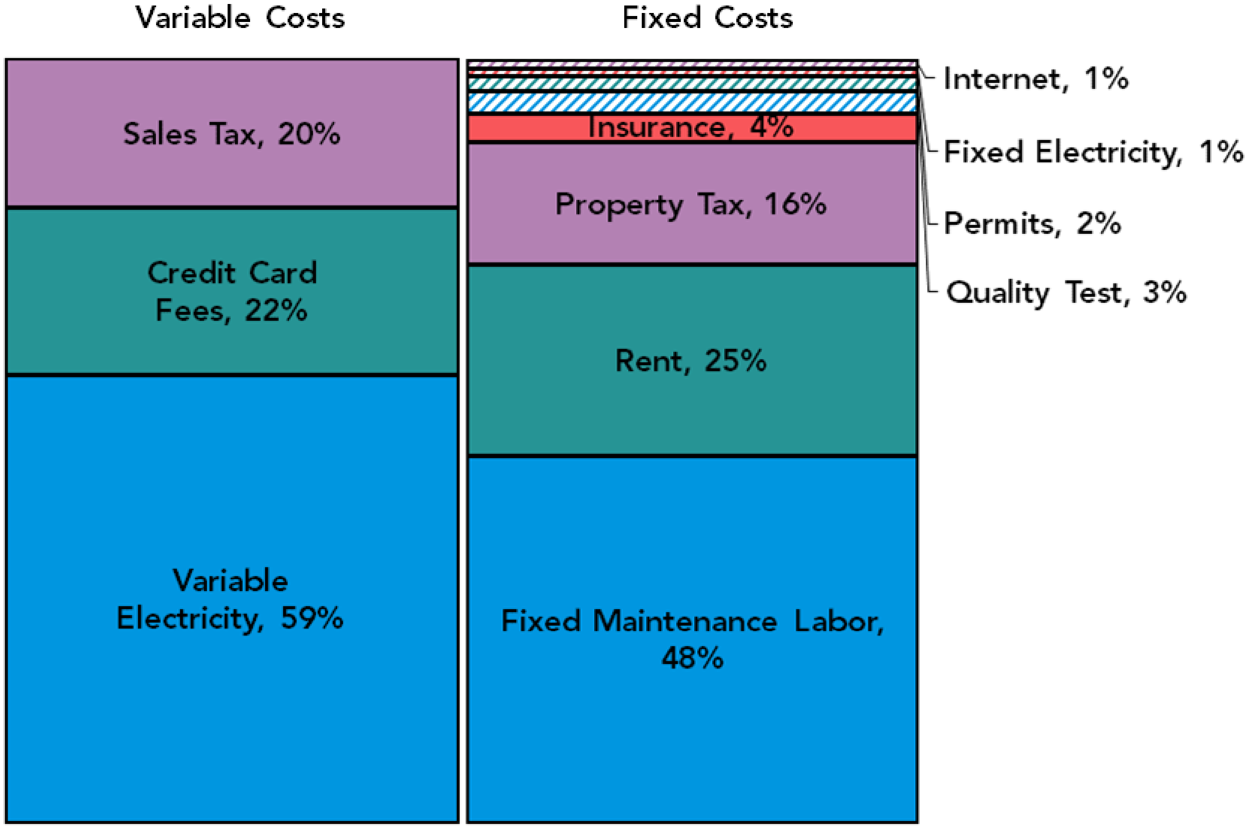
Table 2: Fixed Operations and Maintenance Cost Elements

Fixed Cost Category	Cost Estimate ($/year)
Internet	2,300
Fixed Electricity	2,100
Permits	3,700
Hydrogen Quality Tests	5,400
Insurance	7,200
Property Tax	1% of Capital Expense
Rent	48,000
Fixed Labor	3% of Capital Expense

Table 3: Variable Operations and Maintenance Cost Elements

Variable Cost Category	Cost Estimate
Sales Tax	2.25% of Sales
Credit Card Fees	2.5% of Sales
Variable Electricity	3kWh/kg Sold @ $0.18/kWh

Figure 26: Sample Fixed and Variable Operations and Maintenance Cost Breakdown



The relative proportions of each fixed and variable maintenance and operations cost category are shown in Figure 26 for the example of a midsize station (600 kg/day) with high utilization and no cost reduction due to industry learning. This cost breakdown may therefore be indicative of several stations in today's hydrogen fueling network if they were highly utilized. Approximately 60 percent of variable costs are associated with variable electricity, with the remainder fairly evenly split between sales tax and credit card fees. Fixed maintenance labor contributes 48 percent of fixed operations and maintenance cost, with rent the second-highest cost at 25 percent. Property tax makes up 16 percent of fixed costs, and all remaining categories account for one to four percent each.

Feedback from station operators during the industry interview process indicated that fixed costs represent a larger portion of operations and maintenance expenses than their variable counterparts (not including the cost to procure hydrogen). CARB assessed its cost models against this assertion for several scenarios. Figure 27 shows operations-related costs for midsize stations similar to those in today's network, at both today's average utilization (near 40 percent) and full utilization. At current utilization levels, this assertion is clearly replicated with CARB's cost model. Fixed operations and maintenance costs in this scenario are 25 percent, or 2.5 times their variable counterparts. However, at full utilization, this cost model does narrow the gap and brings the two portions to near equality. At full utilization, fixed operations and maintenance costs are 14 percent of total operational costs and variable costs are 13 percent. In both cases, hydrogen procurement plays the clearly dominant role, representing 57 percent of costs at today's utilization and 69 percent at full utilization.

Figure 27: Dollar-per-Kilogram Cost Breakdown for Midsize Stations without Capital Expense Reductions

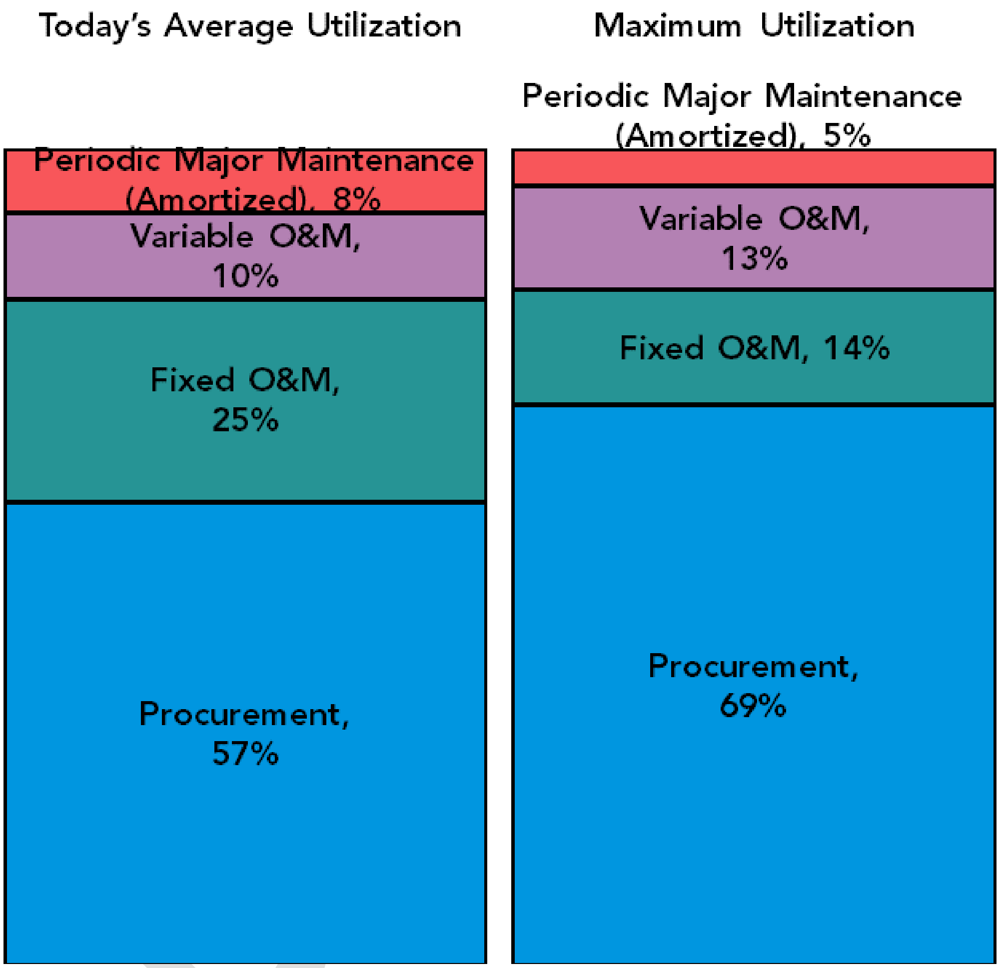
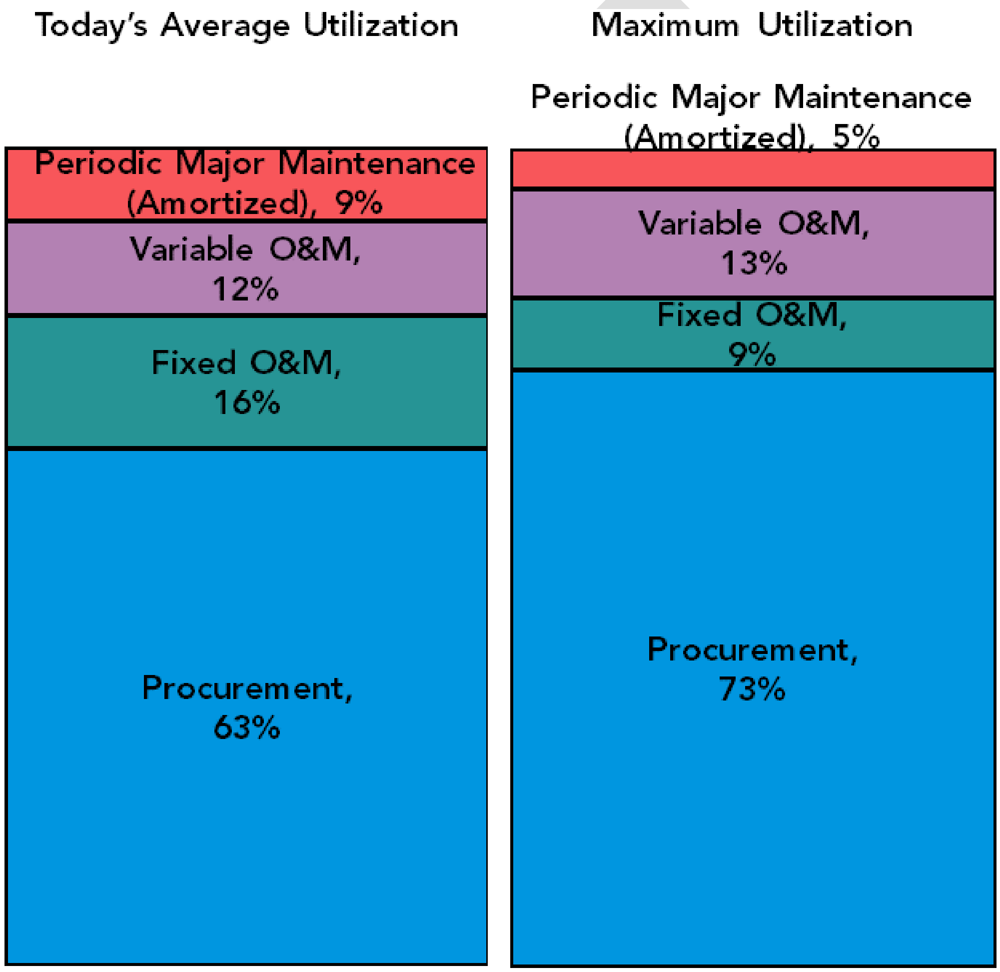


Figure 28 presents a similar analysis, but for a large station built in the future after significant cost reductions due to industry learning. In this case, even at limited utilization rates, fixed and variable operations and maintenance costs are similar at 16 and 12 percent, respectively. At full utilization, these stations demonstrate variable operations and maintenance that exceed their fixed counterparts, at 13 and 9 percent, respectively. This is caused in part by the increased variable cost due to the greater fuel sales throughput. In addition, station equipment capital costs directly affect two of the largest fixed costs. This study's cost models specify lower per-kilogram capital cost for larger station equipment. Also, significant industry learning enables reduced station equipment capital costs. In this case, all these factors combined contribute to higher proportional variable operations and maintenance costs. CARB does not interpret the result for large stations at high utilization with high rates of capital cost reduction to invalidate the overall cost model. Instead, the results of Figure 27 validate the model as they demonstrate a match between current industry trends and direct feedback from station developers. The cost stack on the right of Figure 28 likely represents future potential not addressed by industry information.

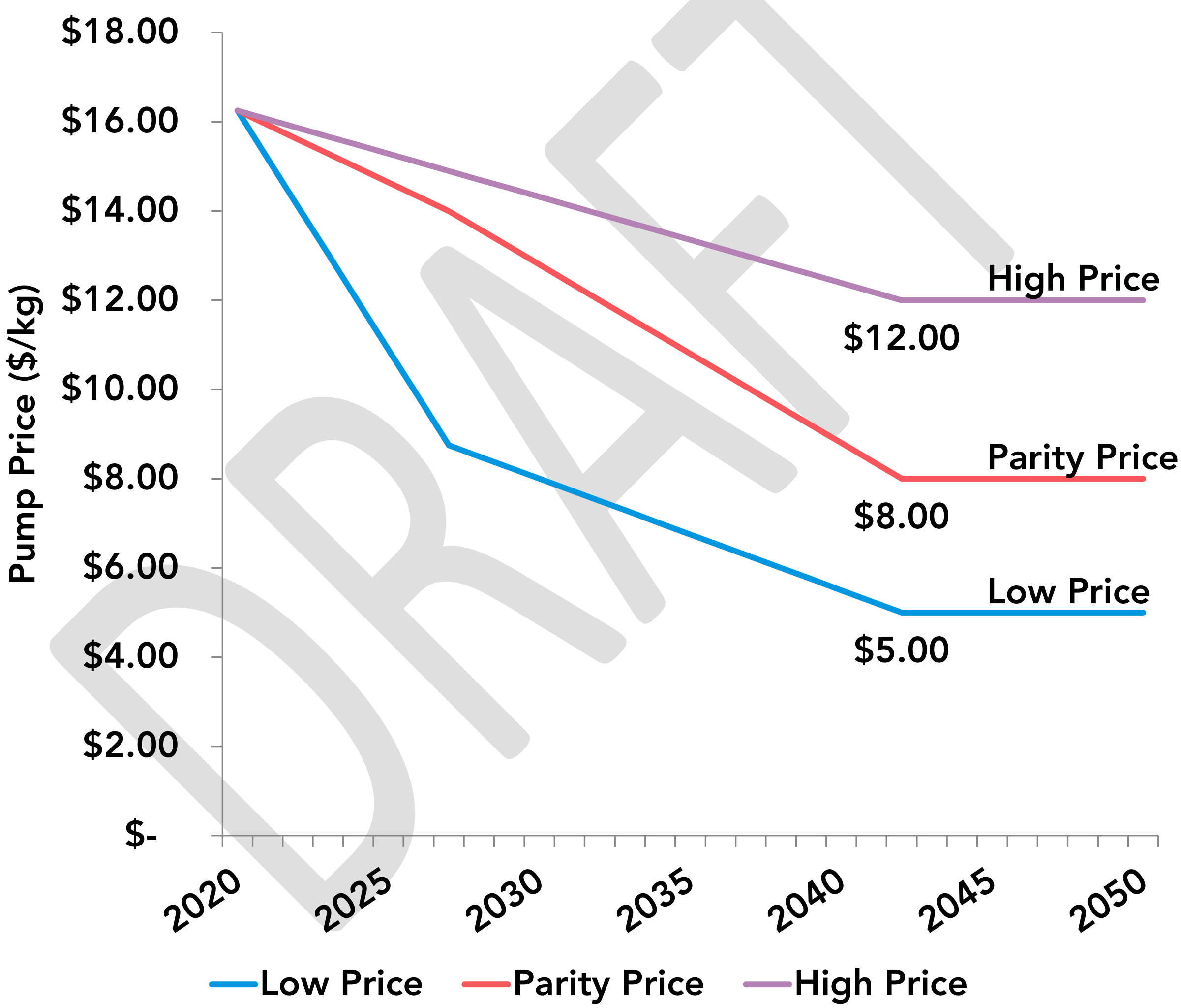
Figure 28: Dollar-per-Kilogram Cost Breakdown for Large Stations After Significant Capital Expense Reductions



Initial Pump Price and Pump Price Reduction

Based on the same references used for the cost estimates in the Section "Initial Operational Costs and Operational Cost Reduction", CARB developed trajectories for price paid at the pump by the consumer, as shown in Figure 29. In addition to high and low cases that respectively fall to $12.00/kg and $5.00/kg in 2040, CARB developed a baseline price case that achieves parity with gasoline by 2040. Parity in this case has been defined according to industry feedback, which centered around $8/kg. All of these cases maintain their prices from 2040 onward. In addition to the cases shown in Figure 29, CARB also investigated other scenarios that advance pump price parity by varying degrees. These scenarios are discussed further in later chapters of this report. Note that the low price scenario achieves parity as soon as 2025. Recent studies have found that hydrogen fuel (even fully renewable hydrogen fuel) could achieve price parity between 2025 and 2030 [39] [40].

FIGURE 29: HYDROGEN PUMP PRICE TRAJECTORIES



ADDITIONAL REVENUES

This study assumes three additional sources of revenue beyond revenue from the sale of hydrogen. The first two are the LCFS throughput-based credit generating revenue potential and HRI credit generating potential. HRI credit generation in this study accounts for the limitations set by the HRI program including:

- Total HRI credits issued do not exceed 2.5 percent of the projected LCFS program deficit (in the actual program, this is evaluated quarterly; for this study, this is evaluated on an annual basis)
- Stations cannot be greater than 1,200 kg/day in size
- Stations can generate HRI credits for a maximum of 15 years

LCFS credit revenue potential also varies annually due to the assumed credit price and the assumed carbon intensity of hydrogen. In this study, both the assumed credit price and the projected program deficit were based on the Illustrative Compliance Scenario Calculator's projections for the proposed amendments [41]. Figure 30 displays the LCFS credit price, while Figure 31 displays the assumed carbon intensity of hydrogen. After 2030, both of these factors and the deficit budget were assumed to maintain their 2030 values.

FIGURE 30: LCFS CREDIT PRICE

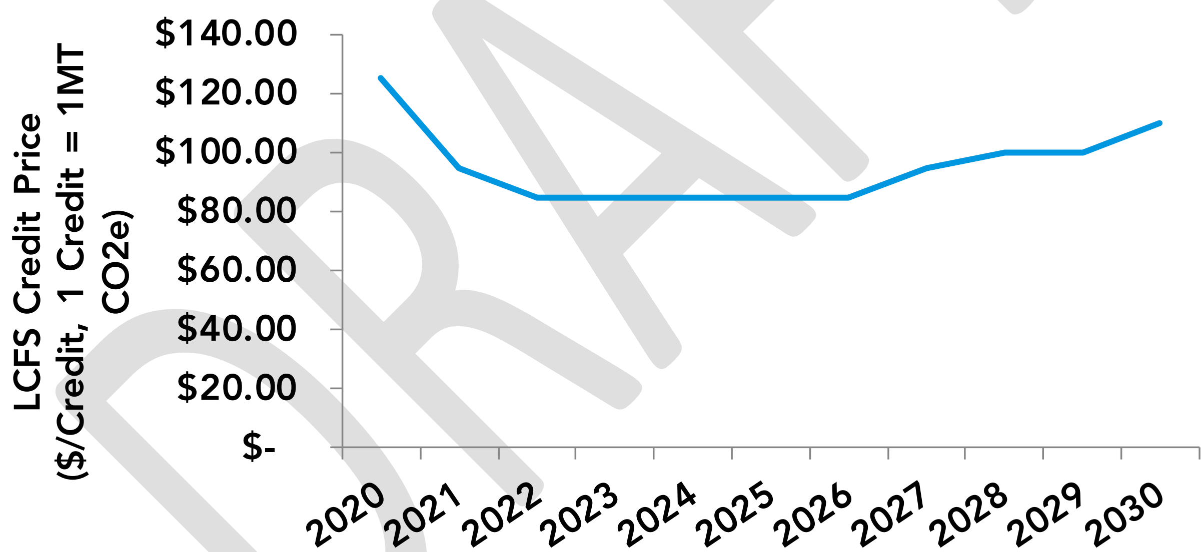
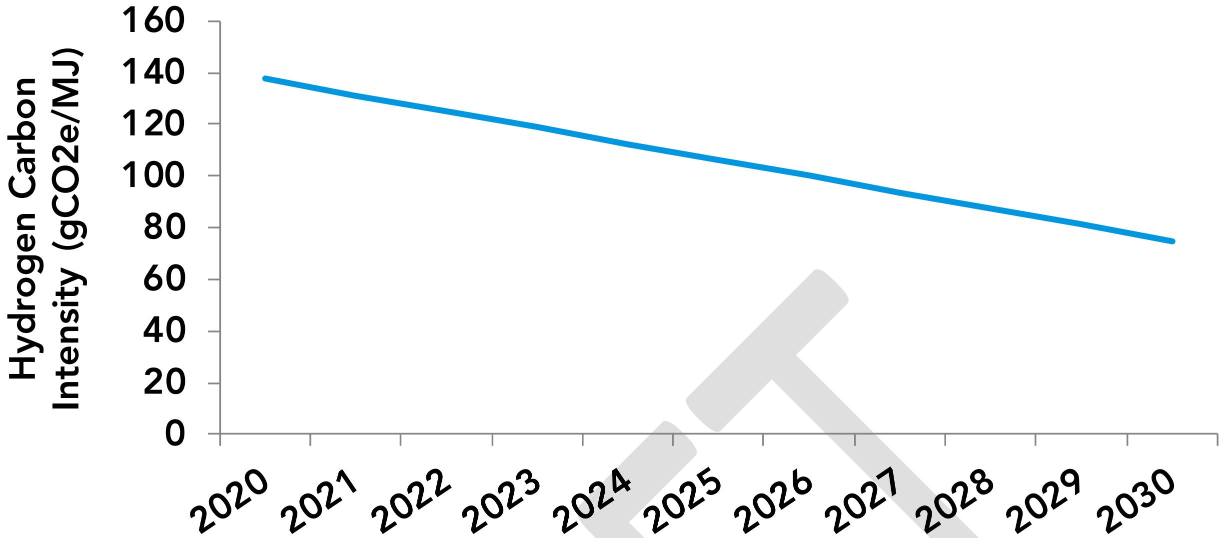


FIGURE 31: HYDROGEN CARBON INTENSITY



In addition to the two sources of LCFS credit revenue, stations are assumed to potentially receive an additional stream of State-provided funding support. This additional support forms the basis of this study's quantification of the time and cost to achieve network self-sufficiency. In this work, this financial support has been modeled as a five-year grant with equal payouts over the five years. Note that this structure was chosen simply for its convenience in calculation; CARB does not endorse or recommend this structure by way of its use in this study. Any hypothetical future State funding support program will require more detailed consideration than this study in order to determine the appropriate structure and implementation. The grant structure is assumed merely as a tool of quantification.

The total amount of the grant ensures that the Modified Internal Rate of Return (MIRR) of each station is equal to or greater than a user-defined minimum value. If a station performs at least as well as the minimum expectation per MIRR, then the station is assumed to not require any additional State support beyond the LCFS provisions. MIRR is evaluated in this study on a 15-year basis and defined as:

$$MIRR = \sqrt[n]{\frac{FV\ (Cash\ In\ @\ Reinvest\ Rate)}{PV(Cash\ Out\ @\ Finance\ Rate)}} - 1$$

where *FV* is the future value of all positive cash inflows based on the reinvestment rate, *PV* is the present value of all negative cash outflows based on the capital financing rate, and *n* is the number of periods over which MIRR is evaluated.

In this study, *n* is set to 15 years. The reinvestment rate is assumed to match the target MIRR specified for each scenario evaluation. This essentially assumes that reinvestment in the company provides equivalent returns to normal operations (that is, there is neither an incentive nor disincentive for reinvestment). The financing rate is assumed to be six percent. MIRR was chosen as the metric for station performance due to its mathematical flexibility, especially its reversibility. That is, the equation is easily uniquely solved in reverse, with MIRR known and a component of the cash flows unknown. In the case of this study, the unknown component is the annual amount of additional State financial support needed to achieve the particular MIRR. Based on feedback from industry regarding desired station financial performance that indicates successful market launch and attracts private financing, CARB investigated cases with target MIRR between ten and fifteen percent. In all scenarios, the target MIRR decreases to the lowest value of ten percent as the network grows. This emulates the reduction in risk for further investment as the market matures. The minimum targeted MIRR is reached either by the 200th or the 500th station in the network, depending on the value of the initial target MIRR.

The final set of input variables are consistent across all scenario evaluations and pertain to the financial performance and evaluation of individual stations. Capital costs in this study are assumed to be financed by a ten-year loan at the assumed finance rate of six percent. Payment for these costs begin in the year the station is assumed to first operate. CARB also discounts future cash flows using a 1.9 percent inflation rate, per recent values published by the Bureau of Labor Statistics [42]. Table 4 provides a summary of the ranges for several of the most important variables that are varied for each scenario evaluation.

TABLE 4: RANGES OF NUMERICAL INPUT VALUES

Input Variable	High Value	Low Value
2035 Vehicle Deployment	1,800,000	300,000
Minimum Station Size	350	200
Maximum Station Size	2,000	1,200
Number of Stations	1,800	310
Maximum Station Utilization	85%	25%
Moore's Law Learning Rate	12%	12%
HSCC Learning Factor	-0.212	-0.106
2040 Pump Price Target	$12.00/kg	$5.00/kg
Fixed Procurement and Delivery Cost Target	$7.56/kg	$2.75/kg
Maximum Rate of Return	15%	10%

Scenario Evaluation Steps

Each scenario evaluation consists of three distinct phases: pre-processed vehicle and station deployment data, individual station finances, and network-wide and adjusted post-analysis. These phases were completed with individual steps in the following order (tools and computational platforms used for each step are shown after the vertical line):

Pre-Processed Vehicle and Station Deployment Phase

- Determine vehicle deployment schedule based on prior studies | Excel
- Determine station development schedule | Excel
- Determine station locations by iterative algorithm utilizing California Hydrogen Infrastructure Tool (CHIT[4]) routines | python and ArcGIS via arcpy library and CHIT ArcGIS toolbox
- Complete station neighbor analysis using CHIT routines and ArcGIS built-in tools | ArcGIS
- Set each station's utilization in each year of operation based on neighbor analysis data | python

Station Finances Phase

The process in this phase is iterative, stepping sequentially through each year of the scenario evaluation and making calculations for each station in the network in each year. All calculations are completed in python. Any year when a station is not yet operating incurs no cash inflow or outflow for the station.

- Assess prior station deployment and calculate capital cost reduction amount for each station
- Calculate capital cost loan payment; if first year of operation, calculate and store total capital expense
- Calculate total sales for year (both kilograms of hydrogen sold and revenue), fuel procurement cost, fixed operations costs, variable operations costs, and periodic major maintenance as necessary
- Calculate LCFS throughput-based credit generation revenue for station
- Calculate LCFS HRI-based credit generation revenue for station
- Adjust all calculated values for inflation
- Calculate sum of station annual cash flows

[4] https://ww2.arb.ca.gov/resources/documents/california-hydrogen-infrastructure-tool-chit

The remaining steps in this phase occur for each station after determining its full financial performance without additional State support.

- Calculate cumulative net cash balance for each year for all stations.
- Calculate MIRR without additional State support
- If MIRR is less than the target, calculate State support amount such that MIRR meets the target
- Write output data to files, including: station cash flows for all years, all stations' annual and cumulative net cash flow in each year, each station's MIRR before and after additional State support, and each station's total additional State support amount

Network Finances and Post-Analysis Phase

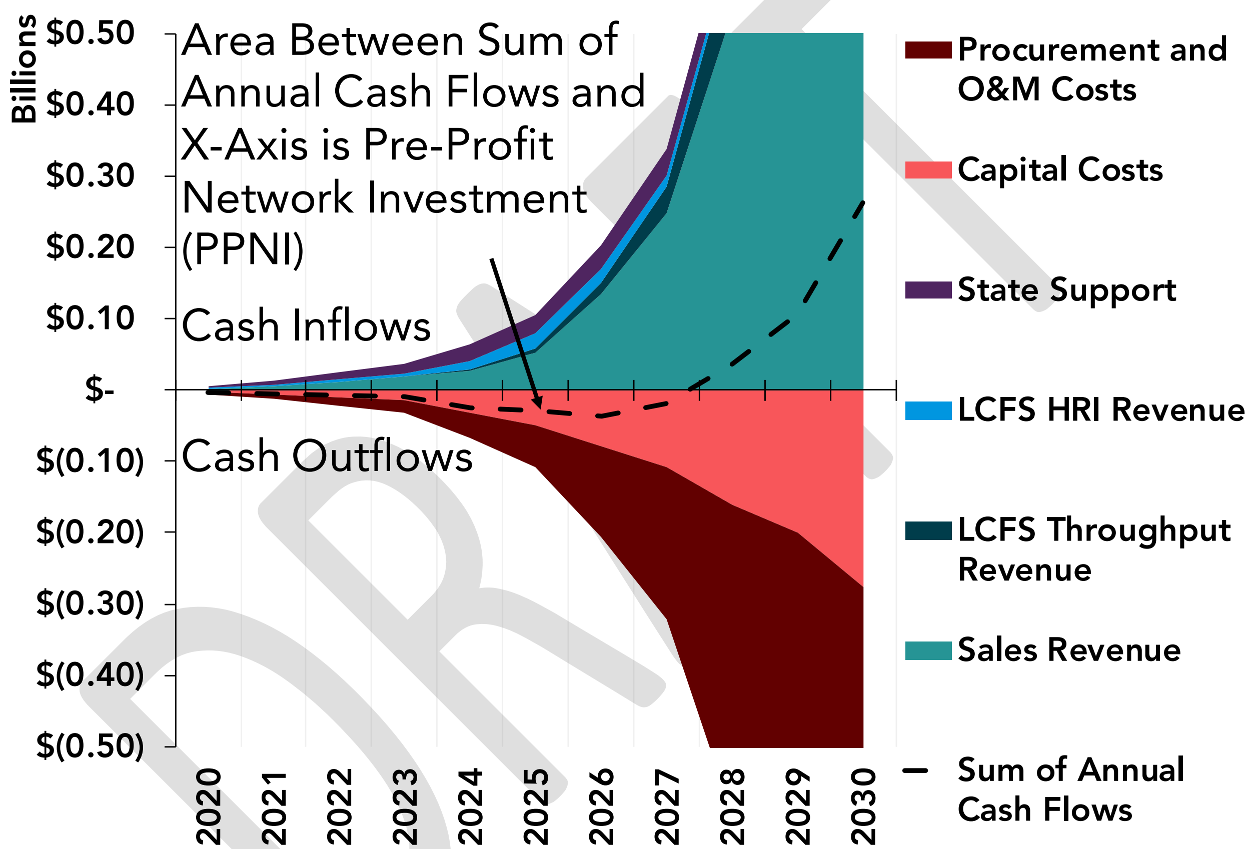
- Aggregate individual station cash flows to network cash flows for all years in scenario evaluation | Excel
- Identify self-sufficiency date, total State support, and other network financial performance metrics | Excel
- Synthesize results across multiple scenarios | Excel
- Detailed evaluation of cash flows according to station size and other metrics for focus set of scenario evaluations | Excel
- Geospatial evaluation of station financial performance for focused set of scenario evaluations | ArcGIS

OUTPUT VARIABLES AND POST-ANALYSES

Network-wide financial performance was evaluated through post-processing of the individual stations' finances. Much like for individual stations, this study focuses on network-wide positive and negative cash flows and evaluates several parameters related to the net total between cash inflows and outflows. Figure 32 depicts a portion of a primary chart output for each scenario evaluation. In the figure, cash inflows (including LCFS revenue and additional State financing) are charted above the x-axis while cash outflows are charted below the x-axis. The annual sum of cash flows is shown by the dashed black line. This annual sum **does not** include the additional State support. This allows evaluation of the network's performance without pre-supposing further State cash flows. By using this definition, if State support were to stop on the day the network first shows a profit, then the network would continue to show profit-generating potential.

In the example shown, the sum of annual cash flows is initially negative until 2028 when it first becomes positive for that year. As a first estimate, this year of crossover to positive annual cash flow may represent the year of self-sufficiency for the network. The area of negative annual sums in cash flow (between the x-axis and the annual sum) up to the self-sufficiency date serves as a metric in this study of the total net cash flow required (provided by both public and private entities) to reach development at the self-sufficiency date and is termed the Pre-Profit Network Investment (PPNI). Importantly, the PPNI **is not** taken in this study as the State's cost to achieve self-sufficiency. The cost to self-sufficiency is instead taken as the total amount of additional State financing for all stations through the self-sufficiency date (labeled as "State Support" in the figure).

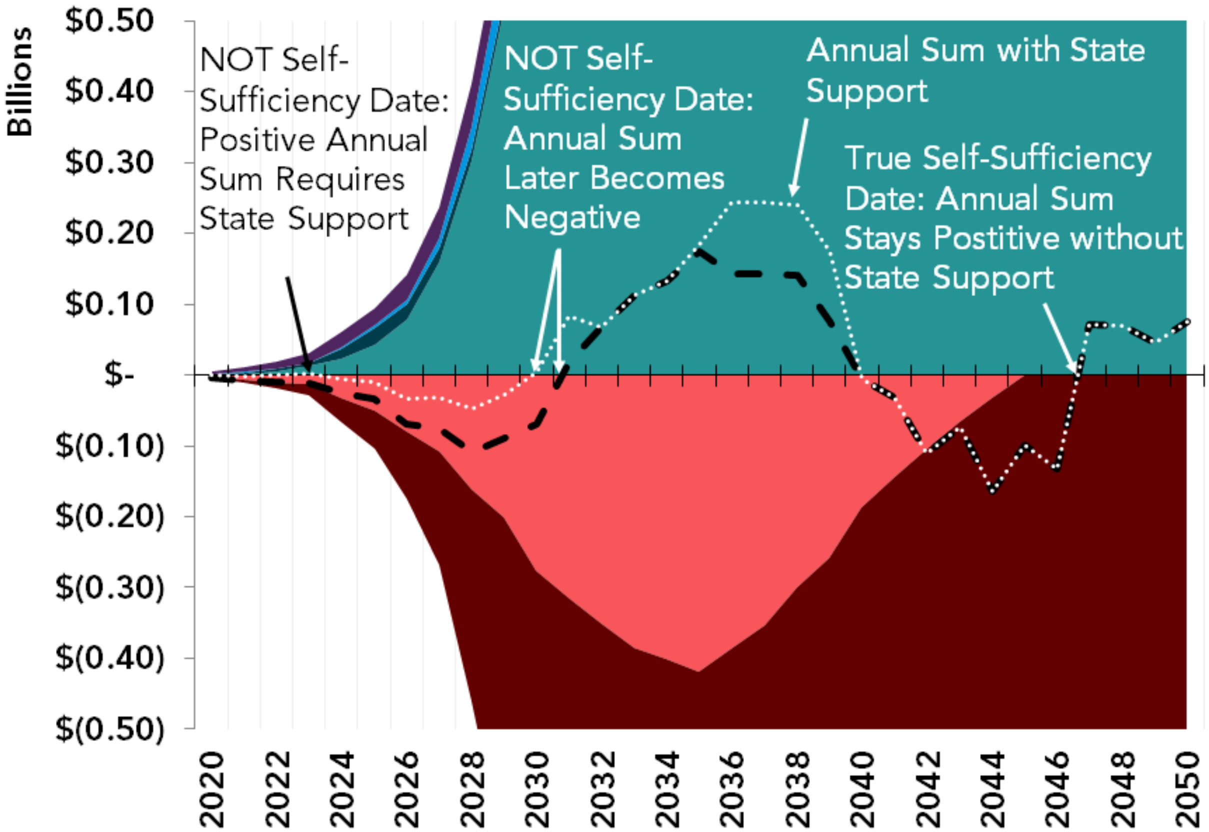
FIGURE 32: PRINCIPAL NETWORK ECONOMIC OUTPUTS OF SCENARIO EVALUATION



The definition of the self-sufficiency date is critical to accurately projecting both the timing and the cost to achieve self-sufficiency. In the example of Figure 32, this appears to be 2028, when network annual profits first become positive. For most scenarios, the date of first achieving positive annual network-wide cash flows proved sufficiently well-defined for the date of self-sufficiency. Figure 33 demonstrates a more complex scenario and the need for a more rigorous definition to account for some uncommon contingencies. In Figure 33, the annual sum of cash flows is shown both without (black dashed line) and with additional State support (white dotted line).

With the additional State assistance, the sum of annual cash flows in immediately positive. On the other hand, the annual sum of cash flows without additional State support is negative. The year 2020 is not identified as the self-sufficiency date because achieving a positive sum of annual cash flows requires additional State support. Around 2030, the annual cash flow sums with and without State financing become positive. This may appear to indicate network self-sufficiency. However, this scenario also shows both annual sums returning to the negative region around 2040. Therefore, the network does not have durable self-sufficiency. This situation can occur in scenarios with a large number of "pessimistic" inputs, including slow capital cost reductions, high hydrogen procurement costs, and low utilization. In addition, LCFS HRI credit generation expires in 2040, typically at a time when many of the largest stations are new and utilization is still growing for a significant portion of the network's fueling capacity. Finally, the true self-sufficiency date in this scenario appears at 2047, at which point the annual sum of cash flows is again positive and remains so through the end of the scenario evaluation timeline.

FIGURE 33: DEMONSTRATION OF SELF-SUFFICIENCY DATE DEFINITION

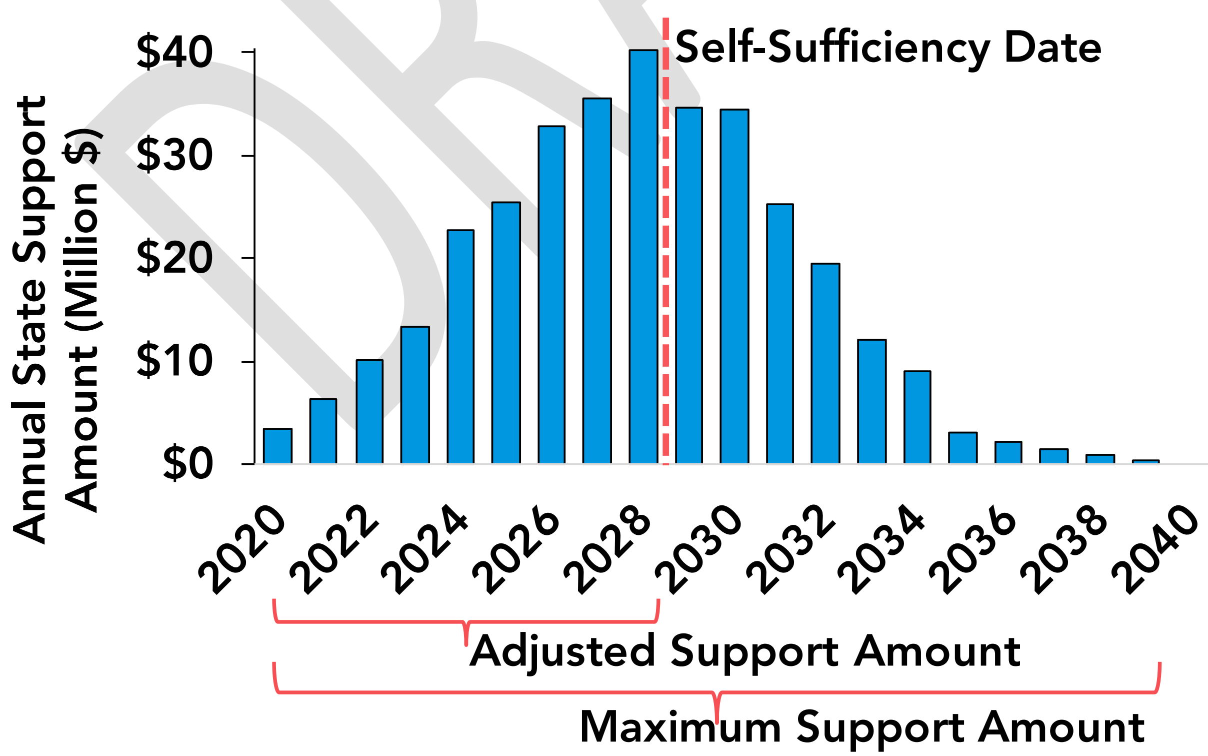


Therefore, the date of self-sufficiency in this study is defined as the date that **annual sum of cash flows without additional State support becomes positive and remains positive for the remainder of the evaluation timeline.** Nearly all scenarios evaluated demonstrated a self-sufficiency date achieved prior to 2050. The few cases that do not achieve self-sufficiency represent highly unfavorable combinations of factors and could be considered a failure of market development.

With the definition set for the self-sufficiency date, the total State support amount can be determined. In general, individual station financial performance may indicate a need for State support beyond the network-wide self-sufficiency date. In pilot studies, State support beyond the self-sufficiency date was often observed mostly for smaller stations built later in the network. These stations would typically require a small flow of funds for their eligible periods. These funds essentially represent a small amount of additional revenue needed to achieve the target MIRR. Individually they do not represent a large amount for each station in each year, but they do add up to a significant amount in aggregate.

CARB has defined the total of State support, regardless of whether the funds are provided before or after the self-sufficiency date, to represent the "maximum support amount". CARB further postulates that once the network demonstrates self-sufficiency, strict assurance of target MIRR for all stations in the network may not be necessary. Therefore, this study additionally defines the "adjusted support amount" as the subset of total State support up to the date of self-sufficiency. These definitions are illustrated with an example scenario in Figure 34. This study reports on both the maximum and the adjusted support amounts, but takes the adjusted support amount as the indicator of the total cost to the State to support station network development to the point of self-sufficiency.

FIGURE 34: DEMONSTRATION OF SUPPORT AMOUNT DEFINITIONS



Typical results are demonstrated in Figure 35 and Figure 36. The first figure highlights the maximum support amount while the second figure highlights the adjusted support amount. There are several important features of these cash flows to note:

- The year of first annual profit (equivalent to the self-sufficiency date) is independent of the additional State support.
- Similarly, the PPNI and the HRI credit revenue are independent of additional State support.
- The net cash flow with additional State support is typically very similar to the net cash flow without additional State support.
- Although they are included in the figure, LCFS throughput, LCFS HRI, and the additional State support are such a small portion of the overall cash flows that they are nearly indistinguishable in the figure.
- While not visible from these two examples alone, maximum support can typically range from one to approximately ten times the adjusted support amount, depending on the combination of input values used to define the scenario.

FIGURE 35: FULL NETWORK ECONOMIC EVALUATION FOR SAMPLE SCENARIO

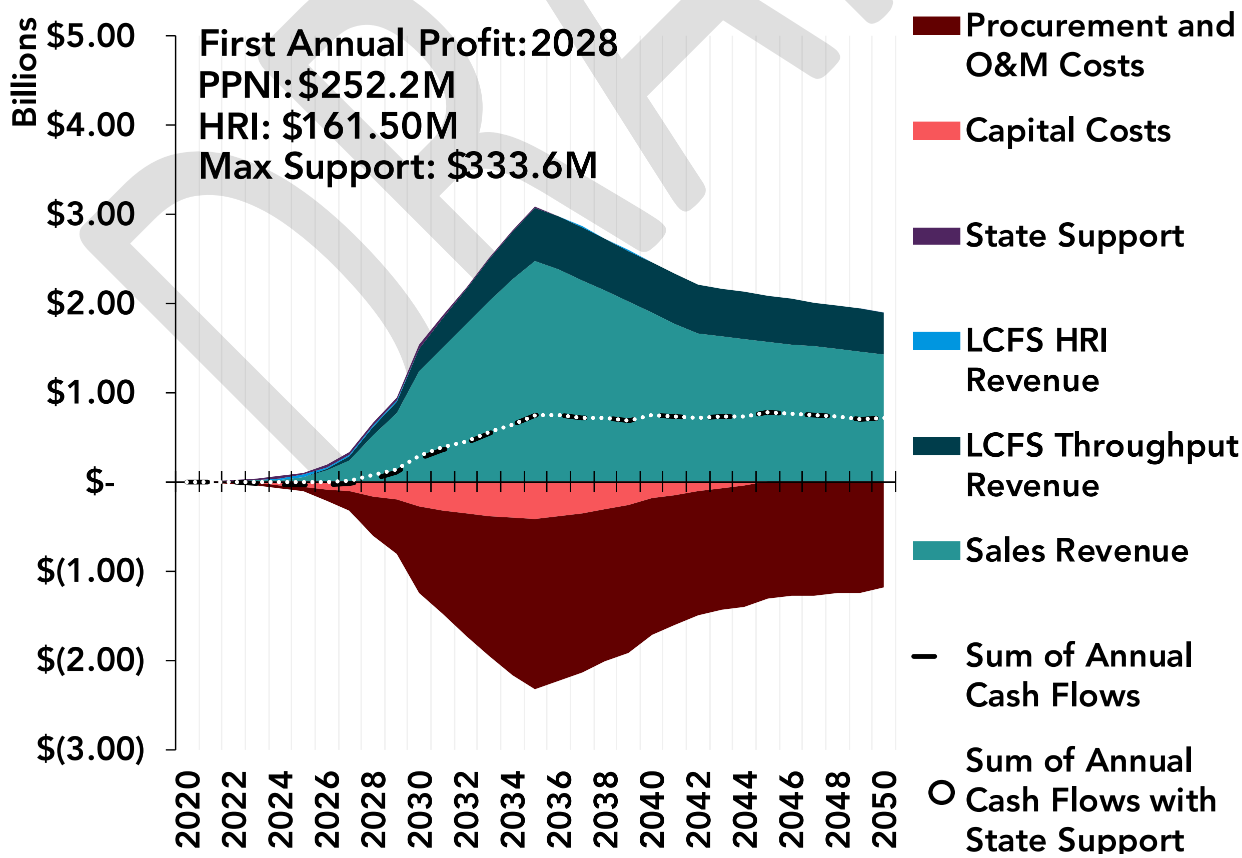
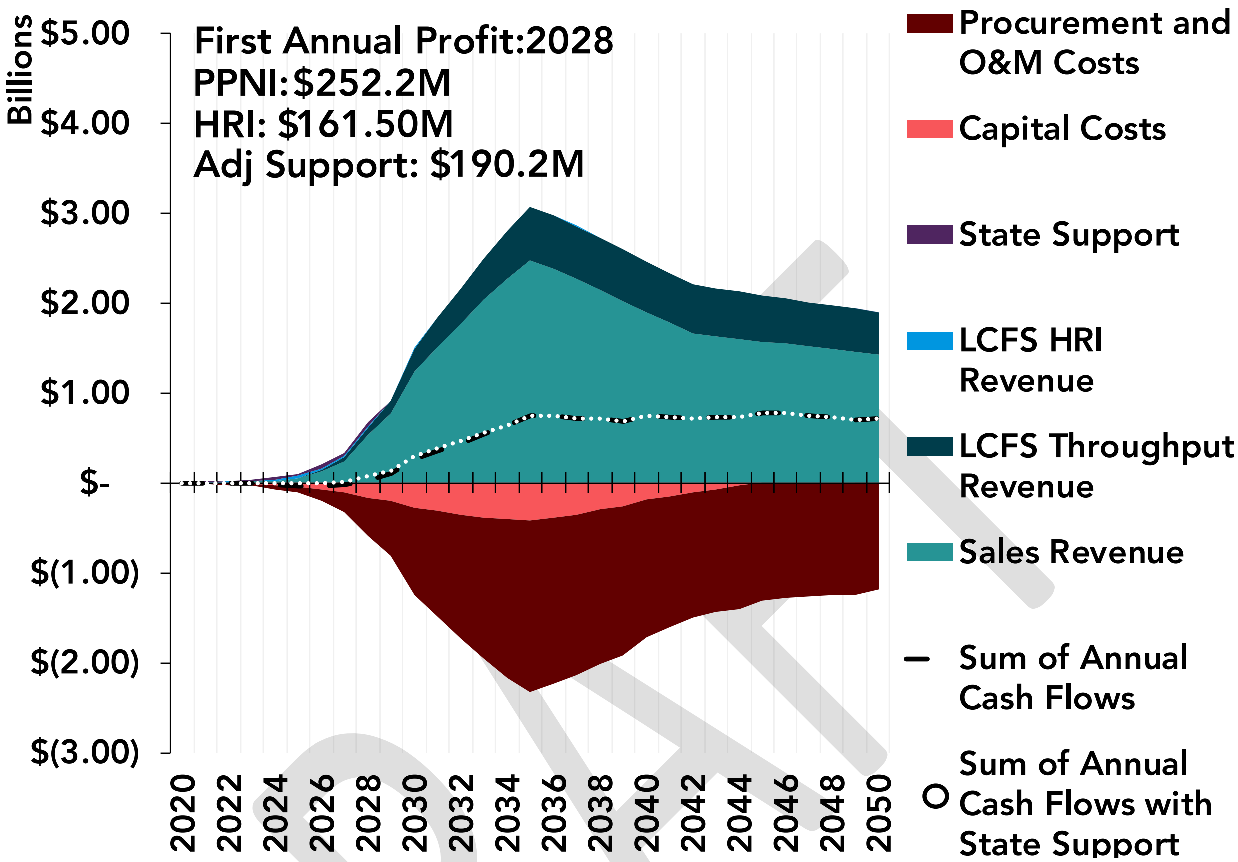


FIGURE 36: FULL ADJUSTED ECONOMIC EVALUATION FOR SAMPLE SCENARIO



Illustrative Results

The effects of changing the various input parameters can be demonstrated by comparing a small set of representative scenarios. The scenarios below are derived from the CAFCR station deployment scenario (see Table 1) with high utilization. In each scenario, specific financial input values were changed to demonstrate the effect that various future development paths may have on the assessment of hydrogen station network self-sufficiency.

- **Scenario A (Industry leads the way):** Industry[5] advancements to reduce costs are extremely rapid (faster perhaps than seen today). While price to the consumer also falls over time, it does not reach gasoline parity[6] until 2040.
- **Scenario B (Parity within the decade):** In an effort to create a more equitable situation for the consumer, the State decides to provide some form of additional support that enables price at the pump to fall sooner, reaching parity around 2030.
- **Scenario C (Government gets ahead of industry):** A State funding program is implemented to enable price parity at the pump by 2030, but industry progress to reduce costs for equipment is slower than expected. The State program additionally absorbs the financial burden due to the slower cost reductions.

These three scenarios represent a range of possibilities for future policy and industry development. All three scenarios achieve self-sufficiency, but do so at different times and with different amounts of additional State support. Figure 37 shows the time and cost to the State for all three scenarios, highlighting their support amounts, self-sufficiency dates, and primary drivers of the station economics in these scenarios.

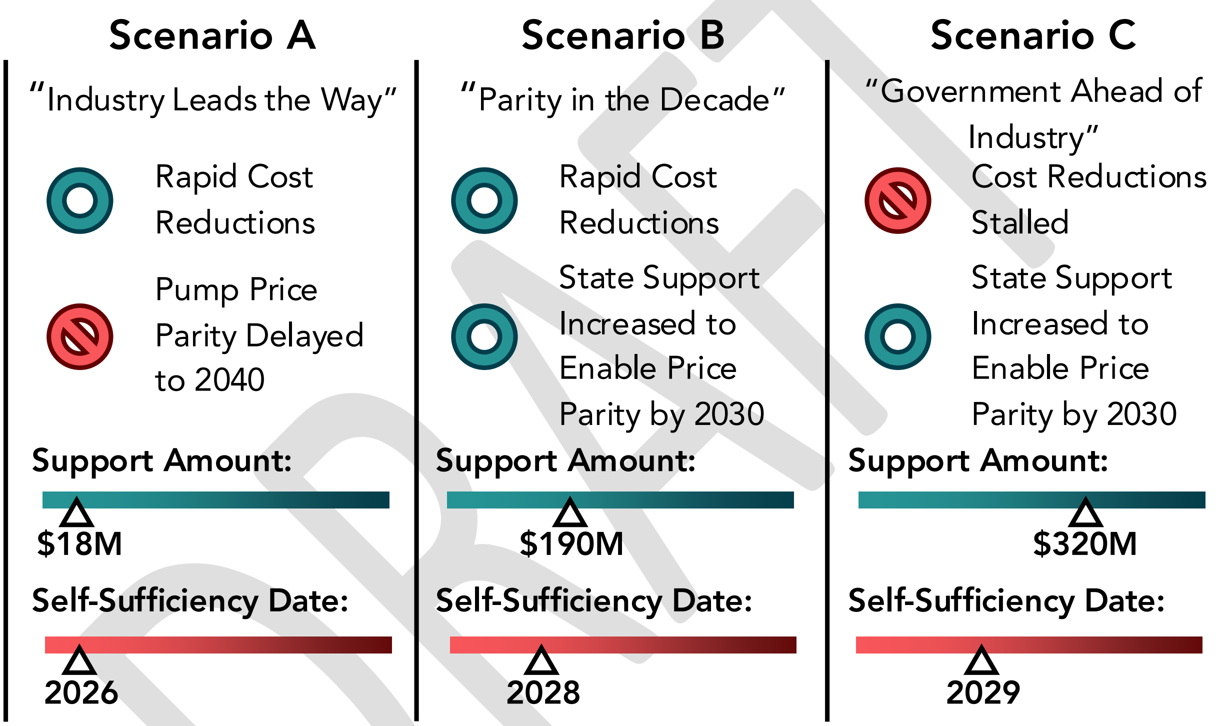
Scenario A models a situation in which industry makes rapid progress in decreasing both the cost to procure hydrogen and the capital costs for equipment. Within this scenario, overall station lifetime costs are low and are balanced well against the revenues from sales of hydrogen (and LCFS credits). Under this scenario, the State essentially does not need to provide any additional funds, and the network will

[5] "Industry" refers to the hydrogen fueling industry in general and includes hydrogen production, transportation, distribution, and sale to consumers. It therefore includes equipment manufacturers and companies that operate related equipment. It does not include the FCEV industry and any impact from reductions of cost to produce an FCEV.

[6] Gasoline parity in this study is with reference to today's gasoline prices and is set at \$8/kg price at the pump; no future gasoline price increase is included in the definition.

achieve self-sufficiency by 2026. However, this scenario assumes essentially all the most optimistic values for the key input parameters. In addition, the profits developed in this scenario are only possible because the price paid by consumers at the pump does not reach parity until 2040, which is likely too late to support large amounts of vehicle deployment. While financially attractive, this scenario may therefore be unviable because it does not represent a fueling market that wells supports the consumer.

FIGURE 37: SELF-SUFFICIENCY DATE AND STATE SUPPORT FOR THREE ILLUSTRATIVE EXAMPLES



Scenario B models a similar situation with the exception that the State seeks to make the experience for fuel cell drivers more equitable. In this scenario, the costs are the same as Scenario A, but the price paid at the pump is forced lower, reaching parity in 2030 and continuing to decrease through 2040. The State then provides funds to recover the loss of revenue at stations. This would cost the State $190M, and network self-sufficiency is postponed to 2028.

Finally, Scenario C models a situation in which the industry costs do not improve as fast, and the State support helps cover this additional cost. Providing support to self-sufficiency then requires $322M through 2029. Scenarios B and C demonstrate the effect that State support can have on achieving consumer-friendly fuel prices and factors that determine the support needed to achieve these goals. Even at a cost of $322M to the State, California's hydrogen fueling network would grow to approximately 1,700 stations by 2035, nearly 1.8 million FCEVs would be on the road, and price parity could be achieved by 2030. Of the 1,700 new stations, approximately 400 would receive State support; the remaining 1,400 would be funded completely by private industry and the existing LCFS credit-generating opportunities.

Figure 38 through Figure 40 portray the full annual financial evaluations for these three scenarios. The HRI credit generation revenue (and the LCFS throughput revenue, though not explicitly highlighted) is the same in all three cases because they all assume the same station network build-out and vehicle deployment. Therefore, demand at stations is the same in all three cases. It is the remaining factors that affect the approach to self-sufficiency. In addition to the differences in self-sufficiency parameters, there is a difference in the potential annual profit between the three cases, with Scenario A settling at a network annual profit of $1.5B in 2050. Scenario B settles at approximately $700M annually and Scenario C settles at approximately $650M annually. In all cases, the PPNI is higher than the additional State support to reach self-sufficiency. This relationship generally holds true for all scenarios investigated and is one metric that demonstrates even significant costs to reach self-sufficiency are not entirely dependent on State support.

FIGURE 38: NETWORK ECONOMIC EVALUATION FOR ILLUSTRATIVE SCENARIO A

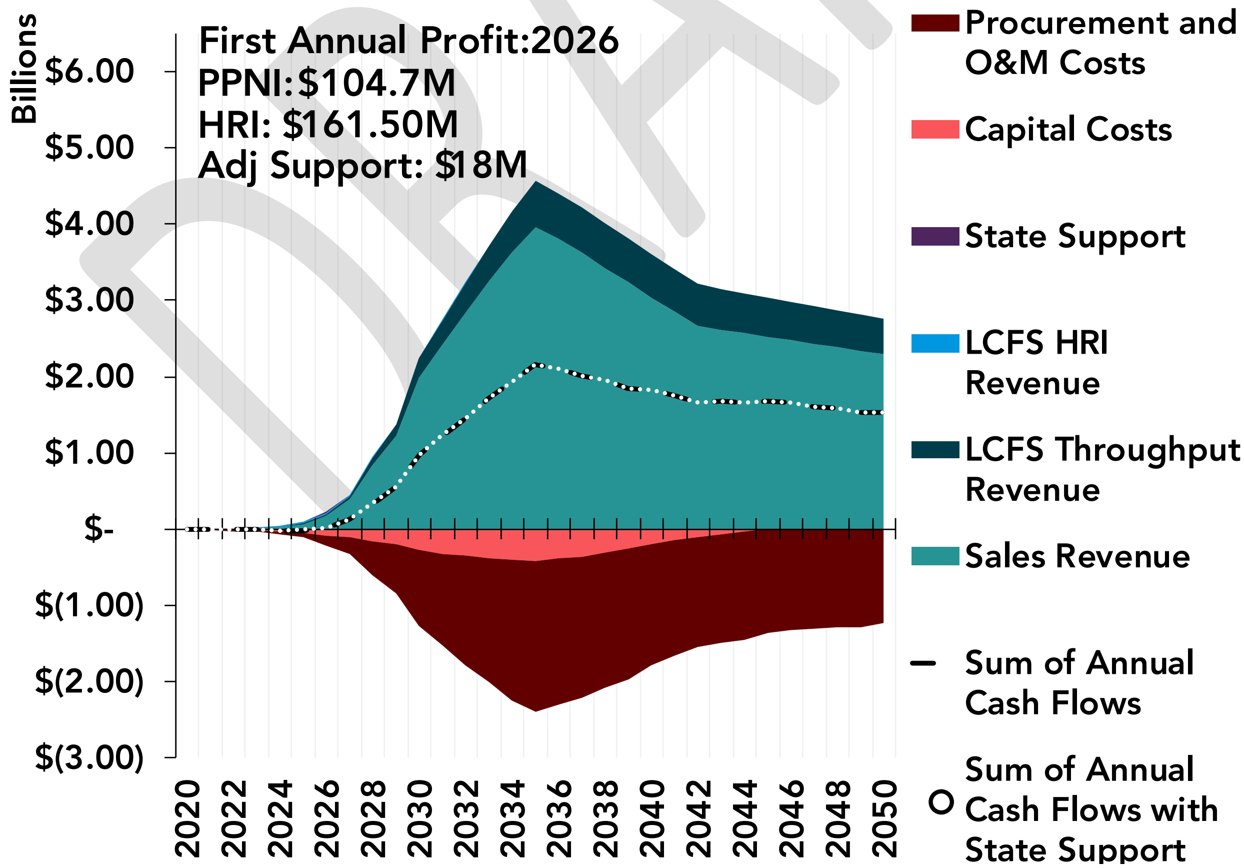


FIGURE 39: NETWORK ECONOMIC EVALUATION FOR ILLUSTRATIVE SCENARIO B

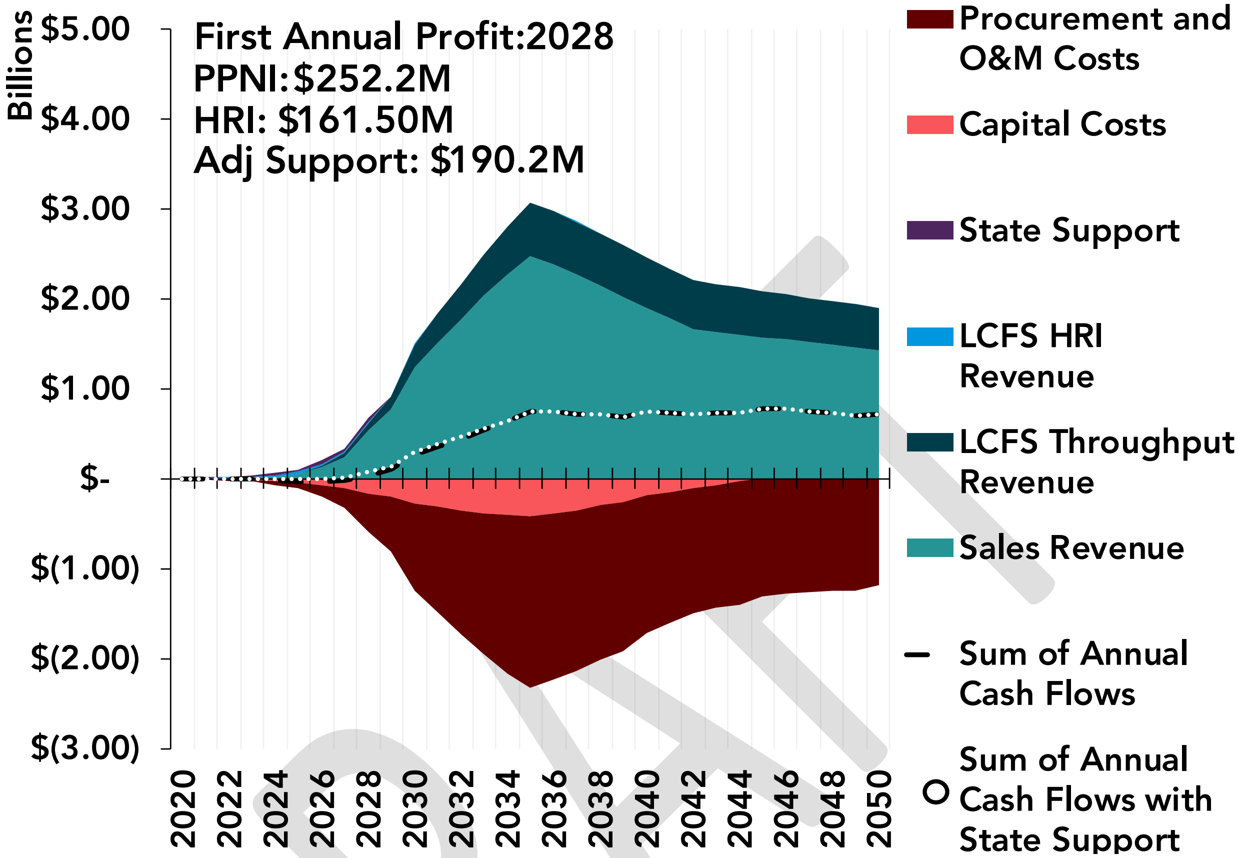
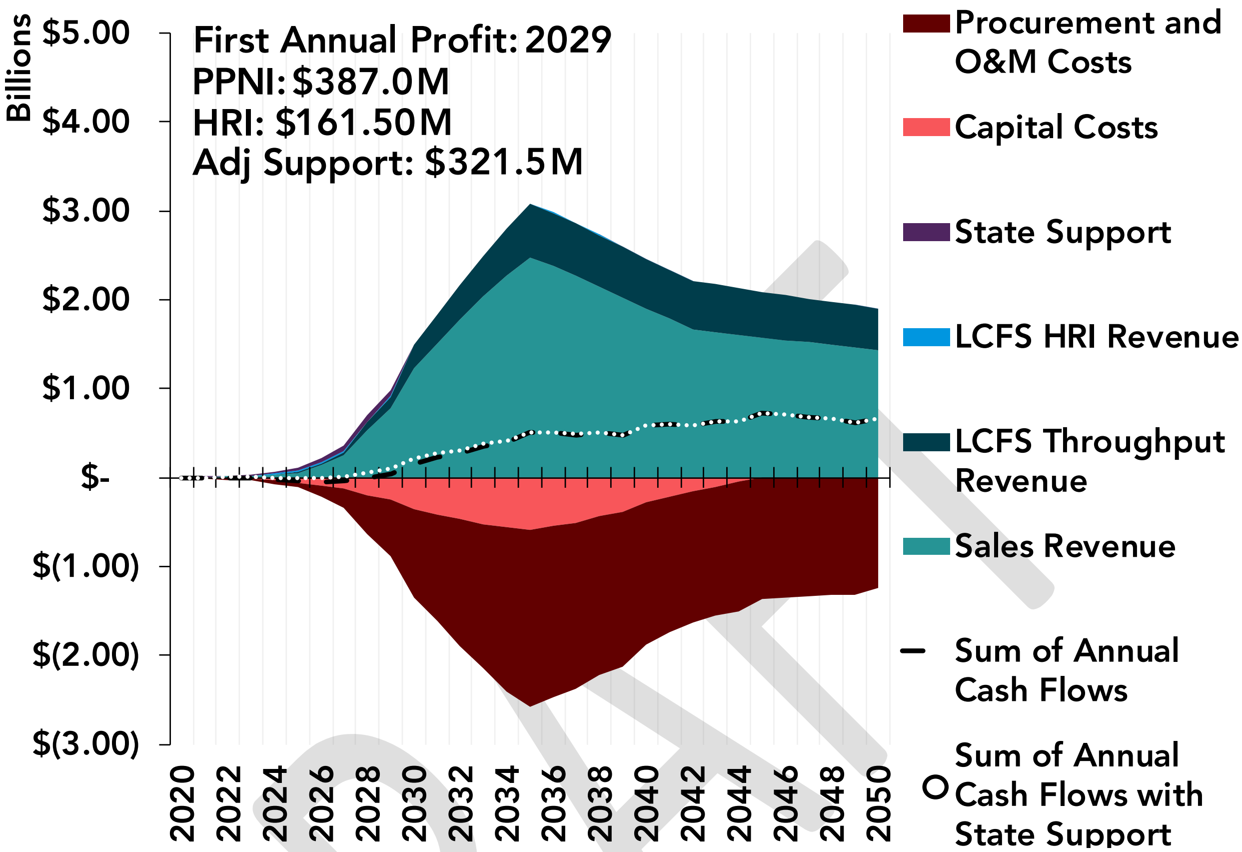


Figure 40: Network Economic Evaluation for Illustrative Scenario C



In addition to the network-wide differences above, each scenario results in different State support needs at the individual station level. Table 5 shows statistics of estimated State support provided to individual stations in the three illustrative scenarios. Scenario A's comparatively low network costs are reflected in the statistics at the per-station level. However, in spite of the network-wide differences between Scenarios B and C, support amounts per station are fairly similar in the two scenarios. The larger network-wide support is therefore due to the larger number of stations that would require additional funds in Scenario C compared to Scenario B.

In addition, Figure 41 demonstrates differences in the stations that receive funding in each scenario. For Scenario A, the majority (80 percent) of State funds would be directed to the smallest stations in the network. In Scenario B, funding shifts more heavily to the 350 kg/day capacity class and is directed at least in a small amount to some of the mid-capacity stations. Scenario C demonstrates the greatest variety in stations receiving State support. Some stations as large as 1,200 kg/day still require additional funds in this scenario.

Table 5: Average and Maximum Support Amount per Station for Illustrative Scenarios[7]

Illustrative Scenario	Average Support ($/Station)	Maximum Support ($/Station)
A	$ 123,000	$ 382,000
B	$ 319,000	$ 667,000
C	$ 289,000	$ 691,000

Figure 42 shows the evolution of profitable stations in the network for each of the three illustrative scenarios. Profitability as shown in the figure is evaluated without the additional State support and demonstrates how individual stations' profitability impacts the amount and timing of additional State support in each scenario. Station profitability is defined according to cumulative cash flows for each station in the network up to the date indicated on the x-axis. Scenario A demonstrates a possible scenario that enables all stations in the network to become profitable and overcome all early costs. However, profitability for every station in the network does not occur until 2045, much later than the self-sufficiency date. The self-sufficiency date is earlier because it accounts for future profit potential (since self-sufficiency is based on a 15-year MIRR). Therefore, this scenario demonstrates a conceptual definition of self-sufficiency that may seem attractive for its certainty but also demonstrates the tradeoffs involved with considering economic performance of hydrogen stations.

Figure 42 also shows that Scenarios B and C have a significant number of stations that never achieve net profitability without additional State support. This is the reason for their higher support amounts and later self-sufficiency date. As shown in Figure 41, these are typically stations in the smaller capacity classifications. Scenario C has the largest number of unprofitable stations with a longer duration before profitability is achieved for many stations in the network. In general, the longer the duration and the greater number of unprofitable stations (without considering additional State support), the later the self-sufficiency date and the larger the support amount.

[7] Statistics limited to stations that receive additional State support

FIGURE 41: COMPARISON OF STATE SUPPORT DISTRIBUTION AMONG STATION CAPACITIES IN ILLUSTRATIVE SCENARIOS

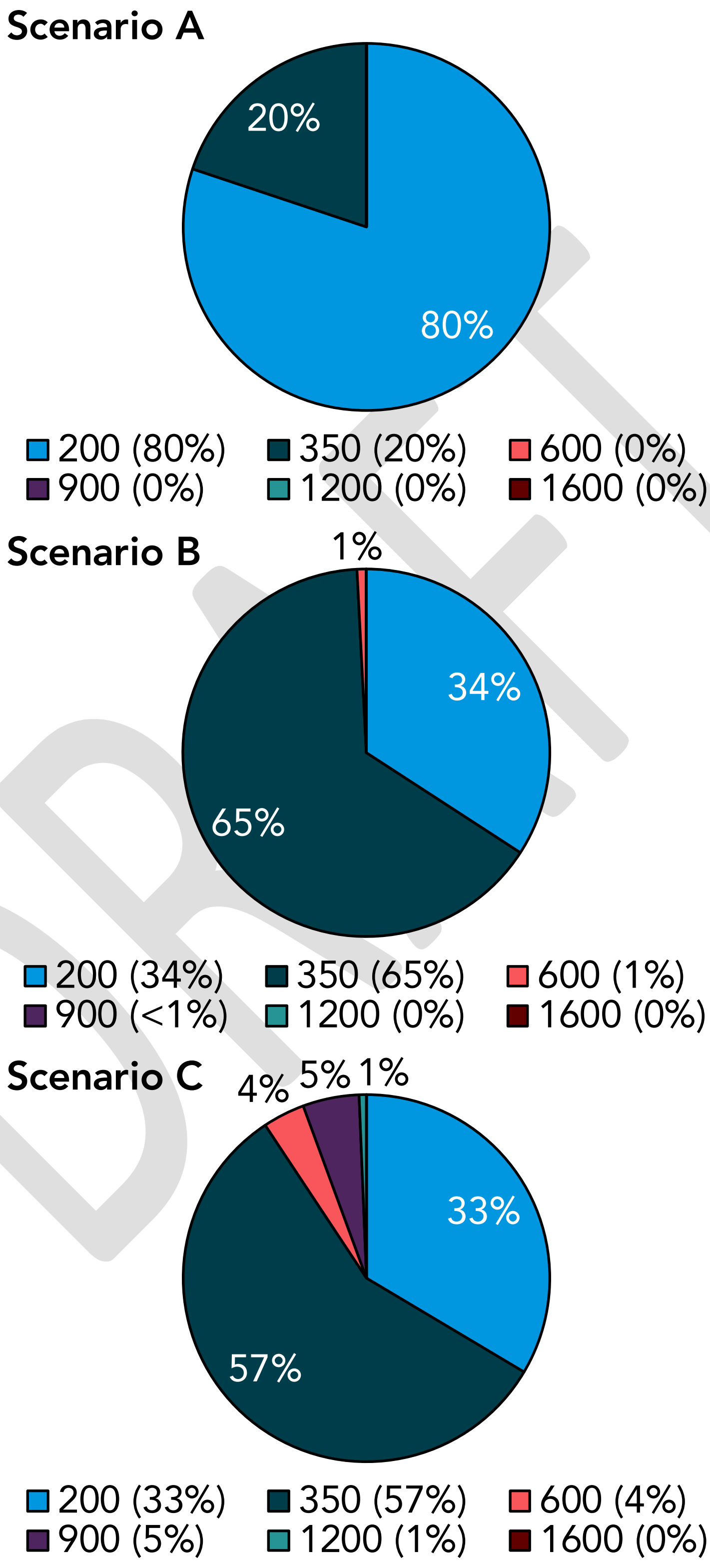


FIGURE 42: COMPARISON OF STATION PROFITABILITY WITHOUT ADDITIONAL STATE SUPPORT IN ILLUSTRATIVE SCENARIOS

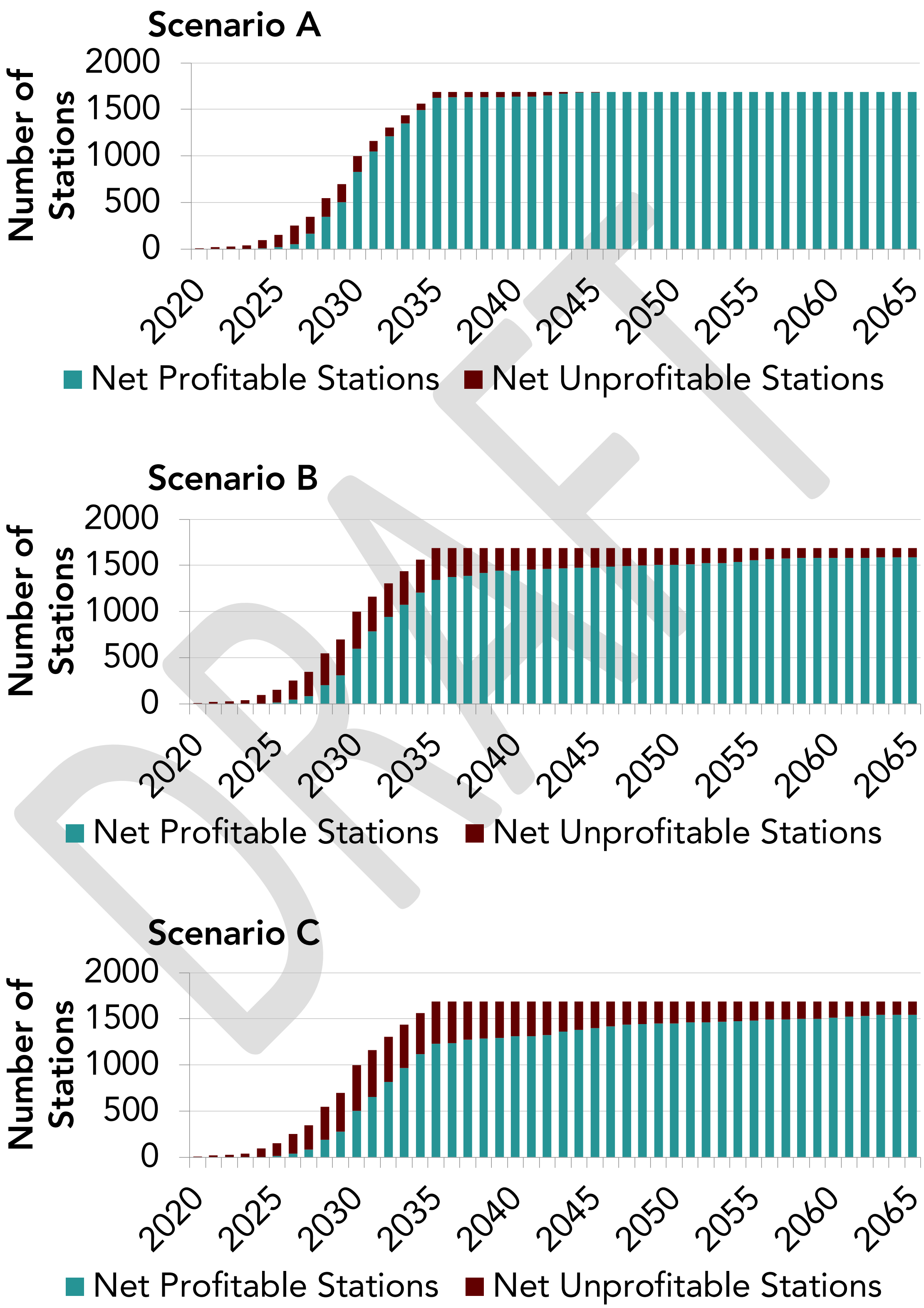
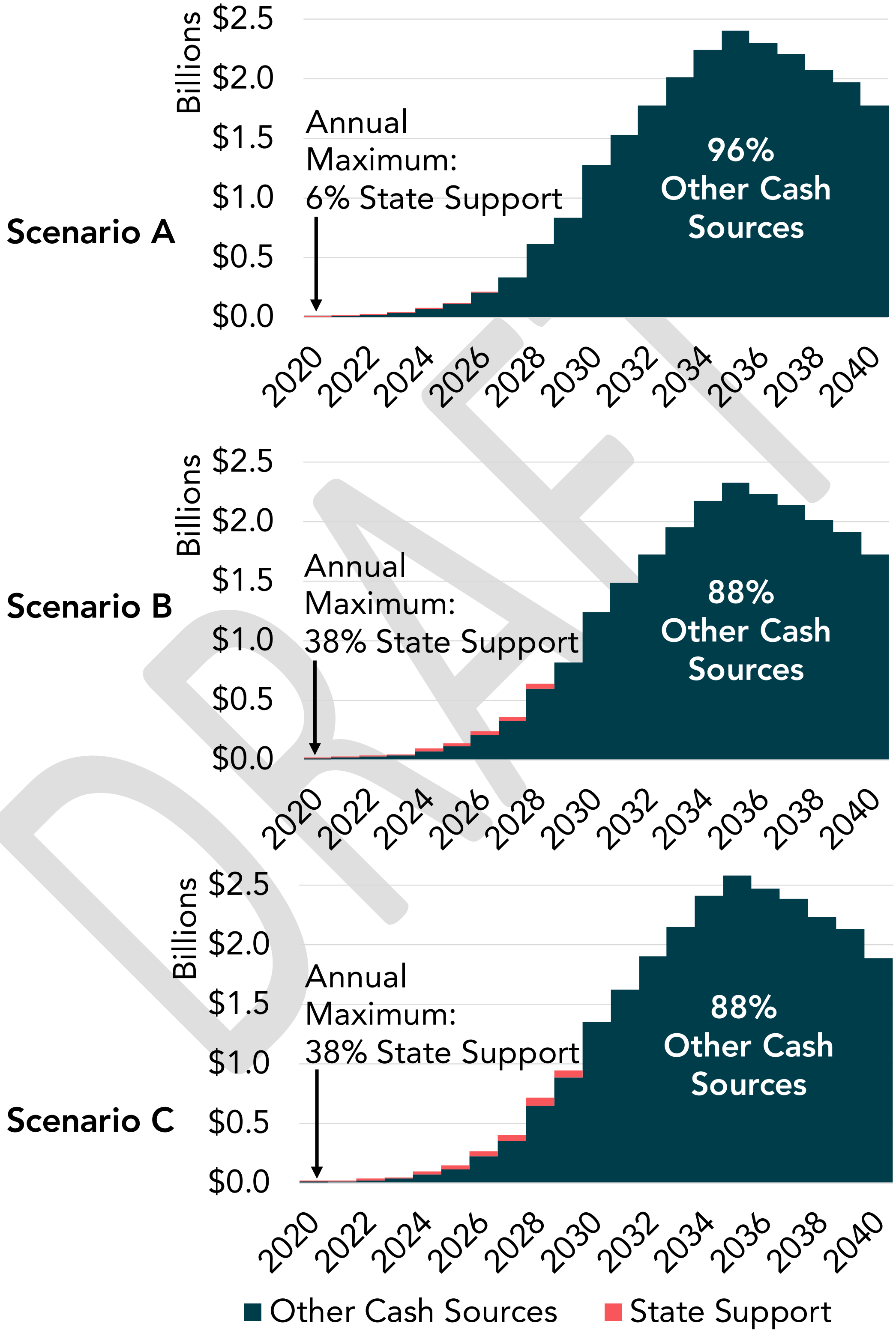


FIGURE 43: COMPARISON OF STATE SUPPORT TO ALL OTHER EXPENDITURES ACROSS ILLUSTRATIVE SCENARIOS



Although Scenario A exhibits essentially no need for additional State support, Scenarios B and C demonstrate a need for significant support amounts. The support amounts in these scenarios are roughly comparable to the total amount that may be funded through the ten years of the existing AB 8 program. They may therefore demonstrate a need for a total State incentive equal to twice the original AB 8 program. The first program delivered the market launch, and the second may be necessary to ensure enduring and stable financial footing of the network, thereby developing a self-sufficient market.

The total funding amount is non-trivial but actually represents a small portion of the total cash that flows into network development in each scenario. Figure 43 displays the annual proportion of cash flow sourced from State support and from other cash sources (the total of capital and operational expenditures across the network in all years). In all scenarios, the highest annual proportion is at the beginning of network development; for Scenario A, the maximum proportion is only six percent, while Scenarios B and C predict 38 percent of cash flows in early years could be sourced from the additional State support. These estimates do not include revenue from either LCSF credit generation opportunity.

However, over the course of the full network development and operation, the State support represents only four percent, twelve percent, and twelve percent of total cash expenditures in Scenarios A, B, and C, respectively. The remainder of funds would come from other (presumably private) sources. These proportions are only representative of the costs for the construction and operation of the station network itself; other costs for hydrogen production and distribution are not included (other than their consideration in operational costs). The majority of the funds for station network development are therefore not sourced from the State, even for the more costly Scenarios B and C.

Verification per Industry Input

Based on surveys and interviews of industry members, several combinations of input variable values could result in individually profitable stations. Insights from the survey and interview process indicate conditions that are deemed most likely to lead to profitable station operations. In order to verify this study's methodology, results from Scenario C were compared to the metrics shown in Figure 5. Scenario C was chosen because the overall network financial performance is well in the mid-range of estimated most likely scenarios (discussed further in the Section "Core Scenario Evaluations"), and the input parameters represent a balance between competing cost and revenue drivers.

All of the parameters in Figure 5 are described via a single value. However, within this study, most parameters typically vary with time and/or between each station. Careful consideration was therefore given to the appropriate metric for comparing each of the parameters between industry member input and the results of Scenario C. In some instances, additional scenarios were investigated with a single deviation from Scenario C to better provide additional insight that aligns the network-wide observations possible through Scenario C with the single-value metrics shown in Figure 5.

For each station, the capacity and capital expenditure do not vary in time. These parameters can be directly compared to the information provided by industry member input. Figure 44 shows station profitability without additional State support, as indicated by the 15-year MIRR, for each value of station capacity. All stations with 200 kg/day capacity exhibit extremely poor economic performance with negative returns. For 350 kg/day stations, a majority also have negative returns, but some have marginally positive returns. At 600 kg/day and above, all stations demonstrate returns, with greater improvements at higher capacities. These results are tightly matched to the industry member survey results, which essentially indicated daily fueling capacity of 400 kg/day or more may be necessary to develop profits. Figure 45 demonstrates the benefits of additional State support. Including this additional funding, all stations at least provide a minimum return, regardless of size. At the same time, mid-range returns become more common while the number of stations showing the highest returns remains the same as without the State aide. This demonstrates the intended outcome that State support assists only the stations most in need.

FIGURE 44: STATION MIRR WITHOUT STATE STUPPORT BY FUELING CAPACITY

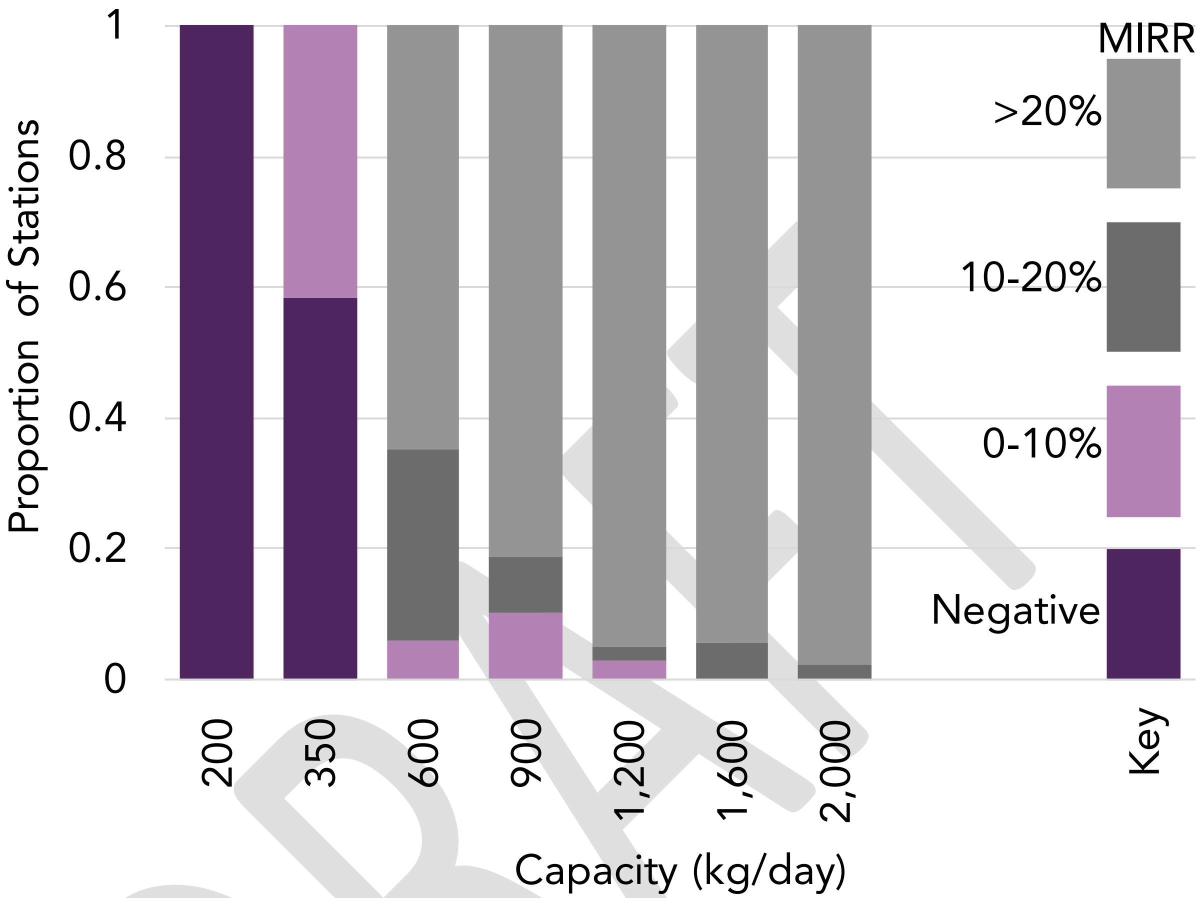
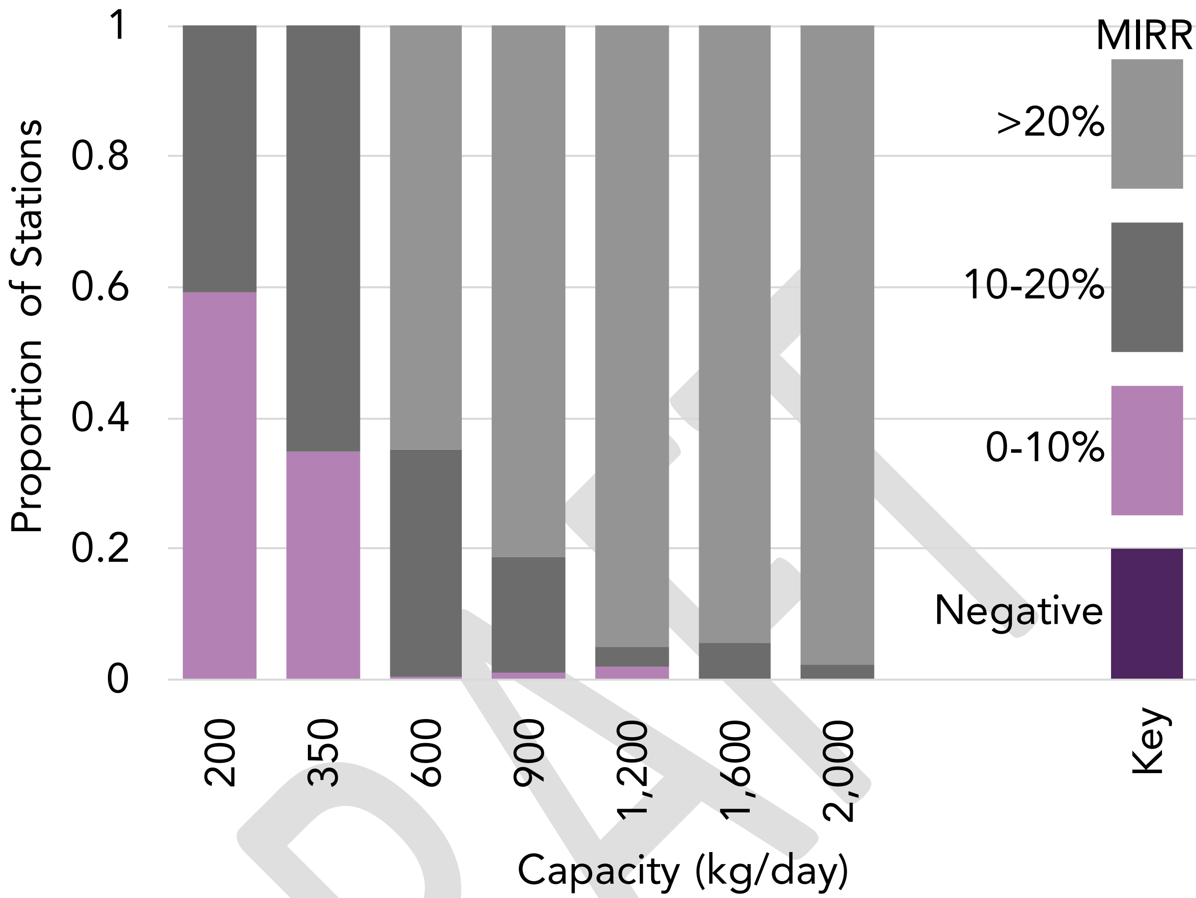
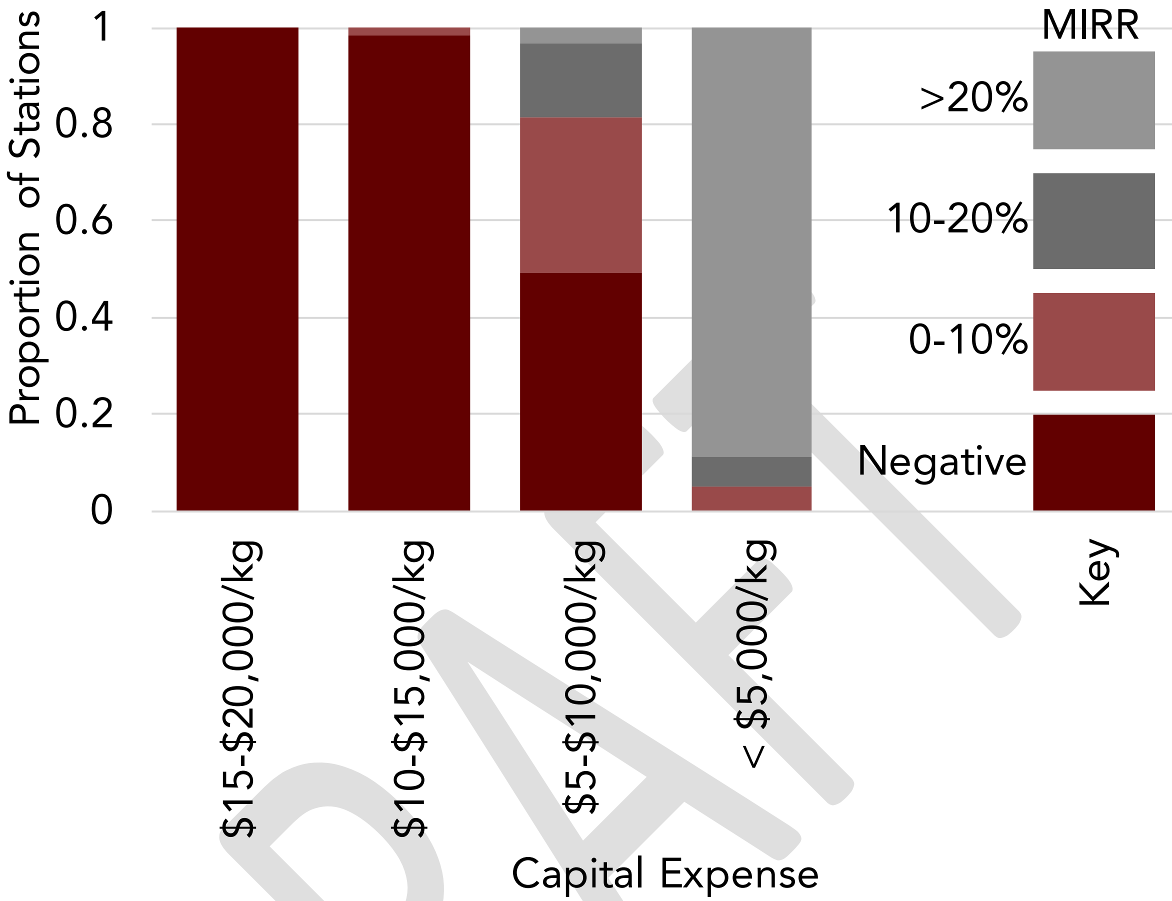


FIGURE 45: STATION MIRR WITH STATE SUPPORT BY FUELING CAPACITY



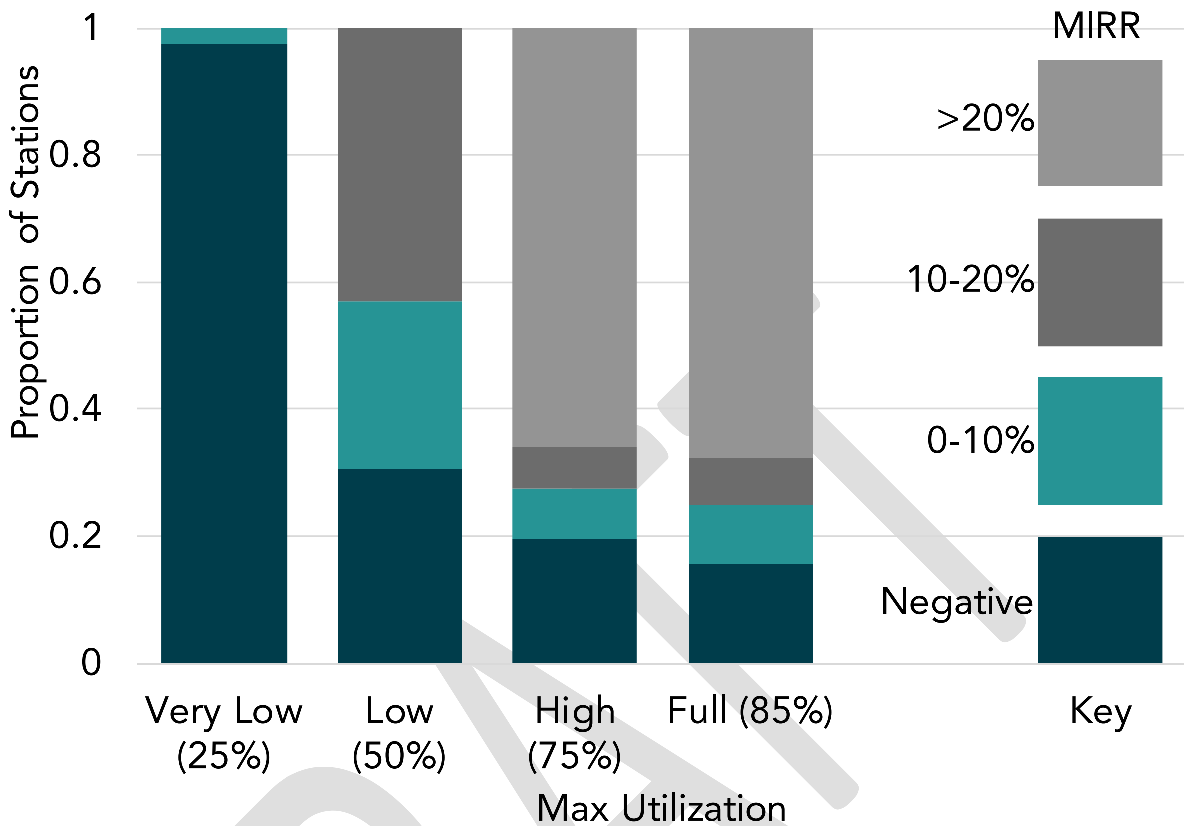
Variations in profitability are shown in Figure 46 as a function of station capital expense. Industry member feedback indicated that capital costs up to $10,000/kg were the most likely to enable profitable station operations. Some industry members did indicate capital costs as high as $20,000/kg could still lead to profitability. Indications from the example of Scenario C point to similar findings, though the study results indicate much lower chance for profitability at higher station capital costs. In fact, for the highest category of capital cost ($15,000-$20,000/kg), no stations provide a return without additional State support. Even at $10,000-$15,000/kg, there are only a few stations that provide a return. However, there are also only seven stations in this scenario that fall into the highest cost bin and 117 (7 percent of all stations) in the second-highest bin. This is likely driven by the scenario's high dependence on larger stations, which have a lower capital expense per kilogram of capacity by definition. This parameter therefore seems in agreement with industry survey results, though slightly more optimistic.

FIGURE 46: STATION MIRR WITHOUT STATE SUPPORTBY CAPITAL EXPENSE



For each station in Scenario C, utilization changes with time; therefore, no single value of utilization completely represents each station. In order to assess the dependence of station profitability on utilization, additional modified scenarios were evaluated and compared to Scenario C. Scenario C assumes Full maximum utilization at 85 percent. Modified scenarios that assume each of the other utilization definitions, and keep all other input assumptions the same as Scenario C, were also evaluated. Industry members did not indicate any utilization rate below 50 percent as viable for a profitable station, and this is verified by the results of Figure 47, which show essentially no stations with positive return rates at Very Low (25 percent maximum) utilization. At Low (50 percent maximum) utilization, profits are also limited, with only 40 percent of stations demonstrating mid-range rates of return. Return rates at High and Full (75 to 85 percent maximum) utilization are fairly equivalent, which also matches well with the relative industry response for these levels of utilization.

FIGURE 47: STATION MIRR WITHOUT STATE SUPPORT BY UTILIZATION



The remaining factors described in Figure 5 (price paid at the pump, hydrogen procurement cost, and operations and maintenance cost) all vary by individual station and along trajectories determined by time. These metrics therefore cannot be directly compared between the results of Scenario C and the single-value indications of Figure 5. In order to make equivalent comparisons, additional scenarios and alternative summary metrics were required. Comparison between scenario C and these additional evaluations provides the necessary insight to make a more direct comparison to Figure 5. The methods to formulate this comparison varied among the metrics and is detailed in the following discussion.

For example, Figure 48 shows the return rates for stations in Scenario C as a function of the price at the pump in the first year in which each station develops an annual profit. This may at first appear to be a convenient indicator of the minimum condition for profitability. After all, Figure 48 does indicate a strong tendency for profits to depend on hydrogen sale price above $8/kg, similar to the results of Figure 5. However, other aspects of the results do not align well with Figure 5. For example, this grouping shows no stations in the >$15kg category even though survey results indicated this price point as a possibility. This mismatch occurs because all stations in Scenario C achieve profitability after several years of operation, when price at the pump has dropped below $15/kg. Grouping stations by the price of hydrogen on one particular day doesn't capture the full impact of the progressive price reduction assumed in Scenario C. This grouping may therefore lead to misleading interpretation of station return rates.

In order to remedy this discrepancy, additional evaluations were performed following all assumptions of Scenario C with the exception that price at the pump was held constant at either \$5, \$8, \$12, or \$15/kg. Figure 49 shows return rates for these modified scenarios. The results of Figure 49 more closely match the full range of industry survey responses in Figure 5 while demonstrating the greater likelihood for hydrogen price at \$8/kg and above leading to profitability.

FIGURE 48: STATION MIRR WITHOUT STATE SUPPORT BY CUSTOMER-FACING SALE PRICE

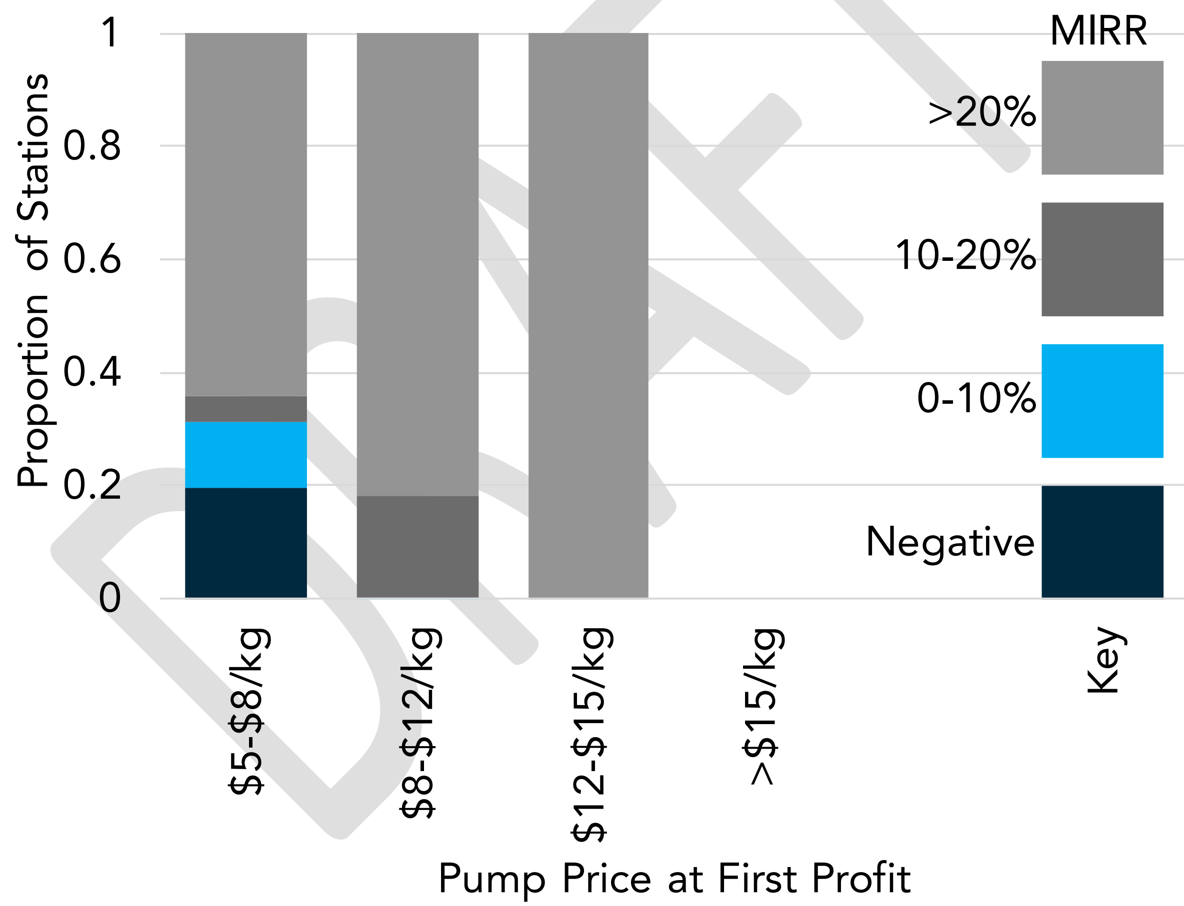
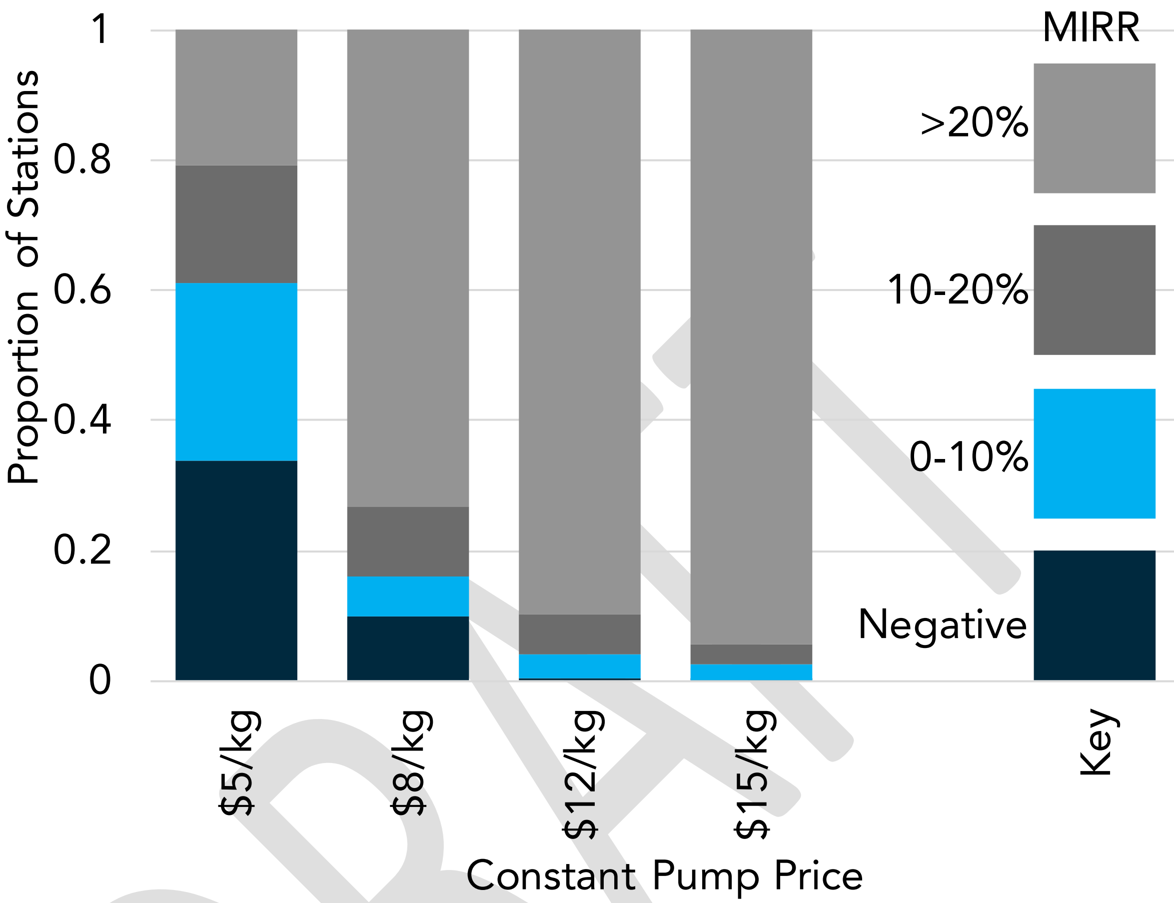


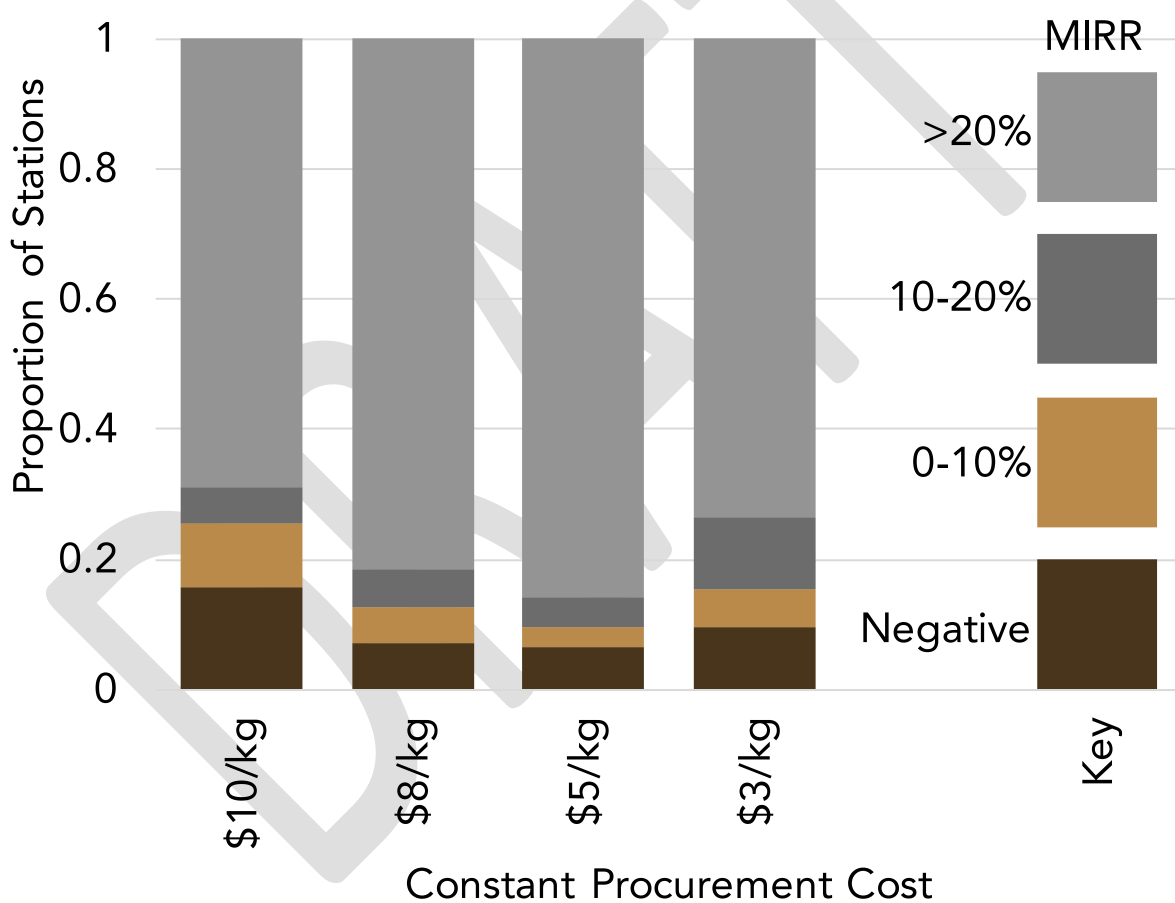
FIGURE 49: STATION MIRR WITHOUT STATE SUPPORT BY CUSTOMER-FACING SALE PRICE UNDER CONSTANT PRICE MODIFIED SCENARIOS



As discussed in the Section "Highlights from Industry Member Input", multiple combinations of hydrogen sale prices and costs (procurement, operations and maintenance, and capital expense) can lead to station profitability. The key consideration to determine profitability is not the value of any one of these parameters on their own, but rather the balance between the costs and revenues indicated by these parameters together. In order to demonstrate this behavior with this study's methodologies, modified evaluations were performed based on Scenario C. These modified scenarios made two changes from input parameters of Scenario C. The first change was to assume a constant hydrogen procurement cost at all times and for all stations at either $3, $5, $8, or $10/kg. Second, the rate of reduction in price paid at the pump was varied based on the hydrogen procurement cost. The pump price trajectory for each procurement cost case was selected from the cases in Figure 29, such that price at the pump showed the fastest reductions possible while maintaining price above hydrogen procurement cost. For example, with hydrogen procurement cost set to $8/kg, the High price trajectory in Figure 29 was selected because the Parity price trajectory does not maintain sale price above procurement cost in all years.

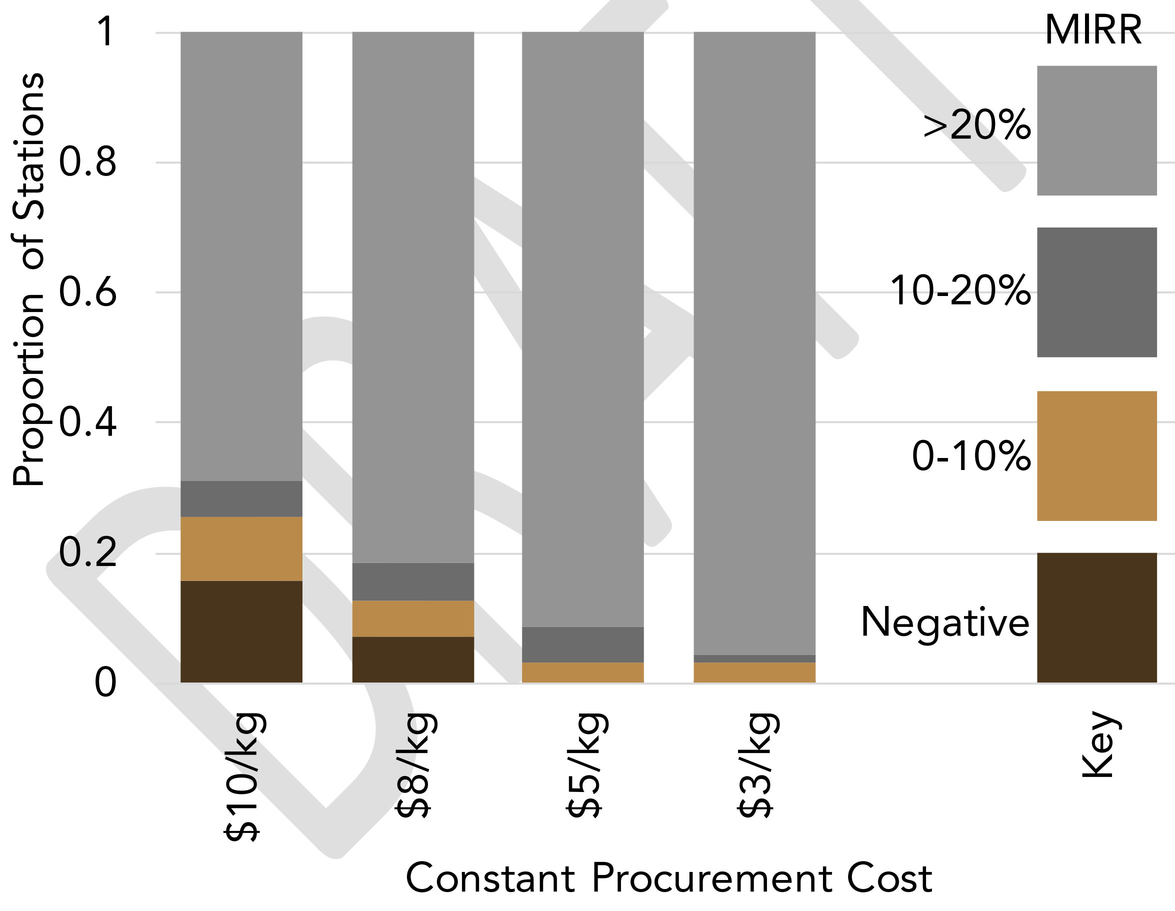
Figure 50 shows the rates of return for these evaluations modified from Scenario C. While the individual hydrogen procurement costs and sale prices vary between the four scenarios, the distribution of return rates are similar. Thus, the methodology of this study replicates the industry members' observations that the balance between costs and revenues is a more important indicator of station profitability than any single component of costs or revenues alone.

Figure 50: Station MIRR without State Support by Hydrogen Procurement Cost under Constant Cost Modified Scenarios



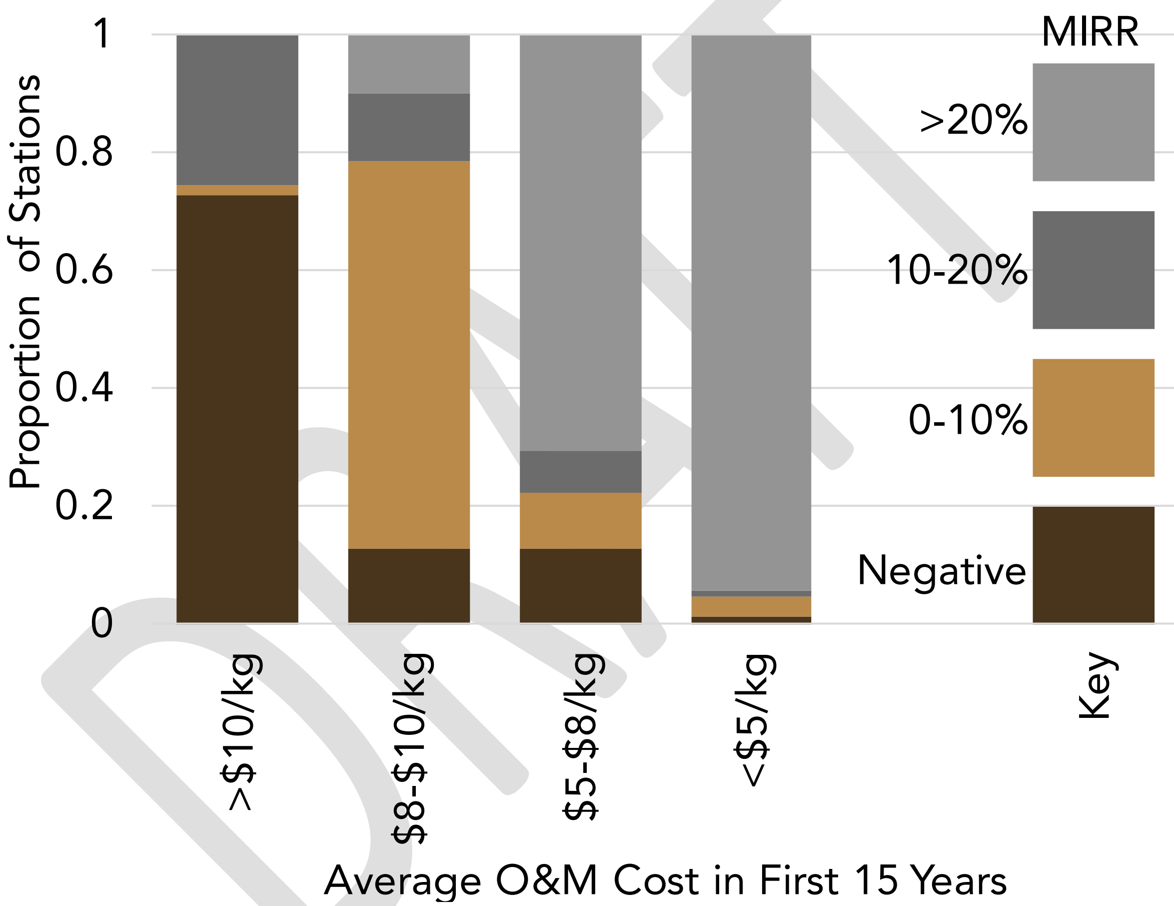
In order to verify the relationship between profitability and the individual factor of hydrogen procurement costs, additional modified scenarios were evaluated with the same procurement costs of $3, $5, $8, and $10/kg and the sale price set to $12/kg. This methodology provides evaluation of the impact of procurement costs without any constraint due to the hydrogen sale price (since it is higher than all procurement assumptions) and without the complication of sale price variations between scenarios. These results share important features with the industry member input. While hydrogen procurement costs of $3/kg provide the most attractive potential rates of return, costs this low are not entirely necessary. Procurement costs at $5/kg similarly eliminate unprofitable stations and even procurement costs at $8/kg only indicate seven percent of stations unable to develop a profit. Industry responses largely considered costs as high as $10/kg as viable, and the results of Figure 51 demonstrate a high likelihood for profit under these conditions, as well.

Figure 51: Station MIRR without State Support by Hydrogen Procurement Cost under Constant Cost and $12/kg Sale Price Modified Scenarios



Station operations and maintenance costs are affected by declining cost trajectories in time, but also include fixed cost factors with no variation. Therefore, additional scenario evaluations do not provide any additional insights with respect to the variation in station economic performance as a function of operations and maintenance costs. In order to develop a comparison to the industry survey responses in Figure 5, return rates were evaluated as a function of the average operations and maintenance cost over the first fifteen years of station operation (the timeline of MIRR evaluation). Figure 52 indicates return rates that are largely in agreement with industry feedback. At operations and maintenance costs above $10/kg, the majority of stations provide zero to little positive returns. At $8-$10/kg (the highest amount indicated by industry members), the number of stations demonstrating positive returns increases dramatically. At even lower operations and maintenance costs, average return rates increase and below $5/kg, almost no stations exhibit negative return rates.

FIGURE 52: STATION MIRR WITHOUT STATE SUPPORT BY OPERATIONS AND MAINTENANCE COST



These evaluations indicate that while there are some differences at the extremes for some parameters, results based on this study's scenario evaluation methodology largely agree with the prior indications from industry members. To some extent, this should be the case given that the prior industry member input helped inform and shape several of the input value trajectories. Still, industry input was not the only data that informed input variables and so the outcomes for individual stations did not always match industry survey responses. However, the aggregate station financial performance in this study has been shown to reflect industry-provided data.

Core Scenario Evaluations

The evaluations presented in the chapter "Illustrative Results" serve as useful demonstrations of the overall evaluation process and individual station financial performance. However, they represent only three of the more than 840 scenario evaluations completed in this study. The majority of scenario evaluations explore the range of possible outcomes based on the several input variable trajectories described in the chapter "Input Variables and Values". Of the 840 scenarios evaluated, CARB identifies a subset of 180 scenarios as the Core Scenario Evaluations. These 180 scenarios are all based on CAFCR deployment with either Full or High utilization rates and explore all the previously described core input variable settings. These Core Scenarios represent desirable and coordinated station network development and FCEV deployment based on published estimations of successful industry development. CARB interprets these evaluations as central cases within this study. This chapter explores these Core Scenarios.

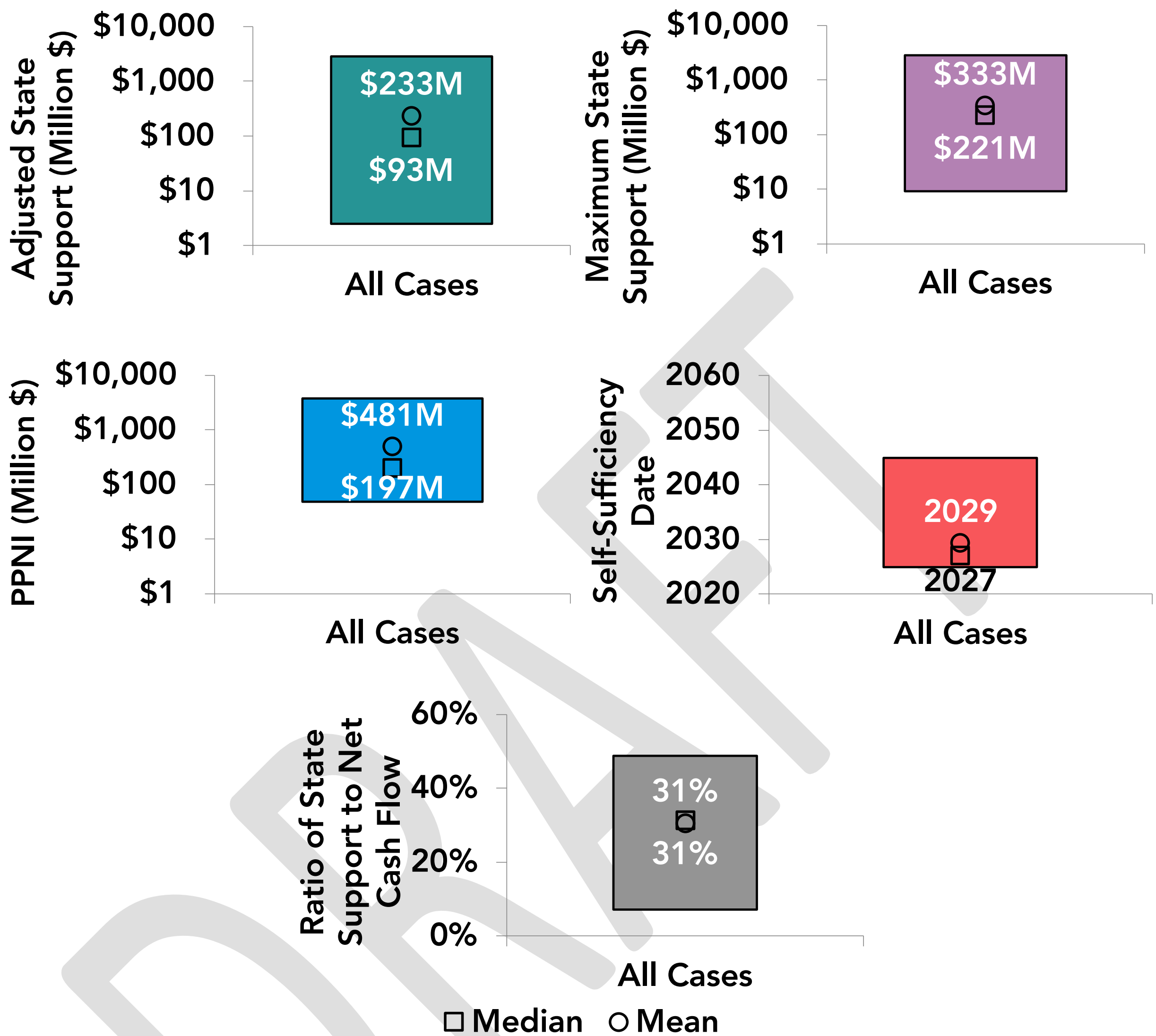
Primary network-wide metrics for the Core Scenarios are presented in Figure 53. Note that the y-axis in Figure 53 (and other similar figures presented throughout this report) is on a logarithmic scale and in units of millions of dollars. The numerical values highlighted in each figure relate to the mean and median values in each chart. Within the Core Scenarios, the adjusted State support ranges from essentially zero to nearly $3B, with mean and median values of $233M and $93M, respectively. The self-sufficiency date ranges from 2025 to 2045 with mean and median values of 2029 and 2027, respectively. The ratio of State support to Net Cash Flow through the self-sufficiency date is defined as:

$$\frac{State\ Support}{(State\ Support + PPNI)}$$

which provides a sense of the importance of State Support in overall network development cash flows[8]. This metric shows central estimates of 31 percent and ranges from seven percent to forty-nine percent.

[8] Note that this definition inherently indicates higher State proportion of funds than the definition used in Figure 43. PPNI is the net cash flow between expenditures and revenues, whereas Figure 43 did not account for revenues from fuel sales or LCFS credit generation opportunities. PPNI is by definition less than the total industry cash flows. This ratio's definition is based on PPNI to intentionally account for the balance of industry cash flows rather than the raw total expenditures.

FIGURE 53: KEY SUMMARY RESULTS ACROSS CORE EVALUATIONS



These results demonstrate the high degree of variability in economic outcomes depending on the assumed variable inputs. Figure 54 displays the distribution of self-sufficiency dates for the subset of 90 scenario evaluations with a maximum MIRR of 15 percent (there was minimal observed difference between cases with maximum MIRR at 15 or 10 percent). While the self-sufficiency date estimates range from 2025 to 2045, most results cluster between 2025 and 2035 (only seven percent of results are in the period 2035 to 2045). The self-sufficiency date appears to have little dependence of the particular scenario, except for extreme cases. CARB staff therefore estimate that the most likely self-sufficiency date from the Core Scenario results is between 2027 and 2030.

On the other hand, Figure 55 shows that the adjusted support amount for the same subset of 90 scenario evaluations is more evenly distributed across its range. The largest potential costs appear to be outliers, but there are still some relatively high costs that are not as rare. As Figure 55 indicates, CARB staff estimate that the range of most likely cost to achieve self-sufficiency is between $100M and $400M, which includes 60 percent of the scenario evaluations.

FIGURE 54: DISTRIBUTION OF SELF-SUFFICIENCY DATE ACROSS CORE SCENARIO EVALUATIONS

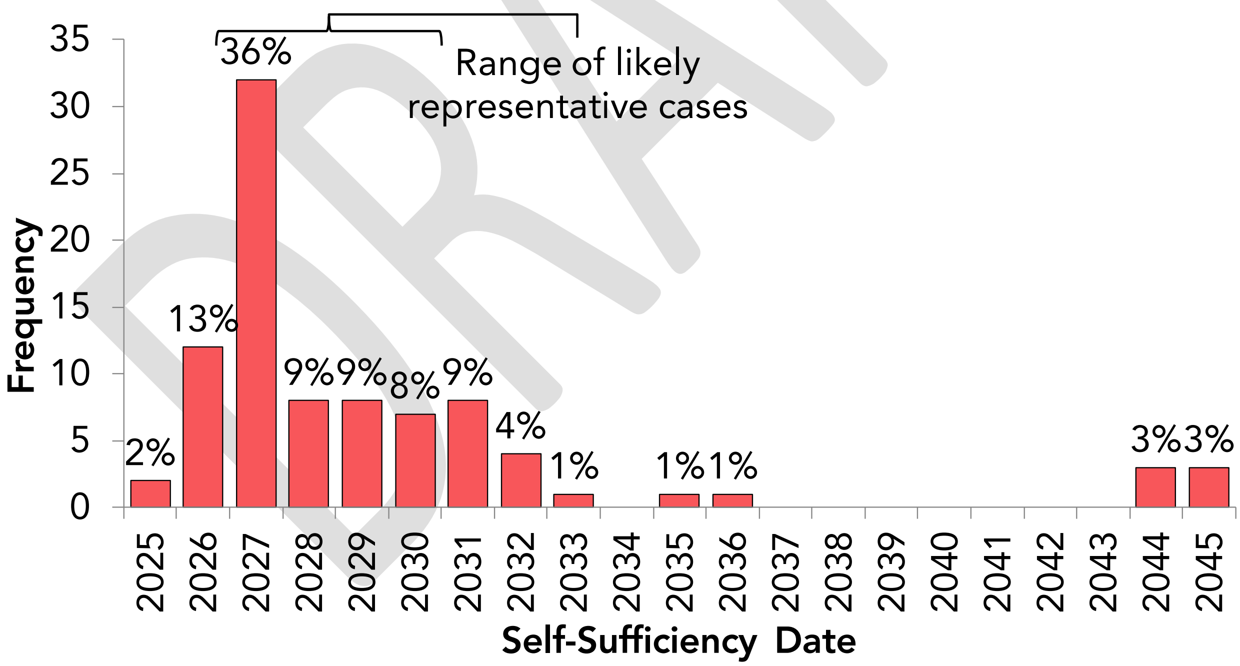
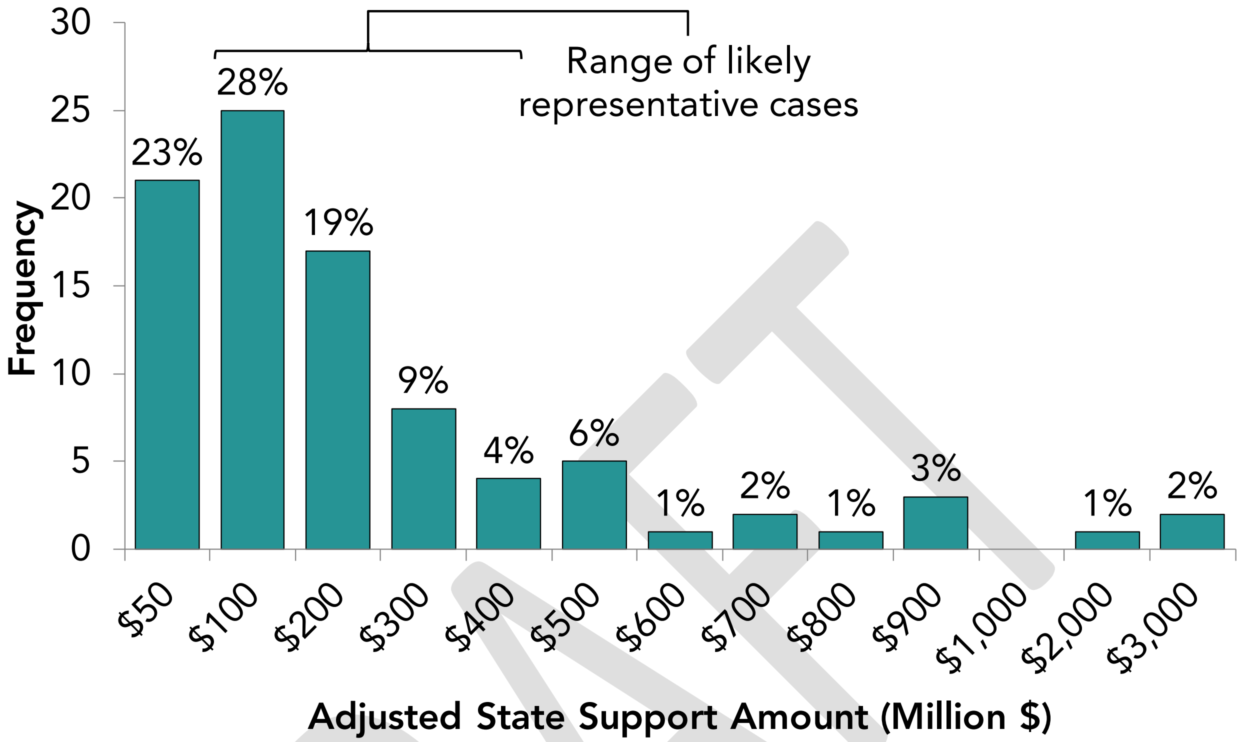


FIGURE 55: DISTRIBUTION OF ADJUSTED SUPPORT AMOUNTS ACROSS CORE SCENARIO EVALUATIONS



The range of likely representative cases for the total State support to achieve self-sufficiency in these Core Scenarios is based on consideration of the input variable values for the scenarios. Figure 56 shows the scenarios binned by a "Profitability Score" and ranges of adjusted support amount. The Profitability Score is a simple count of the number of input values in each scenario that lend themselves more strongly towards profitable stations. This serves as a simplified gauge for how biased the input variables may be in any given scenario evaluation. Table 6 provides the definition of the Profitability Score as determined by input variables.

Scenarios within the likely representative support range of $100-$400M are correlated with all but the most extreme high and low Profitability Scores. State support amounts less than $100M or more than $400M are associated with scenarios that have variable inputs skewed towards High or Low Profitability Score. No scenarios with State support below $100M are associated with Profitability Scores of zero or one, and more than half of these scenarios are associated with Profitability Scores of four and above. Scenarios with adjusted support amounts above $400M appear to be even more heavily skewed, comprised only of scenarios with Profitability Score between zero and three. Therefore, the range $100-$400M appears to demonstrate the most balanced inclusion of potential scenario inputs.

A significant number of scenarios with high Profitability Scores represent desirable profit potential and minimized State cost, but do so at the potential expense of the consumer. For example, high-Profitability cases include scenarios with high vehicle deployment (and therefore station utilization), the fastest equipment cost reductions, the fastest growth rate in individual station utilization, but a slow pace of reducing price at the pump. The optimistic assumptions about industry progress to reduce costs are therefore not shared with the consumer in these cases. The more moderate cases within the likely representative range are not only more balanced in their assumptions but also enable faster reduction in price at the pump to achieve more sustainable consumer market development.

FIGURE 56: DISTRIBUTION OF ADJUSTED STATE SUPPORT BY PROFITABILITY SCORE

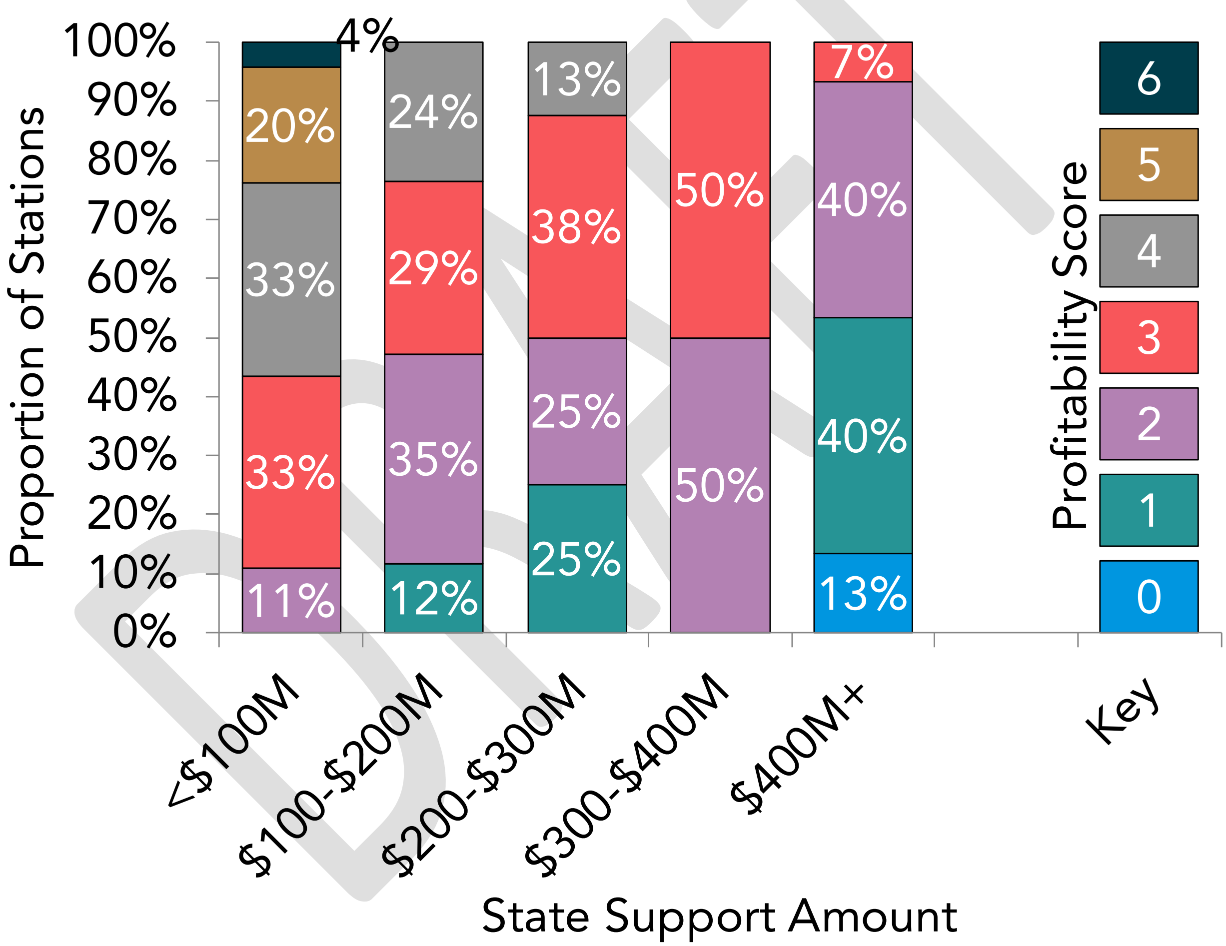


TABLE 6: PROFITABILITY SCORE DEFINITIONS

Cost-Price Pairing	Maximum Utilization	Capital Cost Learning	Individual Utilization
Low-Low: +1 Low-Parity: +2 Medium-Parity: 0 High-Parity: 0 High-High: +1	High: 0 Full: +1	HSCC Slow: 0 HSCC Fast: +1 Moore's: +2	Heuristic: 0 All Others: +1

Each Core Scenario also indicates a varying number of stations that would receive State support to achieve self-sufficiency. Even though all scenarios assess the financial performance for a network that grows to approximately 1,700 statiosn by 2035, most scenarios indicate that the majority of those stations will not require additional State support. Figure 57 shows the distribution of the number of stations that receive State support, along with the scenarios' associated Profitability Score. The most common estimate is up to 300 additional stations (beyond the 64 assumed as the initial condition in this study) receive State support. Considering the distribution of the Profitability Score, CARB estimates that the most likely values are between 200 and 400 additional stations. Therefore, a total of approximately 350 stations beyond the 100-station minimum requirement of AB 8 or 250 stations beyond the 200-station target of EO B-48-18 could receive State support.

FIGURE 57: DISTRIBUTION OF NUMBER OF STATIONS RECEIVING STATE SUPPORT BY PROFITABILITY SCORE ACROSS CORE SCENARIO EVALUATIONS

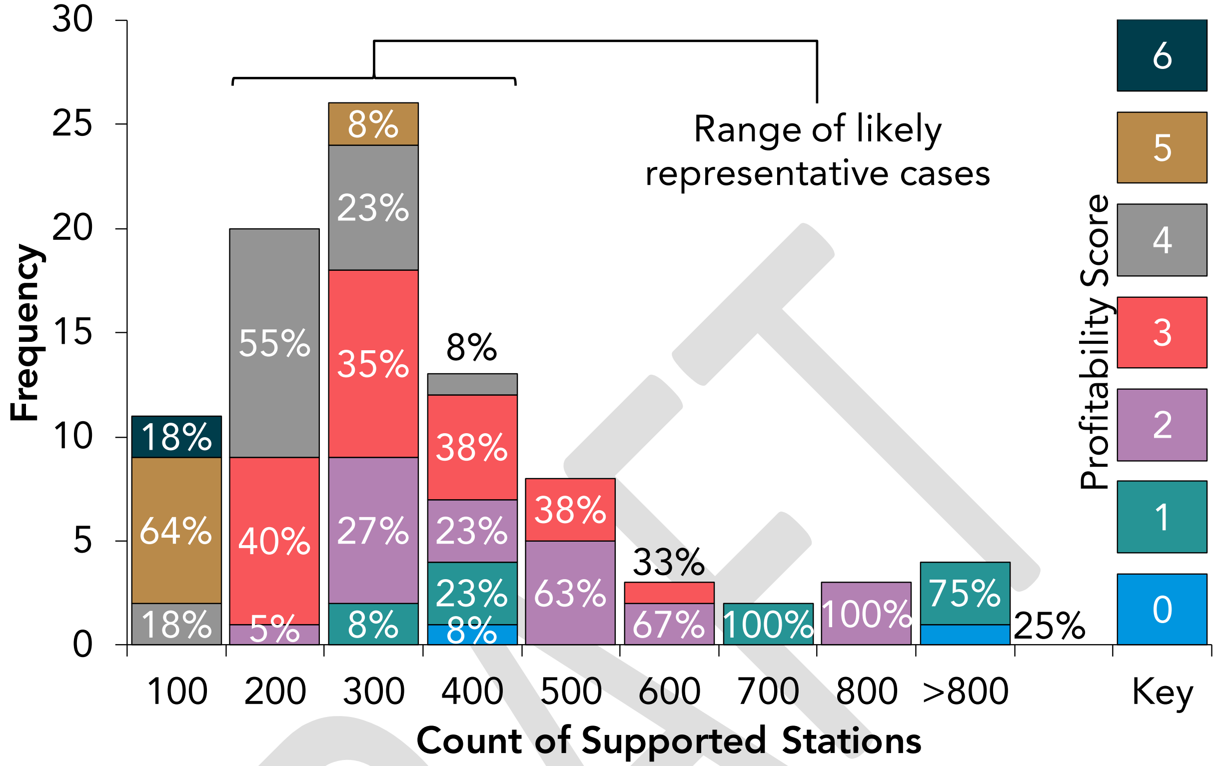


Figure 58 through Figure 61 display the variations of network-wide metrics according to all the input values investigated for the 180 Core Scenario Evaluations. Adjusted support amounts vary most directly with the combination of hydrogen procurement costs and price paid at the pump. As the balance between these two opposing factors plays a critical role in the profits developed by fuel sales, this result is not surprising. The pace of capital expense cost reductions has the next-highest impact, followed by the variables that affect total station utilization. The maximum MIRR has only a marginal effect on the adjusted support amount. These same observations largely hold true for the maximum support amount and the PPNI, though PPNI appears mostly unaffected by changes in variables that determine station utilization. This is likely because the self-sufficiency date in the majority of the Core Scenario Evaluations is relatively early in the network buildout, when differences in utilization between scenarios is small. Finally, the self-sufficiency date is largely independent of most variable input values. Exceptions appear to be scenarios that assume the Moore’s Law capital cost reductions and scenarios with high operational costs and fuel price parity achieved in 2040.

FIGURE 58: SENSITIVITY ANALYSIS OF ADJUSTED STATE SUPPORT FOR CORE EVALUATIONS

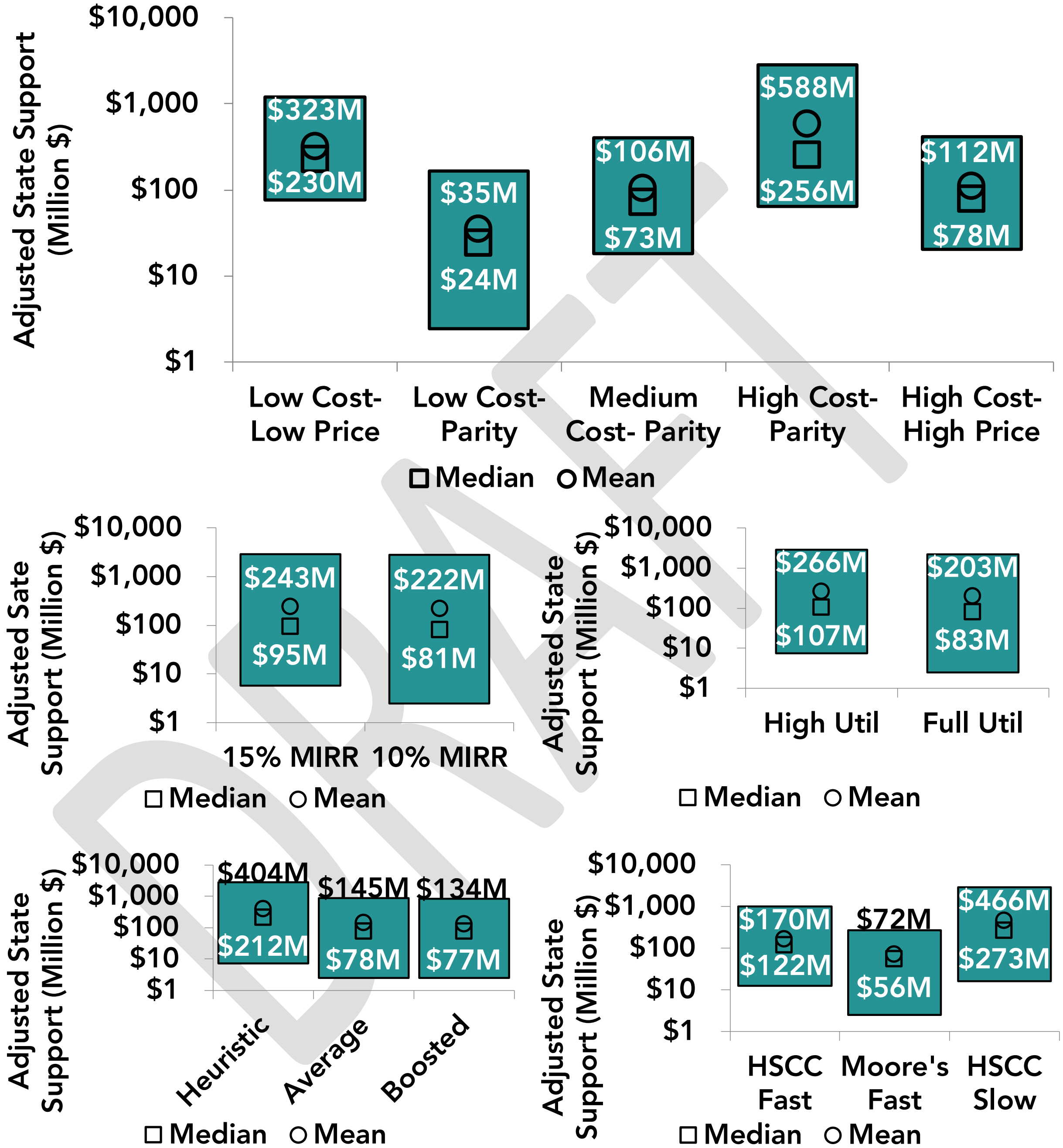


FIGURE 59: SENSITIVITY ANALYSIS OF MAXIMUM STATE SUPPORT FOR CORE EVALUATIONS

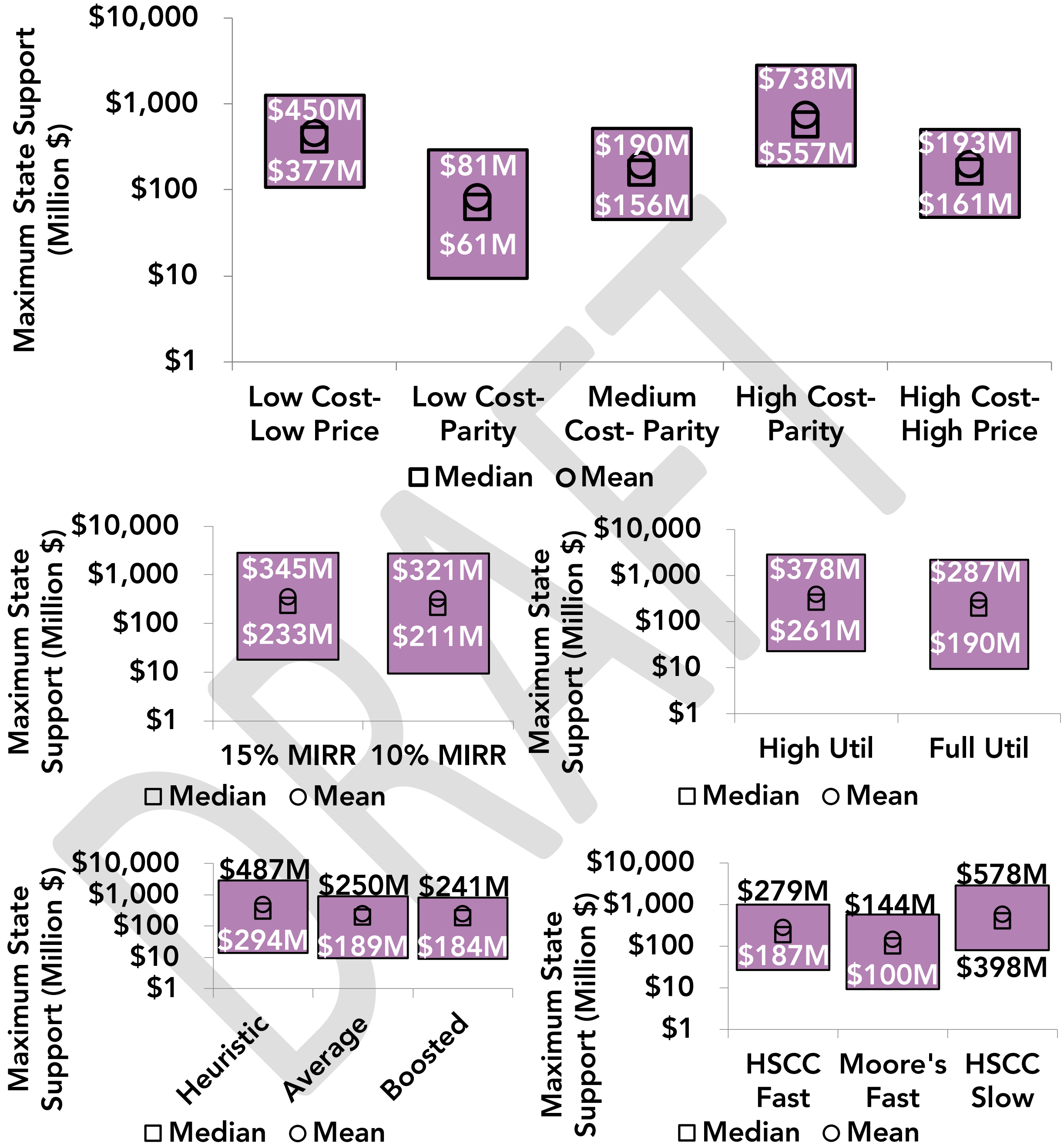


FIGURE 60: SENSITIVITY ANALYSIS OF PPNI FOR CORE EVALUATIONS

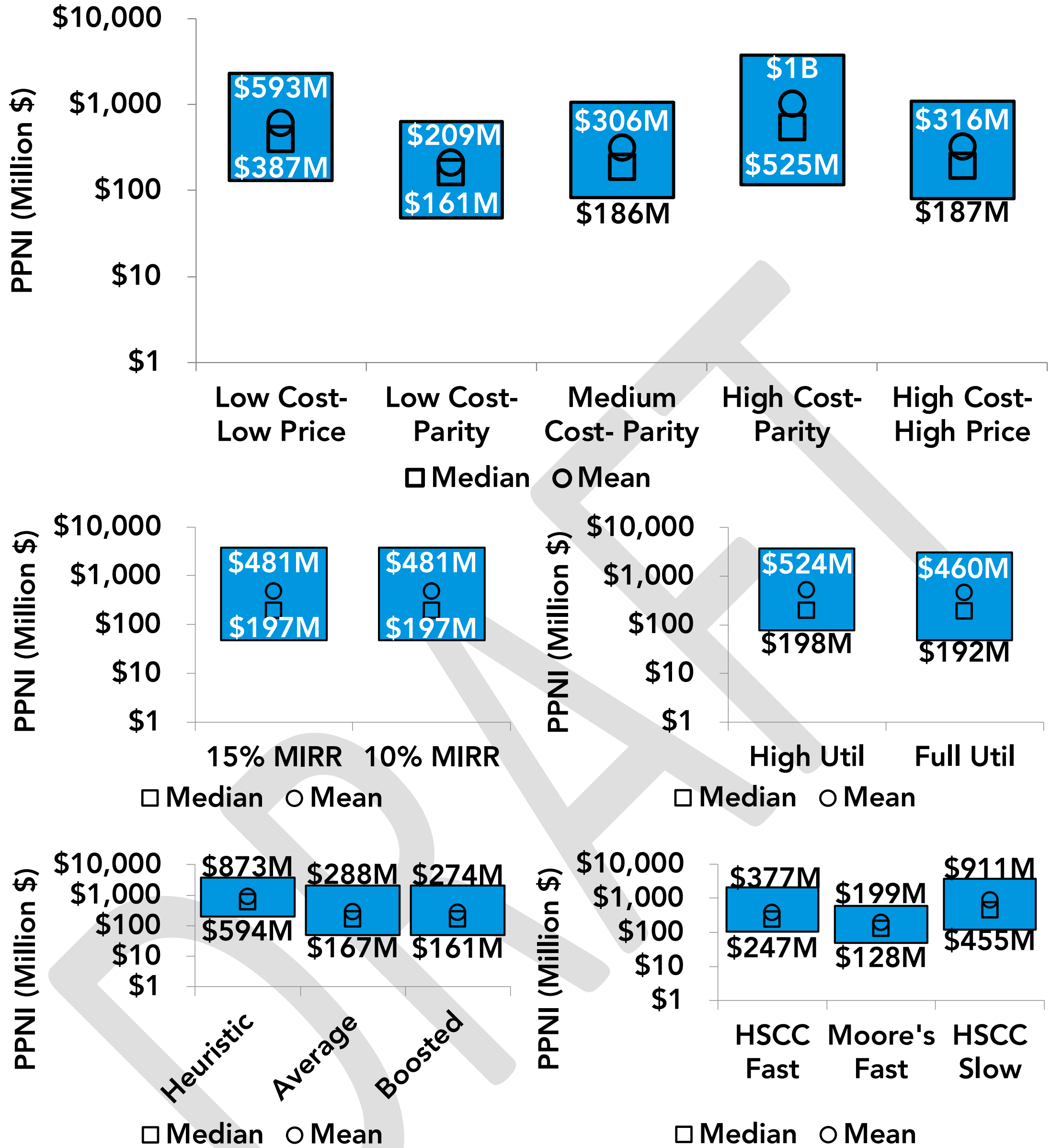
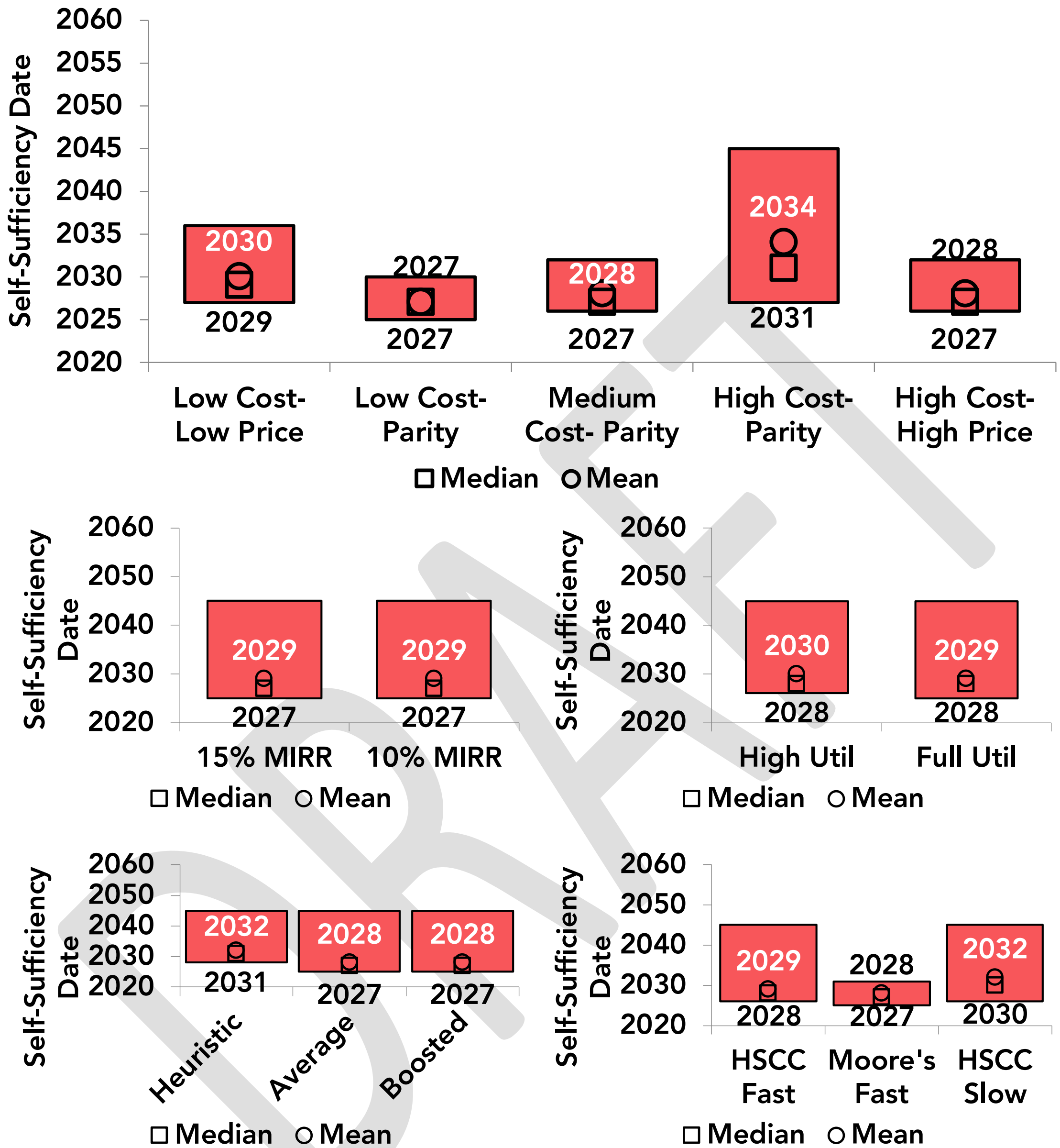


FIGURE 61: SENSITIVITY ANALYSIS OF SELF-SUFFICIENCY DATE FOR CORE EVALUATIONS



Scenario Sensitivities

VARIATIONS OF NETWORK BUILDOUT

The Core Scenario Evaluations focused on the base CAFCR network buildout strategy. Three additional station buildout scenarios were also evaluated in this study, as shown in Table 1. These additional scenarios highlight the potential benefit or disadvantage of adopting a different buildout strategy due to varying expectations or targets of future market potential. Based on the finding that Core Scenario Evaluations do not vary significantly between cases with 15 and 10 percent MIRR, the additional scenarios based on other network buildout strategies simply assumed 15 percent MIRR. A total of 90 scenario evaluations were completed for each of the additional network development scenarios: CAFCR Early, CAFCR Large, and BAU. Results from the base CAFCR scenario (discussed in detail in the chapter "Core Scenario Evaluations") were then compared to results from these additional evaluations. Post-analysis for these scenarios also focuses on the two primary metrics of the adjusted State support and time to achieve self-sufficiency.

Figure 62 displays results for the CAFCR Early scenario with Full and High utilization assumptions and comparisons to the CAFCR results already presented. The CAFCR Early scenario targets the same vehicle deployment schedule as the base CAFCR and uses the same growth in individual station capacity, but assumes more network capacity is developed in early years through increased numbers of stations. Compared to the base CAFCR case, CAFCR Early potentially saves a modest amount. State support amounts are approximately ten to twenty percent less than the base CAFCR results. The distribution of adjusted State support is similar between CAFCR and CAFCR Early, with the latter exhibiting a slightly greater tendency towards the lowest cost estimates. The time to reach self-sufficiency is also slightly shorter by up to two years, but this small variation is not significant.

Figure 63 shows the same metrics for the CAFCR Large scenario. This scenario also targets the same FCEV deployment as the base CAFCR scenario and the same pace of network capacity growth, but does so with increased emphasis on large stations in early years of deployment. This scenario appears to be nearly ideal. Self-sufficiency in the CAFCR Large scenario is achieved noticeably earlier then the base CAFCR scenario at extremely low (potentially near zero) costs. Exceedingly few cases in the CAFCR Large scenario demonstrate appreciable costs to achieve self-sufficiency. While this scenario could be attractive, it is likely overly aggressive given the limited station equipment supply chain available today.

Finally, Figure 64 displays results for the BAU scenario, which targets far fewer FCEVs than any of the CAFCR scenario variations and relies on a smaller network composed of smaller-capacity stations. This scenario takes noticeably longer than any of the other case to achieve self-sufficiency (as much as nearly an additional decade) and has up to twice the total costs of the base CAFCR case. Given that this scenario enables FCEV deployment that is approximately 1/6th of any CAFCR case (with corresponding station development scale), it therefore represents a per-unit (either FCEV or station) cost approximately ten times as large as the base CAFCR case.

Figure 62: Self-Sufficiency Support Amounts and Dates for CAFCR Early Scenarios Compared to base CAFCR Scenarios

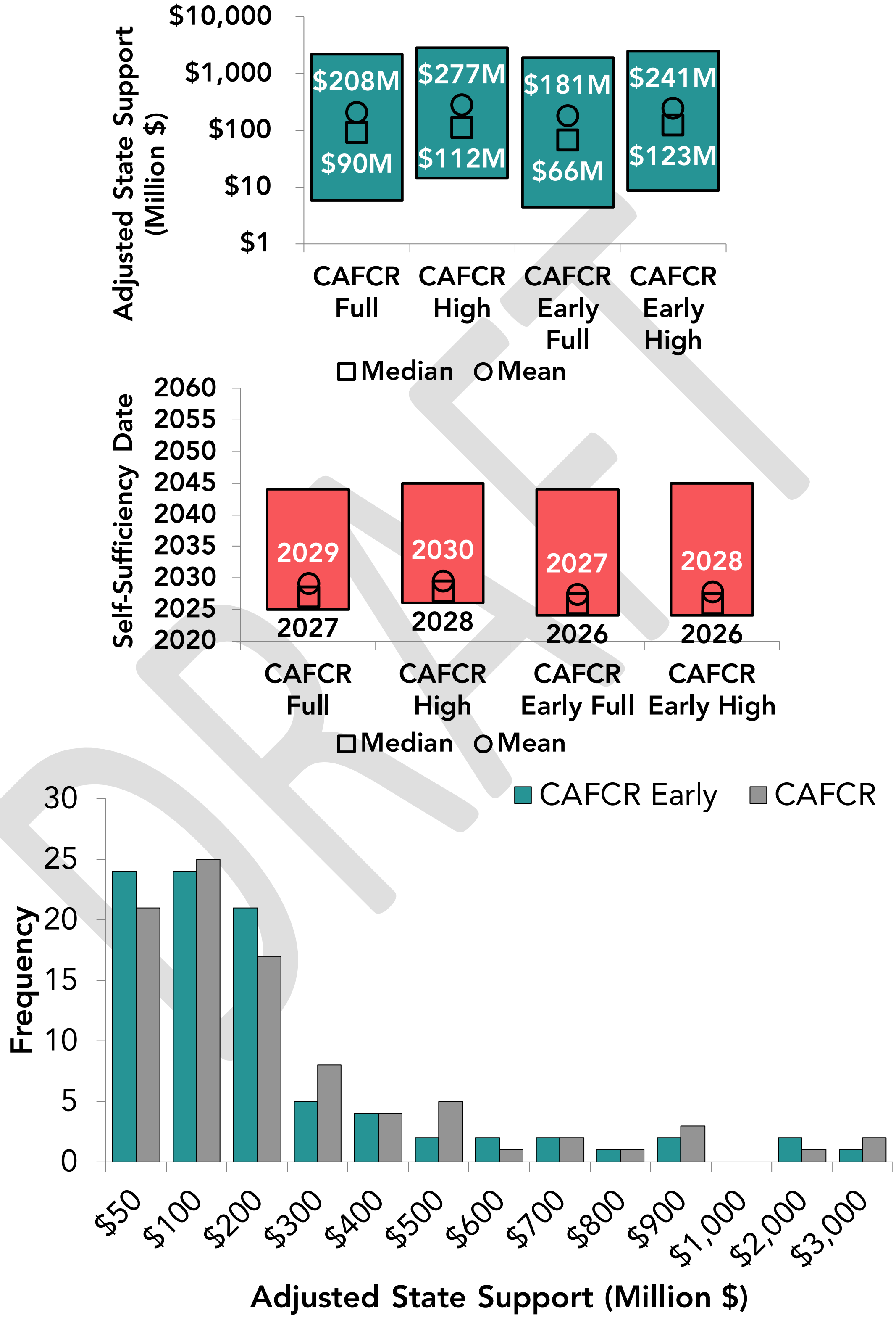


Figure 63: Self-Sufficiency Support Amounts and Dates for CAFCR Large Compared to base CAFCR Scenarios

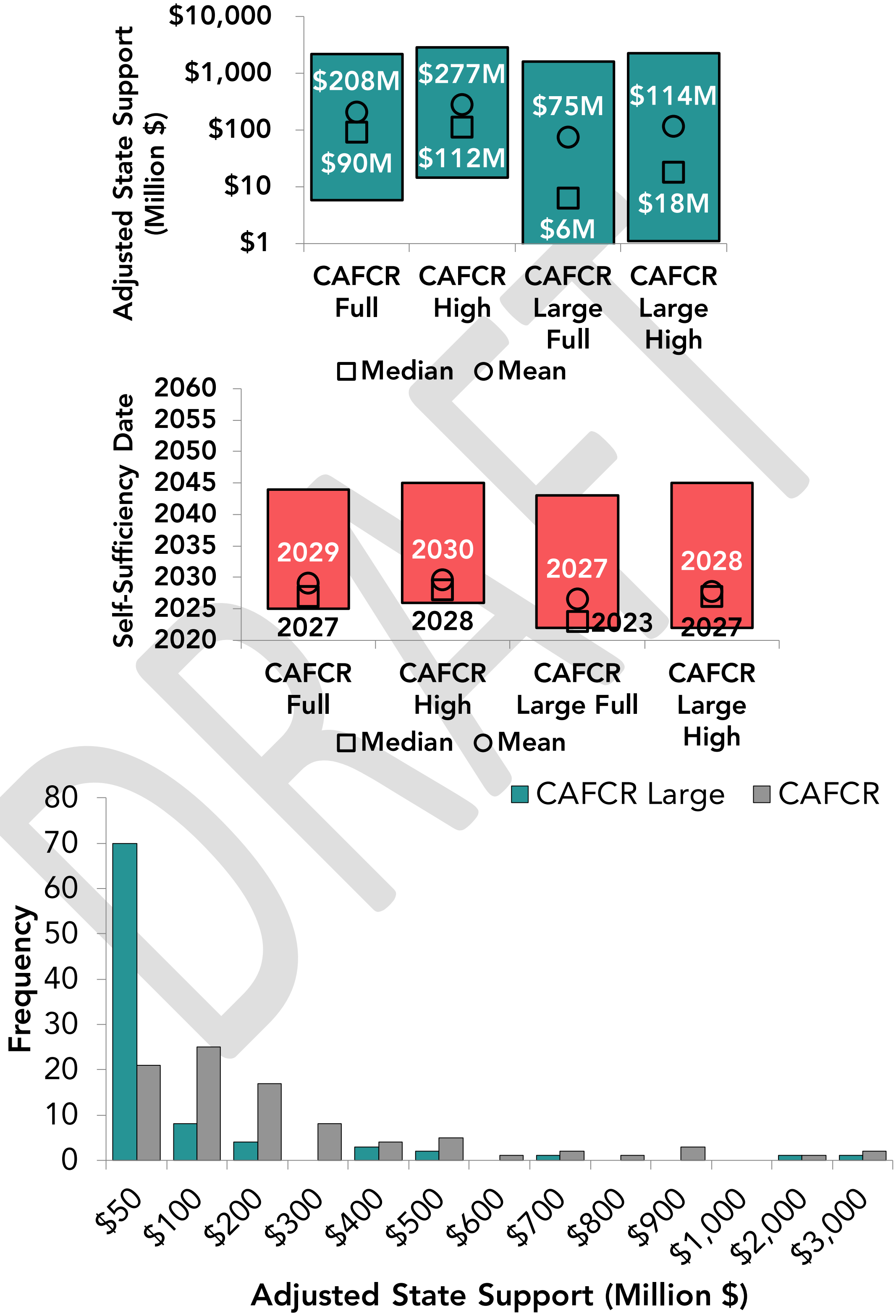
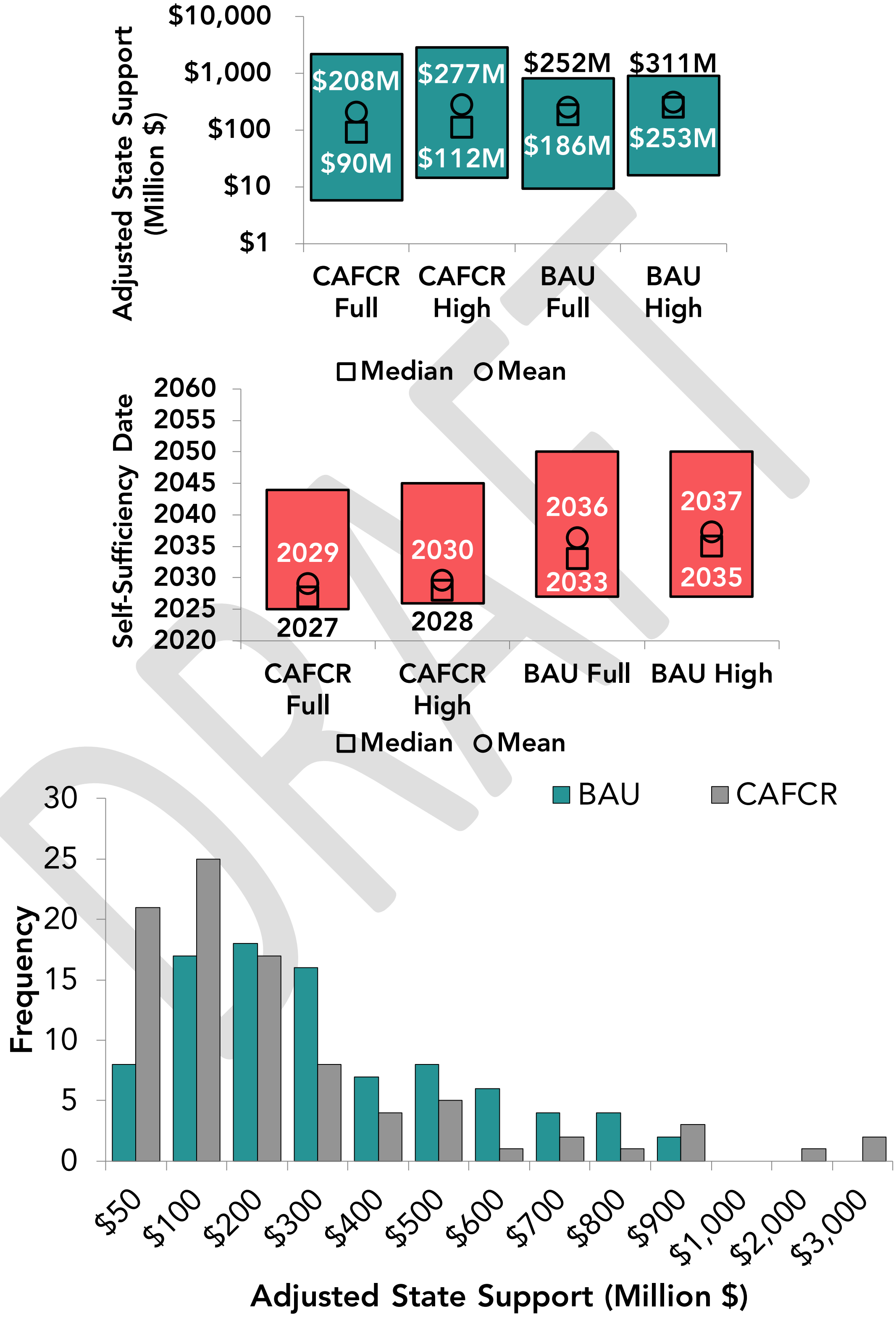


FIGURE 64: SELF-SUFFICIENCY SUPPORT AMOUNTS AND DATES FOR BAU SCENARIOS COMPARED TO BASE CAFCR SCENARIOS



VARIATIONS OF VEHICLE DEPLOYMENT

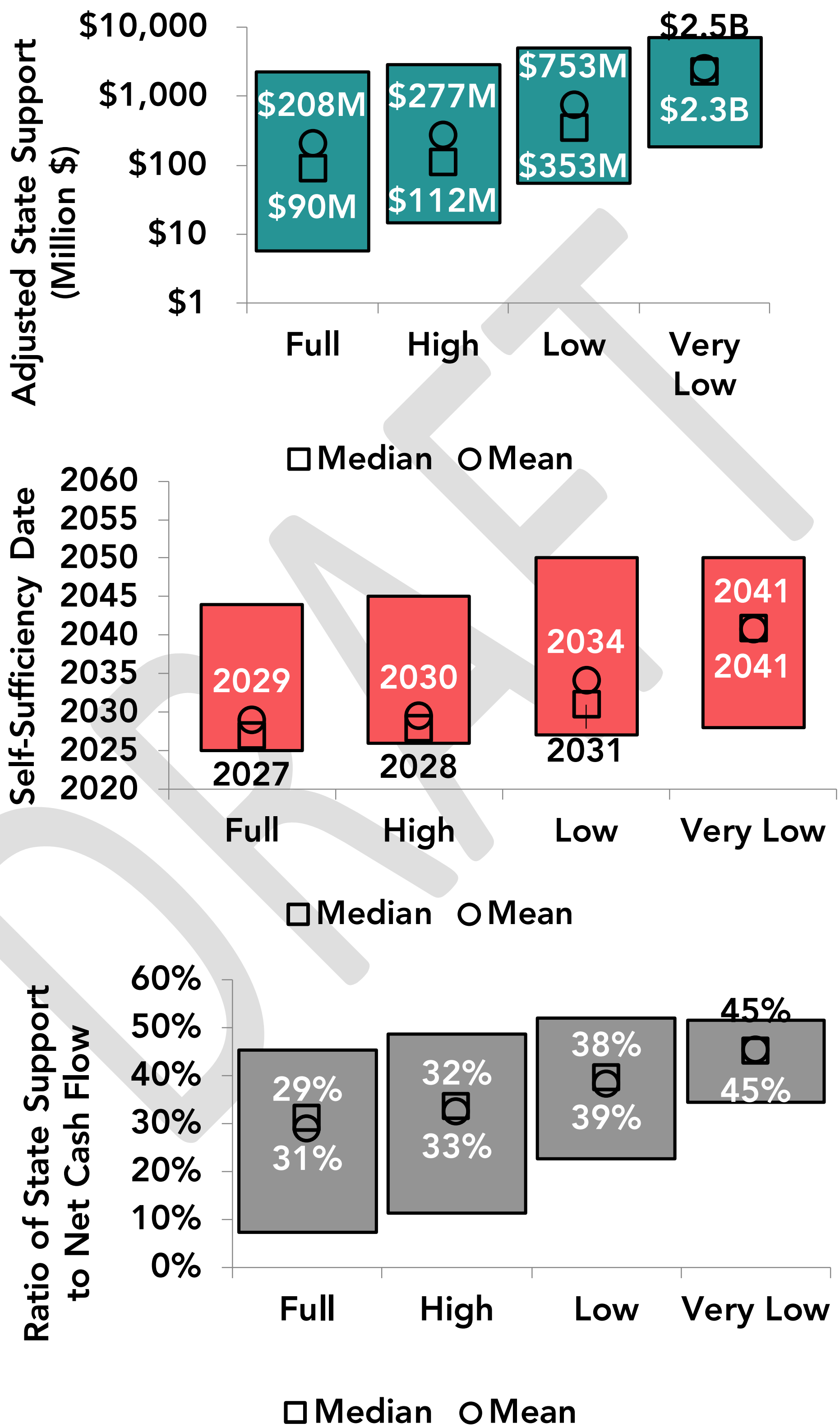
Evaluations were also completed for various vehicle deployment scenarios. Scenarios presented in prior results address the Full (85 percent) and High (75 percent) utilization cases. Additional cases of Low (50 percent) and Very Low (25 percent) maximum utilization were also investigated for each of the four station deployment strategies. A total of 90 additional scenarios were evaluated for each of the base CAFCR, CAFCR Early, CAFCR Large, and BAU deployment scenarios to address the two additional levels of vehicle deployment. These additional scenarios highlight the potential risk of network development that anticipates a larger FCEV market potential than actually develops in California.

Figure 65 demonstrates the effect of reduced vehicle deployment on State support and time to achieve self-sufficiency for the base CAFCR station network development scenario. Other network development scenarios are discussed in the section "Summary of Deployment Scenarios". As vehicle deployment falls, the total State support needed to achieve self-sufficiency increases. As shown in previous results, reducing station utilization from Full to High incurs a modest increase on the order of 30 percent. However, the State support increase becomes more pronounced for the Low and Very Low utilization scenarios. Average State support grows by a factor of 2.7 between High and Low utilization, to $753M in the latter case. The increase is even greater when utilization falls to the Very Low level, with a mean support amount of $2.5B, which is more than three times the support at Low utilization.

In most evaluations presented so far, there is little impact on the timing to achieve self-sufficiency. However, Figure 65 clearly demonstrates that reduction in vehicle deployment between the High and Low utilization cases can add approximately five years to the self-sufficiency timeline. Further reductions in vehicle deployment to the Very Low case adds as much as a decade compared to the Full and High utilization cases. In addition, the proportion of funds supporting network development increases significantly for the Low and Very Low utilization cases. State support represents approximately 30 percent of net cash flows in the Full and High utilization cases. State support represents nearly 40 percent of net cash flows in the Low utilization case, and as high as 45 percent in the Very Low utilization case.

These results clearly demonstrate the need for station network development to be met with proportional FCEV deployment in order to contain costs and accelerate self-sufficiency. In addition, the results indicate greater sensitivity in State support amount and timing to self-sufficiency with lower utilization rates. Sensitivity increases significantly between 75 percent and 50 percent network utilization rates. On the other hand, the similarity between results for Full and High utilization indicate that vehicle deployment does not necessarily need to be exactly matched to station network development. There is some margin below the fully optimal FCEV deployment case for which cost and timing do not increase significantly enough to present a major concern.

FIGURE 65: COMPARISON OF NETWORK-WIDE METRICS ACROSS VEHICLE DEPLOYMENT VARIATIONS FOR CAFCR STATION BUILDOUT SCENARIOS



SUMMARY OF DEPLOYMENT SCENARIOS

State support amounts that achieve self-sufficiency in all 810 Scenario Evaluations described previously are summarized in Figure 66 through Figure 68. These scenarios cover all variations of station development and vehicle deployment as well as industry-wide economic factors like rate of equipment and operational cost reduction, cost reduction in the price to procure hydrogen fuel, and rate of reduction in price paid at the pump by the consumer.

Although the base CAFCR, CAFCR Large, and CAFCR Early scenarios target the same progression of FCEV deployment, they each build the corresponding station network differently, resulting in different numbers of stations and slightly different total capacities. The BAU scenario is further differentiated by assuming a different FCEV deployment progression and building a vastly different network of supporting hydrogen stations. It is therefore necessary to consider these scenarios' Support amounts in total and per-unit of station and installed capacity.

FIGURE 66: VARIATION IN STATE SUPPORT PER KILOGRAM CAPACITY INSTALLED BY SCENARIO

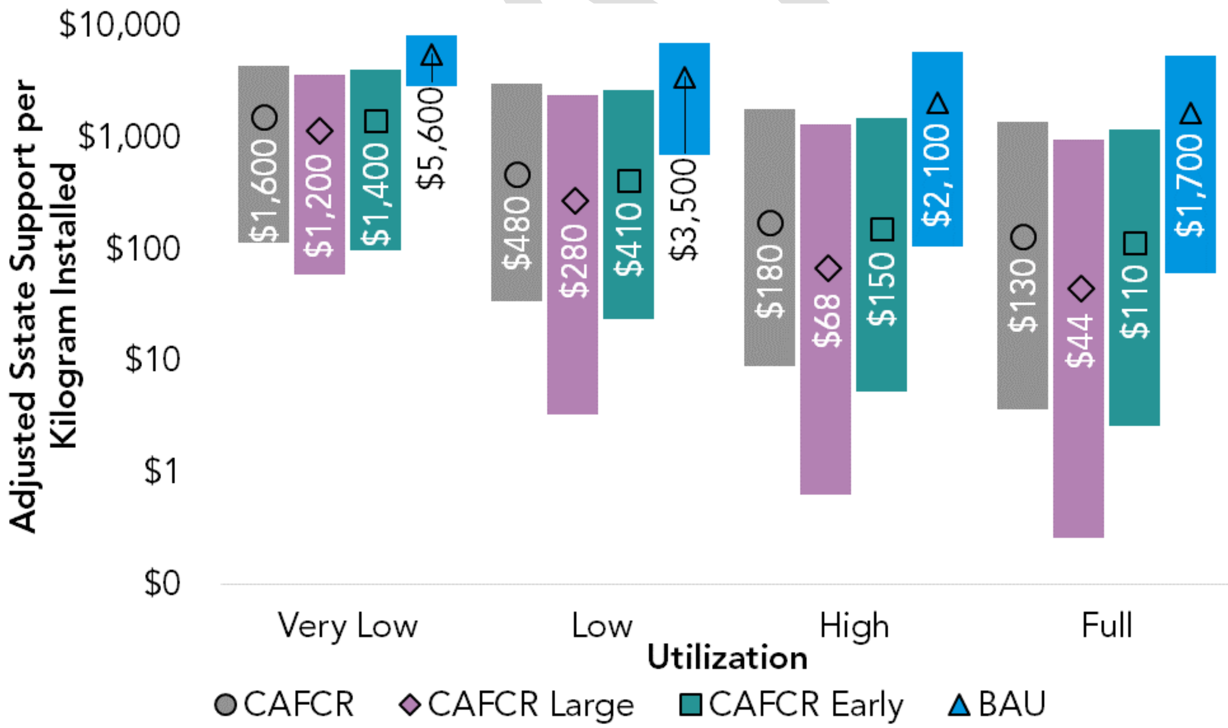


Figure 66 presents the comparisons across all scenarios per kilogram of installed capacity. Colored bars indicate the ranges for each scenario and symbols indicate the mean. Prior discussion indicated that the CAFCR Large scenario appeared to be less costly overall than the other CAFCR-based scenarios. Figure 66 clearly demonstrates that this advantage is highly dependent on the rate of FCEV deployment. At Low and Very Low utilization rates, the CAFCR Large estimates become increasingly similar to CAFCR and CAFCR Early estimates.

Ranges and means of the CAFCR Early scenario are similar to the CAFCR scenario, and the reduced support amounts previously noted for the CAFCR Early scenario are fairly consistent across FCEV deployment cases. The BAU scenario shows support amounts per kilogram that decrease at a slower rate than the other scenarios and this disadvantage is actually more pronounced at higher utilization. At Very Low utilization, CAFCR and BAU support amounts per kilogram are $1,600 and $5,600, respectively. At Full utilization, the support amounts per kilogram drop to $130 for CAFCR and $1,700 for BAU. Therefore, at the lowest station utilization rates, the BAU scenario represents support amounts that are 3.5 times the base CAFCR scenario. At high station utilization rates, the discrepancy is even more pronounced, with the BAU scenario representing more than ten times the support amounts of the base CAFCR scenario. This is due to a combination of the smaller network capacity in the BAU case and the smaller number of stations, resulting in less capital equipment cost reductions and smaller revenues.

Figure 67: Variation in State Support per Station Installed by Scenario

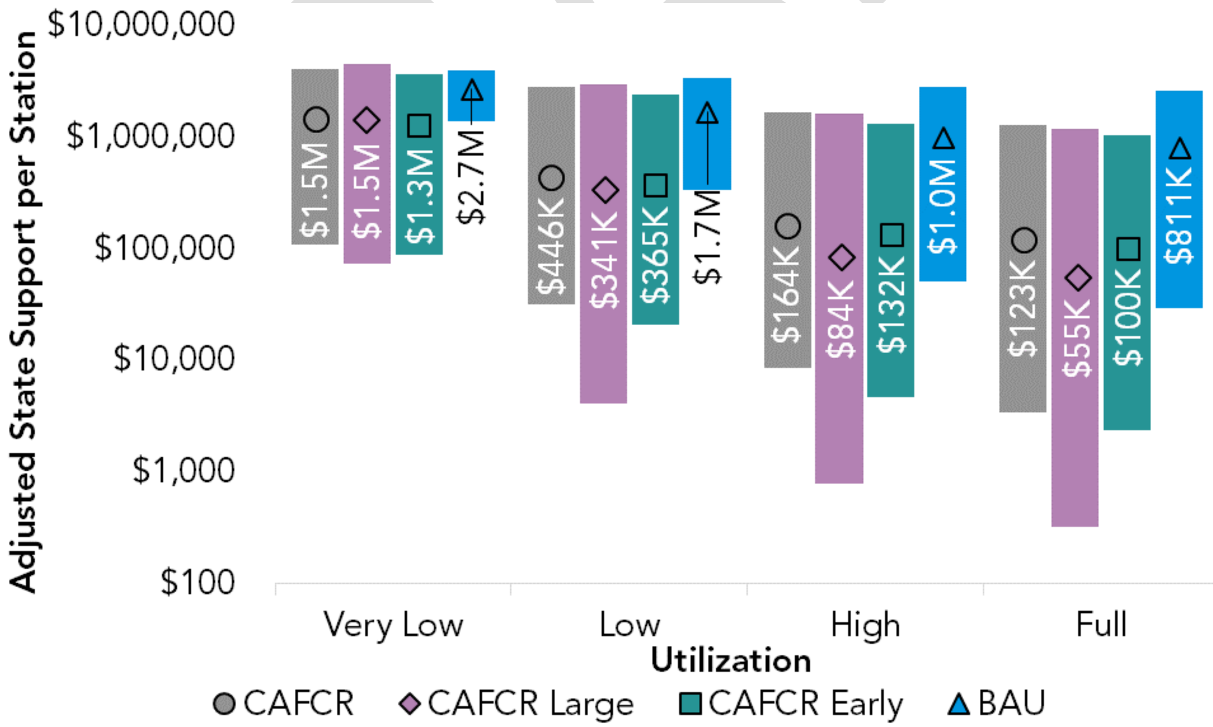


Figure 67 displays support amounts that achieve self-sufficiency for each scenario on the basis of cost per station. Comparisons between scenarios on the basis of support per station are similar to comparisons on the basis of support per kilogram installed. On the basis of support per station, the disparity between BAU and other scenarios at high utilization is not quite as pronounced, but support amounts per station in the BAU scenario are still more than 6.5 times the CAFCR scenario. Support amounts per station presented in Figure 67 are determined by total State support divided by the total number of stations, regardless of the amount of funding received by each individual station, and should be interpreted with this definition in mind.

Figure 68 compares the network-wide costs to the State across all scenarios. As previously mentioned, on the basis of the total network, State support to achieve self-sufficiency for the BAU scenario is more similar to the base CAFCR and CAFCR Early scenarios owing to the smaller network development that occurs. In addition, Figure 68 clearly demonstrates that total self-sufficiency support amounts fall more rapidly for the CAFCR Large scenario than for other scenarios as FCEV deployment and network utilization increase. The figure also demonstrates that the Core Scenario Evaluation result of self-sufficiency support amounts between $100M and $400M is dependent on eventually achieving fairly high FCEV deployment. Mean estimates for total State support are significantly higher than this range for all scenarios with utilization lower than the High case. However, the mean estimate for State support in the CAFCR Large scenario at Low utilization is relatively close to the Core Scenario Evaluation estimate.

Figure 68: Variation in Total State Support by Scenario

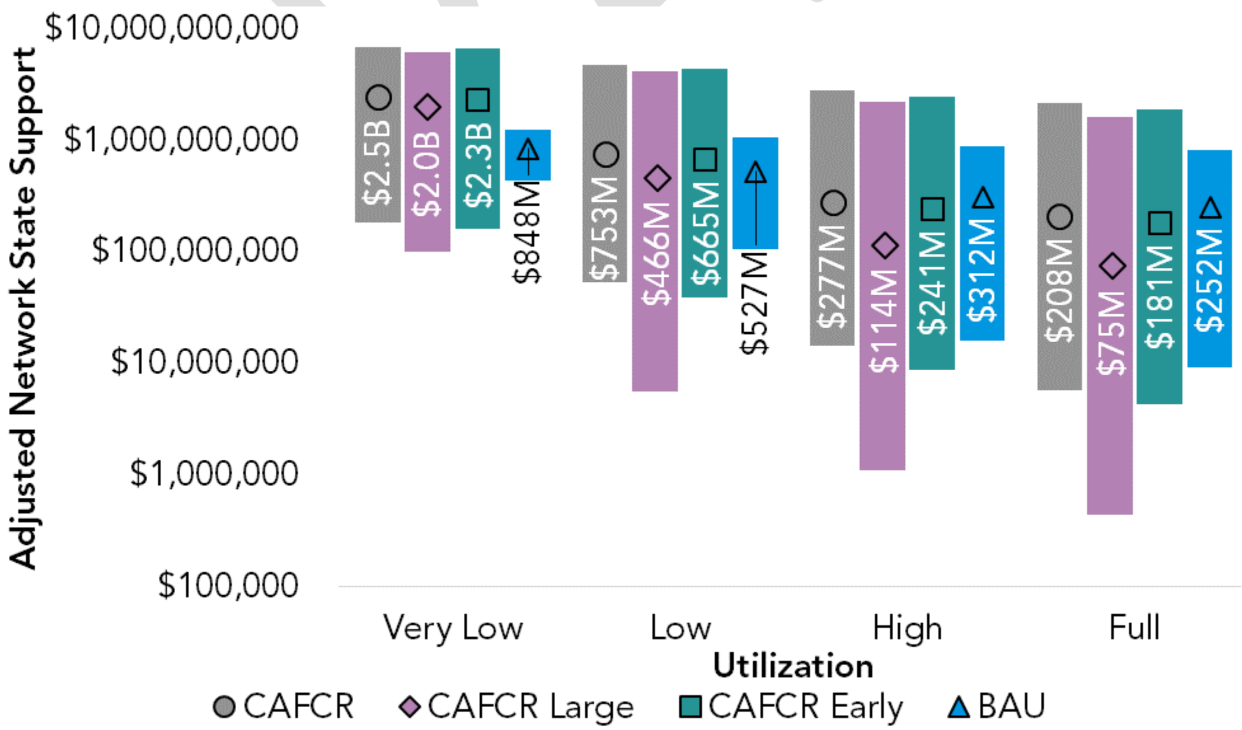


Figure 69 demonstrates the relative impact of State support on net cash flows for each scenario based on FCEV deployment. The CAFCR and CAFCR Early scenarios are nearly indistinguishable, presenting essentially the same trajectory as shown previously in Figure 65. For these scenarios, the ratio of State support to net cash flows grows from approximately 30 percent for Full and High utilization to approximately 45 percent for Very Low utilization. The BAU scenario demonstrates ratios approximately five percent larger than the CAFCR case, except for Very Low utilization when they are equal. CAFCR Large scenario ratios are typically 15 to 20 percentage points below the base CAFCR scenario. The lone exception is again the Very Low utilization scenario, when all values converge around 45 percent. Data in Figure 69 do not account for cases that never achieve self-sufficiency, which may partially explain why all scenarios show similar results for Very Low utilization. Cases that do not achieve self-sufficiency require more State support and are more common in the BAU scenarios; if they were included then the BAU case would show much higher reliance on State support. In addition, at Very Low utilization, revenues based on sales are extremely limited regardless of the network size. Therefore, at Very Low utilization, total station and network income is more critically dependent on LCFS HRI credit generation revenue and additional State support.

FIGURE 69: VARIATION IN STATE SUPPORT PROPORTION OF NET CASH FLOWS BY SCENARIO

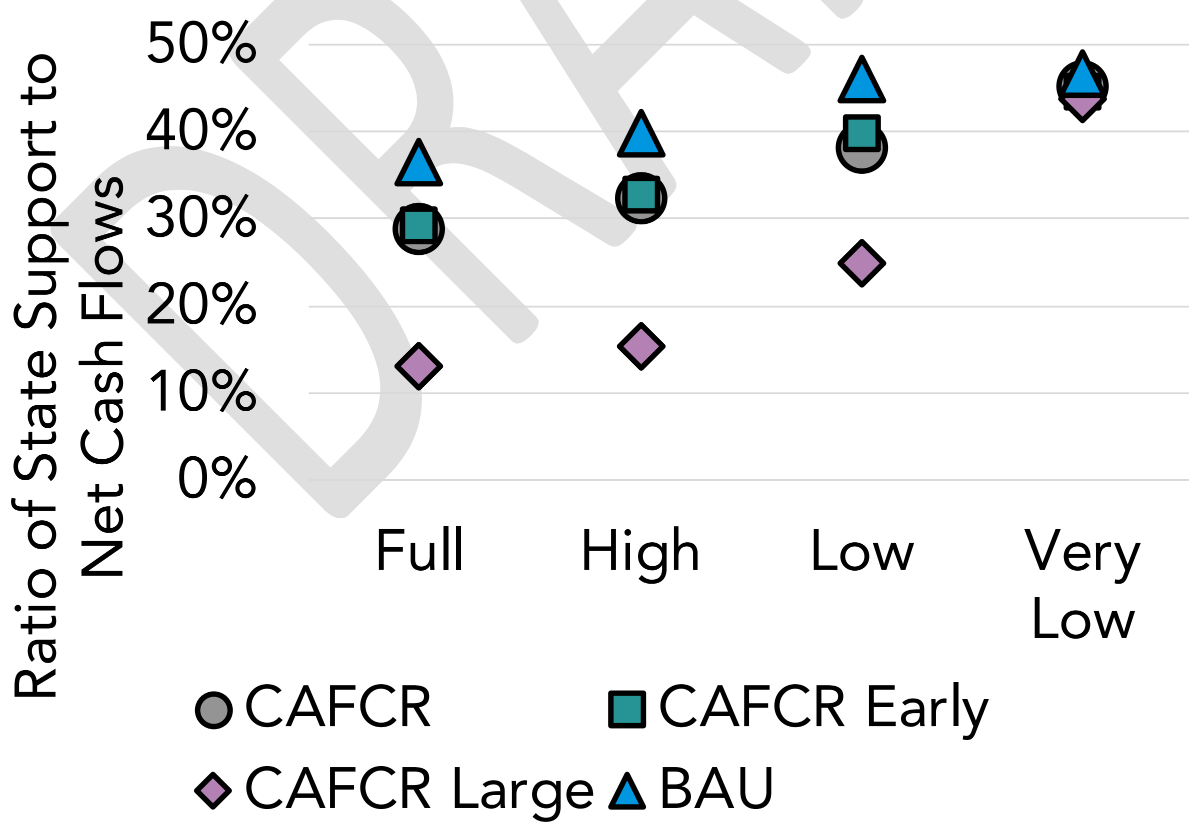


Figure 70 and Figure 71 compare mean results presented above to data from applications in the most recent station funding solicitation, GFO 19-602. The amounts shown in these figures represent only the range of State funding requested by applicants. It is also important to note that GFO 19-602 only allows applicants to request funds to cover capital costs (equipment-related expenses). The range of funding request amounts from GFO 19-602 may therefore be less than what station developers would have requested if more project development costs could be included. In addition, scoring of GFO 19-602 applications more strongly emphasized cost-competitiveness compared to prior solicitations. Thus comparisons to GFO 19-602 may not be entirely comparable to the costs to self-sufficiency indicated in this study, but are likely a useful indicator of current industry status compared to the future projections considered in this study.

As shown in Figure 70, the BAU scenario matches most closely to the range of funding requests in GFO 19-602. Other than cases that assume Very Low utilization, all cases that assume some form of CAFCR network development anticipate lower support amounts than requested in GFO 19-602. On the other hand, cases based on the BAU station development scenario are in good agreement with GFO 19-602 funding requests with the exception of Very Low utilization scenarios. These results may make intuitive sense. All CAFCR-based scenarios anticipate more rapid station network development and vehicle deployment than has been seen to date. BAU cases by definition more closely reflect the development pace seen thus far in California. Thus, they may be a closer proxy for today's real-world industry development. Applicants to GFO 19-602 may have based expected station development costs on economics and market development (including the upstream supply chain) as observed today and not in a hypothetical future case. Therefore, it is clear that in order to achieve network self-sufficiency with the State support amounts estimated by this study, significant market development and economies of scale must also be accomplished.

These insights are also reflected in the support amounts and funding requests at the per-station level, as shown by Figure 71. All variations of CAFCR network development show much lower mean support amounts per station than the solicitation requests. However, the ranges of support amounts shown earlier in Figure 66 and Figure 67 do include the range of funding requests submitted to GFO 19-602 for nearly all combinations of station network development and network utilization rate. This may be an indication that mean values in particular from this study are skewed lower than the costs demonstrated by the industry today. In addition, the higher values of State support estimated by this study may be properly indicative of scenarios that pursue ambitious network development plans but either development and operations cost fall slower than expected, vehicle deployments are tightly constrained, or both.

FIGURE 70: COMPARISON OF STATE SUPPORT PER KILOGRAM INSTALLED TO FUNDING REQUESTS IN GFO 19-602 APPLICATIONS

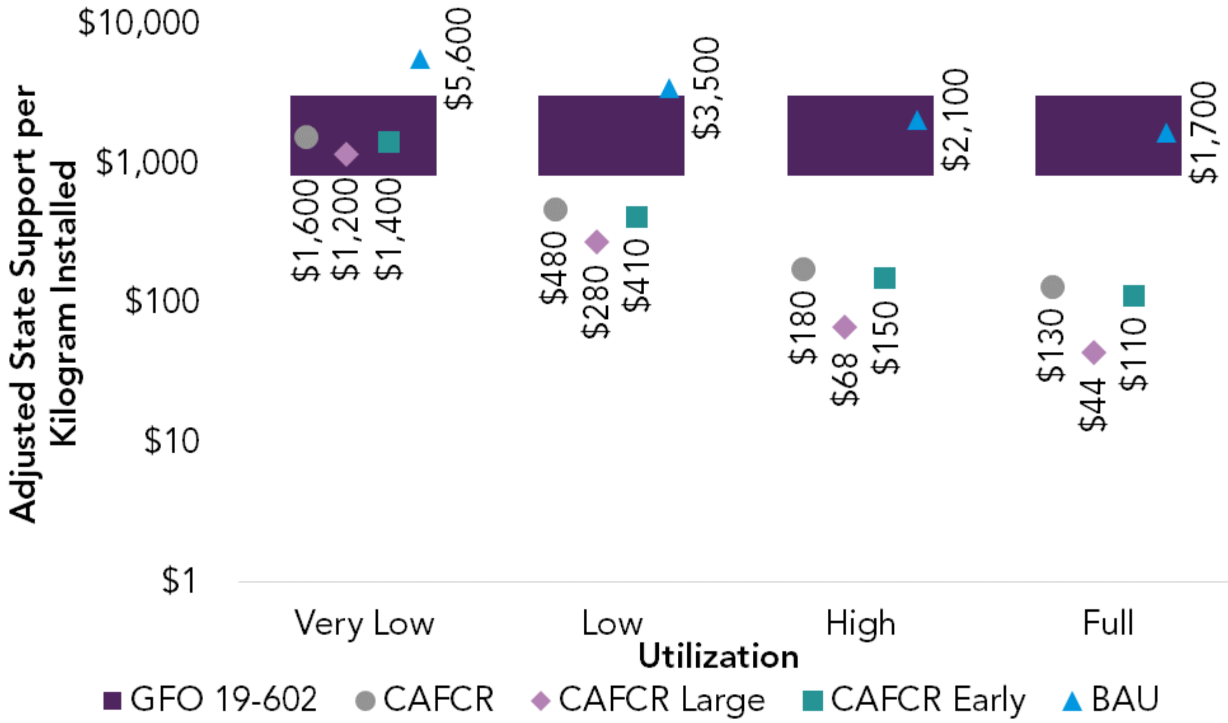
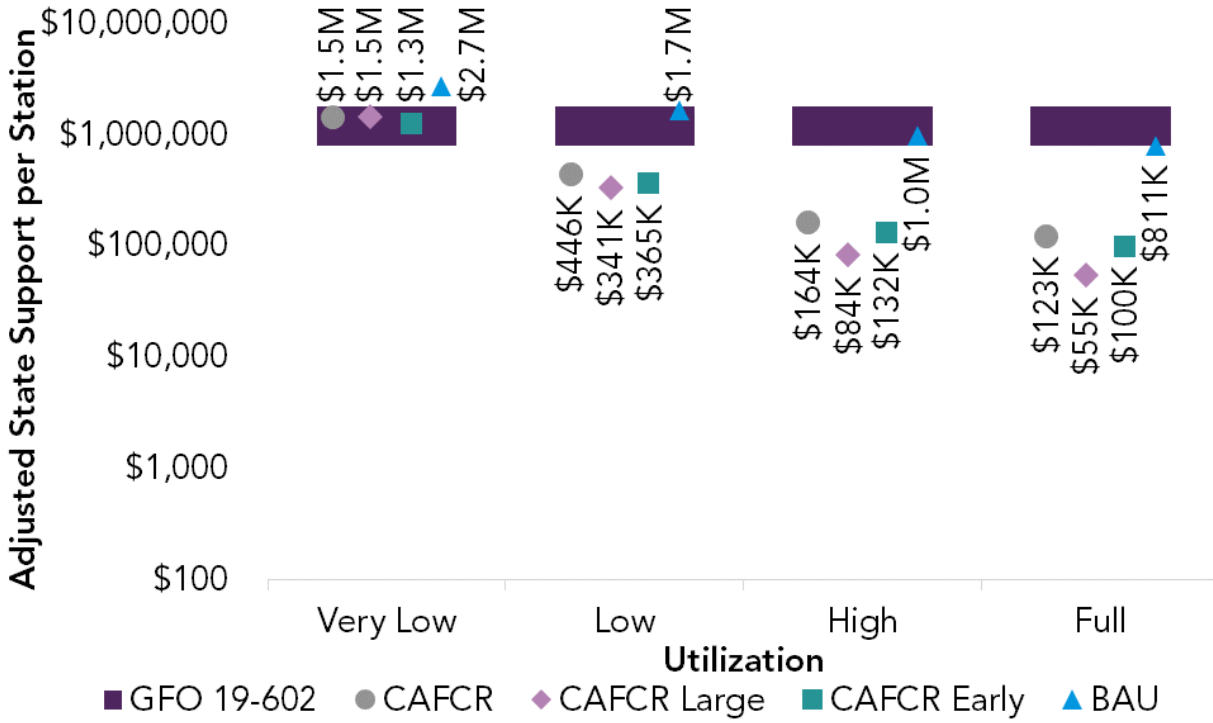


FIGURE 71: COMPARISON OF STATE SUPPORT PER STATION INSTALLED TO FUNDING REQUESTS IN GFO 19-602 APPLICATIONS



Policy-Informing Evaluations

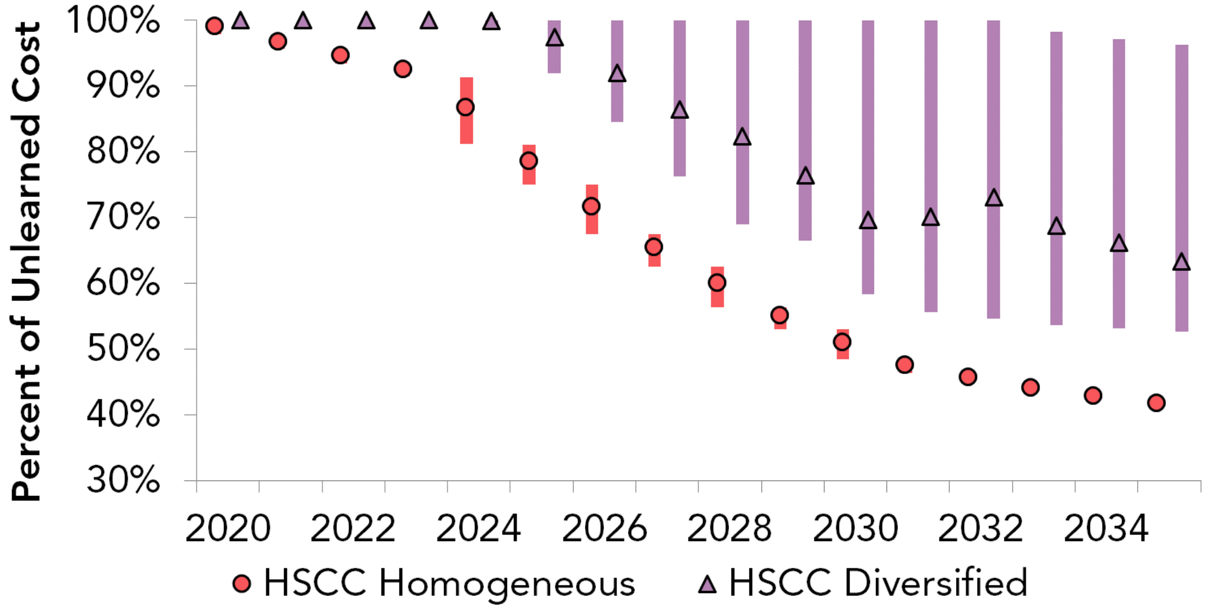
In addition to the wide range of scenarios presented in the previous chapters, CARB performed a series of small-sample evaluations to explore considerations that may inform policy development. These limited-run evaluations specifically address one representative scenario, and make targeted modifications that impact the balance between station development and operations cost and prices paid at the pump. Unless otherwise noted, this base scenario assumes CAFCR vehicle fleet and station network development pace, Full utilization, 15 percent maximum MIRR over 15 years, Average utilization calculation method (see Figure 19 in the section "Individual Station Utilization"), and capital equipment cost reductions based on the HSCC method (see Figure 24 in the section "Initial Capital Costs and Capital Cost Reduction").

Technology Diversification

In all evaluations discussed in prior chapters, the rate of cost reductions for capital equipment expenses was based on the total capacity of the previously built station network. All stations therefore contributed to the rate of capital cost reductions and equally benefitted from these developments. However, the current funded network demonstrates some diversification in capital costs and cost reductions based on the capacity and technology installed at the station. While not always the case, smaller-capacity stations more often tend to utilize gaseous storage and delivery or even on-site hydrogen production. Larger-capacity stations tend to be more likely to incorporate liquid storage and delivery or even pipeline delivery. In the future, more widespread use of pipeline delivery could be a catalyst for cost reduction and acceleration of network growth.

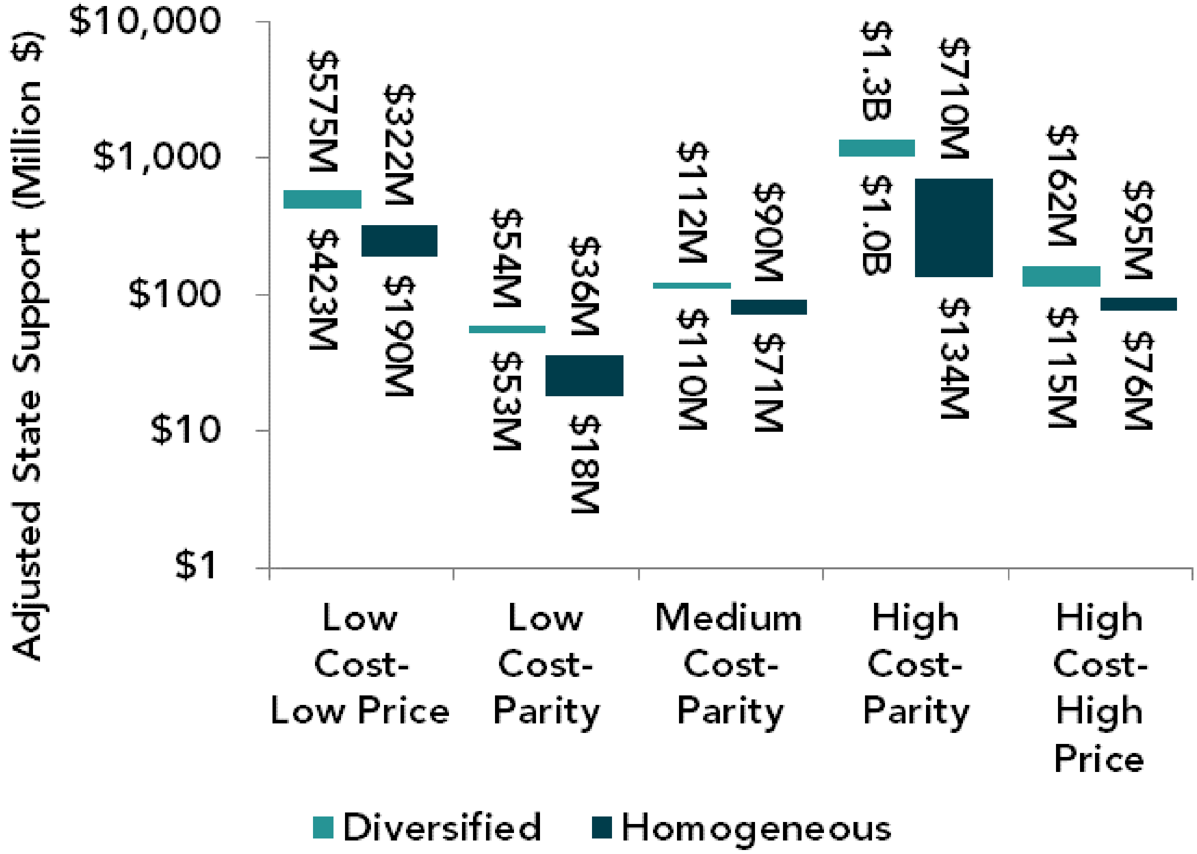
CARB performed a small set of evaluations to estimate the impact on timing and State support to achieve self-sufficiency if the rate of capital cost reductions was separately evaluated for each station capacity. In order to accomplish this task, the HSCC cost reduction method was implemented, but with separate cost reduction trajectories developed for each station size. This is termed "technology diversification" in this study. The effect of diversified capital equipment cost reductions is demonstrated in Figure 72 for the HSCC Fast case. Compared to the case where all stations are assumed to benefit equally from volume production, the average diversified costs are noticeably larger and show a much wider range. The wider range occurs because larger stations enter the network in later years, at which point they are assumed in this method to not benefit from any prior cost reduction (refer to Figure 12).

FIGURE 72: EFFECT OF TECHNOLOGY DIVERSIFICATION ON CAPITAL EQUIPMENT COST REDUCTION RATES FOR HSCC FAST



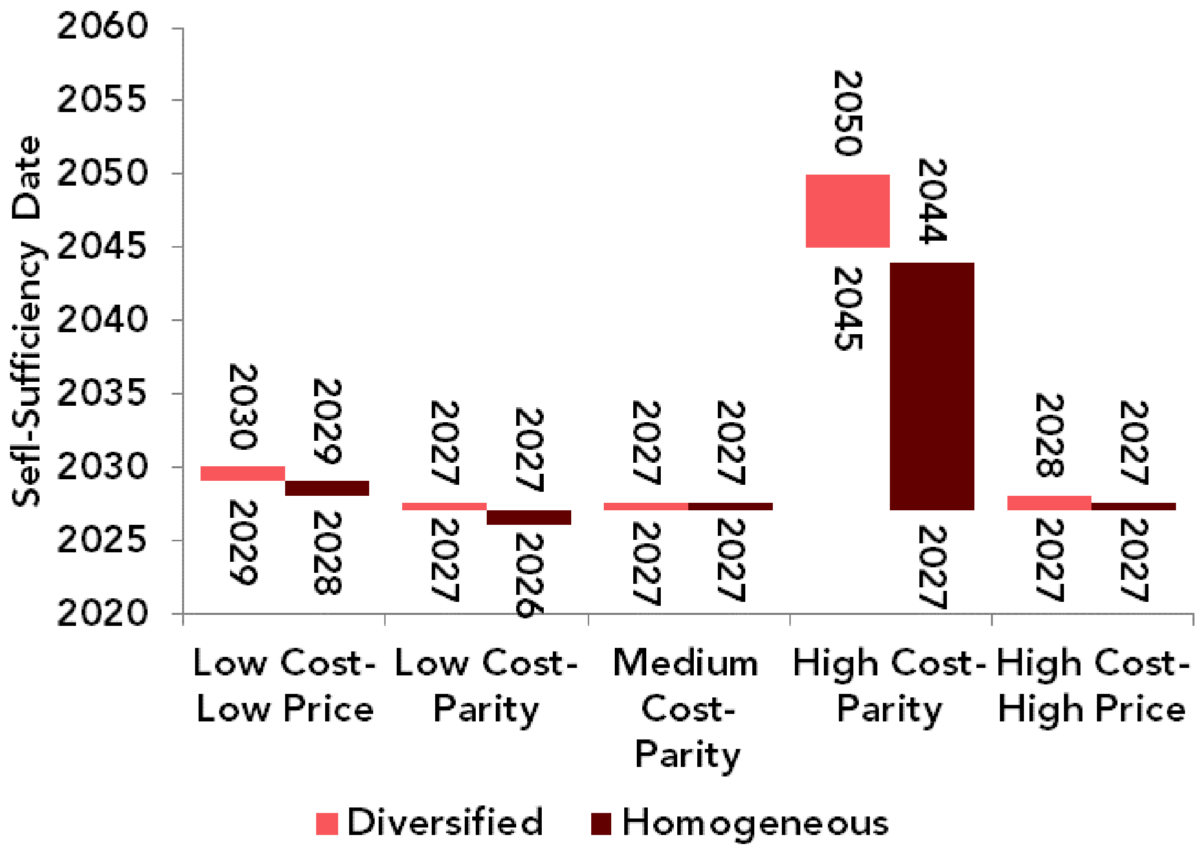
Examples of the difference in costs to the State to achieve self-sufficiency between scenarios assuming homogeneous and diversified cost reductions are shown in Figure 73. Variations are depicted according to Fast (bottom of each bar) and Slow (top of each bar) cost reductions. The categories of the x-axis indicate the various combinations of hydrogen procurement costs (see Figure 25) and price at the pump (see Figure 29). In most cases, technology diversification nearly doubles the estimated State support to achieve self-sufficiency. One notable exception is the High Cost-Parity scenario. In this example, technology diversification inflates the State support amount by as much as nearly ten times. The lowest State support amounts in this case are \$1.0B and \$134M for diversified and homogeneous capital cost reductions, respectively.

FIGURE 73: EFFECT OF TECHNOLOGY DIVERSIFICATION ON STATE SUPPORT (TOP OF RANGE FOR HSCC SLOW, BOTTOM OF RANGE FOR HSCC FAST)



Self-sufficiency dates with diversified cost reductions are presented in Figure 74. In almost all cases, technology diversification does not appreciably affect the self-sufficiency date. Nearly all examples are within the central estimate reported earlier of 2027 to 2030 (see Figure 54). Again, the combination of high procurement costs and prices at the pump achieving parity in 2040 demonstrates a greater impact, with self-sufficiency dates between 2045 and 2050. However, even for the homogeneous cost reduction scenarios (explored in the "Core Scenario Evaluations"), this case exhibited potential for self-sufficiency to be achieved much later than the central estimate.

FIGURE 74: EFFECT OF TECHNOLOGY DIVERSIFICATION ON SELF-SUFFICIENCY DATE (TOP OF RANGE FOR HSCC SLOW, BOTTOM OF RANGE FOR HSCC FAST)



PUMP PRICE PARITY FLEXIBILITIES

The central estimate of the Core Scenario Evaluations showing self-sufficiency achievable by 2030 with State support amounts of $100M to $400M are based on consideration of a large number of scenarios with varying rates of price reduction at the pump. Some scenarios never reach parity with gasoline ($8/kg) in the evaluation timeframe, some achieve parity around 2040, and others achieve parity around 2030 and assumed further price reductions to as low as $5/kg. CARB completed additional analyses to investigate the drivers and opportunities that may present themselves to not only achieve self-sufficiency but also accelerate reduction in price at the pump to achieve price parity with gasoline sooner and to drive price below parity.

This analysis of pump price parity was completed by re-assessing the subset of Core Scenario Evaluations that achieve parity around 2040 and comparing them to scenarios that achieve parity earlier and/or push prices below parity. Figure 75 provides a side-by-side comparison of the price reduction trajectories explored. As shown in Figure 29, all scenario evaluations that follow the “Parity” pump price trajectory from the Core Scenario Evaluations achieve the $8/kg target in 2040 and then maintain that price through the end of the evaluation. These scenarios are included in the “Standard 2040 Price Parity” group of Figure 75. The Core Scenario Evaluations also contained a subset of scenarios that achieve parity around 2030 and further reduce price to $5/kg. These scenarios assumed the “Low Price” trajectory of Figure 29 and are included in the “Advanced Parity and Reduce” group of Figure 75.

CARB completed additional evaluations to investigate the options of achieving parity as soon as 2025 (but not committing State support to reduce price even further) and a modified version of the “Low Price” trajectory that achieves parity a little later (in 2035) before pushing price to $5/kg. For the “Advanced Parity and Hold” gourp, a simple linear price reduction was assumed to achieve $8/kg in either 2025, 2030, or 2035. After the target date, the price was held constant. For the modified “Advanced Parity and Reduce” case that achieves parity in 2035, a linear reduction to $8/kg in 2035 was assumed with further reduction at the same pace to a floor of $5/kg.

FIGURE 75: VARIATIONS ON TRAJECTORIES TO PUMP PRICE PARITY

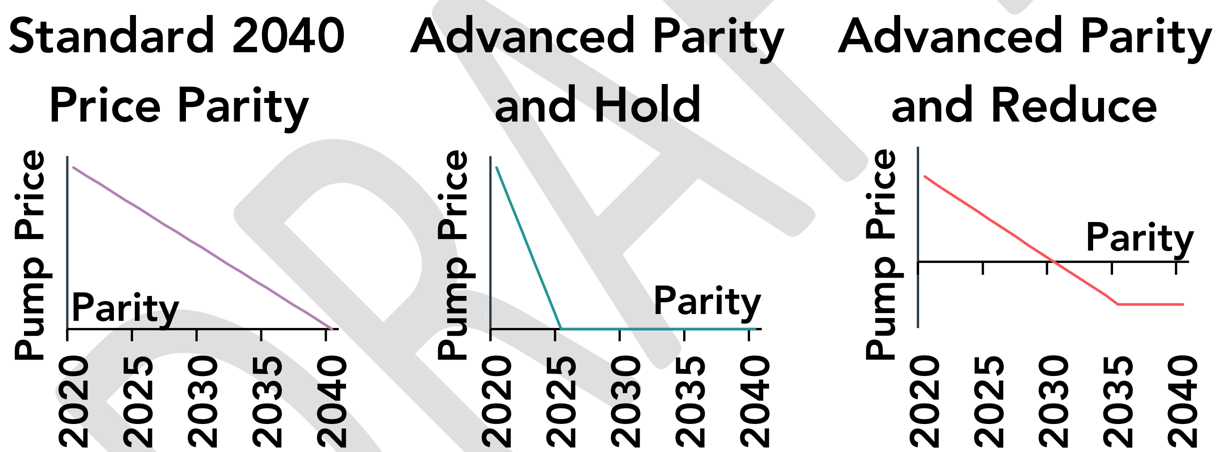


Figure 76 and Figure 77 show the impact on State support and timing to self-sufficiency (respectively) of advancing pump price parity to various years and holding the price of hydrogen at the pump at parity, providing a comparison between the “Standard” and “Advancing Parity and Hold” groups in Figure 75. These scenarios all assume Fast capital equipment cost reductions, and individual trajectories are shown for maximum and adjusted amounts of State support and for each of the three cases of hydrogen procurement cost trajectories (see Figure 25).

In all cases, advancing pump price parity from 2040 to 2025 can multiply support amounts by nearly ten times. If operational costs remain high and price parity is advanced to 2035 or sooner, the support amount to self-sufficiency is more than $1B, indicating these scenarios are infeasible. The maximum amount of State support is $3.8B for price parity advanced to 2025.

Even with the advantage of fast capital cost reduction and low hydrogen procurement costs, the estimated State support to additionally achieve price parity in 2025 is approximately ten times the amount when parity is not achieved until 2040. The magnitude of the impact is similar in the medium and high hydrogen procurement cost scenarios. With medium hydrogen procurement costs, advancing pump price parity can require as much as $664M for a 2025 parity date. However, if costs remain low, then the additional cost to achieve parity even as early as 2025 (with an estimated State support amount of $187M) is well within the central estimate of $100M to $400M to achieve self-sufficiency.

At low hydrogen procurement costs, the date of achieving self-sufficiency is essentially unaffected by advancing pump price parity. At medium hydrogen procurement costs, an additional five years are required to achieve self-sufficiency if pump price parity is advanced to 2030 or earlier. If hydrogen procurement costs remain high, the self-sufficiency date will be severely impacted for all advanced parity dates and is delayed from 2027 to 2041. Figure 78 and Figure 79 provide the same information for cases with slow capital expense reductions. The trends are generally similar though the costs are much higher (as high as $6.3B for parity in 2025 if hydrogen procurement costs remain high). Impacts on the self-sufficiency date are fairly equivalent between fast and slow capital equipment cost reduction scenarios.

Figure 76: Effect of Advancing Price Parity and Holding Steady on State Support for Various Hydrogen Procurement Costs and Fast Capital Expense Reductions with Full Utilization

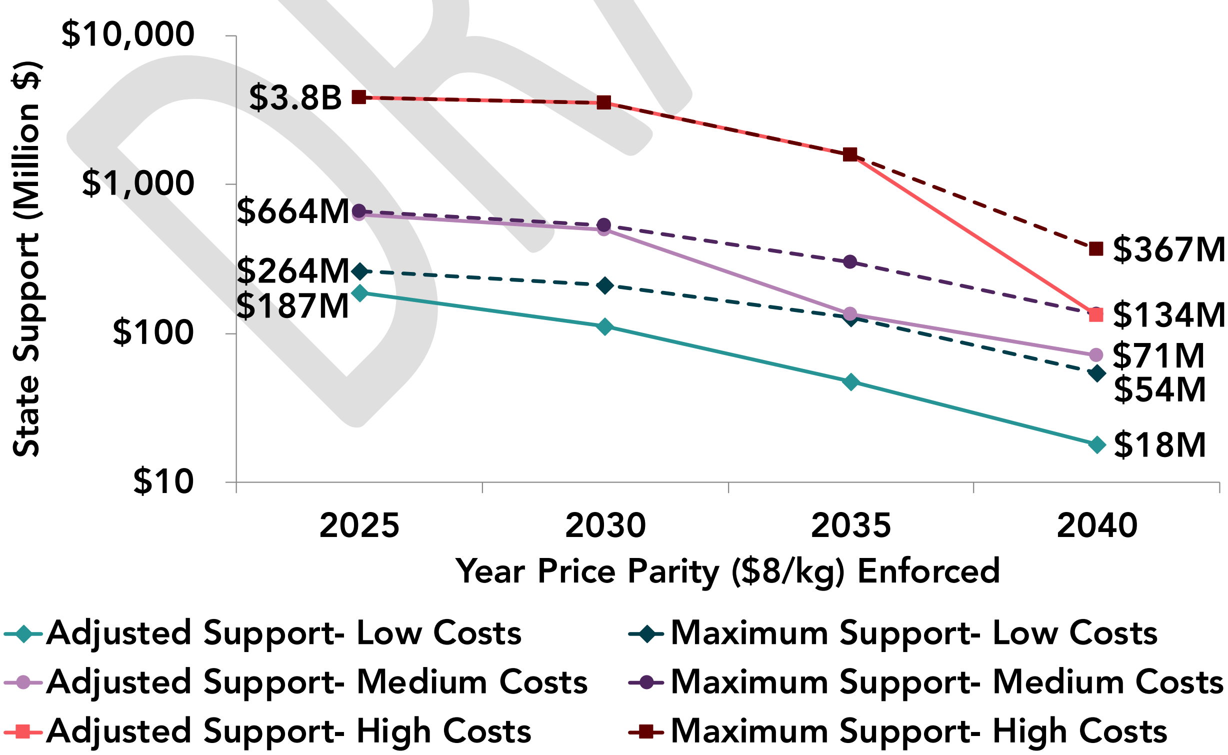


FIGURE 77: EFFECT OF ADVANCING PRICE PARITY AND HOLDING STEADY ON SELF-SUFFICIENCY DATE FOR VARIOUS HYDROGEN PROCUREMENT COSTS AND FAST CAPITAL EXPENSE REDUCTIONS WITH FULL UTILIZATION

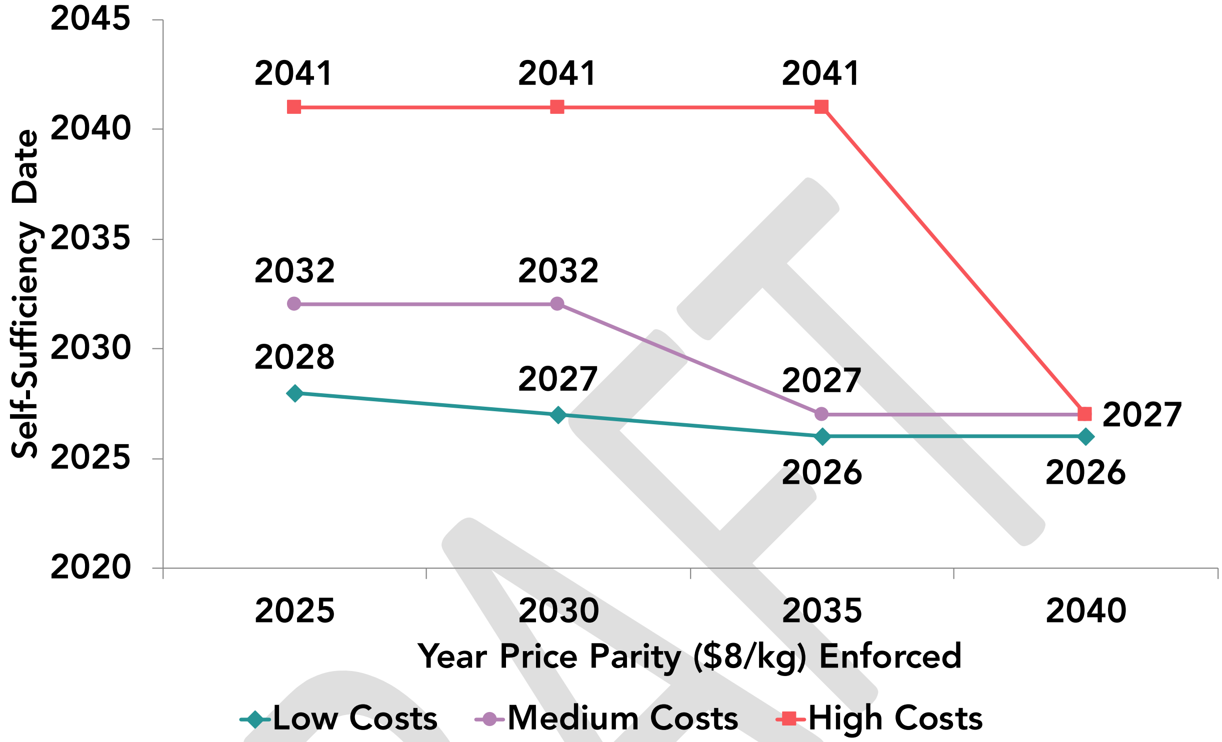


Figure 78: Effect of Advancing Price Parity and Holding Steady on State Support for Various Hydrogen Procurement Costs and Slow Capital Expense Reductions with Full Utilization

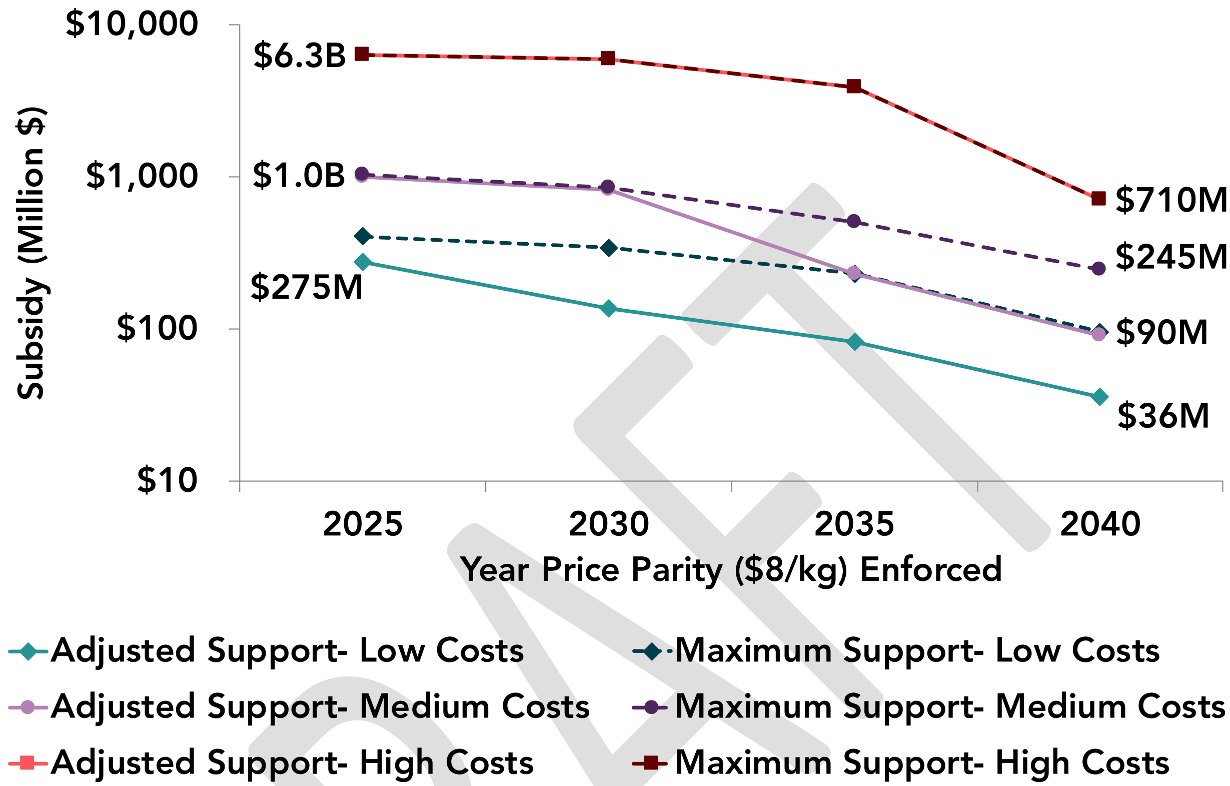


FIGURE 79: EFFECT OF ADVANCING PRICE PARITY AND HOLDING STEADY ON SELF-SUFFICIENCY DATE FOR VARIOUS HYDROGEN PROCUREMENT COSTS AND SLOW CAPITAL EXPENSE REDUCTIONS WITH FULL UTILIZATION

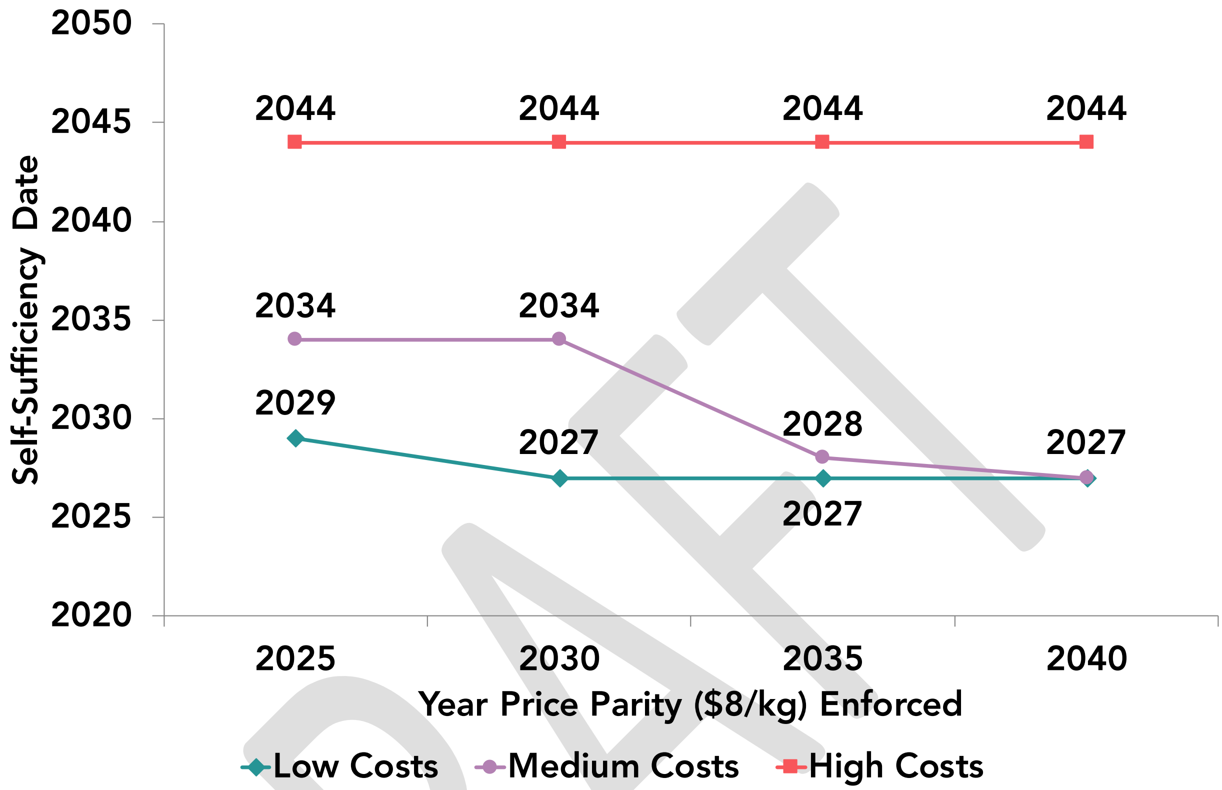
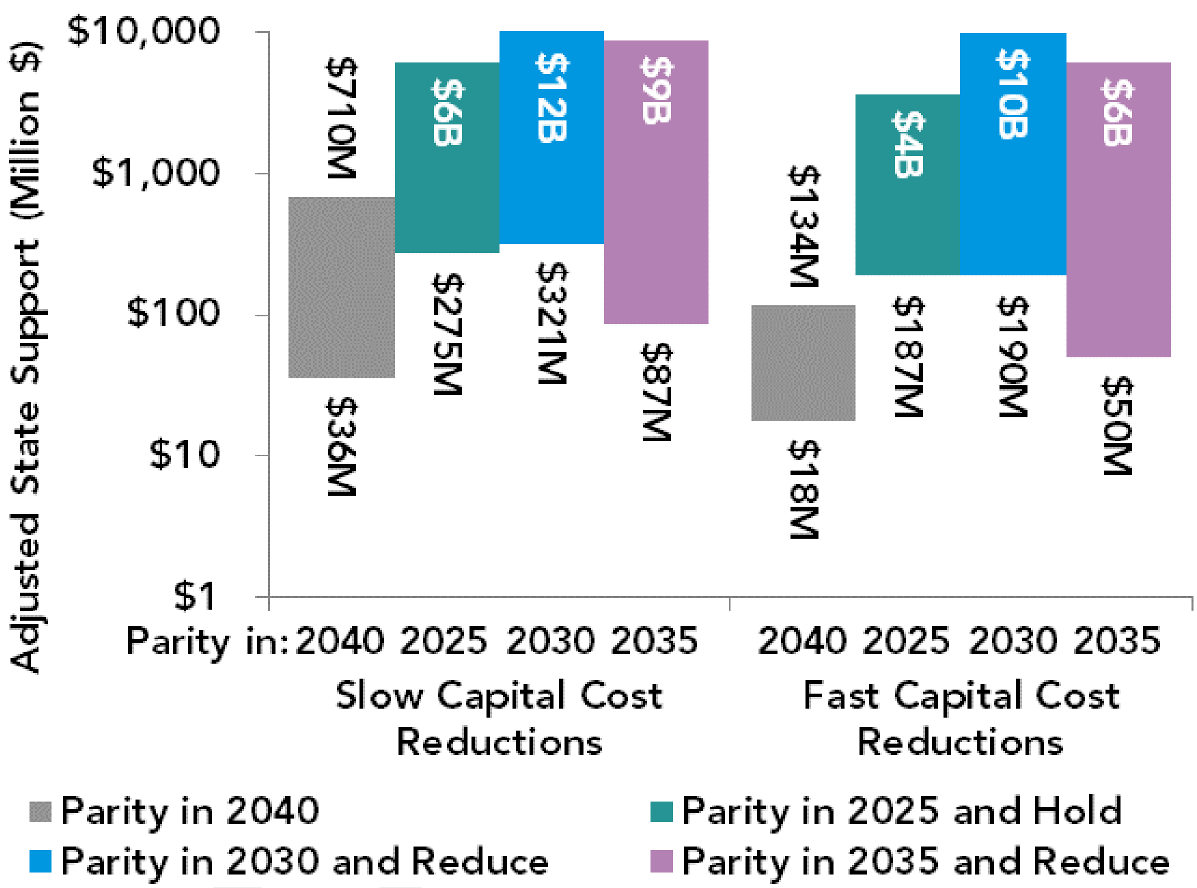


Figure 80 compares the State support amounts for the scenarios that assume price reduction to parity and holding to scenarios that achieve price parity and continue with further reductions to $5/kg. The range of costs to self-sufficiency span cases with low and high hydrogen procurement costs.

Results shown in Figure 76 and Figure 78 indicate that accelerating price parity to 2025 requires significantly larger amounts of State support to achieve self-sufficiency than allowing price parity to be delayed to 2040. If hydrogen procurement costs are low, then advancing price parity to 2030 and further reducing price to $5/kg indicates a similar amount of State support to the case when pump price parity ($8/kg) is advanced to 2025, but prices do not decrease any further. However, if hydrogen procurement costs are high, then pushing price at the pump below parity incurs a much higher amount of State support regardless of the year parity is achieved. On the other hand, if pump price parity is only advanced to 2035 before further reduction and hydrogen procurement costs remain low, then the additional support amount to achieve self-sufficiency is only marginally higher than cases that do not advance pump price parity at all.

All scenarios with accelerated price parity demonstrate the potential for significantly increased State support amounts to self-sufficiency compared to the base case that achieves parity in 2040. However, the ranges of potential State support amounts for all advanced parity scenarios in Figure 80 overlap with the central estimate of $100M to $400M estimated in the Core Scenario Evaluations.

FIGURE 80: COMPARISON OF STATE SUPPORT BETWEEN PUMP PRICE PARITY TRAJECTORIES



Taken together, these results demonstrate some limited flexibility in the design of State support programs that focus on providing maximum benefit to the consumer at the pump. The avenues available to the State depend significantly on the rate of cost reduction in capital expenditures and operations. If capital equipment and hydrogen procurement costs can quickly decrease, then advancing pump price parity to 2030 or even 2025 may indicate State support amounts similar to the central estimates provided in the Core Scenario Evaluations. On the other hand, if costs remain higher, then advancing pump price parity quickly becomes unattainable without significantly greater investment. At the same time, for the most optimistic cases that combine low capital equipment and operational costs, achieving price parity in 2030 and further reducing price at the pump to $5/kg does not incur a large additional support amount.

Intriguing possibilities become available in all cases when at least one of either operational or capital expenditure costs reductions occur quickly. In these cases, after State funding to price parity in 2035, further reductions to $5/kg cost no more to the State than holding price at $8/kg. This implies that further price reductions at the pump can be borne by industry. These scenarios are examples of State funding that enables a phase-out of those same State funding arrangements.

California vs Global Development

California has long been a leader in hydrogen fueling network development and FCEV deployment. However, a significant amount of the upstream supply chain development happens outside of California and even outside of the United States. Many jurisdictions around the world support the development of hydrogen-fueled transportation in various ways as part of their overall strategy to transition their energy system to zero-emission options. It is worthwhile to understand how California's leadership may affect the State support amounts and timing to achieve self-sufficiency of the in-state hydrogen fueling network compared to a strategy that relies more heavily on developments in the supply chain outside of the state.

Modified scenario evaluations were completed and compared to parallel scenarios with the standard CAFCR station network development. Modified scenarios considered network development in California to follow the slower BAU path, but with capital expenditure reductions dictated by broader global industry development. This was achieved by assuming that the broader global industry continued to develop along the CAFCR path, even though California-specific development was slowed. The capital cost for any station in the modified BAU scenario was set equal to the capital cost of the station's counterpart in the CAFCR case. Counterpart stations were determined by matching each station in the modified BAU scenario with the same n^{th} station of the same capacity in the CAFCR case. For example, the 10^{th} 600 kg/day station in the BAU scenario received the same cost reduction benefit as the 10^{th} 600 kg/day station in the CAFCR case. After the initial years of deployment, the counterpart station in the CAFCR case demonstrates greater cost reductions than the matching BAU station because it is built after greater total network development and economies of scale have greater impact. Thus, even though the BAU station was in a reduced California deployment scenario, it was assumed to receive the capital cost reduction benefits from broader global development.

Operational costs were not similarly reduced for the modified BAU cases as these costs are largely due to localized considerations, such as network densification. In addition, although not all future hydrogen fuel must be produced in California, at least some of it is expected to be, and the rest ideally sourced from nearby locations. This minimizes fuel transportation costs and emissions. Therefore, the operational costs are primarily driven by local considerations and not as affected by the broader global supply chain.

The modified BAU scenarios represent California networks that are approximately one-sixth the size of the California networks in the CAFCR scenarios in terms of stations and capacity. For both the modified BAU and CAFCR scenarios, evaluations were performed for Full utilization, Average utilization method, the full range of procurement cost-pump price pairings, and Fast and Slow capital cost reduction rates.

Figure 81 displays the State support amounts to achieve self-sufficiency for the modified BAU cases (labeled "Global Lead") and the CAFCR cases (labelled "California Lead"). Figure 82 displays the self-sufficiency dates for the same scenarios. The bottom of each bar represents data for scenarios with fast capital expenditure cost reductions, while the top of each bar shows data for slow capital expenditure cost reductions. In all cases, the minimum and maximum cost is greater in the global lead case than the California lead case by 25 percent to more than 100 percent[9]. Accounting for the difference in size of the California networks in these scenarios, slowing network development and waiting for broader global supply chain development to occur effectively costs up to ten times as much as the CAFCR case. In addition, California taking a leadership position always allows self-sufficiency to be achieved earlier than waiting on global development.

Comparing the Global Lead scenarios to the BAU results of Figure 64 reveals that the Global lead scenario does provide a modest cost reduction compared to BAU development with cost reductions limited only to California's network development. However, the savings in cost to self-sufficiency are only ten to twenty percent. These modest reductions pale in comparison to the higher effective cost that either BAU scenario (with cost reductions led either by California or global markets) entails compared to strategies that build larger networks in California.

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[9] The high end of High Cost-Parity for Global Lead ($609M) does not represent the likely total cost in this scenario. As Figure 82 shows, this scenario does not achieve self-sufficiency within the evaluation time frame. Therefore, $609M does not include the total cost and is only an estimate of the portion through 2050.

FIGURE 81: EFFECT OF CALIFORNIA SLOWING NETWORK DEVELOPMENT TO BENEFIT FROM GLOBAL INFRASTRUCTURE CAPITAL EXPENDITURE REDUCTIONS ON STATE SUPPORT AMOUNT

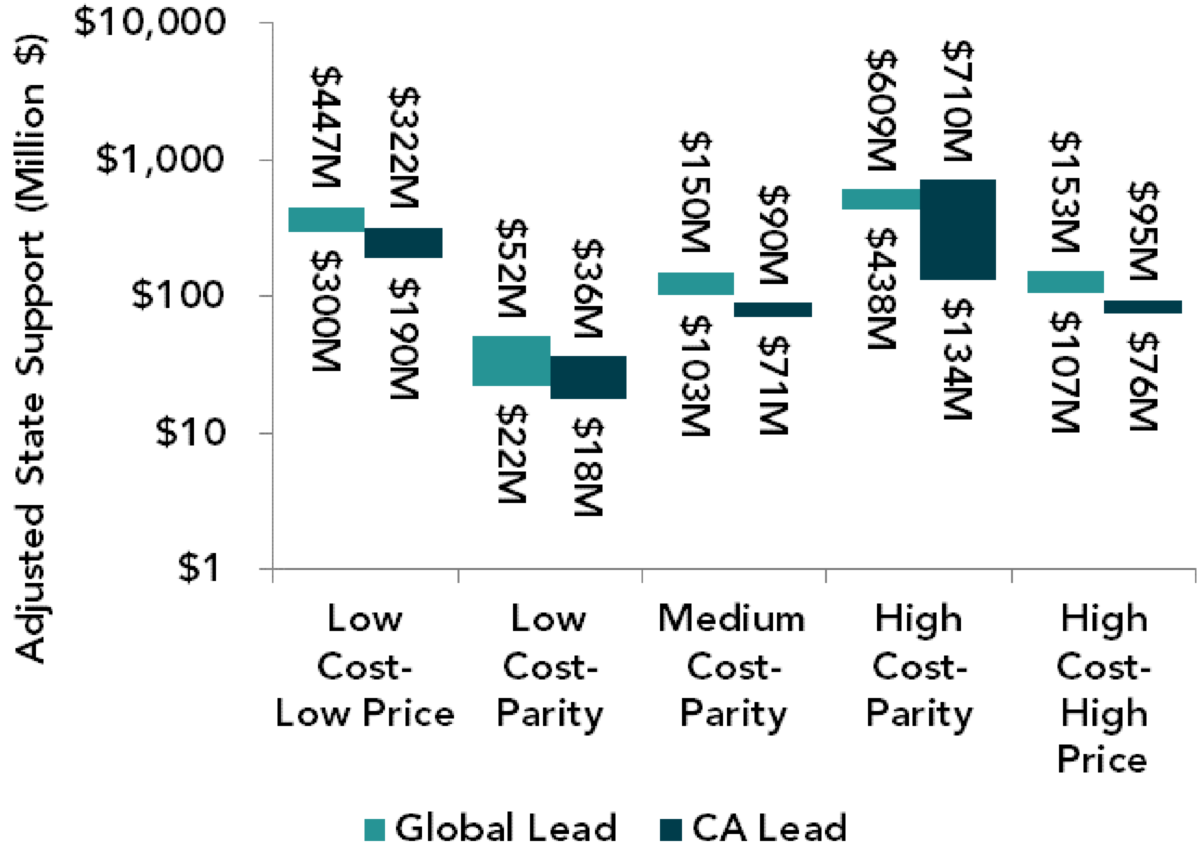
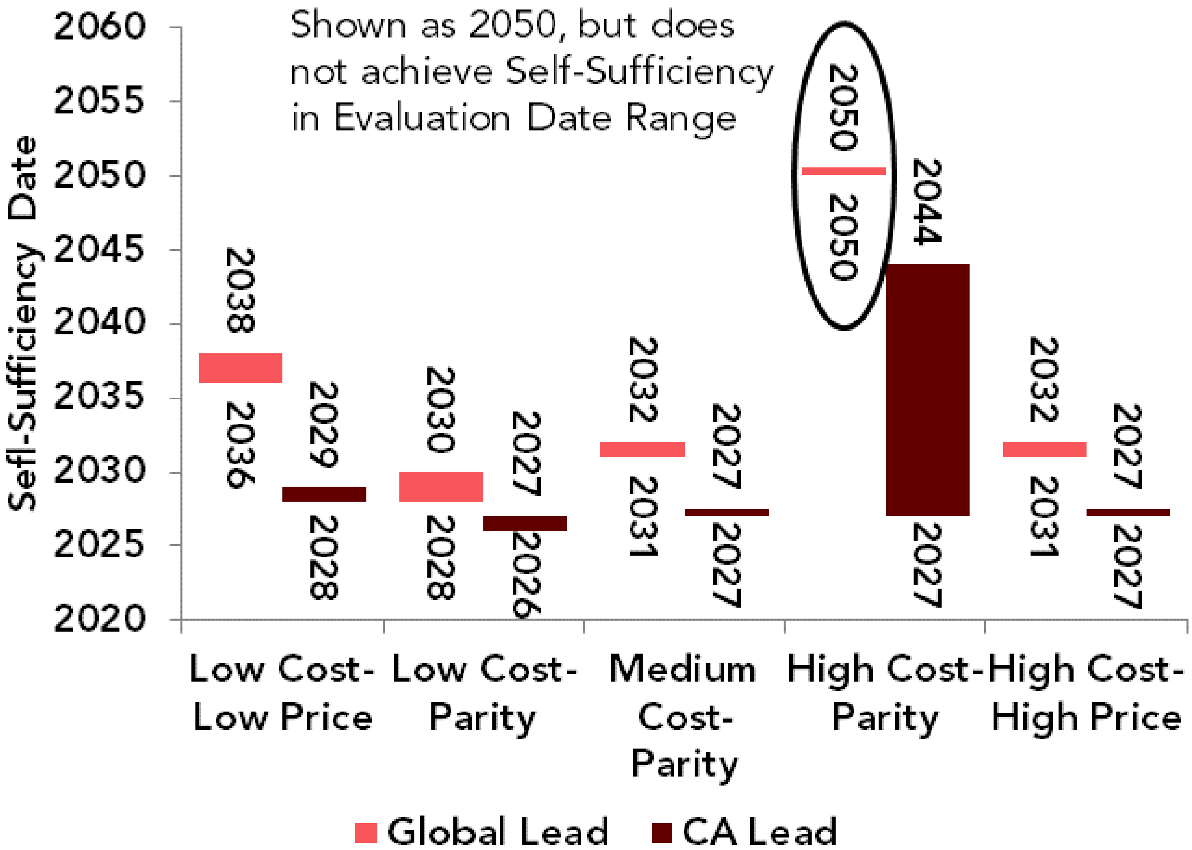
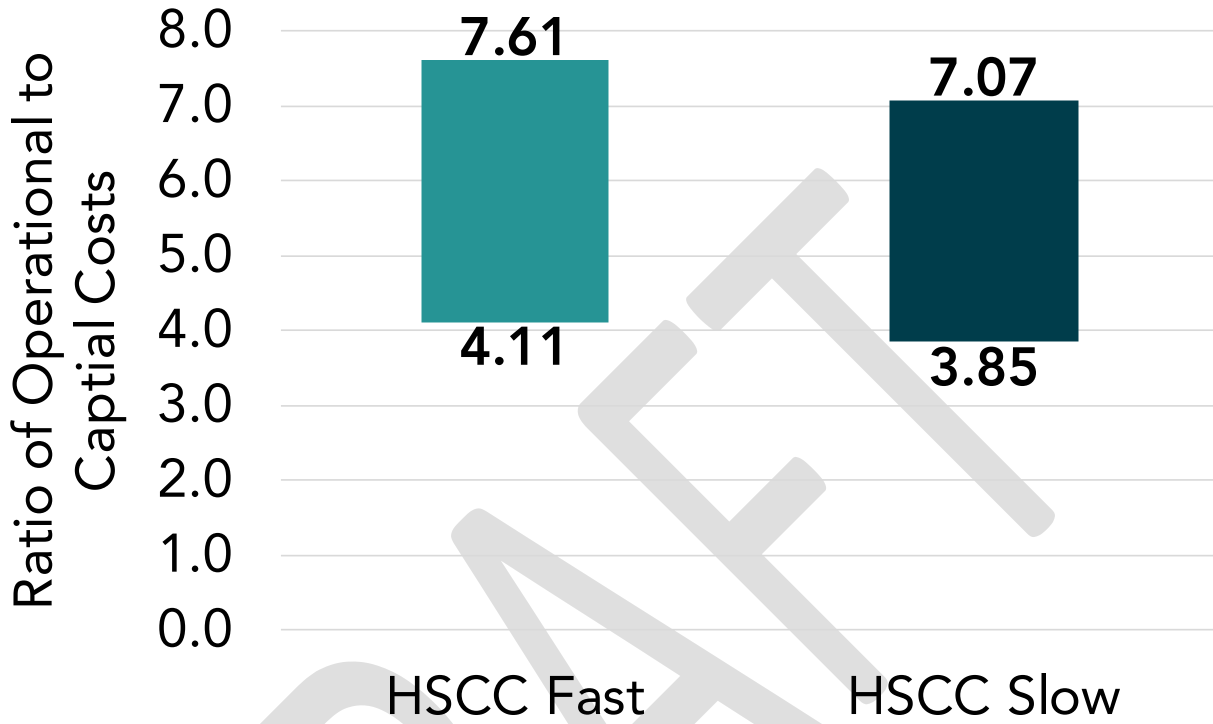


FIGURE 82: EFFECT OF CALIFORNIA SLOWING NETWORK DEVELOPMENT TO BENEFIT FROM GLOBAL INFRASTRUCTURE CAPITAL EXPENDITURE REDUCTIONS ON SELF-SUFFICIENCY DATE



These results may seem counter-intuitive. However, they are easily traced through an analysis of the costs for station development. Two broad categories are included in this study, capital equipment costs and operational costs. Evaluations like those shown for the Illustrative Scenarios in Figure 38 through Figure 40 exemplify the relative magnitudes of these two cost categories. In all three scenarios, it is clear that capital costs are significantly outweighed by operational costs. It is no different in the Global Lead scenario evaluations, as shown in Figure 83. For these scenarios, operational costs are approximately four to seven times the capital costs, regardless of the pace of cost reduction. These results emphasize that in-state operational costs dominate the financial performance of stations in California. These costs take primary consideration and cannot as easily be addressed by global market developments. Therefore, operational cost reductions are a more critical factor than capital cost reductions for achieving network self-sufficiency with smaller State support amounts. Since these costs are driven by scale of in-state network development, California State funds are more effectively used to accelerate industry development through local investment than a strategy that waits for global investments to reduce capital equipment costs.

FIGURE 83: COMPARISON OF CAPITAL AND OPERATIONAL EXPENSES IN GLOBAL LEAD SCENARIOS

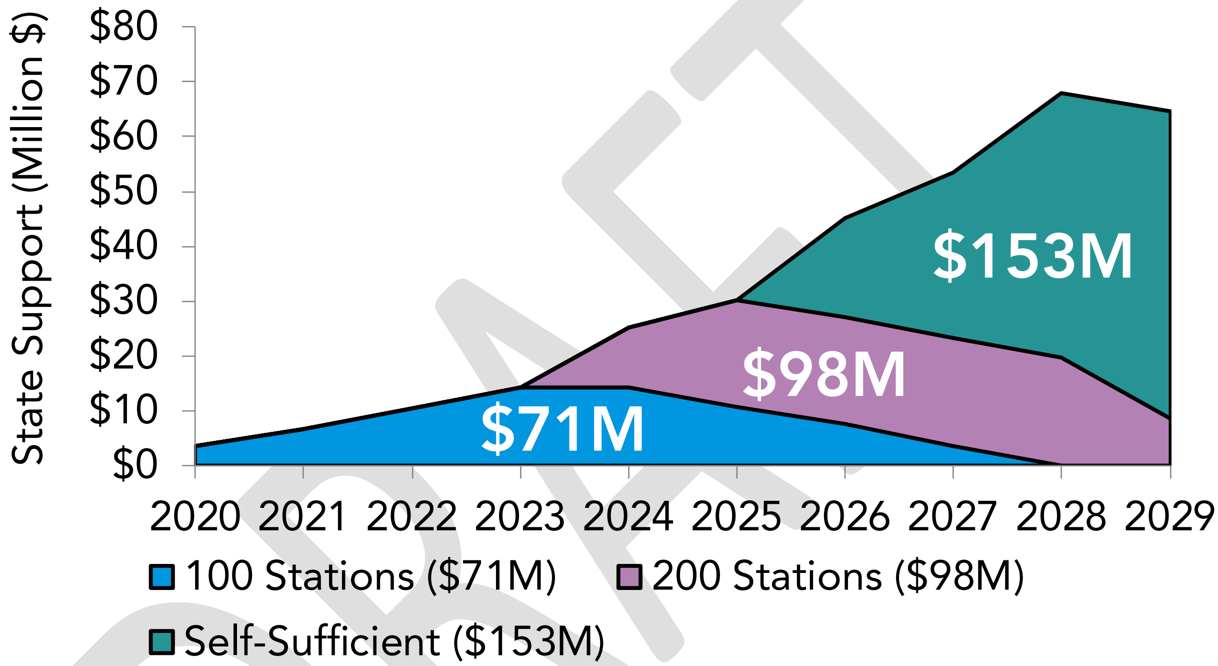


SELF-SUFFICIENCY BENEFITS TO THE CONSUMER

Financial self-sufficiency is a beneficial situation to the State and the station developer industry. Achieving self-sufficiency, as defined in this study, automatically implies that the economics of hydrogen fueling station development and operation are attractive to private investment and offer sufficient rates of return. At the same time, early investment by the State leads to an economically viable hydrogen market that reduces emissions of greenhouse gas and pollutants. Moreover, the industry would not require perpetual State financing in order to maintain operations. In addition to these advantages, the hydrogen-fueling consumer also benefits from access to a growing fueling network with price paid at the pump reducing at least to parity with gasoline.

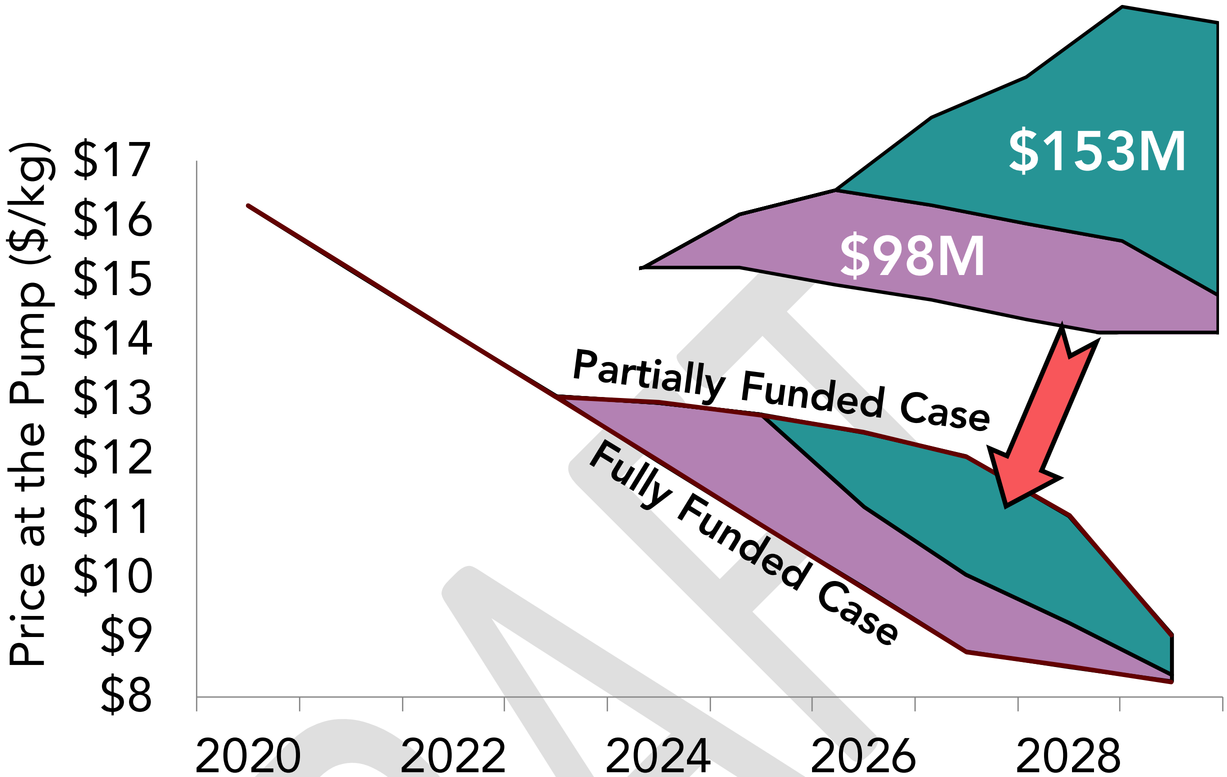
The potential benefit to the consumer was quantified by considering the State support amount that leads to self-sufficiency under the CAFCR deployment scenario with Full utilization, Average utilization calculation method, Low hydrogen procurement costs and Low fuel price, and Fast and Slow capital cost reductions. The State support amounts were then divided based on the network status achieved by each level of investment. Support amounts that achieve the 100-station target of AB 8 ($71M) , the 200-station target of EO B-48-18 (an additional $98M), and the ultimate target of network self-sufficiency (a further addition of $153M) are shown in Figure 84. Note that the total support amount to self-sufficiency for this scenario is $325M, near the middle of the estimates for achieving self-sufficiency as indicated by the Core Scenario Evaluations.

Figure 84: Incremental State Support Amounts to Support Various Levels of Station Network Development



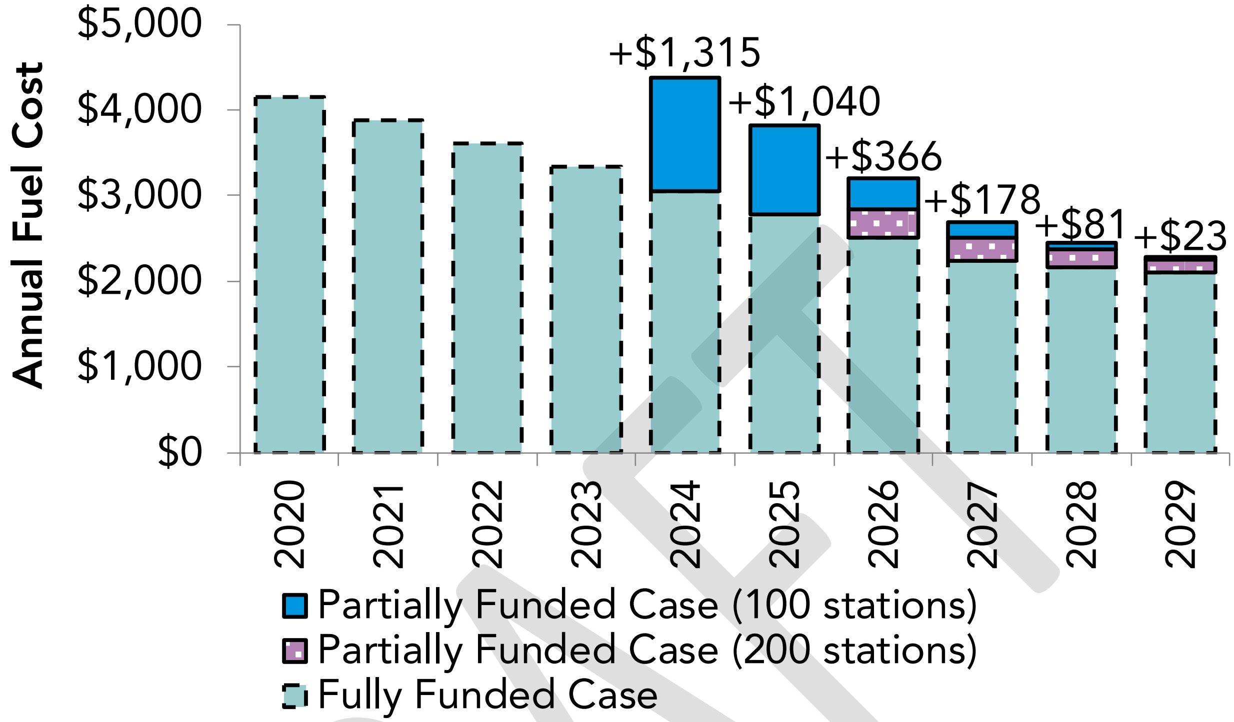
Each successive amount of State support to achieve a more complete network development is assumed to have a direct impact on price paid at the pump as shown by the example of Figure 85. If the State were to limit its role in the network development to only the first 100 AB 8 stations, then the additional gap in financing to station 200 and to self-sufficiency would have to be funded through some other means. In this case, it is assumed that the station operators would not bear the additional financial burden themselves and pass the additional costs on to the fueling customer. Therefore, once the State financing stops, the partially funded case incurs an additional price at the pump that the fueling consumer must pay.

FIGURE 85: EFFECT OF PARTIALLY FUNDING STATION NETWORK DEVELOPMENT ON HYDROGEN PRICE AT THE PUMP



As Figure 85 demonstrates, there is an immediate potential for a price shock, demonstrated by the gap in price at the pump between the Fully Funded and Partially Funded cases. The Partially Funded case immediately incurs a $5/kg additional price at the pump, which is more than a 40 percent increase. The additional price does fall over time, but lasts until nearly 2030. Over time, this additional cost adds up and affects the total cost of ownership and ultimately limits the pace at which a broader consumer base can afford to adopt FCEV technology. Using a standard assumption of 0.7 kg consumed each day for the average driver [37], this additional cost could be nearly $4,000 per driver over the course of approximately five years, as shown in Figure 86. Even with funding to 200 stations, the additional cost is approximately $2,000 to each consumer. These estimates likely represent a lower bound of additional costs to the consumer because they do not include the potential feedback loop of reduced station development pace. The additional financial burden passed onto the consumer could lead to slower FCEV deployment, lower utilization, and ultimately an even larger gap in station finances to be recovered.

FIGURE 86: IMPACT OF REDUCED STATE SUPPORT ON ANNUAL HYDROGEN FUEL COST FOR AVERAGE FCEV CONSUMER



Geospatial Investigations

Results and discussions In the preceding chapters address the economics of station development at the statewide network level, with some insights provided at the individual station level. The modeling methodology in this study also enables insights to be gained spatially. This is accomplished through the use of common station identification indices in both the CHIT-driven station placement algorithm and the subsequent financial evaluations.

Geospatial analyses were completed for the three Illustrative Scenarios:

- **Scenario A (Industry leads the way):** Industry advancements to reduce costs are extremely rapid (faster perhaps than seen today). While price to the consumer also falls over time, it does not reach gasoline parity until 2040.
- **Scenario B (Parity within the decade):** In an effort to create a more equitable situation for the consumer, the State decides to provide some form of additional support that enables price at the pump to fall sooner, reaching parity around 2030.
- **Scenario C (Government gets ahead of industry):** A State funding program is implemented to enable price parity at the pump by 2030, but industry progress to reduce costs for equipment is slower than expected. The State program additionally absorbs the financial burden due to the slower cost reductions.

These scenarios are all indicative of relative success in network development. All of these scenarios target the CAFCR network development rate and investigate highs and lows in the rate of reduced capital expenditures and prices paid by the consumer at the pump. Figure 87 through Figure 89 display the spatial variation in the State support for each of the illustrative scenarios. Figure 90 through Figure 92 display the spatial variations in the year of first profitability for stations in the local network. All data shown are averages within hexagonal evaluation cells with an area of 35 square miles. Note that city names are offset in order to better display the mapped data without conflicting with the labels.

For Figure 87 through Figure 89, areas that do not include any stations receiving State support are not mapped. By comparison to figures Figure 90 through Figure 92, it is immediately apparent that in all scenarios there is a significant portion of the network that does not require any support from the State whatsoever. These regions that do not display a need for State support are mostly concentrated in the highly urban primary markets that have so far been the focus of station co-funding through AB 8.

Scenario A models an extremely optimistic scenario, with significant industry-enabled cost reductions immediately improving station financial performance. However, it also maintains high revenues at the cost of the consumer, with price parity not achieved until 2040. This combination of low cost and high revenue was previously shown to result in little to no need for additional State financing. As shown in Figure 87, all stations in this scenario individually require less than $1M in State support, and there are exceedingly few stations that need any support at all. Most stations require between \$100K and \$500K. These stations also tend to be along long-distance travel routes or in remote locations. Figure 90 shows that the majority of stations are profitable before 2035 (many even before 2030), with an exceedingly small number remaining unprofitable until as late as 2040. In this highly favorable scenario, limited State support is required and it likely could be specifically targeted to individual station projects that expand network coverage into the hardest-to-reach areas. These locations within the state are the most difficult to maintain positive cash flows due to limited FCEV deployment.

Scenario B improves the economics of FCEV ownership for the consumer by advancing hydrogen fuel price parity to 2030. As a result, this scenario demonstrates noticeably more extensive geographic range of stations relying on State support, as shown in Figure 88. The majority of these areas require at least \$100K per station on average, with a non-trivial number of areas requiring more than \$500K and in some cases more than \$1M per station in the region on average. Funding needs are also no longer limited to remote regions or smaller secondary markets, and even some of the highest support amounts are projected for parts of the more urban core market areas like the San Francisco Bay Area and Orange County. There are also notable clusters of funds provided to stations along the CA-99 corridor, which includes many cities that may present significant market development opportunity as the network grows larger, but will need corresponding financial assistance to do so. The time to profitability is not severely impacted in most locations in this scenario, as shown in Figure 91. However, there are a few (mostly outlying) areas where profitability cannot be achieved until after 2045 on average. This scenario highlights the difficult financial position that stations in more challenging areas may face.

In Scenario C, the slower pace of cost reductions results in more stations that experience challenging cash flows. The geographic dispersion of stations receiving State support is greater than in Scenarios A and B, with stations requiring funding in more than 50 percent of the areas where fueling network development occurs. The intensity of funding is also amplified. Approximately one-third of areas indicate a need for at least \$500K per station, and one-sixth of areas require \$1M or more in State support to achieve self-sufficiency. Even these highest-cost stations are dispersed across the state: in the metropolitan core market areas, new markets expected to develop in the near future, and connector and destination markets. In this scenario, less than half the network achieves profitability prior to 2030. Still, most areas still achieve profitability prior to 2040 and particularly challenged areas with extremely late profitability are similar to Scenario B.

FIGURE 87: SPATIAL VARIATION OF STATE SUPPORT IN ILLUSTRATIVE SCENARIO A

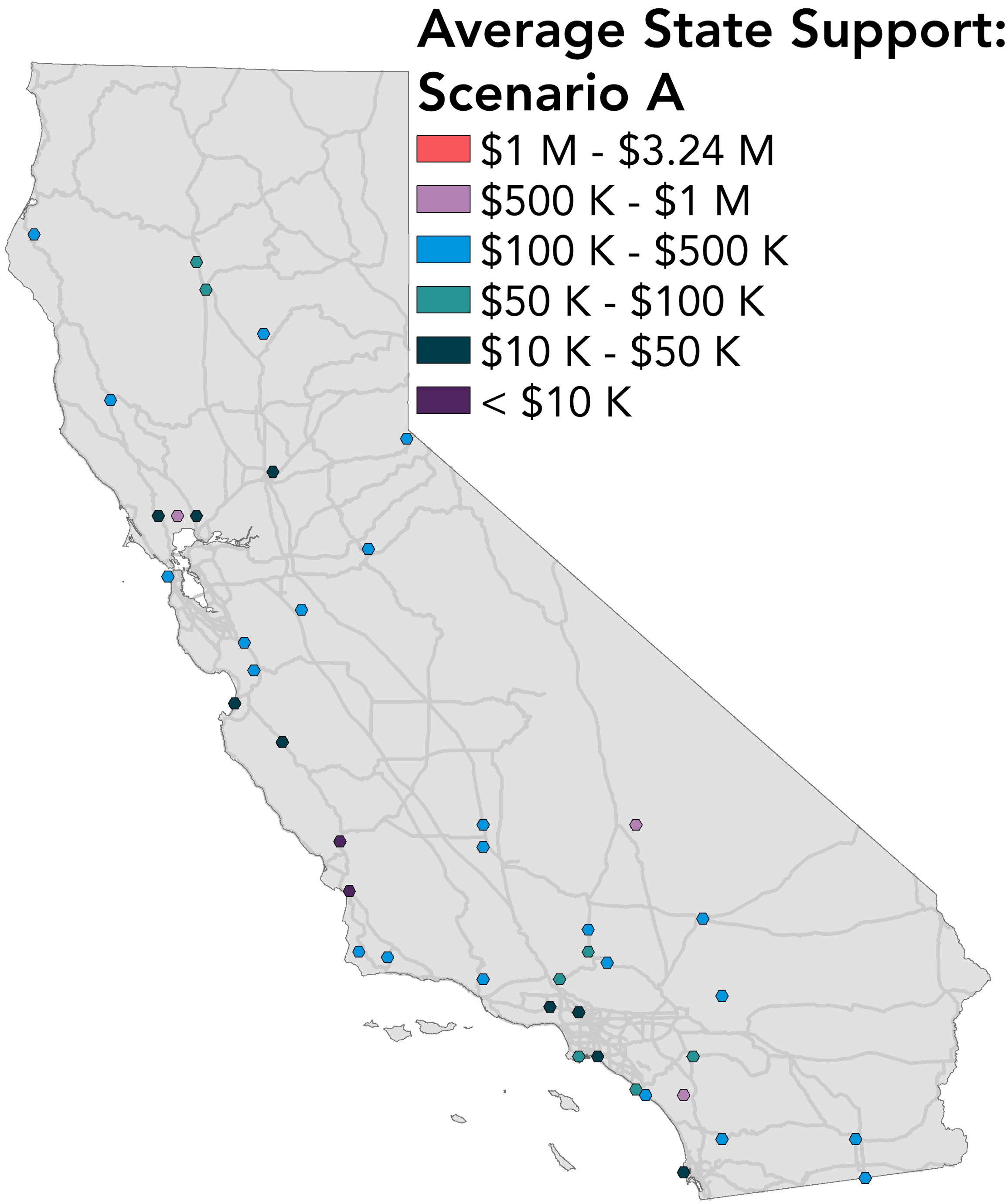


Figure 88: Spatial Variation of State Support in Illustrative Scenario B

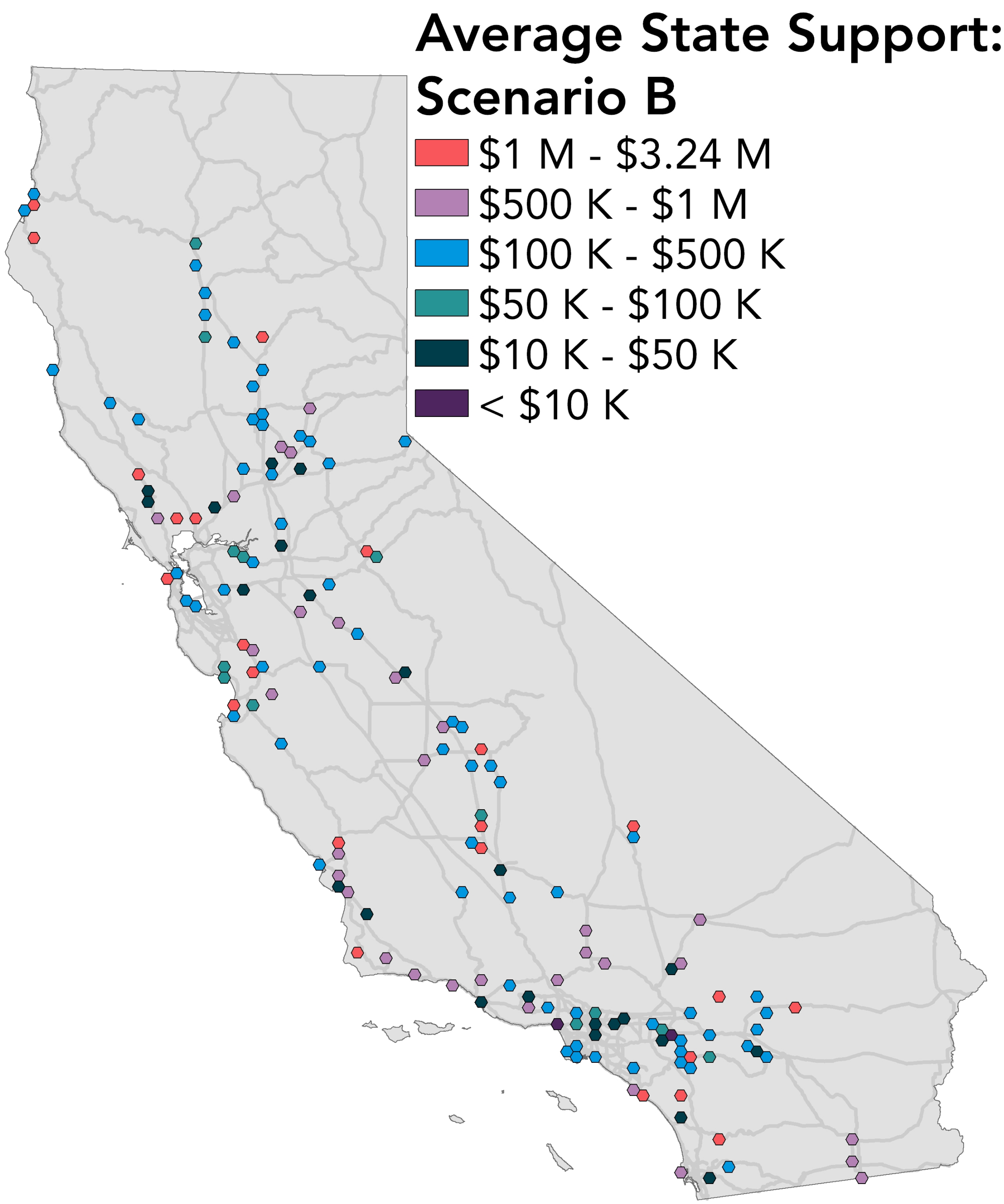


Figure 89: Spatial Variation of State Support in Illustrative Scenario C

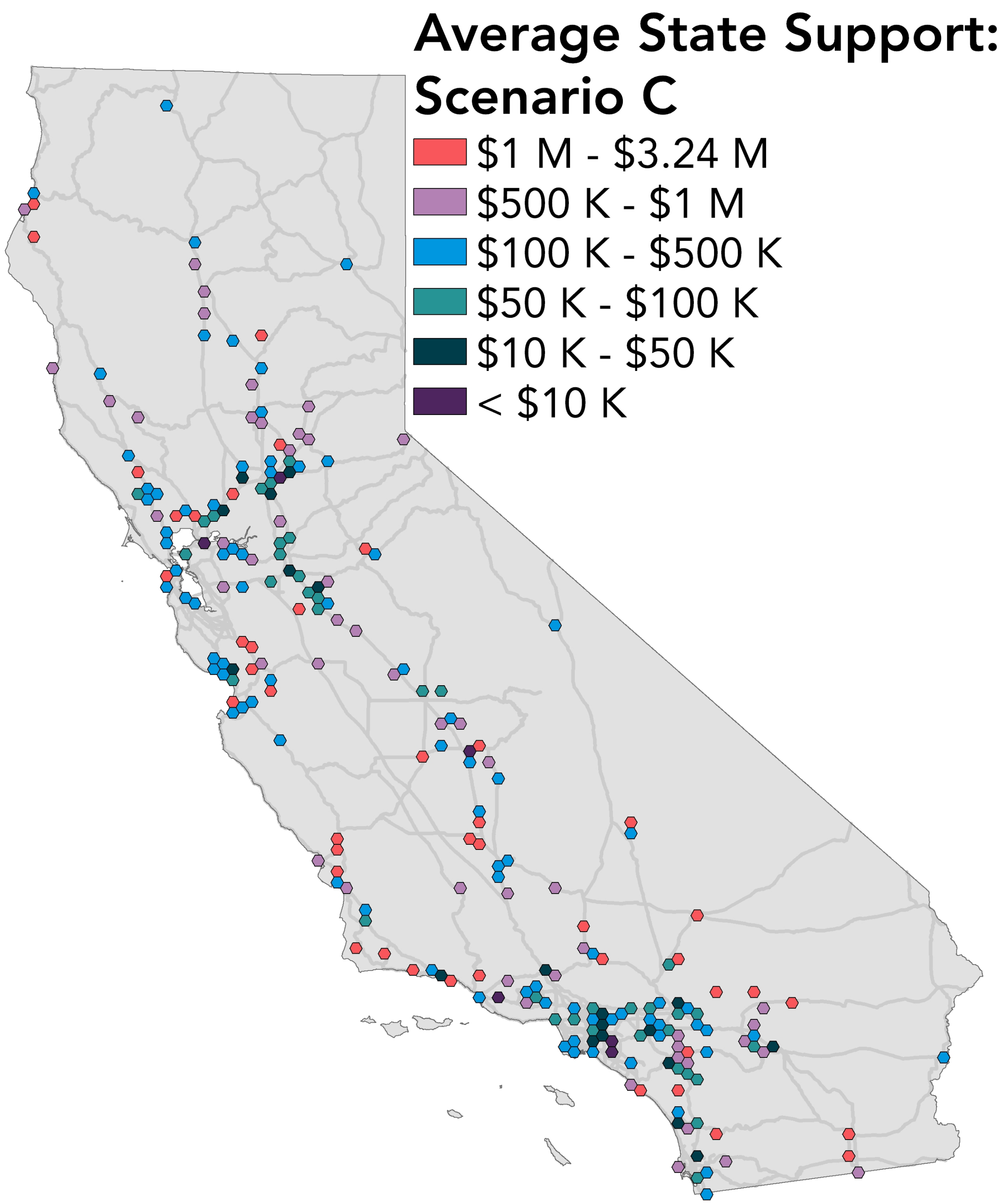


FIGURE 90: SPATIAL VARIATION IN FIRST YEAR OF PROFITABILITY FOR ILLUSTRATIVE SCENARIO A

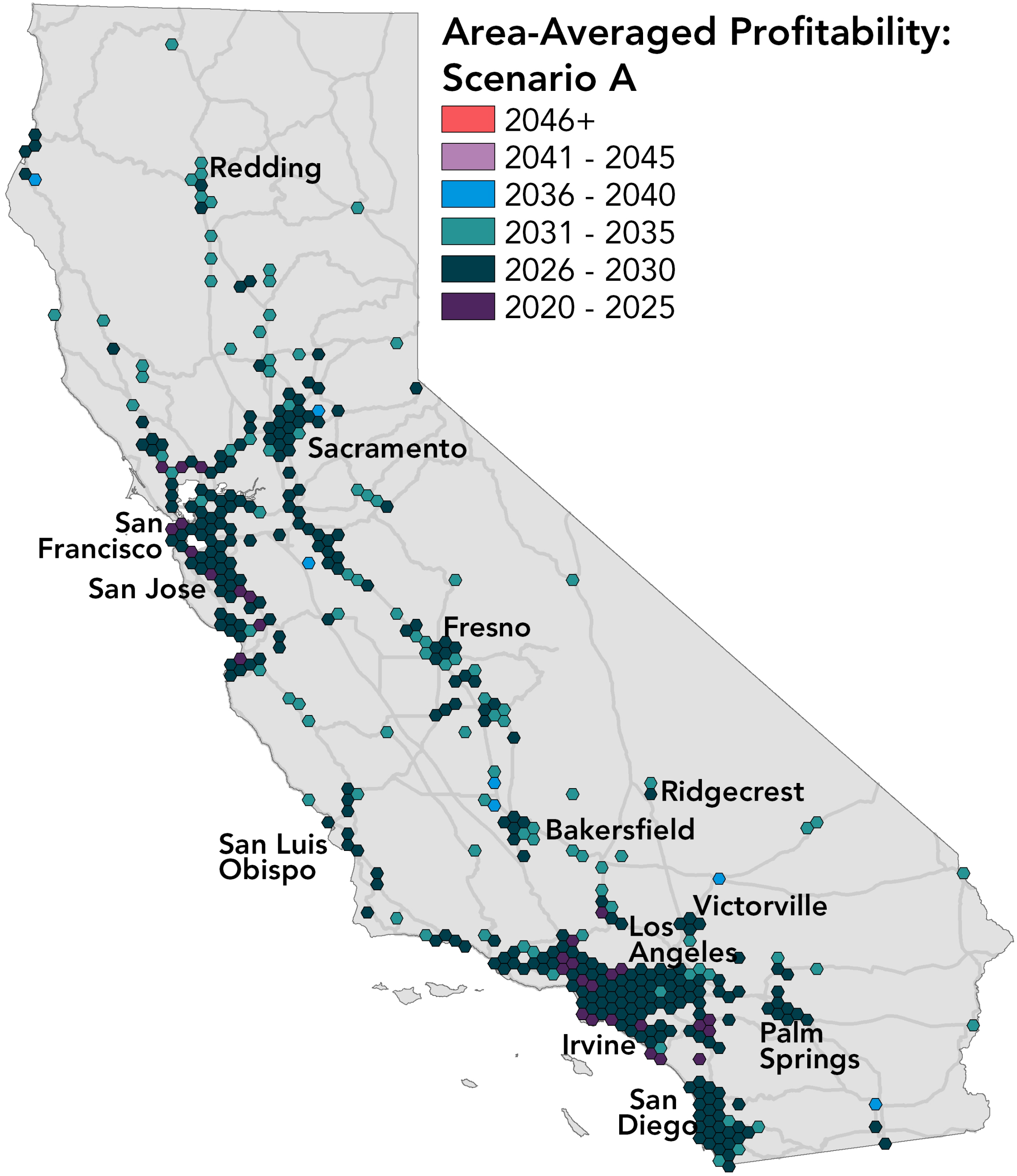


FIGURE 91: SPATIAL VARIATION IN FIRST YEAR OF PROFITABILITY FOR ILLUSTRATIVE SCENARIO B

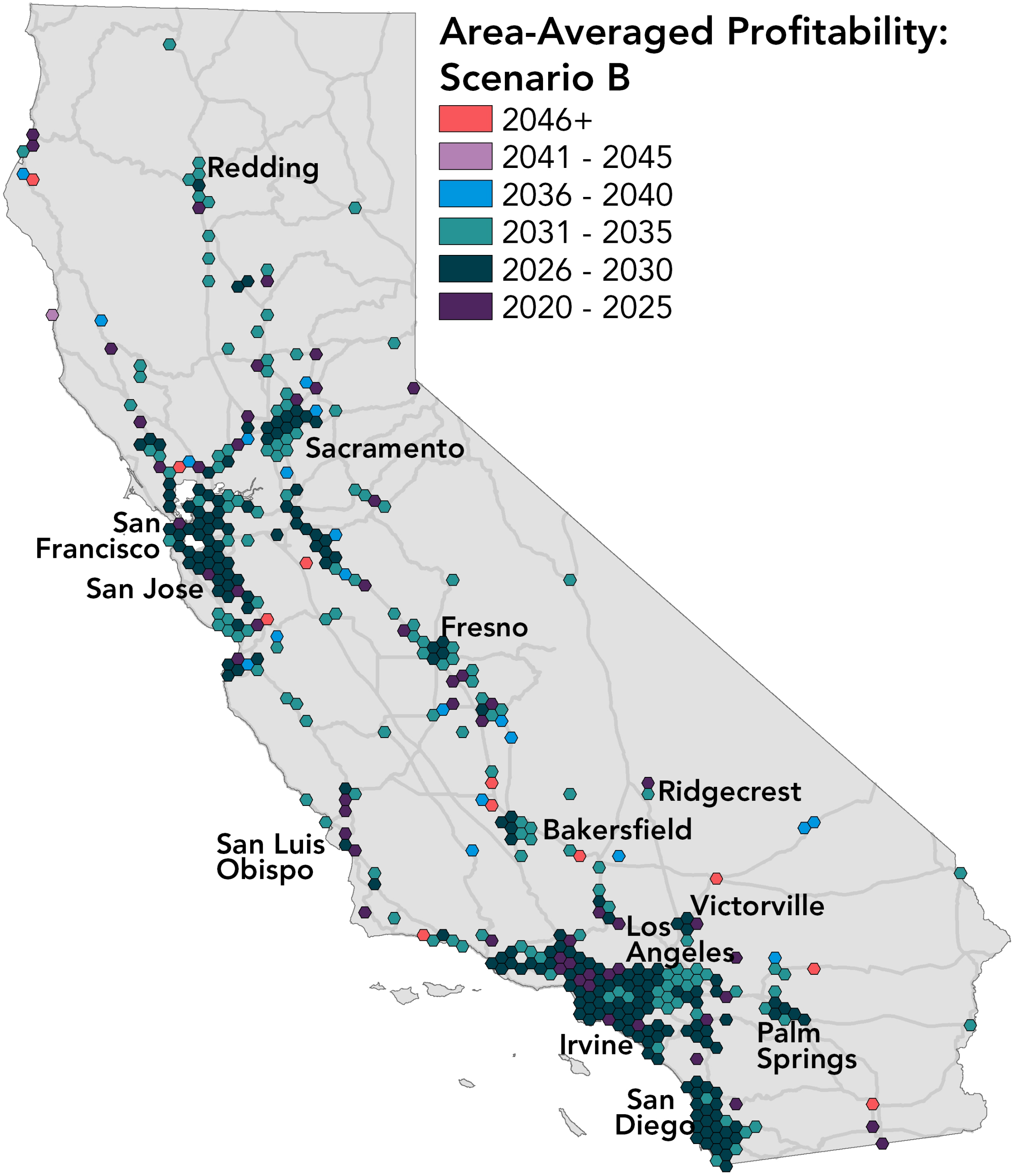
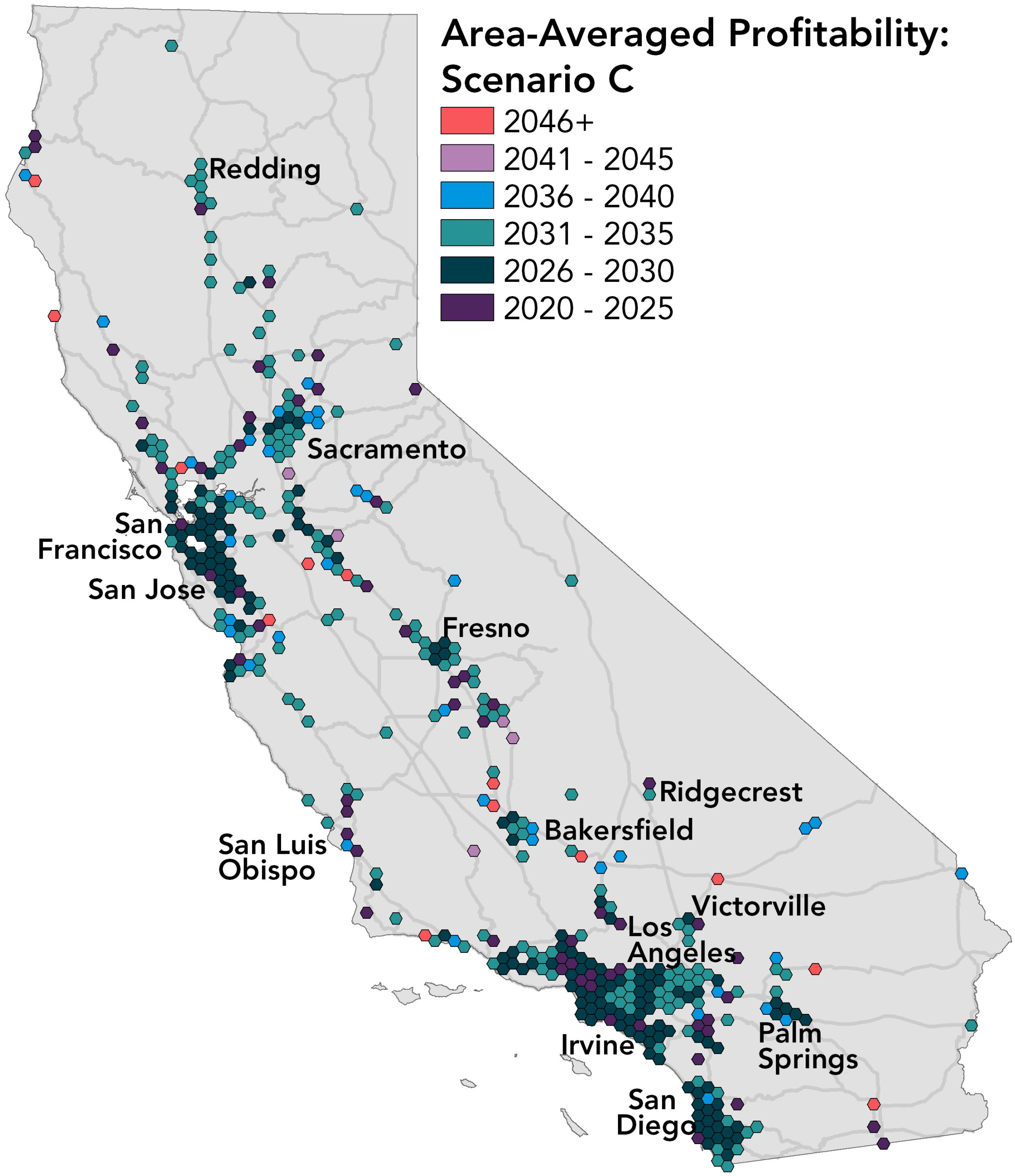


Figure 92: Spatial Variation in First Year of Profitability for Illustrative Scenario C



Conclusions

The analyses presented in this study were developed to directly address the question of cost to the State and timing required to support the development of a financially self-sufficient light-duty hydrogen fueling network in California. The preceding analyses provide insight into the sensitivity of these estimates according to several variables including the target FCEV population and hydrogen station network size and capacity, pace of market development, advances in cost reductions, and rate of reduction in price paid by the consumer. Extended analyses also provide potential guidance for other policy-forming decisions that can impact consumers in addition to the cost and timing to self-sufficiency. Major conclusions based on the preceding analyses are summarized here.

Early and relatively small (compared to the total network-building investment) State support amounts can launch California's hydrogen fueling station network to self-sufficiency.

The results of this study clearly identify multiple scenarios in which State financial support can be phased out and the station economics remain sufficiently favorable to encourage ongoing investment and development by the private sector. The total amount of support beyond the current AB 8 program and the self-sufficiency date vary by scenario, but the most likely scenarios indicate an additional State support amount approximately equal in size to the current AB 8 program. Even though these funds are certainly significant, especially for the potential impact on network development, they are a small part of the total network investment necessary to reach self-sufficiency. Representative scenarios place the State support at approximately 10 percent of the total investment; the remaining 90 percent of costs would be borne by private industry.

The most likely range of total State support to achieve self-sufficiency is estimated at approximately $100 to $400M. When accounting for the $115M anticipated in AB 8 funds through GFO 19-602, the total amount is up to $300M beyond existing programs.

This study demonstrates that the total State cost to network self-sufficiency will depend on a variety of factors both within and outside of State control. Within the range of scenarios studied, costs can be as low as zero additional dollars beyond AB 8 to as high as several billion dollars. However, the extreme high costs are highly unlikely as the scenarios that lead to them include several worst-case assumptions. Even costs above $400M are found to be outside the most likely range of costs in this study. As Figure 93 shows, the central estimate for cost to achieve self-sufficiency is between
$100M and $400M. The AB 8 program has approximately four years of implementation remaining, with $115M to be disbursed through GFO 19-602.

Accounting for these funds, the additional State support remaining beyond AB 8 is up to $300M. This amount may not account for potential additional funds to accelerate reduction in price at the pump and achieve parity with gasoline earlier than 2040. As Figure 94 shows, these funds would support development of up to an additional 250 stations beyond the EO B-48-18 goal of 200 stations by 2025 (which are supported by both the AB 8 and the LCFS HRI programs).

FIGURE 93: SUMMARY ESTIMATES OF STATE SUPPORT TO SELF-SUFFICIENCY

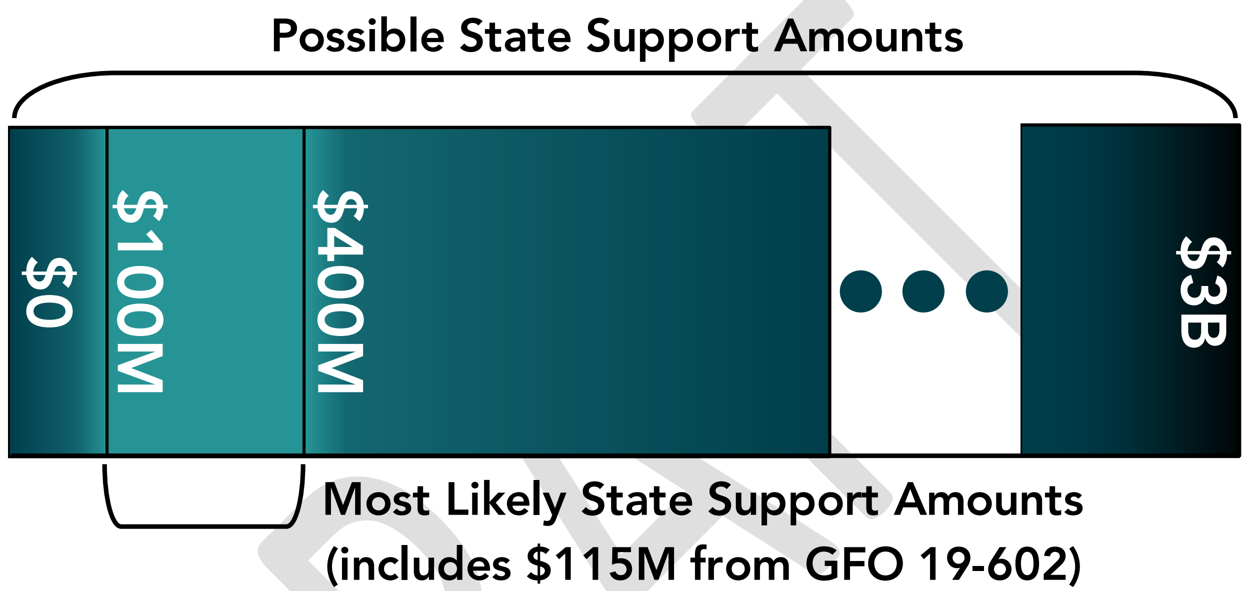
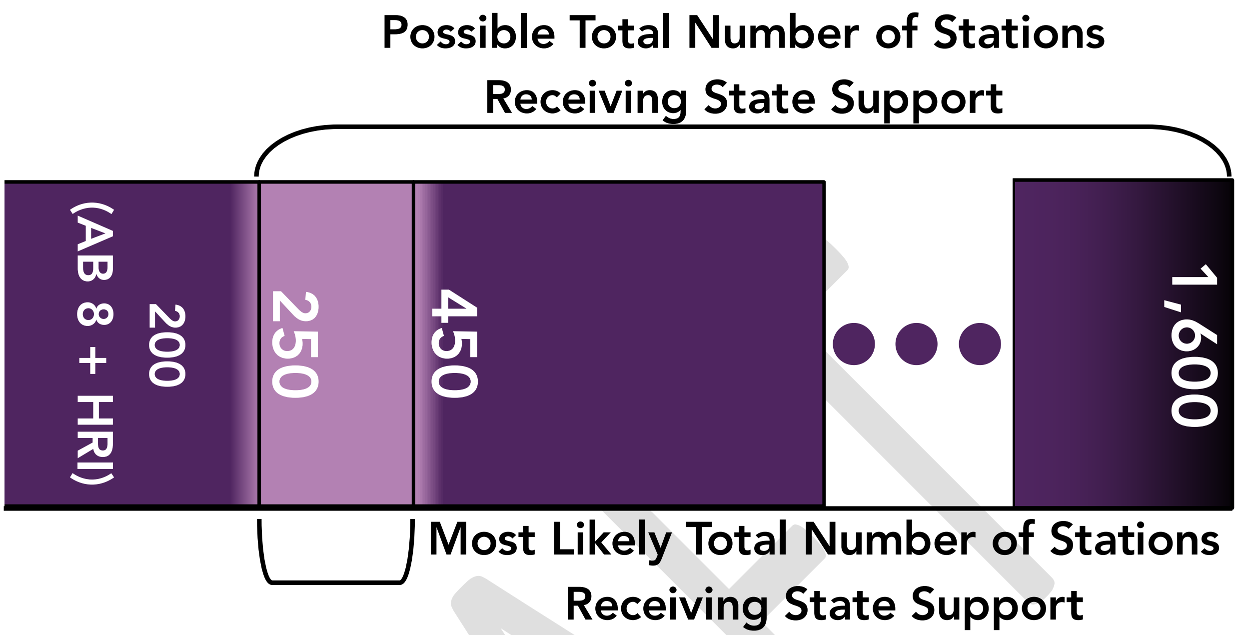


Figure 94: Summary Estimates of Number of Stations Receiving State Support



The amount of State support that leads to self-sufficiency is most strongly impacted by the balance of operational costs and price paid by the consumer, reductions in capital cost, and station utilization.

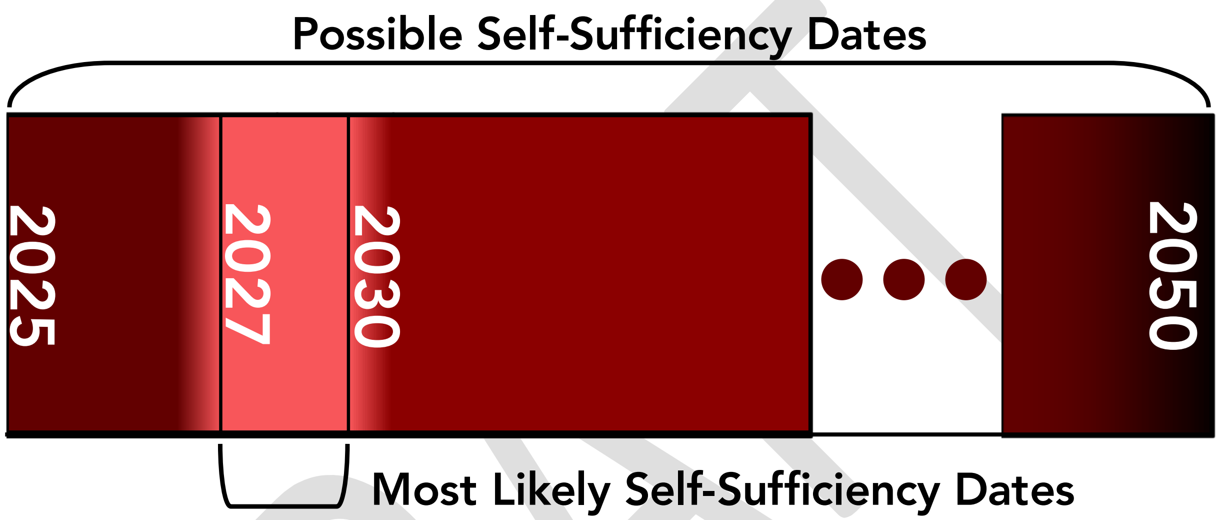
This study investigated a wide range of factors that impact the financial performance of individual hydrogen fueling stations and the network as a whole. These in turn affect evaluation of the State support amount and the time to achieve self-sufficiency. Among the variables investigated, the most influential has been shown to be the balance between operational costs and price paid at the pump, followed by capital expenditure costs, and finally station utilization. These factors are all directly or closely related to classical economic factors of costs and revenue. These results also demonstrate that a financially healthy hydrogen station network also critically relies on sufficient FCEV deployment.

Self-sufficiency is estimated to be achievable between 2027 and 2030 and is relatively unaffected by many factors investigated in this study.

The financial evaluations of this study investigated buildout of the state's hydrogen fueling network through 2035, and investigated their economic performance through 2050. The vast majority of scenario evaluations demonstrate the potential to achieve self-sufficiency within that analysis timeframe. While a few scenarios did not achieve self-sufficiency even by 2050, this occurrence is extremely limited and most closely associated with scenarios that include a high number of worst-case assumptions. As

Figure 95 shows, the central estimate of the self-sufficiency date is tightly clustered in the late 2020s to 2030 range. Unlike the cost to self-sufficiency, the timing to self-sufficiency was relatively unaffected by the variables investigated in this study. Variations do exist, but are most often limited to a handful of years. If a station network was able to achieve self-sufficiency, it most likely did so within this range or a few years thereafter.

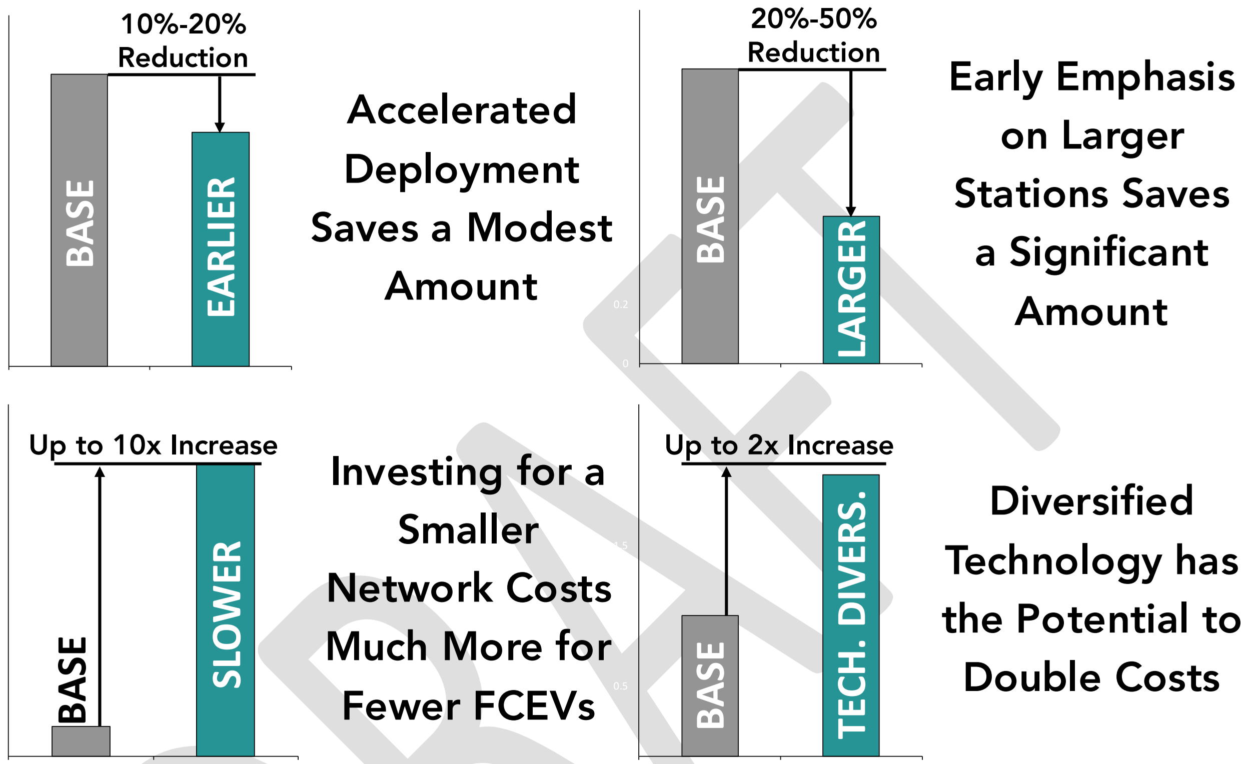
FIGURE 95: SUMMARY ESTIMATES OF TIME TO SELF-SUFFICIENCY



Larger and more rapid station development leads to a greater benefit per dollar of State support than slower development strategies, as long as vehicle deployment matches pace.

This study investigates multiple strategies for planning hydrogen fueling station network development based on assumed future volumes of FCEVs on California's roads. Comparing across scenarios, it is clear that a buildout strategy that targets a larger on-road fleet, initiates station development faster, and enables larger-capacity stations sooner provides a greater benefit for the same cost to the State. While it is possible for a scenario with a much smaller network to cost less than a scenario with a larger network, the cost savings are not large enough to counterbalance the lost revenue due to smaller numbers of FCEVs on the road. Figure 96 demonstrates that, compared to the scenario put forward by the California Fuel Cell Partnership's *Revolution* document, faster station development can reduce State support by 10 to 20 percent. However, if a much smaller pace of station development along the pace of Business-as-Usual continues, then the per-unit costs to the State (per-station, per-kilogram of fueling capacity, or per-FCEV) is nearly ten times as large. More rapid station development targets enable economies of scale sooner, thereby improving the financial picture for individual stations earlier in network development and making the approach to self-sufficiency more affordable and more quickly accomplished.

FIGURE 96: EFFECT OF NETWORK DEVELOPMENT STRATEGIES AND TECHNOLOGY DIVERSIFICATION ON STATE SUPPORT TO SELF-SUFFICIENCY



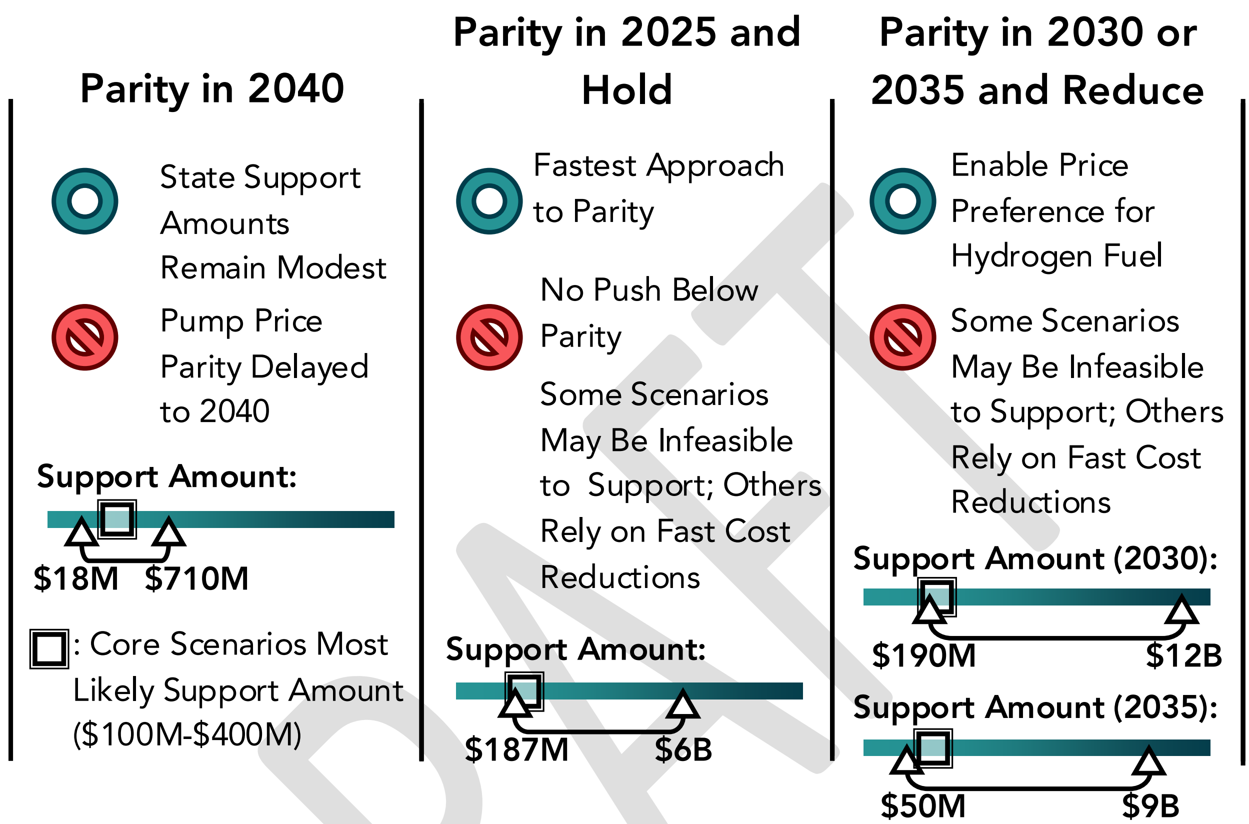
The pace of reducing capital costs can have a significant effect on the State support amount that leads to self-sufficiency, but operational costs play an even greater role.

The pace of capital cost reduction was the second-most influential factor in determining State support to self-sufficiency. As an example, Figure 96 shows how technology diversification (where cost savings cannot be shared among varying station designs) can increase total the State support amount by as much as 100 percent. Even with more homogenous cost reductions, the difference between fast and slow reductions due to economies of scale and technology development can also increase total State support by 100 percent. Still, the influence of variations in capital cost reductions are less impactful to total cash flows at the station and network level than operational costs, which make up a much larger portion of total expenditures.

Advancing pump price parity to deliver consumer savings potentially incurs a range of additional costs to the State, depending on the pace of price reduction. However, opportunities exist to advance price parity and support price reduction below parity, with little to no additional State support, if operational and capital expense costs rapidly decline.

The central estimate of up to $300M to support hydrogen station network development to the point of self-sufficiency is based on State support estimates for several potential scenarios with variations in hydrogen station development and operations costs and price paid at the pump. Further investigation of approaches to accelerate pump price parity indicate that the central estimate may not be sufficient to deliver cost savings to the consumer on an accelerated schedule. Because of the reduced sales revenue, accelerating pump price parity can inflate State support amounts by as much as a factor of ten for equivalent assumptions of capital and operational cost reduction. Figure 97 highlights the opportunities available to advance price reductions at the pump and their dependence on fast cost reductions. The examples in Figure 97 demonstrate that in cases with rapid decreases in capital and operations costs, there may be multiple options for the State to reduce pump price to parity or below at similar support amounts as the central $300M estimate. Some scenarios that push pump price below parity after 2030 demonstrate similar support amounts to scenarios that achieve price parity as early as 2025 but do not further reduce prices paid by the consumer. However, this possibility only appears in scenarios with fast cost reductions. Another option available may be a more modest acceleration of price parity to 2035, with continued reduction thereafter. This scenario has the potential for similar support amounts to scenarios without price parity acceleration and therefore may be more easily financed by industry.

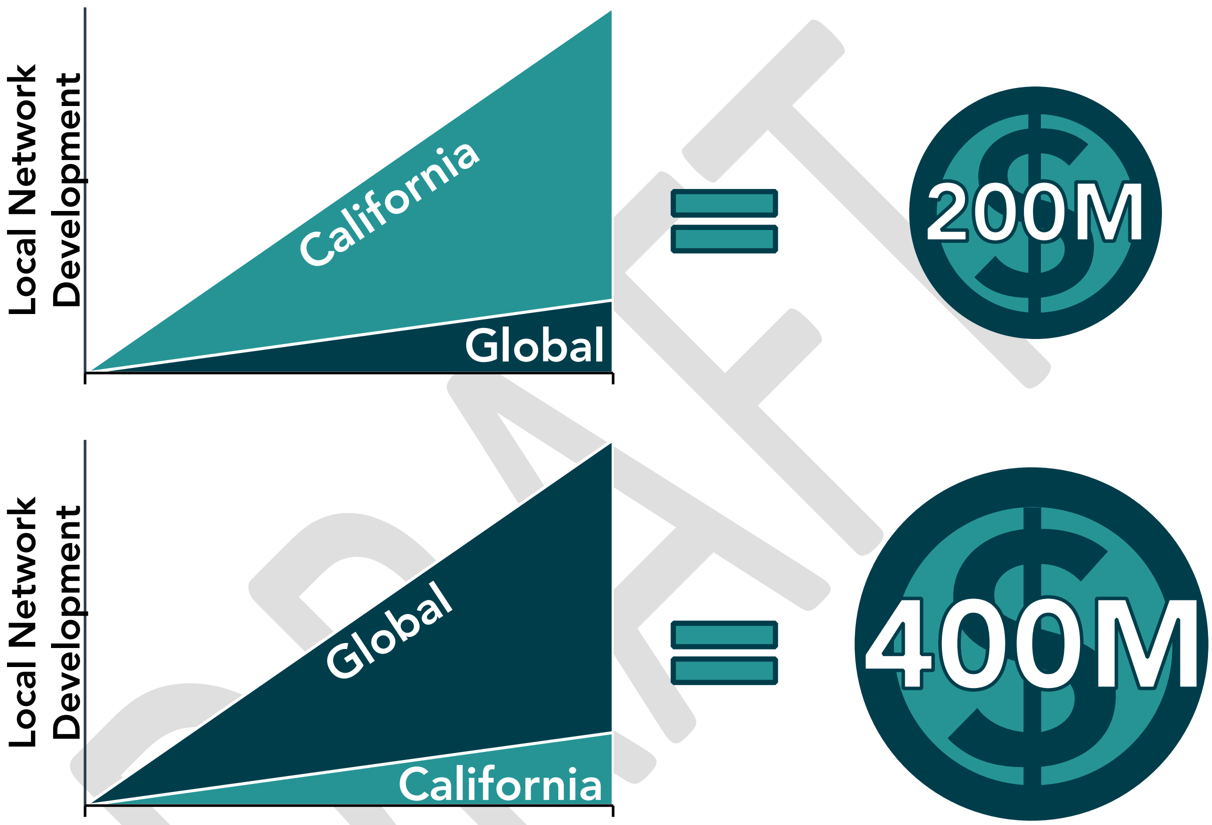
FIGURE 97: STATE SUPPORT MAY ENABLE ACCELERATED APPROACH TO HYROGEN PUMP PRICE PARITY WITH SUFFICIENT PACE IN COST REDUCTIONS



Operational costs reduce more quickly with faster in-state network development, implying that California's network growth provides greater benefit than global reductions in capital equipment costs.

Both capital and operational expenses have important implications for estimating the State support amount and self-sufficiency date. However, station and network cash flows are more heavily weighted towards operational expenditures than capital costs. Cost reductions for operations are most directly affected by local considerations, including the development of locally-available hydrogen fuel supply, cost reductions due to local network densification, and cost reductions due to higher utilization and hydrogen fuel sales. These considerations cannot be easily addressed by cost advances made in other regions outside of California. On the other hand, significant amounts of the capital equipment industry resides outside California and cost reductions for capital expenses may be reduced more readily by global market growth. Because of the larger influence of operational costs, station network buildout strategies that rely more directly on global technology and capital cost developments instead of local hydrogen station network growth actually have the potential to increase the State support amount needed to achieve self-sufficiency. Figure 98 demonstrates that a globally focused strategy may incur a State support amount that is as much as double the support needed with a more locally focused approach.

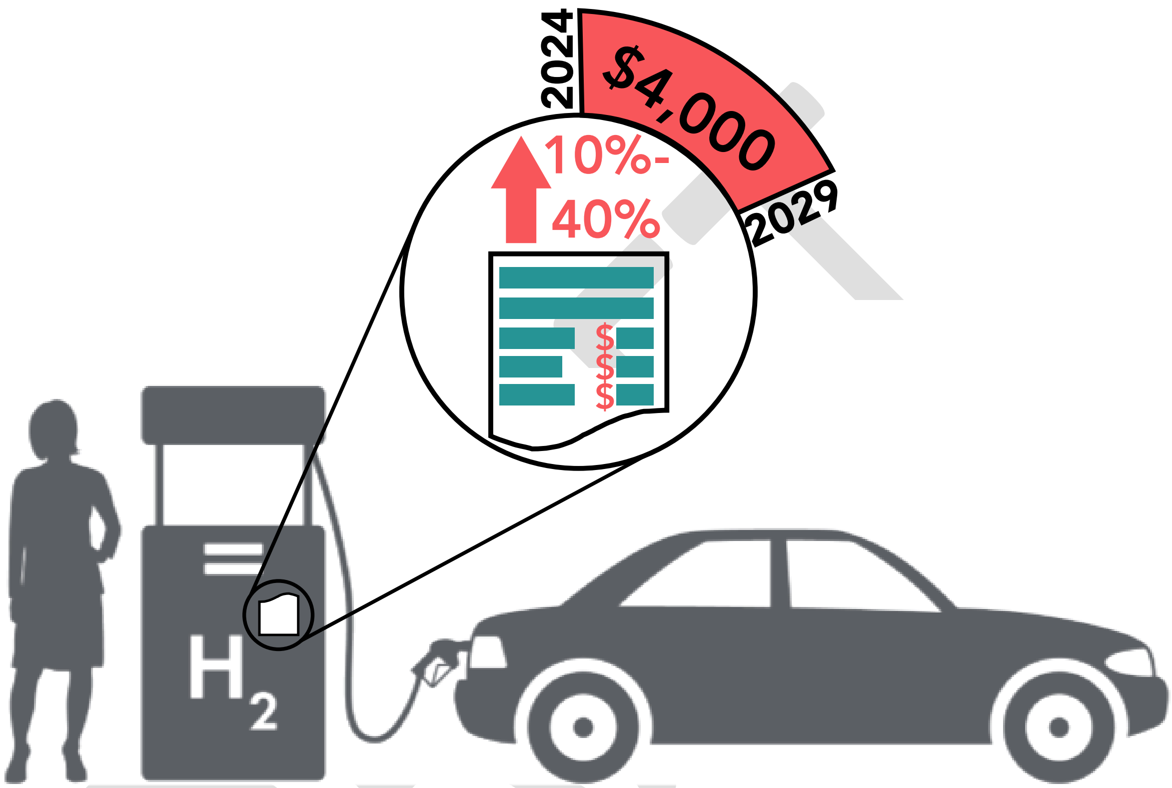
Figure 98: Impact on State Support Amount Incurred by California Waiting for Capital Equipment Cost Reductions Driven by Global Fueling Network Developments



Prices paid by the consumer can be significantly impacted by withdrawals of planned State support.

Much of the analyses in this study focus on economic performance of hydrogen fueling stations and the implications for station operators and potentially the State. However, financial support decisions made by the State may also have implications for consumers purchasing hydrogen fuel. If station network development is targeted to achieve self-sufficiency but State support is reduced before this goal is achieved, then additional financial burden may be passed on to the consumer. As Figure 99 shows, costs that are passed on to the consumer could result in an addition of as much as $4,000 to each consumer's fueling costs over a period of approximately five years of vehicle ownership. This occurs due to an increase in the sale price of hydrogen by 10 to 40 percent in order to recover the cash flow that would otherwise be supported by the State. This study demonstrates the importance of consistency between network development planning and State support programs

Figure 99: Additional FCEV Customer Fueling Costs from Reducing State Support Prior to Self-Sufficiency



The conclusions and analyses presented throughout this report provide an assessment of a wide range of possible scenarios that in most cases lead to the development of a self-sufficient hydrogen fueling network in California. Due to the large number of factors that can influence station economic performance and the range of uncertainty in future projections for these factors, no single value can absolutely determine the State support needed or timing to self-sufficiency. However, assessment of the possible values and their determining factors provides a range of estimates with reasonably high confidence. These estimates have been developed to meet the requirements within AB 8 of analyzing the state’s hydrogen fueling network development with respect to financial self-sufficiency. These results and conclusions may inform future deliberations of the appropriate form and magnitude of future State support beyond the budget and timeline provided by AB 8.

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Appendix: Station Development Data Tables

CAFCR Stations

Year	200 kg/day	350 kg/day	600 kg/day	900 kg/day	1,200 kg/day	1,600 kg/day	2,000 kg/day
2020	0	9	0	0	0	0	0
2021	0	9	0	0	0	0	0
2022	1	8	1	0	0	0	0
2023	1	7	2	0	0	0	0
2024	6	17	27	6	0	0	0
2025	6	17	22	11	0	0	0
2026	10	20	30	40	0	0	0
2027	10	20	20	40	10	0	0
2028	20	40	40	60	40	0	0
2029	15	15	30	30	60	0	0
2030	30	30	30	60	150	0	0
2031	8	8	17	33	66	33	0
2032	7	7	14	14	28	56	14
2033	7	7	7	13	34	40	27
2034	6	6	6	13	19	38	38
2035	6	6	6	12	18	25	49

CAFCR Early Stations

Year	200 kg/day	350 kg/day	600 kg/day	900 kg/day	1,200 kg/day	1,600 kg/day	2,000 kg/day
2020	0	9	0	0	0	0	0
2021	0	9	0	0	0	0	0
2022	1	8	1	0	0	0	0
2023	1	7	2	0	0	0	0
2024	18	55	91	18	0	0	0
2025	19	57	76	38	0	0	0
2026	18	36	53	71	0	0	0
2027	15	31	31	61	15	0	0
2028	15	29	29	44	29	0	0
2029	13	13	25	25	51	0	0
2030	16	16	16	31	78	0	0
2031	7	7	15	30	60	30	0
2032	7	7	13	13	27	53	13
2033	6	6	6	13	32	38	26
2034	6	6	6	12	18	37	37
2035	6	6	6	12	18	24	48

CAFCR Large Stations

Year	200 kg/day	350 kg/day	600 kg/day	900 kg/day	1,200 kg/day	1,600 kg/day	2,000 kg/day
2020	0	3	6	0	6	0	0
2021	0	3	6	0	6	0	0
2022	0	3	6	0	6	0	0
2023	0	1	6	0	7	0	0
2024	0	3	12	0	15	0	0
2025	0	5	14	0	23	5	0
2026	0	6	19	0	32	6	0
2027	0	7	20	0	26	13	0
2028	0	14	41	0	55	27	0
2029	0	11	21	0	42	21	11
2030	0	22	43	0	65	65	22
2031	0	14	29	0	43	43	14
2032	0	13	13	0	39	39	26
2033	0	13	13	0	25	50	25
2034	0	13	13	0	25	50	25
2035	0	12	12	0	12	47	35

BAU Stations

Year	200 kg/day	350 kg/day	600 kg/day	900 kg/day	1,200 kg/day	1,600 kg/day	2,000 kg/day
2020	0	9	0	0	0	0	0
2021	0	9	0	0	0	0	0
2022	1	8	1	0	0	0	0
2023	2	7	1	0	0	0	0
2024	1	5	0	0	0	0	0
2025	2	6	1	0	0	0	0
2026	3	11	2	0	0	0	0
2027	1	10	1	1	0	0	0
2028	3	20	3	3	0	0	0
2029	2	14	5	2	0	0	0
2030	4	22	9	4	4	0	0
2031	3	15	6	3	3	0	0
2032	3	10	5	5	3	0	0
2033	3	10	5	5	3	0	0
2034	3	10	5	5	3	0	0
2035	3	10	5	5	3	0	0